IEEE Guide for Control of Hydroelectric Power Plants

IEEE Power Engineering Society

Sponsored by the
IEEE Energy Development and Power Generation Committee

1010™

IEEE
3 Park Avenue
New York, NY 10016-5997, USA

18 August 2006

IEEE Std 1010™-2006
(Revision of
IEEE Std 1010-1987)

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Abstract: This guide serves as a reference document for practicing engineers in the hydroelectric industry. It documents prevailing industry practices in hydroelectric power plant control system logic, control system configurations, and control modes. It describes the control and monitoring requirements for equipment and systems associated with conventional and pumped-storage hydroelectric plants. It includes typical methods of local and remote control, details of the control interfaces for plant equipment, and requirements for centralized and off-site control.
Keywords: automation, control systems, hydroelectric, unit controls

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The Institute of Electrical and Electronics Engineers, Inc.
3 Park Avenue, New York, NY 10016-5997, USA

Print: ISBN 0-7381-4952-7 SH95530
PDF: ISBN 0-7381-4953-5 SS95530

Introduction

This introduction is not part of IEEE Std 1010-2006, IEEE Guide for Control of Hydroelectric Power Plants.

This document is a guide for the power industry for use in the design and understanding of control systems for hydroelectric power plants. The guide was prepared by the Working Group on Control of Hydroelectric Power Plants of the Hydroelectric Power Subcommittee of the IEEE Energy Development and Power Generation Committee of the IEEE Power Engineering Society (PES).

This guide was originally issued in 1988. Its origin was a direct result of efforts during the 1980s by the Working Group to investigate and document prevalent industry practices for controlling hydroelectric power plants in conjunction with associated application of systems and equipment for implementing these practices.

Since preparation of the 1988 guide, significant changes in control equipment and system technologies, coupled with their application, have occurred. Additionally, ongoing restructuring of the utility industry has imposed new criteria for plant availability and for optimizing a plant's operational costs and power production, in turn increasing the complexity of the control, supervisory, and monitoring functions of the plant control system. The purpose of this revision is to address these new requirements and to harmonize guidelines contained in this document with a subsequently issued companion document IEEE Std 1249™.[a]

This guide is intended to be used as a reference document for practicing engineers in the hydroelectric industry. Although termed a *guide*, it is basically a tutorial document that provides information on the various equipment and systems being controlled in a hydroelectric plant.

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

Participants

Members of this Working Group represent a cross section of the hydroelectric industry, including power plant owners, plant designers, equipment manufacturers, and academic personnel.

At the time this guide was revised, the Control of Hydroelectric Power Plants Working Group had the following membership:

John Yale, *Chair*

Katherine Blanchard	Randy Groves	Walt Pankratz
Steven R. Brockschink	James H. Gurney	Wayne Rand
Stuart Brown	Bob Handel	Larry Rodland
Horst Butz	Bob E. Howell	Alan Roehl
Matthew Davis	David L. Kornegay	Doug B. Seely
Don Evans	Lawrence Long	Philip Spotts
Russ Fostiak	Dieter Meyer	Winfried Stach
Tony Griffiths	Paul Micale	Bill Terry
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Since the initial publication, many IEEE standards have added functionality or provided updates to material included in this recommended practice. The following is a historical list of participants who have dedicated their valuable time, energy, and knowledge to the creation of this material:

Don McCabe, *Chair*

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Amir El-Sheikh	Gregory Luri	Shanmugan Thamilarasan
Gary Engmann	Paul Micale	John Yale

When the IEEE-SA Standards Board approved this standard on 30 March 2006, it had the following membership:

Contents

IEEE Guide for Control of Hydroelectric Power Plants

1. Overview

This document serves as a guide for the power industry by providing information on prevailing industry practices for the control of hydroelectric power plants. The guide discusses basic requirements and characteristics of hydroelectric power plant control systems, including architecture, reliability, redundancy, control level, location, and control modes. By its nature, this control is local to the hydro plant and generating units. For a complete perspective, centralized and off-site control and their specific requirements for hydroelectric plants are reviewed.

Requirements for control and monitoring of plant equipment are discussed, accompanied by block diagrams and detailed descriptions of the control and monitoring of major plant systems and equipment. Control of hydroelectric generating units is described with logic diagrams to show the flow and sequence of the control. This is done for the predominant types of conventional generating units as well as pumped-storage units.

1.1 Scope

This guide describes the control and monitoring requirements for equipment and systems associated with conventional and pumped-storage hydroelectric plants. It includes typical methods of local and remote control, details of the control interfaces for plant equipment, and requirements for centralized and off-site control. Where specific values are given for control parameters, they should be considered as typical.

This document does not address civil and structural details of hydroelectric power plants unless required for the understanding of certain control and monitoring functions. Also excluded is a detailed discussion of protective relaying systems, high-voltage switchyards, and navigational and flood control facilities associated with a hydroelectric plant.

Hydroelectric applications of variable frequency operation and high-voltage generation are not covered in this guide due to the specialized nature of these applications.

1.2 Purpose

This guide serves as a reference document for practicing engineers in the hydroelectric industry. It documents prevailing industry practices in hydroelectric power plant control system logic, control system configurations, and control modes. Implementation of the concepts described in this guide is covered in companion IEEE guides for control of hydroelectric power plants listed in Clause 2.

2. Normative references

The following referenced documents are indispensable for the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments or corrigenda) applies.

ANSI C50.10, American National Standard for Rotating Electrical Machinery—Synchronous Machines.[1]

IEC 60545:1976 (Rev 1.0), Guide for Commissioning, Operation, and Maintenance of Hydraulic Turbines.[2]

IEC 61116:1992, Electromechanical Equipment Guide for Small Hydroelectric Installations.

IEEE Std 421.1™, IEEE Standard Definitions for Excitation Systems for Synchronous Machines.[3, 4]

IEEE Std 421.4™, IEEE Guide for the Preparation of Excitation System Specifications.

IEEE Std 1020™, IEEE Guide for Control of Small Hydroelectric Power Plants.

IEEE Std 1046™, IEEE Application Guide for Distributed Digital Control and Monitoring for Power Plants.[5]

IEEE Std 1248™, IEEE Guide for Commissioning of Electrical Systems in Hydroelectric Power Plants.

IEEE Std 1249™, IEEE Guide for Computer-Based Control for Hydroelectric Power Plant Automation.

IEEE Std C37.101™, IEEE Guide for Generator Ground Protection.

IEEE Std C50.12™, IEEE Standard for Salient-pole 50 Hz and 60 Hz Synchronous Generators and Generator/motors for Hydraulic Turbine Applications Rated 5 MVA and above.

3. Definitions

For the purpose of this document, the following terms and definitions apply. *The Authoritative Dictionary of IEEE Standards Terms* [B2][6] should be referenced for terms not defined in this clause.

3.1 automatic control: An arrangement of controls that provide for switching or controlling, or both, of equipment in a specific sequence and under predetermined conditions without operator intervention after initiation.

3.2 centralized control: A control location one step removed from local control; remote from the equipment or generating unit, but still within the confines of the plant (e.g., controls located in a plant control room).

[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, 25 West 43rd Street, 4th Floor, New York, NY 10036, USA (http://www.ansi.org/).

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[5]IEEE Std 1046-1991 has been withdrawn; however, copies can be obtained from Global Engineering, 15 Inverness Way East, Englewood, CO 80112-5704, USA, tel. (303) 792-2181 (http://global.ihs.com/).

[6]The numbers in brackets correspond to those of the bibliography in Annex A.

3.3 computer-based automation: The use of computer components, such as logic controllers, sequence controllers, modulating controllers, and processors to bring plant equipment into operation, optimize operation in a steady-state condition, and shut down the equipment in the proper sequence under safe operating conditions.

3.4 control hierarchy: A systematic organization incorporating multiple levels of control responsibility.

3.5 control mode: A specific category of controlling a power plant.

3.6 control philosophy: The overall conceptual layout on which a power plant control system is based.

3.7 data acquisition systems: A system that receives data from one or more remote points. Data may be transported in either analog or digital form.

3.8 device (apparatus): An operating element such as a relay, contactor, circuit breaker, sensor, or switch used to perform a given function in the operation of electrical equipment.

3.9 local control: For auxiliary equipment, controls that are located at the equipment itself or within sight of the equipment. For a generating station, the controls that are located on the unit switchboard-governor control station.

3.10 logic (control logic): Predetermined sequence of operation of control devices.

3.11 manual control: Control in which the system or main device, whether direct or power-aided in operation, is directly controlled by an operator.

3.12 off-site control: Controls that are not resident at the plant (e.g., at a switchyard, another plant).

3.13 programmable logic controller (PLC): Digital control system with programming capability that performs functions similar to a relay logic system

4. Control system configuration

4.1 Introduction

Control system configurations for hydroelectric power plants have gone through an evolutionary development as advances in control system technology, new operating strategies for power plants, and increasing requirements for information on plant performance imposed new criteria on the plant control system. To develop basic concepts on control system configuration this clause addresses the following:

a) Hydroelectric power plant control system evolution
b) Basic control system concepts
c) Basic control functions
d) System architecture

4.2 Hydroelectric power plant control system evolution

Traditionally, control systems in a hydroelectric power plant (hydroelectric plant) are associated with the start and stop sequences for the unit, and for control of the unit's power, voltage, and frequency. With evolution of the utility industry, operation of a hydroelectric plant in today's environment requires power plant control systems with capabilities beyond those provided by the earlier traditional systems.

Historically, the architecture, complexity and functionality of a hydroelectric plant control-system was determined by the following:

a) Number, size, and type of turbine-generator unit

b) Type of plant (i.e., conventional or pumped-storage)

c) Type of plant auxiliary systems

d) Nature of operation (i.e., attended or unattended)

These criteria become more complicated when additional capabilities dictated by new power plant operating criteria are imposed on the plant control system (whether new or existing).

Examples of present day “non-traditional” control criteria include pumped-storage plants that add to the complexity of the controls with requirements for control systems capable of handling generating, pumping, and synchronous condensing modes of operation associated with these plants. Pumped-storage plants also require additional control equipment for starting equipment and phase reversing of the main leads in the pumping mode. Conventional and pumped-storage plants may also have operational requirements dictating a capability of “black starting” (i.e., starting the plant without the need for external power), adding another degree of complexity to the control system. Hydroelectric plants may include automatic control systems operated from an off-site location. This type of operation requires the use of supervisory control and a reliable communication link between the powerhouse and the off-site control point.

The bulk of the existing hydroelectric power plant inventory has been in service for many years. Control systems at older plants may have gone through several evolutions or changes in control philosophy and strategy. Consequently, the controls at an existing plant may be a mixture of manual and automatic systems, and hardware implementation a mixture of electromechanical relay logic and microprocessor-based digital logic control systems.

4.3 Basic control concepts

4.3.1 Control system basic design

4.3.1.1 General

An explanation of a basic control system is presented to help the reader to better understand this guide. The simplest form of control is known as *open-loop control*. The controller issues an action to the apparatus being controlled. No direct feedback is provided from the apparatus to the controller. Figure 1 illustrates this concept. There are few true open-loop control systems.

A much more common basic control system is closed-loop control. In this scheme, the controlled apparatus feeds data back to the controller, usually an error signal. The controller uses the error signal to modify the control action. In many cases, the error signal is visual, such as an operator observing a dial or gauge. A simple example of a closed-loop control scheme is shown in Figure 2.

4.3.1.2 Hydroelectric powerhouse control system scheme

For hydroelectric powerhouse control systems, it is convenient to portray the components of the control system in a vertically arrayed scheme. A typical array is shown in Figure 3.

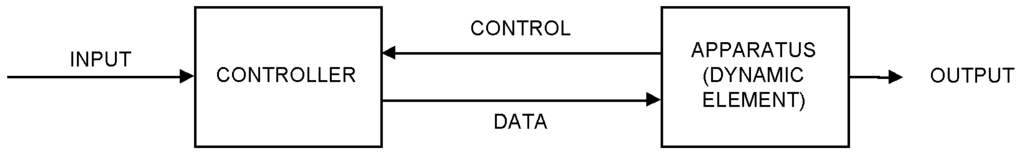

Figure 1—Open-loop control system

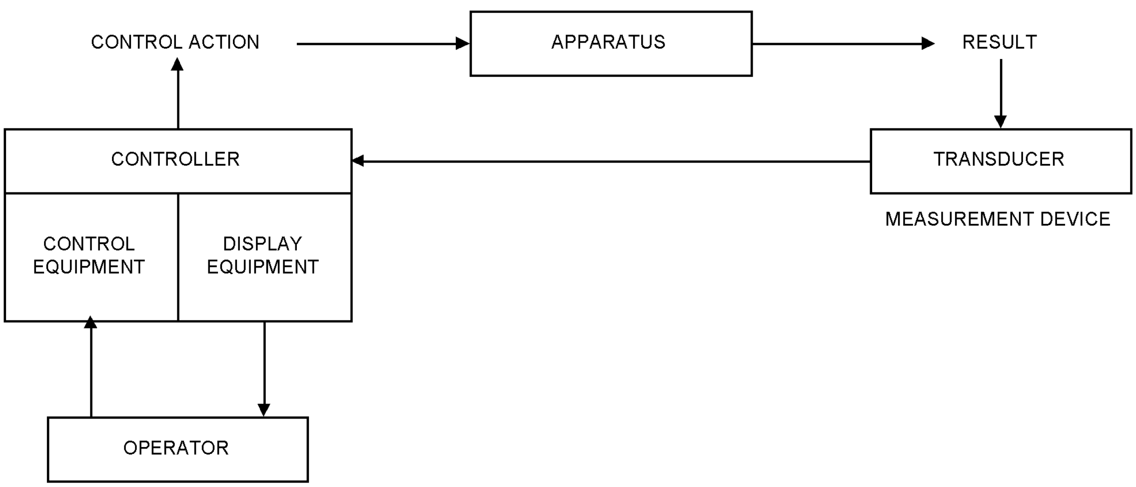

Figure 2—Closed-loop control system

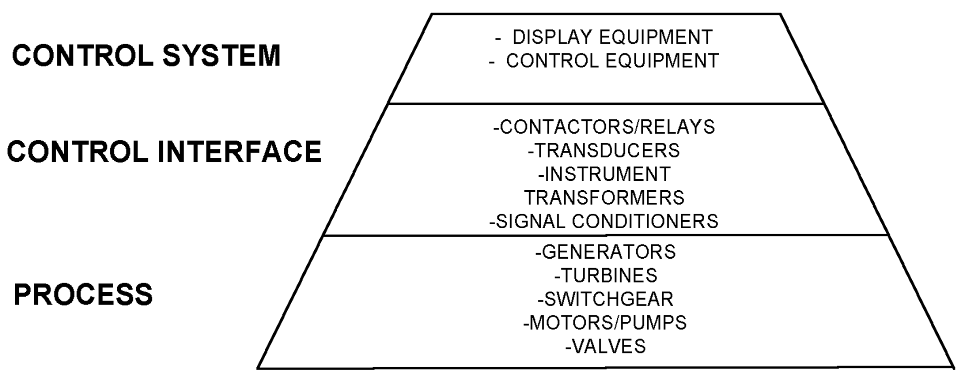

Figure 3—Control system vertical array

4.3.1.2.1 Process level

The lowest level of the vertical control scheme is the process being controlled. This includes the exciter, the hydraulic turbine, switchgear, pumps, valves, or other auxiliary powerhouse equipment.

4.3.1.2.2 Control interface level

The next level is the control interface equipment necessary to send control signals to the apparatus from the controlling equipment and for the apparatus to transmit data back to the controlling equipment. Auxiliary contacts of motor starters, relays, instrument transformers, signal conditioners, transducers, or other such equipment are typical examples of control interface equipment devices.

4.3.1.2.3 Control system level

The highest level is the controlling system that initiates the control signals and receives the data transmitted from the apparatus' control interface equipment. This level also includes appropriate human machine interfaces.

4.3.1.3 Typical hydroelectric powerhouse control system

Frequently, a generating unit's start, stop, reactive power, and active power are controlled by an operator working through a human-machine interface (HMI) to a control system. Figure 4 illustrates a typical HMI for a control system.

A typical scheme illustrating a vertical array controlling a powerhouse is shown in Figure 5. Multiple apparatus exist in this example. Though shown in Figure 5 as being on the same level, the apparatus may actually be nested and exist on several different levels.

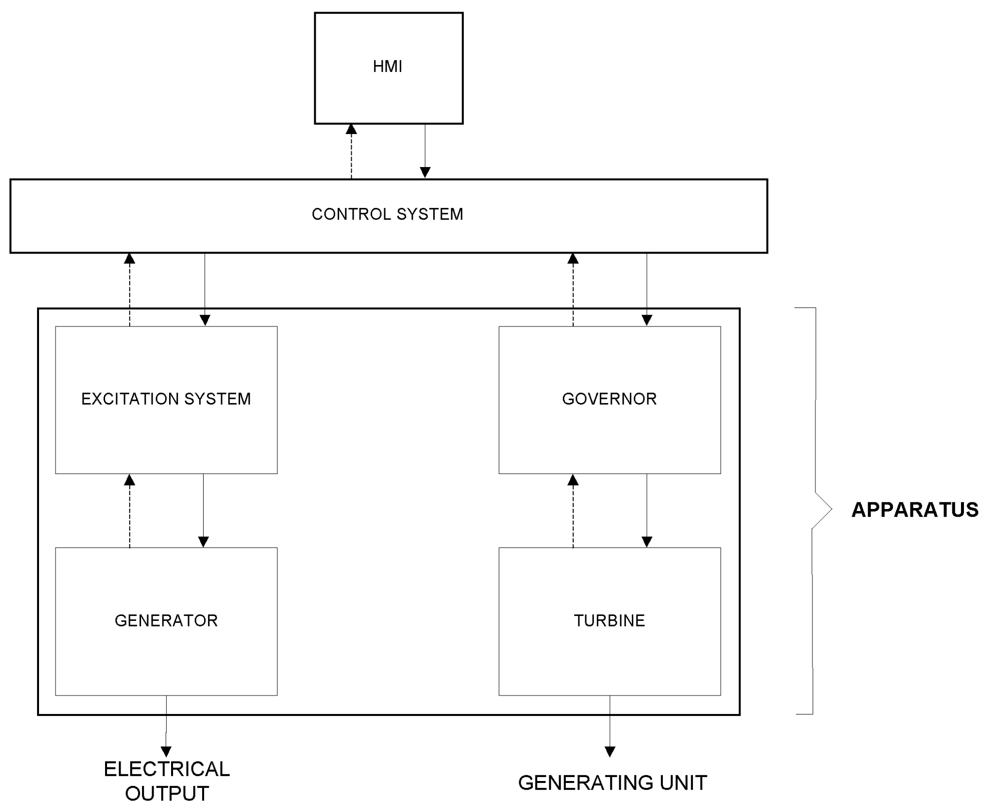

Figure 4—Typical HMI system interface

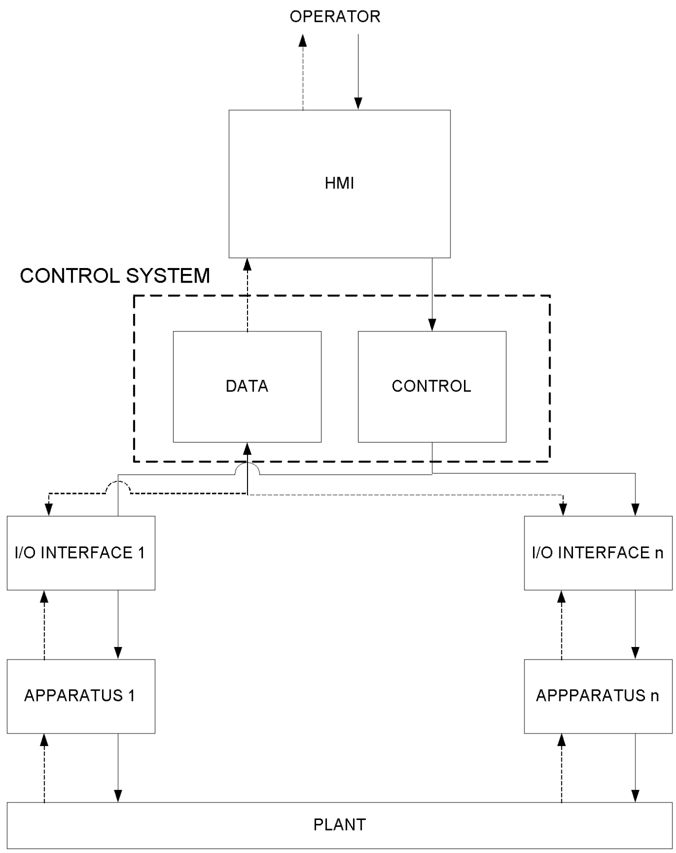

Figure 5—Typical control system arrangement

A hydroelectric turbine-generator is usually thought of as a generating "unit" but is comprised of several apparatus at different levels. The electrical generator is the device that produces the electricity, but the excitation system controls the voltage and reactive power. The prime mover for the generator is the hydraulic turbine that is controlled by the hydraulic governor. The governor controls the active power output of the unit.

4.4 Basic control functions

4.4.1 General

In a modern hydroelectric power station, almost all apparatus is connected with the plant's control system to allow operation in either manual or automatic mode. Most of the major apparatus (e.g., exciter, turbine, spillway gates) is equipped with electrically actuated control elements allowing it to work automatically. Many hydroelectric plants are controlled from off-site locations, and the automatic control systems facilitate unattended plant operation. Regardless of the type of plant operation, the following functions are common to all hydroelectric control systems:

a) Gathering of process information
b) Controlling the process
c) Protecting and supervising the process
d) Monitoring of process information

Figure 6 illustrates basic functions of a typical hydroelectric power plant control system.

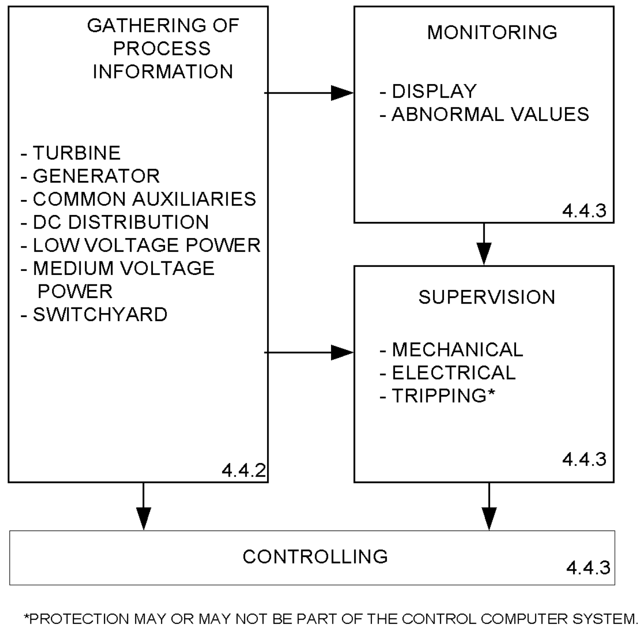

Figure 6—Functions of typical hydroelectric plant control system

4.4.2 Gathering of process information

Gathering and presentation of process information is an essential function of the control process. Process information can be gathered continuously or periodically and can consist of control parameters, status information, or feedback signals. For data gathered periodically, the sampling rate is dependent on the dynamics of the respective process signal.

Presentation of process information can be visual, recorded, audible, or a combination of all. Visual information formats include strip-chart recorders, analog and digital indicating instruments, video display units (VDU), lamp indicators or liquid crystal display (LCD) panels. Audible output is usually associated with a bell, gong, or tone alerting the operator to an alarm condition or message.

4.4.3 Controlling the process

The process information gathered serves two purposes. First, it is used by the automatic control system to perform appropriate control actions. Second, it allows the operator to operate the plant in a safe, reliable, secure, and economical manner. This requires ensuring the operator has the ability to start, stop, load, unload, and monitor the generating units and to control the plant's auxiliary systems including switchyards, water control structures, and other ancillary features associated with the project.

4.4.4 Protecting and supervising the process

4.4.4.1 General

The protection system is divided into two subcategories: the electrical protection system and the mechanical protection system. Electrical protection systems cover protection for major plant electrical apparatus and essential electrical auxiliary systems (e.g., generators, step-up transformers, station service electrical systems). Mechanical protection is usually confined to a generating unit's hydraulic turbine, generator, and major plant mechanical systems (e.g., turbine draft tube air depression system).

4.4.4.2 Electrical protection system

For safety and reliability, prevailing and recommended practice is to separate protective systems from control systems. Protective systems have progressed from systems comprised of specific-purpose electromechanical relays, to specific-purpose electronic analog relays, to contemporary multipurpose digital relays. Protective systems at many existing plants may be a mixture of all three relay types. Tripping commands from the protective relay system should bypass the automatic control system and operate directly on the shutdown circuits of the turbine and generator. In addition, they provide initiating signals for shutdown of related unit auxiliary systems. They also provide alarm signals to the plant annunciator or event recorder.

Multifunction digital relays, in addition to providing the same types of signals and initiating commands as discrete relay systems, may have serial or bus interface systems allowing connection to automatic control systems. These contemporary relays can provide time stamping, relay parameter setting, data trending, and other features such as diagnostics. Integration of the protective system with plant control systems is covered in succeeding subclauses.

4.4.4.3 Mechanical protection

Protection of “non-electrical” apparatus and systems in the plant are normally assigned to the plant control system. The control system generally provides tripping signals required for input to the plant protection system should any of the protected non-electrical systems or apparatus require removal from service.

4.4.4.4 Supervisory process

The supervisory process involves comparing plant and equipment operating values against limits. Typically, the control process monitors the four limit values shown in Table 1.

The supervisory process may also involve monitoring equipment status as well as limits. Whether equipment is on or off, or open or closed, may be incorporated into the supervisory process with consequential control actions. For instance, sequences like pump controls may be monitored to ensure safe and prudent functioning of the system. Another basic concept of the supervisory process is to have redundancy in the monitoring elements. Figure 7 illustrates the concept with a simple temperature monitoring system.

