An Introduction to Controls for Steam Power Plants

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(Figures, tables and formulas in this publication may at times be a little difficult to read, but they are the best available. ***DO NOT PURCHASE THIS PUBLICATION IF THIS LIMITATION IS NOT ACCEPTABLE TO YOU.)***

1. TYPES OF CONTROLS AND CONTROL SYSTEMS. There are basically three types of industrial instrumentation systems for power plant control: analog, microprocessor, and computer.

1.1 ANALOG. Analog control is the representation of numerical quantities by means of physical variables such as current, air pressure, voltage, rotation, resistance, electromagnetic field (EMF), etc. Analog control over the last 30 years has consisted primarily of two types:

a) Pneumatic - the use of air pressure (or other gases occasionally) as the power source to represent numerical values.

b) Electronic - the use of current, voltage, resistance, EMF etc. as the power source to represent numerical values.

1.2 MICROPROCESSOR-BASED CONTROL STATIONS. These are a digital stand-alone single controller type, or a split-architecture control system offering powerful, configurable control capability on a modular basis. These units can accept standard analog electronic inputs plus digital inputs and give analog outputs plus digital outputs. By connection to a data highway for communication, other operator interfaces are easily added.

1.3 COMPUTER - DIRECT DIGITAL CONTROL (DDC) OR SUPERVISORY CONTROL (SC). DDC control can perform all of the control functions, operator displays and graphics, reports and calculations for efficiency and controller tuning, or a computer can be used as a supervisory control for analog control system, microprocessor based control units, or as a data logger with graphic displays. Choice of analog versus microprocessor based control units or computer (DDC) (SC) should be based on relative cost and future requirements. Consideration should be given to the ability to readily interface to or add to a utilities energy management system or other computer networks.

1.4 PNEUMATIC CONTROL SYSTEMS. Pneumatic control systems should only be considered when adding to an existing power plant already equipped with pneumatic control instruments.

1.5 TYPES OF CONTROL SYSTEMS AVAILABLE.

a) On-off controls
b) Single point positioning system
c) Parallel positioning system
d) Parallel metering system
e) Parallel metering system with oxygen trim. CO trim w/coal
f) Steam flow/air flow metering system

Boilers should have oxygen trim in order to optimize fuel usage. CO trim should be considered for larger boiler installations as an adjunct to oxygen trim for increased efficiency, especially for coal firing.

1.6 MAINTENANCE AND CALIBRATION. Maintenance and calibration is a necessity regardless of the type of control equipment being used. Pneumatic instrumentation will require more maintenance because of its usage of air that contains dirt, moisture, oil, and other contaminants than its electronic counterparts. Also, pneumatic instrumentation will require more frequent calibration checks because of its inherent mechanical linkage design versus solid state electronic units.

2. STEAM POWER PLANT CONTROLS.

2.1 COMBUSTION CONTROL. Combustion control comprises a series of devices on a boiler developed to satisfy steam demands automatically and economically by controlling furnace combustion rates through adjustments of the burning components while maintaining a constant set point (such as a fixed but adjustable pressure or temperature) and an optimum (adjustable) ratio of fuel to air.

a) For the metering type (proportioning plus reset plus rate action), see Figure 1.
b) Combustion safeguard.
c) Refer to the ASME Boiler and Pressure Vessel Code Section VII subsection C6 for minimum basic instruments required for proper, safe, efficient operation.
d) See Tables 1, 2, and 3 for typical lists of instruments.

2.2 STEAM TEMPERATURE CONTROL. Critical temperatures should be recorded and also alarmed. An automatic fuel-trip device is required for steam temperature out of normal range. See Table 2 for temperature sensing devices.

