

UNIFIED FACILITIES CRITERIA (UFC)

CENTRAL STEAM BOILER PLANTS



APPROVED FOR PUBLIC RELEASE; DISTRIBUTION UNLIMITED

UNIFIED FACILITIES CRITERIA (UFC)

CENTRAL STEAM BOILER PLANTS

Any copyrighted material included in this UFC is identified at its point of use. Use of the copyrighted material apart from this UFC must have the permission of the copyright holder.

U.S. ARMY CORPS OF ENGINEERS (Preparing Activity)

NAVAL FACILITIES ENGINEERING COMMAND

AIR FORCE CIVIL ENGINEER SUPPORT AGENCY

Record of Changes (changes are indicated by \1\ ... /1/)

Change No.	Date	Location
1	Dec 2007	Pages 8-10 & 8-11, Chapter 8, Para 8-4b(2)

This UFC supersedes TM 5-810-15, dated 1 August 1995. The format of this UFC does not conform to UFC 1-300-01; however, the format will be adjusted to conform at the next revision. The body of this UFC is a document of a different number.

FOREWORD

\1\

The Unified Facilities Criteria (UFC) system is prescribed by MIL-STD 3007 and provides planning, design, construction, sustainment, restoration, and modernization criteria, and applies to the Military Departments, the Defense Agencies, and the DoD Field Activities in accordance with [USD\(AT&L\) Memorandum](#) dated 29 May 2002. UFC will be used for all DoD projects and work for other customers where appropriate. All construction outside of the United States is also governed by Status of forces Agreements (SOFA), Host Nation Funded Construction Agreements (HNFA), and in some instances, Bilateral Infrastructure Agreements (BIA.) Therefore, the acquisition team must ensure compliance with the more stringent of the UFC, the SOFA, the HNFA, and the BIA, as applicable.

UFC are living documents and will be periodically reviewed, updated, and made available to users as part of the Services' responsibility for providing technical criteria for military construction. Headquarters, U.S. Army Corps of Engineers (HQUSACE), Naval Facilities Engineering Command (NAVFAC), and Air Force Civil Engineer Support Agency (AFCESA) are responsible for administration of the UFC system. Defense agencies should contact the preparing service for document interpretation and improvements. Technical content of UFC is the responsibility of the cognizant DoD working group. Recommended changes with supporting rationale should be sent to the respective service proponent office by the following electronic form: [Criteria Change Request \(CCR\)](#). The form is also accessible from the Internet sites listed below.

UFC are effective upon issuance and are distributed only in electronic media from the following source:

- Whole Building Design Guide web site <http://dod.wbdg.org/>.

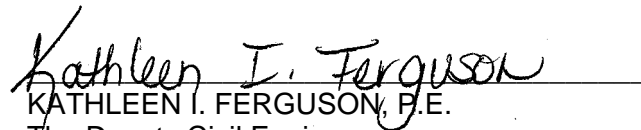
Hard copies of UFC printed from electronic media should be checked against the current electronic version prior to use to ensure that they are current.

AUTHORIZED BY:

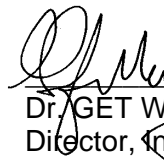

DONALD L. BASHAM, P.E.
Chief, Engineering and Construction
U.S. Army Corps of Engineers



DR. JAMES W. WRIGHT, P.E.
Chief Engineer
Naval Facilities Engineering Command



KATHLEEN I. FERGUSON, P.E.
The Deputy Civil Engineer
DCS/Installations & Logistics
Department of the Air Force



Dr. GET W. MOY, P.E.
Director, Installations Requirements and
Management
Office of the Deputy Under Secretary of Defense
(Installations and Environment)

CHAPTER 1

INTRODUCTION

1-1. Purpose

This manual provides guidance for the design of central steam plants for Army installations.

1-2. Scope.

This manual considers steam plants with capacities from one to three boilers, each rated between 20,000 and 250,000 pounds per hour (pph). Where special conditions and problems are not specifically covered in this manual, acceptable industry standards will be followed. Modifications or additions to existing systems solely for the purpose of meeting criteria in this manual are not authorized. The guidance and criteria herein are not intended to be retroactively mandatory. Clarification of the basic standards and guidelines for a particular application and supplementary standards which may be required for special cases may be obtained through normal channels from HQUSACE, WASH DC 20314-1000.

1-3. References.

Appendix A contains a list of references used in this manual.

1-4. Economic considerations.

The selection of one particular type of design for a given application, when two or more types of design are known to be feasible, will be based on the results of an economic study.

1-5. Design philosophy.

a. General. Steam plants considered in this manual will be fired by gas, oil, gas-and-oil, coal, or waste fuels. Coal fired plants will use any combination of three commercially proven coal firing technologies. These include atmospheric circulating fluidized bed (ACFB), pulverized coal and stoker fired boilers. Stokers are designed to burn any one of the different types of anthracite, bituminous, sub-bituminous or lignite type coals. ACFB boilers offer reduced sulfur dioxide emissions without use of scrubbers while firing a wide range of lower cost fuels such as high sulfur coal and waste fuels. To provide a quick scale for the plants under review here, several categories have been developed, as shown in table 1-1.

b. Reliability. Steam plant reliability standards will be equivalent to a 1-day forced outage in 10 years with equipment quality and redundancy

Table 1-1. Central Steam Plant Sizes.

<i>Category</i>	<i>Size</i>
Small	0-100,000 pph
Medium	100,000-300,000 pph
Large	300,000-750,000 pph

selected during plant design to conform to this standard. This standard also requires quality engineering, equipment, and operations and maintenance personnel. In order for boilers to have high availability it is mandatory that a good water treatment program be implemented. Availability guarantees offered by boiler manufacturers for coal fired units are in the range of 85 to 90 percent and are in the range of 90 to 95 percent for gas fired boilers. A planned outage of a minimum of one day per year is normal for waterside inspection.

c. Maintenance. Steam plant arrangement will permit reasonable access for operation and maintenance of equipment. Careful attention will be given to the arrangement of equipment, valves, mechanical specialties, and electrical devices so that rotors, tube bundles, inner valves, top works, strainers, contactors, relays, and like items can be maintained or replaced. Adequate platforms, stairs, handrails, and kickplates will be provided so that operators and maintenance personnel can function conveniently and safely.

d. Future expansion. The specific site selected for the steam plant and the physical arrangement of the plant equipment, building, and support facilities such as natural gas supply lines, coal and ash handling systems, coal storage, circulating water system, trackage, and access roads will be arranged insofar as practicable to allow for future expansion.

1-6. Design criteria.

a. General requirements. The design will provide for a steam plant which has the capacity to provide the quantity and type of steam required.

b. Steam loads. The following information, as applicable, is required for design:

(1) A forecast of annual and monthly diversified peak loads to be served by the project.

(2) Typical, seasonal, weekly and daily load curves and load duration curves of the load to be served. Figures 1-1 and 1-2 show example load duration curves.

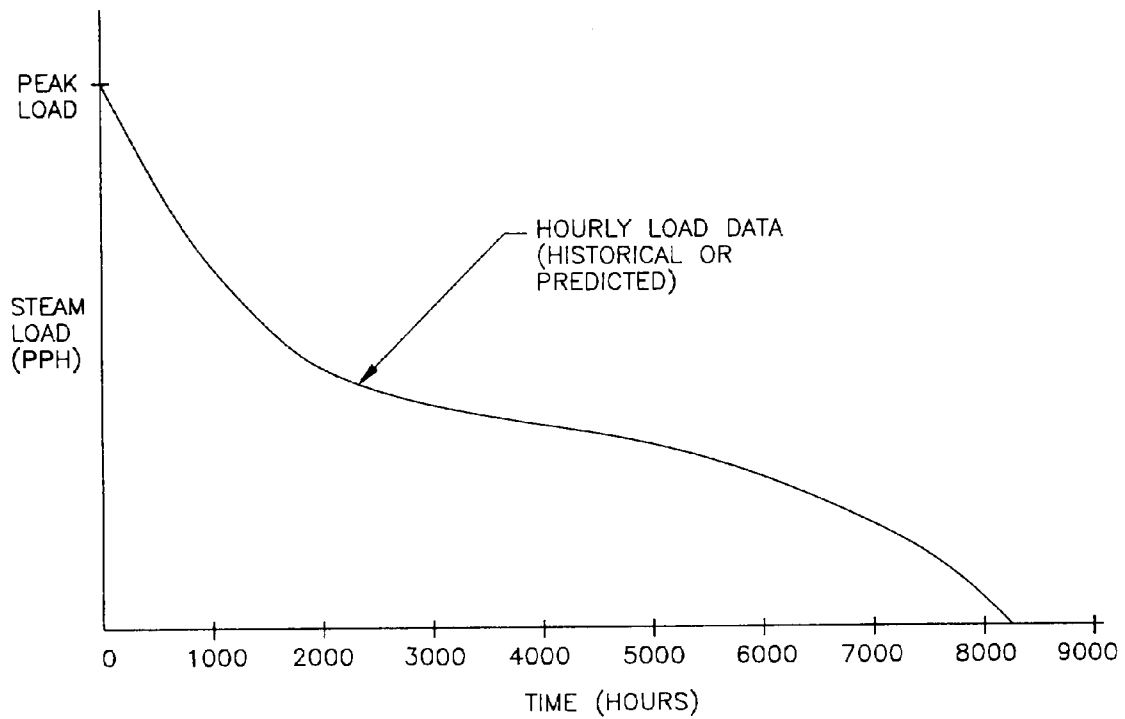


Figure 1-1. Typical Annual Steam Load Duration Curve.

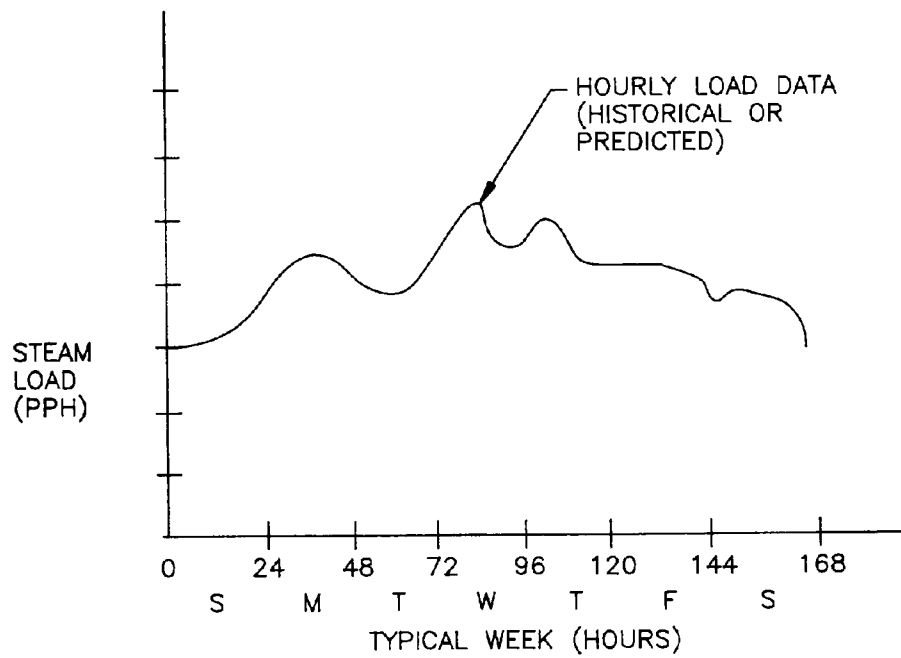


Figure 1-2. Typical Weekly Steam Load Duration Curve.

(3) A forecast of peak loads encountered during the steam plant full mobilization.

(4) If the plant is to operate in conjunction with any existing steam generation on the base or is an expansion of an existing facility, the designer will also need the following:

(a) An inventory of major existing steam generation equipment giving principle characteristics such as type, capacities, steam characteristics, pressures and like parameters.

(b) Incremental thermal efficiency of existing boiler units.

(c) Historical operating data for each existing steam generating unit giving energy generated, fuel consumption, and other related information.

(5) Existing or recommended steam distribution systems to support base operations.

(6) A complete fuel analysis for each fuel being considered for use in the plant. Coal analyses shall include proximate analysis, ultimate analysis, grindability, higher heating value, ash analysis, ash fusion temperature, and agglomerating classification.

(7) Plant site conditions must be identified to include ambient temperature ranges, maximum expected wind conditions, snow load, seismic conditions and any other site conditions that could affect the design of the boiler and its accessories.

(8) Water quality available to the boiler to include such things as total dissolved solids, pH, etc.

(9) All codes that pertain to design, construction and placing of the boiler and its accessories into operation need to be identified.

(10) If any of the above data which is required for performing the detailed design is unavailable, the designer will develop this data.

c. Fuel source and cost. The type, availability, and cost of fuel will be determined in the early stages of design, taking into account environmental regulatory requirements that may affect fuel and fuel characteristics of the plant.

d. Water supply. Fresh water is required for the boiler cycle makeup. Quantity of makeup will vary with the type of boiler plant, amount of condensate return for any export steam, and the maximum heat rejection from the cycle.

e. Stack emissions. A steam plant will be designed for the type of stack gas cleanup equipment which meets federal, state, and local emission requirements. For a coal fired boiler, this will involve an electrostatic precipitator or baghouse for particulates or fly ash removal, and a scrubber for flue gas desulfurization (FGD) unless fluidized bed combustion or compliance coal is employed. If

design is based on compliance coal, the design will include space and other required provisions for the installation of equipment. Boiler design will be specified as required for nitrous oxides (NO_x) control. ACFB boilers have low nitrogen oxide (NO_x) emissions because of their relatively low combustion temperatures. Selective noncatalytic reduction (SNCR) systems are now being required by several states even on ACFB boiler installations to meet new NO_x allowable emissions limits (AEL) that are more stringent.

f. Waste disposal. Both solid and liquid wastes will be handled and disposed of in an environmentally acceptable manner. The wastes can be categorized generally as follows:

(1) *Solid wastes.* These include both bottom ash and fly ash from boilers.

(2) *Liquid wastes.* These include boiler blowdown, cooling tower blowdown, acid and caustic water treating wastes, coal pile runoff, and various contaminated wastes from chemical storage areas, sanitary sewage and yard areas.

g. Other environmental considerations. Other environmental considerations include noise control and aesthetic treatment of the project. The final location of the project within the site area will be reviewed in relation to its proximity to hospital and office areas and the civilian neighborhood, if applicable. Also, the general architectural design will be reviewed in terms of coordination and blending with the style of surrounding buildings. Any anticipated noise or aesthetics problem will be resolved prior to the time that final site selection is approved.

h. Construction cost estimate. The following items should be considered in the construction cost estimate for a boiler plant.

- (1) Substructure
- (2) Structural Steel
- (3) Superstructure
- (4) Painting
- (5) Coal, Limestone, Inert Bed Material & Ash Handling Systems Foundations
- (6) Stack Foundations
- (7) Air Pollution Control Equipment Foundations
- (8) Roads, Grading & Site Improvements
- (9) Ash Pond, Coal Runoff Pond & Coal Pile Stabilization
- (10) Railroad Siding
- (11) Water & Sewers
- (12) Fencing
- (13) Steam Generators
- (14) Particulate Control Equipment
- (15) Sulfur Removal Equipment

TM 5-810-15

- (16) Stacks
- (17) Continuous Flue Gas Monitoring Equipment
- (18) Coal Handling System
- (19) Limestone Handling System
- (20) Inert Bed Handling System
- (21) Ash Handling System
- (22) Panels, Instruments & Controls
- (23) Water Treatment Equipment
- (24) Deaerators
- (25) Feedwater Heaters
- (26) Boiler Feed Pumps
- (27) Fire Protection

- (28) Air Compressors
- (29) Power Piping
- (30) Electrical Equipment
- (31) Power Wiring
- (32) Plant Substation
- (33) Operator Training
- (34) Fuels
- (35) Chemicals
- (36) Fuel Storage

1-7. Explanation of abbreviations and terms.
Abbreviations and special terms used in this regulation are explained in the glossary.

CHAPTER 2

STEAM PLANT LOCATION, SITE DEVELOPMENT AND PLANT STRUCTURES

2-1. General.

Each potential plant site will be evaluated to determine which is the most economically feasible for the size of plant being considered.

a. Steam plant location. The process of evaluating and selecting a possible steam plant site must include the following activities. Identify region of interest. Apply exclusionary criteria to eliminate unsuitable areas within region of interest. Identify candidate sites. Prepare site specific layouts and conduct conceptual engineering studies of the candidate site. Rank candidate sites, based on analyses. Select most suitable site.

(1) The evaluations of candidate sites are performed by specialists from the fields of environmental engineering, biology/ecology, ground and surface water hydrology, geology and seismology, soils and foundation engineering, meteorology, demography, land use and zoning, sociology and economics, system planning, and law.

(2) Selection of the site will be based on the availability of usable land for the plant, including yard structures, fuel handling facilities, and any future expansion. Other considerations that will be taken into account in site selection are: soil information, site drainage, wind date, seismic zone, and ingress and egress. For economic purposes and operational efficiency, the plant site will be located as close to the load center as environmental conditions permit.

b. Lead time. The amount of lead time necessary to perform the studies, and to submit the required environmental impact statements should also be considered in site selection, since this lead time will vary from site to site. Environmentally sensitive areas will probably require lengthier studies, delaying construction. If steam load demands must be met within a limited time period, this factor becomes more important. Generally, the lead time interval should be 18 to 24 months.

2-2. Environmental regulations.

a. Air quality control. Central steam boiler plants must meet current Federal, State and local regulations.

b. Water quality control. Waste water must comply with current regulations including discharge of free available chlorine (FAG), pH, total suspended solids (TSS), oil/grease, copper (Cu), iron (Fe), polychlorinated biphenyl (PCB), and heat.

c. Waste material control. State regulations control disposal of coal ash and FGD wastes and the selection of landfill site.

2-3. Water supply.

a. General requirements. Water supply should be adequate to meet present and future plant requirements. The supply may be available from a local municipal or privately owned system, or it may be necessary to utilize surface or subsurface sources.

(1) Plant requirements must be estimated for all uses, including feedwater makeup, auxiliary cooling, ash transport, coal dust suppression, fire protection, and domestic uses.

(2) Provide backflow preventer upstream of water treatment, ash handling equipment, FGD system and hose bibbs.

b. Quality. Water quality and type of treatment required will be compatible with the type of plant to be built. Surface and groundwater sources must be evaluated for sufficient quantity and quality.

c. Water rights. If water rights are required, it will be necessary to insure that an agreement for water rights provides sufficient quantity for present and future use.

d. Water wells. If the makeup to the closed system is from water wells, a study to determine water table information and well drawdown will be required. If this information is not available, test well studies must be made.

e. Once through system. If the plant has a once through cooling system, the following will be determined:

(1) The limitations established by the appropriate regulatory bodies which must be met to obtain a permit required to discharge heated water to the source.

(2) Maximum allowable temperature rise permissible as compared to system design parameters. If system design temperature rise exceeds permissible rise, a supplemental cooling system (cooling tower or spray pond) must be incorporated into the design.

(3) Maximum allowable temperature for river or lake after mixing of cooling system effluent with source. If mixed temperature is higher than allowable temperature, a supplemental cooling system must be added. It is possible to meet the conditions of (2) above and not meet the conditions in this subparagraph.

(4) If extensive or repetitive dredging of waterway will be necessary for plant operations.

(5) The historical maximum and minimum water level and flow readings. Check that adequate water supply is available at minimum flow and if site will flood at high level.

2-4. Site development.

a. Soils investigation. An analysis of existing soils conditions will be made to determine the proper type of foundation. Soils data will include elevation of each boring, water table level, description of soil strata including the group symbol based on the Unified Soil Classification System, and penetration data (blow count). Geological conditions must support the foundations of plant structures at a reasonable cost with particular attention being paid to bedrock formations and faults. The soils report will include recommendations as to type of foundations for various purposes; excavation, dewatering and fill procedures; and suitability of on site material for fill and earthen dikes including data on soft and organic materials, rock and other pertinent information as applicable.

b. Grading and drainage.

(1) *Basic criteria.* Determination of final grading and drainage scheme for a new steam plant will be based on a number of considerations including size of property in relationship to the size of plant facilities, desirable location on site, and plant access based on topography.

(2) *Drainage.* Storm water drainage will be evaluated based on rainfall intensities, runoff characteristics of soil, facilities for receiving storm water discharge, and local regulations.

(3) *Erosion prevention.* All graded areas will be stabilized to control erosion by designing shallow slopes to the greatest extent possible and by means of soil stabilization such as seeding, sod, stone, riprap and retaining walls.

c. Meteorology. Precipitation, wind conditions, evaporation, humidity and temperature will affect emissions dispersion, coal storage and handling, and other aspects of plant operation.

d. Area requirements. Plant area requirements will be figured on the type of plant; capacity; urban, suburban or rural location; design of fuel storage and handling facilities; disposal of soil waste and treatment of wastewater; condenser cooling; and the plant structure and miscellaneous requirements. Acquisition of land should include plant access roads, rail access and space for future additions to the plant.