Table 1—Limit value monitoring

Monitored value	Control action
Too low	Trip
Low	Alarm
High	Alarm
Too high	Trip

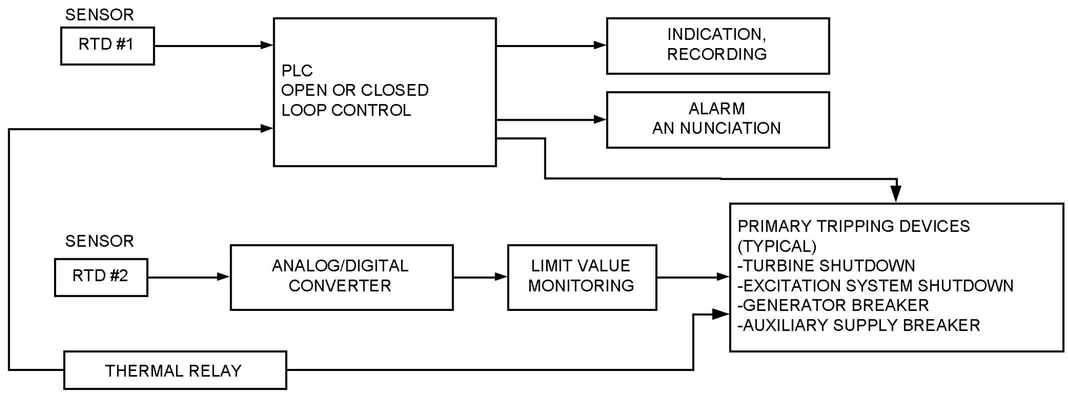

Figure 7—Redundancy in temperature monitoring system

Resistance temperature detector (RTD) #1 is connected to the control system, which performs control functions and monitors the limit values and provides alarm signals if a limit value is reached. Typical means for implementing this process is either through RTD recorders with alarm contacts (traditional) or as a function of a microprocessor-based programmable logic controller (PLC) (contemporary). RTD #2 in this example provides a tripping signal to the protection systems independent of the PLC. A third electromechanical device (e.g., thermal relay) backs up RTD #2 by also providing a tripping signal. Alternative means for providing such redundancy through automation systems are covered in companion guide IEEE Std 1249.[7]

4.4.5 Monitoring process

Instrumented values can be monitored using display devices at their respective control boards (e.g., turbine governor actuator cabinet, unit control board) or at a plant control switchboard. Analog and digital instrumentation, VDUs, and other devices mentioned in 4.4.2 are typical of the monitoring equipment. Some display units also permit manual unit control via touch screen.

4.5 System architecture

This guide describes hydroelectric power plant control system configuration in terms of a hierarchical, vertically arrayed control structure, which has been used in the industry through the years. This approach conforms to the control system logic developed in succeeding clauses. This approach may differ in the terminology, application, and technical issues from the contemporary automated control system described in IEEE Std 1249. However, this does not invalidate the application of the standard to existing systems or rehabilitation of existing systems. The two systems can coexist at the same hydroelectric project. For an in-depth discussion of architecture issues such as reliability, control system configuration, configuration trade-offs, and system capabilities as applied to hydroelectric automation systems, refer to companion document IEEE Std 1249.

4.5.1 General

The control system of a hydroelectric power plant can be defined by identifying three categories of control: location, control mode, and mode of operation. How these categories are assembled for a specific control system defines where it is in the general control hierarchy for hydroelectric power plants.

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

Hydroelectric industry practice is to describe control system configuration in terms of a hierarchical, vertically arrayed structure with the simplest and most basic controls at the lowest level in the array and the most sophisticated (and most remote) controls at the highest level. Industry practice is to describe a control system configuration by location and then mode. It can then be modified by defining the type of supervision (mode of operation). Since the staffing of a plant varies within the industry, it is difficult to define the supervision aspect generically. All combinations of location and mode are legitimate and more than one combination can exist at a plant. For example, a multiple unit plant can have local manual controls at the unit auxiliaries and the control switchboard. It can have a control room that would have both centralized manual and centralized automatic controls. It may even have equipment at the plant that would allow the capability of off-site automatic controls. The plant may also be unattended except for routine maintenance visits.

A general hierarchy of control can, therefore, be developed, going from those controls closest to the equipment and the least complex to the controls located off-site that are the most sophisticated. Typically, the lowest level control has priority. Starting from the lowest (most basic) level in the hierarchy and working to the highest (most sophisticated), the levels are as follows:

a) Local manual
b) Local automatic
c) Centralized manual
d) Centralized automatic
e) Off-site manual
f) Off-site automatic

A summary of this hierarchy is shown in Table 2. The preceding combinations can further be modified by appending either *attended* or *unattended* to them.

Table 2—Summary of control hierarchy for hydroelectric power plants

Control category	Subcategory	Remarks
Location	Local	Control is local at the controlled equipment or within sight of the equipment.
	Centralized	Control is remote from the controlled equipment, but within the plant.
	Off-site	Control location is remote from the project.
Mode	Manual	Each operation needs a separate and discrete initiation; could be applicable to any of the three locations.
	Automatic	Several operations are precipitated by a single initiation; could be applicable to any of the three locations.
Operation (supervision)	Attended	Operator is available at all times to initiate control action.
	Unattended	Operating staff is not normally available at the project site.

4.5.2 Control locations

The first category, *location,* is used to define where the controls are placed in relation to the equipment being controlled. More than one location of control can exist for a single piece of equipment, and the complement of equipment controls available at each location can vary. Location is defined as being local, centralized, or off-site.

4.5.2.1 Local

Local has a dual meaning and can be used with respect to the control's relation to either the generating unit or the auxiliary equipment. If local is being used in reference to the auxiliary equipment, it refers to the controls that are located at the equipment itself or within sight of the equipment. If local is being used in reference to the generating unit, it refers to the unit control system interface-governor control panel. The unit system may have controls that are not within sight of the auxiliaries being controlled, but usage of the term *local* in this respect is understood throughout the industry. Local control is synonymous with the most basic controls in the plant.

4.5.2.2 Centralized

Centralized denotes a control location that is one step further removed from local. It is removed from the equipment or generating unit and yet still within the confines of the plant. An example would be where controls for multiple units are brought to a control room within the powerhouse. The controls could be brought directly from the auxiliaries to the central location or could be incorporated with the unit-plant control system. The full complement of controls available locally need not be present at the centralized area.

4.5.2.3 Off-site

An *off-site* control location is one that is external to the plant. It could be located at the switchyard, at another plant, or at some other remote location. The term *remote* should not be confused with the term *off-site*. Remote can be understood to pertain to a control location distant from the actual equipment but still on-site. This type of control is characterized by a greater degree of sophistication in the controls themselves.

4.5.3 Control modes

After location, the second category of control that can be defined is the *mode* of control. Two types of control modes exist: manual and automatic.

4.5.3.1 Manual

Manual is the most basic control mode. It is characterized by the type of controls installed near or with the devices being controlled, such as pumps, compressors, valves, and motor control centers. The full complement of controls and indication may exist here, but it is more common to only provide a minimal control. Each operation needs a separate and discrete initiation. Manual control can be found in all three sublevels of the location category. It is more predominant in the local area but can be found in off-site systems of control such as control of high voltage power circuit breakers and high-voltage disconnect switches associated with the plant switchyard. Manual control finds use in commissioning, maintenance, or operational training procedures.

4.5.3.2 Automatic

Automatic is a level above the basic control mode. It is characterized by more sophisticated type of controls installed at both local and centralized locations. Automatic control is recognized by several operations being started or, consequently, precipitated by a single initiation. Examples can be found from the sequencing of unit auxiliaries for an automatic unit start, to the loading and balancing of multiple units in a plant. Both examples are initiated by a single operator command. The equipment to accomplish this ranges from simple relay logic to fully computerized automation systems. Automatic load dispatch and automatic generation control are examples of applications associated with fully computerized automation systems.

4.5.4 Control operation (supervision)

After the location and mode of control are defined, the manner in which the plant is supervised or staffed should be recognized. Though this aspect is not commonly addressed in industry-recognized labels for plant control, the equipment selection and its degree of automation is influenced by plant supervision. As the main point of control moves from the equipment to an off-site locale, the need for staffing and supervision at the lower levels of control diminishes. Supervision can, therefore, be described relative to the plant as either attended or unattended.

Attended. The plant is staffed 24 hours a day. The operator is available to perform control actions either locally or at a centralized area. Operators may staff the control location full time or may be roving throughout the plant or a local group of plants.

Unattended. The plant is not staffed for the full 24 hours a day. An operator may be present for a single shift or make a routine visit to the project. With the exception of small hydro, the policy throughout the industry is to have some form of supervision or monitoring at a given plant. If the plant's on-site control is defined as unattended, then it is implied that the supervision-monitoring is performed off-site. Unattended operation is represented by two predominant examples:

a) *Off-site supervisory control.* Here, control of the remote plant exists for all essential operations and a full complement of indications for the remote plant are brought to the off-site control location. Occasional visits by operation and maintenance people are made to ensure plant security.

b) *Off-site monitored control.* All of the controls for the plant are local. A representation of plant indication is brought to an off-site location where full attendance exists. The capability exists at the off-site location to dispatch an operator to the plant if conditions warrant. Routine maintenance visitations can also be made to the plant.

5. Control and monitoring of plant equipment

5.1 General

The control system receives input signals from main equipment such as the turbine, generator, governor, exciter, and auxiliary systems, such as motor control centers and the automatic synchronizer. Refer to Figure 8 for the major components of a hydroelectric unit. The control system receives status inputs from control, level, pressure, and other auxiliary switches, and analog inputs from transducers and other sensors. The control system provides outputs to start, operate or shut down the unit. Abnormal conditions indicated by the inputs should prevent the unit's start-up, or if already online, provide an alarm or initiate its shutdown or other protective measures.

Block diagrams illustrating controls for a large reaction-type hydroelectric unit are shown in Figure 9. For multiple unit sites, each unit should be equipped with a control interface located physically close to the individual units. A centralized control panel may be located in a control room. This guide is not intended to cover unit protection although the protective devices could be housed in cabinets or on panels associated with unit controls.

The unit control system interface should be designed to perform the following functions:

a) Data gathering and monitoring
b) Start-stop control sequencing
c) Annunciation of alarm conditions
d) Temperature monitoring
e) Metering and instrumentation

f) Event recording, when required
g) Synchronizing and connecting the unit to the system
h) Control of real and reactive power

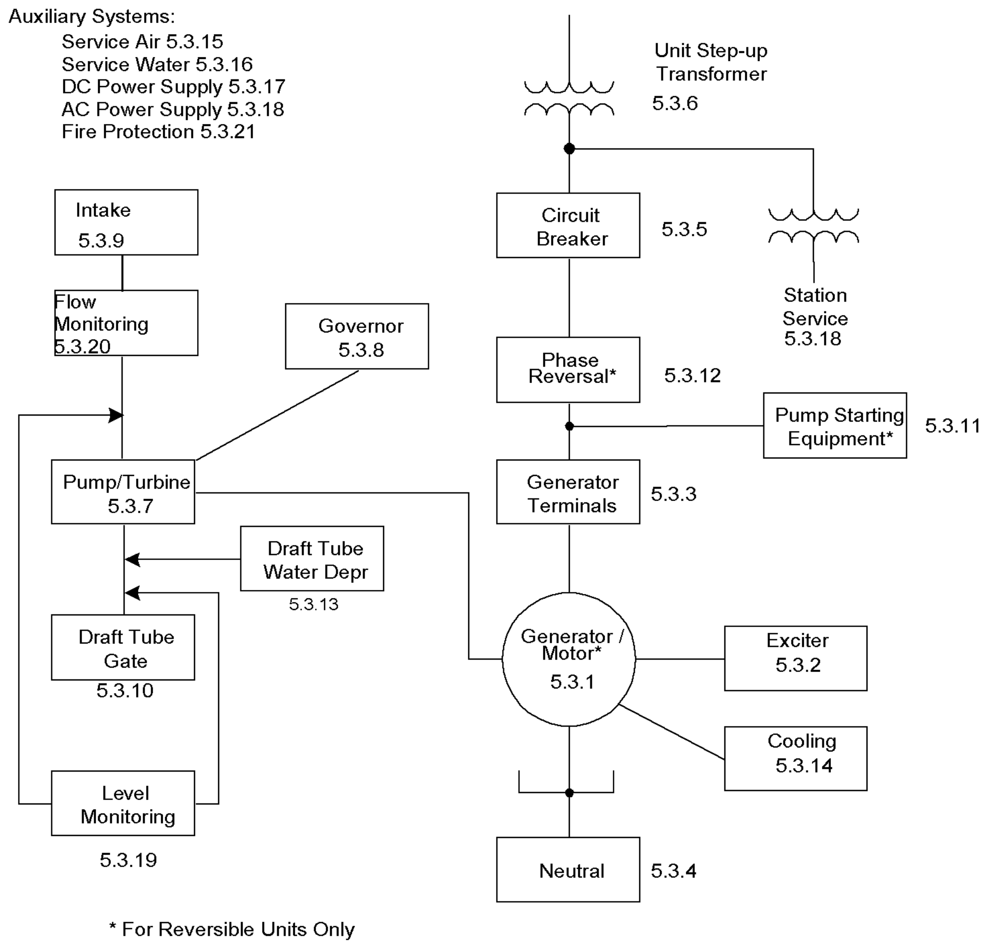

Figure 8—Major components of a hydroelectric unit with reference to descriptive subclauses

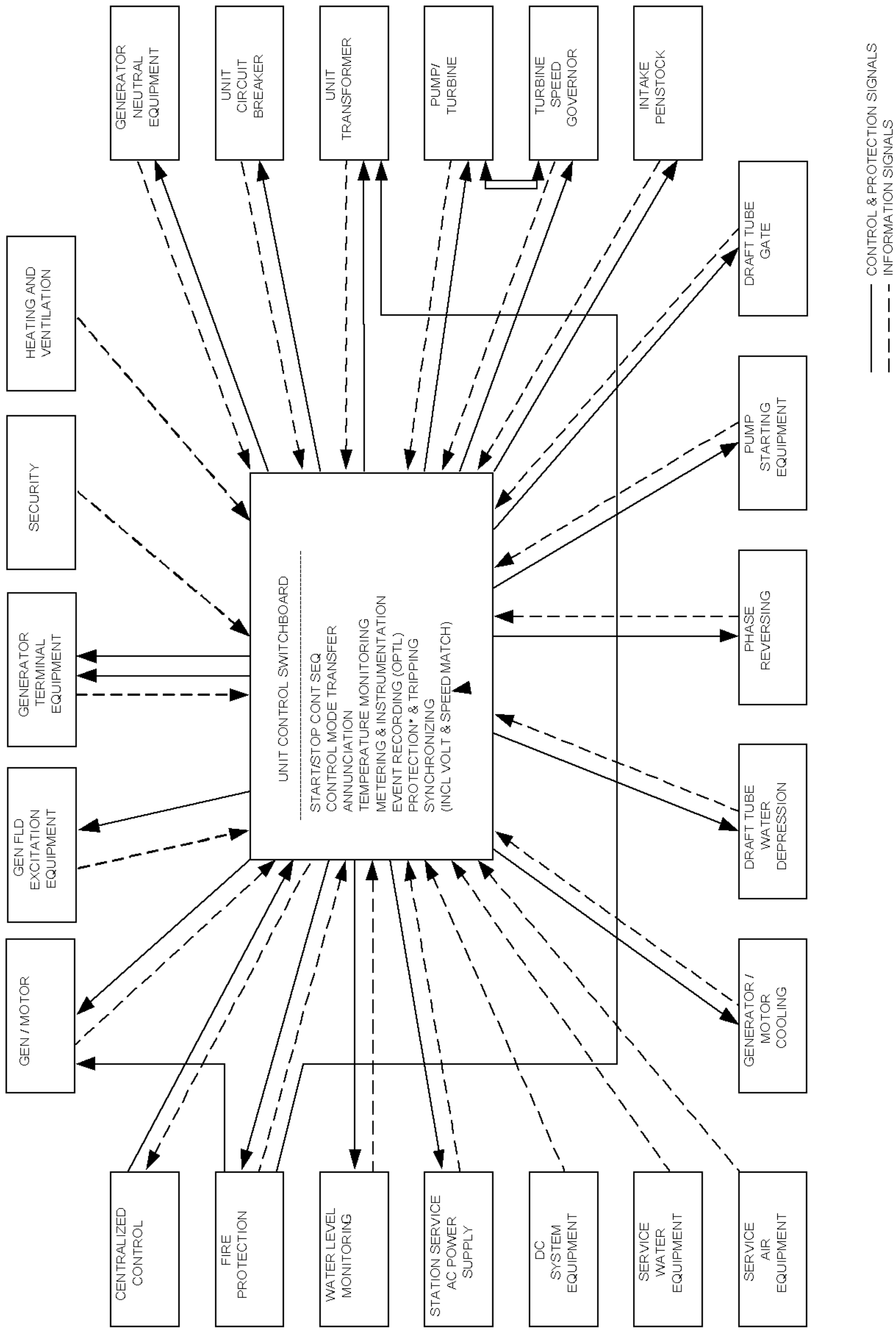

Figure 9—Controls for large hydroelectric unit—basic block diagram illustrating extent of controlled or associated equipment

5.2 Information and control signals

5.2.1 General

There are four types of signals that may be provided between the control board and any particular piece of equipment, as follows:

a) Analog inputs to transmit variable signals from the current transformers (CTs), voltage transformers (VTs), RTDs, thermocouples, pressure, flow, level, vibration, or other transducers.

b) Digital inputs (typically contact closures) to provide status or digitized values of variable quantities from the equipment.

c) Digital outputs to send command signals from the control board to the equipment.

d) Analog outputs to transmit variable signals from the control board to equipment, such as the governor, voltage regulator, etc.

5.2.2 Communications with control board

The communication links between the control board and the equipment should be adequate to transmit information and control signals. Data and control signals will be needed between the control board and each of the following unit equipment:

a) Generator neutral and terminal equipment

b) Headwater and tailwater level equipment

c) Water passage facilities (shut-off or bypass valves, gates, etc.)

d) Turbine or pump-turbine

e) Unit transformer

f) Circuit breaker and switches

g) Generator-motor

h) Intake gate (and/or inlet valve) and draft tube gate

i) Turbine speed governor

j) Generator excitation system

k) Synchronous condenser equipment

5.2.3 Communications with auxiliary equipment

Data and control signals will be needed between the control board and auxiliary systems and equipment. Figure 9 shows the interconnection of the following auxiliary equipment:

a) Fire protection

b) AC power supply

c) DC power supply

d) Service water

e) Service air

5.3 Control system interfaces

The following subclauses describe the characteristics of interfaces to the major equipment and systems.

5.3.1 Generator-motor

This subclause provides a guide for interfacing a typical generator-motor to the unit control system. The description is based on a vertical synchronous generator-motor with thrust bearing and one or more guide bearings. Horizontal and inclined axis units are similar with different bearing arrangements.

Interface points between the generator-motor and the unit control system are shown in Table 3 and Table 4. Connections between the generator-motor and the station service equipment are shown in Table 5.

Signal designators shown in the tables and figures are in common practice.

Table 3—Control and status data transmitted from generator-motor to unit control system

Signal	Description	Type[a]	Notes
26GS	Stator winding temperature	T, A, P	Temperature detectors (typically 12) embedded in stator winding. Two hottest RTDs connected to thermal overload relay 49G.
38THT	Thrust bearing temperature	T, A, P	Temperature detectors embedded in wells in the shoes or segments with provision for interchanging sensors between segments.
38GT	Guide bearing temperature	T, A, P	Temperature detectors. Provision for mounting sensors in all segments.
38QB	Bearing oil temperature	T, A, P	Temperature detectors in each separate bearing oil reservoir.
26AO	Air cooler outlet air temperature	T, A	Temperature detectors. (Quantity dependent on number of coolers and desired level of coverage.)
26AI	Air cooler inlet air temperature	T, A	Temperature detectors. (Quantity dependent on number of coolers and desired level of coverage.)
26GF	Generator field temperature	T, A, P	Temperature monitoring system for continuously monitoring field temperature.
71QBH	Bearing oil level high	A	One sensor for each separate oil reservoir often equipped with direct reading visual indicator.
71QBL	Bearing oil level low	A	One sensor for each separate oil reservoir often equipped with direct reading visual indicator.
38QW	Bearing water contamination detector	A	One sensor in each separate oil reservoir, for detection of water buildup or emulsified oil.
39V	Bearing-shaft vibration detector	A, P	Detectors installed near the guide-bearing segments at 90 degrees to each other, for detection of equipment defects and rough zone operation. Used in conjunction with probes on turbine guide bearing.
63QTH	Thrust bearing high-pressure oil system start interlock-failure alarm	C, A, I	Pressure switch provides confirmation that the oil pump motor has established sufficient pressure to allow the start sequence to proceed. Used also to generate alarm if pressure fails to establish after pump is commanded to start.
CPD	Combustion products detectors	A	Several ionization detectors located in air cooler outlet air stream and in other areas of the generator housing.

Table 3—Control and status data transmitted from generator-motor to unit control system *(continued)*

Signal	Description	Type[a]	Notes
26G	Temperature detectors for fire protection system	P, C, A	Fixed temperature or rate-of-rise of temperature or both; detectors mounted in stator end turn area. Used to initiate fire extinguishing system in conjunction with fault detecting equipment.
63FG	Fire extinguishing system operation	P, A	Pressure switches installed downstream of actuating valve. Back trips generator protection. May also be used to generate an extinguishing system failure alarm if system is initiated but pressure fails to establish within a fixed time.
33AB	Air brake position indication	C, I	Start interlock indicating all brake shoes have cleared runner plate.
33CW or 80CW	Cooling water valve position	C, I	Position, pressure, or flow switch provides confirmation that cooling water is available to coolers. Start interlock and status indication.
CT-SP	Split phase or current unbalance CT	P, I	Double window split phase CTs or single window CT in each parallel circuit for protection against bar-bar faults within a parallel circuit or parallel-parallel faults in one phase. Split phase currents can also be monitored to determine changes in the air gap profile.
CT-G	Neutral end and terminal end CT	P, I	Furnished in quantities and ratings compatible with the metering and primary-standby protection requirements.

[a]Type: C = control; P = protection trip; A = annunciation—event recording; T = temperature monitoring; I = indication (analog, digital, status lamps).

Table 4—Control and status data transmitted from unit control system to generator-motor

Signal	Description	Type[a]	Notes
2THS	Thrust bearing high-pressure oil pump start-stop command	C	Start pump prior to starting unit. Confirmation of pump starting via 63QTH.
20CWS	Generator cooling water system start-stop command	C	Open valve or start pump prior to starting unit. Confirmation of water flow via 33CW or 80CW.
20FGS	Fire extinguishing system operate command	C, P	Open valve upon detection of fault and excessive heat. Confirmation of valve operation via 63FG.
20AL	Air louver operate command	C, P	Close discharge and inlet air louvers in generator housing in event of a fire.
1GL	Generator lube oil system start-stop command	C	Enables generator lubrication prior to unit run.
1CF	Cooling fan start-stop command	C	When forced air cooling is used for the generator.
1SH	Unit housing heaters on-off	C	Turned off when unit is online.

[a]Type: C = control; P = protection trip.

Table 5—Operating power, air, and water from service equipment to generator-motor

Description	Type[a]	Notes
Power supply for thrust bearing high-pressure oil pump	AC	May be fed alternatively from dc source.
Power supply for dc control circuits	DC	For uninterruptible systems such as air cooler temperature control system, fire protection.
Air supply for brakes and rotor jacking system	A	Control valve may be located in governor cubicle.
Water supply for fire extinguishing system	W	May also be atomized.
Power supply for generator housing space heaters	AC	Thermostatically controlled, for reducing condensation on windings when generator is shut down.
Water supply for generator air coolers and bearing oil coolers	W	
Air supply for operating discharge and inlet air louvers	A	
Power supply for $C0_2$ fire extinguishing system	DC	
Power supply for generator lube oil system	AC	May be fed alternatively from dc source.

[a]Type: AC = ac power; DC = dc power; A = air; W = water.

5.3.2 Generator field excitation equipment

This subclause provides a guide for interfacing the excitation system to the unit control system. The description is based on the use of a potential source-controlled rectifier-high initial response (PS-CR-HIR) excitation system. This is the most common type of excitation system presently being specified for large generators.

A typical PS-CR-HIR excitation system is shown in Figure 10. Interface points between the excitation system and the unit control system and between the excitation system and the station service equipment are detailed in Table 6, Table 7, and Table 8.