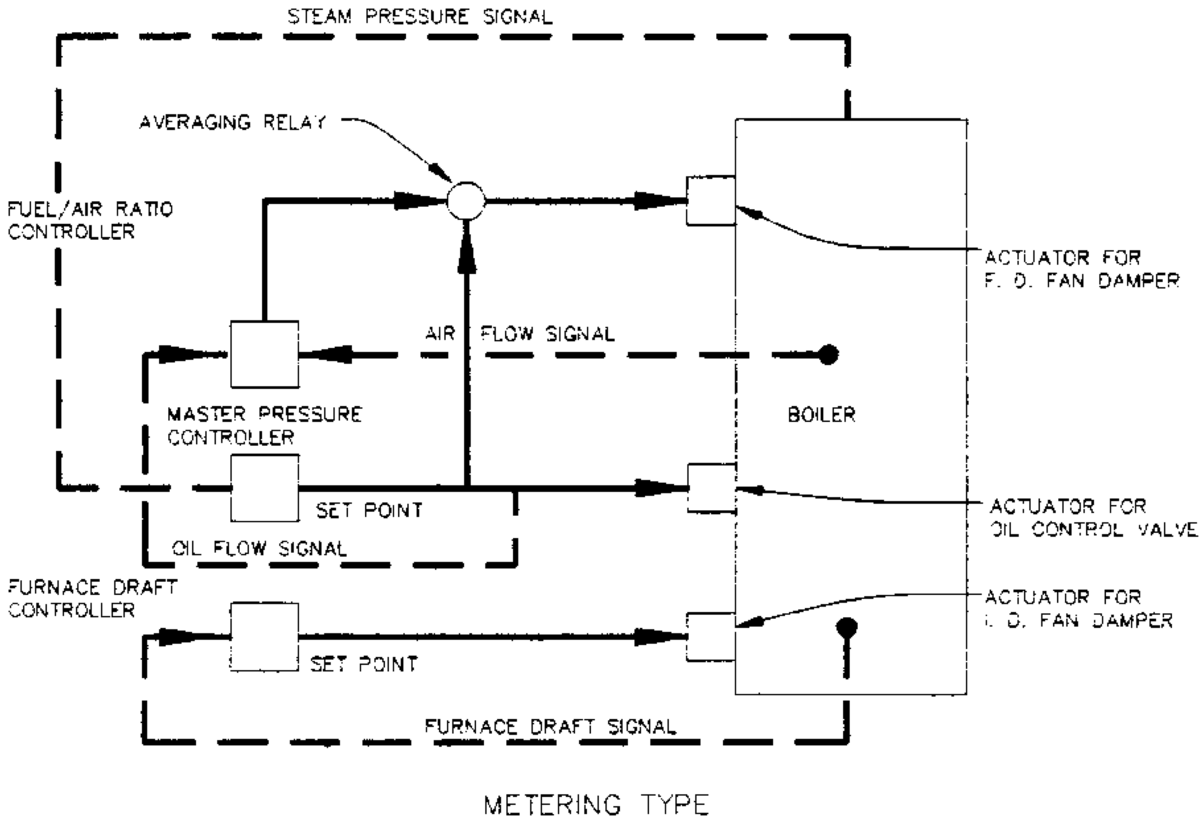

Figure 1

Typical combustion control system

Sensing element	Location of sensing element	Indicator	Recorder	Totalizer
Pressure	Steam boiler drum	A		
	Superheated steam outlet		A	
	Main steam header		A	
	Feedwater header	A		
	Fuel oil header	A		
	Gas fuel header	A		
	Steam at turbine (extraction or condensing)	A	C	
	Steam at turbine first stage	A		
	Steam at turbine No. 1 extraction	A		
	Steam at turbine No. 2 extraction	A		
	Steam at turbine No. 3 extraction	A		
	Steam at turbine exhaust	A		
	Instrument air	A		
	House service air	A		
	House service water	A		
	Auxiliary steam	A		
Draft	Forced draft fan discharge	A		
	Burner or stoker wind box	A		
	Furnace draft	A		
	Boiler gas outlet	A		
	Air heater or economizer gas outlet	A		
	Dust collector outlet, or I.D. fan inlet	A		
	Air heater air discharge	A		
	Flyash return fan	A		
Temperature	Superheated steam		A	
	Boiler outlet gas		A	
	Air heater or economizer outlet gas	A	B	
	Air heater outlet air	A	A	
	Economizer water outlet	A	B	
	Feedwater header	A		
	Steam to extraction turbine		A	
Vacuum flow	Absolute pressure at turbine exhaust	A		
	Steam	A		A
	Air		A	
	Feedwater		D	
	CO_2 (alternate to air flow)		E	
	Fuel oil			A
	Gas fuel		A	A
	Coal weight			A
	Steam to extraction turbine		A	A
	Extraction steam from extraction turbine		A	A

Table 1

List of instruments on control panels

Sensing element	Location of sensing element	Indicator	Recorder	Totalizer
Level	Boiler drum		A	
	Coal bunker – pilot lights	A		
	Fuel oil tank	A		
	Deaerator storage section	A		
Flame safeguard	Safeguard panel	A		
Control instruments	Combustion control	A		
Hand/automatic selector stations with indicators for remote or automatic operation	Combustion control			
	Fuel control	A		
	Forced draft damper	A		
	Induced draft damper	A		
	Feedwater control	A		
Conductivity	Condenser hotwells		A	
	Sample coolers		A	
Alarms	Annunciator	A		
Oxygen	Stack percent		A	
Carbon dioxide	Stack percent (coal)		A	

A = necessary
B = desirable but not necessary
C = necessary in some instances but not in others
D = necessary but not necessarily on located panel
E = alternate to some other instrument

Table 1 (continued)

List of instruments on control panels

Element	Type		Common applications	
			Control	Instrument
Flow	Mechanical	Batch totalizing	Filling containers	Weighing containers. Totalizing positive displacement water and gas meters.
	Variable differential pressure with constant area	Continuous and totalizing	Proportioning large flows	Orifice, flow nozzle, and Venturi nozzle meters. V-slot
	Variable differential pressure with constant area	Combustion	Control valves	Air and gas flow
	Constant differential pressure with variable area	Tapered tube and float	Proportioning small flows	Rotameter
	Variable differential with variable velocity anemometer	Pitot tube. Velocity. Electric resistance of hot wire affected by velocity of flow.	Airflow	Airflow
	Vortex-linear volumetric flow	Batch, continuous and totalizing	Filling containers, proportional flow, control valves, air flow, liquid flow, steam flow	Vortex flowmeter 16 to 1 turndown
Temperature	Solid expansion	Bimetal	On-off thermostats	Dial thermometer 100 to 1000 deg F
	Fluid expansion	Mercury or alcohol		Glass thermometer 38 to 750 deg F
		Mercury in coil	Temperature regulators	Dial thermometer 38 to 1000 deg F
		Organic liquid		125 to 500 deg F
		Organic vapor liquid		40 to 600 deg F
		Gas		400 to 1000 deg F
	Gas expansion	Nitrogen gas	Temperature regulators	Recorders and transmitters 350 to 1400 deg F
	Thermocouples	Copper-constantan	Temperature regulators	Low voltage 300 to 600 deg F
		Iron-constantan		0 to 1400 deg F
		Chromel-alumel		600 to 2100 deg F
		Platinum-platinum rhodium		1300 to 3000 deg F