(1) Space must be provided for the long term coal storage pile. Maximum allowable height

of the coal pile and methods of stockout and reclaim will further affect space requirements. If oil is used as primary fuel or as a backup fuel, storage tank space must be calculated.

(2) Space for the disposal of wet and dry ash will be provided.

(3) Control of runoff from material storage areas is required by EPA regulations. Space for retention ponds must be provided.

e. Flood protection. Site protection for flood frequency of once every 500 years will be calculated into area requirements.

f. Other requirements. Space for parking, warehouses, cooling water systems, environmental systems, construction laydown areas and other requirements will be provided.

2-5. Plant access.

a. Plant roadway requirements. Layout of plant roadway will be based on volume and type of traffic, speed, and traffic patterns. Proximity to principle highways should permit reasonably easy access for construction crews and deliveries. Roadway design will be in accordance with American Association of State Highway and Transportation Officials (AASHTO) standard specifications. Roadway material and thickness will be based on economic evaluations of feasible alternatives. Vehicular parking for plant personnel and visitors will be located in areas that will not interfere with the safe operation of the plant. Turning radii will be adequate to handle all vehicle categories.

b. Railroads. If a railroad spur is selected to handle fuel supplies and material and equipment deliveries during construction or plant expansion, the design will be in accordance with American Railway Engineering Association (AREA) Manual.

(1) Spur layout will accommodate coal handling facilities including a storage track or loop track for empty cars. Refer to chapter 5 for additional information.

(2) If liquid fuel is to be handled, unloading pumps and steam connections for tank car heaters may be required in frigid climates.

2-6. Plant structures.

a. Size and arrangements. The steam plant main building size and arrangement depend on the selected plant equipment and facilities including: whether steam generators are indoor or outdoor type; coal bunker or silo arrangement in the cases of pulverized coal and stoker fired plants; coal, limestone and inert bed silo arrangement in the case of atmospheric circulating fluidized bed (ACFB) boiler plants; source of cooling water supply relative to the plant; provisions for future expansion; and aesthetic and environmental con-

siderations. Generally, the main building will consist of: a steam generator bay (or firing aisle the semi-outdoor units); an auxiliary bay for feedwater heaters, pumps, and switchgear; and general spaces as may be required for machine shop, locker room, laboratory and office facilities. For very mild climates the steam generators may be outdoor type (in a weather protected, walk-in enclosure) although this arrangement presents special maintenance problems. If incorporated, the elevator will have access to the highest operating level of the steam generator (drum levels).

b. Layout considerations. The layout of the structural system will identify specific requirements relative to vertical and horizontal access, personnel needs and convenience, equipment and respective maintenance areas, floors and platforms.

c. Soil investigation requirements. A subsurface exploration program will be conducted. Design information regarding the interaction of the structure and the surrounding ground is required. In addition, an investigation should furnish information as to the source of construction materials and the types and extent of materials which will be encountered during construction will be investigated. Information required for design includes: extent of each identifiable soil stratum, depth to top of rock and character of the rock, elevation of normal ground water at site, and engineering properties of the soil and rock.

d. Foundation design. Selection of the type of foundation to be used for each component of the plant (i.e., main building, boiler, stacks and coal handling structure) will be determined from the subsurface exploration data, cost considerations and availability of construction trades.

e. Structural design. Thermal stations will be designed utilizing conventional structural steel for the main steam station building. Separate structural steel will be provided to support building floors and platforms; boiler steel will not be used in support building structure. The pedestal for supporting the turbine driven boiler feed pump if utilized will be of reinforced concrete. Reinforced concrete or masonry construction may be used for the building framing (not for boiler framing); special concrete inserts or other provisions must be made in such event for support of piping, trays and conduits. An economic evaluation will be made of these alternatives.

f. Structure loading.

(1) Buildings, structures and all portions thereof will be designed and constructed to support all live and dead loads without exceeding the allowable stresses of the selected materials in the structural members and connections. Typical live

loads for steam plant floors are as follows:

Basement and operating floors	200 psf
Mezzanine, deaerator, and miscellaneous operating floors	200 psf
Office, laboratories, instrument shops, and other lightly loaded areas	100 psf

Live loads for actual design will be carefully reviewed for any special conditions and actual loads applicable.

(2) Live loads for equipment floors will be based on the assumption that the floor will be utilized as laydown for equipment parts during maintenance. Load will be based on heaviest piece removed during maintenance.

(3) Live load assumptions will be in accordance with TM 5-809-1.

g. Other loads. In addition to the live and dead loads, the following loadings will be provided for:

(1) *Piping load.* Weight of major piping sized and routed will include weight of pipe, insulation, hydraulic weight (pipe full of water) in addition to any shock loads. Pipe hanger loads will be doubled for design of supporting steel. In congested piping areas increase live load on the supporting floor by 100 pounds per square foot (psf). Structural steel will be provided to adequately support all mechanical piping and electrical conduit. Provision will be made to accommodate expansion and contraction and drainage requirements of the pipe. Piping connections must be made to preclude rupture under the most adverse conditions expected. Pipe supports will be close coupled to supporting structures when the more severe seismic conditions are expected.

(2) *Wind loading.* Building will be designed to resist the horizontal wind pressure available for the site on all surfaces exposed to the wind. Wind load assumptions will be in accordance with TM 5-809-1.

(3) *Seismic loading.* Buildings and other structures will be designed to resist seismic loading in accordance with the zone in which the building is located. Seismic design will be in accordance with TM 5-809-10.

(4) *Equipment loading.* Equipment loads are furnished by the various manufacturers of each equipment item. In addition to equipment dead loads, impact loads, short circuit forces for generators, and other pertinent special loads prescribed by the equipment function or requirements will be included. Dead load assumptions will be in accordance with TM 5-809-1. Ductwork, flue gas breeching, stacks, and other hot equipment must be

supported such that expansion and contraction will not impose detrimental loads and stresses on related structures.

(5) *Snow loading.* Snow load assumptions will be in accordance with TM 5-809-1.

h. Architectural treatment.

(1) The architectural treatment will be developed to harmonize with the site conditions, both natural and manmade. Depending on location, the environmental compatibility may be the determining factor. In other cases the climate or user preference, tempered with aesthetic and economic factors, will dictate architectural treatment.

(2) For special circumstances, such as areas where extended periods of very high humidity, frequently combined with desert conditions giving rise to heavy dust and sand blasting action, indoor construction with pressurized ventilation will be required.

(3) Control rooms, offices, locker rooms, and some outbuildings will be enclosed regardless of enclosure selected for main building.

(4) Equipment room size will provide adequate space for equipment installation, maintenance and removal. A minimum of aisle space between items will be 4 feet if feasible. Provide a minimum of 8 feet clearance between boilers 60,000 pph and larger. If future expansion is planned, size of room will be based on future requirements. Equipment room construction will allow for equipment removal and include double doors and steel supports for chain hoists. Adequate ventilation and heating will be included. Attenuation of noise will be considered in room design.

(5) Provide openings or doorways for passage of the largest equipment units. Make openings for ventilation louvers, breechings, and piping where necessary. Fire doors, fire shutters or a combination of both, may be required.

(6) On multiple floor installations, provide a freight elevator.

(7) Furnish necessary shower room, toilet room facilities and lockers for operating personnel for both sexes in buildings. The plant should contain a sampling laboratory space, storage area, small repair area, control room (in larger plants), generator room, lunch room, compressor room, chemical storage area, office space for supervisors and clerks. Parking spaces for plant personnel and visitors should be provided near the boiler plant.

(8) Finish of plant interior walls and tunnels will have a coating which will permit hose down or scrubbing of areas.

(9) Concrete will be in accordance with TM 5-805-1, American Concrete Institute (ACI) 318 and 301.

i. Special considerations.

(1) Crane bay-provide removable openings in floor above major equipment for removal by station crane (if provided).

(2) Provide hoists and supports for maintenance on pumps, fans and other heavy equipment. Provide a beam into the plant to hoist equipment to an upper level.

(3) All anchor bolts for equipment will be sleeved to allow adjustment for final alignment of equipment.

2-7. Heating, ventilating and air conditioning systems (HVAC).

a. General. System analysis and design procedures provided in the American Society of Heating, Refrigeration and Air Conditioning Engineers (ASHRAE) Guide for Data books and TM 5-810-1 should be followed, unless otherwise stated or specifically directed by other criteria.

b. Design considerations. When a computer program is required, provisions for showing an estimate of the hourly space heating and cooling requirements, and hourly performance of the heating and cooling system can be structured. When manual computation is used, the heating and cooling load estimates will be in accordance with the current edition of the ASHRAE Handbook of Fundamentals.

2-8. Drainage.

a. Drains which may contain coal or oil will have suitable separators to separate coal or oil from drainage before being connected to sewer lines.

b. Provide drains and connect to storm water drainage system for diked areas for above ground oil storage.

c. Maximum temperature of effluent to the drain system will be as required by governing codes. A temperature regulating valve will be used to inject potable water into the high temperature waste stream from the blowdown tank. This technique will also be used on other equipment as required.

2-9. Plant design safety.

a. Introduction. The safety features described in the following paragraphs will be incorporated into the steam plant design to assist in maintaining a high level of personnel safety.

b. Design safety features. In designing a steam plant, the following general recommendations on safety will be given attention:

(1) Equipment will be arranged with adequate access space for operation and for maintenance.

Wherever possible, auxiliary equipment will be arranged for maintenance handling by monorails, wheeled trucks, or portable A-frames if disassembly of heavy pieces is required for maintenance.

(2) Safety guards will be provided on moving or rotating parts of all equipment.

(3) All valves, specialties, and devices needing manipulation by operators will be accessible without ladders, and preferably without using chain-wheels.

(4) Valve centers will be mounted approximately 7 feet above floors and platforms so that rising stems and bottom rims of handwheels will not be a hazard. Provide access platforms for operations and maintenance of all valves and equipment over 7 feet above the floor.

(5) Stairs with conventional riser-tread proportions will be used. Vertical ladders should be installed only as a last resort.

(6) All floors, gratings and checkered plates will have nonslip surfaces.

(7) No platform or walkway will be less than 30-inches wide.

(8) Toe plates, fitted closely to the edge of all floor openings, platforms and stairways, will be provided in all cases. Handrails will be provided on platforms and floor openings.

(9) Not less than two exits will be provided from catwalks, platforms longer than 10 to 15 feet in length, boiler aisles, floor levels and the steam plant. Emergency lighting will be provided for all modes of egress.

(10) All floors subject to washdown or leaks

will be sloped to floor drains.

(11) All areas subject to lube oil or chemical spills will be provided with curbs and drains.

(12) If plant is of semioutdoor or outdoor construction in a climate subject to freezing weather, weather protection will be provided for critical operating and maintenance areas such as the firing aisle, boiler steam drum ends and soot blower locations.

(13) Adequate illumination will be provided throughout the plant. Illumination will comply with requirements of the Illuminating Engineers Society (IES) Lighting Handbook.

(14) Comfort air conditioning will be provided throughout control rooms, laboratories, offices and similar spaces where operating and maintenance personnel spend considerable time.

(15) Mechanical supply and exhaust ventilation will be provided for all of the steam plant equipment areas to alleviate operator fatigue and prevent accumulation of fumes and dust.

(16) Noise level will be reduced to at least the recommended maximum levels of OSHA. Use of fan silencers, compressor silencers, mufflers on internal combustion engines, and acoustical material is required as discussed in TM 5-805-4 and TM 5-805-9.

(17) Color schemes will be psychologically restful except where danger must be highlighted with special bright primary colors.

(18) Each equipment item will be clearly labeled in block letters identifying it both by equipment item number and name.

CHAPTER 3

STEAM GENERATORS

3-1. Introduction.

a. General. This chapter addresses the design requirements for gas, oil, coal, and waste fuel fired steam generating, water-tube boilers and components with steam capacities between 20,000 and 250,000 pph and maximum pressures of 450 pounds per inch gauge (psig)/saturated and 400 psig/700 degrees F superheated.

b. New combustion technologies. The only major development in combustion technology in the past seventy years has been fluidized bed combustion.

(1) *History.* Earlier fluidized bed technologies included the bubbling bed boiler. Bubbling bed boiler efficiency is similar to that of a stoker boiler (80 to 82 percent). Atmospheric circulating fluidized bed (ACFB) boiler efficiency is comparable to pulverized coal boiler efficiency (86 to 88 percent). Bubbling bed boilers are not included in this manual not only because they are less fuel efficient, but also because they are inferior to ACFB units in the areas of sorbent utilization, emissions reductions and fuel flexibility.

(2) *Advantages.* Fluidized bed boilers have gained acceptance in the industrial and utility sectors by providing an economical means of using a wide range of fuels while meeting emissions requirements without installing flue gas desulfurization systems, such as wet and dry type scrubbers.

(3) *Emission reductions.* Sulfur capture is accomplished by injecting a sorbent, such as limestone or dolomite into the furnace along with coal and other solid fuels. Storage and handling of limestone must be included. Optimum sulfur capture and reduced thermal NO_x (nitrogen oxide) emissions are achieved by maintaining a combustion temperature at approximately 1550 degree F which is lower than other coal firing technologies. Sulfur is removed as calcium sulfate in the bag-house and either landfilled or sold.

(4) *Unique components.* Atmospheric fluidized bed (ACFB) boilers in addition to having components which are common to other combustion technologies (superheater, airheater, steam coil air preheater, economizer, sootblowers, etc.), ACFB boilers have unique components. The following list of unique ACFB boiler components is described in more detail in individual sections later in this chapter: lower combustor, upper combustor and transition zone, solids separator, solids reinjection device, and external heat exchanger (optional).

3-2. Boiler design.

a. Design. Boilers will be designed and constructed in accordance with Section 1 of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code.

b. Type. The boilers are to be natural circulation and two drum design. Coal fired boilers are balanced draft and gas/oil fired boilers are forced draft.

3-3. Boiler construction options.

a. Construction types. The specific type of boiler construction will depend on the boiler size, type of firing and life cycle costs. Three boiler construction types are available: shop assembled package units, field assembled modular units and field erected units.

b. Package units. Package units are completely assembled before leaving the boiler manufacturer's factory. For this reason, the quality of workmanship is generally better and the field installation costs are considerably lower than for the modular and field erected units. Package units covered by this manual are limited to stoker fire boilers with steam capacities of approximately 50,000 pph and below, and gas and/or oil fired units of approximately 200,000 pph and below.

c. Modular units. Modular units are too large for complete shop assembly. Some of the components, such as the boiler furnace, superheater, boiler tube bank and economizer and air heater are assembled in the manufacturer's shop prior to shipment for final erection at the field site. Modular units should be subject to better quality control due to manufacturing plant conditions. Since component assembly has taken place in the manufacturer's shop, the field manhour erection time will be reduced. Modular units are limited to stoker fired boilers ranging in steam capacity from approximately 50,000 to 150,000 pph.

d. Field erected units. Field erected boilers have numerous components, such as the steam drum, the lower (mud) drum, furnace wall panels, superheater sections, generating tube banks, economizer and air heater plus flue gas and air duct sections which are assembled at the job site. Therefore, they take longer to install than either a package or a modular type unit. Field erected units are available from about 40,000 to 250,000 pph and, if required, much larger. Field erected stoker fired boilers are available in this size range, and pulverized coal

fired units may be specified for boilers with capacities of 100,000 pph and above. Field erected atmospheric circulating fluidized bed boilers (ACFB) are 80,000 pph or larger. Gas and oil fired boilers and field erected for capacities of 200,000 pph or larger. Field erected units are the only boilers available for any of these technologies above 200,000 pph.

3-4. Available fuels.

a. Natural gas. Natural gas is the cleanest burning of the widely used commercially available fuels. It contains virtually no ash which reduces design, building and operating costs. This also eliminates the need for particulate collection equipment such as baghouses or electrostatic precipitators. Thorough mixing with combustion air allows low excess air firing. The high hydrogen content of natural gas compared to the oil or coal causes more water vapor to be formed in the flue gas. This water takes heat away from the combustion process, making less heat available for steam generation which lowers the boiler efficiency.

b. Natural gas analysis. Two types of analyses of natural gas are commonly used. Proximate analysis provides the percentage content by volume of methane, ethane, carbon dioxide and nitrogen. Ultimate analysis provides the percentage content by weight of hydrogen, carbon, nitrogen and oxygen. Table 3-1 gives natural gas analyses from selected United States fields.

c. Fuel oil. Compared to coal fuel oils are relatively easy to handle and burn. Ash disposal and emissions are negligible. When properly atomized

oil characteristics are similar to natural gas. Even though oil contains little ash, other constituents such as sulfur, sodium and vanadium present problems. These concerns include emission of pollutants, external deposits and corrosion.

d. Fuel oil analysis. Historically petroleum refineries have produced five different grades of fuel oil. Fuel oils are graded according to gravity and viscosity as defined by ASTM standard specifications with No. 1 being the lightest and No. 6 being the heaviest. Table 3-2 lists typical analyses of the various grades.

e. Coal types. For the purpose of boiler design, domestic U.S. coals are divided into four basic classifications: lignite, subbituminous, bituminous, and anthracite. Anthracite, however, requires special furnace and burner designs due to its low volatile content and is not normally used in the U.S. for boiler fuel. Note the following illustrations, figures 3-1 and 3-2. In general, these coal classifications refer to the ratio of fixed carbon to volatile matter and moisture contained in the coal, which increases with the action of pressure, heat, and other agents over time as coal matures. The changes in this ratio over the stages of coal information are illustrated in figure 3-3. Volatile matter consists of hydrocarbons and other compounds which are released in gaseous form when coal is heated. The amount present in a particular coal is related to the coal's heating value and the rate at which it burns. The volatile matter to fixed carbon ratio greatly affects boiler design, since the furnace dimensions must allow the correct retention time to properly burn the fuel.

Table 3-1. Analyses of Natural Gas from Selected United States Fields.

	Pittsburg	So. Cal.	Birmingham	Kansas City	Los Angeles
<i>Proximate, % by Volume</i>					
Methane CH ₄	83.40	84.00	90.00	84.10	77.50
Ethane C ₂ H ₆	15.80	14.80	5.00	6.70	16.00
Carbon D.C.O ₂	—	0.70	—	0.80	6.50
Nitrogen N ₂	0.80	0.50	5.00	8.40	—
Total	100.00	100.00	100.00	100.00	100.00
<i>Ultimate % by Weight</i>					
Hydrogen H ₂	25.53	23.30	22.68	20.85	20.35
Carbon C	75.25	74.72	69.26	64.84	69.28
Nitrogen N ₂	1.22	0.76	8.06	12.90	—
Oxygen O ₂	—	1.22	—	1.41	10.37
Total	100.00	100.00	100.00	100.00	100.00
Sp Gr (Air= 1.0)	0.610	0.636	0.600	0.630	0.697
HHV Btu/ft ³ *	1,129	1,116	1,000	974	1,073
Btu/lb	23,170	22,904	21,800	20,160	20,090
Fuel lb/10,000 Btu	0.432	0.437	0.459	0.496	0.498
Theoretical Air lb/10,000 Btu	7.18	7.18	7.50	7.19	7.18
Total Moisture lb/10,000 Btu	0.915	0.917	0.971	0.933	0.911

*At 60 degree F and 30 in. Hg

Table 3-2. Range of Analyses of Fuel Oils.