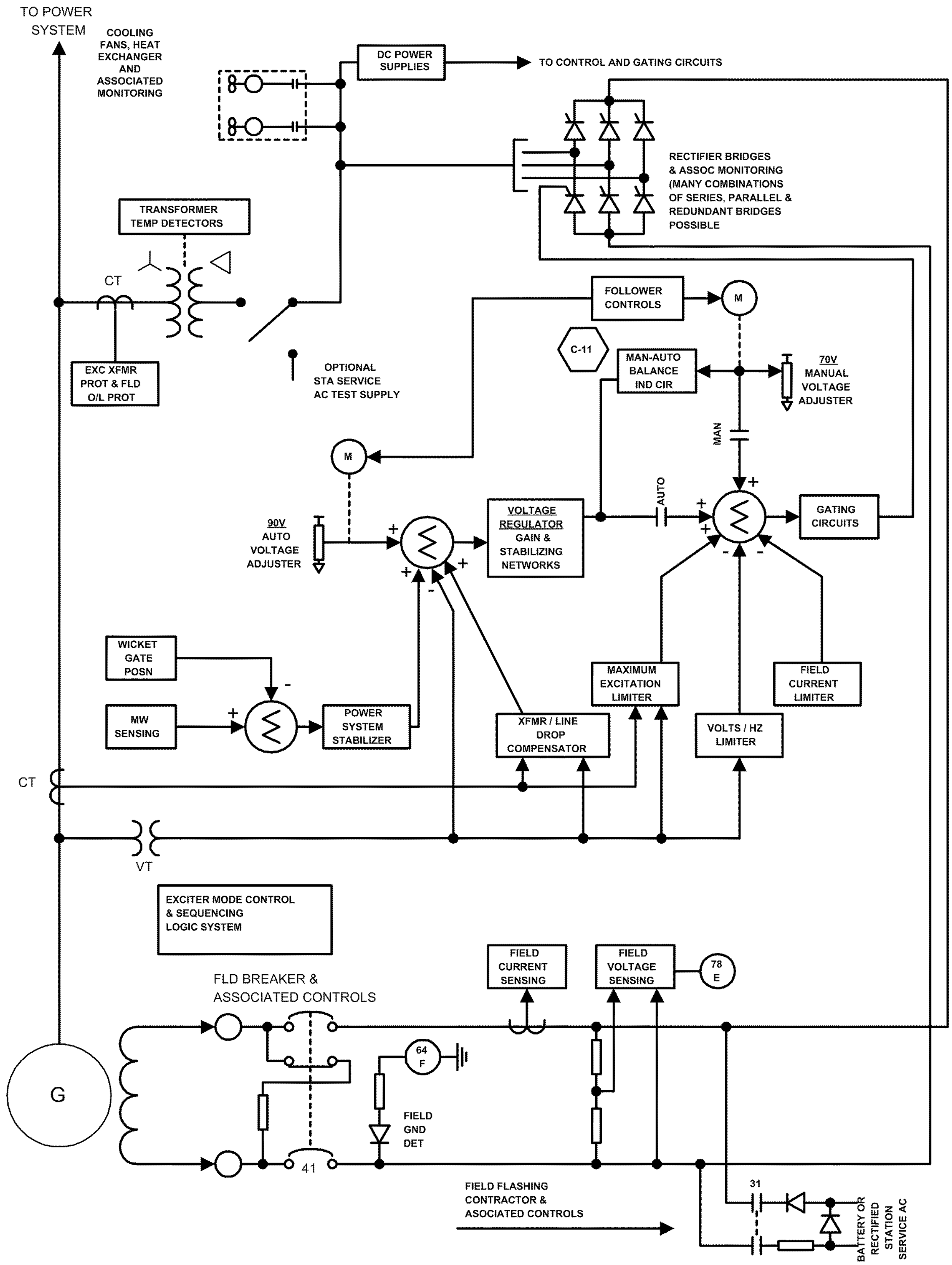

Figure 10—Typical potential source-controlled rectifier (high initial response excitation system) block diagram

Table 6— Control and status data transmitted from excitation system to unit control system

Signal	Description	Type[a]	Originating device at exciter	Notes
51ET	Exciter transformer o-c protection	P	C-2	Set to coordinate with field winding thermal characteristic.
49GF	Field overload protection	P or A	C-2 or C-3	Transduced from DCCT (saturable reactor).
If	Field current indication	I	C-3	
Vf	Field voltage indication	I	C-7	
64F	Field ground detection	P or A	C-8	
27FF	Failure of preferred field flashing source	A	C-9	Provision of this alarm assumes two sources provided, ac and dc. AC should be preferred source to minimize chance of backfeeding field voltage onto battery if blocking diode fails. Automatic transfer to alternate source on failure of preferred source.
41-a, b	Field breaker position	C, I	C-12	
31-a, b	Field flashing contactor position	I	C-9	
48E	Exciter start sequence incomplete	P, A	C-13	Set to operate after normal time required for field flash source to build terminal voltage to level sufficient for exciter gating to commence.
78E	Pole slip protection	P	C-7	
63F-1	Cooling fan failure—Stage 1	A	C-14	Failure of redundant fan(s).
63F-2	Cooling fan failure—Stage 2	P	C-14	
27PS	DC power supply failure	P or A	C-15	Trip or alarm depending on level of power supply redundancy.
26ET-1	Exciter transformer over temperature—Stage 1	A	C-1	
26ET-2	Exciter transformer over temperature—Stage 2	P	C-1	
58-1	Rectifier failure—Stage 1	A	C-16	Thyristor fuse, conduction, or gating failure.
58-2	Rectifier failure—Stage 2	P	C-16	
49HE	Heat exchanger failure	A	C-14	Various heat exchanger arrangements are possible; e.g., once-through, closed system.

Table 6— Control and status data transmitted from excitation system to unit control system *(continued)*

Signal	Description	Type[a]	Originating device at exciter	Notes
26RTD	Exciter transformer temperature indication	I	C-1	Temperature detectors. Quantity variable depending on number of secondary windings and whether transformer is 3 phase or 3 × 1 phase.
70V	Manual voltage adjuster with position indication	I	C-4	
90V	Auto voltage adjuster with position indication	I	C-5	
	Voltage regulator set point at preset position	C	C-4	Interlock in start sequence,
89LS	Station service ac test supply switch position	I	C-6	Optional.
MAN-AUTO balance	Indication of mismatch between auto voltage regulator output and manual voltage set point	I	C-11	To ensure bumpless transfer from AUTO to MAN and MAN to AUTO.
	Field temperature	I		Calculated field temperature.

[a]Type: C = control; P = protection trip; A = annunciation—event recording; T = temperature monitoring; I = indication (analog, digital, status lamps).

Table 7—Control and status data transmitted from unit control system to excitation system

Signal	Description	Type[a]	Originating device at exciter	Notes
41 protective trips	Field breaker tripping from generator protection	P	C-12	May not use a field breaker, initiates exciter shutdown.
41 control trips	Field breaker tripping from manual control and unit shutdown sequence logic	C	C-12	
41 close	Field breaker closing from manual control and unit start sequence logic	C	C-12	
1E	Exciter start	C	C-9, C-13	Close contact to initiate field flashing at 95% speed during auto start or under manual control.
1E	Exciter de-excite	C	C-13	Open contact to initiate phase-back below 95% speed, unit separated from system.
83VT	Voltage transformer potential supervision	C	C-13	Transfer exciter from auto voltage control to manual control.
43VM	Close contact to transfer exciter to manual voltage control	C	C-13	
43VA	Close contact to transfer exciter to auto voltage regulator control	C	C-13	
AVR runback logic	Set automatic voltage regulator (AVR) to preset position in preparation for unit starting	C	C-4	
MVR runback logic	Set manual voltage regulator (MVR) to preset position in preparation for unit starting	C	C-5	
70V raise	Raise manual voltage adjuster	C	C-4	
70V lower	Lower manual voltage adjuster	C	C-4	
90V raise	Raise auto voltage adjuster	C	C-5	
90V lower	Lower auto voltage adjuster	C	C-5	
52G-a	Generator CB auxiliary switch	C	C-10, C-13	De-excite control, disable power system stabilizer off-line.
Wicket gate position	Analog signal representing wicket gate position	C	C-10	Used to develop accelerating power input to PSS if required.

[a]Type: C = control; P = protection trip; A = annunciation—event recording; T = temperature monitoring; I = indication (analog, digital, status lamps).

Table 8—Operating power, air, and water from service equipment to excitation system

Description	Type[a]	Destination at exciter	Notes
Station service ac test supply	AC	C-6	Used for exciter testing and emergency operation if exciter transformer out-of-service (optional).
Battery-fed field flashing source	DC	C-9	
Station service field flashing source	AC	C-9	AC preferred source. Auto transfer to dc if ac not available.
Cooling water supply for heat exchanger	W	C-14	

[a]Type: AC = ac power; DC = dc power; A = air; W = water.

5.3.3 Generator terminal equipment

This subclause provides a guide for interfacing information obtained from the generator to the unit control system and operating power, air and water service equipment. (See Table 9, Table 10, and Table 11.)

The major part of this information is standard practice and should be considered common for any generator terminals. However, some specific units may need additional or different information (signals) to be transmitted depending on the type of equipment that is used. (Refer to Figure 11.)

Table 9—Control and status data transmitted from generator terminal equipment to unit control system

Signal	Description	Type[a]	Originating device	Notes
CT	Current signal for relaying and metering		CT	
VT	Voltage signal for relaying and metering		VT	
A	Current indication	I	CT	
F	Frequency indication	I	VT	
V	Voltage indication	I	VT	
W-VAR	Metering	I, A	CT & VT	Analog signals for indication and/or recording.
AVR	Voltage signal for AVR	C	VT	Analog signal from a VT.
63	Pressure relay in the closed-loop forced air cooled isolated phase bus duct, if used	A, P	Bus duct	

Table 9—Control and status data transmitted from generator terminal equipment to unit control system *(continued)*

Signal	Description	Type[a]	Originating device	Notes
49	Thermal device to service air or bus temperature	A, T	Bus	Temperature detector embedded in the hottest location of the phase. It could back up pressure differential devices (trip optional).
N	Governor speed sensing	C	VT	May be used in lieu or in addition to direct shaft speed sensing by the governor.
XDCR	Power transducer	C	CT & VT	Unit power input to electric governor-control system.

[a]Type: C = control; P = protection trip; A = annunciation—event recording; T = temperature monitoring; I = indication (analog, digital, status lamps).

Table 10—Control and status data transmitted from unit control system to generator terminal equipment

Signal	Description	Type[a]	Notes
20	Fire extinguishing system command	C, P	Deluge valve open upon differential operation and high temperature detection.
80	Forced air bus duct cooling control start-stop	C	External controls to start-stop forced air cooling are associated with the generator breaker (closed-open) and generator connected to the system (ON-OFF).

[a]Type: C = control; P = protection trip.

Table 11—Operating power, air, and water from service equipment to generator terminal equipment

Description	Type[a]	Notes
Power supply from dc control circuits	DC	For uninterruptible systems such as fire protection.
Power supply for forced air bus duct circulation system	AC-DC	
Water supply for fire extinguishing system and forced air cooling	W	

[a]Type: AC = ac power; DC = dc power; A = air; W = water.

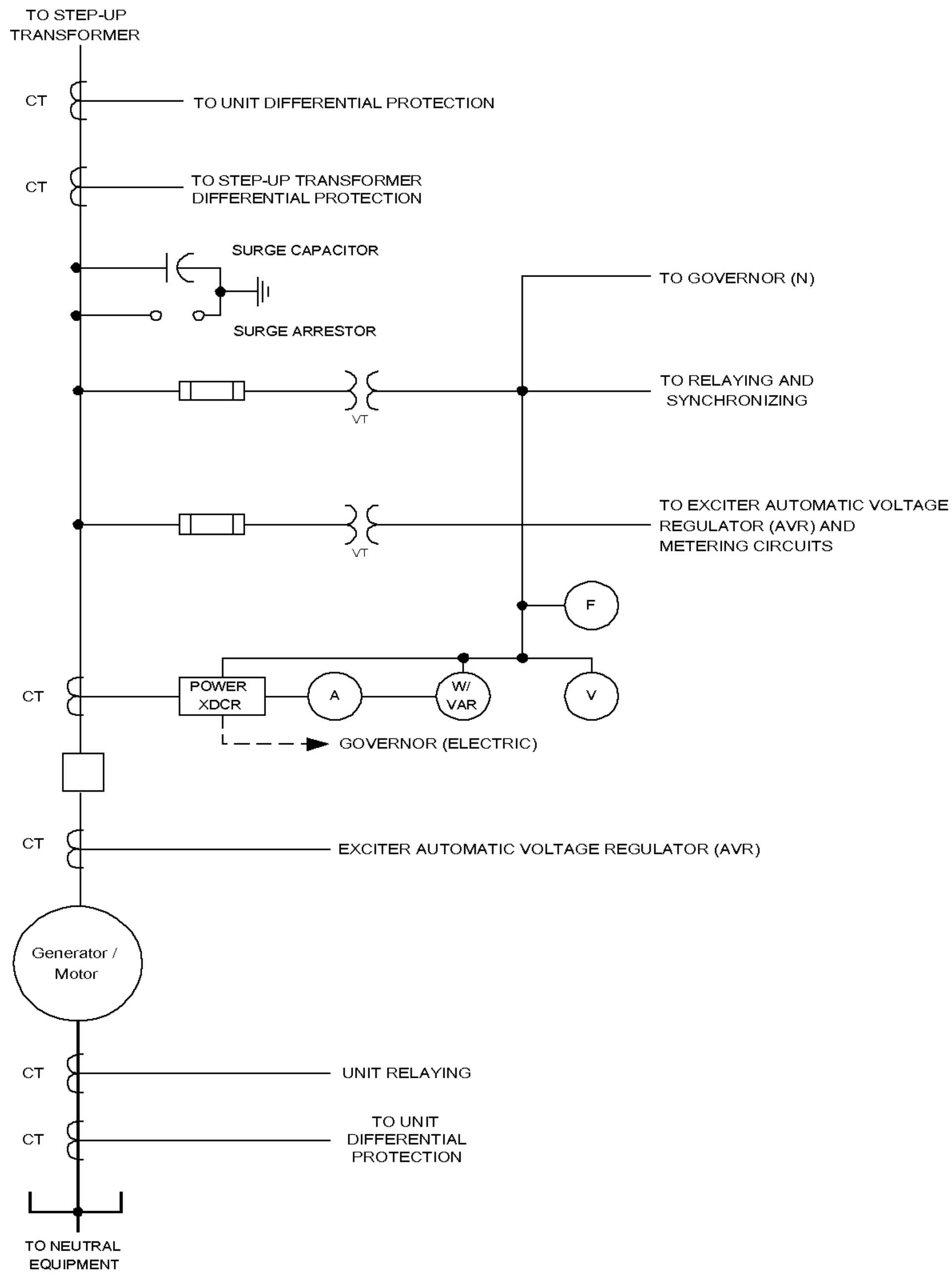

Figure 11—Typical hydro generator terminal

5.3.4 Generator neutral equipment

The generator neutral equipment needed for the various methods of neutral grounding is determined by the amount of phase-to-ground fault current that is allowed to flow. Due to the relatively low zero sequence impedance in most synchronous machines, a phase-to-ground fault results in much higher winding current than a 3-phase fault. Therefore, a neutral impedance should be provided to limit this current and the resulting damage to the generator under these conditions.

When static starting systems are used for pumped-storage units, a capacitive grounding system may be needed in addition to conventional grounding to limit circulating dc ground current.

Neutral impedance to ground can be provided by the following methods:

a) Grounding transformer in generator neutral with secondary resistance or impedance
b) Neutral resistor
c) Ground fault neutralizer
d) Grounding transformer (i.e., zigzag bank) on the generator bus, with secondary resistance or impedance

The application of these methods is affected by the electrical configuration of the station, the number of generators, the number and method of switching of the main voltage bus, and the owner's protection philosophy.

Approved grounding methods are covered in detail in IEEE Std C62.92.1 [B6].

IEEE Std C37.101 will also aid in the application of relays and relaying schemes for the protection of synchronous generators for single phase-to-ground faults in the stator winding. The various protective schemes as well as alternative methods of protection for the most commonly used generator connections and grounding practices are covered.

5.3.5 Unit generator breaker equipment

This subclause provides a guide for interfacing the generator breaker control to the unit control and protection system.

A typical, large hydroelectric generator station to a generator breaker interface is shown in Figure 12. Interface points between the generator breaker equipment and the unit control system are detailed in Table 12 and Table 13.

Table 12—Signals transmitted from plant equipment to generator breaker

Signal	Description	Type[a]	Notes
4	Unit control master relays	C	Normal shutdown.
1XJ	Breaker control switch, trip-close	C	
12G	Generator overspeed	P	
25	Synchronizing equipment	C	
33	Wicket gate position switch	C	Permissive switch.
38GB	Generator bearing temperature	P	
38TB	Turbine bearing temperature	P	
43XJ	Breaker test switch	C	
49T	Step-up transformer over temperature	P	
63T	Step-up transformer sudden pressure	P	
71K	Kaplan low oil	P	
80TBQ	Turbine bearing oil	P	
38G	Generator winding temperature	P	
43S	Unit synchronizing selector switch	C	Permissive switch.

[a]Type: C = control; P = protection trip.

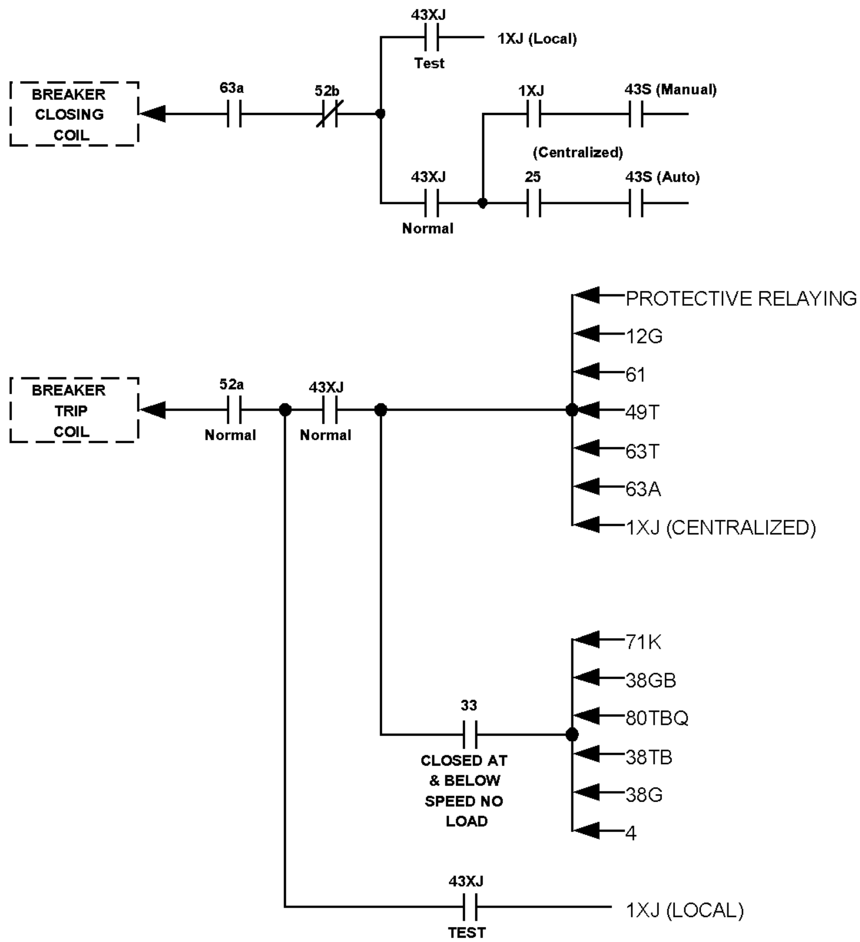

Figure 12—Typical hydro generator breaker interface diagram

Table 13—Signals transmitted from generator breaker to unit control system

Signal	Description	Type[a]	Notes
52a, b	Breaker open-close	C, I	
27CB	Generator breaker loss of dc control power	A	
61	Generator breaker pole failure	P, A	Trip to isolate breaker.
63a	Breaker air or gas pressure switch	C	Permissive switch.
63A	Generator breaker low air or gas pressure	P, A	Trip blocking.

[a]Type: C = control; P = protection trip; A = annunciation—event recording; T = temperature monitoring; I = indication (analog, digital, status lamps).

5.3.6 Unit step-up transformer

This subclause provides a guide for interfacing information between the unit step-up transformer and the unit control system. (See Table 14, Table 15, and Table 16.)

The major part of this information is standard practice and should be considered common for any step-up unit transformer. However, some specific units may need additional or different information (signals) to be transmitted depending on the type of equipment that is used. The description is based on the assumption that tap changer position indication would normally not be provided at any location remote from the transformer site.

Table 14—Control and status data transmitted from transformer to unit control system

Signal	Description	Type[a]	Originating device	Notes
CT	Current signal for relaying and metering	A, P, I	CT	
71G	Gas accumulation detection	A	Transformer Tank	Event recording (optional).
63G	Gas pressure device	A, P	Transformer tank	Event recording.
63Q	Main tank sudden pressure relief device	A, P	Transformer tank	Hand reset contact (local). Event recording.
63T	Main tank over pressure switch	A, P	Transformer tank	Trip generator breaker.
49-1W 49-2W	Transformer winding temperature thermal device in each separate winding	A, T, P	Transformer winding	Temperature detectors embedded in each separate winding for first stage temperature control. RTDs are in each winding because of the possibility of unbalanced loading.
26Q	Top oil temperature indicator	A, T	Transformer tank	Dial type oil temperature indicator at the transformer. First stage annunciation, tripping optional. Second stage tripping.
71QC	Conservator tank oil level indicator	A	Transformer tank	Dial type indicator with maximum and minimum indicating levels. Tripping optional.

[a]Type: C = control; P = protection trip; A = annunciation—event recording; T = temperature monitoring; I = indication (analog, digital, status lamps).

Table 15—Control and status data transmitted from unit control system to transformer

Signal	Description	Type[a]	Notes
20	Fire extinguishing system command	C, P	Actuated upon differential relay operation or sudden pressure relief device. Fire detection sensors shut off the transformer fan and pumps.

[a]Type: C = control; P = protection trip.

Table 16—Operating power, air, and water from service equipment to transformer

Description	Type[a]	Notes
Power supply for dc control circuits	DC	For uninterruptible systems such as fire protection.
Power supply for fans, pumps, ac control circuits	AC	For FA, FOA transformers. If an FOW transformer is used, additional information and control signals may be needed, such as monitoring of the pressure difference between the oil and water systems.
Water supply for fire extinguishing system	W	
Water supply for cooling	W	

[a]Type: AC = ac power; DC = dc power; A = air; W = water.

5.3.7 Turbine and pump-turbine

This subclause provides a guide for interfacing a typical turbine or pump-turbine to the unit control system.

Modern turbines can be separated into two broad classifications: impulse turbines and reaction turbines. Impulse turbines are commonly referred to as *Pelton turbines*. The reaction turbine classification includes Francis, axial flow propeller, diagonal flow propeller, Kaplan, bulb, and Deriaz turbines.

Impulse turbines are controlled by moving the needles into and out of the nozzles to throttle flow, and by deflecting the water with deflectors during rapid load changes. Most reaction turbines are controlled by adjusting wicket gates to control flow. In addition to wicket gate control, the blade angle is adjusted on Kaplan, bulb, and other turbines both to maximize efficiency and to limit overspeed.

Reversible pump-turbines are usually Francis-type, although axial and diagonal flow turbines have been used. Flow control for pump-turbine applications is identical to that for conventional turbines. Due to the similarities between turbines and pump-turbines, only the control and auxiliary systems for turbines will be discussed.

Servomotors are used to position the flow control devices—wicket gates, needles, blades, etc.—of the turbine. Servomotors can be coupled directly to each individual gate or needle, or one or more servomotor can be coupled to a regulating ring that is coupled to the wicket gates or nozzle deflectors. A single servomotor is generally used to position the blades.

Auxiliary systems associated with turbines and pump-turbines include wicket gate shear pin failure systems, wicket gate greasing systems, bearing cooling and lubrication systems, shaft seal or packing systems, turbine runner seal systems (wearing rings), and runner band drain valve system.

Interface points between the controlled equipment and the unit control system are shown in Table 17 and Table 18. Connections between the controlled equipment and the station service equipment are shown in Table 19.

Table 17—Control and status data transmitted from turbine and pump-turbine to unit control system

Signal	Description	Type[a]	Notes
38TG	Turbine guide bearing temperature	T, A, P, I	Temperature detectors. Provision for mounting sensors in all segments.
38QTG	Turbine guide bearing oil temperature	T, A, P, I	Temperature detectors in bearing oil reservoir.
71QTGH	Turbine guide bearing oil level high	A	Sensor in bearing oil reservoir, with direct reading visual indicator.
71QTGL	Turbine guide bearing oil level low	A	Sensor in bearing oil reservoir, with direct reading visual indicator.
39TV	Bearing-shaft vibration detector	A, P	Vibration probes installed in guide-bearing segments at 90 degrees to each other, for detection of equipment defects and rough load zone operation. Used in conjunction with probes on generator guide bearing.
26RS	Upper runner seal temperature	T, A	Temperature detectors for sensing excessive temperature due to inadequate cooling water flow.
33SP	Wicket gate shear pin failure	A, P	Reaction turbines only.
80WB	Bearing cooling water low flow	A, P	Pump failure, obstructed piping or pipe rupture.
8OWS	Shaft seal water low flow	A, P	Conditional trip during condensing operation or pump starting. May also be required for turbine operation.
80WTS	Turbine seal water low flow	A, P	Conditional trip during condensing operation or pump starting. May also be required for turbine operation.
71WTH	Turbine pit water level high	A, C	Senses excessive water level in turbine pit due to plugged drains or major seal failure. Operates turbine pit pump.
63AMS	Turbine shaft air maintenance seal applied	A, P	Contact blocks unit start-up and initiates shutdown when seal applied.
SCWP	Spiral case water pressure	I	
DTWP	Draft tube water pressure-vacuum	I	
48TG	Turbine greasing system failure	A	Alarm if lubrication cycle not completed.
74TG	Turbine greasing system low voltage	A	Detects failure of power supply to solenoid valve used to control greasing cycle.

Table 17—Control and status data transmitted from turbine and pump-turbine to unit control system *(continued)*

Signal	Description	Type[a]	Notes
73DTH	Draft tube water level high	A	Initiated if draft tube water level increases excessively during the synchronous condenser mode. Indicative of problems in air system or excessive wicket gate leakage.
71DTEH	Draft tube water level extremely high	C, A	Transfers unit from synchronous condenser to generate mode, or may initiate shutdown.
48SC	Synchronous condenser incomplete sequence	C, A	Transfers unit from synchronous condenser mode to generate mode if draft tube water level is not fully depressed within a set time from initiation of the sequence.
	Gate-needle position	C	Feedback to the governor control system.
	Blade position	C	Feedback to the governor control system (adjustable blade turbines only).
	Deflector position	C	Feedback to the governor control system (Pelton turbines only).

[a]Type: C = control; P = protection trip; A = annunciation—event recording; T = temperature monitoring; I = indication (analog, digital, status lamps).

Table 18—Control and status data transmitted from unit control system to turbine and pump-turbine

Signal	Description	Type[a]	Notes
1GS	Turbine grease system start-stop	C	Enables grease system when unit is running.
4SC	Synchronous condenser sequence start-stop	C	Upon actuation, wicket gate closure is initiated, compressed air is admitted to the draft tube to depress the water level and cooling water is applied to the runner seals. Upon reset, wicket gates are opened; depression air valves and running seal cooling water valves are closed.
4RA	Atmospheric or compressed air admission under runner	C	Used on some Francis turbines to reduce rough operation over a selected range of wicket gate positions. Control signal will initiate opening or closing of a solenoid valve.
1TL	Turbine lube oil system start-stop	C	Enables turbine lubrication prior to unit run.
20RBD	Runner band drain valve	C	Releases water trapped in turbine runner during water depression.

[a]Type: C = control.

Table 19—Operating power, air, and water from service equipment to turbine and pump-turbine

Description	Type[a]	Notes
Power supply for control and protection devices	DC	
Power supply for turbine pit water pump	AC or DC	May be in combination.
Air supply for shaft maintenance seal, greasing system, air admission under runner, draft tube water level depression system for synchronous condenser mode and pump starting, shear pin failure	A	
Water supply for bearing oil coolers and turbine seals	W	
Power supply for turbine lube oil system	AC	May be alternately fed from dc.