Table 2

Sensing elements for controls and instruments

Element	Type		Common applications	
			Control	Instrument
Temperature (cont)	Electric resistance of metals	Copper	Temperature regulators	Potentiometer 40 to 250 deg F
		Nickel		300 to 600 deg F
		Platinum		300 to 1800 deg F
	Optical pyrometer	Comparative radiant energy		850 to 5200 deg F
	Radiant pyrometer	Radiant energy on thermo-couples	Flame safeguard, surface temperature regulation	Potentiometer 200 to 7000 deg F
	Fusion			Pyrometric cones 1600 to 3600 deg F; Crayons 100 to 800 deg F
Pressure	Mechanical	Bourdon tube	Pressure, draft and vacuum	Pressure gauge
		Bellows or diaphragm	Vacuum regulators	Low pressure, draft and vacuum gauges
		Manometers		Barometer
	Variable electric resistance due to strain	Pressure transducer	Process pressure regulator	Potentiometer 100 to 50,000 psi
	Variable electric resistance due to vacuum	Thermocouple	Vacuum regulator	High vacuum 1 – 700 microns Hg
	Variable electronic resistance to vacuum	Vacuum tube	Vacuum regulator	High vacuum down to 0.1 microns Hg
	Variable capacitance	Capacitance	Pressure regulators	Indicators and recorders 1” H_2O to 1200 psig
	Variable frequency	Frequency transducer	Pressure regulators	Indicators and recorders 1 “ H_2O to 1200 psig

Table 2 (continued)

Sensing elements for controls and instruments

Element	Type		Common applications	
			Control	Instrument
Level	Visual			Gauge stick, transparent tube
	Float	Buoyant float	Mechanical level regulator	Tape connected to float
		Displacement	Pneumatic level regulator	Torque
	Differential pressure	Manometer	Level regulator	Remove level gauge
Motion	Centrifugal		Speed governs	Tachometer
	Vibrating reed			Tachometer
	Relative motion			Stroboscope
	Photo-electric cell		Limit control	Counter
Chemical	Flue gas analysis		Combustion control	Orsat
	Water analysis		Water treatment	Water constituents
	Flue analysis			Ultimate analysis of fuels
Physical	Specific gravity			Hydrometer for liquids
	Weight			Scales for solids
	Humidity			Hygrometer
	Smoke density			Ringelman chart
	Gas density		Combustion	CO_2 meter
	Heat	Combination of water flow and temp. diff.	Combustion	Btu meter
Electric and electronic	Photo-conductivity		Flame safeguard	Photo-electric cell, smoke density
	Elec-conductivity	Probes	Alarm	pH of water, oil in condensate

Table 2 (continued)

Sensing elements for controls and instruments

Sensing element	Location of sensing element	Indicator	Recorder	Totalizer
Pressure gauges	Boiler drum	A		
	Boiler outlet steam	A		
	Turbine steam inlet	A		
	Extraction steam outlets	A		
	Feedwater heater steam inlet	A		
	Deaerator steam inlet	A		
	Condenser hotwell	A		
	Condenser pumps discharge	A		
	Boiler feed pumps suction	A		
	Boiler feed pumps discharge	A		
	Deaerator condensate inlet	A		
	Feedwater heater condensate inlets	A		
	Feedwater heater condensate outlet	A		
	Cooling water pump discharge	A		
	Condenser cooling water inlet	A		
	Condenser cooling water outlet	A		
	Pressure reducing valves, low pressure side	A		
	Air compressor discharge	A		
	Compressed air receiver	A		
Thermometers	Boiler steam outlet	A		
	Turbine steam inlet	A		
	Feedwater heater steam inlets	A		
	Turbine exhaust	A		
	Condenser condensate outlet	A		
	Deaerator condensate outlet	A		
	Feedwater heater condensate inlets	A		
	Feedwater heater condensate outlet	A		
	Boiler flue gas outlet	A		
	Economizer feedwater inlet	A		
	Economizer feedwater outlet	A		
	Condenser cooling water inlet	A		
	Condenser cooling water outlet	A		
	Cooling tower basin water	A		
Level	Boiler drum	A		
	Deaerator	A		
	Condenser hotwell	A		
	Condensate storage/return tank	A		
	Fuel oil tanks	A		

Table 3

Locally mounted instrumentation

2.3 FEEDWATER CONTROL. For small packaged boilers and boilers with constant loads a single or two element feedwater control system will suffice. Larger boilers and boilers with widely fluctuating loads should use a three element type. An automatic fuel trip device is required for low drum water level.

2.4 STEAM TURBINE GENERATOR CONTROL. Steam turbine controls should be supplied by the turbine manufacturer. With the rapid advancement of electronics, an electrohydraulic control (EHC) system is desirable over an all mechanical system. The EHC system is more versatile and faster responding, which gives improvement in control reliability and accuracy which is manifested in improved turbine performance. The Mechanical Hydraulic Control System (MHC) has not been used since the late 1970's. Many are still in use but they are for the most part not a currently manufactured unit. Automatic startup and shutdown is easily done with microprocessor based control equipment. A standard EHC system is comprised of four primary functions:

a) Speed control
b) Load control
c) Flow control
d) Trip

3. SAFETY DEVICES AND INTERLOCKS. Safety devices such as boiler shutdown devices, startup and shutdown interlocks, and alarms should be installed as recommended by the equipment manufacturer. Coal, oil, and gas fired boilers can have different shutdown safety trips. Check boiler manufacturer's recommendations and ASME Boiler and Pressure Vessels Code Section VII for standard trip conditions. Safety controls for boilers are needed for protection against explosions and implosions. Criteria for protection against boiler explosions have been well established. Protection against boiler implosions is not so well understood. For a boiler, implosion would be the result of a negative pressure excursion of sufficient magnitude to cause structural damage. Boiler implosions are caused by one of two basic mechanisms: (1) The induced draft fan of a balanced draft boiler is capable of providing more suction head than the boiler structure is capable of withstanding, and (2) the so-called flame collapse or flameout effect. Implosion concerns have resulted in many new control-system developments. Each steam generator manufacturer has recommendations and the National Fire Protection Association has issued NFPA 85-G on the subject. For a detailed discussion of boiler implosions, see also Combustion Engineering, Inc, 1981.