Weight, %	No. 1	No. 2	No. 4	No. 5	No. 6
Sulfur	0.01-0.5	0.05-1.0	0.2-2.0	0.5-3.0	0.7-3.5
Hydrogen	13.3-14.1	11.8-13.9	(10.6-13.0)*	(10.5-12.0)*	(9.5-12.0)*
Carbon	85.9-6.7	86.1-88.2	(86.5-89.2)*	(86.5-89.2)*	(86.5-90.2)*
Nitrogen	0-0.1	0-0.1	—	—	—
Oxygen	—	—	—	—	—
Ash	—	—	0-0.10	0-0.10	0.01-0.50
<i>Gravity</i>					
Deg API	40-44	28-40	15-30	14-22	7-22
Specific	0.825-0.806	0.887-0.825	0.966-0.876	0.972-0.922	1.022-0.922
Lb per gal	6.87-6.71	7.39-6.87	8.04-7.30	8.10-7.68	8.51-7.68
Pour Pt,F	0 to-50	0 to -40	-10 to +50	-10 to +80	+15 to +85
<i>Viscosity</i>					
Centistokes, 100 F	1.4-2.2	1.9-3.0	10.5-65	65-200	260-750
SSU @ 100 F	—	32-40	60-300	—	—
SFS @ 122 F	—	—	—	20-40	45-300
Water & Sediment, Vol %	—	0-0.1	0-1.0	0.05-1.0	0.05-2.0
<i>Heating Value</i>					
Btu/lb, gross (Calculated)	19,670-19,860	19,170-19,750	18,280-19,400	18,100-19,020	17,410-18,990

*Estimated

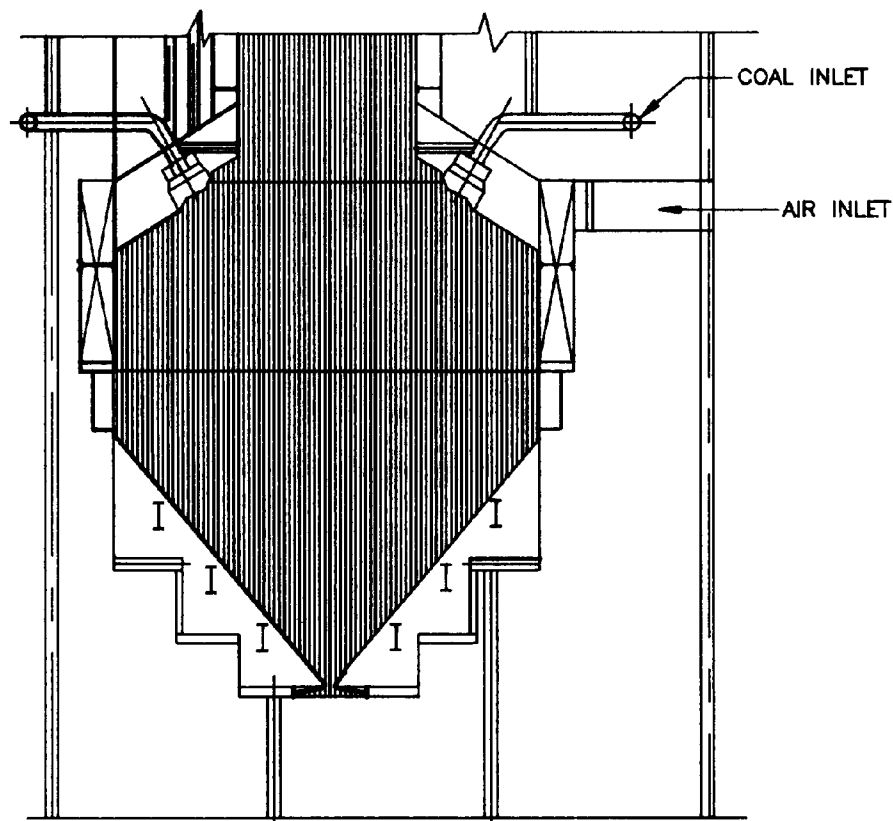
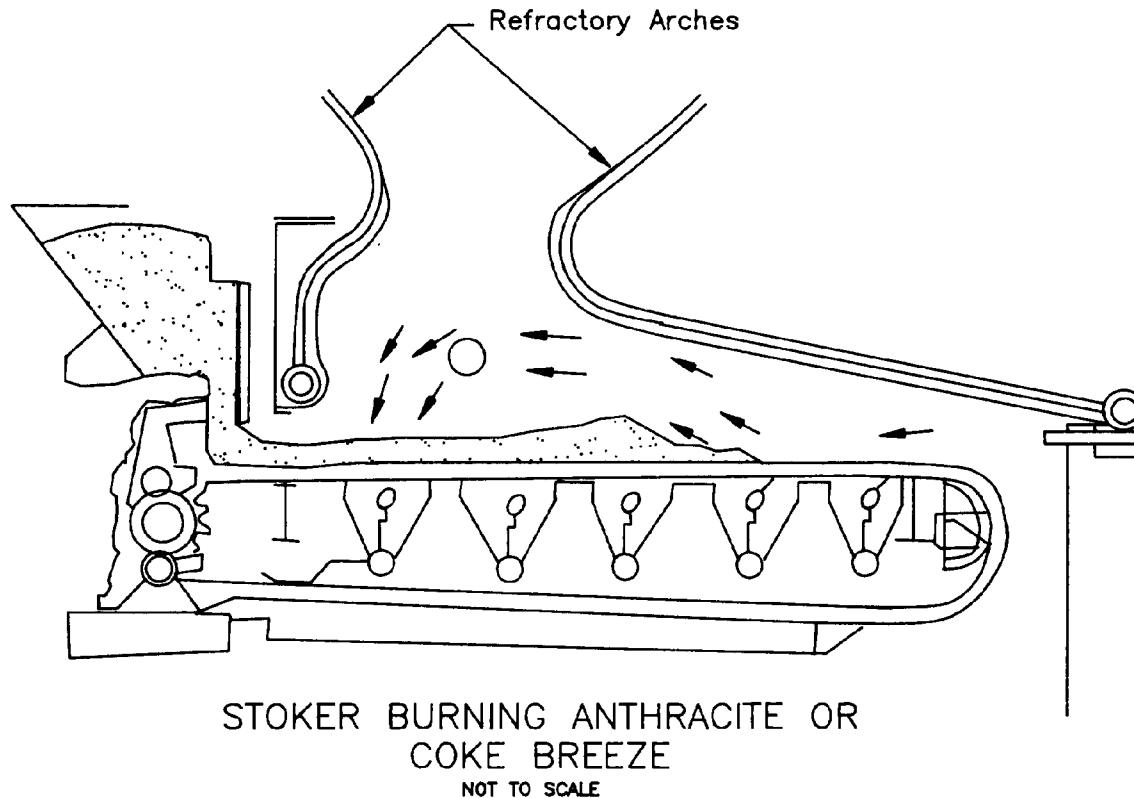


Figure 3-1. Typical Furnace Design for Pulverized Anthracite Coal and Low Volatile or Petroleum Coke Type Solid Fuels.



NOTE: THE CONTOUR OF THE FUEL BED WOULD BE THINNER AND MORE CONCENTRATED TOWARD THE FRONT OF THE STOKER WHEN LOWER VOLATILE ANTHRACITE COAL IS USE.

Figure 3-2. Typical Stoker Arch Arrangement for Anthracite Coal.

f. *Coal analysis.* Two analyses of coal are commonly used to determine the classification and constituents of coal: proximate analysis and ultimate analysis. Proximate analysis provides the percentage content by weight of fixed carbon, volatile matter, moisture, and ash, and the heating value in Btu per pound. These classifications are shown in table 3-3. Ultimate analysis provides the percentage content by weight of carbon, hydrogen, nitrogen, oxygen, and sulfur. These data are used to determine air requirements and the weight of combustion by-products, both of which are used to determine boiler fan sizes. Table 3-4 lists coal and ash analysis together, ash fusion temperatures and other data needed by boiler manufacturers for the design and guarantee of boiler performance.

g. *Alternate ACFB boiler fuels.* ACFB systems when properly designed can burn a wide variety of materials that contain carbon. Many can be utilized by themselves, while others are limited to a certain percentage of total heat input as part of a mixture with another fuel. Fuels with sulfur are burned in combination with a calcium rich material such as dolomite or limestone. Sulfur is removed as calcium sulfate in the baghouse and either landfilled

or sold. If sulfur capture is not required then another manufacturer recommended inert material such as sand may be used. ACFB fuel flexibility includes the following list of potential fuels—

- (1) Anthracite coal
- (2) Anthracite culm
- (3) Bark and woodwaste
- (4) Bituminous coal
- (5) Bituminous gob
- (6) Gasifier char
- (7) Industrial sludges, wastes, residues
- (8) Lignite
- (9) Municipal refuse
- (10) Oil
- (11) Oil shale
- (12) Paper products waste
- (13) Peat
- (14) Petroleum coke
- (15) Phenolic resins
- (16) Plastics
- (17) Sewage sludge
- (18) Subbituminous coal
- (19) Textile waste
- (20) Shredded tires

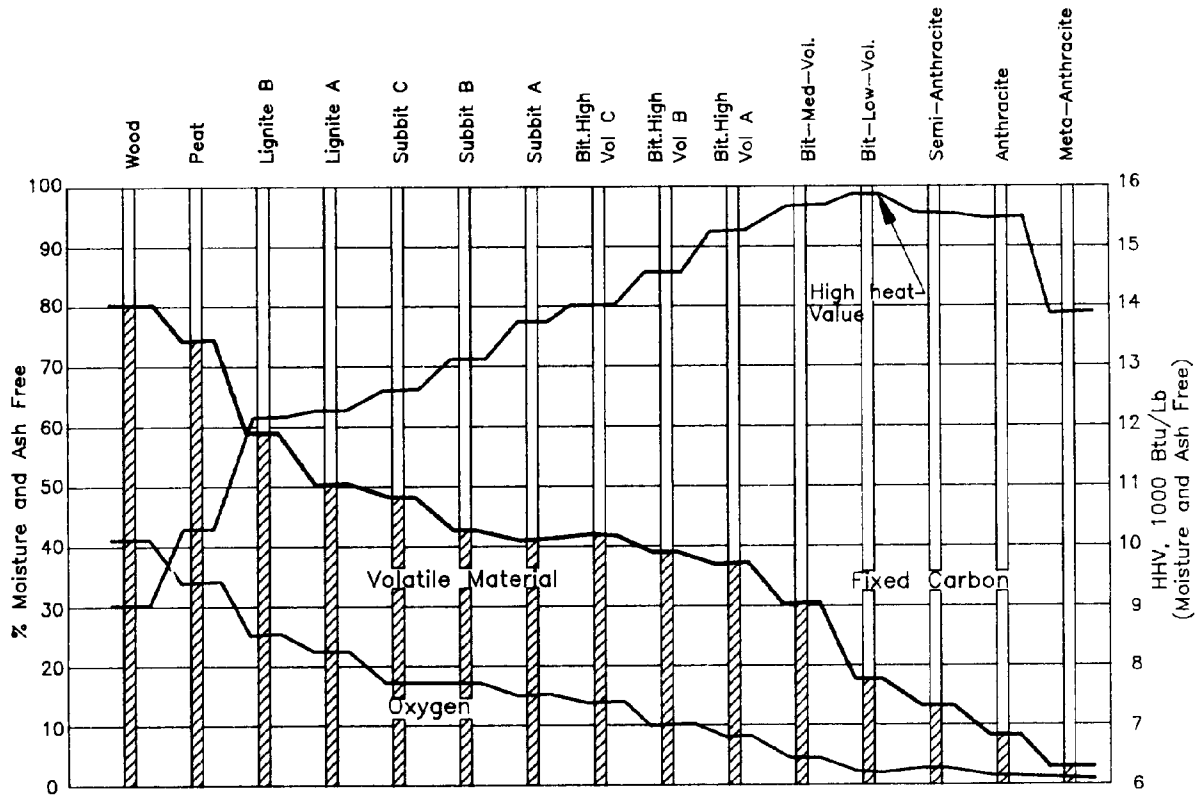


Figure 3-3. Progressive Stages of Coal Formation.

Table 3-3. Analysis of Typical U.S. Coals. (As Mined)

State	Rank	Btu/lb	% Proximate Analysis				% Ultimate Analysis					
			H ₂ O	VM	FC	Ash	H ₂ O	C	H ₂	S	O ₂	N ₂
AL	F	14,210	5.5	30.8	60.9	2.8	5.5	80.3	4.9	0.6	4.2	1.7
AR	C	13,700	2.1	9.8	78.8	9.3	2.1	80.3	3.4	1.7	1.7	1.5
AR	D	13,700	3.4	16.2	71.8	8.6	3.4	79.6	3.9	1.0	1.8	1.7
CO	B	13,720	2.5	5.7	83.8	8.0	2.5	83.9	2.9	0.7	0.7	1.3
CO	F	13,210	1.4	32.6	54.3	11.7	1.4	73.4	5.1	0.6	6.5	1.3
CO	I	10,130	19.6	30.5	45.9	4.0	19.6	58.8	3.8	0.3	12.2	1.3
IA	H	10,720	14.1	35.6	39.3	11.0	14.1	58.5	4.0	4.3	7.2	0.9
IL	G	12,130	8.0	33.0	50.6	8.4	8.0	68.7	4.5	1.2	7.6	1.6
IL	H	11,480	12.1	40.2	39.1	8.6	12.1	62.8	4.6	4.3	6.6	1.0
IN	H	11,420	12.4	36.6	42.3	8.7	12.4	63.4	4.3	2.3	7.6	1.3
KS	F	12,670	7.4	31.8	52.4	8.4	7.4	70.7	4.6	2.6	5.0	1.3
KY	F	14,290	3.1	35.0	58.9	3.0	3.1	79.2	5.4	0.6	7.2	1.5
KY	G	12,080	7.5	37.7	45.3	9.5	7.5	66.9	4.8	3.5	6.4	1.4
MD	D	13,870	3.2	18.2	70.4	8.2	3.2	79.0	4.1	1.0	2.9	1.6
MI	H	11,860	12.4	35.0	47.0	5.6	12.4	65.8	4.5	2.9	7.4	1.4
MO	F	12,990	5.4	32.1	53.5	9.0	5.4	71.6	4.8	3.6	4.2	1.4
MO	G	11,300	10.5	32.0	44.6	12.9	10.5	63.4	4.2	2.5	5.2	1.3
ND	J	7,210	34.8	28.2	30.8	6.2	34.8	42.4	2.8	0.7	12.4	0.7

Table 3-3. Analysis of Typical U.S. Coals. (As Mined) (Continued).

State	Rank	Btu/lb	% Proximate Analysis				% Ultimate Analysis					
			H ₂ O	VM	FC	Ash	H ₂ O	C	H ₂	S	O ₂	N ₂
NM	B	13,340	2.9	5.5	82.7	8.9	2.9	82.3	2.6	0.8	1.3	1.2
NM	F	12,650	2.0	33.5	50.6	13.9	2.0	70.6	4.8	1.3	6.2	1.2
OH	F	12,990	4.9	36.6	51.2	7.3	4.9	71.9	4.9	2.6	7.0	1.4
OH	G	12,160	8.2	36.1	48.7	7.0	8.2	68.4	4.7	1.2	9.1	1.4
OK	D	13,800	2.6	16.5	72.2	8.7	2.6	80.1	4.0	1.0	1.9	1.7
OK	F	13,630	2.1	35.0	57.0	5.9	2.1	76.7	4.9	0.5	7.9	2.0
PA*	B	11,950	5.4	3.8	77.1	13.7	5.4	76.1	1.8	0.6	1.8	0.6
PA**	B	13,540	2.3	3.1	87.7	6.9	2.3	86.7	1.9	0.5	0.9	0.8
PA***	B	12,820	4.9	3.7	82.2	9.2	4.9	81.6	1.8	0.5	1.3	0.7
PA	C	13,450	3.0	8.4	78.9	9.7	3.0	80.2	3.3	0.7	2.0	1.1
PA	E	14,310	3.3	20.5	70.0	6.2	3.3	80.7	4.5	1.8	2.4	1.1
PA	F	13,610	2.6	30.0	58.3	9.1	2.6	76.6	45.9	1.3	3.9	1.6
RI	A	9,313	13.3	2.5	65.3	18.9	13.3	64.2	0.4	0.3	2.7	0.2
TN	F	13,890	1.8	35.9	56.1	6.2	1.8	77.7	5.2	1.2	6.0	1.9
TX	F	12,230	4.0	48.9	34.9	12.2	4.0	65.5	5.9	2.0	9.1	1.3
TX	J	7,350	33.7	29.3	29.7	7.3	33.7	42.5	3.1	0.5	12.1	0.8
UT	F	12,990	4.3	37.2	51.8	6.7	43.0	72.2	5.1	1.1	9.0	1.6
VA	C	11,850	3.1	10.6	66.7	19.6	3.1	70.5	3.2	0.6	2.2	0.8
VA	E	14,030	3.1	21.8	67.9	7.2	3.1	80.1	4.7	1.0	2.4	1.5
VA	F	14,510	2.2	36.0	58.0	3.8	2.2	80.6	5.5	0.7	5.9	1.3
WA	F	12,610	4.3	37.7	47.1	10.9	4.3	68.9	5.4	0.5	8.5	1.5
WV	D	14,730	2.7	17.2	76.1	4.0	2.7	84.7	4.3	0.6	2.2	1.5
WV	F	14,350	2.4	33.0	60.0	4.6	2.4	80.8	5.1	0.7	4.8	1.6
WY	G	12,960	5.1	40.5	49.8	4.6	5.1	73.0	5.0	0.5	10.6	1.2
WY	I	9,420	23.2	33.3	39.7	3.8	23.2	54.6	3.8	0.4	13.2	1.0

*Orchard Bed. **Mammoth Bed. ***Holmes Bed.

RANK KEY: A-Meta-anthracite

- B-Anthracite
- C-Semianthracite
- D-Low Volatile Bituminous
- E-Medium Volatile Bituminous
- F-High Volatile Bituminous A
- G-High Volatile Bituminous B
- H-High Volatile Bituminous C
- I-Subbituminous
- J-Lignite

Table 3-4. Typical coal and ash analysis information suitable for boiler design.

	As Received (Raw)		Washed	
	Typical	Range	Typical	Range
<i>Proximate Analysis</i>				
Moisture (%)	_____	_____ to _____	_____	_____ to _____
Ash (%)	_____	_____ to _____	_____	_____ to _____
Fixed Carbon (%)	_____	_____ to _____	_____	_____ to _____
Total	100.0		100.0	
Btu per pound (as received)	_____	_____ to _____	_____	_____ to _____
Btu per pound (dry)	_____	_____ to _____	_____	_____ to _____
Sulfur (%)	_____	_____ to _____	_____	_____ to _____
<i>Ultimate Analysis</i>				
Carbon (%)	_____	_____ to _____	_____	_____ to _____
Hydrogen (%)	_____	_____ to _____	_____	_____ to _____
Nitrogen (%)	_____	_____ to _____	_____	_____ to _____

Table 3-4. Typical coal and ash analysis information suitable for boiler design. (Continued)

	<i>As Received (Raw)</i>		<i>Washed</i>	
	Typical	Range	Typical	Range
Chlorine (%)	_____	_____ to _____	_____	_____ to _____
Sulfur (%)	_____	_____ to _____	_____	_____ to _____
Ash (%)	_____	_____ to _____	_____	_____ to _____
Oxygen (%)	_____	_____ to _____	_____	_____ to _____
Moisture (%)	_____	_____ to _____	_____	_____ to _____
<i>Mineral Analysis</i>				
Phos. Penioxide, P ₂ O ₅	_____	_____ to _____	_____	_____ to _____
Silica, SiO ₂	_____	_____ to _____	_____	_____ to _____
Ferric Oxide, Fe ₂ O ₃	_____	_____ to _____	_____	_____ to _____
Alumina, Al ₂ O ₃	_____	_____ to _____	_____	_____ to _____
Titania, TiO ₂	_____	_____ to _____	_____	_____ to _____
Calcium Oxide, CaO	_____	_____ to _____	_____	_____ to _____
Magnesium Oxide, MgO	_____	_____ to _____	_____	_____ to _____
Sulfur Trioxide, SO ₃	_____	_____ to _____	_____	_____ to _____
Potassium Oxide, K ₂ O	_____	_____ to _____	_____	_____ to _____
Sodium Oxide, Na ₂ O	_____	_____ to _____	_____	_____ to _____
Undetermined	_____	_____ to _____	_____	_____ to _____
Total	100.0		100.0	
		<i>Reducing</i>		<i>Oxidizing</i>
<i>Fusion Temperature of Ash, deg. F</i>				
Initial Deformation (IT)	_____		_____	
Softening (H=W)	_____		_____	
Hemispherical (H= 1/2W)	_____		_____	
Fluid (FT)	_____		_____	
Free Swelling Index	_____		_____	
Viscosity T ₂₅₀ , deg. F	_____	_____ to _____	_____	_____ to _____
Silica Value	_____	_____ to _____	_____	_____ to _____
Base/Acid Ratio	_____	_____ to _____	_____	_____ to _____
<i>Sulfur Forms</i>				
Pyritic Sulfur (%)	_____	_____ to _____	_____	_____ to _____
Sulfate Sulfur (%)	_____	_____ to _____	_____	_____ to _____
Organic Sulfur (%)	_____	_____ to _____	_____	_____ to _____
<i>Water Soluble Alkalis</i>				
Water Soluble Na ₂ O	_____	_____ to _____	_____	_____ to _____
Water Soluble K ₂ O	_____	_____ to _____	_____	_____ to _____
Equilibrium Moisture	_____	_____ to _____	_____	_____ to _____
Hardgrove Grindability Index	_____	_____ to _____	_____	_____ to _____

3-5. Coal ash characteristics.

a. Slagging and fouling potential. The slagging potential of ash is the tendency to form fused deposits on tube surfaces exposed to high temperature radiant heat. The fouling potential is the tendency of ash to bond to lower temperature convection surfaces. The slagging and the fouling potential of the coal also directly affects furnace design. Ash analyses of the expected fuel source must be performed before undertaking the boiler design, using ash prepared according to ASTM D 3174.

