

IEEE Guide for the Application of Turbine Governing Systems for Hydroelectric Generating Units

IEEE Power & Energy Society

Sponsored by the
Energy Development & Power Generation Committee



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IEEE Guide for the Application of Turbine Governing Systems for Hydroelectric Generating Units

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Energy Development & Power Generation Committee
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IEEE Power & Energy Society

Approved 16 May 2011

IEEE-SA Standards Board

Abstract: This guide is intended to complement IEEE Std 125™, providing application details and addressing the impact of plant and system features on hydroelectric unit governing performance. It provides guidance for the design and application of hydroelectric turbine governing systems. There is a heightened awareness within the electric utility industry of the importance in the effective application of governing systems for dynamic stability. The need exists to provide guidance in the effective governing system application for a better understanding among users.

Keywords: control, governor, governing system, hydroelectric, IEEE 1207, speed, stability

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Introduction

This introduction is not part of IEEE Std 1207-2011, IEEE Guide for the Application of Turbine Governing Systems for Hydroelectric Generating Units.

This document is a guide for the application of turbine governing systems for hydroelectric generating units. The Hydroelectric Power Subcommittee of the IEEE Energy Development and Power Generation Committee began to look into forming a working group to draft an application guide for hydroelectric units at the 1987 Winter Power Meeting. Subsequently, a project authorization request (PAR) was issued, and work began on the guide.

At the same time progress was being made on the guide, governing technology was changing rapidly from mechanical to analog electronic to digital electronic controllers. Also, during this time period, new guides produced by working groups of the Hydroelectric Power Subcommittee addressed some portions of the original scope of this guide. Therefore, in 1998, the PAR for this Governor Application Working Group was revised, and the working group's efforts were focused on producing a guide that acted as a companion document to IEEE Std 125-1988.

The final format of this guide contains four major clauses, which are directly related to the subject matter addressed in IEEE Std 125-1988. Clause 4 discusses the functions and characteristics of the turbine governing system and of the equipment related to the design of the turbine governing system. Clause 5 is somewhat tutorial in nature and discusses the major elements of the turbine governing system from a control theory perspective. Clause 6 provides some application insights to specifying a turbine governing system. Clause 7 provides a discussion of the issues related to the stability of the turbine governing system. Numerous bibliographic citations related to the subject matter are also provided, and examples are included to illustrate many of the systems and concepts discussed. More specialized information dealing with the impact of turbine characteristics, system modeling and tuning, and performance auditing is presented within the informative annexes of this guide.

This guide is designed to be a reference document for practicing engineers in the hydroelectric industry. It is intended to offer application insight for applying turbine governing systems for hydroelectric units. IEEE Std 125-1988 offers guidance for what elements of a turbine governing system need to be specified, and this guide offers experience-based guidance on the impact of these specifications on system performance.

Members of the Governor Application Working Group represent a cross-section of the hydroelectric industry, including power plant owners, plant designers, equipment manufacturers, engineering consultants, and academic personnel. The members of this working group wish to dedicate this guide to the memory of Bernard "Bud" Crittenden. Bud worked in the area of governing system design for 45 years. His numerous contributions to the industry involve many of the issues addressed by this guide. Perhaps Bud's greatest contribution to the industry was his mentoring of a number of young engineers entering the field of governing system design and application. This guide can be viewed as a continuation of Bud's work.

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1. Overview

1.1 Scope

This guide ~~is intended to~~ complements IEEE Std 125™ by providing application details and ~~addressing~~ the impact of plant and system features upon hydroelectric ~~unit~~ governing performance.¹

1.2 Purpose

The purpose of this guide is to provide guidance for the design and application of hydroelectric turbine governing systems. There is a heightened awareness within the electric utility industry of the importance in the effective application of governing systems for dynamic stability. The need exists to provide guidance in the effective governing system application for a better understanding among users. Present standards do not adequately address this need.

2. Normative references

The following referenced documents are indispensable for the application of this document (i.e., they must be understood and used; therefore, each referenced document is cited in text, and its relationship to this document is explained). For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments or corrigenda) applies.

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¹ Information on references can be found in Clause 2.

ANSI/ASME ~~Std~~ PTC29-1980, Speed-Governing Systems for Hydraulic Turbine-Generator Units.²

IEC 60308-(1970-01), International code for testing of speed governing systems for hydraulic turbines.³

IEC 61362-(1998-03), Guide to specification of hydraulic turbine control systems.

IEEE Std 125, IEEE Recommended Practice for Preparation of Equipment Specifications for Speed-Governing of Hydraulic Turbines Intended to Drive Electric Generators.⁴

ISO 4406, Hydraulic fluid power—Fluids—Method for coding level of contamination by solid particles.⁵

3. Definitions

For the purposes of this guide, the following terms and definitions apply. *The ~~Authoritative~~ IEEE Standards Dictionary: Glossary of Terms, ~~Seventh Edition~~ [B23]⁶ and Definitions* should be referenced for terms not defined in this clause.⁶

beta ratio: A measure of the efficiency of a hydraulic oil filter, defined for a specific particle size as the ratio of the number of particles of the specified particle size that are trapped by the filter to the number of particles that pass through the filter.

damping ratio: The ratio of a second-order closed-loop control system that is defined as follows:

$$\zeta = \sqrt{1 - \left(\frac{\omega_d}{\omega_n} \right)^2} \quad (1)$$

where

ζ is the damping ratio

ω_d is the damped natural frequency of the system response after a step change

ω_n is the undamped natural frequency of the system response after a step change

This ratio is a measure of how oscillatory a control system is in responding to a step change. A control system with a damping ratio of 1.0 is critically damped, with no oscillatory action and no overshoot on the initial transient after a step change. A control system with a damping ratio of 0.0 is undamped, and such a ratio results in continuous oscillatory action.

electrohydraulic governor : A turbine governing system that uses either analog electronic or digital electronic circuitry to develop the setpoint signal that is used to position the control actuators on the hydroelectric turbine. An electrohydraulic interface is used to convert the electronic setpoint signal into a hydraulic oil flow from a hydraulic servo-valve system. The hydraulic servo-valve system determines the position of the turbine control actuators. *Syn:* [electric-hydraulic governor](#).

² 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/>).

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

⁶ *The IEEE Standards Dictionary: Glossary of Terms and Definitions* is available at <http://shop.ieee.org/>.

governor control system: A feedback control system that controls the speed and power output of a prime mover, such as a hydroelectric turbine. The governor control system comprises a “setpoint” or reference input, a feedback from the speed of the prime mover, optional feedbacks from other parameters as appropriate for the application, a controller function, and one or more control actuators.

NOTE—Figure 1 illustrates a basic governor control system.⁷

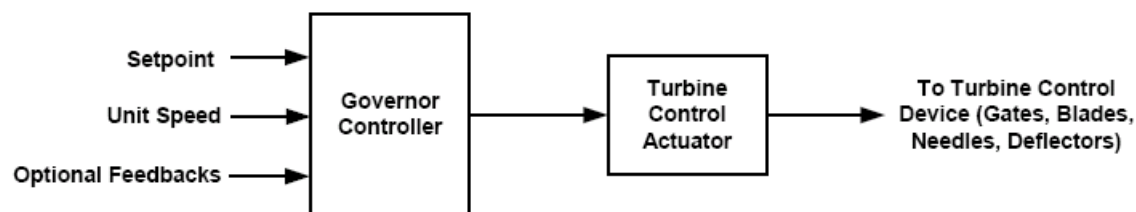


Figure 1—Basic governor control system

islanded operation: Operation of a generating unit that is interconnected with a relatively small number of other generating units, such as may occur after inadvertent tripping of circuit breakers that interconnect the island with a large interconnected power system. An island of generating capability may feed local loads connected to its electrical distribution system.

isolated operation: Operation of a generating unit without being interconnected with other generating units. An isolated unit may feed electrical loads connected to its electrical distribution system, such as the equipment within the plant that is powered by the station service system.

kidney loop filter: A hydraulic oil filtration system in which oil from the system’s sump tank is continuously circulated through a filtration element to maintain the cleanliness level of the hydraulic oil.

mechanical-hydraulic governor: A turbine governing system that typically uses rotating weights to measure the rotating speed of the hydroelectric turbine. The setpoint signal used to position the turbine control servomotors is developed by mechanically linking the speed sensing device, the mechanical setpoint, and compensation devices to a hydraulic servo-valve system. The hydraulic servo-valve system determines the hydraulic oil flow to set the position of the turbine control actuators.

turbine governing system: A control system that controls the operation of a prime mover. The turbine governing system may include functions that are not directly related to the governor control of turbine speed or power output.

4. Functions and characteristics

This clause describes some of the functions and characteristics of system elements that are commonly involved in the specification and design of a turbine governing system.

4.1 Servomotor position feedback

Typically, the servomotor position feedback to the turbine governing system is calibrated at the ends of the servomotor travel (if possible) since these two points are the most repeatable positions achievable. For wicket gates, there is some “squeeze” near zero percent gate. The wicket gates contact each other before the wicket gate servomotor reaches the end of its travel. The closing force of the gate servomotor deflects the wicket gates and their connecting linkages, ~~in-effect “squeezing” them and improving and this deflection squeezes the wicket gates and improves~~ the sealing of the wicket gates against water leakage. The governor system hydraulic pressure may affect the amount of wicket gate squeeze that can be achieved. Therefore, the most repeatable results can be

⁷ Notes in text, tables, and figures are given for information only and do not contain requirements needed to implement the guide.

achieved by calibrating the zero percent wicket gate position feedback ~~position~~ when the hydraulic pressure supply system is at its nominal pressure and the maximum achievable gate squeeze is applied.

4.2 Servomotor position

There is always some mechanical nonlinearity between the servomotor position and the controlled parameter, such as the wicket gate angle, wicket gate opening, or blade angle. The percent servomotor stroke is usually displayed and used by the turbine governing system. Some manufacturers, however, use linearizing calibration devices or algorithms to convert the servomotor position feedback to actual gate angle, gate opening, or blade angle. One benefit of feedback linearization is to make the governor parameters agree more closely with the turbine model data. For example, if blade control algorithms are based on gate opening rather than on servomotor stroke, using gate feedback linearization can help correlate the blade control cam or data map more closely with the actual turbine characteristics, and the efficiency of operation will be improved. There is generally little or no impact on the achievable performance of the turbine governing system by calibrating the servomotor position feedback in this manner.