4. CONTROL LOOPS. A single control loop includes a controlled variable sensor, controlled variable transmitter, the controller, automatic-manual control station, and final control element including positioner, if any. Control loops used for power plants are usually of the pressure, temperature, or liquid level type. See Figure 2.

4.1 PRESSURE. Pressure control loops may be used for control of boiler pressure, deaerator pressure, auxiliary steam pressure, building heating steam pressure, and fuel oil pressure. For control of boiler pressure the final control element regulates fuel flow to the boiler in response to boiler drum steam pressure. For other pressure applications the final control element is usually a pressure reducing control valve which regulates in response to downstream pressure.

4.2 TEMPERATURE. Temperature control loops may be used for control of steam temperature from boilers or desuperheaters and fuel oil temperature from fuel oil heaters.

4.3 LEVEL. Liquid level control loops may be used for control of boiler drum water level, condenser hotwell water level, feedwater heater drain cooler water level, and deaerator storage tank water level.

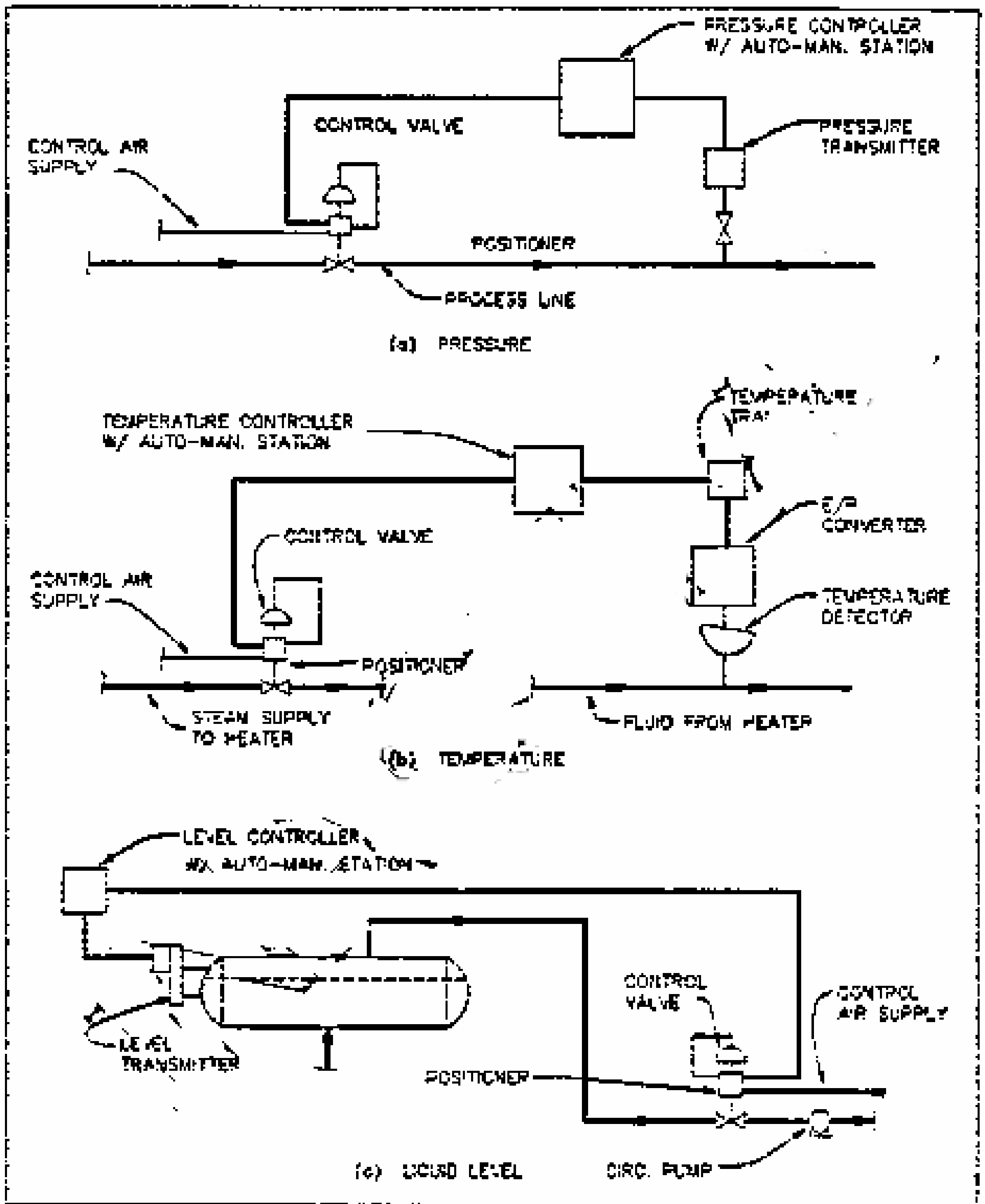

Figure 2

Typical control loops

5. FLOW METERS. Flow meters, particularly differential pressure type, have remained unchanged over the past decade. There have been several new types of flow meters added to the flow measurement arena. The new meters such as vortex, ultrasonic, and Doppler have added improved accuracy, linear signals, and rangeability as high as 16:1. With the improvements in electronic transmitters over the past decade there has been an improvement in their overall specifications. However, the differential pressure type flow meters have remained the same; accuracy of 2 to 3 percent and rangeability of4:1 maximum. The cost of electronic transmitters is now lower than pneumatic counterparts and should be used except for all pneumatic systems. For types of flow meters see Table 4; for applications see Table 2.

6. PRESSURE GAUGES. Pressure gauges are usually direct-connected and field mounted. Size and ranges are specified by user. Local-mounted gauges give a "backup" reading and also help operators in determining if equipment or pressure systems are working satisfactorily. Accuracy is normally 0.5 to 1 percent of span. For test and calibration purposes, use 0.25 to 0.5 percent gauges.