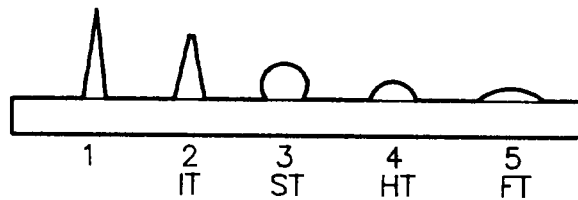
(1) *Fusion temperature.* Many comparisons of chemical makeup have been developed to analyze the behavior of ash in boilers, empirical testing of ash fusion temperature is still the most basic way of predicting slagging and fouling

potential. One testing method of determining ash fusion temperature is prescribed in ASTM D 1857. The test consists of observing the gradual thermal deformation (melting) of a pyramid shaped ash sample and recording the Initial Deformation Temperature (IT), Softening Temperature (ST), Hemispherical Temperature (HT), and Fluid Temperature (FT). The stages at which these temperatures are recorded are shown in figure 3-4.

(2) *Chemical analyses.* The fusion temperature of ash is influenced by the interaction of the acidic oxide constituents silica dioxide (SiO₂), aluminum oxide (Al₂O₃), and titanium dioxide (TiO₂) with the basic oxides; ferric oxide (Fe₂O₃), calcium oxide (CaO), magnesium oxide (MgO), and potassium oxide (K₂O)—all of which are present in the coal ash in widely varying

proportions. Depending on their relative proportions they can combine during combustion to form compounds with melting temperatures ranging from 1610 degrees F for sodium silicate (Na_2SiO_3) to 2800 degrees F for calcium silicate (CaSiO_3). In determining the slagging potential and fouling potential of ash, studying the base/acid

ratio, silica/alumina ratio, iron/calcium ratio, iron/dolomite ratio, dolomite percentage, silica percentage, total alkalies, and the role of iron in coal ash can all be useful, as shown in figure 3-5. The chemical elements found in coal, their oxidized forms, and the ranges in which they may be present in coal ash are listed in table 3-5.



1. Cone Before Heating
2. IT (or ID) Initial Deformation Temperature
3. ST Softening Temperature (H=W)
4. HT Hemispherical Temperature (H=1/2W)
5. FT Fluid Temperature

Figure 3-4. Critical Temperature Points as Defined by ASTM Standards D 1857.

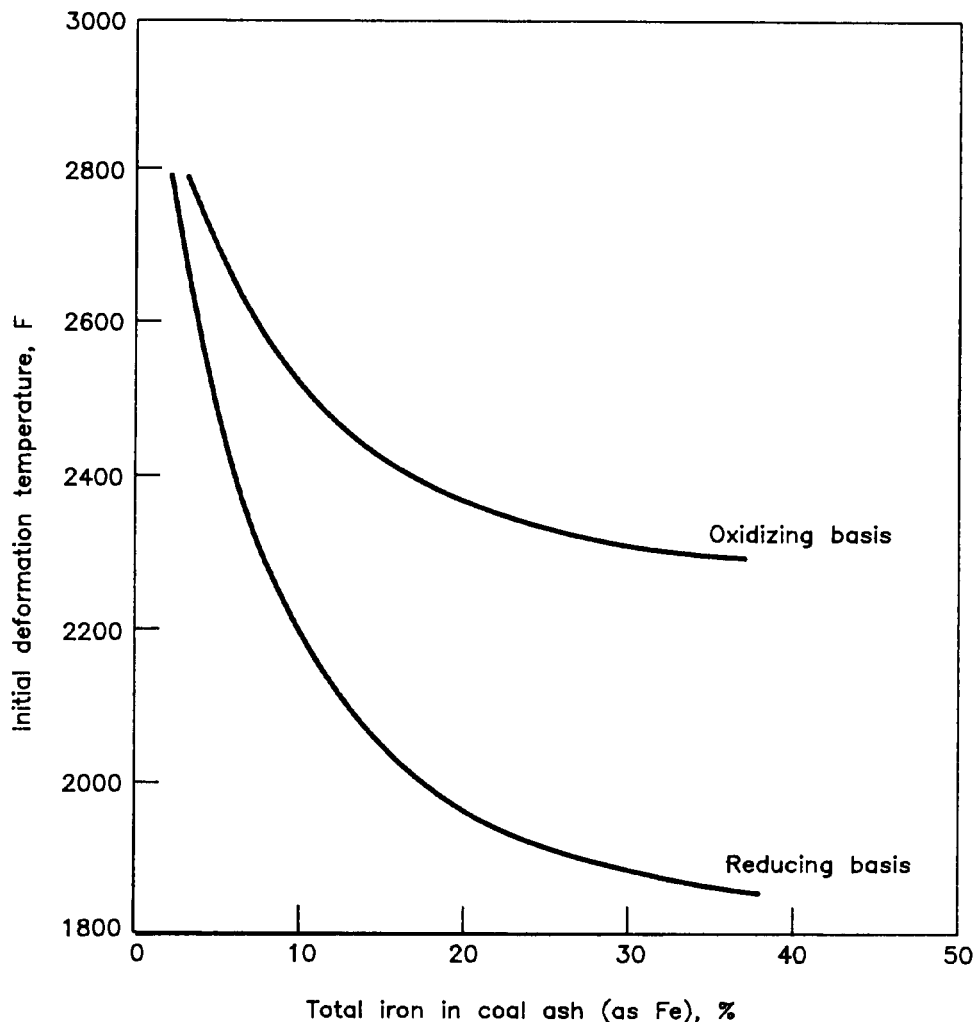


Figure 3-5. Influence of Iron on Coal Ash Fusion Temperatures.

Table 3—5. Chemical Constituents of Coal Ash.

Elemental Form	Oxidized Form	Range Present in Ash—%
Acidic		
Si (silicon)	SiO ₂ (silica dioxide)	10—70
Al (aluminum)	Al ₂ O ₃ (aluminum oxide)	8—38
Ti (titanium)	TiO ₂ (titanium oxide)	0.4—3.5
Basic		
Fe (iron)	Fe ₂ O ₃ (ferric oxide)	2—50
Ca (calcium)	CaO (calcium oxide)	0.5—30
Mg (magnesium)	MgO (magnesium oxide)	0.3—8
Na (sodium)	Na ₂ O (sodium oxide)	0.1—8
K (potassium)	K ₂ O (potassium oxide)	0.1—3
S (sulfur)	SO ₃ (sulfur oxide)	0.1—10

b. Ash characteristics and boiler design. The characteristics and quantity of ash produced by a specific coal strongly influence several aspects of pulverized coal, ACFB and stoker boiler design, including the selection of a bottom ash handling system and furnace sizing. Ash with a high (2400 degrees F and above of a reducing basis) fusion temperature is most suitable for dry bottom boilers, while lower (1900 degrees F to 2400 degrees F on a reducing basis) ash fusion temperatures are

required for wet bottom boilers to prevent solidification of the ash during low load operation. Furnace volume must be increased for coals producing ash with high fouling and slagging potentials, or to counteract the erosive effects of large quantities of ash or very abrasive ash. The greater furnace volume results in both lower exit gas temperatures-reducing fouling and slagging-and lower exit gas velocities, reducing tube erosion. The relationship between coal classification and furnace volume is shown in figure 3-6.

3-6. Combustion technology selection.

a. Exclusionary factors. Gas and oil fired boilers are available over the entire size range. Their use is limited to areas where these fuels are economically available. Stoker-fired boilers are available for the entire load range covered by this manual. Pulverized coal (PC) boilers are available in capacities of 100,000 pph and above. Atmospheric circulating fluidized bed (ACFB) boilers are available in capacities of 80,000 pph and above. PC fired units were used in capacity ranges below 100,000 pph prior to the advent of package boilers, but with the new designs it became more difficult to evaluate PC firing as a preferred method of firing coal and hence have essentially become obsolete. When

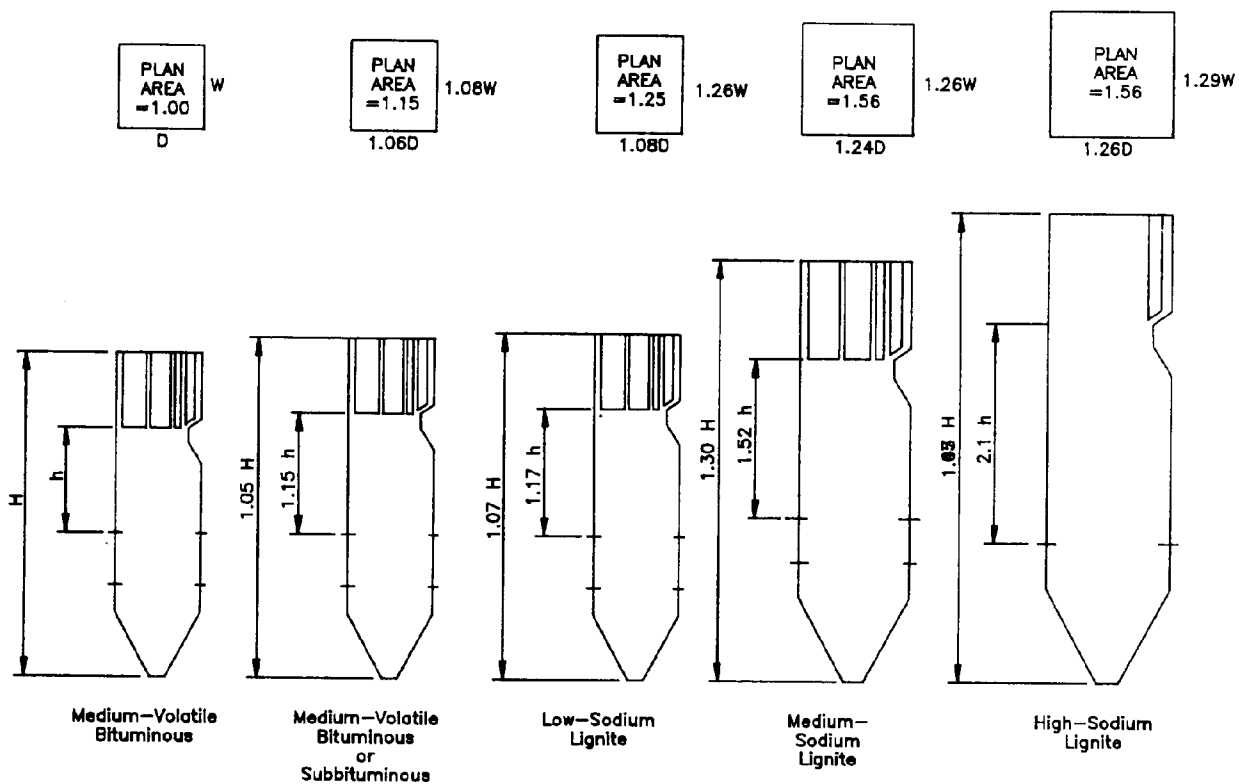


Figure 3-6. Effects of Coal Classification on Furnace Sizing.

rapid load swings are expected, stoker-fired units may be eliminated because of their inferior response to these conditions. When economics dictate the use of low grade fuels including those of high or variable ash content or high sulfur content then stoker-fired and PC systems may be eliminated in favor of ACFB systems. If none of these firing systems are excluded by these factors, then the choice between firing systems must be made on the basis of a life cycle cost analysis (LCCA).

b. Base capital cost. The base capital cost of a dual firing system is the total price of purchasing and installing the entire system, including the boiler, furnace, either stoker, pulverizer or fluidization system, fans, flues, ducts, and air quality control equipment. PC fired and ACFB boilers are more expensive than stoker-fired boilers of a given capacity, in part because they have a larger furnace to provide space and time for the combustion process to go to completion. Approximately 60 to 90 percent of the ash content of the coal passes through the unit along with the gases of combustion. Tube spacing within the unit has to be provided in order to accommodate this condition and the ability of this ash to cause slagging and fouling of the heating surface. These factors can increase the size of the boiler and its cost. PC fired units have been replaced by packaged boilers in capacity ranges below 100,000 pph. Gas, oil and PC boilers require a flame failure system which increases their cost. The total cost of an ACFB boiler addition is offset by not requiring flue gas desulfurization (FGD) or selective catalytic reduction (SCR). Selective noncatalytic reduction (SNCR) is required on ACFB boilers in place of SCR.

c. Average boiler duty. The remaining expenses calculated for an LCCA are all functions of the average boiler duty. This value is based on the estimated annual boiler load during the expected life of the plant. It is calculated as follows:

$$\frac{\text{average load (pph)}}{\text{rated capacity}} \times \frac{\text{hours of operation}}{8,760 \text{ hours}} = \text{average boiler duty}$$

For example, if a 100,000 pph boiler operates at an average load of 75,000 pph for 8,000 hours per year out of a possible 8,760 hours, the average boiler duty is 68 percent.

d. Fuel flexibility. When economically feasible the ability to satisfy steam requirements with more than one type of fuel offers significant advantages. Problems with only one fuel's source, transportation, handling or firing system will not stop steam production. The flexibility of alternate fuel supplies can be a powerful bargaining tool when

negotiating fuel supply contracts.

e. Fuel selection considerations. The use of natural gas has the lowest first cost provided there is adequate supply in a nearby supplier's pipeline. Natural gas does not require storage facilities; however, it is subject to interruption and possible curtailment. Although diesel oil burns more efficiently than natural gas, oil requires on site storage and pumping facilities. Because oil has the potential to contaminate ground water, storage facilities are required to include spill containment and leak detection systems. Coal can be stored in piles outdoors. Steel tanks and spill containment are not required. Coal pile runoff (coal fines in rain water) into surrounding waters and airborne fugitive dust emissions are concerns that have to be addressed. Transportation of coal from stockpiles to the bunkers requires dedicated labor to operate unloading, storage, reclaim, and handling systems. These needs along with sizing, ash handling, and particulate emissions reduction requirements make coal firing the highest capital investment alternative.

f. Solid fuel considerations. Due to the special coal sizing requirements of stoker and ACFB fuel for such a unit may cost (5 to 15 percent) more than the unsized coal that could be purchased for a PC fired unit. However, if unwashed or run-of-mine (ROM) coal is purchased for a PC fired unit, a crusher and motor should also be included in the coal handling system in order to reduce the coal particle size to approximately 1-1/4 by 0-inch. Another consideration is that it may be difficult to obtain the size stoker or ACFB coal due to either transportation difficulties or lack of equipment at a mine site. When using the same bituminous quality coal, PC and ACFB fired units have a higher thermal efficiency (86 to 88 percent) compared to stoker fired units (80 to 84 percent) that effectively lowers their fuel usage costs. The primary reason for these differences is unburned carbon loss and dry gas (exit gas temperature) losses and amount of fly ash reinjection. These efficiency percentages will vary with the quality of the fuel. With low sulfur western fuels having a high moisture content (20 to 30 percent), a PC fired unit efficiency may be as low as 82 to 85 percent. A particular ACFB boiler can fire a wide range of low grade inexpensive fuels. These include high sulfur coal, petroleum coke, refuse derived fuel, waste water plant treatment sludge and mixtures of coal with various scraps such as shredded tires, wood chips and agricultural waste. Another feature of PC and ACFB fired units that results in increased costs and must also be considered in the overall evaluation is

the natural gas or No. 2 fuel oil burner lighters which are normally in the range of 3 million to 10 million Btu per hour for each device. Stoker fired units are normally started by spreading kerosene or other waste oil and scrap wood over a coal bed and lighting it. Annual fuel cost is based on the cost of the fuel, in dollars and cents per million Btu multiplied by the hours of operation and average load and divided by the percent boiler efficiency.

g. Power cost. Gas fired boilers have the lowest electrical energy requirements. Oil fired units are next due to oil pumping and heating needs. Auxiliary power requirements for gas and oil boilers are considerably less than coal fired units because ash handling, coal handling, sorbent handling and pollution control systems are not needed. A comparison can be approximated by listing the fan and drives with their respective duties and the sizes of each. For example, on a PC fired unit there are forced draft (FD) and induced draft (ID) fans and drives, primary air (PA) fan(s) and exhaustor(s) and drive(s) and pulverizer drive motor(s). It is possible the primary air fan or exhaustor drive and pulverizer drive motor may be combined so there is a single motor driving both devices. Normally, there would be two or more pulverizers and PA or exhaustor fans per boiler unit. For the stoker fired unit, there are also an FD and ID fan drive, and an overfire air and ash reinjection system that likewise may be combined as a single piece of equipment. The pulverizer drive and primary air fan and exhaustor drive are relatively high duty or horsepower (hp) consumers compared to the stoker overfire air and ash reinjection system fan drive together with the stoker drive motor. Annual power costs, kilowatthours per year, is directly related to average boiler duty. Sootblower motors are fractional horsepower and generally are not included in any power comparison. ACFB boilers also have high electrical power requirements. The fluidized bed is suspended on air that is provided by a primary air fan. The solids reinjection device has fluidizing air needs which are provided by blowers. Limestone handling is another electrical user which is unique to ACFB. Inert bed handling is also in this category. ACFB boilers, however, unlike PC and stoker boilers, may not require sulfur removal equipment such as scrubbers. This must be considered when evaluating power cost.

h. Maintenance costs. Gas fired boilers have the lowest maintenance cost. Oil fired boiler installations are higher than gas fired systems due to oil pumping needs, oil storage requirements and boiler corrosion and external deposits on heat transfer surfaces resulting from sulfur, sodium and

vanadium in the oil. ACFB boilers have higher maintenance when compared to PC boilers. The abrasive action of the solids circulating through the combustor and solids separator causes wear. ACFB systems are more complicated with more components which add to the maintenance cost. As more ACFB experience is gained, maintenance costs can be expected to decrease as improvements are made. Maintenance costs for a PC fired unit are generally higher than that for a stoker fired boiler due to the higher duty requirements of such items as the pulverizers, primary air fans or exhaustors, electric motors, coal lines and greater number of sootblowers. Maintenance costs are also a reflection of the hours of operation and average boiler duty.

i. Operating costs. These expenses include manpower, sorbent, and other costs incurred on a continuing basis while the plant is in operation. Manpower requirements for oil fired boilers are somewhat higher than gas boilers, because of the fuel storage and increased handling concerns associated with oil. Coal fired technologies require considerably more manpower than either oil or gas. Fuel handling, ash handling and pollution control systems account for the majority of the increase in operating costs. Even though stoker fired and PC boilers are less complicated than ACFB boilers, stoker and PC boilers, unlike ACFB boilers, must include scrubbers. The evaluation of operating costs among coal firing technologies is site specific and must include all relevant factors.

3-7. Pulverizers (Mills).

a. Types. There are four basic types of pulverizers frequently used on industrial sized boilers. They are commonly referred to by the type of grinding elements, i.e., ball and tube, attrita, ball-and-race, and ring-and-roll.

(1) The ball and tube type mill is commonly used on boilers that use coal as the principle fuel. They require more space and use more power input than the other types, so they are at an economic disadvantage unless only one mill is used.

(2) Attrita type mills are usually used on boilers that use gas or oil as the primary fuel with coal as a backup fuel. These mills are subject to high maintenance due to the use of unwashed (ROM) coal and foreign objects (rail, spikes, rebar, wood) getting into the coal stream. This mill combines the pulverizer and the exhaustor in a single package.

(3) The following information and illustrations primarily pertain to the more frequently used ball-and-race and ring-and-roll type mills.

Figures 3-7 and 3-8 illustrate the two more commonly used pulverizer types.

b. Capacity. Pulverizer capacity is a function of coal type, based on a grindability index, moisture content, and fineness of the product. At least two pulverizers should be provided, and with one pulverizer off line for maintenance the remaining pulverizers should be capable of supplying coal to the boiler at the desired load with worst case coal. Figures 3-9, 3-10 and 3-11 show the influence of grindability and moisture content of coal on pulverizer operation.

3-8. Coal burner ignitors.

a. Types. Natural gas or No. 2 fuel oil ignitors are required for firing pulverized coal. These ignitors will be capable of preheating the boiler prior to starting the pulverizer and firing coal. The ignitors should be able to carry about 10 percent of maximum continuous rating (MCR) and are also used to stabilize the coal flame when the burner load is less than approximately 40 to 50 percent or other adverse fuel conditions such as high moisture. The steam load at which the pulverized coal flame

has to be stabilized should be investigated in the design stage so that suitable auxiliary fuel provisions can be designed into the plant. If oil ignitors are used, either compressed air or steam atomizers are used. Pressure on mechanical atomization should not be considered due to safety factors.

b. Cost. The cost of these ignitors and the labor required for their installation plus the fuel system required should be included in the LCCA. Ignitors will be lit by high energy spark plug type lighters.

3-9. Burners and NOx control.

a. Burner design. State-of-the-art burner design calls for low excess air operation to improve the boiler thermal efficiency (reduced exit gas temperature and dry gas loss) as well as to reduce NOx emissions. Coal burners will be specifically designed for pulverized coal and compatible with the gas or oil ignitors to be supplied and produced by a qualified manufacturer. Note, in the case of gas, oil and pulverized coal fired units, a flame safety system is also required.