4.3 Servomotor time

The servomotor full-stroke travel time for hydraulic servomotors is affected by several factors. The mechanical loading of the servomotor affects its rate of travel. This mechanical loading consists of both frictional loading (of the turbine control device and its connecting linkages) and dynamic loading of the water passing through the turbine control device. The dynamic loading of the water passing through the wicket gates is a function of the wicket gate angle, and this effect is greater near the closed position of the wicket gates. The frictional loading can change as a function of the lubrication of the moving parts, the cumulative wear of these moving parts, and the angle of the wicket gates or runner blades. The dynamic loading of the water can be affected by the magnitude of the flow, the head across the unit, and the rate of travel of the turbine control device. Typically, the servomotor time is initially set with the unit unwatered. The servomotor time may be readjusted, if necessary, with the unit running.

Servomotor timing devices restrict the flow of hydraulic oil to limit the maximum travel rate of the hydraulic servomotor. Some examples of servomotor timing devices include orifice plates, timing valves, and adjustable mechanical stops (“stop nuts”) on the distributing valve spool.

4.3.1 Maximum transient overspeed

The servomotor closing time of the primary turbine control device generally affects the maximum transient overspeed achieved by the turbine as a result of a full load rejection. In general, there is a maximum allowable transient overspeed that a unit can experience without resulting in an unacceptable level of degradation of the rotating components. After a load rejection, the primary turbine control servomotor should reduce the water flow to the turbine quickly enough to limit the maximum turbine speed to a value at or below this maximum overspeed specification. During certain portions of the transient overspeed condition experienced after a load rejection, the water flow through the turbine may actually be limited by the flow cutoff characteristics of the turbine rather than directly by the operation of the primary turbine control device.

4.3.2 Maximum water passage pressure

The servomotor closing time of the turbine control device that controls the water flow through the water passage generally affects the pressure rise in the water passage due to the water hammer effect. In general, there is a maximum pressure that the water passage to the turbine can safely withstand without risk of the catastrophic rupture of some component of the water passage. The maximum closing rate of the turbine control servomotor that controls the water flow through the water passage should not cause the water passage pressure to exceed this maximum pressure specification.

4.3.3 Minimum water passage pressure

The servomotor opening time of the turbine control device that controls the water flow through the water passage generally affects the pressure drop in the water passage due to the water hammer effect. In general, there is a minimum absolute pressure that the water passage to the turbine can safely withstand without risk of the catastrophic collapse of some component of the water passage. The maximum opening rate of the turbine control servomotor that controls the water flow through the water passage should not cause the water passage pressure to drop below this minimum pressure specification.

4.4 Cushioning time

The cushioning time is the time of travel from the point at which the cushioning, or slow closure, feature takes effect until the turbine control device is fully closed. Cushioning is a feature that is built into turbine control servomotors, such as wicket gate servomotors, to soften both the mechanical impact and the water hammer effect when the turbine control device reaches the end of its travel. If two or more servomotors are used on a turbine control device, the connections from the servomotors to the turbine control device generally need to be adjusted so the cushioning effect becomes effective on all servomotors at the same time in the closing direction of the servomotor stroke. The cushioning time is generally adjusted with some type of flow control valve to set the cushioning time of the servomotors. Generally, each servomotor has a cushioning time control valve, and these valves should be adjusted so the servomotors equally share the mechanical loading of the turbine control device during the cushioned portion of the servomotor stroke. In some designs, there is a single cushioning control device for two servomotors.

4.5 Permanent speed droop and speed regulation

Permanent speed droop (also known [simply](#) as “speed droop”) and speed regulation (also known as “power droop”) are used to coordinate the responses of interconnected units to changes in the system frequency. Permanent speed droop can be developed either by using feedback from the wicket gate position (or,

sometimes, from the governor's position setpoint to the wicket gate actuator) or by using feedback from the unit power generation. If unit power generation is used to develop the permanent speed droop characteristic, the permanent speed droop term is usually called "speed regulation" or "power droop."

4.5.1 Permanent speed droop

Permanent speed droop determines the amount of change in gate servomotor position a unit produces in response to a change in unit speed. Permanent speed droop (in per-unit terms) is defined as the change in unit speed (as a percentage of rated speed) divided by the change in governor output (as a percentage of gate position). Permanent speed droop is usually expressed in terms of a percentage, which is 100 times the per-unit value. Figure 2 is a block diagram representation of a typical governor controller using permanent speed droop.

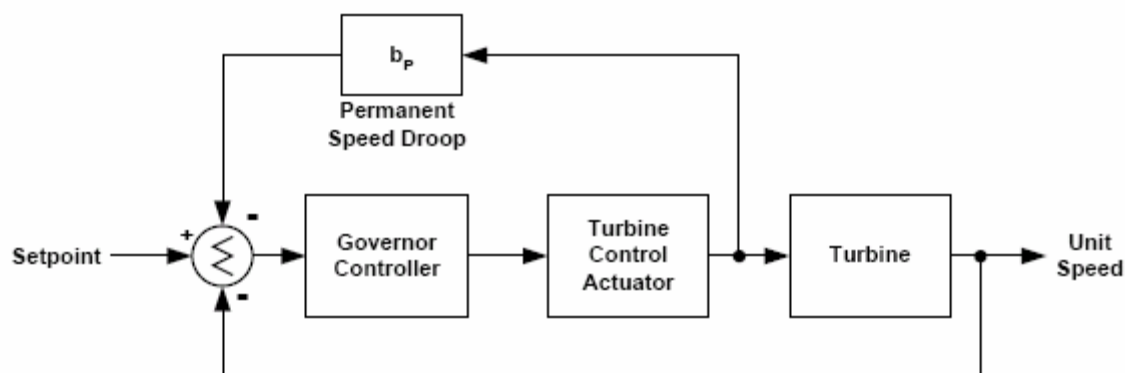


Figure 2—Typical governing system with permanent speed droop

The steady-state effect of adding the permanent speed droop feedback loop is a governor operating characteristic as shown in Figure 3. The value of permanent speed droop determines the slope of the characteristic curve. A typical permanent speed droop value is 5%, resulting in a unit that changes speed by 1% (0.6 Hz on a 60 Hz system) in response to approximately a 20% change in load (requiring a 20% change in wicket gate position) when operating connected to an isolated load. For a unit connected to a large interconnected power system, a unit with 5% permanent speed droop changes its gate position by 20% (approximately 20% change in output power) if the system frequency changes by 1%.

NOTE—Permanent speed droop relates changes in speed (or frequency) directly to changes in wicket gate position. Corresponding changes in turbine power output depend on the gate-to-power characteristics of the turbine.

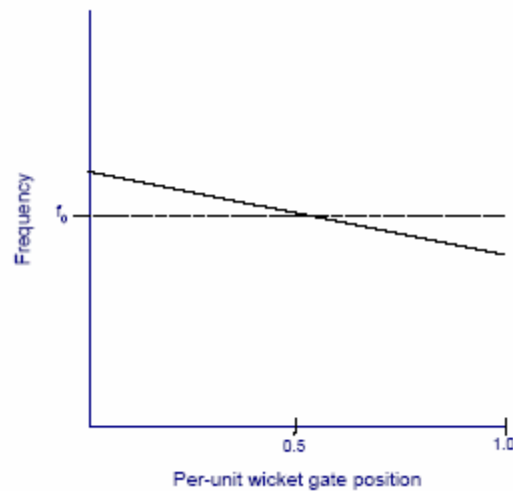


Figure 3.—Permanent speed droop characteristics

If two generators with different permanent speed droops are connected to a common load, they share changes in this load proportionally to their respective permanent speed droop characteristics because their rotating speeds are dictated by the system frequency, which is common to the units. Figure 4 illustrates the steady-state load-sharing effect of permanent speed droop upon two units with different permanent speed droop settings.

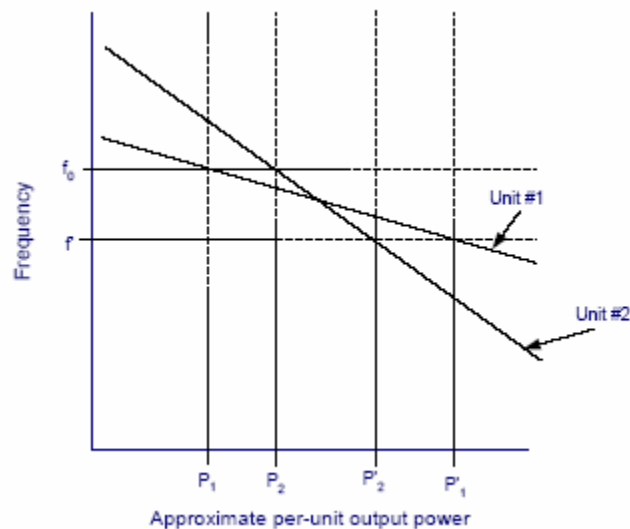


Figure 4.—Allocation of unit loads with different governor permanent speed droops

It should be noted that if the governors on the interconnected units were adjusted for zero permanent speed droop, the units would not effectively share the system load. Differences in both the unit response times and in the governor calibrations would eventually result in one unit's attempting to provide all of the load power while the other unit would be driven toward a motoring condition.

The governor parameter primarily used to control the operation of the unit is the "setpoint," which is also known as the "speed reference," the "speed adjustment," the "speed-load adjustment," or the "speed changer setting." By changing the setpoint, the governor can be set to operate at the system frequency at any desired unit output. On a large interconnected system, the setpoint can be used to dispatch the desired generation into the grid when operating at rated system frequency. Figure 5 illustrates the steady-state effect of different governor setpoints on the output of a unit at rated frequency and 5% permanent speed droop.