7. TEMPERATURE SENSORS. The basic types of temperature sensors are thermometers, thermocouples, and resistance temperature detectors.

7.1 THERMOMETERS. Thermometers are located on equipment and piping to provide local temperature indication.

7.2 THERMOCOUPLES. Thermocouples provide a reliable and accurate temperature measurement for most remote temperature sensing applications. Thermocouples can be used with pneumatic and electronic transmitters or they can be direct connected to some instruments. Thermocouples are non-linear.

7.3 RESISTANCE TEMPERATURE DETECTOR. Resistance temperature detectors offer a temperature range about the same as a copper-constantan thermocouple with detection of temperature changes of 0.03 degrees F (0.02 C). The resistance detector does not have a reference junction, as a thermocouple, since it operates on the measured change in the resistance of a metal or semiconductor (thermistor) with temperature. Platinum, because of its inherent stability and linearity, is becoming the standard of the industry with some copper and nickel still being used. Copper is quite linear but nickel is quite nonlinear. Resistance detectors can be used with pneumatic and electronic transmitters or can also be direct-connected to some instruments. See Table 2 for ranges and use.

8. TRANSMITTERS. Transmitters are primarily used to transmit an analog output (pneumatic or electronic) proportional to its measured signal. The American Petroleum Institute Recommended Practice 550 suggests for general service applications that the pneumatic tubing length from transmitter to controller to control valve not exceed 400 feet. Neither run should exceed 250 feet. Standard output signal for pneumatic transmitter is 3-15 psi with a 20 psi air supply and 4-20 mA DC for electronic transmitters with a nominal 30 VDC power supply. There are options for other output signals depending upon the manufacture. Recent electronic enhancements have made most electronic transmitters much more accurate, reliable, and smaller in size, weight, and less expensive than its pneumatic counterpart. Electronic signals are easier to adapt to microprocessor and computer based systems and should therefore be given prime consideration over pneumatics. Material of construction is of prime importance when selecting a transmitter. Many options are available and should be selected on the basis of need or life expectancy and cost. Most transmitters are field-mounted near point of measurement. Most electronic transmitters are the two wire type. Sensing line lengths longer than 50 feet are not usually recommended and should be used only when absolutely necessary. Where transmission line length (pneumatic) poses a problem in a flow loop, use a volume booster, or mount the controller near the valve.

FLOWMETER	PIPE SIZE, IN. (MM)	GASES (vapors) CLEAN	GASES (vapors) DIRTY	LIQUIDS CLEAN	LIQUIDS VISCOUS	LIQUIDS DIRTY	LIQUIDS CORROSIVE	LIQUIDS SLURRIES FIBROUS	LIQUIDS SLURRIES ABRASIVE	ACCURACY, UNCALIBRATED (INCLUDING TRANSMITTER)	REYNOLD'S NUMBER	TEMPERATURE, °F (°C)	PRESSURE PSIG (kPa)
SQUARE-ROOT SCALE, MAXIMUM SINGLE RANGE 4:1													
ORIFICE												PROCESS TEMPERATURE TO 1000 F (540 °C), TRANSMITTER LIMITED TO -20 TO 250 °F (-30 TO 120 °C)	TO 6000 PSIG (41,000 kPa)
SQUARE-EDGED	> 1.5 (40)	■	□	■	□	▒	▒	□	□	± to 2% URV	R_D > 2000		
HONED METER RUN	0.5 to 1.5 (12 to 40)	■	□	■	▒	□	▒	□	□	± 1% URV	R_D > 1000		
INTEGRAL	< 0.5 (12)	■	□	■	■	□	▒	□	□	± 2 to 5% URV	R_D > 100		
QUADRANT/CONIC EDGE	> 1.5 (40)	□	□	■	■	▒	▒	□	□	± 2% URV	R_D > 200		
ECCENTRIC	> 2 (50)	▒	■	▒	□	■	▒	□	□	± 2% URV	R_D > 10,000		
SEGMENTAL	> 4 (100)	▒	■	▒	□	■	▒	□	□	± 2% URV	R_D > 10,000		
ANNUBAR	> 4 (100)	▒	■	▒	□	■	▒	□	□	± 2% URV	R_D > 10,000		
TARGET	> 0.5 to 4 (12 to 100)	■	■	■	■	■	▒	□	□	± 1.5 to 5 % URV	R_D > 100		
VENTURI	> 2 (50)	■	▒	■	▒	▒	▒	▒	▒	± 1 to 2% URV	R_D > 75,000		
FLOW NOZZLE	> 2 (50)	■	▒	■	▒	▒	▒	□	□	± 1 to 2% URV	R_D > 10,000		
LO-LOSS	> 3 (75)	■	□	■	□	□	■	□	□	± 1.25% URV	R_D > 12,500		
PITOT	> 3 (75)	■	□	■	▒	□	▒	□	□	± 5% URV	NO LIMIT		
ANNUBAR	> 1 (25)	■	□	■	□	□	▒	□	□	± 1.25% URV	R_D > 10,000		
ELBOW	> 2 (50)	■	▒	■	□	▒	▒	▒	▒	± 4.25% URV	R_D > 10,000		
LINEAR SCALE: TYPICAL RANGE 10:1													
MAGNETIC	0.1 TO 72 (25 TO 1800)	□	□	■	■	■	■	■	■	± 0.5% of rate to ± 1% URV	NO LIMIT	360 (180)	≤ 1500 (10,500)
POSITIVE-DISPLACEMENT	< 12 (300)	■	□	■	□	□	▒	□	□	GASES: ±1% URV LIQUIDS: ±0.5% of rate	≤ 8000cS	GASES: 250 (120) LIQUIDS: 600 (315)	≤ 1400 (10,000)
TURBINE	0.25 TO 24 (6 to 600)	■	□	■	□	□	▒	□	□	GASES: ±0.5% of rate LIQUIDS: ±1% of rate	≤ 2 to 15cS	-450 to 500 (-268 to 260)	≤ 3000 (21,000)
ULTRASONIC												-460 to 500 (-268 to 260)	
TIME-OF-FLIGHT	> 0.5 (12)	□	□	■	▒	□	■	□	□	± 1% of rate to ± 5% URV	NO LIMIT	-300 to 500 (180 to 260)	PIPE RATING
DOPPLER	> 0.5 (12)	□	□	□	▒	■	■	■	■	± 1% of rate to ± 5% URV	NO LIMIT	-300 to 250 (-180 to 120)	PIPE RATING
VARIABLE-AREA	≤ 3 (75)	■	□	■	■	□	▒	□	□	± 0.5% rate of ± 1% URV	TO HIGHLY VISCOUS FLUIDS	GLASS: ≤ 400 (200) METAL: ≤ 1000 (540)	GLASS: 350 (2400) METAL: 720(5000)
VORTEX	1.5 to 16 (40 to 400)	■	▒	■	□	▒	▒	□	□	± 0.75 to 1.5% of rate	> 10,000	≤ 400 (200)	≤ 1500 (10,500)