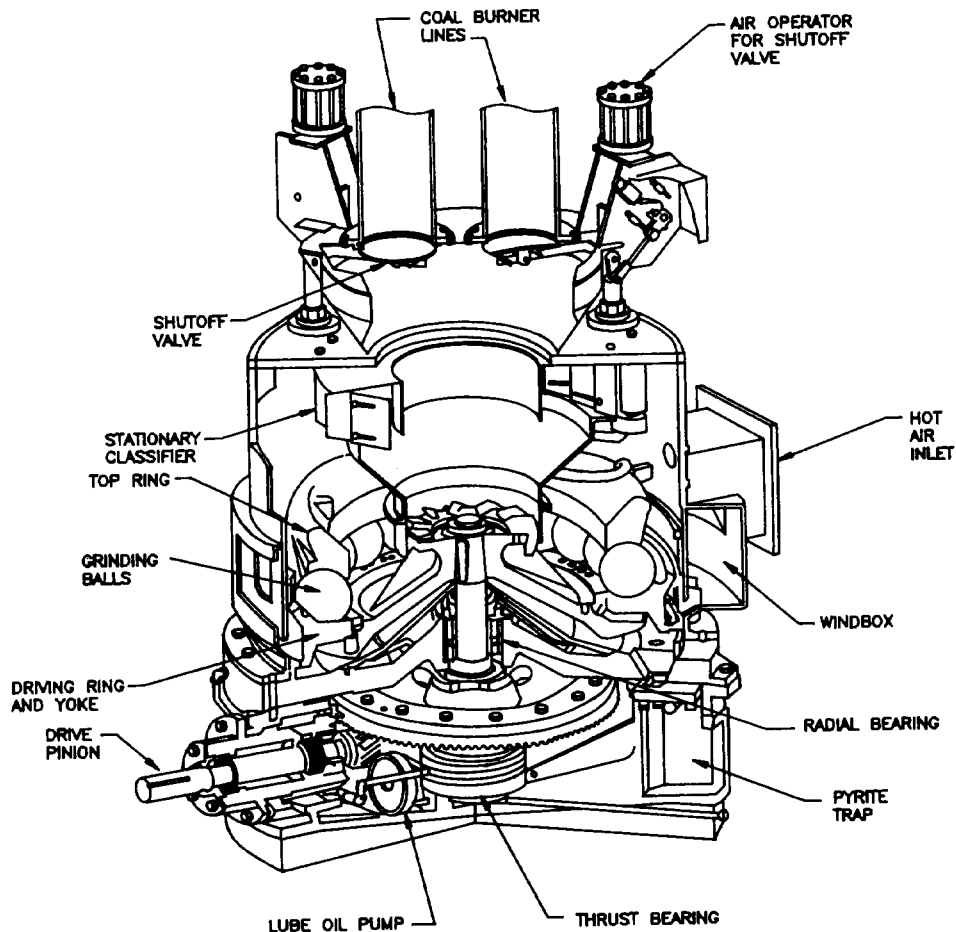


Figure 3-7. Ball-and-Race Pulverizer.

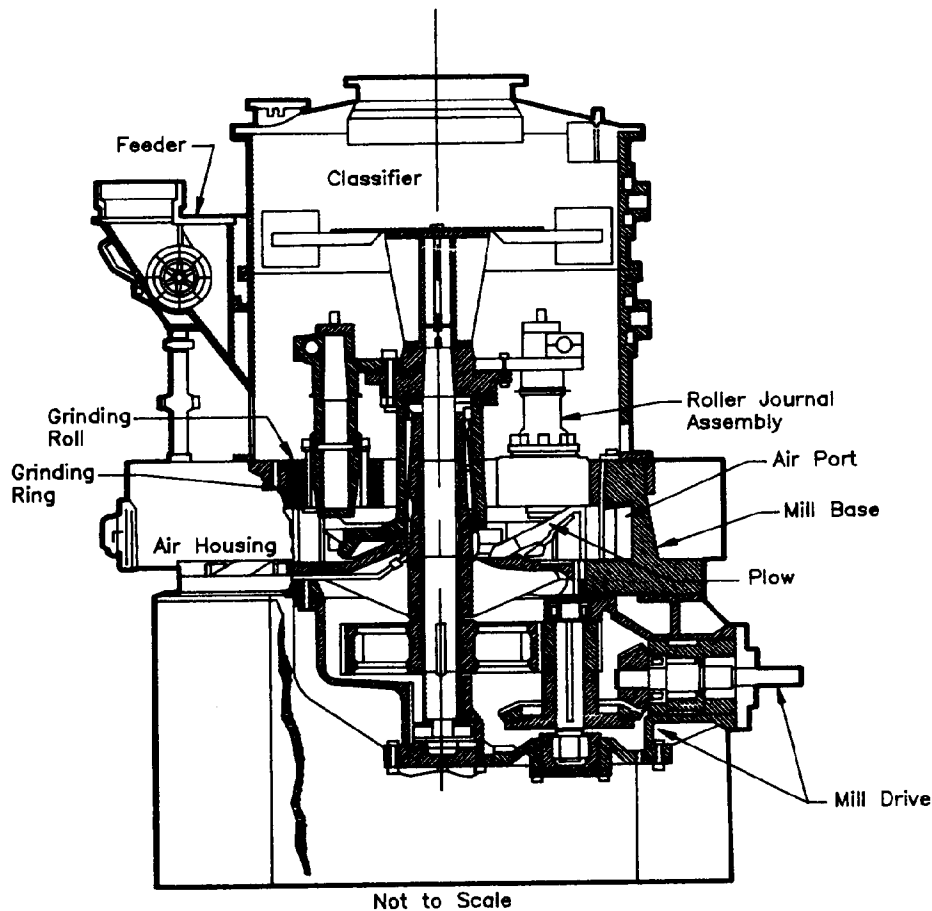


Figure 3-8. Ring-and-Roll Pulverizer.

b. Flame safety detectors.

(1) Ultra violet type detectors are used on natural gas and some oil fuels, but will not be used on pulverized coal boilers since the flame masks most of the light rays of that type.

(2) Infrared type detectors are used on pulverized coal boilers to detect coal fire.

(3) For reliability, with a suitable life span, solid state type controls should be used for the detectors.

c. NO_x control options and considerations. Many options are available to reduce NO_x emissions as mandated by recent regulations. The nitrogen content of fuels, especially oil and even coal, should be specified in the fuel purchase contract. Restrictions on the nitrogen content will limit fuel flexibility. A careful analysis of proposed NO_x reduction technologies must be performed to account for any required changes to auxiliary equipment and to identify future increases in O&M costs. Important questions that should be answered and be a part of the evaluation include the performance of NO_x reduction over the entire load range,

performance during backup fuel firing, and the performance over the lifetime of the unit.

(1) Harmful effects of NO_x on the environment include contributions to acid rain, to the destruction of the ozone layer, to global warming, and to smog.

(2) Components of NO_x include nitric oxide (NO), nitrogen dioxide (NO₂), and nitrous oxide (N₂O) as a residual pollutant of some NO_x control processes. Emissions from combustion processes are 90 to 95% NO with the balance being NO₂.

(3) Title IV of the Clean Air Act Amendments of 1990 (CAAA) requires application of low NO_x burner (LNB) technology. Title I of the CAAA has more impact in ozone nonattainment areas which are near the nation's largest cities. State implementation plans may place even more strict limits on NO_x. Flexibility may be allowed by having provisions for averaging NO_x emissions over the system.

(4) NO_x is formed as a result of oxidizing various sources of nitrogen. Fuel NO_x is formed when the nitrogen contained in the fuel is oxidized.

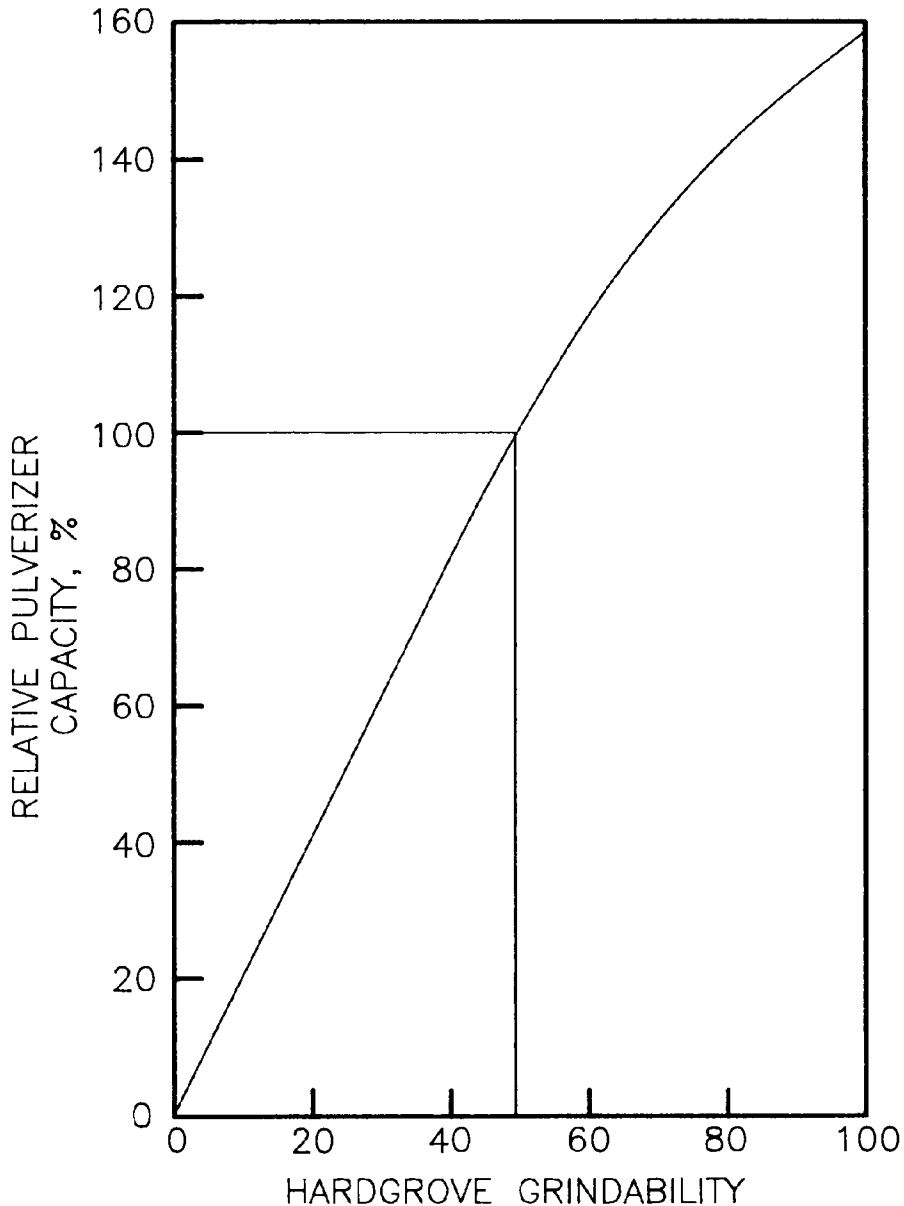


Figure 3-9. Relative Pulverizer Capacity as a Function of Hardgrove Grindability.

Thermal NO_x results from the oxidation of nitrogen in the combustion air at high temperatures. At very low levels of NO_x prompt NO_x is formed when intermediate hydrocarbons present in the flames oxidize.

(5) NO_x control techniques can be defined as either combustion modifications or post combustion reduction. The goals of combustion modification include redistribution of air and fuel to slow mixing, reduction of O_2 in NO_x formation zones, and reduction of the amount of fuel burned at peak flame temperatures.

(6) Combustion modifications primarily deal with the control of fuel and air. Vertical staging includes overfire air (OFA) ports above the main combustion zone. Horizontal staging use registers or other devices to introduce air at different points along the flame. Fuel staging establishes a fuel rich zone above an air lean main combustion zone. Burner out of service (BOOS) techniques direct fuel to lower burner levels, while operating upper burners with air only. Flue gas recirculation (FGR) reduces O_2 available to react with nitrogen and cools the flame. In addition to low NO_x burners

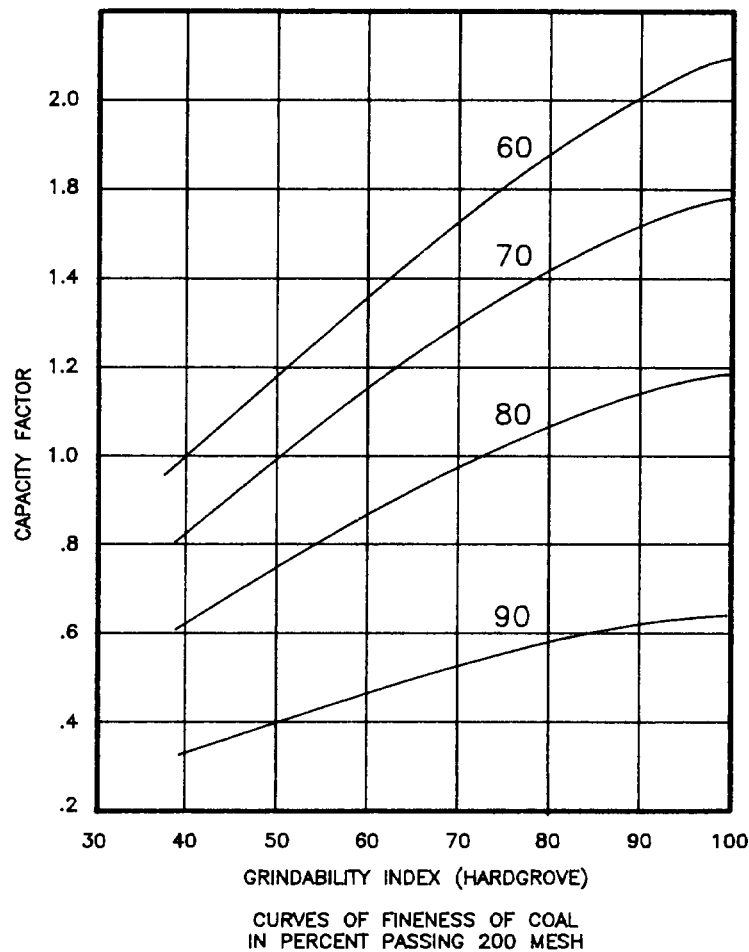


Figure 3-10. Effect of Fineness on Capacity of Pulverizers.

(LNB), OFA, and BOOS other combustion modification techniques include fuel biasing, low excess air (LEA), and fuel reburning. Oil fired boilers have successfully used advanced oil atomizers to reduce NO_x without increasing opacity. Oil/water emulsion is a technique to reduce NO_x on smaller industrial boilers.

(7) NO_x reduction side effects should be considered in the evaluation of alternatives. Reduction techniques may require constant operator attention or a high degree of automation. LNB's on coal fired boilers increase carbon loss in the ash by 0.5 to 10% which may require the installation of classifiers and reinjection lines. Loss on ignition (LOI) reduction techniques have other impacts. Classifiers may place constraints on pulverizers which decrease operation flexibility. Unit efficiency may decrease if excess air has to be increased. Changes in slagging patterns may occur. Soot blowing may be needed more frequently. Difficulties may arise during changes in load. Mechanical reliability may decrease. Burner barrel temperature is difficult to control with some LNB's which leads to premature failure. Corrosion

potential increases because highly corrosive hydrogen sulfide forms instead of SO₂ due to the reducing atmosphere. Changes in flame length can cause impingement and can alter heat absorption characteristics. Fly ash loading may increase at the air heater or particulate collection equipment.

(8) Selective catalytic reduction (SCR) uses ammonia as reagent to reduce NO_x to water and elemental nitrogen. SCR offers 90 percent or greater NO_x removal. Reactions take place between 1600 degrees F and 2200 degrees F. Catalyst is needed to promote reactions at lower temperatures. Catalyst life is guaranteed up to 5 years and has reportedly been as long as 10 years. Catalyst replacement is the largest part of O&M costs. The other popular form of post combustion technology is selective noncatalytic reduction (SNCR). SNCR involves the injection of either urea, ammonium hydroxide, anhydrous ammonia, or aqueous ammonia into the furnace within the appropriate temperature window (1600 degrees F to 2000 degrees F) to reduce NO_x. Some of the NO_x is converted to N₂O which is considered a "greenhouse" gas. Ammonia emissions of "slip" is an-

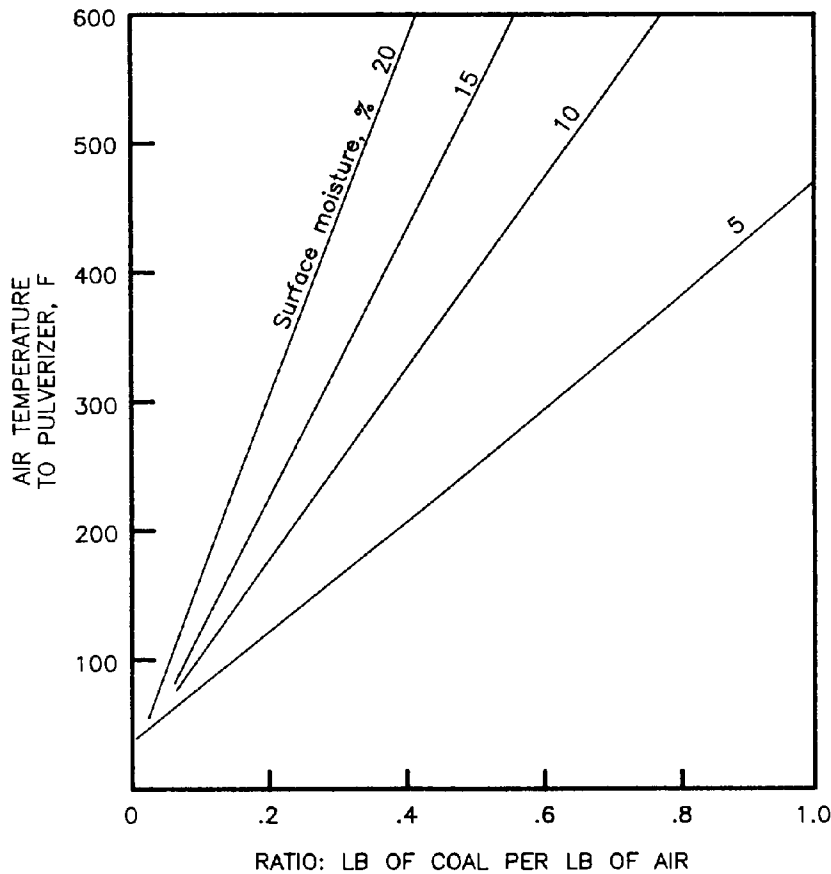


Figure 3-11. Effect of Moisture on Pulverizer Air Temperature Requirements.

other concern. SCR concerns include fouling or blinding catalyst surfaces and poisoning the catalyst with arsenic, lead, phosphorus or other trace compounds found in coal.

(9) Operation and maintenance cost increases should be identified. Coal boiler bottom ash systems may have to be retrofitted with ash separators and carbon recovery devices if LOI increases substantially. Ash sold for reuse may no longer be attractive and could even be considered hazardous waste. As regulations become more strict additional catalyst could be needed to meet NO_x emissions and ammonia slip. Changing fuels could have detrimental effects on existing NO_x reduction equipment.

(10) Installation and retrofit of various NO_x reduction systems have unique installation and space requirements that should be considered. LNB may or may not require pressure part modifications. FGR involves routing large ductwork. OFA is very effective, involves routing of ductwork, and also

involves modifications to pressure parts. Fuel staging requires pressure part modifications for reburn fuel injection and/or OFA ports.

3-10. Primary air.

a. Air moving system. Pulverized coal firing requires heated primary air to dry the surface moisture in the coal fed to the pulverizers and to provide the conveying medium for getting the finely ground pulverized coal from the pulverizer to the burner and out into the furnace. This primary air is supplied either by the FD fan for a hot primary air system or a separate cold primary air fan for pressurized pulverizer systems; or is drawn through the pulverizer by an exhauster fan in the negative pressure pulverizer system.

(1) The use of a separate high pressure fan to force the coal through the mill and burner lines to the furnace burner and out into the furnace itself requires all the burner piping, and pulverizer to be sealed against this pressure in order to prevent coal leaks.

(2) In the negative pressure pulverizer operation, the exhauster fan pulls the air through the mill and then forces it up through the riffle box, then the burner lines to the furnace. In this case, any leakage would be into the mill. However, the burner lines are under pressure and any leakage would result in finely ground coal showing up around these leaks.

b. Coal air mixture. In either case, pressure or exhauster type mills, the coal-air mixture is usually at a temperature of approximately 150 degrees F and a velocity 2000 feet per minute (fpm) or higher, to prevent the coal from settling out in the burner lines. If the coal does settle out in these burner lines, fires or explosions in the burner lines or pulverizers may occur.

3-11. Stokers.

a. Type. Mechanical stokers continuously supply coal to their grates in a manner that allows for controlled combustion of the coal. There are several combinations of stokers and grate types hereafter referred to as stoker types and are available for use in coal fired boilers with steam capacities of 20,000 to 250,000 pph which is the entire range covered by this manual. However, not all of them are acceptable for state-of-the-art boiler plant design.

b. Unacceptable stoker types.