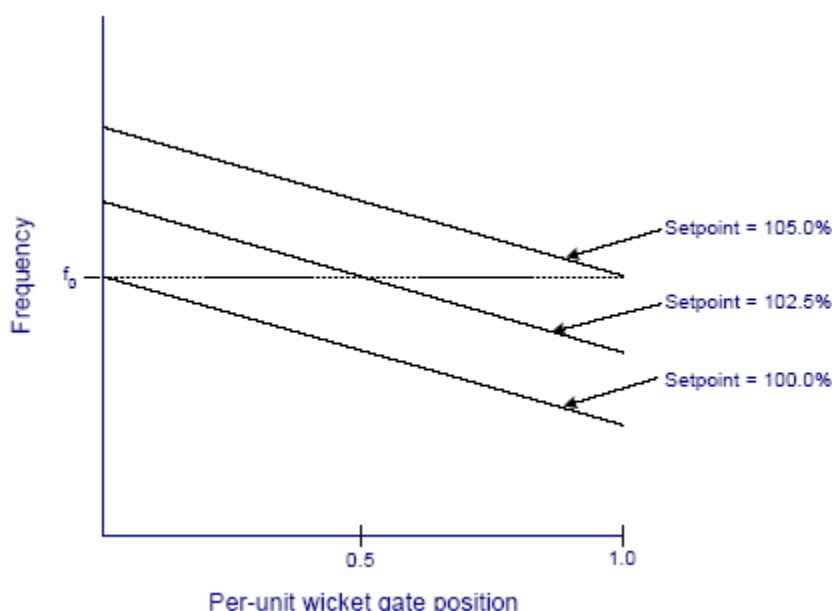


Figure 5.—Unit loading with governor setpoint (at 5% permanent speed droop)

The principle of operation of a unit with permanent speed droop is essentially the same for both small, isolated systems and large, interconnected systems. The steady-state system frequency change after a significant disturbance, such as a large load trip or a large generation trip, is proportional to the size of the generation/load change. On an interconnected system, there is often a greater resulting frequency error than might be expected from the equivalent permanent speed droop of the units connected to the system (see Schultz [B40]⁸). This additional frequency error typically results from nonlinear governor characteristics and units operating either at maximum generation or against their turbine control actuator position limits (limited or "nongoverning" operating mode).

It should be noted that, because of the permanent speed droop characteristics of the governors, after a system disturbance, the governors alone are not able to restore the system frequency to its predisturbance value (e.g., 60 Hz). The governors respond dynamically to the system disturbance and, as a result, limit the frequency disturbance to the permanent speed droop characteristic curve. Trimming out any residual frequency error as a result of the remaining load/frequency error may be done manually by operating personnel on small systems or by an automatic generator control (AGC) on a large interconnected system.

Figure 6 shows a frequency recording of a test performed in the Western Electricity Coordinating Council (“WECC,” one of the North American reliability councils, [formerly called “WSCC”](#)) where 1250 MW of generation was tripped. The total generation in the system was approximately 111 650 MW. The test was performed with all AGC systems in the WECC turned off. The settling frequency deviation 90 s after the trip was approximately -0.095 Hz, or -0.158% . As the 1250 MW generation trip was 1.12% of the total generation in the system, the “effective” permanent speed droop of the system is calculated to be approximately 14.1%. WECC’s policy is to have all governors set to 5% permanent speed droop. The difference noted between the measured permanent speed droop and the theoretical permanent speed droop of the system is attributed to several phenomena occurring within the system, including nonlinearities in governors, which effectively change their permanent speed droop as a function of the unit loading levels and a number of machines operating in a limited (i.e., nongoverning) mode. The most likely largest contributing factor to the high value of measured system permanent speed droop is the effect of a significant number of units running in a limited mode of operation. If a unit is, for example, running against its gate limit, it cannot increase its generation in response to a drop in the system frequency. The equivalent permanent speed droop of such a limited unit is infinite, which raises the average equivalent permanent speed droop of the system in proportion to the rated generation of the limited unit.

⁸[The numbers in brackets correspond to the numbers in the bibliography in Annex A.](#)

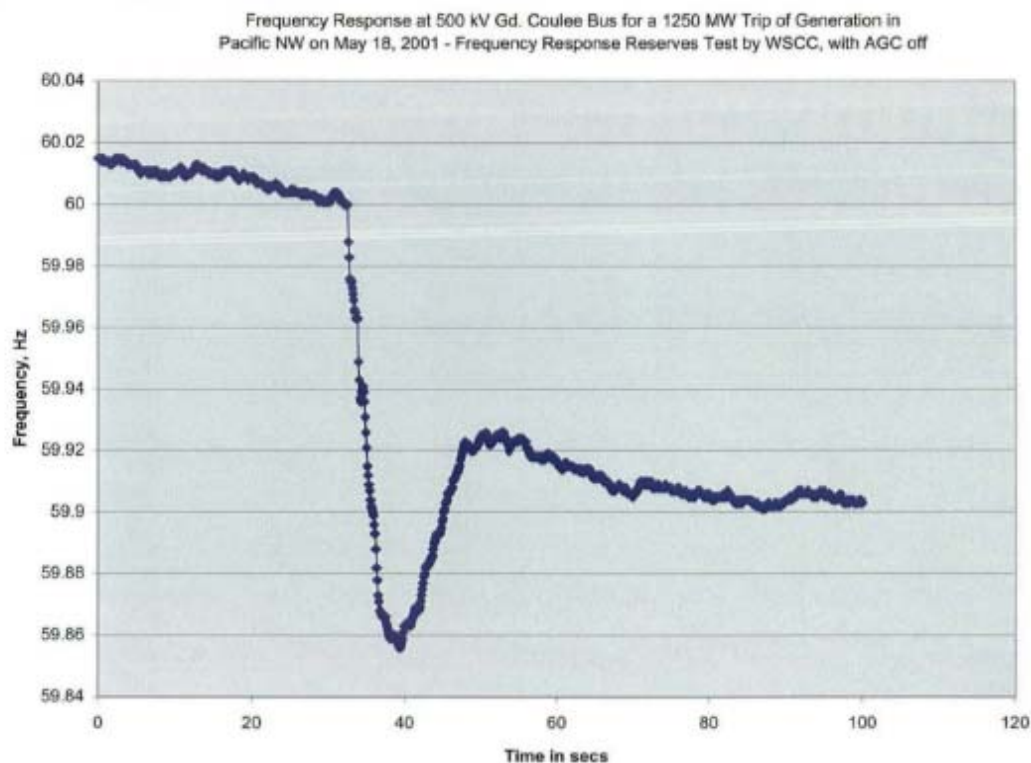


Figure 6—Example of testing the equivalent system permanent speed droop

4.5.2 Speed regulation

A speed regulation (also known as “power droop”) governing system is similar to a permanent speed droop governing system, but with unit generation being used as the intermediate feedback from the controlled process instead of actuator position. Adding a portion of the unit power generation feedback to offset the detected unit speed error develops speed regulation. Figure 7 is a block diagram representation of a typical speed regulation governing system. The controller setpoint may be calibrated in terms of desired power output (e.g., megawatts) from the unit. The governor characteristic response for a speed regulation governor controller is essentially the same as the permanent speed droop characteristic described in Figure 3, except that the “per-unit output” axis is in terms of generated power rather than actuator position. Generally, a speed regulation characteristic can be beneficial when accurate dispatch of generation is required for system operation or when a unit is required to operate at a constant base generation level despite any changes in operating head of the unit. However, using this type of feedback as the primary control feedback tends to destabilize governor operation if the unit experiences operation on a small, islanded, or isolated system.

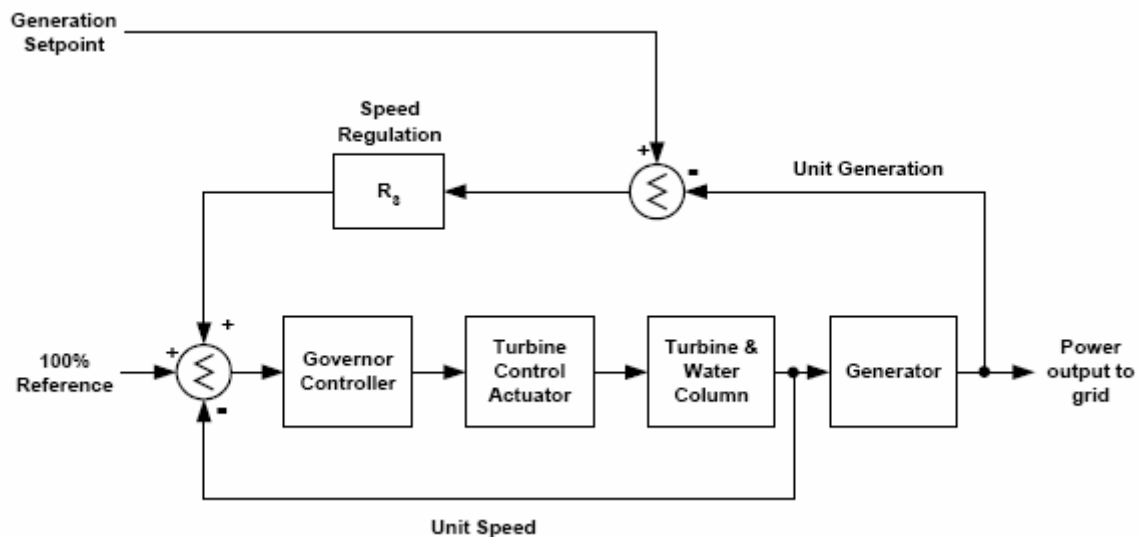


Figure 7.—Governing system with speed regulation

Generally, governing systems using speed regulation are appropriate only for units that are generating into a large interconnected system, where the output of any single unit cannot have a significant impact on the system frequency. As with permanent speed droop governors, speed regulation governors respond to disturbances in the system frequency with changes in unit output that reduce the effects of a load/generation imbalance within the interconnected system. Using speed regulation governors on relatively small or islanded systems can result in the units’ responding in a manner detrimental to the system stability as a result of changes in system loads or other electrical system disturbances.

Synchronizing a unit with a speed regulation governor can sometimes be more difficult than with a permanent speed droop governor. The reason is that, with the unit breaker open, there is no power feedback to produce the permanent speed droop characteristic and the unit is essentially operating at zero permanent speed droop when synchronizing. A turbine governing system is inherently less stable at zero permanent speed droop; because a permanent speed droop feedback adds some degree of stabilizing influence to the control loop. The operating characteristics of some turbines at speed-no-load accentuate this influence. Operating the unit governor with conventional permanent speed droop when synchronizing, and then switching to speed regulation operation after closing the unit breaker, can avoid this stability problem.