[a]Type: AC = ac power; DC = dc power; A = air; W = water.

NOTE—Wicket gate automatic lock functions are described in 5.3.8.[8]

5.3.8 Governor

This subclause provides a guide for interfacing the governor with the unit control system.

Typical mechanical, hydraulic, and pneumatic interfaces between the governor and a reaction turbine are shown in Figure 13. Interfaces for an impulse turbine are similar, except control is by needle valves and deflectors. Electrical protection, control, alarm, and indication interfaces between the governor and the unit control system are developed in Table 20 and Table 21.

Figure 13 represents a typical electronic-hydraulic governor using a proportional plus integral plus derivative (PID) controller strategy. Other variations of governors include electronic-hydraulic governors using a temporary droop controller strategy, electronic-hydraulic governors using a double-derivative controller strategy, and mechanical-hydraulic governors using a temporary droop controller strategy.

Integrating all unit control functions into one digital controller can reduce hardware, system design, and interfacing costs. As a result of the reduced hardware and interconnectivity between systems, an integrated digital unit control system may also have a significantly increased reliability when compared to a system that comprises separate unit controller, governing controller, and excitation controller systems.

Both the electronic-hydraulic and the mechanical-hydraulic governors use a speed reference (also known as *speed adjust* or *speed-load adjust*) as the set point for controlling the turbine. Governors with electronic controllers may also utilize a separate generation stipend (also known as *megawatt set* or *load set*) as a reference for controlling the generator output when online. The controller strategy used will determine the responsiveness of the governing system.

Position feedback from the turbine control servomotors to the hydraulic amplifiers may be done either mechanically (via cables or connecting linkages) or electronically (via position transducers). Mechanical feedback systems require more site-specific design and installation efforts, and the moving parts involved tend to require more routine maintenance. Electronic feedback systems can provide more accurate positioning of the turbine control servomotors, and they require less site-specific design and installation efforts. Electronic position feedback systems are generally provided with electronic-hydraulic governing

[8]Notes in text, tables, and figures are given for information only and do not contain requirements needed to implement the standard.

systems. A position feedback system should be designed so that, upon failure of the position feedback system, the turbine control servomotors will be driven to their fail-safe positions (closed gates, steep blades, closed needles, or deflectors in full deflection position).

Multiple-regulated turbines, such as the Kaplan and impulse type, require coordination between the primary control servomotors (such as the gates or needles) and the secondary control servomotors (such as the blades or deflectors). This coordination may be accomplished by a mechanical cam or an electronic data table that positions the secondary control servomotor as a function of the primary control servomotor position. A 3-dimensional cam or data table may also be used by factoring in the effects of operating head upon the optimum position of the secondary turbine control servomotor. With digital controllers, other coordination methods may be used to accomplish a more precise optimization of the secondary control servomotor positioning. For impulse turbines, the governor may be structured to operate the deflectors as the primary control element because of their dominant effect in deflecting hydraulic power from the turbine runner.

Additional information on governing systems may be found in IEEE Std 125™-1988 [B3], IEEE Std 1207™-2004 [B4], and IEC 61362:2000 [B1].

The auxiliary functions shown in Figure 13 are not technically part of the governing function, but they are often included within the governor controller or actuator cabinet. These functions may also be located within other equipment systems.

Just as nongoverning auxiliary functions can be included within the governing controller, the governing function can also be included within another controller, such as the unit controller. Some control functions of the excitation system may also be integrated into the unit controller. This integration of control functions is simplified by using a digital controller.

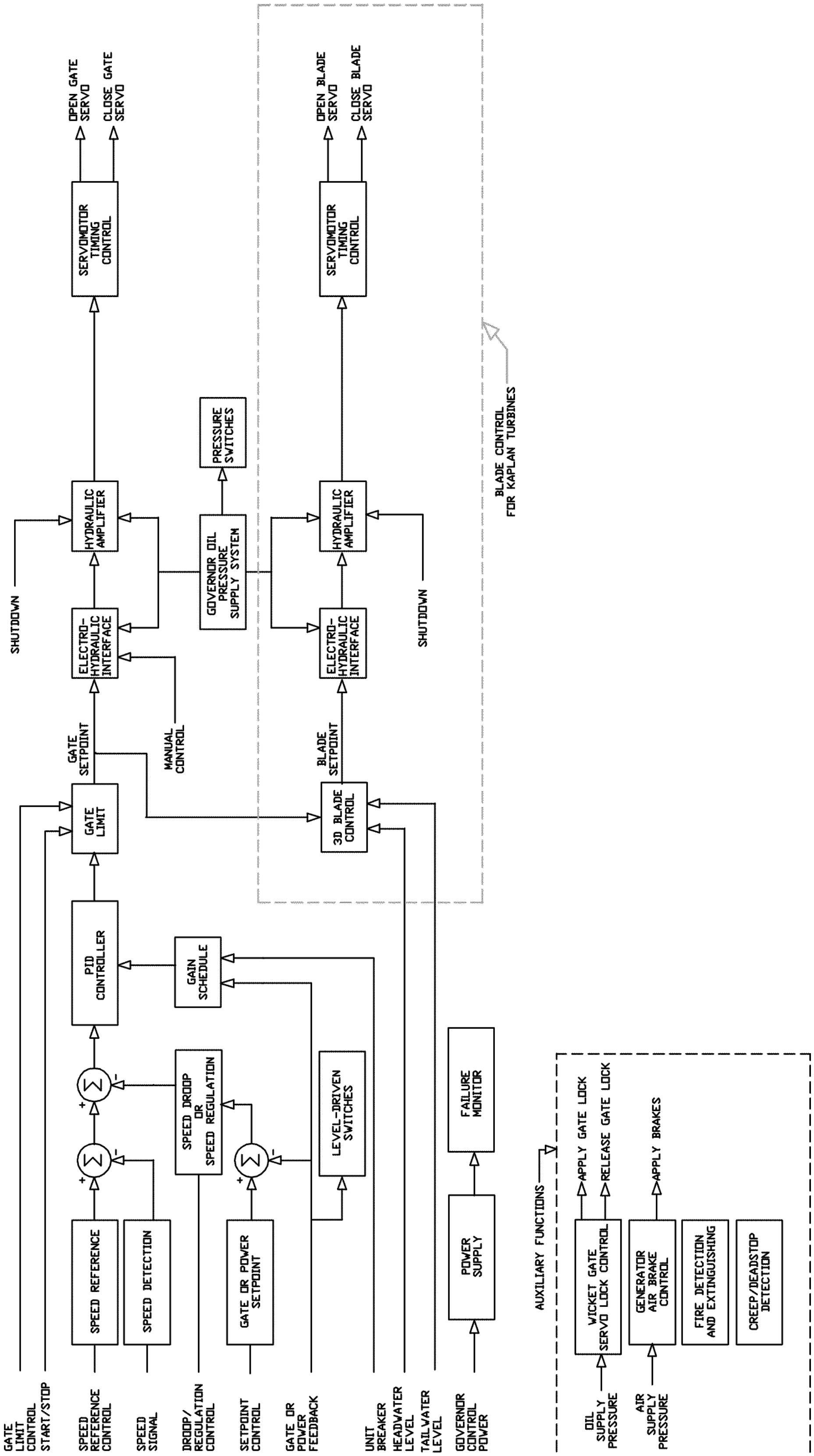

Figure 13—Typical electro-hydraulic reaction turbine governor

Table 20—Control and status data transmitted from governor to unit control system

Signal	Description	Type[a]	Originating device at governor	Notes
n	Speed indication[b]	I	H-2	Methods of developing the speed signal include the following: —Hall effect, eddy current, magnetic or optical sensors operated in conjunction with toothed wheels, or other devices directly connected to the generator shaft [speed signal generator (SSG)]. —Permanent magnet generators (PMG) coupled to the generator shaft. PMG output frequency and voltage are proportional to unit speed. —VTs connected to the generator output leads. Should be capable of operating at low residual voltages in absence of field excitation.
12-X 13-X 14-X	Overspeed, synchronous speed, and underspeed switches	C, P, I		Speed switches may be actuated mechanically by means of a positive coupling to the rotating elements of the turbine generator unit or may be actuated electrically by comparing the speed signal to a reference signal.
65SF	Speed signal failure	A, C, P	H-2	Loss of speed signal may initiate control action (such as, actuator lock) or shutdown of the unit and annunciation.
39C	Creep detector operation	A, C	H-2	Control action upon detection of shaft movement after shutdown may include any or all of the following: —Start generator thrust bearing HP oil pump —Release brakes —Start unit —Trip intake gate or draft tube gate —Alarm —Start turbine guide bearing oil pump
15FM-LS	Speed reference motor drive limit switches	C, I	H-3	Adjustable limit switches may be used to pre-position the speed reference prior to starting and synchronizing the unit. “End-of-travel” limit switches may be used for indication at local or off-site control stations.
N(ref)	Speed reference indication	I	H-3	Typically derived from a potentiometer or synchro ganged to the motor drive.
65PM-LS	Power reference limit switches[b]	C, I	H-4	Adjustable limit switches may be used to pre-position the power reference prior to starting the unit and prior to transferring from generate mode to synchronous condenser mode. “End-of-travel” limit switches may be used for illumination of lamps at remote raise-lower control switches or push buttons.

Table 20—Control and status data transmitted from governor to unit control system *(continued)*

Signal	Description	Type[a]	Originating device at governor	Notes
P(ref)	Power reference indication	I	H-4	Electronic signal used to indicate the level of the reference.
65GL-LS	Gate limit position switches	C, I, P	H-9	Adjustable limit switches may be used to position the gate limit in various automatic control and protection sequences (see Table 21, 65GLR, 65GLL). Switches also used for “end of-travel” indication at local or off-site raise-lower control stations.
GL	Gate limit position indication[b]	I	H-9	Typically derived from a potentiometer or synchro ganged to the motor drive.
33GL	Gate limit coincidence switch[b]	A	H-9	Operates when wicket gates are opened up to the position of the gate limit. Annunciates “governor action blocked” or “blocked gate.” Also used to block further raise action on speed or power reference.
63QAL or 33AL	Actuator lock applied indication[b]	C, P, I	H-10	Actuator lock may be initiated by the following governor failures: —Power supply failure —Electronics failure —Plugged oil filter —Loss of speed signal —Printed circuit card removal —Loss of MW transducer —Typical control and protection functions involving 63QAL or 33AL include —Tripping of unit if overspeed detected while actuator is locked —Control schemes that allow unit to be controlled remotely via the gate limit
65SS	Complete shutdown (start-stop) auxiliary contacts[b]	C, I	H-12	Provides confirmation of 65SS operation.
65SNL	Partial shutdown (speed-no-load) auxiliary contacts[b]	C, I	H-12	Provides confirmation of 65SNL operation. Used to seal in remote controls and provide remote indication.
WG	Wicket gate position indication	C, I	H-13	

Table 20—Control and status data transmitted from governor to unit control system *(continued)*

Signal	Description	Type[a]	Originating device at governor	Notes
33WG	Wicket gate position switches[b]	C, P, I	H-1	Typical uses of gate position switches for control and indication: —Generator brake application (that is, apply brakes at low speed if gates at 0%) —Synchronous condense transfer (that is, admit draft tube depression air as gates close) —Turbine gate lock (apply at 0% gate position) —Trip generator breaker as gates pass through speed-no-load position (auto-stop, protective shutdowns without overspeed) —Incomplete stop detection —Unit running detection —Initiate time delay for stopping auxiliaries —Reenergize starting relays to provide restart after momentary loss of power —Actuator lock
71QP	Governor hydraulic system pressure tank level switches[b]	A, P	H-14	Alarms for high, low, and extreme low levels. Shut down for extreme low level. Air admission for high level.
63Q	Governor hydraulic system pressure switches[b]	A, P	H-14	Pump control, alarms for high, low, and extreme low pressures. Shut down for extreme low pressure.
63AR	Governor hydraulic system air relief valve operation	A	H-14	Alarms for operation of the air relief valve.
71QS	Governor hydraulic system sump tank level switches[b]	A, P	H-14	Alarms for high, low, and extreme low levels. Shut down for extreme low level.
26QS	Governor hydraulic system sump tank fluid temperature high	A	H-14	Indicative of excessive governor action.
6Q	Governor hydraulic system lag pump operation	A	H-14	Indicative of excessive governor action or pump failure.
27PS	Governor power supply failure	A, C, P	H-8	Indicates failure of input ac or dc power or failure of regulated dc power supplies. May result in application of actuator lock or unit shutdown depending upon level of power supply redundancy.
63AB	Generator air brakes applied	C, I	H-16	Indication and auto-start interlock.
63ABS	Generator air brake supply pressure low	A	H-16	Alarm that air brake supply pressure has fallen below acceptable level.

Table 20—Control and status data transmitted from governor to unit control system *(continued)*

Signal	Description	Type[a]	Originating device at governor	Notes
33WGL	Wicket gate automatic lock applied-released	C, I	H-15	Indicates status of the gate lock (applied on shutdown when gates at 0%).
65WGLF	Wicket gate automatic lock failure	A	H-15	Indicates that the gate lock has not been fully applied on shutdown.
65M-LS	Manual control indication	I	H-11	Provides remote indication that the governor is in manual control at the governor cubicle.
63QPV	Pilot valve filter-strainer obstruction	A	H-17	Alarm that pilot valve filter-strainer has become obstructed.
49F	Fire detection system operation trouble	A, P	H-18	Operation or failure of detection-extinguishing system.
BAL	Governor balance indication	I	H-6	For electric governors, indication of electric-hydraulic transducer input voltage. Indicates degree of error between desired servomotor position computed by the electric circuits and the actual servomotor position, for effecting bumpless transfer from actuator lock to governor control.

[a]Type: C = control; P = protection trip; A = annunciation—event recording; T = temperature monitoring; I = indication (analog, digital, status lamps).
[b]May be accomplished using electronic transducers or developed as functions within digital controller logic.

Table 21—Control and status data transmitted from unit control system to governor

Signal	Description	Type[a]	Destination at governor	Notes
39	Creep detector enable	C	H-2	Enables rotor creep detector after a fixed time following application of brakes on shutdown.
15FR, 15FL	Speed reference raise-lower commands	C	H-3	If power reference also provided, speed raise-lower operable only off-line or in a designated speed control mode. Some installations may input reference analog or digital signal rather than raise-lower commands.
65PR, 65PL	Power reference raise-lower commands	C	H-4	Some installations may input reference analog or digital signal rather than raise-lower commands.

Table 21—Control and status data transmitted from unit control system to governor *(continued)*

Signal	Description	Type[a]	Desti-nation at gover-nor	Notes
65GLR, 65GLL	Gate limit raise-lower commands	C	H-9	Primary function of the gate limit is to limit the maximum opening of the wicket gates under operator control to prevent overloading the unit at the prevailing head. Other control and protection applications include the following: —Pre-positioning gate limit to 0% prior to starting to permit controlled opening of the gates upon energization of the start-stop function 65SS —Raising gate limit to turbine breakaway gate position after energization of 65SS —Generate-synchronous condenser transfer schemes —Rapid unloading of the machine during certain stop and protection shut-down sequences
65AL	Actuator lock on-off	C	H-10	Permits the actuator lock to be applied or to be reset by an operator at a location remote from the governor.
3SS	On-off command to start-stop function 65SS	C, P	H-12	The start-stop function 65SS typically operates as follows: —Energized to allow wicket gates to open and close under control of the electric governor, gate limit, or manual gate control, that is, “energized to start and run” —De-energized to initiate complete closure of the wicket gates at maximum rate and block subsequent opening of the gates, that is, “de-energized to stop” In some applications, 65SS may be “de-energized to start and run” and “energized to stop” although this method may not be fail-safe for loss of control voltage. Typical functions that will block start and/or initiate stop are as follows: —Unit protection operation (includes all electrical and mechanical fault detectors that initiate shutdown of the unit) —Operator-initiated stop —Generator thrust bearing high-pressure oil pump failed to achieve full pressure —Turbine shaft maintenance seal on or low gland water flow —Generator brake shoes not cleared or brake air pressure not off, or both —Intake gate not fully open —Generator and turbine bearing cooling water not available —Wicket gate lock not released

Table 21—Control and status data transmitted from unit control system to governor *(continued)*

Signal	Description	Type[a]	Destination at governor	Notes
3SNL	On-off command to partial shutdown (speed-no-load)	C, P	H-12	The partial shutdown function 65SNL (if used) is typically used to limit the opening of the wicket gates, or return them, to a position slightly above the speed-no-load position. If a relay or valve is used, it is: —Energized when unit circuit breaker closes to allow generator to be loaded. —De-energized whenever unit circuit breaker trips to restore unit to near rated speed; provides backup to the electric governor. —De-energized to unload the unit for certain protection operations (that is, hot transformer).
V, I	Generator voltage and current	C	H-5	Inputs to power transducer (for governors utilizing power feedback rather than gate feedback).
52	Unit online	C	H-7	Generator circuit-breaker auxiliary contact. Used to switch between online and off-line gains in compensation circuits (PID) and to switch between speed and power references.
3AB	Generator air brakes on-off command	C	H-16	Air brakes automatically applied on shutdown if wicket gates close and speed below a predetermined level.
4C	Generate to synchronous condenser transfer initiation	C	H-12	Initiates pre-positioning of governor reference setters (power, gate limit) followed by rapid closure of the wicket gates by application of command to wicket gate control.
71NH	Level difference between headwater and tailwater including piping losses.	C		Used for optimum turbine blade positioning and optimum pumping unit gate position.

[a]Type: C = control; P = protection trip; A = annunciation—event recording; T = temperature monitoring; I = indication (analog, digital, status lamps).

5.3.9 Penstock—Intake gates or valves

The penstocks or pressure conduits are the pipes connecting the hydraulic turbines with the intake structure. The penstocks may consist of lengths of tunnels and may be provided with a surge tank. There are no controls or instrumentation normally associated with the penstocks except piezometer taps near the connection to the turbine or pressure-flow instrumentation sensors.

The intake gates or valves serve the purpose of stopping the flow of water to the turbines by closing the inlet to the penstocks. Alternate methods of stopping the flow are to have the gates at an intermediate point in the penstock or to have guard valves in the penstock just upstream from the generating unit. Inlet valves are desirable for each unit if one penstock is used for two or more turbines. Plants having intake gates or valves should have their controls interfaced with the unit's control system.

The gates are normally closed for one of two purposes—maintenance or emergency—but not during normal operation. An emergency can include a unit runaway due to such things as load rejection and failure of the wicket gates to close. It is critical that the intake be capable of closing under all flow conditions and is timed to avoid excessive tunnel pressures. Tripping of the gates is initiated from the power plant by overspeed switches or controls monitoring unit speed, or other devices, or by operator action. Control and trip circuits use dc power from the plant battery. Stored energy systems, such as gravity or hydraulic accumulators, provide the power to close the gates. Instrumentation and alarms are usually limited to indication of fully open-fully closed position and status of the stored energy system.

5.3.10 Draft tube gate

The draft tube gate provides the means to isolate the hydraulic turbine from the tailwater when the turbine is in a shutdown mode. Various types of draft tube gates are used depending upon the function.

If the purpose of the gate is to isolate the turbine only for inspection and maintenance, the gate can be simply a "stop-log" device that is moved into place by a crane or hoist under no-flow conditions. The draft tube may also be used to protect the plant from tailwater infiltration in the event of a failure in the water conductors to the plant. In this case, the draft tube gates should be designed to close against flow under tailwater head conditions.

If the purpose of the gate is to provide runaway protection or back-up shutdown of the turbine during an emergency shutdown of the unit, then the gate would be motor-operated or hydraulically operated and should be capable of closing under full-flow conditions.

Automatic operation of the draft tube gate is needed when it is used to regulate flow through the unit during the sluicing operation associated with bulb turbine units. The purpose of this mode of operation is to minimize the disturbance that an abrupt interruption of the flow of water might cause during a load rejection. During sluice operation, the generator is disconnected from the grid, and the speed of the turbine is controlled by the draft tube gate.

Typical controls for automatic operation of the gate are as follows:

a) Unit control system
    1) Raise-lower control
    2) Indicating lights for fully open-fully closed
    3) Position indication showing actual position of the gate
b) Local
    1) Raise-lower control
    2) Gate position indication
c) Annunciation
    1) Failure of gate to open or close in response to an automatic signal
    2) Failure of gate to maintain partial closure position during sluice operation

5.3.11 Pump starting equipment

A pumped-storage unit is a turbine-generator that can be reversed to pump water upstream. When operating as a pump, the generator becomes a motor, which now supplies mechanical power to the pump-turbine or pump.

Starting the unit in the pump mode requires a means of accelerating the generator-motor in the pump direction. Regardless of how this is done, the motor is started with its gates closed and the tailwater depressed. Once the unit is at rated speed and online, the depressing air is vented and the pump is primed. The gates are then opened and pumping begins.

Six of the most common methods of starting a reversible pump-turbine machine as a pump-motor unit are as follows:

1) *Full voltage, across-the-line starting.* With this type of starting, the unit breaker is closed, and the unit is started as an induction motor. The induction motor action is provided by amortisseur windings with special damper bars. At about 95% speed, excitation is applied and the machine becomes a synchronous motor.

   The acceleration time for this type of starting depends on the machine inertia and is usually on the order of one minute or less. Because of the voltage drop on the plant's transmission system and heating of the machine windings, full voltage starting is used primarily on smaller units.

2) *Reduced voltage, across-the-line starting.* When across-the-line starting is desired and full voltage starting is not practical, reduced voltage starting should be considered. The system configuration for this method is shown in Figure 14. One method is by a tap on the generator step-up transformer to feed a starting bus at one-third to one-half rated generator-motor voltage. A breaker is provided to connect the machine to the starting bus. When the machine accelerates to about 95% speed, excitation is applied. When synchronism with the system is attained, the starting breaker is tripped and the running breaker is closed. Another method of reduced voltage starting is by connecting a series reactor during starting, and then short-circuiting it near synchronous speed.

   If the generator-motor stator winding consists of multiple circuits, partial winding starting can be considered. This is a variation of reduced voltage starting in which one-half or less of the winding circuits are used for accelerating the machine. When the unit reaches 95% speed, excitation is applied and the remaining circuits are connected. A one-line diagram for this method is shown in Figure 15.

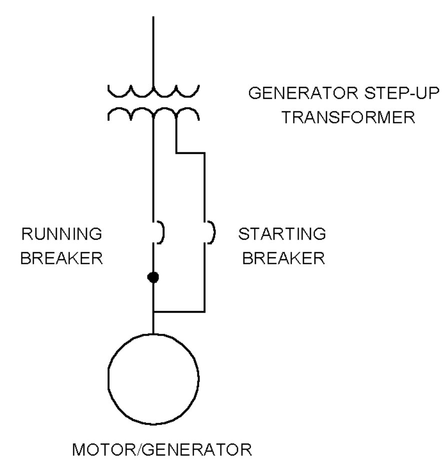

Figure 14—Reduced voltage starting (phase reversing not shown)

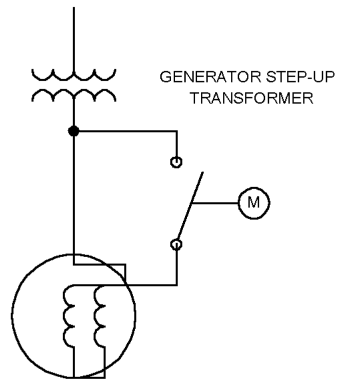

Figure 15—Part winding starting (unit breaker and phase reversing not shown)

3) *Pony motor starting.* A pony motor is a wound-rotor machine that is attached to the motor-generator shaft. Its rotor winding is connected to an adjustable resistor, usually a liquid rheostat, making it a variable speed device.

   The pony motor is usually fed from the plant's station service system. It is built with two or four fewer poles than the unit motor-generator, so that it can accelerate it to just above 100% rated speed for synchronizing. Since its rotor is usually directly coupled to the motor-generator shaft, a separate pony motor is required for each reversible unit. With proper switching, however, one liquid rheostat can be used on several units. A controller is provided with the liquid rheostat to adjust resistance during starting.

   A typical pony motor starting sequence begins with closing the station service breaker. The rheostat controller adjusts pony motor torque to provide linear acceleration of the unit. At approximately 95% speed, excitation is applied to the motor-generator field. The liquid rheostat control is transferred to the synchronizing controls, which adjust pony motor and unit speed for synchronization. Once the unit is paralleled, the station service supply to the pony motor is tripped. Typical acceleration time is from 5 min to 10 min.

   Pony motor starting is suitable for use with large motor-generator units. Pony motor size could range up to several thousand horsepower, depending upon the requirements of the unit being started. A one-line diagram for this starting method is shown in Figure 16.

   The pony motor and liquid rheostat have interfaces to both the unit protection and the control system on the unit control system. These are listed in Table 22.

4) *Synchronous starting.* This technique uses another generator (sometimes only a fraction of the size of the primary unit) to start the unit that is acting as a motor. The two machines are electrically connected together through a starting bus, but are isolated from the transmission system. Excitation is applied to both machines and the gates on the unit that is acting as a generator are opened. As it accelerates, the motor unit follows in synchronism. When both machines reach system frequency, the motor unit is disconnected from the starting bus and placed online. Other motor units can be started in a similar fashion with the same generator by connecting them through the starting bus. Typical starting times for this method are from 3 min to 5 min. Figure 17 shows a one-line diagram for synchronous starting.