(1) *Dump grate stoker.* This type of stoker is not recommended because it has a high particulate emission rate whenever the grates are dumped. This factor necessitates added cost for air pollution control equipment due to the increased size required to handle the dust loading. Maintenance costs are relatively high. However, one use of this type of stoker that may be desirable is in conjunction with a pulverized coal fired unit for the reduction of refuse derived fuel (RDF) at the furnace hopper outlet. The use of this type of stoker in the described application will prevent large particles of refuse that fall to the bottom of the furnace from being dumped into the furnace ash pit before having been completely consumed in the combustion process.

(2) *Single retort underfeed stoker.* This type of stoker is not recommended to be used in boilers with steam capacities above 25,000 pph which is at the low end of the size range addressed by this manual. Because of its limited application, the single retort underfeed stoker will not be considered for this manual.

(3) *Multiple retort underfeed stoker.* This type of stoker is a grouping of the single retort underfeed stokers to increase potential applications of the underfeed retorts for boilers with steaming

rates over 25,000 pph. It is not recommended because of high costs for installation and maintenance.

c. Acceptable type stokers..

(1) *Vibrating or oscillating grate stoker.* This type of stoker is available for boilers with steam capacities between 20,000 and 150,000 pph, depending upon what feed types are used. It is available with either mass feed or spreader feed.

(2) *Traveling grate stoker.* This type of stoker moves the coal through the boiler furnace on a continuous belt made of the stoker grate bars. Combustion air passes through the grate bars to reach the fuel bed. The combustion air pressure drop across the grate due to the construction of the grate bars is evenly distributed to the fuel at all loads. This design feature makes the traveling grate stoker acceptable for use with spreader type coal feed. For mass burning, plenums and dampers must be incorporated into the design of the stoker. The traveling grate stoker is acceptable for boilers with steam capacities of 50,000 pph and above.

(3) *Traveling chain grate stoker.* This type of stoker moves the coal through the boiler furnace on a continuous belt made of interlocking links or bars. Unlike the traveling grate stoker, it has a low pressure drop across the chain due to the spaces between the links. As a result, the air flow on this type of stoker is not evenly distributed at all boiler loads. Therefore, the traveling chain grate stoker is acceptable only with a mass type feed in boilers with steam capacities between 20,000 and 75,000 pph.

3-12. Stoker feed.

a. Types. Two types of stoker feed are available for use with vibrating grate and traveling grate stokers; cross-feed (or mass feed) and spreader feed distributor (or flipper). Selection of one type or other of these stokers will depend primarily on a comparative analysis of the capital and operating costs associated with the pollution control equipment needed for these feed types. With the traveling chain grate, only a mass fuel feed type will be used.

b. Cross feed. This type of stoker feed is a mass fuel overfeed in which coal is placed directly on the grates from a coal hopper. Continuous feed is automatic as a fuel bed moves away from the coal hopper. This type of fuel feed must have adjustable air dampers under the fuel bed to control combustion zones. The depth of the fuel bed is generally controlled by a gate.

c. Spreader feed. This type of stoker feed throws coal to the rear of the furnace and evenly distributes coal from side to side with a small degree of

segregation. Approximately 25 to 50 percent of the coal is burned in suspension by this method. This spreader feed has a larger grate heat release rate than the cross feed type; requires a smaller furnace envelope; and has a quicker response time for load changes. This type of fuel feed must have a uniform air flow through the grates due to the large amount of suspension burning. For best results, the fuel fed to this type of unit should be properly sized. Refer to Figure 3-12 illustrating coal size.

d. Stoker selection considerations. Table 3-6 provides a summary of factors to be considered when selecting a stoker for a boiler within the range of 20,000 to 250,000 pph of steam. Prior to submitting a set of specifications to the boiler or stoker manufacturers, the type of coal that is to be burned must be known. Selection of the design coal is required so that these manufacturers are able to guarantee their equipment performance. When the coal is not known, or when the possibility exists that many different types of coals will be burned over the life of the stoker, the selection emphasis

should lean toward spreader stokers. This type of stoker is more flexible in its capability to efficiently burn a wider range of coals.

3-13. Fly ash reinjection for coal firing.

a. General. A fly ash reinjection system for coal fired boilers is used to return coarse, carbon bearing particulate back into the furnace for further combustion. This is only economically justified in stoker fired boilers with steam capacities over 70,000 pph. Fly ash reinjection from the boiler, economizer, air heater and dust collector hoppers can improve boiler thermal efficiency by 3 to 5 percent. However, fly ash recirculation within the boiler is significantly increased.

b. Equipment sizing. Tube erosion and other maintenance costs in addition to requiring an increase in the capability of the air pollution control equipment are to be expected and must be taken into consideration when sizing the air pollution control equipment.

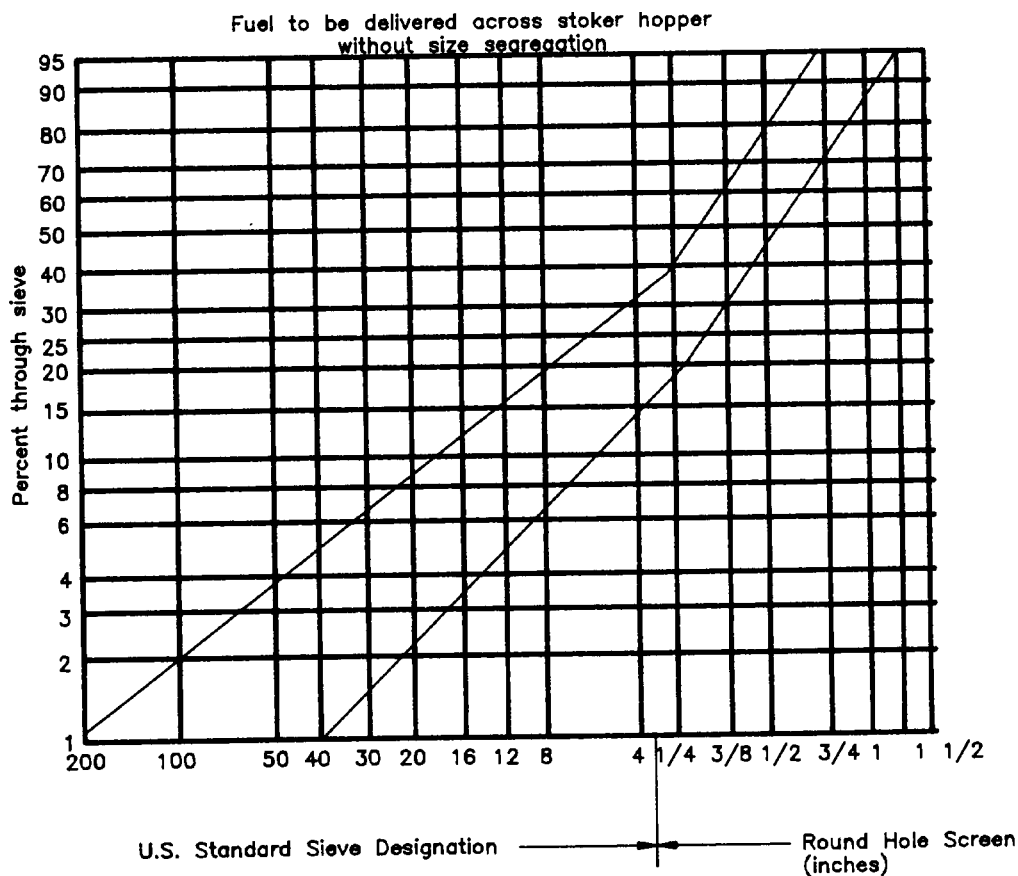


Figure 3-12. Coal Sizing Chart—Recommended Limits of Coal Sizing for Spreader Type Stokers.

Table 3-6. Stoker Selection Factors.

	Vibrating Grate Stoker		Traveling Grate Stoker		Traveling Chain Grate Stoker
	Crossfeed	Spreader Feed	Crossfeed	Spreader Feed	Crossfeed
Applicable Boiler Size, pph	100,000- 150,000	20,000- 150,000	100,000- 250,000	50,000- 250,000	20,000- 75,000
Maximum Grate Heat Release, Btu/ft ² -hr	400,000	600,000	450,000	750,000	450,000
Maximum Furnace Heat Release, Btu/ft ³ -hr	25,000	25,000	25,000	25,000	25,000
Coal Parameters					
Moisture %	0-10	0-10	2-15	0-10	2-15
Volatile Matter %	30-40	30-40	30-45	30-40	30-45
Fixed Carbon %	40-50	40-50	40-55	40-50	40-55
Ash %	5-10	5-10	6	5-15	6
Btu/lb (Mm)	12,500		11,000		11,000
Free Swelling Index (Max)					5
Ash Softening Temp, F (Reducing Stimulus)	2,300	2,300	2,200	2,300	1,900
Coal Size	1"x0"	1-1/4"x3/4"	1"x0"	1-1/4"x3/4"	1"x0"
Max Fines thru 1/4" Screen Max	40%	50%	60%	40%	60%
Stoker Turndown ¹ (Stable Fire)	3:1	3:1	3:1	3:1	3:1
Particulate Emissions 10 ⁶ Btu	1.0-1.5	1.4-10	0.6-1.5	1.4-10	0.6-1.5

¹To achieve this turndown rate, reference should be considered in the construction of the boiler for either membrane or welded wall construction or tube and tile type construction. Note some loss in boiler thermal efficiency will occur at lower loads.

Note: Coal sizing and quality have a direct influence on the efficiency of stoker fire boilers. These selection factors do not apply to those western fuels which have high moisture 25 percent or more content and have a lignite type ash characteristic.

3-14. Overfire air.

a. *General.* Overfire air is the ambient air supplied by either the FD fan or a separate fan that may also be used for fly ash reinjection and is used on all types of stoker fired boilers. The purpose is to aid combustion and to insure the coal particles are as completely burned as possible.

b. *Port location.* Overfire air ports are located on either or both the front and rear furnace walls.

3-15. Atmospheric circulating fluidized bed (ACFB) boiler components.

a. *Lower combustor.* Fuel is fed into the refractory lined lower combustor section where fluidizing air nozzles on the floor of the combustor introduce

air which controls the velocity of solids through the combustor. Ash must be removed from the bottom of the combustor to control solids inventory, bed quality, and prevent agglomeration of solids. Arrangement of tuyeres or air distribution devices must direct ash flow toward bed drains. Figure 3-13 shows the major ACFB boiler components.

b. *Upper combustor and transition zone.* The upper combustor is waterwall design. Solids and gases leave the combustor through a transition section which must account for three dimensional thermal expansion between the major boiler components.

c. *Solids separator.* The transition section with expansion joint connects the combustor to a solids separator. Two different separator designs include

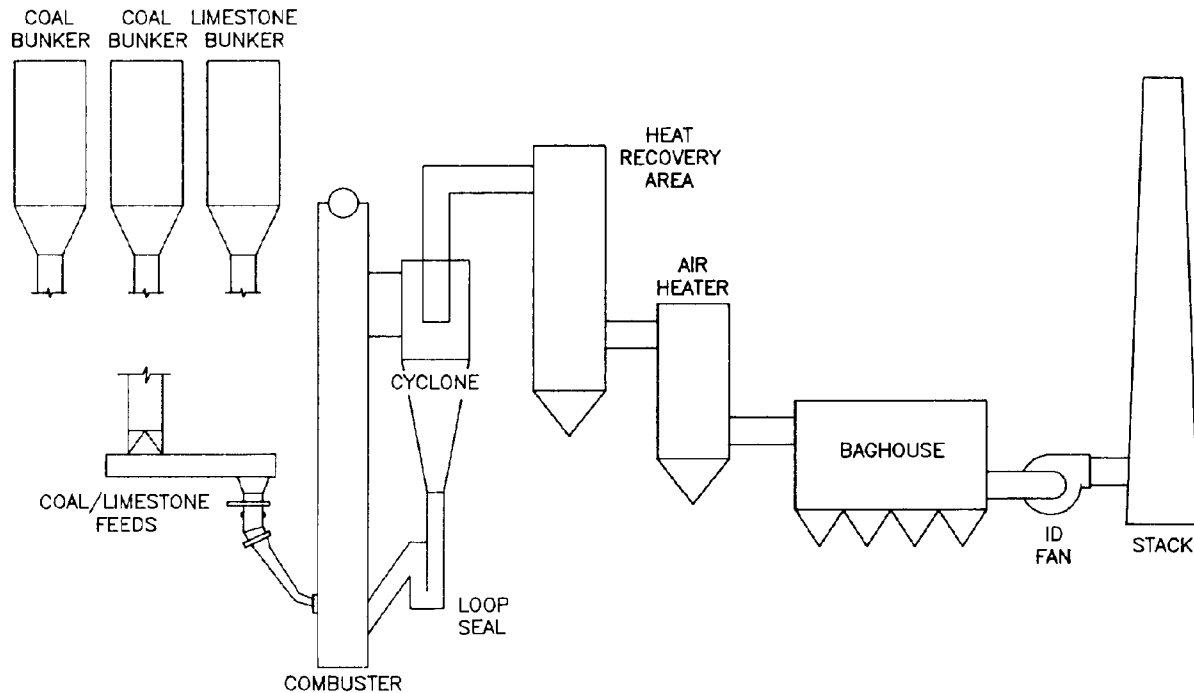


Figure 3-13. Atmospheric Circulating Fluidized Bed Boiler.

mechanical cyclone type and U beam. Cyclone separators are more common. Cyclones can be either water or steam cooled to reduce refractory thickness.

d. Solids reinjection device. Solids that have been removed in the separator are reintroduced into the combustor for additional carbon burnout and increased combustion efficiency. This recirculating loop is sometimes referred to as the “thermal fly wheel.” Solids reinjection devices consist of a refractory lined pipe with fluidizing air nozzles. This device is frequently called either a J-valve, L-valve or loop seal. Sorbent for sulfur capture enters the boiler either through the reinjection device or through separate feeders into the lower combustor section.

e. External heat exchanger (EHE). One design includes the use of an EHE to recover heat from recycled solids. Most manufacturers do not use an EHE due to problems encountered.

3-16. Boiler components.

a. Superheaters. Superheaters receive saturated steam from the boiler steam drum after having gone through the steam and water separating components within the steam drum. This steam should have a purity of 1 part per million (ppm) or better depending on the quality of the boiler water. The superheater is sized so as to add sufficient heat to the steam to obtain the desired final steam temperature. For units with a final steam

temperature of no more than 700 degrees F, boiler manufacturers will normally use a single section style superheater. Superheaters on coal fired units are of the pendant type and hence are not drainable. Further, superheaters are either exposed to the radiation of the fire in the furnace, or are located above a "nose" usually on the rear furnace wall that provides for a radiant-convection superheater surface. The design and construction of superheaters is in accordance with the ASME Boiler and Pressure Vessel Code that applies to the boiler. Normally, superheaters for boilers covered by this manual, will have tubes made of carbon steel, either SA-210 or SA-192, whereas the saturated or water carrying tubes of the boiler and furnace will be made of carbon steel type SA-178.

(1) For proper operation, particularly of pendant, nondrainable type superheaters, fluid pressure drop is needed to provide proper distribution of the steam through the tubes. It is desirable to locate the steam outlet connection at the center of the superheater outlet header for proper steam distribution, but end outlets are acceptable if proper design consideration is given to the flow distribution imbalances caused by the header configuration.

(2) A factor to be considered about superheater pressure drop is the power cost required for the boiler feed pump. The higher the pressure drop, the more pump power required.

(3) Another factor to be considered in superheater design is the flue gas velocity over the outside of these tubes. This flue gas velocity should normally be in the range of 55 to 60 feet per second (fps) in order to avoid external tube erosion from the fly ash particles entrained in this gas.

(4) Another factor to be considered for units with superheaters is the outlet steam piping and the shutoff valves. As the temperature approaches 700 degrees F at the superheater outlet, the steam piping material can be either SA-106B or 106C. This material has an allowable limit of 800 degrees F and a maximum allowable stress of 10,800 and 12,000 pounds per square inch (psi), respectively. The higher the steam temperature, the better and more expensive the steam piping material should be.

b. Air heater. Either recuperative (tubular) or regenerative (rotating plate type) air heaters may be used to heat combustion air on stoker fired boilers

firing lignite or subbituminous coal or any coal that has an inherent moisture content greater than 15 percent. Air heaters are normally not used on stoker fired boilers where the coal being burned has a caking tendency. Coal of the caking type is normally associated with areas such as the midwest. Air heaters are required on pulverized coal and ACFB fired boilers to heat the combustion air and the primary air. The use of either a recuperative or regenerative type air heater may be determined by space requirements, desired exit gas temperature, maintenance and related costs and other factors involved in a LCCA. The air heater reclaims some of the heat energy in the escaping flue gas and adds that heat to the air required for the combustion of the fuel. This not only decreases the heat loss to the stack, but also decreases the excess air required at the burner. Each 100 degrees F increase in air temperature represents an increase of about 2 percent in boiler unit efficiency.

Example:

	Input—MB/hr	Effcy. Increase x Percent	Load Factor x Hours/year	Fuel Cost Dollars x Per MB	Fuel Cost Savings Per Year
Air Heater example*	140	x 0.10	x 7,000	x 2.00	= \$196,000

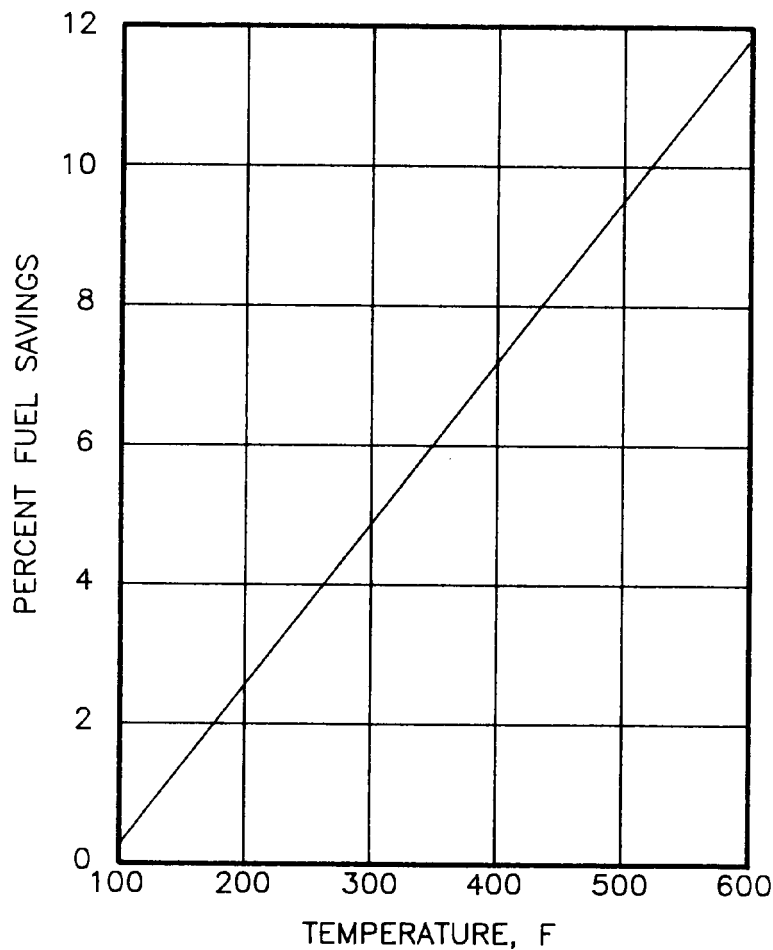
*Example assumes 100,000 lb/hr capacity, 140 MB/hr full load input, 10 percent efficiency increase with air heater, fuel cost \$2.00/MB, and MB = Million Btu's. Refer to figure 3-14 for fuel savings that can be realized by preheating combustion air. Regenerative type air heaters are suitable for a lower exit gas temperature dependent upon the dewpoint of the fuel to be burned. However, they are more susceptible to pluggage and the probability of requiring water washing should be built into the design of the unit. On the other hand, tubular heaters are also difficult to keep clean and in order to prevent excessive maintenance costs, retubing or manual cleaning, usually an exit gas temperature in the order of 300 to 350 degrees F is preferred.

c. Steam coil air preheaters. Steam coil air preheaters are used to heat air entering the air heater, recuperative or regenerative type, in order to raise the average cold end temperature to prevent acid dewpoint corrosion. This type of equipment is normally incorporated into the design of a boiler unit for low load operation and startup operation particularly in those areas with low ambient air temperatures. They are desirable in that the main air heaters, recuperative or regenerative, have corrosion sections that are more readily maintained. This type of air heater uses extended surface, normally referred to as fins, to reduce the overall size of this air preheater. The air pressure drop through the steam coil air preheater is generally limited to about 1 inch of water. It is generally located in the duct between the FD fan and the main air heater. However, in those areas that have extremely low ambient air temperatures, it is not uncommon to have an air preheater ahead of the FD fan that could preheat cold winter air up to about 40 degrees F.