■ = DESIGNED FOR THIS APPLICATION, ▒ = NORMALLY APPLICABLE , □ = NOT DESIGNED FOR THIS APPLICATION

Table 4

Flowmeter selection

9. RECORDERS. Recorders are primarily used to record data to provide a permanent record of present and past conditions. Selection of recording signals should be based on the following:

a) Federal and state requirements
b) Equipment manufacturer recommendations
c) Accounting purposes
d) Safety requirements
e) Operator requirements

Recorders are available in different sizes, shapes, (roll, fold and circular) and number of recording points. The selection of types should be based on suitability to needs and, in particular, the number of points being recorded. Trend recording is becoming more popular since it allows the selection of a large number of inputs to be recorded and for time periods as desired by the operator. Trend recording also allows for recording of critical points during startup. Most panel-mounted recorders are the 4-inch strip chart type because of space requirements. Most field-mounted recorders are the 12-inch circular large case type, because they usually meet NEMA Type 3 or better protection; see NEMA, Standard Publication/No. 250, Enclosures for Electrical Equipment (1000 volts Maximum). Recorders are normally supplied with 115 V, 60 cycle, or 24 VDC for the chart drives; some can be supplied with a pneumatic impulse or mechanical chart drives.

10. CONTROLLERS. Controllers can be used in either closed loop (feedback) or open loop control configurations. In a closed loop control configuration, a measurement is made of the variable to be controlled, and is compared to a reference or set point. If a difference or offset exists between the measured variable and set point, the automatic controller will change its output in the direction necessary for corrective action to take place. (See Figure 3a). Open loop control simply does not have a measurement sensor to provide an input to the controller for a comparison. See (Figure 3b). Open loop control can also occur when an automatic controller is placed in its manual position; saturation of the controller output at zero or 100 percent of scale; or failure of the final operator, when it can no longer be changed by its input signal. Feed-forward control is relatively new and, in most cases, it is also used in closed loop control configurations. While feedback control is reactive in nature and responds to the effect of an upset which causes an offset between the measured variable and set point of the controller, feed forward schemes respond directly to upsets and, thus, offer improved control. (See Figure 3c). There are also several types of control units available such as:

a) Ratio control
b) Cascade control
c) Auto-selector control
d) Nonlinear control

These units can be analog type and either electronic or pneumatic; however, additional pieces of instrumentation may be required to actually do the above types of control. With the new microprocessor-based control stations, they can perform most of the types of control listed above without additional devices and still provide 18 or so control algorithms. For standard controller action see Figure 4. For a controller to operate correctly, the controller must be properly tuned. Each controller must be tuned for its control loop; seldom are two alike. This can be time consuming, but it is necessary to have correct controller response to process changes. Some new microprocessor controllers have "Self Tuning" capability. This is a major addition for exact tuning of the control parameters to match the process dynamics. The new microprocessor-based controllers should be given first consideration as they are less expensive, state of the art, and can perform many more functions than a standard analog controller without additional pieces of equipment. These new units should also be considered for retrofit work as they can easily replace old electronic and pneumatic analog controllers and other devices. Some of the new microprocessor-based controllers are configured from push buttons located on the controller face plate. Special calibrators or mini-computers are not required to configure these stand alone controllers.