A speed regulation unit is inherently less stable than a permanent speed droop governor because additional dynamic influences from the water column are included in the primary feedback path (generated power) of the turbine governing system. The differences in these control systems can be seen by comparing Figure 2 with Figure 7. This difference in control loops generally requires that the speed regulation governor's damping adjustments (e.g., proportional plus integral plus derivative (PID) gains) be tuned for slower governor compensating action to achieve stable control using speed regulation. Additionally, dynamic water conditions such as draft tube surging have an influence on the generated power of the unit. These influences can result in undesirable movement of the turbine control actuator unless appropriate compensating measures are taken within the governor controller.

It is important to note that if a speed regulation governor controller uses a generation setpoint calibrated in units of generation (e.g., megawatts), the unit controls at its setpoint generation level only when the unit speed is at the 100% reference level. The composite error input to the governor controller algorithm is the summation of the generation error (multiplied by the speed regulation constant) and the speed error. Thus, the steady-state unit generation is a linear function of the unit speed, similar in nature to the permanent speed droop curve shown in Figure 3. The slope of the [speed regulation](#) ("power droop") characteristic response is determined by the speed regulation constant R_s .

4.6 Governor speed deadband

The governor speed deadband is a measure of the smallest speed change that can be detected and to which the turbine governing system can respond. For a hydroelectric generating unit operating into an isolated system, the governor speed deadband determines the smallest band within which the unit can maintain the system frequency under steady-state loading conditions. Typically, a governor speed deadband of 0.02% is achievable and is commonly specified for hydroelectric turbine governing systems. Increasing the amount of speed deadband in a turbine governing system decreases the accuracy of frequency control that the governing system can achieve. Increased deadband also results in an increase in governor deadtime.

4.7 Blade control deadband

The blade control deadband is a measure of the smallest change in blade position setpoint that can be detected and to which the blade servomotor positioning system can respond. The blade control deadband determines the accuracy of the gate/blade relationship for an adjustable-blade turbine. The accuracy of the gate/blade relationship determines the efficiency of the turbine as well as the amount of vibration and cavitation produced by off-peak operation. Typically, a blade control deadband of 1.0% is achievable and is commonly specified for hydroelectric turbine governing systems. Increasing the amount of blade control deadband decreases the accuracy of positioning the blades as a function of gate position. The resulting deviation from the ideal blade position reduces the efficiency of the turbine. This reduction in turbine efficiency may result in loss of revenue due to the reduced efficiency, increased cavitation damage to the turbine runner, and increased vibration damage to the turbine, generator, and bearings.

4.8 Governor deadtime

The governor deadtime is a measure of the amount of time elapsed between a change in speed to the first corrective action by the hydroelectric turbine governing system. The governor deadtime affects the peak overspeed after a load rejection as a result of the delay in governor response to the rising speed of the unit. The governor deadtime also affects the stability limit as achieved via the governor gain (or compensation) settings. Deadtime adds phase lag to the governing control system without a corresponding decrease in gain, which limits the amount of compensating gain that can be used in the governor controller. This limitation in governor stability requires the governor gains to be reduced to maintain control system stability. Reduction of governor gains makes the governor system slower to respond to system disturbances. Typically, a governor deadtime of 0.2 s is achievable and is commonly specified for hydroelectric turbine governing systems. However, modern

control systems can often achieve shorter deadtimes due to improved control valve and control algorithm design.

4.9 Stability

The stability of a turbine governing system can be expressed as a damping ratio and a settling time. These quantities cannot be measured directly, but they can be deduced from the measured response of the unit ~~in~~ **response** to a specified disturbance. Another method of specifying the stability of a governing system is to specify the relative size of successive peak deviations of the controlled speed after a disturbance. Typically, specifying the desired damping ratio and the settling time sufficiently defines the desired stability and responsiveness of the unit. As with many control systems for nonlinear processes, turbine speed governing systems may exhibit small oscillations around a steady-state operating point that are more related to the deadbands and nonlinearities of the system ~~rather~~ than to the stability of the control system.

4.10 Rated speed

The rated speed is the speed at which the generator frequency is at its rated value. If the generator is directly coupled to the turbine, the rated speed of the turbine is the same as the rated speed of the generator. If a speed increaser is used, the rated speed of the generator is greater than the rated speed of the turbine.

4.11 Overspeed

Any speed greater than the rated speed is referred to as overspeed and is typically expressed as a percentage of the rated speed (e.g., 125% of rated speed is an overspeed condition). Sometimes, overspeed is expressed as a percentage of unit speed in excess of 100% rated speed (e.g., 10% overspeed = 110% of rated speed).

4.12 Underspeed

Any speed less than the rated speed is referred to as underspeed and is expressed as a percentage of rated speed (e.g., 25% of rated speed is an underspeed condition).

4.13 Maximum momentary speed variation

The maximum momentary speed variation is the maximum change in unit speed when the unit load is changed by a specified amount. This variation is expressed as a percentage of rated speed. The size of the load change, the characteristics of the turbine, the rotating inertia of the unit, the water column inertia, and the responsiveness of the unit governor determine this maximum momentary speed variation. The maximum momentary speed variation generally occurs when the unit governor responds to the change in unit speed and begins to return the unit speed toward its rated value.

4.14 Runaway speed

The runaway speed of a unit is influenced primarily by the turbine characteristics. Typical runaway speeds for reaction turbines range from 140% to 190% of rated speed for fixed-geometry turbines, and from 200% to 350% of rated speed for adjustable-blade turbines. Typical runaway speeds for impulse turbines range from 180% to 200% of rated speed. To avoid false operation of speed-related functions, the turbine governing system should be able to accurately measure and display unit speeds up to the runaway speed of the unit.

4.15 Rated operating head

The rated operating head, as stated on the turbine nameplate, may be based on several different conventions. Often, the rated operating head is stated in terms of net head, which is the net pressure drop across the turbine runner, adjusted for the change in kinetic energy of the water as it passes through the turbine. The rated operating head may also be stated in terms of gross head, which is the net elevation difference between the headwater and the tailwater. The turbine is designed to operate over a range of operating heads that reflects the **normal head typical** range that may be experienced during normal operation. The turbine nameplate rating may be stated as the maximum power output achievable at the minimum operating head, and it may also be stated as the maximum power output achievable at the maximum operating head. The nameplate convention used can vary, depending on the turbine manufacturer, the country of origin, and the requirements of the owner.

4.16 Steady-state governing speed band

The steady-state governing speed band is a measure of the peak-to-peak speed deviations that occur when the turbine governing system is controlling the speed of the turbine. This stability index is discussed in more detail in 7.1.1.1. This performance index is intended to represent the peak-to-peak speed deviations caused by the turbine governing system. In 9.2.7, a more detailed discussion of the interpretation of the steady-state governing speed band is presented.

4.17 Steady-state governing load band

The steady-state governing load band is a measure of the peak-to-peak deviations in generated power that occur when the turbine governing system is controlling the generation of the hydroelectric unit into a large interconnected power system. This stability index is discussed in more detail in 7.1.1.2. This measurement is done under constant-generation conditions, and it determines the peak-to-peak power deviations caused by the turbine governing system. Disturbances in unit-generated power induced by irregularities in water flow through the turbine should be excluded from the steady-state governing load band. Disturbances in unit generated power can also be induced by the actions of the excitation system for the generator. Normally, these disturbances are also excluded from the steady-state governing load band. However, if the turbine governing system is integrated into the same controller package as the excitation control system, the composite of disturbances caused by the turbine governing function and the excitation control system may be considered in computing the steady-state governing load band.

4.18 Speed

The instantaneous speed of the turbine is typically expressed either in percentage of rated speed or in revolutions per minute. Normally, all speed-related indication, control, and protection functions use the same units of speed measurement.

4.19 Speed reference

A speed reference is either a fixed or an adjustable setting, usually expressed as a percentage of rated speed, which is compared with the actual speed of the turbine. An adjustable speed reference, sometimes called the “speed changer” or “speed adjustment,” is often the primary setpoint to the turbine governing system that is used to synchronize the unit to the interconnected power system. The speed reference is also often used to load the unit once it is paralleled to the interconnected power system. If a different governing system setpoint is used during online operation, such as a power setpoint or a flow setpoint, a fixed 100% speed reference is typically used for computing the unit speed error within the governing algorithm.

4.20 Speed deviation

The speed deviation (also known as “speed error”) is the instantaneous difference between the speed reference and the actual turbine speed, usually expressed as a percentage of rated speed. The speed deviation may be used, via an adjustment of the speed reference, to control either the turbine speed or the generator power output.

4.21 Power output

The power output of a generator is generally measured at the generator terminals (in either kilowatts or megawatts). Typically, some electrical power is consumed during [the generator's](#) operation for excitation, hydraulic pumps, and other equipment. The electrical power available for transmission to users outside the hydroelectric generating station is the difference between the power output of the generators and the power consumed within the station.

4.22 Rated power output

The rated power output of a generator is generally stated in terms of megawatts or kilowatts at a specified power factor and temperature rise. A generator may have more than one rated power output if different temperature rises or power factors are also specified.

The rated power output of a turbine is generally stated in terms of kilowatts or megawatts. The mechanical power output of the turbine is generally not measured directly because of the difficulties in measuring shaft torque.

4.23 Maximum power output

The maximum power output of the hydroelectric unit with maximum head and maximum gate may be greater than the generator can safely sustain for extended periods of time due to generator heating. If the maximum turbine output is significantly greater than the rated generator output, there may be a danger of slipping generator poles.

4.24 Governor controller

The governor controller accepts a setpoint command, compares this command against the feedback from the controlled process, and positions the turbine control actuator. Subclauses 4.24.1 through 4.24.6 discuss some types of governing controllers commonly used in the hydroelectric generation industry at the time of publication of this guide.

It is important to note that one common characteristic of all governor controllers is a responsiveness to the speed of the unit. Sometimes, when a unit is synchronized to a large interconnected system, the sensitivity of the turbine governing system to the unit speed is disabled as a result of certain operating practices common within the hydroelectric generating industry. A turbine governing system may be operated against its gate limit, or an artificial speed deadband may be tuned into the speed-sensing portion of the governor controller. This [action](#) may be done to reduce unwanted control action induced by system frequency fluctuations or other control system irregularities. In these instances, the turbine controllers are no longer functioning as governing systems, and these units are not able to participate in unison with the governing systems of the other units connected to the power system that are dedicated to maintaining the system frequency.