(1) The source of the steam is normally low pressure, 100 psig or less, and it is frequently the exhaust steam from some other piece of equipment such as a steam turbine drive or other process that exhausts steam at a pressure of 15 psig or higher.

(2) When justified by a LCCA, the steam coil preheater drains may be individually piped to another receiver tank from which the condensate can be recovered. Drains to this receiver tank may need to be heat traced to prevent freezing. If a receiver tank is not justified by the LCCA, the air preheater drains will be piped to wastewater drains. The piping arrangement should conform to the steam coil manufacturer's recommendations. However, it should be noted that this is treated water and the cost for treating should be included in the cost analysis.

d. Economizers. Only bare tube economizers should be used on any coal fired boiler. Finned tube (extended surface) economizers should not be used on coal fired boilers as they are more susceptible to both pluggage and corrosion when used in



APPROXIMATE IMPROVEMENT IN EFFICIENCY WHEN HEATED COMBUSTION AIR IS USED IN BOILER UNITS.

Figure 3-14. Air Heater Fuel Savings.

conjunction with coal fired boilers. Another desirable feature of the bare tube economizer is that the tubes should be “in line” so as to have clear spaces between each tube. This arrangement enables the sootblowers to keep the gas lines clear. Extended surface economizers for gas and/or oil fired units offer economic advantages when compared to bare tube economizers. Extended surface economizers are lower first cost and have smaller installation space requirements. For oil fired boilers fin spacing should take into account the particular grade of oil to avoid fouling problems.

(1) The purpose of the economizer is to raise the temperature of the boiler feedwater while lowering the flue gas temperature. Economizer surface is usually less expensive than heating surface in either the furnace area or the boiler convection tube bank.

(2) In order to provide the required primary air temperature, economizers may not be used on some pulverized coal fired units. They are generally used on all gas, oil, and stoker fired boilers and as indicated in b above, and may be the only type of heat recovery used on some stoker fired boilers and the only type used on gas/oil fired boilers. Economizer sections on ACFB boilers are sometimes called “heat recovery areas (HRA)” and are an integral part of the boiler and are typically not furnished and manufactured by an economizer company. As a rule of thumb, with the common fuels (coal, oil, gas) steam generator efficiency increases about 2.5 percent for each 100 degrees F drop in exit gas temperatures. By putting flue gas to work, air heaters and economizers can improve boiler unit efficiency by 6 to 10 percent and thereby improve fuel economy.

Example:

	Input-MB/hr	Effcy. Increase x Percent	Load Factor x Hours/year	Fuel Cost Dollars x Per MB	Fuel Cost Savings = Per Year = \$117,600
Economizer example*	140	x 0.06	x 7,000	x 2.00	

*Example assumes 100,000 lb/hr capacity, 140 MB/hr full load input, 6 percent efficiency increase with economizer, fuel cost \$2.00/MB, and MB = Million Btu's.

Refer to figure 3-15 for fuel savings based on reduction of exit or flue gas temperature. Normally an economizer is less costly and requires less space than an air heater.

e. Sootblowers. Sootblowers are used on all heavy oil and coal fired boilers to clean ash deposits from furnace, boiler and superheater surfaces in addition to economizers and air heaters. Sootblowers will be spaced as specified by the boiler manufacturer to maintain unit efficiency and prevent coal ash pluggage. Ash deposits on the tubes may bridge the space between tubes unless stopped before such pluggage occurs. Sootblowers are used to keep the tubes clean in order to maintain tube cleanliness and hence efficiency.

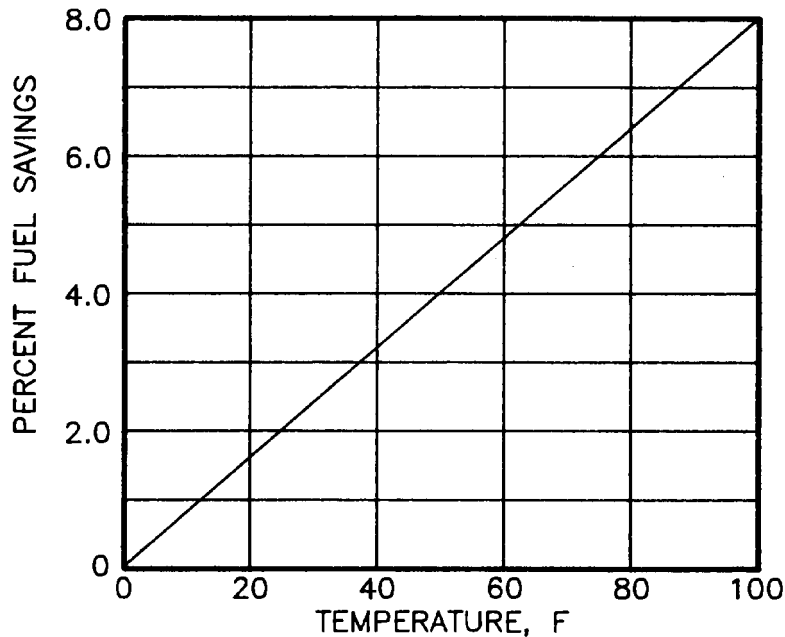
(1) Sootblowers may be either steam or air blowing.

(2) Unless water scarcity is an overriding factor, only steam should be used due to capital and operating costs of an air compressor and its

related system. The cost of water treatment for the steam consumption by the sootblowers is an evaluation factor.

f. Boiler casing or setting. The boiler casing or setting is the most visible component of the unit and if not properly designed may be the source of excessive maintenance costs and loss of boiler efficiency.

(1) The term boiler setting was originally applied to the brick walls enclosing the furnace and heating surfaces of the boiler. Since the boiler settings and casing have been the source of a large portion of boiler related maintenance and operating (heat loss) costs, a great deal of attention and improvements have taken place. This is particularly true of the recent past during which time boilers became so large that heat losses and maintenance costs would have been totally unacceptable. As the technology of water treatment plus boiler design and manufacturing improved, water cooled furnace



APPROXIMATE IMPROVEMENT IN BOILER UNIT EFFICIENCY AS FEEDWATER HEAT IS INCREASED.

Figure 3-15. Economizer Fuel Savings.

surface replaced the refractory setting. Casing, frequently 10 gage, was used to seal the refractory placed adjacent to the furnace tubes and backed with block type insulation. This construction is still in use on some small boilers applicable to this manual. However; the products of combustion, particularly with coal fired boilers, will cause corrosion to take place and air leaks will develop when the corrosive (mainly sulfur) substances come in contact with the relatively cool casing. The first signs of leakage will be the gases condensing and dripping through the casing. This condition led the manufacturers to place the casing behind the refractory and then insulating over the casing and protecting the insulation with galvanized or aluminum lagging. However, the latest and to date best design is the use of welded wall construction. Welded-wall construction positively contains internal flue gas pressure by seal welding metal plates between the tubes. Insulating materials cover the outside of the welded-wall tubes. Lagging is then placed over the insulation.

(2) The advantage of the welded wall construction currently being used by all major boiler manufacturers is that it virtually eliminates the flue gas corrosion that has taken place on the boiler casing. Another advantage is that it reduces air infiltration which in turn reduces exit gas temperature and fuel costs as well as the maintenance costs that were involved in repair of the refractory and insulation that previously existed. The design of boiler settings will include several considerations. High temperature air and corrosive gases will be safely contained. Air leakage will be held to a minimum. Heat loss is reduced to an acceptable level. Differential expansion of the component parts will be provided. The surface temperature should be such that it would not be a source of hazard or discomfort to operating personnel. If located outdoors, should be weatherproofed. The probability of injury or plant damage in the event of an explosion will be reduced. The use of welded wall construction and its inherent strength is probably the most imperative reason for the current design of boiler settings.

g. Flue and ducts. Flues and ducts will be designed to operate at the pressure and temperature to which they are subjected. As a general rule, the following velocities will be used in arriving at the cross-sectional flow area of boiler flues and ducts. Cold air ducts—2000 to 2500 fpm. Hot air ducts—3000 to 3500 fpm. Gas flues upstream of particulate collection equipment—2,500 to 3,000. Gas flues—3500 to 4000 fpm. It should be noted that velocities can be higher at elevated temperatures because the air or gas is less dense and

therefore has less impact energy. Directional or straightening vanes should be used at bends in ductwork to minimize turbulence or draft loss.

h. Desuperheaters. Normally on boilers with an outlet superheat temperature of no more than 750 degrees F, desuperheaters will not be used. However, if the steam is used for a process at a lower pressure and the temperature may be harmful or unwanted, a desuperheater can be installed in the steam line to control the desired temperature. Water for this device will normally be obtained from the boiler feed pump or a separate pump. The source of the water used by the desuperheater will be such as deaerating heater and will be of the same quality as used in the boiler. If a desuperheater is used and the discharge of the device is into the superheater, the water and entrained impurities will be sprayed into the superheater tubes.

i. Fan blades and applications. Table 3-7 provides a summary of available fan blade types and their respective applications. Individual fan types are more fully described in paragraph 7-12 of this manual. Items that must be identified for the design of a particular fan application include: anticipated flow of air or combustion gas (pph), temperature of air or gas (degrees F), density of air or gas (pounds per cubic foot, lb/ft³), fan inlet pressure (inches water gauge, in. wg), fan outlet pressure (in. wg), and fan curves of applicable fan types.

Table 3-7. Fan Blades and Applications.

Fan Blade Type	Application
Backware Inclined	Hot Primary Air (HPA)
Backward Curved	Cold Primary Air (CPA)
Hollow Air Foil	FD, ID, CPA, OFA, BF
Radial	FD, OFA, ID, BF
Open Radial	HPA, OFA, ID, FTB
Radial Tip	Pulverizer Exhauster
	CPA, ID
FD - Forced Draft.	
ID - Induced Draft.	
HPA - Hot Primary Air.	
CPA - Cold Primary Air.	
OFA - Overfire Air.	
BF - Booster Fan.	
FTB - Fly Ash Transport.	

j. Fan inlet. The following guidelines apply to the fan inlet design.

(1) Intake areas will be at least 20 percent greater than the fan wheel discharge areas.

(2) Fans positioned next to each other will be separated by at least six fan diameters and a separation baffle.

(3) Fans will have turning vanes or inlet boxes, or four to five diameters of straight duct at the inlet. The FD, PA, or Overfire Air (OFA) fan inlets located too close to building walls will have splitters.

(4) Where the duct arrangement imparts a swirl to the inlet of the air or gas, the swirl will be in the same direction as the fan rotation.

(5) All fans will use inlet bells to insure a smooth air or gas flow at the fan inlet.

k. *Fan outlet.* For a minimum pressure drop, there will be three to six diameters of straight duct at the fan outlet.

3-17. Boiler water circulation and chemical treatment.

a. *Water circulation.* A description of the internal or water/steam-circulation features of water-tube boilers is listed below:

(1) The limits of the capability of a boiler is determined by water circulation and the feedwater and boiler water treatment. Boilers that do not circulate properly will rupture tubes in a very short period of time when operated at or near rated load. Such items as superheat and tube metal temperatures as well as fire side design considerations, physical limits of firing equipment and air and gas fan and their physical limits are not being overlooked.

(2) The basic design of boilers and the size pressure and temperature range of this manual are at the lower end of the technology scale.

(3) The American Boilers Manufacturers Association has set certain standards for boiler water limits. Table 3-8 shows the allowable concentrations for boiler water. These conditions are normally stated in proposals submitted by those manufacturers. They should be considered minimums for feedwater and boiler water treatment. All reputable feedwater treatment consultants or vendors will be able to meet and improve on the conditions required for the operating conditions of boilers covered by this manual.

Table 3-8. Boiler Water Concentrations.

<i>Operating Pressure psig</i>	<i>Total Solids ppm</i>	<i>Total Alkalinity ppm</i>	<i>Suspended Solids ppm</i>
0-300	3500	700	300
301-450	3000	600	250
451-600	2500	500	150
601-750	2000	400	100
751-900	1500	300	60
901-1000	1250	250	40

American Boiler Manufacturers Association
Stipulation in Standard Guarantees on Steam Purity

(4) Boilers should not be operated at capacities or pressure and temperature conditions not anticipated by the manufacturer.

(5) As previously stated, boilers with superheaters are guaranteed to meet a 1 ppm steam purity condition leaving the steam drum. Boilers without superheaters can be guaranteed to meet a 3 ppm steam purity limit; or in the case of some low pressure, 150 psig saturated and lower, boilers used for heating or similar conditions may only be required to meet a 0.5 percent moisture condition. These limits are not stringent if the proper feedwater treatment is used and the proper equipment incorporated in the plant design. In addition, the operators must make proper use of the boiler water blowdown and the addition of the chemical treatment. Steam drum internals are revised when lower guarantee limits are stated. In fact at times, manufacturers may rely on natural separation of steam and water within the steam drum. In this case they may eliminate all steam drum internals except a dry pipe or other such collecting device.

(6) In referring to the proper feedwater treatment and operation of the boiler blowdown and chemical treatment, attention to these items will pay off in the long run in reduced maintenance, retention of design efficiency and minimum cost of feedwater treatment chemicals through elimination of tube deposits and steam carryover problems.

(7) Figure 3-16 graphically describes the difference in the specific weights per cubic foot of water and saturated steam at various pressures up to approximately 3200 psig. This chart illustrates their ratio which may be considered a margin of safety. For boilers operating in the range of 150 to 400 psig, depending on the boiler design, location of the tube in the furnace or boiler area, slope, and other similar conditions, the ratio of pounds of water circulated to the pounds of steam entrained and then released from the steam drum is very approximately 30 to 15 to 1. This ratio decreases quite rapidly as the operating pressure rises. Circulation is assisted by the height of the boiler as well as the burner heat input located at the bottom of the U-tube which acts as a thermal pump.

b. *Chemical treatment.*

(1) Oxygen (O₂) is one of the more troublesome components of feedwater. It is readily removed by proper operation of the deaerating heater together with a minimum water temperature of approximately 220 degrees F leaving that heater. Frequently a chemical O₂ scavenger such as sodium sulfite or hydrazine is used in the boiler feedwater

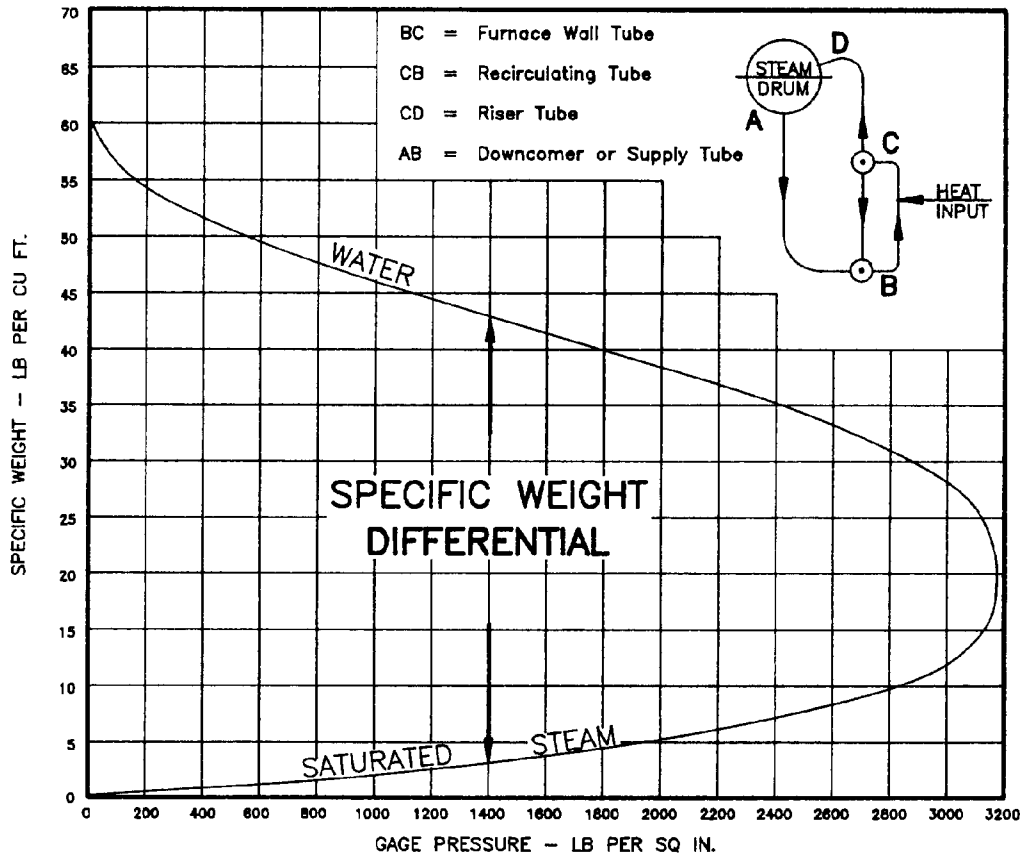


Figure 3-16. Specific Weight Differential of Water to Steam.

to make sure any residual dissolved O₂ is not permitted to pit the tubes.

(2) Water hardness, expressed as calcium carbonate (CaCO₃) in ppm should be as close to zero as possible under all conditions. This can be accomplished by proper feedwater treatment and boiler water testing.

(3) Another item of importance is to maintain the proper acidity or alkalinity (pH value) reading of the boiler water. For boilers in the range of this manual, a pH reading of 9.0 to 10.5 should be acceptable depending on the chemical composition of the water source and the type of treatment used. In the latter category, some of the more common types of treatment are: sodium zeolite, hot lime zeolite, phosphate hydroxide and coordinated phosphate. In some cases the use of a demineralizer or evaporation may be desirable. These latter methods are more appropriate for higher pressures and temperatures in a steam cycle that has more complex problems due to the source of water for the boiler or boilers. These water treatment methods are addressed in more detail in chapter 7.

c. Boiler internals. Figures 3-17 and 3-18 indi-

cates the steam drum internals showing the chemical feed line and the continuous blow pipe in addition to the feedwater line. The diameter and length of the drum are determined by the capacity of the boiler in the number of primary or cyclone separators needed. These devices in addition to separating steam and water, aid water circulation by a reactive (pumping) action that promotes water flow along the length of the steam drum.

(1) The drying screen or secondary scrubbers further separates the steam and water particles so that the steam leaving the drum meets the desired steam purity condition. Another feature of the steam drum is the reserve water holding capacity which permits load swings besides being the collecting and distribution point of the steam.

(2) The primary function of the lower (mud) drum is to complete the circuit for the tubes in the boiler section and generally to act as a water reservoir and supply source for the lower furnace wall headers and tubes connected thereto. Except in unusual cases, the lower drum has no internals. It should be sized so that maintenance people can roll tubes into the drum holes as well as inspect those tubes. Some designs may permit rolling of

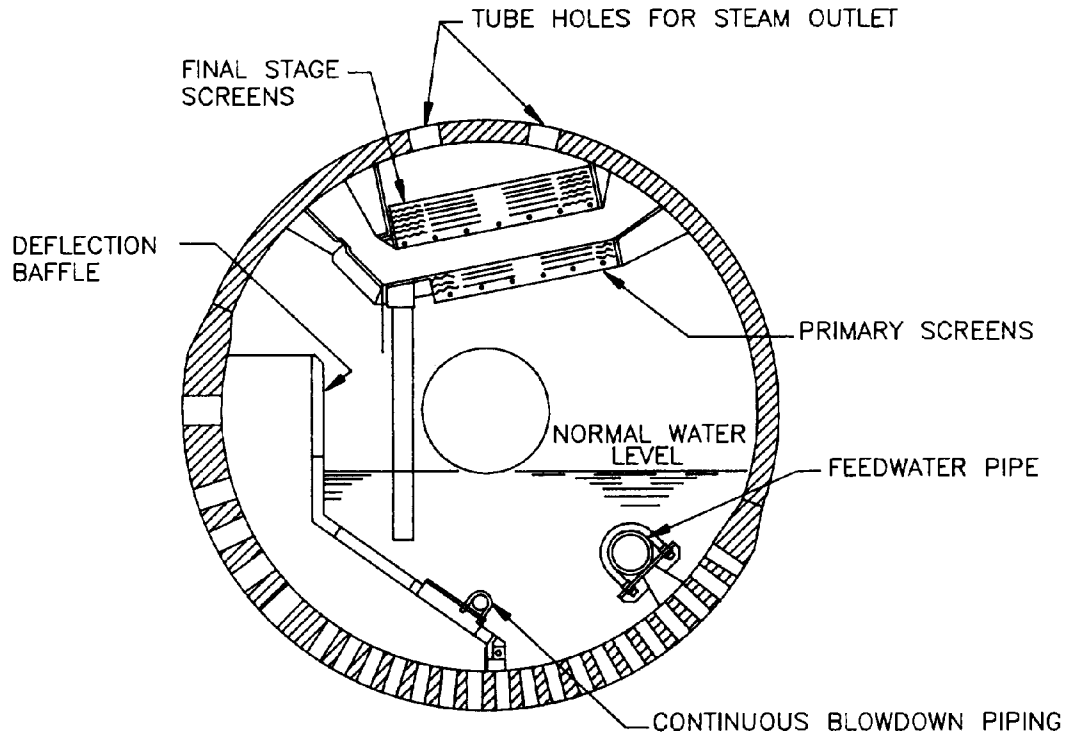


Figure 3-17. Steam Drum Internals-Baffle Type.

the tubes through inspection or handhole access ports.