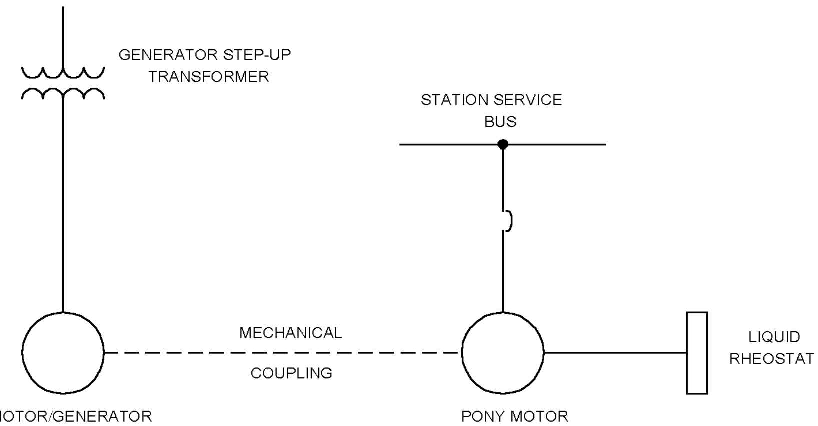

Figure 16—Pony motor starting (unit breaker and phase reversing now shown)

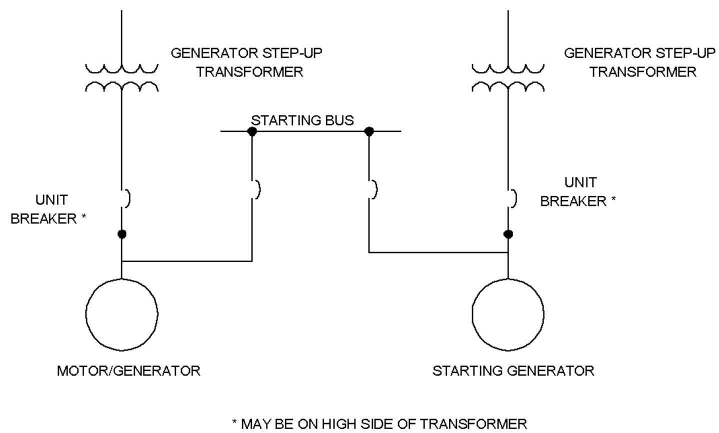

Figure 17—Synchronous starting (phase reversing not shown)

Table 22—Control and status data transmitted from pony motor unit starting equipment to unit control system

Signal	Description	Type[a]	Originating from[b]	Notes
23LR	Liquid rheostat electrolyte temperature	P	LR	Trips pony motor lockout relay.[c]
46PM	Pony motor phase unbalance relay	P	PM	Trips pony motor breaker.
48S-1, 2	Acceleration (speed versus time) check	P	LR	Trips pony motor lockout relay.[c]
49PM	Pony motor stator temp	P, T	PM	Trips pony motor lockout relay.[c] Temperature monitoring optional.

Table 22—Control and status data transmitted from pony motor unit starting equipment to unit control system *(continued)*

Signal	Description	Type[a]	Originating from[b]	Notes
51PM	Pony motor overcurrent relay	P	PM	Trips pony motor lockout relay.[c]
64PM	Pony motor rotor ground relay	P, A	PM	Alarms only or trips pony motor lockout relay,[c] depending on operating company practice.
71LRE	Electrolyte level	A, C	LR	Alarms, and pump starting sequence pre-start check.
80E	Loss of electrolyte flow	P, A	LR	Alarms; optional trip of pony motor lockout relay.[c]
87PM	Pony motor differential relay	P	PM	Trips pony motor lockout relay.[c]

[a]Type: C = control; P = protection trip; A = annunciation—event recording; T = temperature monitoring.
[b]PM = pony motor; LR = liquid rheostat.
[c]Pony motor lockout relay trips pony motor breaker and initiates unit normal shutdown; locks out starting control sequence.

5) *Semi-synchronous starting*. Sometimes referred to as *reduced frequency* or *reduced voltage starting,* the semi-synchronous starting method depends on the transfer of rotational energy from a spinning generator to the pump unit. Prior to pump starting, the generator is accelerated to about 80% of rated speed, and its wicket gates are held at a fixed position. The pump unit is tied to the generator through a starting bus. Excitation is applied to the generating unit and the pump unit starts as an induction motor with its field shorted or by using amortisseur windings. Since the generating unit's wicket gate position is fixed, it will decelerate as the pump unit accelerates. When the speed of the two units is approximately equal, excitation is applied to the pump unit to bring it into synchronism with the starting generator. The generating unit's wicket gates are then opened to accelerate both units to rated speed.

   After synchronism to the system, the generator unit may be tripped off and used to start other pump units. Typical acceleration time for the pump unit is from 3 min to 5 min.

   Due to the manner by which this starting method works, the generator unit should have a similar flywheel effect (WK^2) to that of the pump unit. Also, the demands on the generator unit's excitation are rather high since it must maintain terminal voltage when the machine is decelerating. An individual case study is mandatory to determine the feasibility of this starting method for a particular application.

   The one-line diagram for semi-synchronous starting is similar to that for synchronous starting. Therefore, reference is again made to Figure 17.

6) *Static starting*. A static starter is a converter-inverter combination that converts station auxiliary power into a variable frequency output of sufficient magnitude to accelerate the motor unit. As in synchronous starting, the static starter is electrically connected to the unit through a bus, but isolated from the system. At the beginning of the start sequence, excitation is applied to the unit and the static starter is energized from station service.

   As the starter's output frequency increases, the generator-motor starts to accelerate. When the unit frequency matches the system, the starter is isolated from the unit and the unit breaker is closed. As in synchronous starting, other units can be started from the same static starter with proper switching. Figure 18 illustrates the connections involved.

The starter can also provide dynamic braking of the machine after the unit has been tripped off the system. Circuitry inside the starter changes the direction of power flow to allow motor braking. This feature can result in greater life of the unit's mechanical brakes.

Static starting can be used on a variety of sizes of machines. Typical starting time is less than 10 min. The interfaces from the static starter to the unit control system are listed in Table 23.

7) *Soft start motor-generator starting method*. In a power plant where a fast start of a pump-turbine unit is required or only one unit is available, the soft-starting method, utilizing a static frequency converter (SFC), can be used. This starting method has a much smaller impact on the grid and the motor-generator unit as compared to other starting methods. In the SFC mode, the SFC controller regulates the excitation system output until rated speed is reached. By using an SFC, it is not only possible to prevent the machine from falling out of step, but also to drive the unit at a desired speed, pending the sizing of the converter. In the shut-down mode, the kinetic energy of the rotating unit can be recuperated into the grid.

Table 23—Control and status data transmitted from static starting equipment to unit control system

Signal	Description	Type[a]	Notes
1	Starter ready for service	C, A	Pump mode pre-start check, alarms.
2	Start time to 5% speed exceeded	P, A	Trips static starter,[b] alarms.
27	Incoming power to starter failure	P, A	Trips static starter,[b] alarms.
27PS	Internal power supply failure	P, A	Trips static starter,[b] alarms.
27SV	Converter sync voltage failure	A	
33	Thyristor cubicle door open	P, A	Trips static starter,[b] alarms.
33RS	Phase reversing switch wrong position	P, A	Trips static starter,[b] alarms.
48	Start-stop sequence incomplete (time exceeded)	P, A	Trips static starter,[b] alarms.
49	Cooling oil-water high temp	P, A	Trips static starter,[b] alarms.
5OG	Starter ground fault	P, A	Trips static starter,[b] alarms.
51	Starter overcurrent	P, A	Trips static starter,[b] alarms.
52b	Cooling system feeder breaker tripped	P, A	Trips static starter,[b] alarms.
59	Starter overvoltage	P, A	Trips static starter,[b] alarms.
63	High cooling water pressure	P, A	Trips static starter,[b] alarms.
80	Cooling oil-water low flow	P, A	Trips static starter,[b] alarms.
	Firing signal failure	P, A	Trips static starter,[b] alarms.

[a]Type: C = control; P = protection trip; A = annunciation—event recording; T = temperature monitoring.
[b]When starter trips, pump unit will shut down.

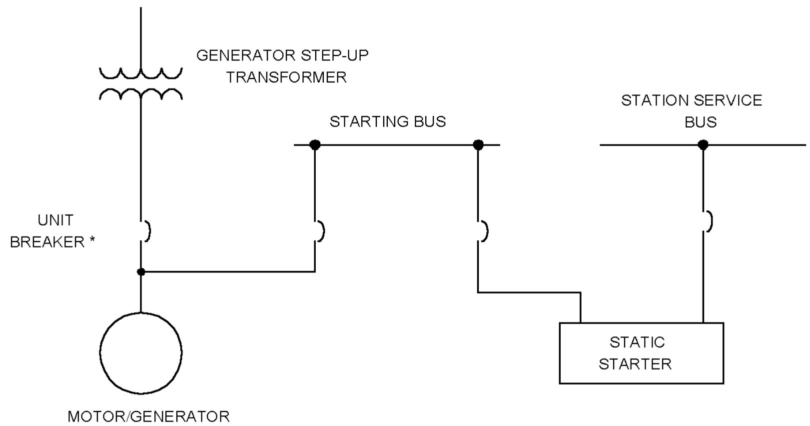

Figure 18—Static starting (phase reversing not shown)

5.3.12 Phase reversing equipment

Operating a pumped-storage unit in the pump mode requires reversing the direction of rotation of the generator-motor unit. This is accomplished by interchanging any two of the phases with motor-operated multipole switches or with breakers. Signals between the phase reversing equipment and the unit control system are shown in Table 24.

Usually, the simplest and most cost-effective method, especially for large units, is to use a motor-operated switch. It can be either a four-pole or five-pole design, depending on whether or not it is desired to open the third phase when the switch is operated. A typical connection of a five-pole switch is shown in Figure 19.

Breakers can be used for phase reversal in two ways. First, two-unit breakers can be provided with the phases interchanged in the external bus work. This connection is shown in Figure 20. Interlocks must be provided to prevent both breakers from closing at the same time. Second, a five-pole unit breaker can provide phase reversal as well as unit disconnection. Its connection would be similar to the motor-operated switch shown in Figure 19.

Phase reversal can be accomplished either on the low side or the high side of the unit step-up transformer. Several arrangements are illustrated in Figure 21. The method chosen will depend on the usual constraints of cost, space, size of unit, maintainability, etc.

When specifying phase reversing equipment, major consideration should be given to the severe duty usually imposed on it by the change of modes at most pumped-storage projects. Care should also be taken when applying protective relaying especially differential, reverse power, or negative sequence overcurrent and phase fault back-up protections that use voltage as a supervising, restraining, or operating quantity (phase overcurrent with voltage control/restraint, distance protection, and out-of-step protection) to prevent mis-operation when phase rotation is reversed. High quality position switches should be used with the phase reversal equipment so that its position can be reliably checked prior to unit start-up.

Table 24—Control and status data transmitted from phase reversing equipment to the unit control system

Signal	Description	Type[a]	Notes
43	Generator-motor phase selector control switch	C	
33	Phase switch position	C	Indication on unit system and input to pre-start checks.

[a]Type: C =control.

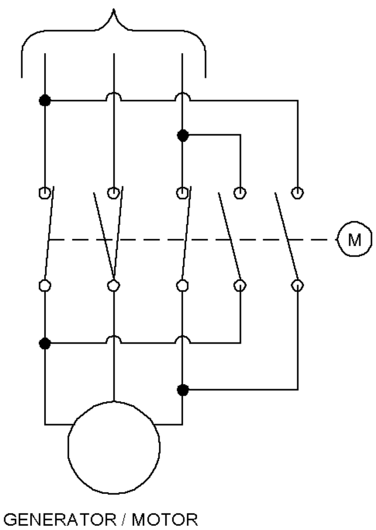

Figure 19—Phase reversal with five-pole motor-operated switch (low side reversing shown) to unit step-up transformer

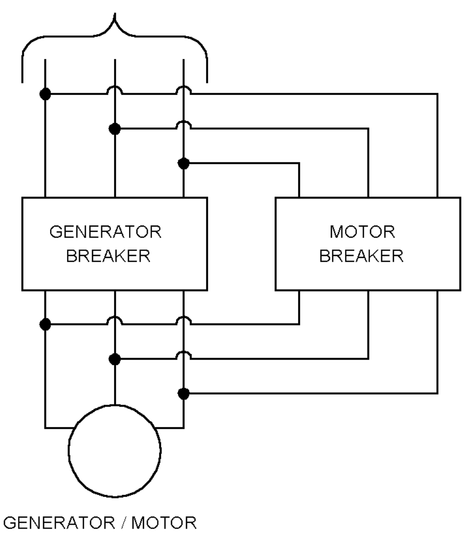

Figure 20—Phase reversal with two-unit breakers (low side reversing shown) to unit step-up transformer

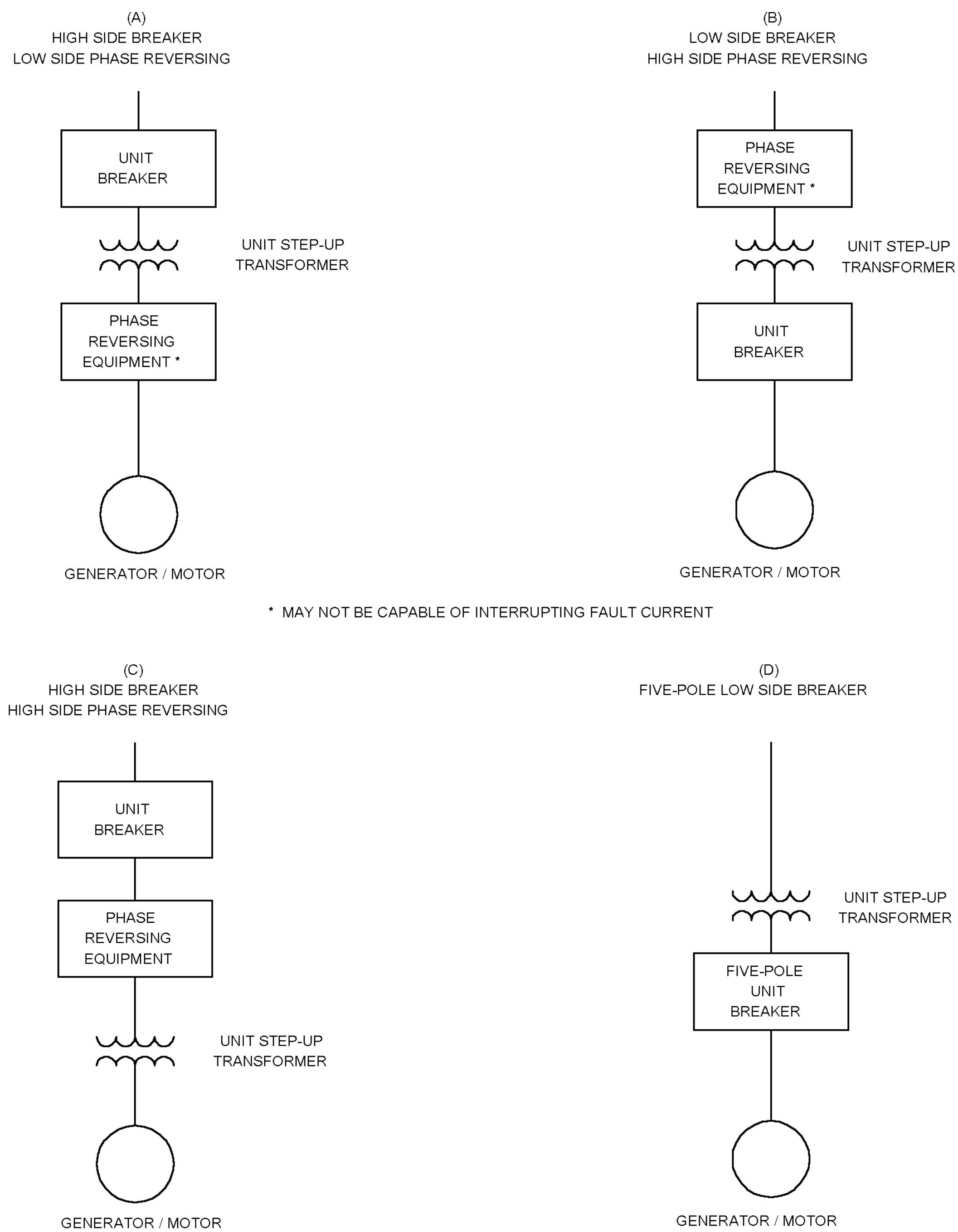

Figure 21—Phase reversing equipment locations

5.3.13 Draft tube water depression system

The draft tube water depression system is utilized both in conventional hydroelectric units and in pumped-storage units to depress the water below the runner. This allows the unit to be motored with minimum power consumed from the system since the runner is spinning in air. Motoring of a conventional hydroelectric unit is desired so it can be utilized as a synchronous condenser for electrical system enhancement, or to provide spinning reserve for rapid response to system needs. Motoring of a pump-turbine unit, in addition to those items for a conventional unit, is required during the acceleration of the unit in the pump mode.

The draft tube water depression system consists of (1) a level detector located in the draft tube gallery for monitoring water level directly below the runner, (2) a depressing air system that supplies an adequate air volume at the required pressure for depressing the water to a predetermined level, and (3) control valves for controlling the air admitted to the turbine for depressing the water. A pressure switch often monitors the depression air system supply pressure, with alarm occurring when pressure drops to a level where full depression of a unit cannot be completed.

Depression systems can utilize low-pressure fans or compressors with or without accumulator tanks. Controls may be off-on via solenoid or motor-operated valves, or via continuous analog control of the air admitted to the turbine discharge chamber.

Where off-on control is provided, two valves are used (a small and a large valve). The large valve is used to provide a rapid blowdown of the water to a preset point below the runner, and the small valve is utilized to maintain the required air pressure to keep the water at that point and to compensate for any air leakage. Control of these valves for initial blowdown and make-up is totally automatic. This operation usually requires a minimum of three level set points, as follows:

Level 1—Set to sense that the water level is below the runner for motoring operation (nominal depressed level) (both large and small valves are de-energized at this level).

Level 2—Set to sense that the water level is below the runner for motoring operation but is above the nominal level, and therefore, makeup air needs to be added. (Small valve is energized.)

Level 3—Set to sense when water level is above Level 2, but still below the runner. This level is utilized to energize both the large and small valves since the make-up air is not adequate for making up the losses. An alarm is usually given at this level. There could be a Level 4 switch added for tripping the unit if water does reach the turbine runner. Also, an extremely low-level switch could be used to alarm, indicating a depression valve has stuck open.

Continuous control is normally accomplished with blowers. Air admitted to the chamber is controlled with a waste valve to discharge excess air or with a variable speed drive on the blower that operates in response to a continuous level signal.

5.3.13.1 Pumping operation

For pumping operation, the draft tube water level is depressed prior to rotating the unit in the pumping direction. After the unit is paralleled to the system, the depression air is vented to prime the pump. The priming system may include one or more vent valves, solenoid or motor-operated, depending on the size. The system also includes a pressure switch located in the head-cover that detects pressure at the runner tip as air is vented during priming. Operation of this switch indicates the runner is effectively watered and the pump is primed. When this condition is detected, the gates are opened to the desired pumping opening. Prolonged operation with the gates closed and the pump primed will result in overheating of the trapped water being agitated by the pump runner.

5.3.13.2 Synchronous condensing operation

For synchronous condensing operation, the unit is started and paralleled to the system in the generating direction. The wicket gates are then closed and the draft tube water level is depressed by admitting the depression air. A unit may transition from condensing operation to generating operation by venting the depression air and opening the wicket gates to begin generating. Depression air can be vented by opening venting valves or by opening the wicket gates.

5.3.13.3 Transition from pumping mode

Transition between pumping operation and synchronous condensing operation is possible, but not common. The transition from synchronous condensing to pumping is done by priming the pump as previously described, and opening the gate. Transition from pumping operation to synchronous condensing is done by closing the wicket gates and depressing the draft tube water level, as described in 5.3.13.2.

5.3.14 Generator-motor cooling

Conventional unit cooling is usually accomplished by circulating air through the unit windings and then through heat exchangers. Service water is the most common cooling medium used in heat exchangers. Instrumentation associated with conventional cooling is usually limited to fan failure, water flow, and cooling water strainer differential pressure. Signals between the cooling system and unit control system are shown in Table 25.

Cooling water may be a once-through system. Closed-loop systems are used where solids or salt water (tidal discharge plants) are present that could cause fouling or damage of the generator heat exchangers.

On-off valves are used to shut off the flow of cooling water when it is not needed. Temperature control may be provided by an automatic control valve on the discharge of the air coolers.

A more sophisticated means of unit cooling is direct-winding water cooling. This method of cooling involves circulating water through hollow conductors in either the stator or the rotor windings and is used in conjunction with conventional cooling. Water quality is of utmost importance in this type of cooling.

A closed-loop demineralized water system provides the cooling water for the winding cooling system. The demineralized water system consists of filtering equipment to maintain water purity; analyzing equipment to monitor purity, flow, and pressure instrumentation; and a makeup water and leak detection system.

The demineralized water is cooled by circulating it through service water-cooled heat exchangers. A normal complement of flow and differential pressure instrumentation is provided on the raw cooling water system.

In addition to the demineralized and service water systems, a rotating manifold is required on the rotor to provide the rotor demineralized water supply and return interface.

Waste heat produced by the generator-motor is often used for powerhouse heating. Control can be part of the digital control system or stand-alone thermostats. Air may be directly vented to the powerhouse, or the cooling water return line from the generator can also be routed through heat exchangers to warm powerhouse air. Useful heat is only available once the generator has been online sufficiently to warm the air-housing air above that required for the powerhouse ambient temperature.

Care should be used in this type of application to ensure that cooling water temperatures high enough to heat the powerhouse air can be reliably achieved without increasing generator air housing or winding temperatures above desired levels.

Table 25—Control and status data transmitted to and from the cooling system and unit control system

Description	Type[a]	Notes
Conventional cooling		
Fan failure	A, P	Trip occurs on multiple fan failures resulting in insufficient airflow.
Raw water low flow	A	Trip is accomplished by winding temperature.
Strainer differential pressure	A	
Direct-winding water cooling		
Rotating manifold high temperature	A, P, T	
Control voltage failure	A, P	
High conductivity	A, P	
Chemical filter high conductivity	A	Cleaning necessary.
Dissolved oxygen high	A	Water purification necessary.
Rotor differential pressure	A, P	Low flow back-up or manifold failure.
Stator differential pressure	A	Flow restriction.
Raw water strainer high differential pressure	A	Cleaning necessary.
Demineralized water low pressure	A	Potential pump failure.
Stator low flow	A	
Rotor low flow	A	
Raw water low flow	A	
Expansion tank high-low level	A, P	
Stator water temperature	A, P, T	
Rotor water temperature	A, P, T	
Rotor-stator water inlet high temperature	A, P, T	Potential raw cooling water failure.
Excessive leakage	A, P	
Back-up pump start	A	Potential cooling failure.
Nitrogen pressure high-low	A	
Unit started	C	Starts demineralized water flow.
Field breaker closed	C	Starts raw water-cooling of demineralized water (can be sensed as field voltage).
Unit auxiliaries started	C	Controls housing heaters.

[a]Type: C = control; P = protection trip; A = annunciation—event recording; T = temperature monitoring.

5.3.15 Service air

The service air system supplies compressed air for unit and general plant purposes such as for governor air, braking, and air-operated tools.

The source for station air is an air compressor and a storage receiver. Often a duplicate compressor and receiver set is provided for backup and to allow maintenance on one set. Both sets would connect to a common header that would have pressure switches for alarm and control. Lead-lag compressor controls may include alternators to equalize the duty on each compressor. Compressor controls are often stand-alone provided by the compressor manufacturer, but can be integrated with the unit control system. Air compressors may require service water for cooling.

The header pressure switches perform the following as a function of detected pressure:

63ARHH	high-high	alarm
63ARNH	normal high	stop compressor
63ARNL	normal low	start lead compressor
63ARLL	low-low	start lag compressor and alarm

Compressed air for draft tube water depression, circuit breaker operation, and governor oil system make-up air is frequently supplied from similar, but separate air systems.

5.3.16 Service water

The service water system supplies water for unit cooling, fire protection, and general powerhouse needs. Although some filtration is provided for these purposes, additional filtration and purification would be needed for special purposes such as direct generator cooling or potable water supply.

Service water may be obtained from a penstock tap with suitable pressure reduction, or from tailwater. Service water may be passed through a strainer for removal of silt. Often, duplex strainers are provided to permit one to be taken out of service for maintenance or back washing. A differential pressure switch across the strainer will alarm that back-washing is needed.

Unit cooling water in some cases may be supplied directly from the water header, or unit cooling water pumps may be required. Usually, a motor-operated cooling water valve is provided to shut off flow to the unit when it is shut down, and a pressure switch upstream of the valve detects that correct water pressure exists. Valve position can be modulated if required to reflect actual water temperature and unit operating temperatures.

If there are no cooling water pumps, the valve is opened at the time other auxiliary systems are started during unit startup, and closed after the unit has stopped. The cooling water pump, if supplied, is started with the other auxiliary systems, and when pressure is established on the closed valve, the valve is opened automatically. Frequently, dual pumps are provided for backup and for servicing. The pumps would have lead-lag controls, and operation of the lag pump would be initiated automatically if the pressure drops for a preset time.

The unit cooling water header provides distribution for the following:

a) Generator bearing oil coolers
b) Turbine bearing oil coolers
c) Turbine packing box or shaft seal cooling and lubrication

d) Generator air coolers
e) Main step-up transformer oil coolers
f) Wearing ring seal water

Each unit cooler branch discharge is provided with flow switches, which operate to verify that flow has been established during unit startup for sequence interlocking and for alarming upon sustained loss of flow. Flow to the packing box and wearing rings is monitored at its intake. Generally, the unit will not be directly shut down on loss of cooling water flow unless the main transformer has no self-cooled capability and cooling is supplied from the cooling water system, or if the turbine wearing ring supply is interrupted while in a condensing mode.

Instrumentation indicates intake water temperature and temperature of each cooler discharge. If water is required for generator or transformer fire protection or for hose connections, booster pumps connected to the filtered water header may be needed. These pumps would start automatically upon receiving an appropriate signal.

Other powerhouse requirements, such as air conditioning and service connections, may be supplied from the water header.

5.3.17 DC power supply

The dc power supply for the power plant will normally consist of redundant battery banks and battery chargers. A dc power distribution panel is normally used, together with subpanels as required, for distributing the dc power to various control circuits and other loads in the plant. Instrumentation and controls are provided on the distribution panel and on the battery chargers. Alarm devices are provided with the chargers and/or distribution panels.

Instrumentation will include dc volts and amperes for each battery charger and battery bank, and incoming ac volts and amperes. Protection and alarms may consist of ac and dc undervoltage, overcurrent, and battery ground. DC undervoltage is normally interlocked with the unit start circuits to prevent starting the unit without proper control power.