4.24.1 Temporary droop [governor](#) controller

A temporary droop governor controller uses a feedback function from the governor actuator position to “temporarily” cancel part of the error between the governor setpoint and the unit speed feedback. This feedback function may be described as a lead-lag, a reset, a washout, or a filtered derivative function. The net error resulting from this summation is integrated by the governor controller to position the turbine control actuator. The temporary droop feedback within the governor controller helps to stabilize the control of unit speed by reducing overshoot of the turbine control actuator. Typical stabilizing adjustments for temporary droop governor controllers are error integration gain, temporary droop (in percentage), and damping device time constant (in seconds). Originally, temporary droop governor controllers were implemented using mechanical devices such as floating levers (for summation and gain functions) and dashpots (for stabilization using temporary droop). This same controller strategy has also been implemented both in analog and digital electronic control systems. A temporary droop governor controller is approximately equivalent to a proportional plus integral ([PI](#)) controller. A functional block diagram for a temporary droop governor controller is shown in Figure 8.

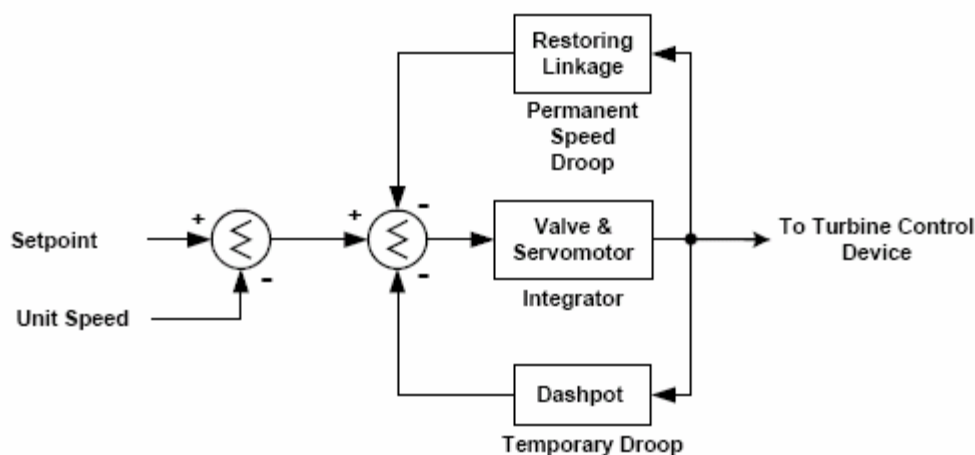


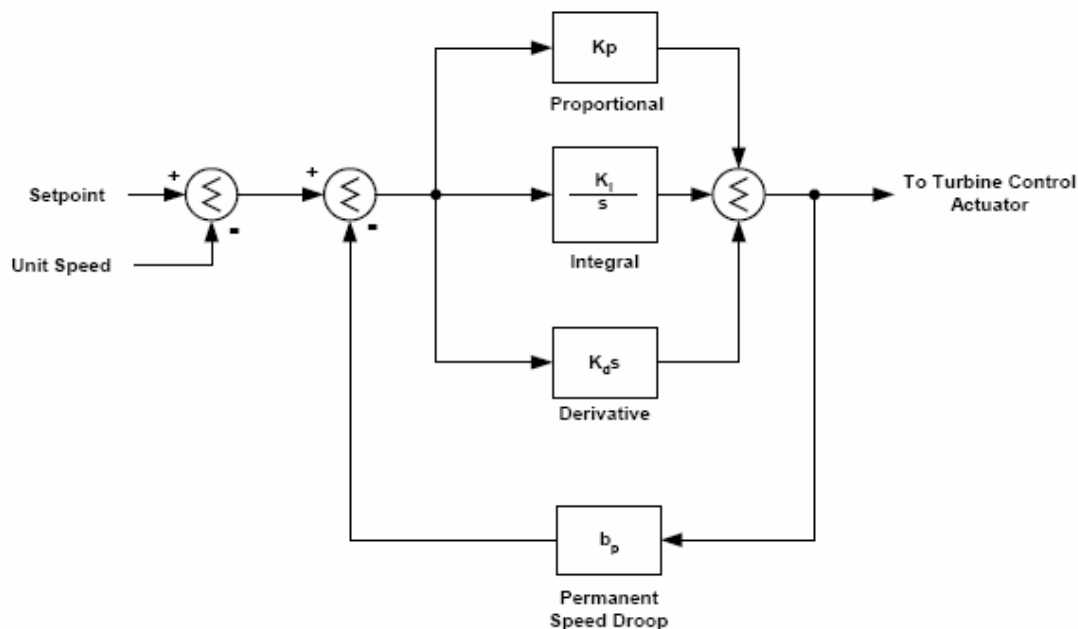
Figure 8.—Typical temporary droop governor controller

4.24.2 PID governor controller

A PID governor controller uses proportional plus integral plus derivative terms to process its error input into a command signal to the turbine control actuator.

- The proportional term
 - Produces a control action proportional to the size of the error input. ~~The proportional term produces~~
 - Produces an immediate response to an error level input.
 - Has typically a significant influence on the stability of the governed system.
- The integral term
 - Produces a control action that accumulates at a rate proportional to the size of the error input.
 - Works in unison with the proportional term to determine the stability of the governed system.
 - Trims out the error input to the governor controller to determine the steady-state accuracy of the governed system.
- The derivative term
 - Produces a control action that is proportional to the rate of change of the error input.
 - Helps to extend the stability limits of the governed system by allowing higher proportional and integral gains while maintaining a stable control system.

Typical stabilizing adjustments for a PID governor controller are proportional gain, integral gain (in inverse seconds), and derivative gain (in seconds). PID governor controllers have been implemented in both analog and digital electronic control systems. A functional block diagram for a typical PID governor controller is shown in Figure 9.



where

K_P is the proportional gain (p.u)
 K_I is the integral gain (s-1)
 K_d is the derivative gain (s)
 b_P is the permanent speed droop (p.u.)
 s is the Laplace operator

Figure 9—Typical PID governor controller

4.24.3 Double-derivative governor controller

A double-derivative governor controller is a variation of the PID governor controller. In this governor controller strategy, a proportional term, a first derivative term, and a second derivative term process the input error. The summation of these three terms is then integrated by the output stage of the governor controller. This final integrating stage may be either an electronic integrator or a hydraulic integrator. The double-derivative governor controller strategy can result in a lower overspeed peak upon startup of the unit, and it can result in a smaller overtravel of the turbine control actuator when a position limitation is released, when compared with a corresponding PID governor controller. This controller strategy also eliminates the derivative and proportional influences from changes in the setpoint. Typical stabilizing adjustments for a double-derivative governor controller are the first derivative gain (similar to the PID proportional term), second derivative gain (similar to the PID derivative term), and the overall integral gain. A functional block diagram for a typical double-derivative governor controller is shown in Figure 10. Other structures may be implemented to achieve the same functionality as described in Figure 10.

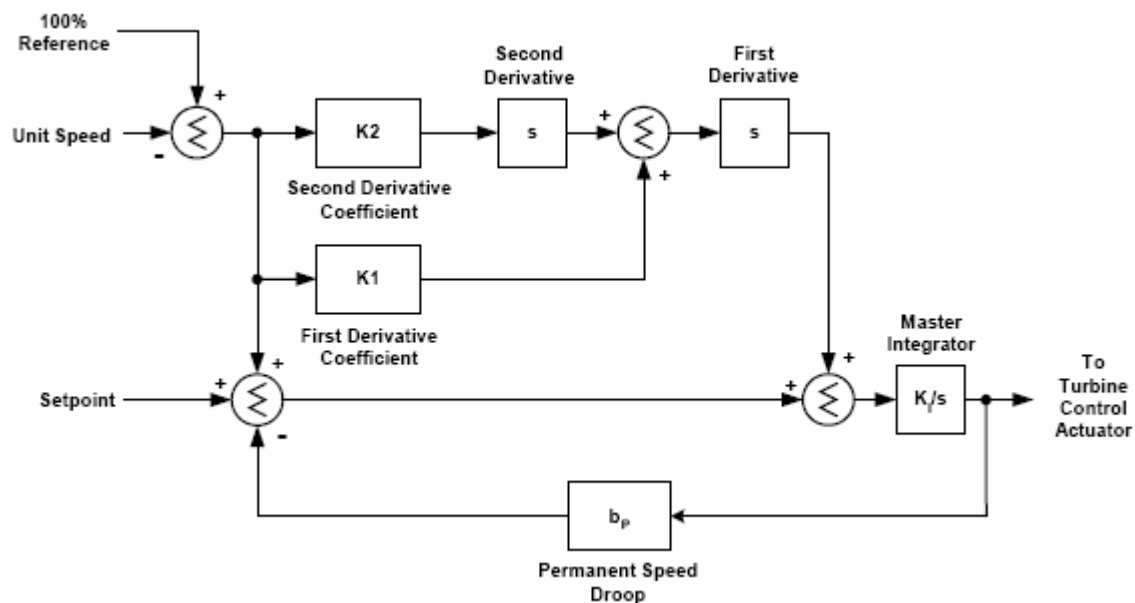


Figure 10—Typical double-derivative governor controller

4.24.4 Feedforward controller

Feedforward is a predictive control strategy that can be used in conjunction with any closed-loop controller to achieve a faster response to a change in setpoint without compromising the contribution of the unit governor controller to the overall system stability. Historically, many governing units were switched to a separate set of online damping parameters (also known as “dashpot bypass” or “online gains”) when synchronized to a large interconnected system. These online damping parameters allowed the unit to respond quickly to power dispatch commands. The unit derived its speed stability from its interconnection with the large interconnected power system. However, the high gains from speed to wicket gates could cause the system frequency to become unstable if the unit became islanded from the grid or if high online gains were used on a significant portion of units on the grid. Figure 11 shows how the setpoint feedforward strategy is used with a typical closed-loop governor controller.