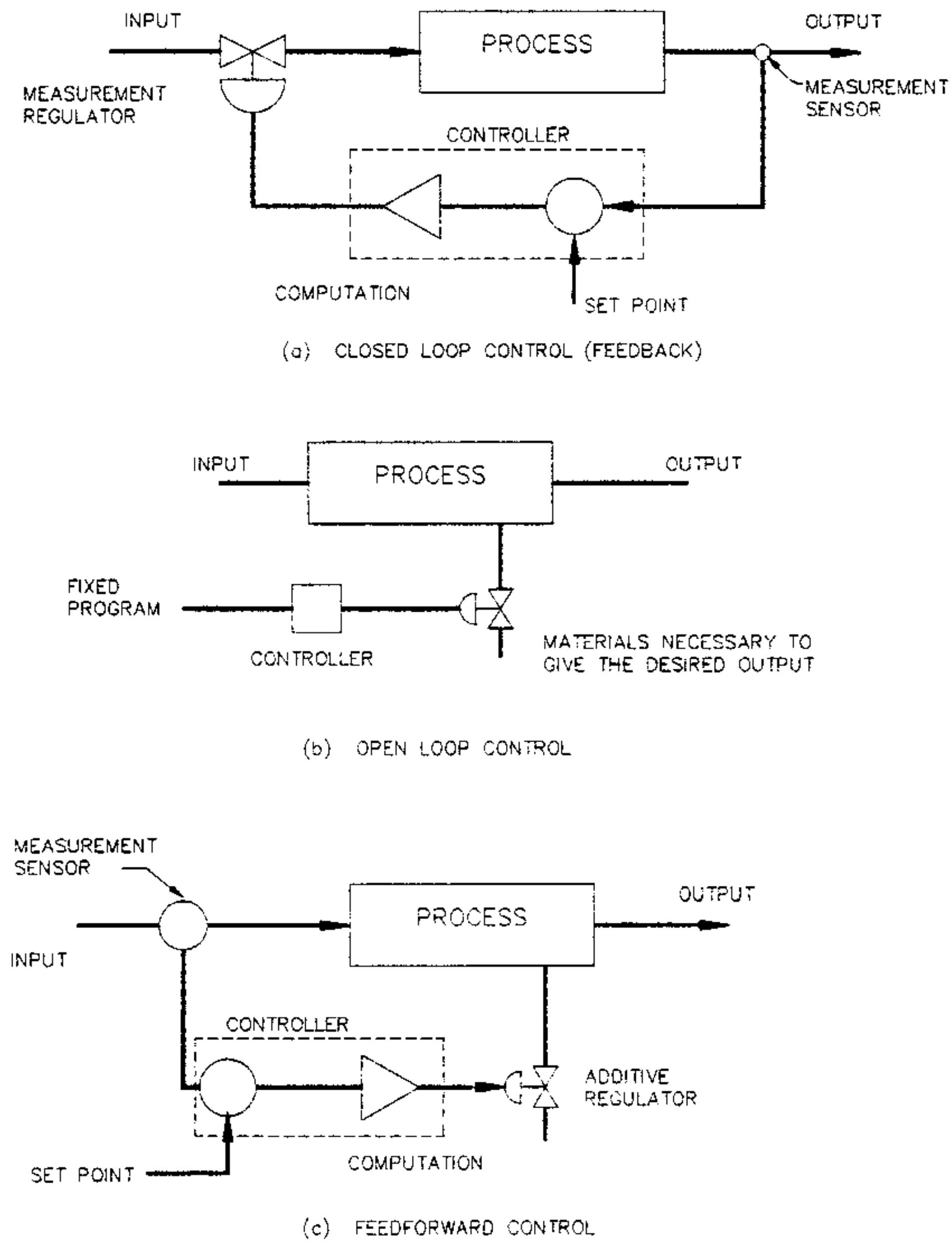

Figure 3

Typical controls

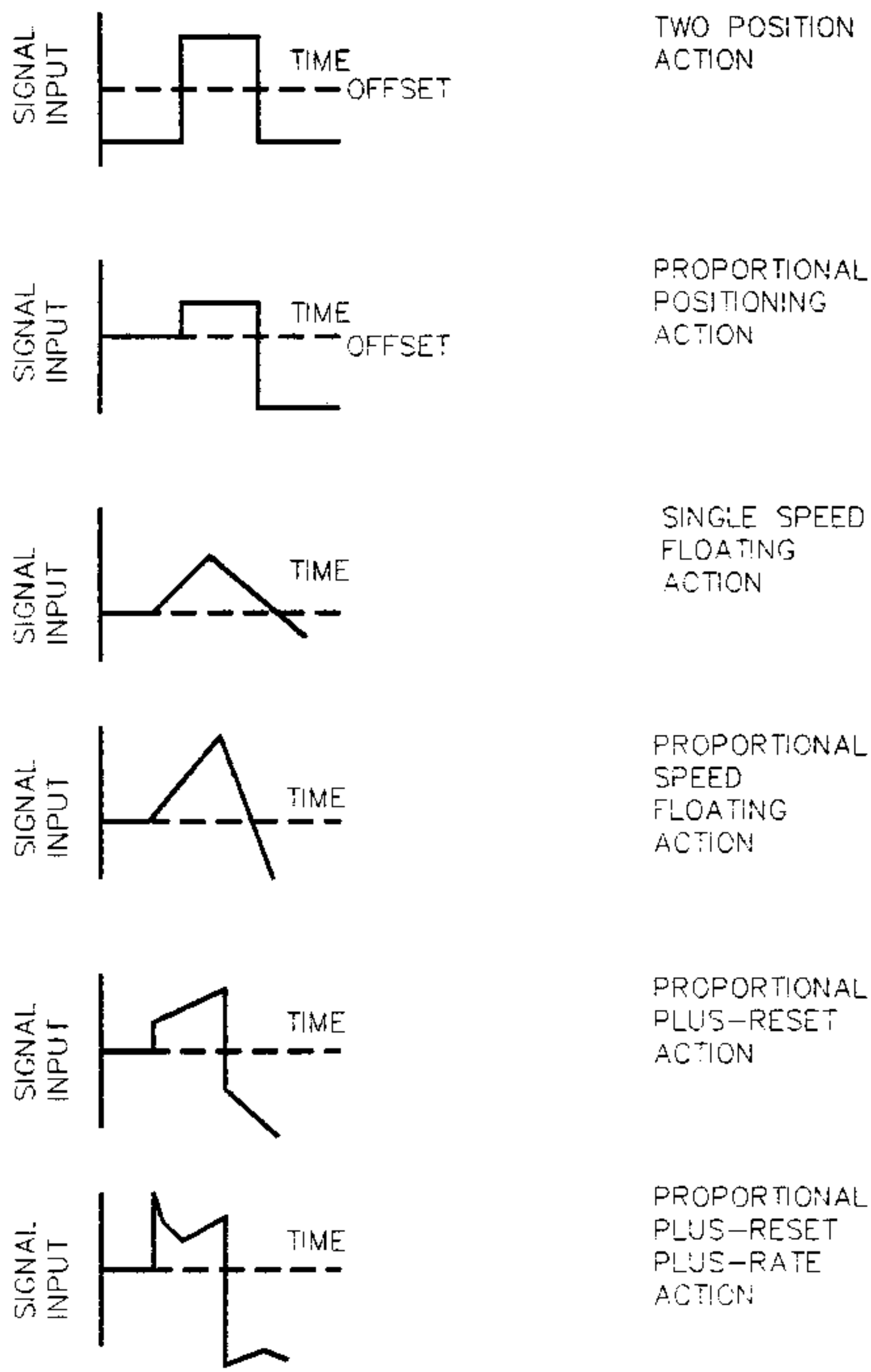

Figure 4

Types of automatic controller action

11. OPERATORS. Operators are used to drive (move) final control elements such as control valves and dampers from one position to another. The general types of operators are pneumatic diaphragm or piston, electric, and electro-hydraulic.

11.1 PNEUMATIC OPERATORS. Pneumatic operators including I/P converters are the least expensive when compared to electric or electric-hydraulic types. Operators (final control elements) for major control loops should be pneumatic unless normally furnished otherwise on equipment as standard by a manufacturer.

11.2 ELECTRIC OPERATORS. Electric operators are used prevalently in heating, ventilating, and air conditioning systems.

11.3 Electro-Hydraulic Operators. Electro-hydraulic operators are used for high force or torque applications and in remote locations where lack of compressed air supply rules out the use of pneumatic operators.

12. POSITIONERS. Positioners are used on control valves to force the stem and valve plug to move to a position as called for by the control signal. Positioners are used primarily to overcome valve stem friction, to compensate for long pneumatic transmission lines, or when extreme or variable line pressure can offset the valve plug. Every control valve exhibits from 2 to 10 percent hysteresis unless it is equipped with a positioner. The effect of valve position hysteresis is indicated in Figure 5. A positioner should be used for liquid level, volume (as in blending), and weight (as in blending) whenever a two mode controller (proportional plus integral) is used. For temperature