5.3.18 AC power supply

The ac power supply equipment for the power plant can take several forms. A common one consists of one or two unit substations, depending on the number of generating units. A unit substation will contain a high-voltage section, a stepdown transformer, and a low-voltage switchgear section. The high voltage section will consist of a circuit breaker or a fused disconnect switch and buses for connection to the generator bus, or other power source, and the stepdown transformer. The transformer will step the voltage down to the value used in the plant. The low-voltage switchgear will consist of power circuit breakers for incoming power from the transformer and for each major load. Motor control centers, power distribution panels, and lighting panels feed power to the various loads around the plant. Instrumentation and controls are provided on the front of the high-voltage and low-voltage switchgear sections. Centralized instrumentation and control is usually provided; however, off-site control normally is not. Alarm devices are mounted on the unit substations, with all alarms combined into one for transmittal to the central control room.

Instrumentation will include ac volts, amperes, watts, and watthours. Protection and alarms may consist of over- and undervoltage, overcurrent, differential overcurrent, sudden pressure, and over-temperature.

5.3.19 Water level monitoring equipment

The headwater and tailwater elevations are measured very precisely for various purposes, such as reservoir level control, net head calculations, pumping unit control, spillway gate control, power generation control, minimum water release control, and gathering statistical data. For large multiple unit plants, several headwater and tailwater sensors may be needed since a single one may not truly reflect the headwater or tailwater profile across the entire plant. Accurate head and tail water measurement for each unit is needed for net head calculations.

The array of water level monitoring equipment is almost limitless, but a few types are most commonly used. The standard for many years and still frequently used are float-chain operated level switches and pressure transducers.

Another frequently used system, the bubbler system, measures levels by measuring the pressure required to release air bubbles from a nozzle set below the water surface. Other systems use changes in electrical conductance, electrical capacitance, ultrasonic sound reflectance, float switches, and other schemes. At some plants where the reservoir is remote from the plant, the penstock pressure is used for measuring the water level.

Typical water monitoring instrumentation and alarms would be as follows:

a) Reservoir (headwater) level, an analog signal transmitted to the plant computer and to level recorders.
b) Downstream (tailwater) level, an analog signal, same as item a).
c) Reservoir level switches, to give alarms if the level is above or below operating limits and to operate spillway gates if the level exceeds a set limit.
d) Downstream level switches, to give alarms if the level drops below operating limits and to operate low-level release valves if the level drops below minimum water release limits.

5.3.20 Turbine flow monitoring

Turbine flow may be monitored by several methods. Application depends on the type of intake section available for measurement and the purpose of the flow measurement. Where the measurement is to be used for turbine performance testing, the method and application of the flow measurement must meet the applicable turbine test codes.

Acoustic: Using ultrasonic waves, the velocity of the water is calculated from the Doppler shift or transit time of the signal through the water. Multiple path systems are used for higher accuracy. Acoustic systems are used on open and closed inlet sections and penstocks and pipes.

Differential pressure: Measurement in penstock and pipe inlet sections where the differential pressure is measured across a transition or restriction in the pipe system such as an elbow.

Winter-Kennedy taps: Measurement of pressures in the turbine spiral (or semi-spiral) case. The measurements are correlated with model test data for defined wicket gate openings and head conditions.

5.3.21 Fire protection

This subclause provides a guide for interfacing the fire protection system to the unit control system. (See Table 26.)

Fire protection in a hydroelectric station is usually automatically initiated. As a minimum, the generator and hydraulic oil equipment need fire alarm and protection systems; oil-filled transformers may also be protected. Heat and smoke detectors are put in other station areas for alarm. Station accessibility, hazard evaluation, cost of station equipment to be protected, ease of installation, and insurance requirements dictate degree of protection and actions required by the control system in other areas.

Table 26—Fire protection

Equipment or area	Type of detector	Typical response
Generator	1) Temperature 2) Smoke 3) Differential relay trip	—$C0_2$ system (enclosed units only). Discharge $C0_2$, trip unit. —Water deluge system—Do not spray on differential relay trip. Do not use smoke detectors. Need more than one detector to operate before spraying. Some plants rotate unit with field breaker open while deluge system operates. Others require a protective relay trip plus temp alarm before deluge system operates.
Transformers	1) Temperature 2) Protective relay trip	Water deluge system—Protective relay trip should initiate only if water supply is unlimited and oil spill cleanup is considered.
Hydraulic, lubricating oil, other mechanical areas	1) Temperature 2) Smoke	—Water deluge system—Bearing over-temperature protection (covered elsewhere for generators) helps prevent ignition of lubricating oil. —CO_2
Control equipment rooms, cable		$C0_2$
Control equipment rooms, cable spread areas, switchgear	1) Temperature 2) Smoke 3) Heat detection cables	$C0_2$

Fire protection and alarm and control systems can add significantly to the cost of a station; therefore, it is important to consider early in the design and to involve both fire protection engineers and the insurance carrier.

Fire protection or detection systems for electrical or mechanical equipment should always be interlocked to de-energize or otherwise disable the equipment. This will help to remove the source of ignition.

Location and type of heat detection device is important. Thermostats, heat detection cable, ionization and smoke detectors are among devices used.

The supply of substance used to cool or smother the fire is often limited. Even a large volume of water may be difficult to obtain in the hydroelectric station, due to head considerations at the fire location. Timed-flow cycling systems, which apply water, stop and measure heat, then reapply protection if necessary, may be required to conserve supply but are generally not recommended in fire protection systems. Provision for getting rid of or containing the fire protection substance, such as water after discharge, is also a consideration.

Unless properly designed, false operation of fire protection systems can harm personnel and damage equipment. $C0_2$ systems should be alarmed or interlocked with access ways to prevent discharge if people are in an area or to delay discharge to allow people to leave the area. As an added precaution, monitoring equipment could be provided to detect gas pocketing.

When fires are detected, and/or a fire extinguishing system operates, an alarm should sound in the area and at the same time be transmitted to the closest manned location. As a minimum, each unit and the general station should be separately alarmed. Never include fire detection on general trouble alarm circuits.

Emergency power is needed to operate fire protection equipment and associated controls and alarms. Dedicated circuits from the station battery or other highly reliable power source should be used for control and alarm. Diesel or gas turbine generators can provide back-up power for fire water pumps and battery chargers.

6. Control sequencing-generating units

The unit control system provides operating mode selection and a means of starting and stopping a hydroelectric generator. The control system can have varying degrees of operator intervention, from a “push-one-button” automatic system to one that is totally manual. Regardless of the type selected, the system should follow a certain sequence of events during start-up and shutdown. This clause will discuss in detail the logic involved in, and the automation of, this sequence. The steps in the sequence depend on the complexity of the units and plant.

As shown on the block diagram in Figure 9, the control system has inputs from various other equipment, such as the governor, the exciter, and the automatic synchronizer. Status inputs come from control switches, level switches, pressure switches, position switches, etc., throughout the plant. The combination of these inputs to the control system logic will provide outputs to the governor, exciter, and automatic synchronizer to accelerate the unit and place it online. Abnormalities in the inputs should prevent the unit’s start-up, or limit extended operation, if already online.

Regardless of the degree of automation desired, the control sequence can be divided into four parts, as follows:

a) Pre-start checks

b) Auxiliaries start

c) Unit run and load

d) Unit shutdown

6.1 Steps in the starting sequence

6.1.1 Pre-start checks

In the first step of the starting sequence, the control system verifies that various levels and pressures associated with the governor and turbine are normal and that certain breakers, switches, valves, and other devices have been properly pre-positioned. Any other restraints to unit operation, such as reservoir levels, are also checked at this time.

If these devices are arranged to provide a contact closure in their normal or permissive state, a multiple input logic “AND” gate can perform the checking operation. When the gate’s output is “ON,” all pre-start conditions have been satisfied and the auxiliaries start sequence can begin. The logic of the pre-start checks step is shown in Figure 22; a listing of typical inputs is presented in Table 27.

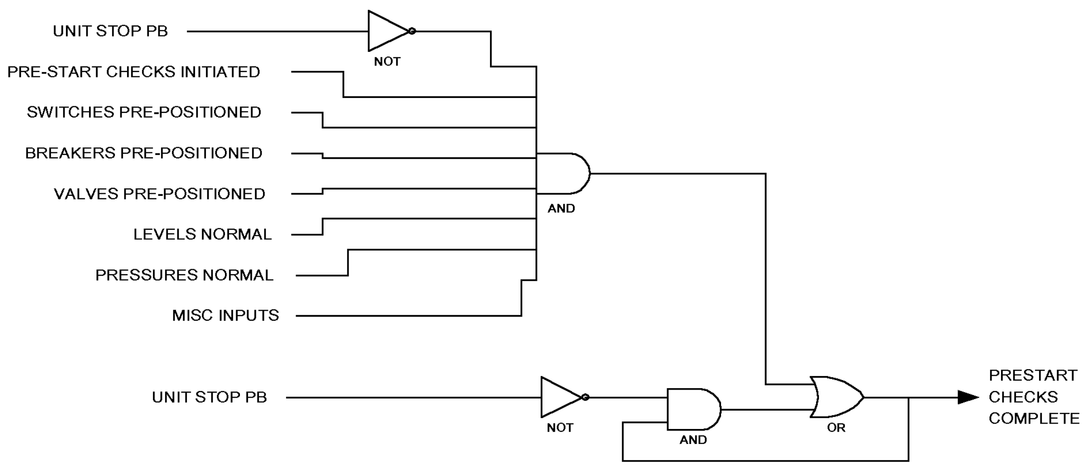

Figure 22—Logic representation of pre-start checks—generate/condense

Table 27—Inputs to the pre-start checks sequence generate/condense mode

Input	Position for startup	Type[a]	Originating from[b]	Notes
Mode switch	Generate/condense	C	SB	
Governor control switch	Gov	C	GV	
Brake control switch	Auto	C	GV	
Tailwater depressing control switch	Auto	C	SB (or OT)	
Governor oil pump control switch	Auto	C	GV	
Grease system control switch	Auto	C	TB	
Cooling water control switch	Auto	C	OT	
Phase reversing control switch	Generate/condense	C	SB	Reversible units only.
Thrust bearing oil pump control switch	Auto	C	GN	
Turbine bearing oil pump control switch	Auto	C	TB	
Unit breaker	Tripped	C	OT	
Exciter supply breaker	Tripped	C	EX	If used.
Field breaker	Tripped	C	EX	If used.
Turbine vent valve	Closed	C	TB	
Runner band drain valve	Closed	C	TB	

Table 27—Inputs to the pre-start checks sequence generate/condense mode *(continued)*

Input	Position for startup	Type[a]	Originating from[b]	Notes
Maintenance seal, below head-cover	Released	C	TB If used.	
Runner wear ring cooling water valve	Closed	C	OT	
Runner shaft seal water valve	Open	C	OT	Unit specific, may be part of auxiliaries start sequence.
Turbine guide bearing oil level	Normal	C, P	TB	
Governor sump oil level	Normal	C, P	GV	
Governor press tank oil level	Normal	C, P	GV	
Thrust bearing oil level	Normal	C, P	GN	
Governor oil pressure	Normal	C, P	GV	
Tailwater depressing air pressure	Normal	C	OT	
Brake air pressure	Normal	C, P	GV	
Exciter firing sequence	Normal	C	EX	Reversible unit if exciter tap on machine side of phase reversal switch.
Lockout relays	Reset	P	SB	
Control/protection voltage	Normal	C, P	OT	
Headgate position	100% open	C	OT	
Reservoir levels	OK for generator	C	OT	
Auto-synchronizer outputs	Connected to governor speed adjust and exciter voltage adjust	C	SB	

[a]C = control; P = protection.
[b]TR = transformer; GN = generator; TB = turbine; GV = governor; EX = exciter; SB = unit system; OT = other.

6.1.2 Auxiliaries start

After pre-start checks have been completed, the unit auxiliary systems (such as the cooling water pumps, the turbine grease system, and the thrust-bearing oil lift pumps) should be started, as shown in Figure 23. Also, at this time, the following actions should occur:

a) Gate limit is set to the turbine start position.
b) Governor speed set point is set for synchronous speed, if not already at this point from previous shutdown.
c) Turbine penstock shut-off valve, if used, is opened.
d) Gate closing rate limiters, if used, are applied.
e) Exciter manual and automatic voltage regulators are set at unit start values, if not already done from previous shutdown.

The status of these items, as well as the pressures and flows associated with the unit auxiliary systems, are input to another "AND" gate. Its output is a permissive for beginning the unit run sequence. Table 28 lists typical inputs that are checked to verify the completion of this step.

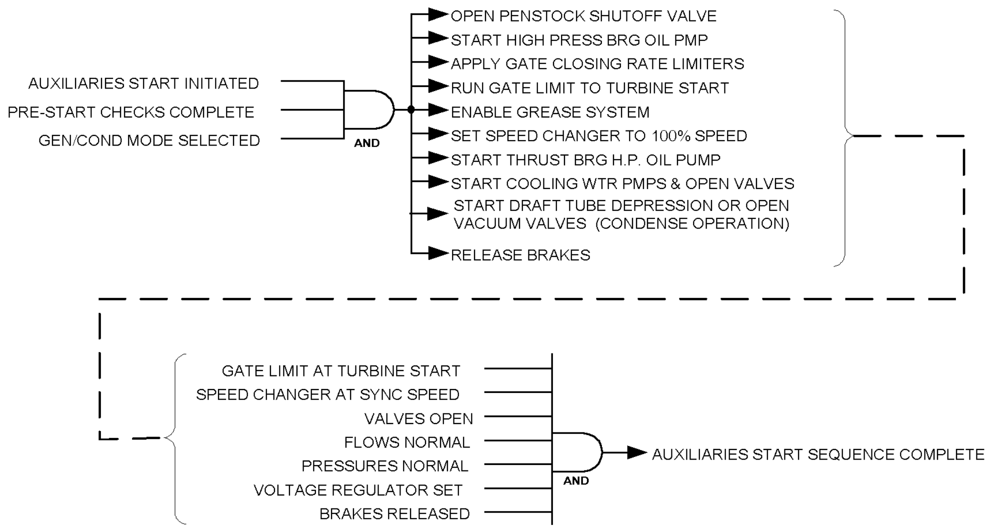

Figure 23—Logic representation of auxiliaries start—generate/condense mode

Table 28—Inputs to the auxiliaries start completed sequence

Input	Position for startup	Type[a]	Origi-nating from[b]	Notes
Mode switch	Generate/condense	C	SB If used.	
Gate limit	Turbine start	C	GV	
Speed changer	100%	C	GV	
Manual voltage regulator	Pre-start	C	EX	
Automatic voltage regulator	Pre-start	C	EX	
Thrust bearing oil press	Normal	C	GN	
Cooling water flow	Normal	C	OT	
Penstock shut-off valve	100% open	C	OT If used.	
Guide bearing oil flow	Normal	C	OT	
Brakes	Released	C	OT	

[a]C = control.
[b]TR = transformer; GN = generator; TB = turbine; GV = governor; EX = exciter; SB = unit system; OT = other.

6.1.3 Unit run

After the auxiliaries start sequence is completed, the unit run sequence begins. At this time, the following events occur:

a) The gate lock is released.

b) The complete governor shutdown is released, allowing the gates to start opening. The partial shutdown release is normally delayed until after breaker closure.

c) The exciter voltage regulators are enabled.

As the gates open, the unit accelerates until approximately 95% speed is attained. Then,

d) The field breaker closes (if used).

e) Field flashing begins if necessary.

f) Potential is applied to the automatic synchronizer.

The synchronizer adjusts the governor speed changer to match frequency and the voltage regulator to match voltage. When this is accomplished, and any operator pre-sync interaction is performed, the synchronizer closes the unit breaker, placing the unit online. The operator or control system then adjusts the governor for the desired generator output. If condenser operation is desired, the gates are closed, tailwater is depressed, and the voltage regulator is adjusted for the desired reactive power output. The logic of the unit run sequence is shown in Figure 24.

In the event that an induction generator is being used, the start-up sequence is to start the turbine in the normal manner, as is done with a synchronous generator. The generator is run up to synchronous or very slightly above synchronous speed and connected to the system, thereby limiting current inrush to the machine. The system determines the voltage and frequency.

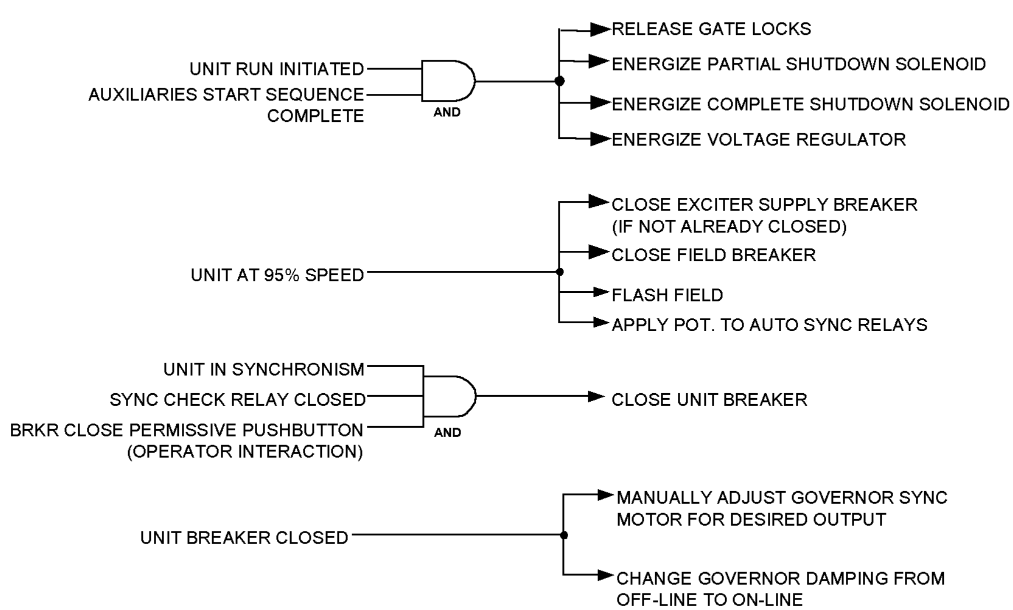

Figure 24—Logic representation of unit run sequence—generate/condense

6.1.4 Unit shutdown

The control system can provide three types of unit shutdown: emergency, quick, and normal. The emergency shutdown is the most rapid means of disconnecting the unit. An emergency shutdown lockout relay is triggered by protective relaying or the operator's emergency trip switch. The following actions occur simultaneously:

a) The unit breaker is tripped.
b) Excitation is shut down.
c) The governor complete and partial shutdown solenoids are de-energized, driving the gates closed.
d) Gate limit is run back to zero position.
e) The governor speed changer is driven back to the pre-start position.
f) The starting control sequence is disabled.

As the unit speed decreases, the thrust-bearing oil lift pump is started. When the unit reaches about 30% speed, the brakes are applied until the unit is stopped. The unit auxiliary systems are shut down and the turbine penstock shut-off valve, if used, is closed. The logic for the emergency shutdown sequence is shown in Figure 25, and a listing of typical inputs is shown in Table 29.

Table 29—Inputs to the normal shutdown sequence

Input	Position for shutdown	Type[a]	Originating from[b]	Notes
Generator thrust bearing temperature	High	P, T	GN	
Generator guide bearing temperature	High	P, T	GN	
Turbine packing box temperature	High	P, T	TB	
Turbine guide bearing temperature	High	P, T	TB	
Governor sump oil level	Low	P	GV	
Penstock shut-off valve oil level	Low	P	OT if used	
Cooling water flow	Low	P	OT	
Starting sequence dropout	Closed	P	SB	
Unit stop push button	Closed	C	SB	

[a]C = control; P = protection; T = temperature.
[b]TR = transformer; GN = generator; TB = turbine; GV = governor; EX = exciter; SB = unit system; OT = other.

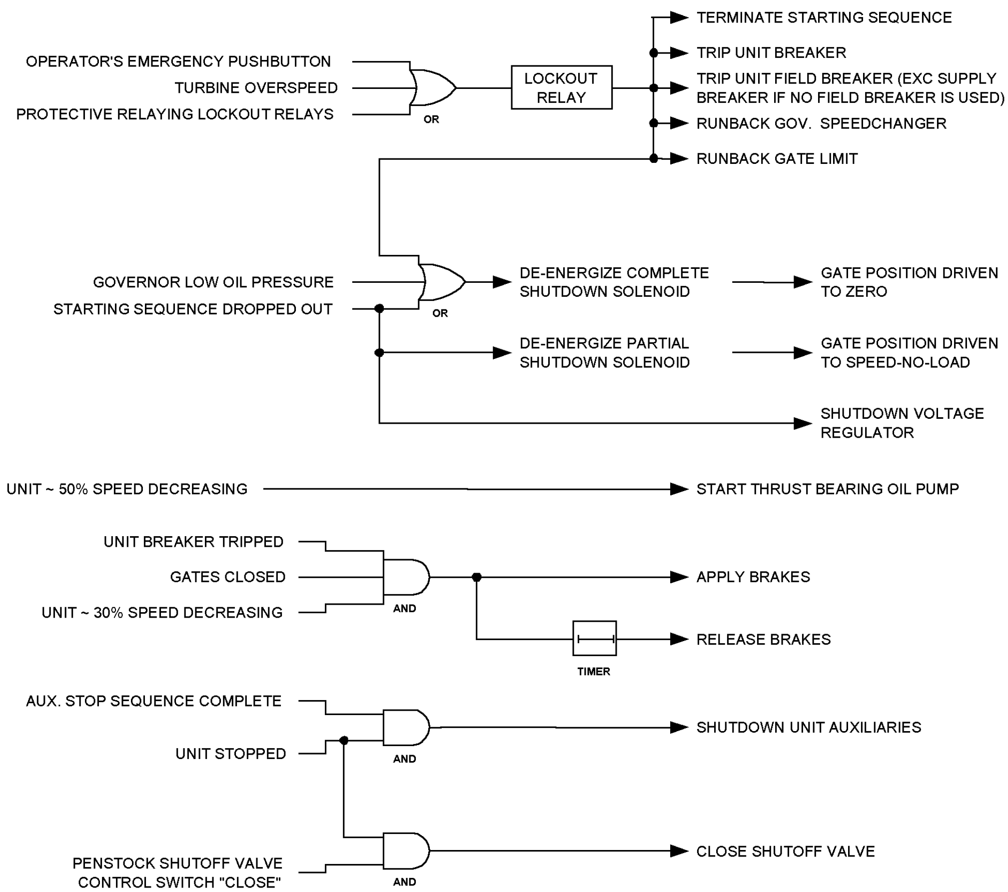

Figure 25—Emergency shutdown sequence logic

The quick shutdown is initiated generally by mechanical problems such as low governor oil pressure, vibration, and bearing high temperatures. A lockout relay may be operated by these conditions, if desired, to accomplish shutdown functions. A listing of typical inputs to the quick shutdown sequence is given in Table 30. A logic diagram is shown in Figure 26.

The quick shutdown is similar to the emergency shutdown in that the gates are driven closed at maximum rate by de-energizing the governor's complete shutdown solenoid. However, the unit breaker is not tripped until the speed-no-load gate position or zero power output is reached, thus avoiding a load rejection trip. Also, at speed-no-load:

a) Excitation is shut down.
b) The governor speed changer is run back to its pre-start position.
c) Gate limit is run back to zero position.
d) The starting control sequence is dropped out, de-energizing the governor partial shutdown solenoid.

The thrust bearing oil pump is then started on decreasing speed, and the brakes are applied. The unit auxiliary systems are shut down and the turbine penstock shut-off valve, if used, is closed.

The normal shutdown sequence, like the quick shutdown, unloads the unit prior to tripping its breaker. The gates are closed at less than maximum rate by driving gate limit to zero position. This sequence should be used for routine unit shutdown, but it is also actuated by various abnormal levels, pressures, and flows of a less critical nature.

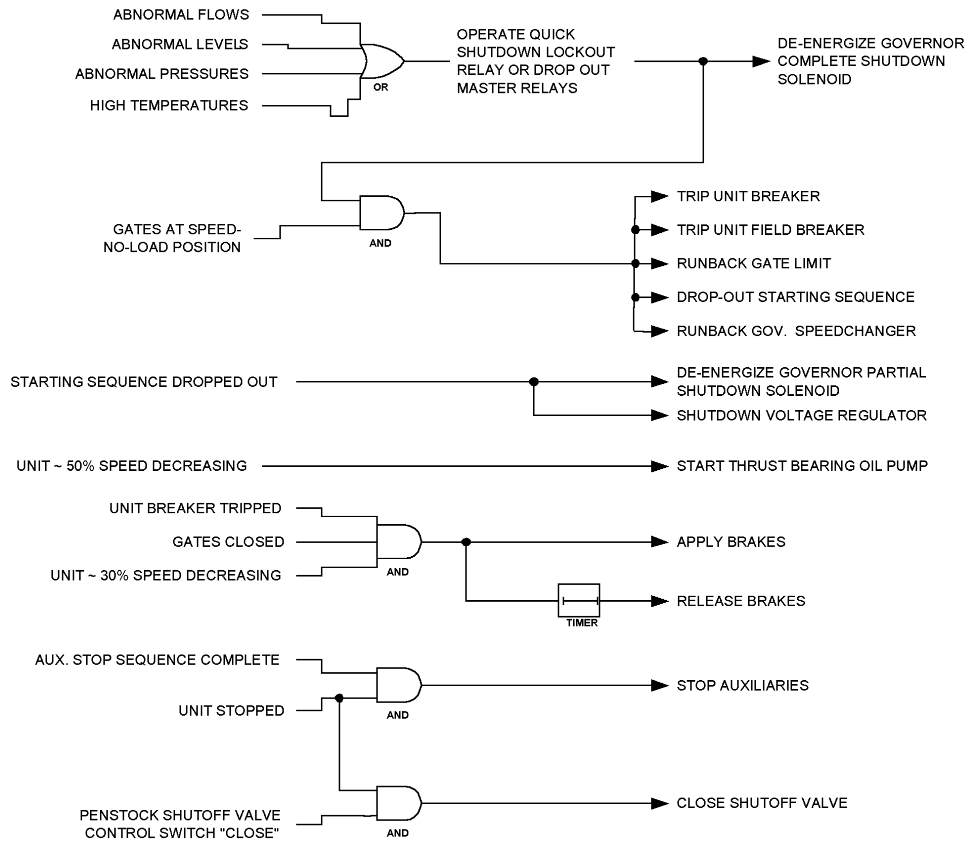

Figure 26—Quick shutdown sequence logic

Table 30—Inputs to the quick shutdown sequence

Input	Position for shutdown	Type[a]	Originating from[b]	Notes
Turbine guide bearing temperature	High	P, T	TB	
Shaft packing box temperature	High	P, T	TB	
Runner seal temperature	High	P, T	TB	
Generator thrust bearing temperature	High	P, T	GN	
Generator guide bearing temperature	High	P, T	GN	
Overspeed switch	Closed	P	GV	
Unit vibration	High	P	OT	
Governor press tank oil level	Hi-Low	P	GV	
Governor oil pressure	Low	P	GV	
Shaft packing box cooling water flow	Low	P	TB	

[a]P = protection; T = temperature.
[b]TR = transformer; GN = generator; TB = turbine; GV = governor; EX = exciter; SB = unit system; OT = other.