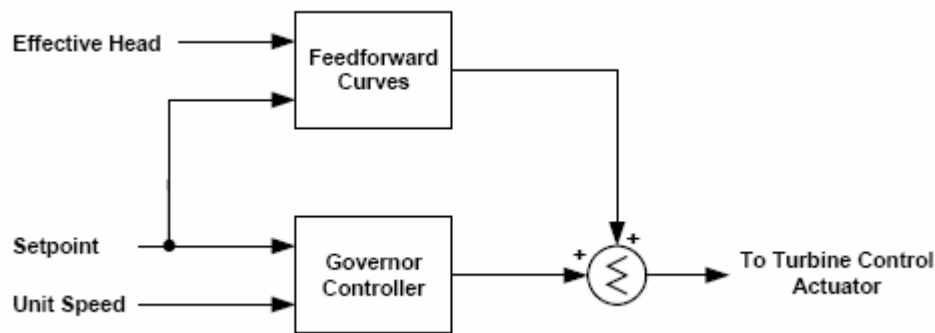


Figure 11—Typical governor controller with speed feedback and setpoint feedforward

It is important to note that a feedforward strategy be designed for operation only while the unit is paralleled with a large interconnected power system. The feedforward function is typically disabled when operating off-line, or when the unit becomes isolated or isolated, as detected by a significant disturbance in the unit speed. If a unit's generation-versus-gate-position characteristics are not significantly influenced by the unit's operating head at a particular installation, the feedforward function may be simplified by eliminating the effective head input. If, however, the unit's generation-versus-gate-position characteristics are significantly influenced by other operating parameters, such as the flow through other units sharing the same water passage, these conditions should be accommodated by the feedforward curves to achieve acceptable performance by the governor controller. If the factors influencing the unit's generation-versus-gate-position characteristics become too complex, it may be more expedient to eliminate the feedforward function from the governor controller strategy and depend on the governor controller gains to provide the desired online response to the governor setpoint.

4.24.5 State space controller

A state space controller is a predictive control strategy, and it may be used to optimize the response of a well-defined system by modeling the system characteristics and taking the control action necessary to achieve the desired control response. An accurate model of the controlled process is required to implement a state space control strategy. A state space control system may be used in conjunction with a feedback control system. The purpose of the feedback control system is to trim out any errors that may occur as a result of inaccuracies in the state space controller model. A functional block diagram of a typical state space controller with a feedback control trim function is shown in Figure 12.

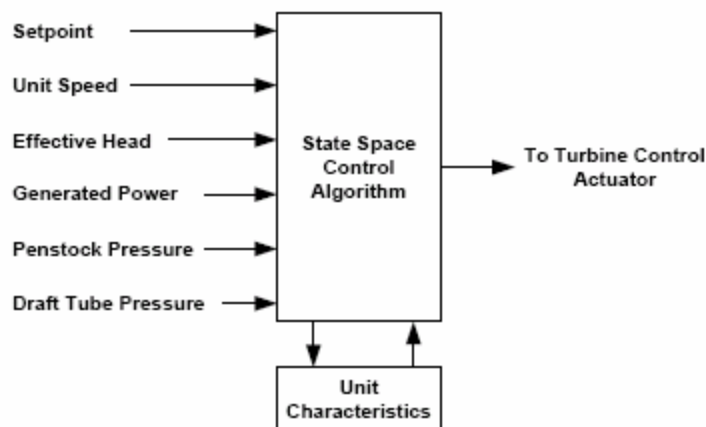


Figure 12—Typical state-space controller

4.24.6 Impulse turbine controller

An impulse turbine presents a unique challenge for a turbine governing system. The impulse turbine needles control the flow of water into the turbine. As many impulse turbines use relatively long water conduits, the water hammer effect can be significant, and, if so, requires a relatively long needle servomotor operating time. To achieve the desired dynamic operation, many impulse turbines include deflectors that divert the water stream away from the turbine buckets and thus remove some or all of the water energy from the turbine runner. The deflectors do not affect the flow rate of the water in the conduit; therefore, the deflector servomotors may operate at relatively fast servomotor timings.

4.24.6.1 Water-saving control mode

A water-saving control mode for an impulse turbine achieves maximum turbine efficiency by positioning the deflectors outside the water stream and thus allowing all water discharged from the turbine needles to impinge on the turbine runner. To reduce the deadtime of bringing the deflectors into the water stream when needed, the deflectors are often placed as closely as possible to the edge of the water stream using either a two-dimensional function based on needle servomotor position or a three-dimensional function based on needle servomotor position and turbine operating head. Figure 13 is a block diagram representation of a classical water-saving governor controller strategy for impulse turbines.

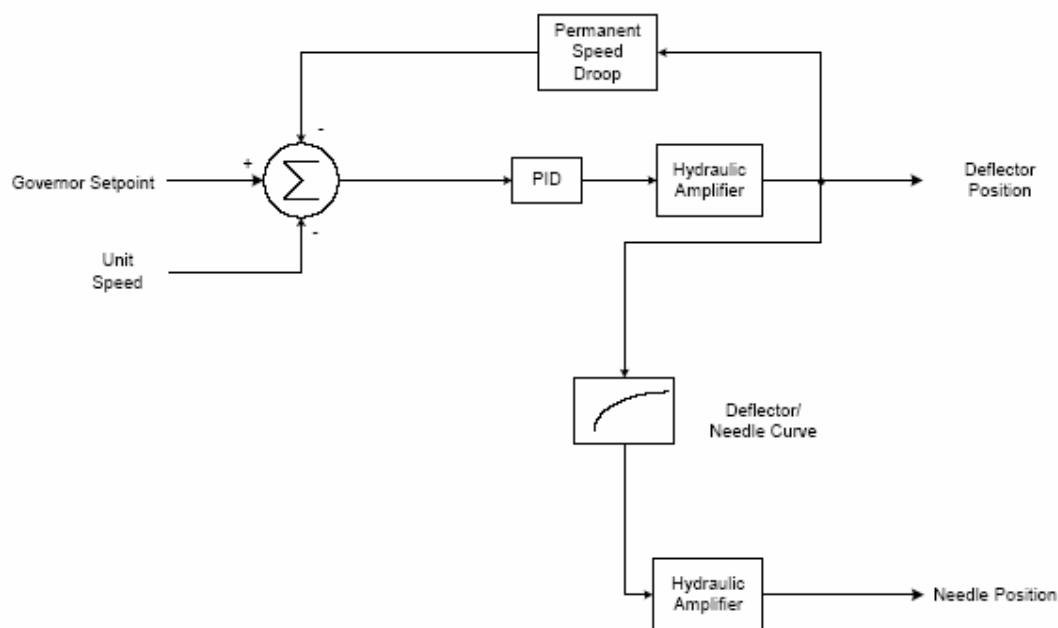


Figure 13—Classic water-saving governor controller for impulse turbines

4.24.6.2 Water-wasting control mode

Deflectors can be used to rapidly decrease the amount of water that impinges on an impulse turbine runner. However, if the deflector is outside the water stream, it cannot rapidly increase the amount of water impinging on the turbine runner. If an impulse turbine is used to control the frequency of an isolated electrical system, the deflectors can be positioned slightly within the water stream to allow for the rapid increase of water flow to the turbine runner in response to an increase in electrical load connected to the system. It is important to note that when the deflectors are in the water stream, their action dominates the control of the turbine speed. Because deflector motion does not result in a water hammer effect, the governor can be tuned to be very responsive in this mode. Once the deflectors are out of the water stream, they no longer have any effect on the turbine operation. At that point, only the needles have an effect on the turbine operation. If a water-wasting mode of operation is specified, it should specify a method of determining the amount of hydraulic power to be deflected away from the turbine runner. This [deflected power](#) determines the amount of load acceptance the turbine can handle while keeping the deflectors within the water stream. Any water-wasting mode of operation should have a method of coordinating the dynamic response of the turbine governing system when the deflectors are within the water stream and when the deflectors are outside the water stream. When operating in a water-wasting mode, the deflectors continuously deflect water away from the turbine runner. The deflectors should be designed to withstand the erosion effects of operating in this mode for extended periods of time.

4.24.6.3 Needle sequencing

To achieve higher operating efficiencies at different power levels, an impulse turbine may sequence its needles to use different numbers of needles to operate at different power levels. Normally, sets of needles are used that are symmetrically spaced to minimize the radial loading of the turbine guide bearings. Switch points for operating with 2, 3, 4, or 6 needles (for example) should be determined from the crossover points of the turbine efficiency curves.

4.24.6.4 Needle/deflector dynamic coordination

To optimize the dynamic operating characteristics of the impulse turbine governing system, the governor controller may have separate compensating gains (e.g., PID gains) for operation with the deflectors within the water stream and with the deflectors outside the water stream. In this way, both the deflector servomotor and the needle servomotor can respond simultaneously to a frequency disturbance. The effects of these respective servomotor responses are determined by the mode of operation (e.g., water-saving or water-wasting). This approach should have some method of returning the deflectors and needles to the desired relationship during steady-state operating conditions. Annex D [includes](#) a ~~block—diagram~~ [representation](#)[discussion](#) of a dual-loop governor controller ~~strategy~~ for impulse turbines.

4.25 Stabilizing adjustments

For any turbine governing control system to achieve the desired performance, it should be tuned to accommodate the characteristics of the turbine, the water inertia, the rotating inertia, and the load characteristics. Annex F summarizes some methods used to tune governing systems. Brief descriptions of some typical stabilizing adjustments, and their impact on performance, are provided in 4.25.1 [through](#) 4.25.6.

4.25.1 Temporary droop

Temporary droop is used to limit overshoot of the turbine control servomotor during a transient condition. Temporary droop may be developed either mechanically or electronically in the governing controller. Mechanically, connecting a dashpot (hydromechanical lead-lag, or reset, device) develops temporary droop from the wicket gate position to the governor error summing point. Electronically, temporary droop may be developed by adding a filtered derivative of wicket gate position to the governor error summing point, or it may be approximated as a PI controller.

4.25.2 Time constant of the damping device

The time constant of the damping device determines the rate at which the effect of the temporary droop decays to zero. If temporary droop is developed mechanically with a dashpot, this time constant is adjusted with a needle valve to determine the equalization time of the dashpot pistons. If temporary droop is developed electronically with a filtered derivative term, the time constant of the damping device is the filter time constant of this derivative term. If temporary droop is approximated by using a PI controller, then the time constant of the damping device may be approximated as the proportional gain divided by the integral gain.

4.25.3 Integral gain

Integral gain produces a controlling action that is the time integral of the governor controller error in a PI or a PID governor controller. Integral gain, also known as “reset,” acts to trim the controller error to a value of zero. The rate of trim is proportional to both the magnitude of the error and to the integral gain setting. Integral gain is defined as the rate of change (in percentage/second) of the integrator output divided by the governor controller error (in percentage).