control, a positioner will be helpful but not essential. As a general rule, use a positioner on control systems that have a relatively slow response such as liquid level, blending, and temperature control loops. Do not use a positioner on control systems which have a relatively fast response such as liquid pressure, most flow, and some pressure control loops.

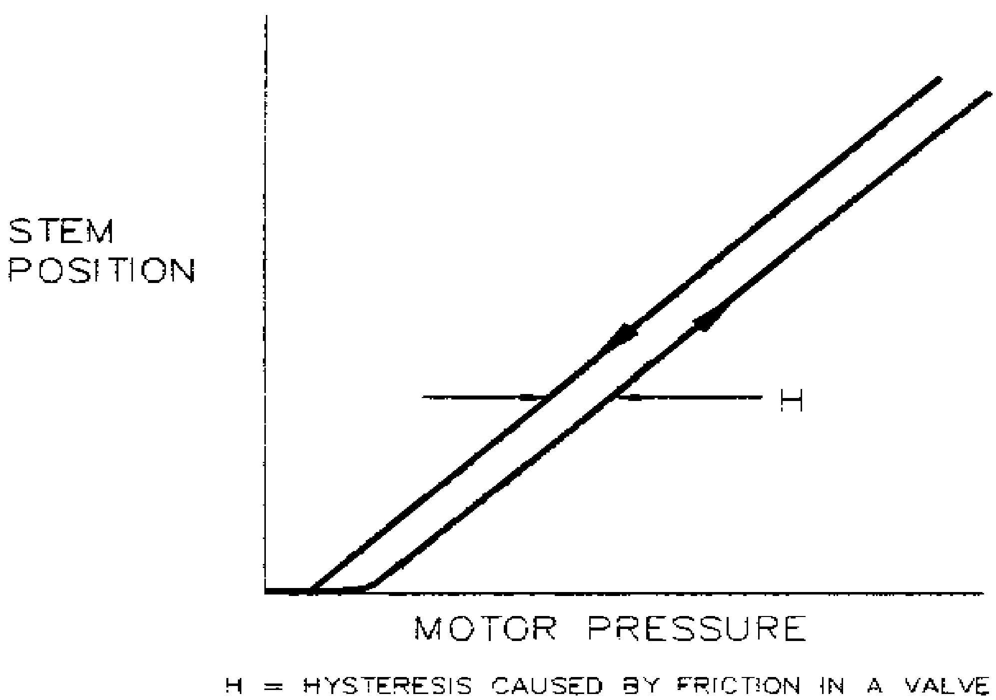

Figure 5

Hysteresis caused by friction in a valve

13. CONTROL ROOM. The control room should be located in the boiler turbine area where visual inspection can still be made, but completely enclosed and air conditioned with high efficiency filtration. Instruments should be mounted on a panel within the control room. A positive pressure should be maintained within the control room to keep dust and other dirt particles from entering. The control room must have:

a) Clean dry atmosphere
b) Relatively constant temperature and humidity
c) No vibration
d) Adequate light
e) Reliable electric power, free of surges in voltage and frequency
f) Clean, dry air of adequate pressure and capacity (for pneumatic instruments)
g) Air conditioning; a necessity for electronic distributive control systems and computers

See Tables 1 and 2 for typical lists of analog instruments. With the new microprocessor-based control systems, the operator interface can be a color or black and white cathode ray tube (CRT) monitor, thus eliminating the need for panels. The operator can control the boiler plant from a single CRT with redundant CRTs located elsewhere if desirable. Field inputs and outputs should be done through the floor or ceiling of the control room. All field measurements should come into one central control room.