The unit breaker is then tripped at speed-no-load gate position or zero power output. The remainder of the shutdown sequence is the same as for the quick shutdown. Inputs to the normal shutdown sequence are listed in Table 31, and the associated logic is shown in Figure 27.

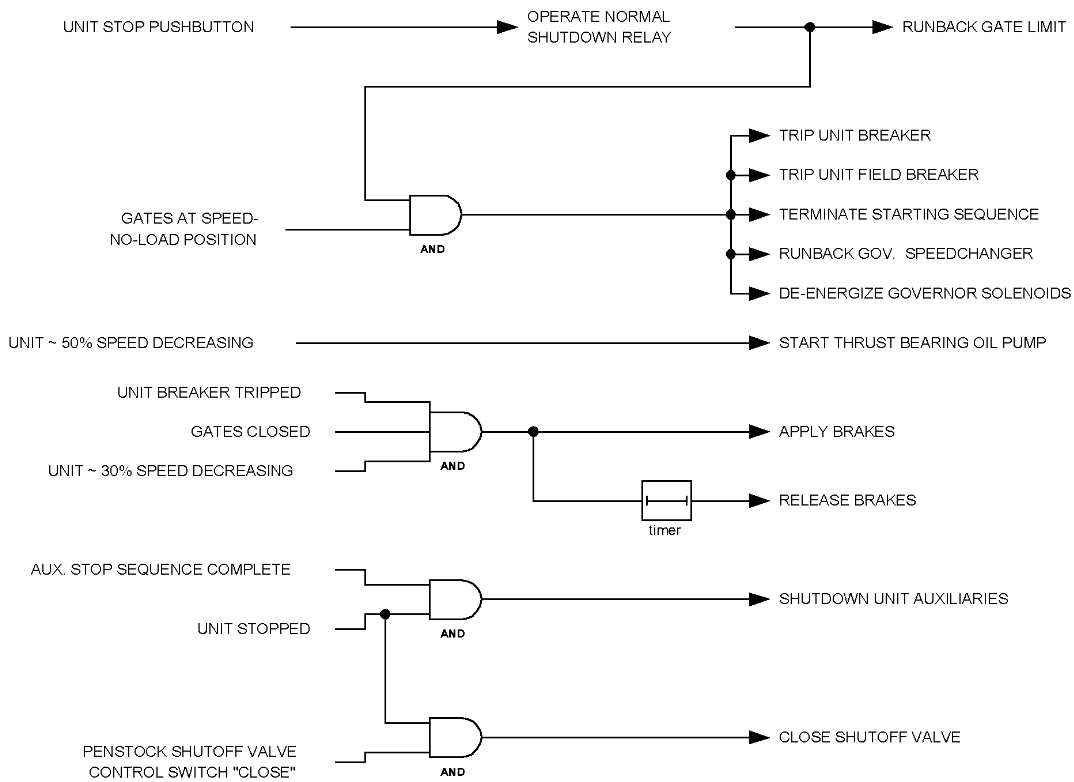

Figure 27—Normal shutdown sequence logic

Table 31—Inputs to the emergency shutdown sequence

Input	Type[a]	Originating from[b]	Notes
Differential relays actuated	P	GN, TR, OT	
Overcurrent relay actuated	P	GN, TR	
Electrical disturbance detected	P	System	
$C0_2$ released	P	OT	
Turbine overspeed occurs	P	GV, GN	
Emergency push button actuated	C	SB	

[a]C = control; P = protection.
[b]TR = transformer; GN = generator; TB = turbine; GV = governor; EX = exciter; SB = unit system; OT = other.

6.2 Automation of the control system

One of the first decisions that should be made prior to designing a unit control system is how much operator intervention in the starting sequence is desired.

An automatic control system operates as shown in Figure 28. No manual action is needed to begin pre-start checks. When pre-start conditions are met, the operator initiates unit start, energizing the master relays. Unit auxiliaries are started and checked. The unit run sequence begins, the unit accelerates, speed and voltage are matched at the point of synchronization, and the unit is placed online. If the unit speed fails to reach 95% within a predetermined period, an alarm will indicate that the attempted start is incomplete. After a successful start, the operator or automation system adjusts the governor for the desired power output and may adjust the voltage regulator. Even this can be automated if a fixed output is desired, or if the load curve is such that it can be programmed into the control system.

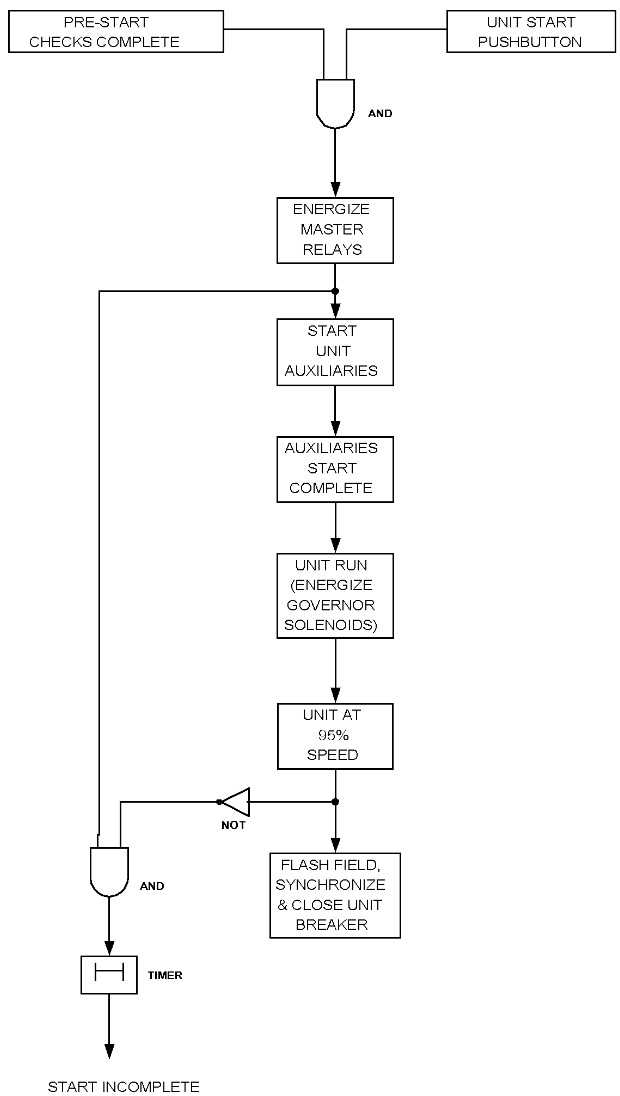

Figure 28—Master relay control system

Another type of automatic system involves several operator input steps that can be performed prior to the desired starting time. This causes the system to become semi-automatic and requires more operator intervention. As shown in Figure 29, the sequence stops after pre-start checks. Start sequence will not begin until the operator initiates a start. The sequence stops again after auxiliaries checks are completed and requires another operator action before the unit run sequence begins. From this point on, the system is fully automatic. A permissive may also be needed prior to closing the field breaker, field flashing, and synchronizing and closing of the generator breaker. Note that timers may be added to check the progression of each step.

The unit shutdown system is similar for both types of starting systems. Shutdown is initiated by de-energizing the master sequence relays.

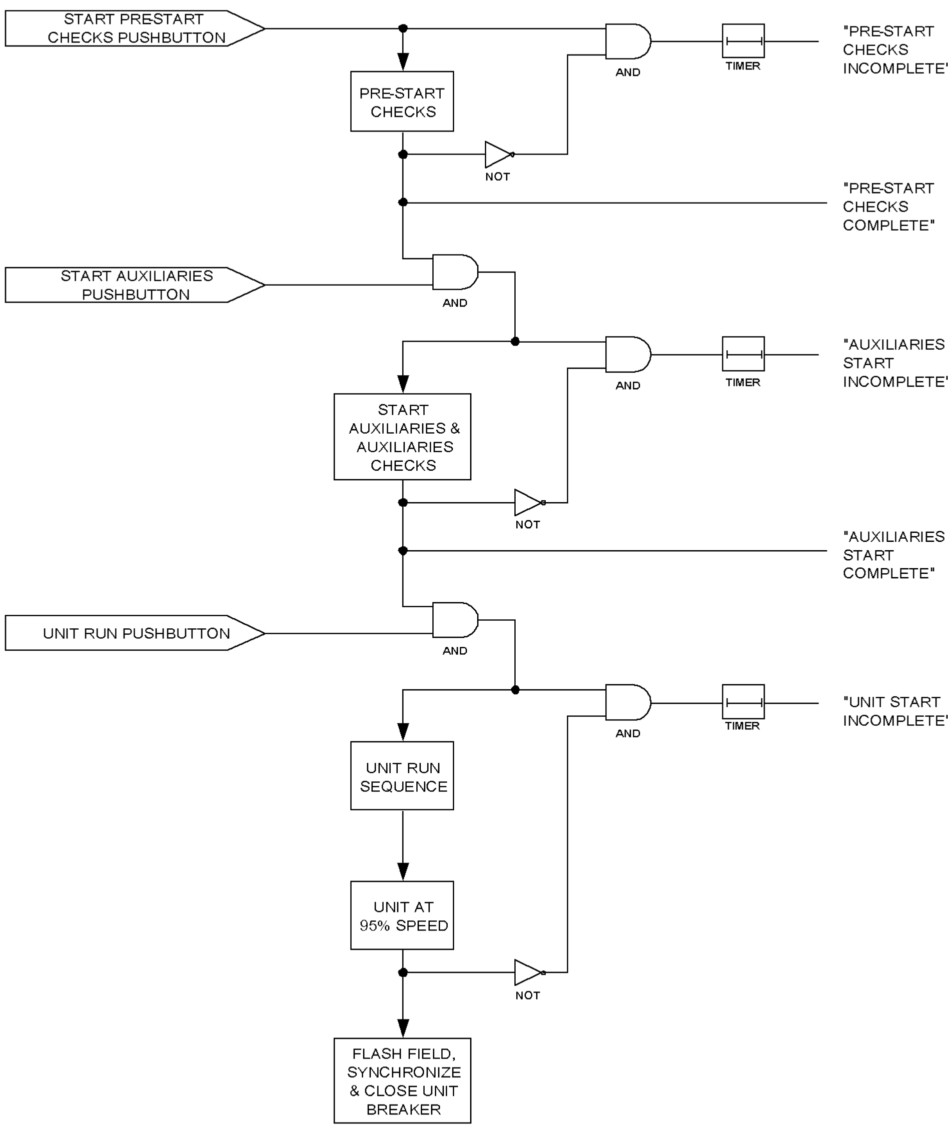

Figure 29—Stepped sequence control system

7. Control sequencing—Pumped-storage units

The unit control system functions on a pumped-storage unit are similar to those on a conventional unit for generation as discussed in Clause 6. This clause discusses in particular the control sequences for "motoring" during pumping operation.

The pump control sequence can be divided into four parts, as follows:

a) Pre-start checks
b) Auxiliaries start
c) Unit run, pump prime, and pump load
d) Shutdown

7.1 Steps in the starting sequence

7.1.1 Pre-start checks

Most of the inputs to the pre-start checks sequence are the same as in the generate mode. The phase reversing switch should be placed in the motor position. If pony motor or static starting is used, there may be temperature, pressure, flow, and level switches associated with the starter that should be checked. For synchronous and semi-synchronous starting, the availability of the starting generator should be verified. The logic for the pump pre-start checks is presented in Figure 30, and the typical inputs are listed in Table 32.

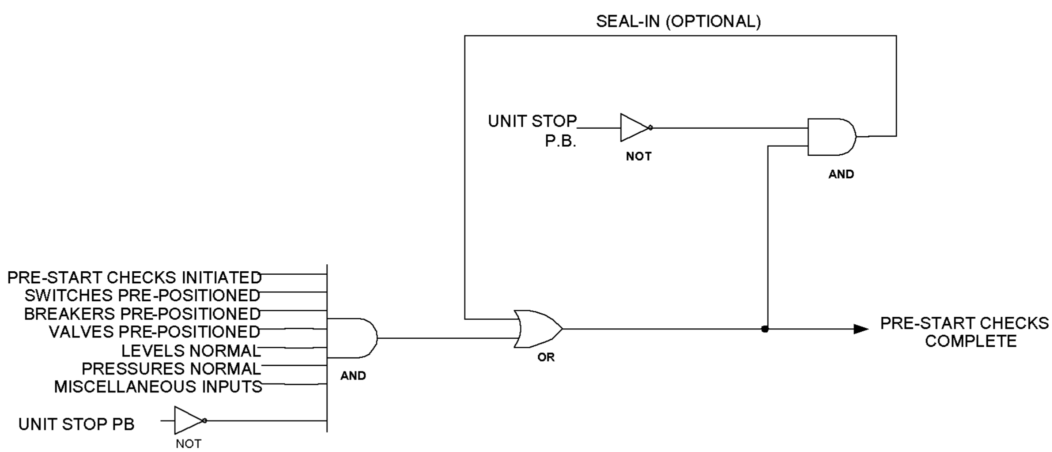

Figure 30—Logic representation of pre-start checks—pump mode

Table 32—Inputs to the pre-start sequence pump mode

Input	Position for startup	Type[a]	Originating from[b]	Notes
Mode switch	Pump	C	SB	
Governor control switch	Gov	C	GV	
Brake control switch	Auto	C	GV	
Tailwater depressing control switch	Auto	C	SB (or OT)	
Governor oil pump control switch	Auto	C	GV	
Grease system control switch	Auto	C	TB	
Cooling water control switch	Auto	C	OT	
Phase reversing switches	Pump	C	SB, OT	
Thrust bearing oil pump control switch	Auto	C	GN	
Turbine bearing oil pump control switch	Auto	C	TB	
Unit breaker	Tripped	C	OT	
Exciter supply breaker	Tripped	C	EX	If used.
Field breaker	Tripped	C	EX	If used.
Turbine vent valve	Closed	C	TB	
Runner band drain valve	Closed	C	TB	
Runner wear ring cooling water valve	Closed	C	OT	
Runner shaft seal water valve	Open	C	OT	Unit specific, may be part of auxiliaries start sequence.
Shaft maintenance seal	Released			
Turbine guide bearing oil level	Normal	C, P	TB	
Governor sump oil level	Normal	C, P	GV	
Governor press tank oil level	Normal	C, P	GV	
Thrust bearing oil level	Normal	C, P	GN	
Pump starting equipment cooling-oil and electrolyte level	Normal	C	OT	
Governor oil pressure	Normal	C, P	GV	
Tailwater depressing air pressure	Normal	C	OT	
Brake air pressure	Normal	C, P	GV	
Pump starting equipment temp	Normal	P	OT	

Table 32—Inputs to the pre-start sequence pump mode *(continued)*

Input	Position for startup	Type[a]	Originating from[b]	Notes
Exciter firing sequence	Reversed	C	EX	If exciter tap on machine side of phase reversal switch.
Lockout relays	Reset	P	SB	
Control/protection voltage	Normal	C, P	OT	
Brakes	Released	C	GN	
Headgate position	100% open	C	OT	
Gate locks	Locked	C	TB	
Reservoir levels	OK for pump	C	OT	
Auto-synchronizer outputs	Connected to starting equipment and exciter volt reference	C	SB	
Starting breaker	Tripped	C	OT	

[a]C = control; P = protection.
[b]TR = transformer; GN = generator; TB = turbine; GV = governor; EX = exciter; SB = unit system; OT = other.

7.1.2 Auxiliaries start

Upon the completion of pump pre-start checks, the auxiliaries start sequence depresses the tailwater, drives the gate limit to zero position, and starts the thrust-bearing oil lift pump. In addition, the governor speed changer is driven “out high,” since it has no speed control function in the pump mode.

The pump starting equipment is readied at this time. For pony motor starting, the liquid rheostat is positioned for maximum resistance (minimum motor speed). The rheostat’s cooling equipment is energized and proper flow is verified.

All of these processes are verified by status contact inputs to an “AND” gate, as shown in Figure 31. Other inputs verifying actions taken during the pre-start step are included in Table 33. The output of the “AND” gate is a permissive for beginning the unit run sequence.

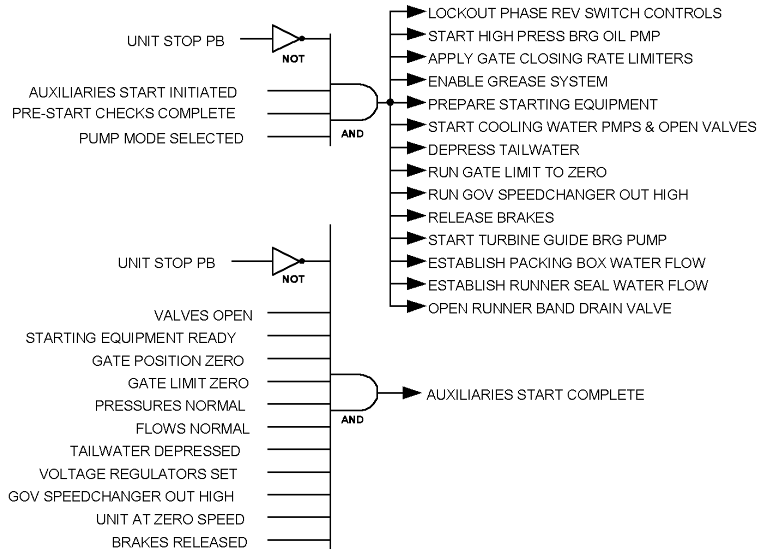

Figure 31—Logic representation of auxiliaries start—pump mode

Table 33—Inputs to the auxiliaries start complete sequence pump mode

Input	Position for startup	Type[a]	Originating from[b]	Notes
Mode switch	Pump	C	SB	
Start auxiliary push button or master relays energized	Closed	C	SB	
Gate limit	Zero	C	GV	
Speed changer	Out high	C	GV	
Gate position	Zero	C	GV	
Manual voltage regulator	Pre-start	C	EX	
Automatic voltage regulator	Pre-start	C	EX	
Thrust bearing oil pressure	Normal	C	GN	
Cooling water flow	Normal	C	OT	
Starting equipment cooling water flow	Normal	C	OT	
Tailwater level switch	Depressed	C	OT	
Penstock shut-off valve	100% open	C	OT	
Turbine guide bearing oil flow	Normal	C	TB	
Packing box water flow	Normal	C	TB	
Seal water flow	Normal	C	TB	

[a]C = control; P = protection.
[b]TR = transformer; GN = generator; TB = turbine; GV = governor; EX = exciter; SB = unit system; OT = other.

7.1.3 Unit run

The unit run portion of this step brings the machine up to 100% speed in the motor direction and places it online and spinning in air. The sequence varies somewhat with the type of starting used. Figure 32 illustrates the logic involved.

a) *Full voltage, across-the-line starting.* The machine is started as an induction motor, which requires a specially designed amortisseur winding. At the beginning of the unit run sequence, the unit breaker is closed, which applies system power to the machine. When the unit reaches approximately synchronous speed, excitation is applied and the machine then accelerates to rated speed as a synchronous motor.

b) *Reduced voltage, across-the-line starting.* As in full-voltage starting, the machine is accelerated as an induction motor. At the beginning of the unit run sequence, the starting breaker is closed, applying reduced voltage to the machine. At approximately synchronous speed, excitation is applied. When synchronous speed is reached, the starting breaker is tripped and the unit breaker is closed. Figure 33 illustrates the logic involved.

   Partial winding starting is similar, except at near rated speed the remainder of the winding is connected.

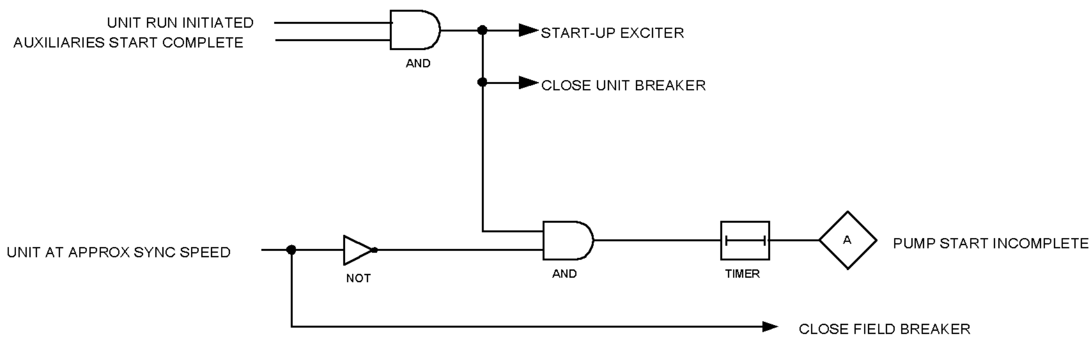

Figure 32—Logic representation of unit run sequence—pump mode—full-voltage starting

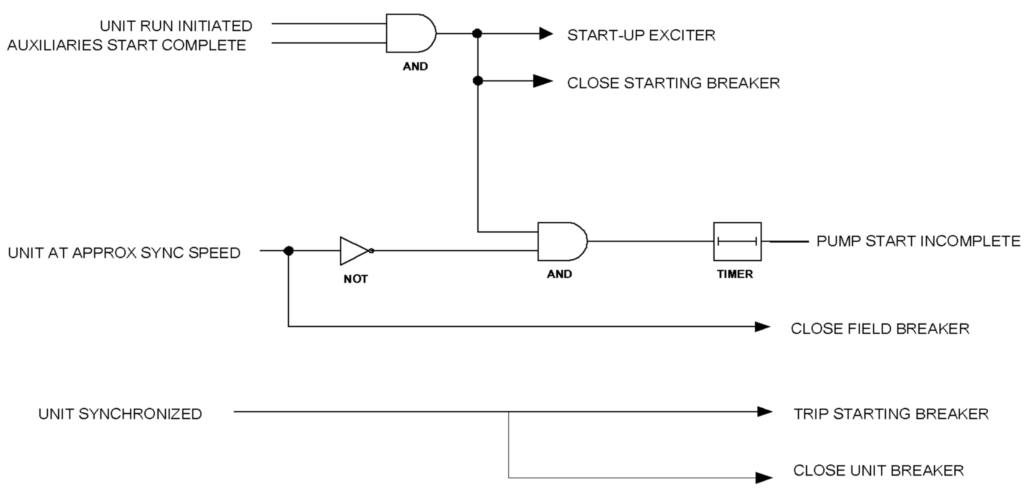

Figure 33—Logic representation of unit run sequence—pump mode—reduced-voltage start

c) *Pony motor starting.* The unit run sequence begins by applying power to the pony motor. Its field rheostat controller adjusts resistance to provide constant pony motor torque during the initial acceleration period. When unit speed reaches 95%, rheostat control is transferred to the synchronizing equipment. The field is flashed, establishing machine terminal voltage. When the unit is synchronized, its breaker is closed, placing it online. The pony motor supply breaker is tripped and the rheostat is repositioned for the next start. The unit run logic is illustrated in Figure 34.

d) *Synchronous starting.* The first step in the unit run sequence for synchronous starting is electrically connecting the starting generator to the unit motor. At this time, the starting generator's control sequence must be in the unit run mode. Excitation is applied to both machines. The gates are opened on the generator. As it accelerates, the motor unit follows. The speed of both units is brought to system frequency. When frequency is matched, the generator unit is isolated from the motor unit and the motor unit's breaker is closed. Figure 35 shows the logic involved.

e) *Semi-synchronous starting.* Prior to initiating the unit run sequence for the pump unit, the starting generator must be accelerated to about 80% of rated speed, with its excitation not applied. The unit run sequence begins with connecting the two units together through the starting bus. Excitation is applied to the starting generator, which establishes voltage on the starting bus and begins pump unit acceleration. As the starting generator decelerates and the pump unit accelerates, the two will reach approximately equal speed. At this point, which is determined by a speed-matching device, excitation is applied to the pump unit to pull it into synchronism with the generator. The wicket gates on the generator unit are then opened to accelerate both units to above synchronous speed. The starting breakers are tripped, and the synchronizing equipment places the pump unit online. The generating unit may then be used for starting another unit or tripped. Figure 36 illustrates the unit run logic for this starting method.