4.25.4 Proportional gain

Proportional gain produces a controlling action that is proportional to the magnitude of the controller error in a PI or a PID governor controller. The proportional gain contributes an immediate response to a governor controller error. Proportional gain is defined as the magnitude of the proportional element output (in percentage) divided by the magnitude of the governor controller error (in percentage).

4.25.5 Derivative gain

Derivative gain produces a controlling action that is the time derivative of the governor controller error. The derivative gain term acts to limit controller overshoot by reducing controller action proportional to the rate of change of error input to the governor controller. Derivative gain is defined as the magnitude of the derivative element output (in percentage) divided by the rate of change of the governor controller error input (in percentage/second).

4.25.6 Permanent speed droop

Permanent speed droop determines the amount of change in output a unit produces in response to a change in unit speed. Permanent speed droop can be developed either by using the wicket gate position or by using the unit power generation. If unit power generation is used to develop the permanent speed droop characteristic, the permanent speed droop term is sometimes called “speed regulation” or “power droop.” Permanent speed droop (in per-unit terms) is defined as the change in unit speed (in percentage of rated speed) divided by the change in governor output (percentage of gate position or percentage of rated power generation). Permanent speed droop is often expressed in terms of a percentage, which is 100 times the per-unit value.

For isolated or islanded operation, the permanent speed droop, if derived from the turbine control servomotor position, can help to stabilize the unit speed control by providing an intermediate feedback that limits the overtravel of the turbine control servomotors while controlling the unit speed. For operation while synchronized to an interconnected power system, the permanent speed droop determines the amount of participation the unit produces when responding to disturbances in system frequency. This participation should be coordinated with the other interconnected units to assure stable operation of the power system.

4.26 Water inertia time

The water inertia time (often called the “water starting time”) affects the water hammer effect of changing the water flow through the turbine using the primary turbine control device, such as the wicket gates. This parameter also affects the small signal stability of the frequency control system. The dynamic performance of the control system is very much dependent on the penstock water time T_w . T_w is a simplified approximation of the relative inertia of the water column, and it does not include the effects of wave time on the dynamic

$$T_w = \frac{Q}{g \times H} \times \sum \frac{L}{A} \quad (2)$$

influence of the water column. Water starting time is normally calculated for the unit at rated generation and at rated head. Other turbine operating conditions have different effective water starting times. For a simple penstock system, the classical treatment of water start time computes its value as in Equation (2):

where

- T_w is the water start time (s)
- Q is the rated water flow (m^3/s)
- g is the gravitational acceleration (m/s^2)
- H is the rated operating head (m)
- L is the length of each given portion of water column with constant area (m)
- A is the cross-sectional area of the corresponding portion of water column (m^2)

Normally, dynamic performance degrades with increasing T_w . As T_w is directly proportional to the length of the penstock, control performance degrades with increasing penstock length. The computation of the water start time is meaningful only if the water start time is relatively short. For very long penstocks, the wave travel time of the water column becomes significant, and the reflected pressure waves in the water

column cause the preceding treatment of water start time to no longer be valid. When the wave travel time approaches 25% of the T_w , engineers should not rely on only the classic value of T_w , and the performance of the turbine governing system should be evaluated by considering the effects of both the water starting time and the wave travel time.

On long penstocks, a surge tank is often added. A surge tank consists of a branch in the water passageway that is typically vented to atmosphere. The elevation of the surge tank's vented end should be sufficient to prevent overflowing of water under normal operation of the unit. The surge tank reduces the effective water starting time by absorbing some of the inertial effects of the water flow and temporarily providing or storing water from the penstock in response to pressure changes within the penstock (see Chaudhry [B6]). The surge tank also reduces the effect of the traveling pressure wave in the water column upon the unit operation by reflecting the pressure wave back away from the unit. This reflection reduces the effective wave travel time and makes it less likely to impact the performance of the turbine governing system (see Sanathanan [B36] and Trudnowski and Agee [B41]).

4.27 Mechanical inertia time

The mechanical inertia time (often called the “mechanical starting time”) [see Equation (3)] and the inertia constant [see Equation (4)] are normally used to characterize the mechanical inertia of the rotating parts:

$$T_M = \frac{I \times \omega^2}{P} \quad (3)$$

where

T_M is the [mechanical inertia time \(s\)](#)

I is the [combined rotating inertia of generator, turbine, shaft, flywheel, and generator speed increaser](#) (kg-m²)

P is the rated ~~water flow, m³/s;~~ [power output of the unit \(W\)](#)

~~g is the gravitational acceleration, m/s²;~~

ω is the rated rotational speed of the turbine (rad/s)

$$H = \frac{T_M}{2} \quad (4)$$

where

H is the [inertia constant \(s\)](#)

[Experience has shown that the turbine rotating inertia is normally approximately 5% of the generator rotating inertia. The choice of generator inertia is an important consideration in the design of a hydroelectric plant, as follows:](#)

The speed rise of the turbine-generator unit under load rejection conditions is inversely proportional to T_M (and thus inertia). Choice of plant design parameters involves optimization of unit inertia, effective gate closing time, and penstock design to control pressure rise, speed rise, and costs. Increasing T_M (rotating inertia) reduces the maximum transient speed rise, but at additional cost. Additional inertia may be provided either by increasing the mass of the generator rotor or by adding a flywheel.

The inertia constant, H , also has a significant effect on electrical system transient stability, as this factor influences the speed with which energy can be moved in or out of the generator to control the rotor angle acceleration during system fault conditions.

4.28 Impact upon stability

Both the water inertia time (T_W), also known as the “water starting time,” and the mechanical inertia time (T_M), also known as the “mechanical starting time,” affect the achievable controllability of the turbine governing system. One benchmark that is often used to estimate the controllability of a hydroelectric generating unit’s governing system is the ratio of the T_M to T_W . Although steady-state stability can generally be achieved for essentially any T_M/T_W ratio (see Wozniak [B43]), a ratio of approximately 1:1 is often considered to be a practical lower limit for achieving acceptable controllability for an isolated unit that experiences normal load transients. Classically, many older hydroelectric generating units had T_M/T_W ratios in the range of 3:1 to 4:1. Older mechanical-hydraulic governors using a temporary droop type of governor controller strategy could generally achieve acceptable controllability for T_M/T_W ratios as low as 2:1. Units

with lower T_M/T_W ratios, down to approximately 1:1, generally require electrohydraulic governors using a PID (or similar) type of governor controller strategy to achieve acceptable controllability.

4.29 Automatic generation control

An interconnected power system consists of a number of control areas (each consisting of one or more power companies) interconnected with each other through tie lines. In each control area, a central computer-controlled AGC system controls to a target steady-state frequency and the net tie-line power exchanges between the control areas in the interconnected system. Generation [control](#) and frequency control are thus performed on a decentralized basis. Each control area tries to maintain the amount of generation required to meet internal load, adjusted by the interchange demand. The frequency of the interconnected system is coordinated and maintained by the cooperative operation of all interconnected control areas.

Before the development of AGC, speed governors provided frequency control. This [task](#) often placed an excessive burden on the governing systems of a few units. Furthermore, after a disturbance, governors with permanent speed droop could not restore frequency to the predisturbance frequency level. With AGC, the governing burden is distributed among many units at various plants so that each unit assumes its regulating share depending on unit capability, unit response, transmission availability, economic loading, and so on, as determined by the control area operator. The net interchange of power with neighboring control areas is maintained using real-time power measurements of all tie lines. After a system disturbance, such as a large generator outage when the system settles to a lower frequency (determined by the permanent speed droop settings), the AGC-controlled units increase their generation level to restore the system frequency to its predisturbance level. In small systems without AGC, operators perform this restoration of frequency manually on the governor frequency or power reference settings.

The AGC interfaces with the unit turbine governing systems either directly or via a plant-level control system. The AGC system issues raise/lower commands to adjust the setpoint for the unit or station control system, or the AGC system may issue a level setpoint (generally in terms of power generation) to determine the desired output of the unit or of the plant.

Hydroelectric plants that are capable of rapid response are good candidates for AGC. One approach to achieve rapid stable response is to use setpoint feedforward within the turbine governing system. This approach allows the governor stabilizing parameters (i.e., gains and damping adjustments) to be adjusted so the hydroelectric generating unit contributes to the frequency stability of the interconnected system, and the feedforward function achieves the desired unit responsiveness.

4.30 Efficiency optimization

On a unit basis, the efficiency of an adjustable-blade turbine may be optimized by use of a blade/gate relationship that is also dependent on the operating head of the unit. By positioning the turbine blades as a three-dimensional function of both gate position and operating head, the operating efficiency of the turbine is optimized, based on the most recent turbine efficiency testing of the turbine that produced the gate/blade relationship used in the blade controller. This optimization strategy is often called “3D blade control.”

With the proliferation of modern computer-based control systems, software is sometimes applied to optimize the operational efficiency of hydroelectric generating stations. These optimizing software programs normally reside in the plant control system with control interfaces to the unit governor control systems. These programs contain representations of the unit efficiency curves for various operating heads as determined from test measurements. Optimization of the station’s output is based on preestablished algorithms, which determine the unit generation levels to maximize the efficiency of the station under all conditions. Although these optimization programs usually reside outside the unit governing system, they typically interface with it through a station-level communication system.

In addition to the plant optimization control link, these optimization programs may also interface with the unit governors to optimize the unit efficiency of adjustable-blade turbines. This optimization is often done by computing a “cam offset” value and by transmitting this offset value to the unit governor’s blade control algorithm. The blade control optimization program may compute this cam offset as a function of the unit output, the unit flow, and the unit operating head. The blade control cam offset can be optimized using either the unit generation or the calculated unit efficiency as the parameter to maximize. This optimization strategy is sometimes called “automatic index testing.”

When implementing an optimization system, the amount of additional control activity that results from the optimization process should be considered. If the optimization system continuously searches for an optimum operating point, this [searching](#) may result in excessive movement of the unit governors. The result of this excessive movement can be both increased wear of the turbine control actuators and the turbine control devices and a reduced overall operating efficiency because of the increased percentage of time the unit or station is operated off its peak efficiency. Typically, this situation is avoided by “locking in” the computed optimization parameters for an operating point so that operating point is not optimized again until the optimization system is commanded to do so. An optimization system that uses stored efficiency curves to schedule the operating levels of the units in a station does not typically exhibit the symptoms of excessive searching activity.