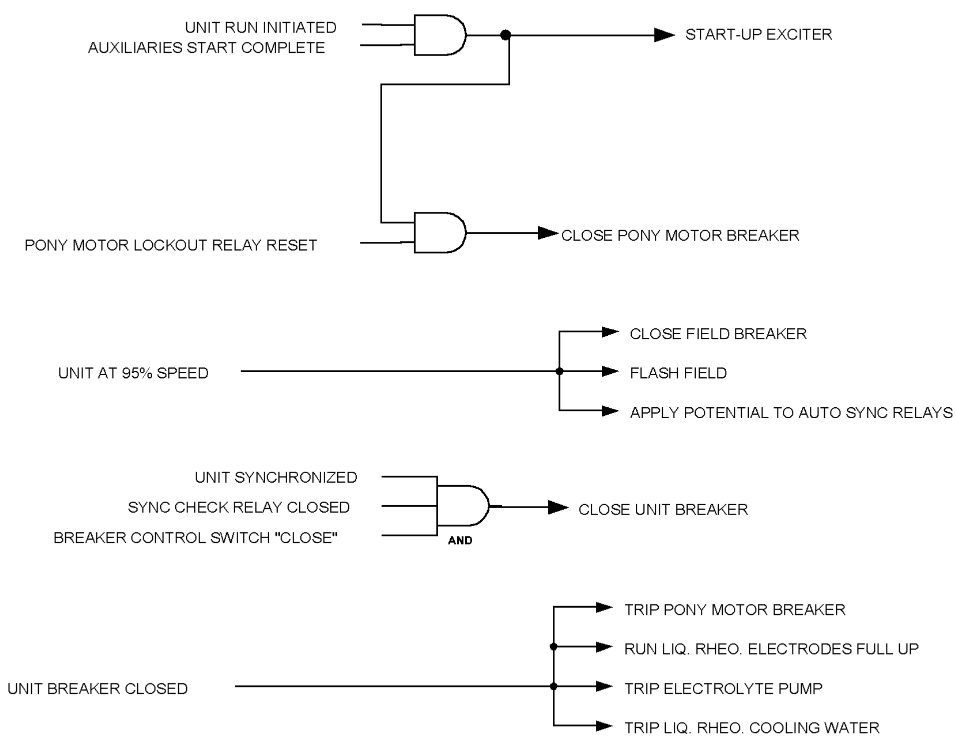

Figure 34—Logic representation of unit run sequence—pump mode—pony motor start

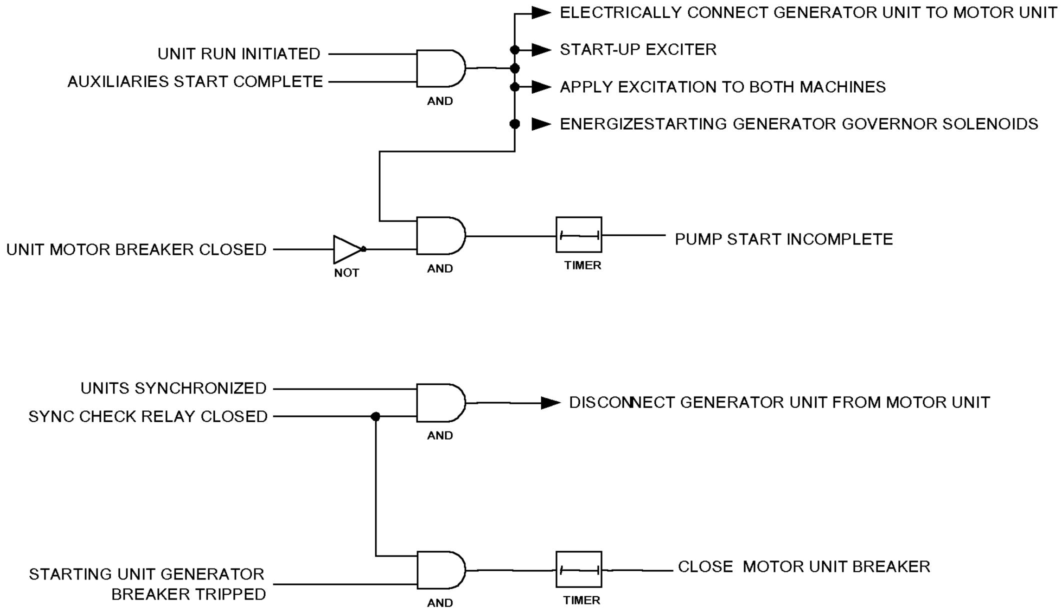

Figure 35—Logic representation of unit run sequence—pump mode—synchronous starting

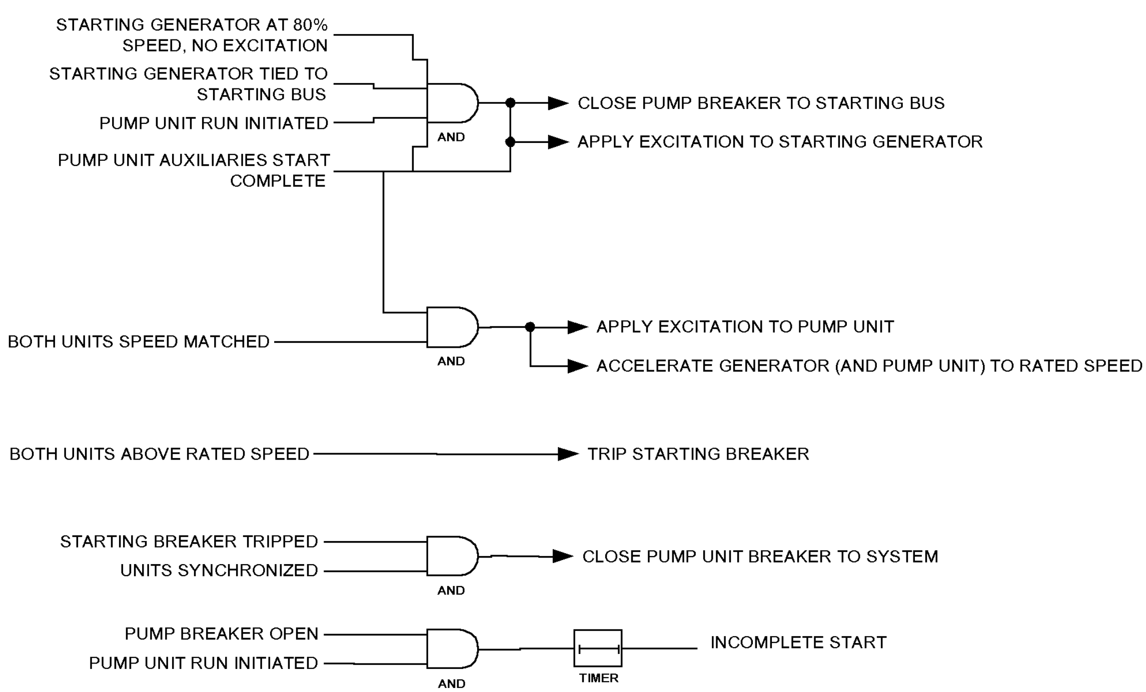

Figure 36—Logic representation of unit run sequence—pump mode—semi-synchronous starting

f) *Static starting*. Since this is also a type of variable frequency starting, the unit must be isolated from the system during startup. At the beginning of the unit run sequence, the unit is electrically connected to the static starter. Excitation is applied to the machine field, the starter is enabled, and the unit begins rotating. The output frequency of the starter is increased to maintain a constant accelerating torque. Speed versus time checks in the starter will shut down the unit if acceleration does not proceed normally.

Synchronizing may be accomplished as the unit approaches synchronous speed; alternatively, the starter may bring the unit up to just above synchronous speed. The unit and the static starter are then isolated. When unit speed matches system frequency, the synchronizer closes the unit breaker, placing it online and shuts down the starter. Figure 37 illustrates the alternate unit run sequence for static starting.

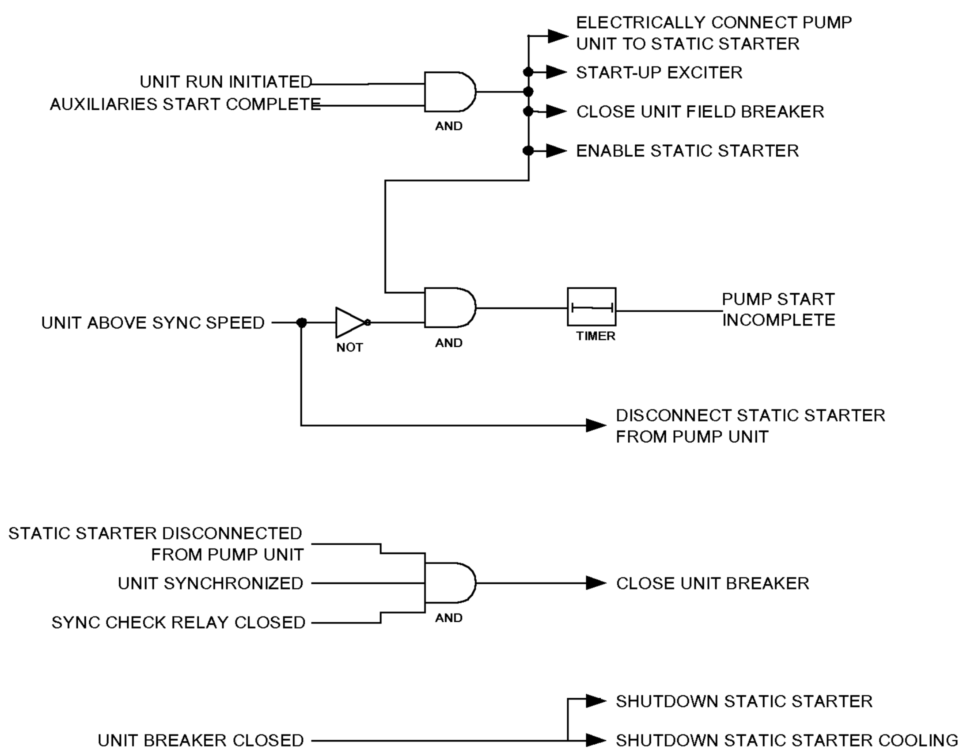

Figure 37—Logic representation of unit run sequence—pump mode—static starting

7.1.4 Pump prime and unit loading

At the end of the unit run sequence, the pump-turbine is spinning in the air. The pump priming sequence is the same for all types of unit starting. It begins with closing the tailwater depression valves and opening the turbine vent valve that releases the depressing air. When the tailwater completely immerses the turbine blades, the vent valve closes. A pressure switch in the runner senses that priming is complete, and the gates must be opened and the pump must be loaded immediately.

The pump load sequence energizes the governor solenoids, allowing the gates to open. Gate limit is driven to the “most efficient pump” position. When gate position reaches this point, the loading sequence and the starting sequence are completed. During pumping operation, the optimum gate position may be automatically controlled for net head changes by the governor. If gate position does not reach 10% to 20% in a few seconds, the unit should be shut down. The logic for the priming and loading sequences are shown in Figure 38.

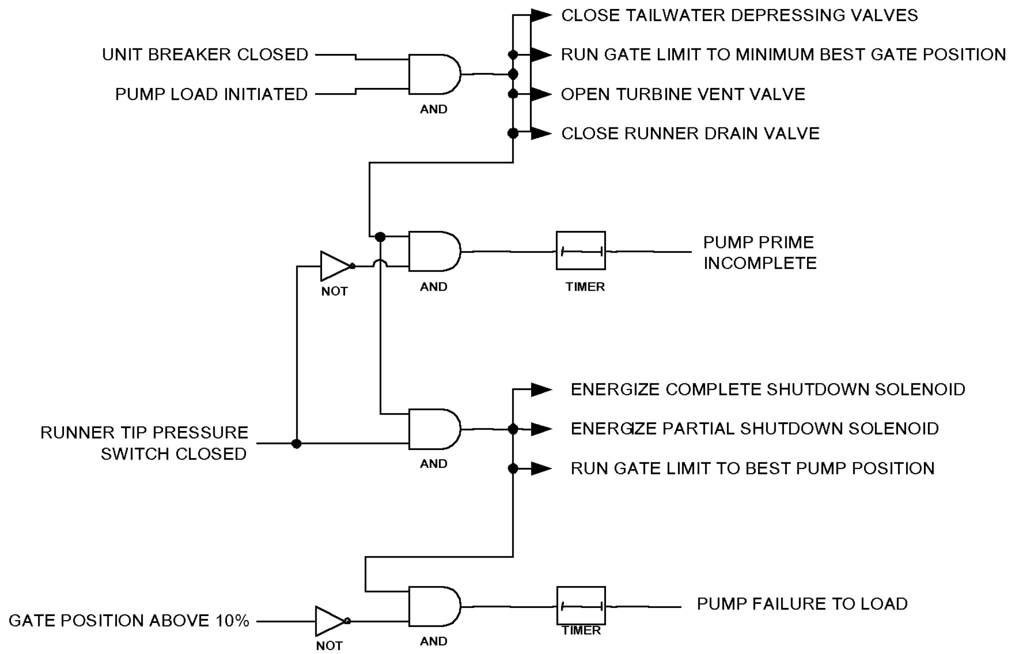

Figure 38—Logic representation of pump priming and unit load sequence—pump mode

7.2 Unit shutdown

The shutdown sequence for a pump unit is very similar to that for a conventional generator. Reference is made to the discussion of unit shutdown in Clause 6. Both normal and emergency shutdown sequences are provided in the pump mode. In the unit normal shutdown sequence, the machine is unloaded prior to tripping the unit breaker by first closing the gates. Care should be taken to assure tripping the unit immediately upon gate closure to avoid pumping against a shut-off head. The shutdown logic diagrams are shown in Figure 39 and Figure 40.

7.3 Control sequence automation

Both the "master relay" and the stepped sequence type of control systems discussed in Clause 6 can be applied to a pumped-storage unit. While some operator intervention may be desired, the timing involved in the pump prime and loading sequences is too critical to depend on operator control, and the control systems should be fully automatic.

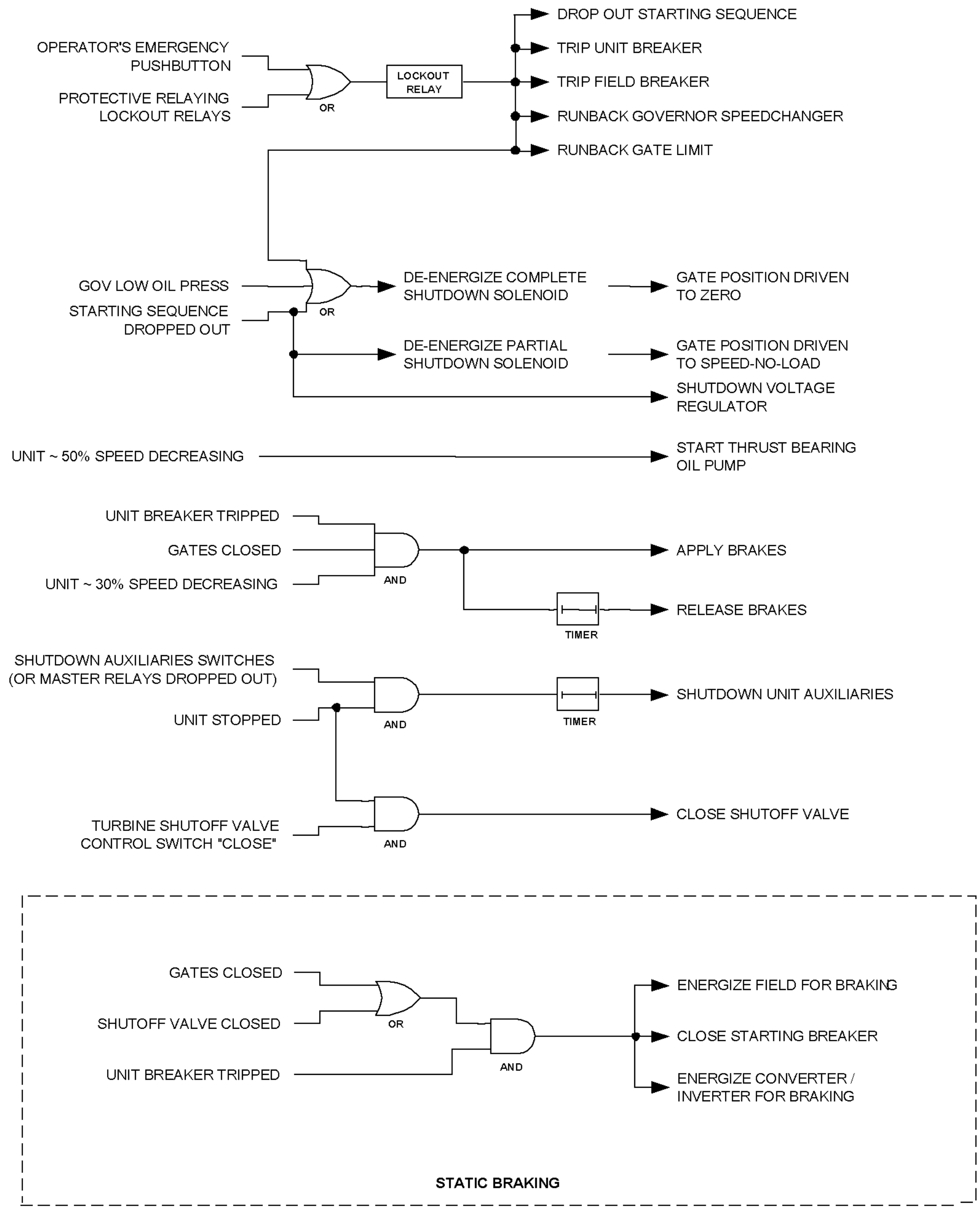

Figure 39—Emergency shutdown sequence logic—pump mode

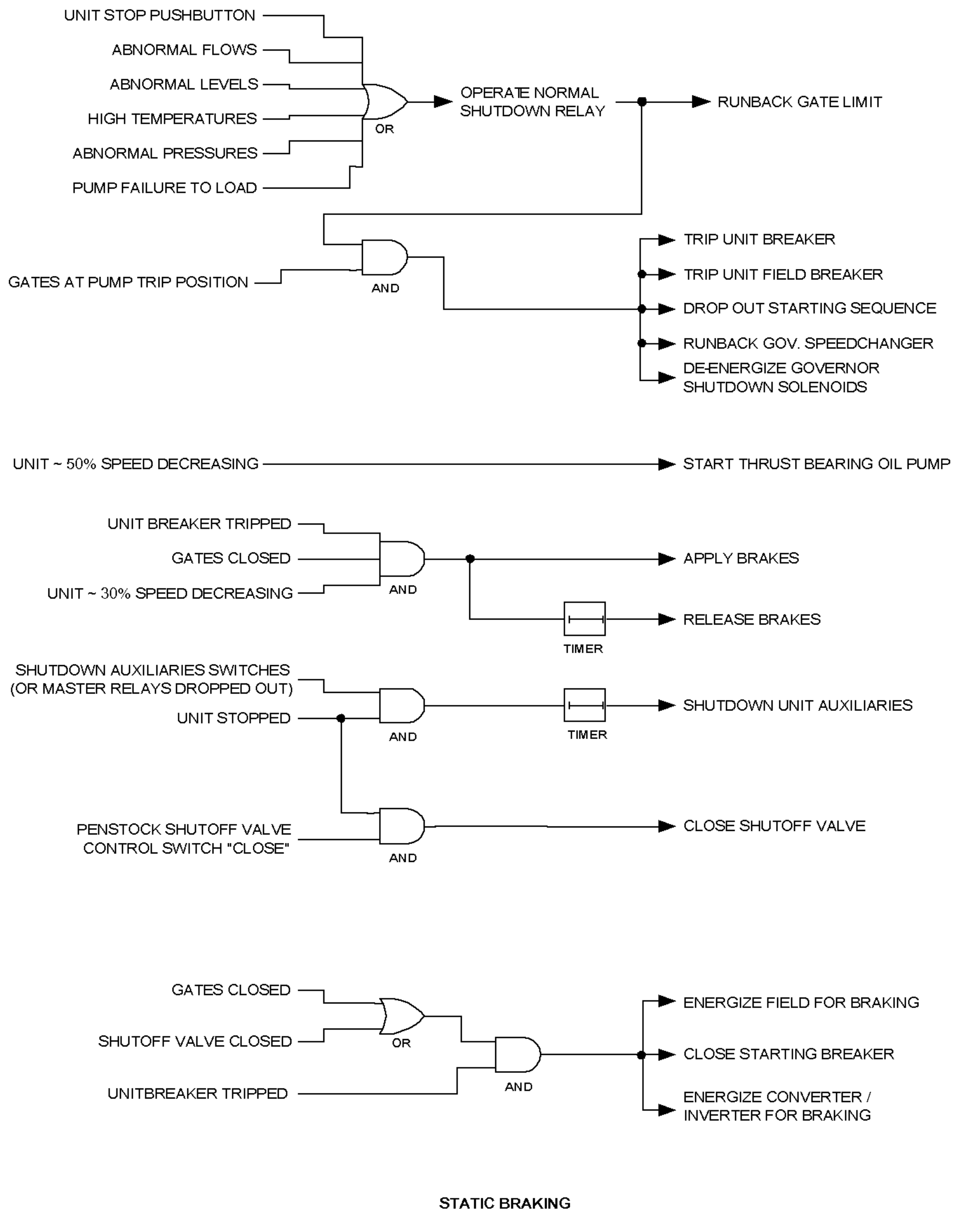

Figure 40—Normal shutdown sequence logic—pump mode

8. Centralized control

8.1 General

This clause describes control systems and equipment that could be used to accomplish the control and monitoring functions of hydroelectric power plants. Such control systems normally interface with the unit control panels located near the units or in a centralized control area, and with off-site control facilities.

The term *centralized control,* as defined in this guide, refers to a common control location from which control functions can be initiated, and from which plant operating data can be collected and displayed.

The goal of centralized control is to consolidate control functions and plant operating data at a common location in order to facilitate plant operation and reduce operating staff.

In the past, hard-wired relay logic and conventional electromechanical control devices and monitoring equipment were used for centralized control. Today, computer-based systems are increasingly being used in place of or in conjunction with hard-wired control equipment. Specific application of computer-based control systems can be found in IEEE Std 1249. Centralized control system configuration for a particular plant is a function of the plant's characteristics, such as size, number of units, and capability of operating-maintenance staff.

The major control and monitoring functions of a hydroelectric power plant may consist of the following:

8.1.1 Unit start

This initiates the automatic start sequence that will start, accelerate, synchronize, and tie the unit to the system. The unit may then be loaded as desired or, optionally, it can be loaded automatically to some preset load point.

8.1.2 Unit stop

The normal automatic shutdown is initiated, whereby the unit is unloaded before the circuit breaker is tripped. The unit is usually unloaded at a moderate rate.

8.1.3 Emergency shutdown

Initiation of this sequence trips the circuit breaker immediately and is the usual automatic response to protective relay operation at the plant.

8.1.4 Speed reference control

This control is used to raise or lower the governor speed reference setting online, thereby adjusting unit generation.

8.1.5 Generation level control

This is also an online control function similar to speed reference control, but it allows the operator to set a generation level to be regulated automatically by a local control system, frequently built into the governor. For the computer-based system, unit generation could be controlled by the computer system through an interface with the governor on the basis of the required plant generation and unit participation factor. Many modes of operation such as set point control, regulating, base loaded, ramped control, manual control, and others relative to the nature of the project and operating philosophy could be applied.

8.1.6 Voltage—Var control

This control adjusts the set point of the voltage regulator to adjust the reactive power of the machine.

8.1.7 Joint load generation—Var control

For a multi-unit plant, the set point for desired plant output can be entered by either the local operator or the dispatch control center and regulated automatically by the joint load-var controller. The desired unit contribution is computed from the plant set point, then applied to each unit participating in the joint control scheme within the plant. Units may also be started or stopped as needed to achieve the desired plant output. This function may also be scheduled by a plant or unit optimization routine to obtain the best operating efficiency for the jointly controlled units.

8.1.8 Monitoring of status—Information

Status information allows the operator to be aware of unit and plant conditions. The following are samples of status information:

a) Readiness for automatic start
b) Automatic start sequence initiated
c) Automatic stop sequence initiated
d) Unit under automatic or manual control
e) Unit on or off joint or automatic control
f) Unit on or off dispatch center or plant control
g) Unit circuit breaker open or closed
h) Intake gate open or closed
i) Mode of operation

8.1.9 Monitoring of analog measurements

These data are presented to the operator to provide information required for monitoring and control of the power plant and include the following:

a) Unit and plant real and reactive power
b) Unit voltage, current, and frequency
c) Turbine wicket gate and/or blade or nozzle position
d) Headwater and tailwater levels
e) Various temperature readings
f) Gate limit position

8.1.10 Alarms

These advise the operator of abnormal conditions. Examples of alarms are as follows:

a) Major troubles
b) Minor troubles
c) Protective relay operations
d) Initiation of emergency or other protective type shutdown sequences
e) Troubles in unit equipment including generator-turbine, governor, exciter, transformer, and controls
f) Plant troubles such as fire, flood, security, and station service systems

8.1.11 Report generation

Logs and reports are generated from unit and plant activities and generally done with computer-based systems as discussed in IEEE Std 1249.

8.1.12 Trending

A plant control system can include video trending or conventional chart recorders.

8.1.13 Sequence-of-events recording

This is used for recording and correlating event information related to and occurring prior to, during, and after disturbances to plant operation. Each event is time tagged and logged in sequential order. Time resolution in the range of 1 ms to 2 ms is normal. This function can be integrated in the computer-based control system as discussed in IEEE Std 1249.

8.2 Control system hardware requirements

8.2.1 Conventional control systems

The hardware needed for performing the functions in 8.1 in a conventional, centralized hard-wired control system is generally similar to that used for individual local unit control. This consists of equipment such as control panels with discrete control, alarm, and indication devices, dedicated data logging, load and voltage control equipment, and annunciators. This equipment interfaces to the units in parallel to the local unit control or through the local unit control board control circuits with appropriate interlocks.

8.2.2 Computer-based control systems

Computer-based control systems are used for control of hydroelectric units because of the speed and flexibility needed to run the complex real-time control algorithms and to manage the associated data.

The computer system interfaces to the plant and to the conventional control system via input-output (I-O) interface equipment suitable for operation in the sometimes harsh power plant environment. This interface may be in parallel to the hard-wired control system and may operate conventional hard-wired control circuits.

It may be desirable to furnish a programming and training console that permits software development and operator training while providing back-up hardware for alternate use when the normal operator interface is out-of-service. Interlocking may be provided to permit only one console to be in control at a time.

Special consideration must be given to the design of the computer system power supply, grounding, and shielding in view of the harsh power plant environment and generally sensitive nature of computer equipment. Protection from electromagnetic and radio frequency interference should be provided. Computer equipment may be located in controlled environments such as control rooms. However, they may also be located in areas of the plant subject to extremes of temperature, humidity, and moisture.

Battery or uninterrupted power supplies are commonly used to provide reliable power for the control system. The capacity and duration requirements are dependant on the shutdown and operation procedures and critical nature of the unit.

Software development and purchase must be considered early in the design so that the hardware will be compatible, the software will perform the desired control, and the human-machine interface will meet operators requirements. IEEE Std 1249 gives a discussion in greater detail on the subject of computer-based control systems.

9. Off-site control

Off-site control of a hydroelectric unit assumes the remote location is interconnected via a communications link in lieu of hardwired, point-by-point control. For a more detailed discussion on this application, refer to IEEE Std 1249.

Annex A

(informative)

Bibliography

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[B5] IEEE Std C37.10™-1995, IEEE Guide for Diagnostics and Failure Investigation of Power Circuit Breakers.

[B6] IEEE Std C62.92.1™, IEEE Guide for the Application of Neutral Grounding in Electric Utility Systems, Part I—Introduction.

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