5. Elements of the turbine governing system

As with any conventional control system, a turbine governing system comprises three basic components: the setpoint controller, the actuator or actuators, and the controlled process.

5.1 Setpoint controller

The setpoint controller portion of the turbine governing system determines the basic operating function of the hydroelectric generating unit. The operating parameters and controller strategy used in the setpoint controller determine the conditions to which the turbine governing system responds and the action to be taken by the turbine governing system.

Hydroelectric generating stations are sited for diverse reasons. Energy generation could be either the primary justification for the project or ~~it could be~~ a mere byproduct of the project that was justified for other reasons. For example, hydrogeneration may be an ancillary component in an irrigation, flood, or reservoir- level control project. In these instances, water flow or reservoir levels are the primary controlled variables. Whenever hydrogeneration capability is added to a project, control takes on new dimensions.

To be useful, the output of a hydroelectric generating station should have defined performance requirements for power, voltage, and frequency. The hydrogenerator, with its own specific unit control system, should be in harmony with the load or the grid to be supplied, and the total system should be stable to assure a reliable supply of electrical energy.

5.1.1 Error computation and processing

A typical governor’s setpoint controller subtracts the process output (speed) from the setpoint input (speed reference). The error processing elements of the governor perform operations on the input-output difference (the error) to arrive at a correcting command for the actuators. The most common controlled process outputs for a hydroelectric turbine governing system are unit speed and generated power.

5.1.1.1 PID control

A common computing algorithm is the PID. Speed or power errors, or both, are inputs to a typical PID governor on a hydroelectric unit. The PID gains should be independently adjustable to achieve the desired dynamic performance. Several possible structural implementations of the basic PID control algorithm have been used in hydroelectric turbine governing systems.

5.1.1.2 Gain scheduling

The characteristics of a hydroelectric turbine can vary significantly over its operating range. In other words, if the turbine governing system is tuned for optimum performance at one operating point, its performance may be different at a different operating point with those same gain settings. With a single set of gains for the turbine governing system, the system is typically tuned at its worst-case operating point, and the resulting performance at the other operating points prevails. One method to approach optimum performance at all operating points is to use a schedule of gains based on some operating parameter such as generation level. With this method, the unit is tuned for the best achievable performance at several different operating levels and the gains are stored in a data map that is used to set the controller gains as a function of the operating point. Gain settings between the stored data points can be interpolated to yield smooth transitions between operating levels.

5.1.1.3 Adaptive control

Adaptive control is a technique used to automatically adjust the dynamic characteristics of the control system to achieve optimum performance at any operating point. This technique also compensates for changes in unit characteristics and other system parameters. Although adaptive control can theoretically provide optimum performance under all conditions, the additional actuator movement inherent to many adaptive control approaches can have a negative impact on the longevity of many unit components. The term “adaptive control” is broad in scope. Many control techniques used in conjunction with feedback control systems, such as feedforward, gain scheduling, and 3D blade control, also fit the general definition of adaptive control.

5.1.1.4 State space control

State space control is a control technique that uses more information than a single computed error for making corrective action to the control system actuator. This [technique](#) may include the processing of information from several independent parameters that affect the operation of the unit. Often, this information is input to a mathematical model of the controlled unit, and the best control action is predicted from this model. The benefits of state space control include improved responsiveness and stability along with improved robustness over a wide range of changing system parameters. Some elements of state space control techniques are in common usage in the hydroelectric power industry. However, turbine governing systems based primarily on state space control techniques are not common, as practical forms of this control strategy are still in their early stages of development.

5.1.1.5 Other control approaches

Several other control approaches to error processing have been used during the evolution of hydroelectric unit control. These approaches include temporary droop control (approximately equivalent to a PI controller), gain-plus-reset (approximately equivalent to a PI controller), double-derivative implementation of the PID controller, and deadband control. The specific characteristics of these variations of control approaches are not addressed in this guide.

5.1.2 Feedback

The process of continuously monitoring the output of a process to maintain it at a desired level is known as feedback control. The desired operating level, whether power, gate position, pond level, or frequency, is called the “setpoint.” An elementary feedback control system is shown in Figure 14.

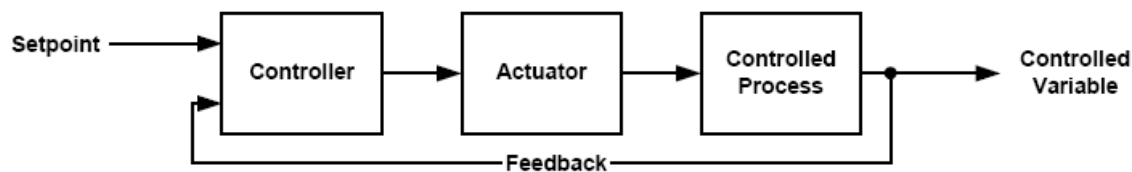


Figure 14—Elementary feedback control system

5.1.2.1 Multiple feedbacks

More than one feedback from a controlled process can be used in a feedback control system. Generally, one feedback comes from the process output, and one feedback comes from an intermediate point in the controlled process. Using this control approach establishes a relationship (generally linear) between the two feedbacks and improves the stability of the control loop by reducing the phase lag in the control loop. This approach, however, also reduces the accuracy of the control system because the intermediate feedback allows the setpoint controller to be satisfied when a difference exists between the setpoint and the process output.

5.1.2.1.1 Permanent speed droop governing system

A permanent speed droop governing system is a common type of control that uses multiple feedbacks. Permanent speed droop determines the amount of change in the position of the turbine control servomotor a unit provides in response to a change in unit speed. Permanent speed droop is discussed in 4.5. Figure 2 is a block diagram representation of a typical governing system using permanent speed droop.

5.1.2.1.2 Speed regulation governing system

A speed regulation (also known as “power droop”) governing system is similar to the permanent speed droop type of control system, but generated power is used as the intermediate feedback from the controlled process instead of actuator position. Speed regulation determines the amount of power generation a unit provides in response to a change in unit speed. Speed regulation is discussed in 4.5.2. Figure 7 is a block diagram representation of a typical governing system using speed regulation.

5.1.3 Feedforward

The process of setting a controlled variable to a target level computed to achieve the desired level is known as feedforward control. Figure 15 is a simplified block diagram of a feedforward control system. Feedforward control differs from feedback control in that it does not actually measure the output of the controlled process. Instead, it computes the necessary level of the controlled variable or variables based on the setpoint and the known characteristics of the controlled process. Noncontrolled inputs, which affect the controlled process, other than the setpoint may also be used in this computation. The advantage of feedforward control is that the actuator and process dynamics are not included in the control action, [and this exclusion allows](#) the control to be very responsive without risking instability of the control loop. The disadvantage of feedforward is that it cannot compensate for the inevitable deviations of an actual process from its model. Most real-world feedforward control systems include some supplemental feedback control

to enhance the steady-state accuracy of the control. Refer to Figure 11 for a simplified block diagram of a governor controller using both feedback from the unit speed and feedforward from the setpoint to the controller output. This system allows the gains in the feedback controller to be set for stable operation while providing a very fast response to setpoint changes.

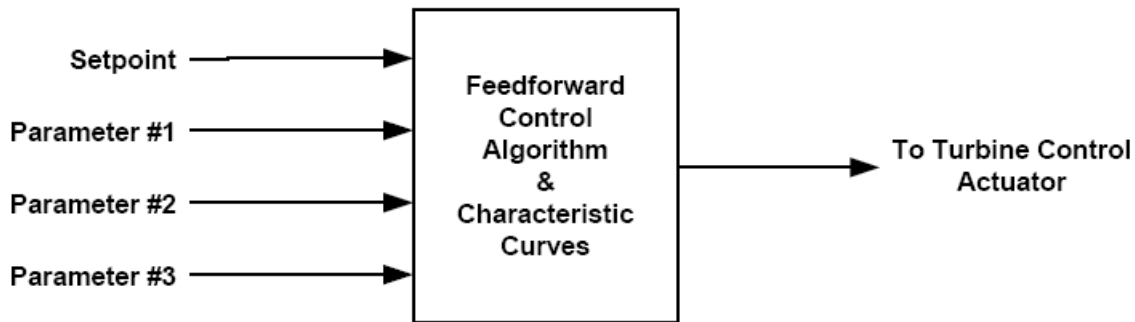


Figure 15—Feedforward control system

5.2 Actuator

An actuator is the connection between the setpoint controller and the controlled process. The output of the actuator should be able to effect a change in the controlled variable of the process. Most controlled variables related to the control of a hydroelectric generating unit require the mechanical positioning of the controlled variable, such as the wicket gates or turbine blades. Other processes may require an electrical current as the actuator output, such as the generator field or the demand of a shunt load bank.

The actuator system compares the desired turbine actuator position command or setpoint with the actual actuator position, and it provides the necessary work to hold the actuator output at the desired value. Several types of governor actuators are commonly used, but they all perform the same basic function.

For dual-regulated turbines with adjustable blades, such as Kaplan or bulb turbines, separate actuator servomotors are generally used to independently control the wicket gates and the runner blades. On a double-regulated turbine such as an impulse turbine, the number of turbine control actuators used varies with the number of needles controlling the water flow to the wheel. It is common for each needle to be driven by a dedicated servomotor. It is also common for the needle valves of an impulse turbine to be designed with a loading spring built into the control servomotor to provide fail-safe operation to close the needles upon control system failure or loss of hydraulic control pressure. A separate actuator servomotor generally controls the deflector mechanism, which acts to deflect the water stream away from the turbine runner to reduce the developed torque of the turbine more rapidly than can be done with the slower moving needle servomotors.

The work capacity of the actuator used to control a turbine's actuating device should be greater than the maximum work necessary to move the device throughout its operating range. The maximum work capacity required to move the turbine actuating device is affected by the following items:

- a) Type of turbine
- b) Operating head across the turbine
- c) Mechanical design of turbine actuator linkages
- d) Maintenance history (e.g., lubrication) of turbine actuator linkages
- e) Hydraulic design of the turbine actuator
- f) Hydraulic design of the turbine distributor passageway
- g) Rate of travel of the actuator