(3) The amount of heating surface in the furnace and its configuration is generally arranged to suit the firing method, and to provide the necessary time and space for complete combustion of the fuel. Firing methods include gas, oil, pulverized coal, stoker fired, and atmospheric circulating fluidized bed. The particular fuel(s) fired also impacts design. The boiler bank is sized in conjunction with the furnace and superheater to provide the steam capacity as well as to lower the exit gas temperature to the value required. The economizer, if provided, is sized to lower the exit gas temperature to the desired value without getting into a (steaming) condition under normal operating conditions. Generally this means the economizer is sized to permit a 25 to 50 degrees F margin between the exit water temperature and saturation temperature at operating conditions. The air heater, if provided, is sized to provide the desired air temperature to the pulverizers or stoker as well as to lower the exit gas temperature to the desired value.

(4) Fitting the size of each component into the most efficient and least expensive unit is the function of the boiler manufacturer and their

engineering staff. In addition to the various mathematical approaches for sizing these components a good deal of this design is based on years of experience with its empirical data as well as various manufacturing considerations.

3-18. Boiler stacks.

a. General. In boiler operation applications, the stack flue gas temperature will be below the dew point a considerable amount of the time due to low loads, start-up and shutdown, plus normal weather conditions. Drainage of water should be provided due to operating conditions as well as rain and snow. Some of the factors to consider in stack design are:

(1) Flue gas conditions. The erosive and corrosive constituents, dew point temperature, and maximum temperature if bypassing the economizer or air preheater.

(2) Temperature restrictions which relate to the methods of construction and the type of stack lining material to be utilized.

(3) Stack and lining material must be selected to withstand corrosive gases (related to sulfur in the fuel).

(4) Wind, earthquake and dead loads, which includes the moment 1 load from deflection.

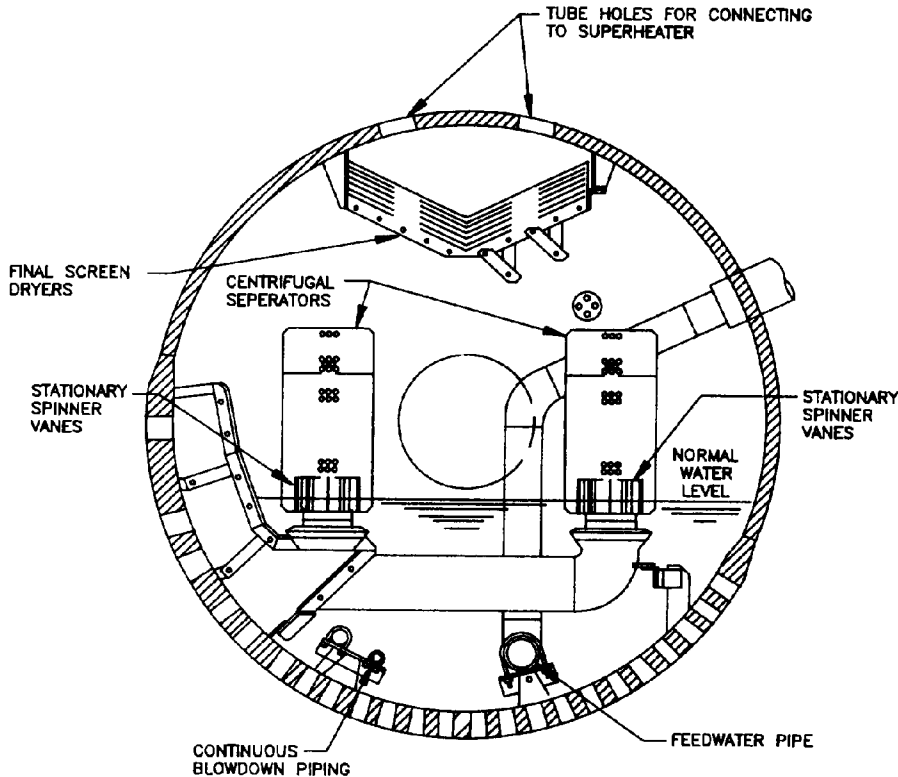


Figure 3-18. Steam Drum Internals-Perforated Centrifugal Type.

(5) After structural adequacy has been determined, both static and dynamic analyses should be made of the loads.

(6) With welded steel stacks, a steady wind can produce large deflections due to Karmen Vortices phenomenon. If the frequency of these pulsations is near the stacks natural frequency, severe deflections can result due to resonance.

(7) The plant location, adjacent structures, and terrain will all affect the stack design.

(8) Cleanout doors, ladders, painter trolleys, EPA flue gas testing ports and platforms, lightning protection and aviation warning lights will be provided, as required.

b. Stack design. The stack height calculations are for the effective stack height rather than the actual height, this is the distance from the top of the stack to the centerline of the opening of the stack where the flue gas enters. Air and gas flow losses through the inlet air duct, air heater (air side), windbox, furnace and passes, air heater (gas side) or economizer, gas cleanup equipment and other losses through duct and breeching should be plotted and overcome with the fans. The kinetic discharge head, the friction losses at the entrance to

the stack, and friction losses in the stack should be provided by the natural draft of the stack. Barometric pressures adjusted for altitude and temperature must be considered in determining air pressure. The following stack parameters must be determined:

- (1) The extreme and average temperatures of ambient air and gas entering the stack.
- (2) All heat losses in the stack (to find mean stack temperature).
- (3) Altitude and barometric corrections for specific volume.
- (4) Gas weight to be handled. The infiltration of air and combustion air into the stack casing and ductwork must also be considered.
- (5) Stack draft losses due to fluid friction in the stack and kinetic energy of gases leaving the stack.
- (6) The most economical stack diameter and the minimum stack height to satisfy dispersion requirements of gas emissions.
- (7) The stack height for required draft. (Where scrubbers are used, the temperature may be too low for sufficient buoyancy to overcome the stacks internal pressure losses.)

(8) A static and dynamic structural analyses must be made of the wind, earthquake, dead, and thermal loads. Vortex shedding of wind loads must be considered to be assured that destructive natural frequency harmonics are not built into the stack.

d. Stack construction. The stack height and diameter, support, corrosion resistance, and economic factors dictate the type of construction to be utilized.

(1) Stacks are generally made of concrete or steel because of the high cost of radial brick construction. If stack gases are positively pressurized, or if flue gases will be at or below the dew point of the gases, corrosion resistant linings must be provided; linings must be able to withstand temperature excursions which may be experienced in the flue gas if flue gas scrubbers are bypassed.

(2) Stacks of steel or concrete construction will be insulated to avoid condensation by not allowing

the internal surfaces to drop below 250 degrees F. This requirement does not apply when scrubbers are used with low temperature discharge (150 to 180 degrees F) into the stack because the flue gas is already below dew point temperature.

(3) A truncated cone at the top of the stack will decrease cold air downdrafts at the periphery of the stack and will thus help maintain stack temperature, but stack draft will decrease considerably.

3-19. Adjustable Speed Drives.

Significant electrical power savings can be realized at reduced boiler loads by installing adjustable speed drives (ASD) on ID and FD fans. The economics of ASD's depend on the boiler load profile (number of hours at different loads). The feasibility of ASD installation should be verified by an LCCA.

CHAPTER 4

AIR QUALITY CONTROL AND MONITORING EQUIPMENT

4-1. General.

Refer to TM 5-815-1 for a detailed description of the major air quality control devices available for boiler plant emissions control. Air pollution control guidelines are discussed in AR 42049.

4-2. Particulate control systems.

The types of particulate control systems which are commonly used are mechanical cyclone collectors, fabric filter baghouses and electrostatic precipitators.

4-3. Flue gas desulfurization systems.

The dry and wet types of FGD systems are commonly used to remove sulfur oxides from the boiler flue gas.

4-4. Nitrogen Oxide (NO_x) control systems.

Two types of systems available for NO_x emissions reduction are selective catalytic reduction (SCR) and selective noncatalytic reduction (SNCR). SCR systems require periodic replacement of the catalyst. SNOR removal efficiency is maintained only within a narrow temperature range.

4-5. Air monitoring equipment.

a. General. Federal regulations require new sources to obtain and maintain acid rain permits. A permit is good for five years and must be renewed. Emission allowances are required to emit sulfur dioxide. Pollutants must be monitored to verify compliance with the acid rain program. Reported values include SO₂ (lb/hr), NO_x (lb/MB), CO₂ (lb/hr), excess opacity (percent), and heat input (MB). Measurement options are available to gas/oil fired units, depending upon the type or category of gas/oil unit. Exemptions from acid rain permit requirements including exemptions from continuous emissions monitoring (CEMS) are available to certain types and sizes of emitters by petition. A thorough investigation of local, state, and federal regulations is required for each new source.

b. CEMS components. CEMS include four major components or subsystems. Gas monitors measure the concentration of pollutants at a particular point in the flue gas stream. Flow monitors measure flue gas flow and fuel flow monitors measure natural gas and fuel oil flow rate. Opacity monitors indicate the emission of particulate matter from the stack.

The data acquisition system (DAS) stores monitored information, performs necessary calculations and generates the required reports.

c. Gas monitors. Gas monitors can be classified as either in situ or extractive.

(1) In situ analyzers are attached directly to the probe on the stack or breeching. Access for routine maintenance is required and personnel weather protection may also be desirable for outdoor installations depending upon the climate. In situ monitors relay information to the DAS using 4 to 20 mA signals.

(2) Extractive monitors pull samples from the flue gas stream using stack or breeching probes. The flue gas sample is then transported to the cabinet mounted analyzer located on the plant floor or ground level as required. This cabinet is placed to provide convenient access for operation and maintenance. The interior of the cabinet can also include any necessary heating, air conditioning or humidity control. Extractive systems are further classified as either wet, dry or dilution. Since raw samples contain SO₂ and moisture, ambient cooling of wet samples will cause condensation of sulfuric acid. For longevity of the equipment wet sample tubes must be heated to avoid acid corrosion. Removal of water from the sample using a cooler provides a dry sample which no longer requires heating. These systems are called dry extractive. Dilution extractive systems use clean dry air to dilute the sample gas in the probe from between 50 to 200 times. This diluted sample eliminates the need for heat traced sample lines, pumps, filters or dryers. Analyzers are readily available to accurately and reliably measure diluted pollutant concentrations.

d. Flue gas flow monitors. Monitoring of flue gas flow is sometimes required. In these cases flue gas flow is used along with the primary measured value to calculate the reported value. Three types of flue gas flow monitoring systems that have been used include ultrasonic monitors, thermal monitors and differential pressure monitors.

(1) *Ultrasonic flow rate monitors.* Ultrasonic flow monitors consist of two ultrasonic transducers mounted at different elevations and on opposite sides of the stack. This type of monitor measures the time required for an ultrasonic pulse to travel from the downstream transducer to the upstream transducer. The speed of sound in the flue gas stream and the flue gas stream temperature are

determined from the average of these two measurements. The velocity of the flue gas stream is determined from the difference between the measurements. An input signal from the plant barometer can be provided so that flow rate can be calculated in standard cubic feet per minute. Automatic zero checks of ultrasonic flow monitors are conducted by sending successive pulses in the same direction. Span checks are conducted by again firing successive pulses in the same direction, but with a time delay between the pulses which represents a specific flue gas flow velocity.

(2) *Thermal flow rate monitors.* Thermal flow monitors depend on temperature measurements and thermal properties of the flue gas. There are two types of thermal measurement. One type measures the temperature difference between two similar resistance temperature devices (RTD), one is heated at a constant rate and the other is unheated. The temperature difference will be a function of the velocity of the flue gas. The higher the velocity, the greater the cooling effect, and hence the smaller the temperature difference. The other type of thermal probe varies the current to the heated element as necessary to maintain a constant temperature difference. The higher the velocity of the flue gas, the greater the heat rate required to maintain the temperature differential. Zero and span checks of these devices require their removal from service. Techniques for conducting automatic daily calibration drift tests have not yet been developed.

(3) *Differential pressure flow monitors.* Differential pressure flow monitors use the pitot tube principle to measure the flow. A pitot tube is a device which measures both the static pressure and the impact pressure created by the flue gas. The square root of the difference in these two pressures is a function of the gas velocity. Types include single point and across-the-duct averaging. One version of the averaging pitot probe has a diamond shaped cross-section and multiple impact and static pressure taps along the length of the probe. Standard differential pressure transmitters are used to sense the difference between the static and total pressure. These devices are simple and use standard pressure transmitters. In high particulate applications, a purge system may be needed to keep the pitot pressure taps clear. Zero checks are accomplished by pneumatically connecting the two sides of the pressure transmitter. These checks can easily be automated for daily zero drift checks. Span checks can be performed by using a water manometer. This type of span procedure is more difficult to automate.

e. Opacity monitors. Opacity monitors use the principle of transmissometry to indicate the level of

particulate emissions. A beam of light is projected across the flue gas stream. A measurement detector registers variations in the light transmittance caused by the amount of particulate in the flue gas.

f. Data acquisition systems. Data acquisition systems (DAS) typically consist of personal computers (PC). A typical system includes a central processing unit (CPU), hard disk drive, a floppy disk drive, a keyboard, a cathode ray tube (CRT) or TV screen and a printer. Serial ports and required software are included to accept the input signals from the monitoring equipment. The hard disk drive provides magnetic storage of data and allows quick access for rapid calculation. The floppy disk drive allows storage of years of historical data in more than one remote location which decreases the risk of losing this information while at the same time provides rapid regeneration of past reports. The printer provides hard copy of all data while the keyboard and CRT allow operator interface. The DAS performs several tasks. Signals from the monitors must be interpreted and stored. This data is stored in the form of ASCII files. A continuous readout of emissions in the required measurement units is produced. The DAS performs monitor calibration errors and bias adjustments. Missing data procedures are also computed and recorded by the DAS. Required reports are also generated by the DAS.

g. Regulatory requirements. The regulations include several specific equipment requirements. These include span values, calibration capabilities, calibration error limits, relative accuracy, bias limits, calibration gas quality and cycle response time.

(1) Proper monitor location for specific installations is essential. The final location must be representative of total emissions, must pass the relative accuracy (RA) test and must meet point/path requirements as outlined in the regulations. Location has to provide representative flow over all operating conditions. This requires that the velocity at sample point be representative of the average velocity over the cross section. Emission rate in terms of lb/MB must reflect actual emissions. Monitor location must also represent actual pollutant concentration. Location has to minimize the effects of condensation, fouling and other adverse conditions. Tests are also required to determine the acceptability of the location and to also determine the number and location of flow monitor points.

(2) There are specific reporting requirements that have to be addressed. Notification must be given to governing federal, state and local agencies prior to certification and recertification tests. A

monitoring plan must be established. Applications have to be submitted for certification and recertification tests. Quarterly reports and opacity reports are also mandatory.

(3) The monitoring plan although not part of the GEMS specifications has several elements that are common to both. Monitoring plans include pre-certification information, unit specific information, schematic stack diagrams, stack and duct engineering information, monitor locations, monitoring component identification table, DAS table and emissions formula table.

(4) Records have to be maintained for at least three years. Record keeping includes current monitoring plan, quality plan and hourly operating data. Hourly data must include date, hour, unit operating time, integrated hourly gross unit load, operating load range and total heat input in MMBtu.

(5) The certification tests have to be successfully executed on time. These tests include a 7 day calibration error test for gases and flow, a linearity check, cycle time/response time test, relative accuracy test and bias test. Guidelines clearly outline whether or not recertification tests are required when changes have been made to equipment, location or the DAS.

(6) Quality assurance and quality control procedures must be developed into a well defined program which includes calibration error testing and linearity checking procedures, calibration and linearity adjustments, preventative maintenance auditing procedures or relative accuracy test audit (RATA). Calibration error tests have to be performed on a daily basis. SO₂ and NO_x monitors must be challenged by zero level and high level calibration gases. The measured values must be within 2.5 percent of the cal gas value. If the span is less than 200 ppm then the values must be within 5 ppm. CO₂ or O₂ monitors also have to be challenged by zero level and high level calibration gases. For these monitors the measured value must be within 0.5 percent of the cal gas value. Flow monitors are required to zero at 20, 50 and 70

percent of span. The measured values have to be within 3 percent of the referenced value. Linearity checks are required quarterly. These checks must use dedicated low, mid and high level cal gases. Measured values must be within 5 percent of the cal gas value. Average difference among three nonconsecutive checks with each cal gas must be less than or equal to 5 ppm for SO₂ and NO_x or less than or equal to 0.5 percent of CO₂ or O₂.

(7) Several daily adjustments are required. Error adjustments on gas and flow monitors are required daily. Recalibration must then be performed after each adjustment. A flow monitor interference check is necessary. This includes sample sensing line port pluggage and RTD/transceiver malfunction. An out of control period is when calibration error exceeds two times the calibration error limit or when flow fails interference check. Data recording must include unadjusted values and magnitude of adjustment.

(8) Quarterly adjustments are also required. Linearity must be checked on a quarterly basis when no adjustments are made. Leak checks are required for differential pressure monitors. An out of control period is when linearity exceeds limit on any test run or when a flow leak is detected.

(9) Preventive maintenance procedures must be in writing, including equipment manufacturer's recommendations. A schedule for the implementation of these procedures has to be maintained. An inventory of spare parts is also required.

(10) A relative accuracy test audit (RATA) is required semi-annually unless accuracy is better than 7.5 percent. The RATA has to be performed during a 7 day period. A minimum of 9 sets of reference method test data are needed. One set of data consists of a 3 point traverse at 0.4, 1.2 and 2.0 meters from the wall of the stack or duct. The gas sample must be analyzed for concentrations or flow using the reference methods. Calculations must include determinations of the mean, standard deviation, confidence coefficient and bias. A flow test is required.

CHAPTER 5

FUEL AND SORBENT HANDLING AND STORAGE

5-1. General.

This chapter addresses requirements for fuel handling and storage systems for gas, oil and coal fired boiler plants. Solid fuel policies and procedures are discussed in AR 420-49. Criteria for petroleum product storage and distribution is also prescribed in AR 420-49. While not intended to give the reader a complete in-depth study of handling and storage system design, it is written to give a basic understanding of how to select handling and storage system equipment for a small to medium size boiler plant.

5-2. Gas design considerations.

a. Natural gas is not stored on site. It is furnished through the supplier's pipeline. The takeoff line from the pipe is either furnished by the customer or subsidized by the gas company depending upon how the contract is negotiated. Liquefied petroleum gas (LPG) is stored on site in specially built tanks that can either be leased or purchased.

b. Gas piping will be in accordance with ASME B31.8, Gas Transmission and Distribution Piping Systems.

5-3. Oil design considerations.

a. Fuel oil piping systems require special consideration for connections on small pipes. Small threaded fuel oil piping tends to leak due to the penetrating action of oil under pressure. For this reason it is recommended that pipe 2 inches and smaller be socket welded.

b. Fuel oil storage tank design and installation will include spill containment and leak detection. Spill containment can be in the form of a double wall tank or a berm as in the case of above ground installations. Leak detection can be electronic using alarms or it can be visual. An example of a visual system is the leak detection technique of providing underground drainage to a single point next to an above ground storage. A vertical pipe is routed from this point to above ground for periodic visual inspection. A removable cap is used to prevent rain water from entering the pipe.

5-4. Sorbent and alternate fuel considerations.

a. Sorbent or limestone is used for sulfur emissions reduction on atmospheric circulating fluidized bed (ACFB) boilers. Sorbent is transported to the

site by truck or rail cars. Sorbent is conveyed pneumatically beginning with site storage if required in a silo and plant storage in a limestone bunker. Pneumatic systems are further discussed in this chapter and also in chapter 6. Bunker design should accommodate all possible sorbents being considered. Cylindrical silos and bunkers are commonly used for sorbent storage. Bunker design considerations for sorbent are similar to coal and are discussed in more detail later in this chapter. It is important to measure the amount of limestone going into the combustor. This is done using a belt scale at the outlet of the bunker. The belt scale discussion later in this chapter is applicable.

b. Alternate fuels such as petroleum coke can be handled similar to coal. Because of the variance of properties within a single fuel type and especially between fuel types, each system will be designed for the fuel being considered and the unique site conditions and operating scenarios.

5-5. Coal handling design considerations.

a. Developing conceptual designs. The process of selecting and laying out coal handling system components should systematically proceed through three preliminary phases before any detailed design work is performed: setting design criteria, evaluating design alternatives, and developing a flow schematic. The design criteria should address such factors as plant location, climatic conditions, available land, system requirements, types of boiler (stoker or pulverized coal) amount of coal storage, conveying rate and method of coal delivery. After these basic criteria have been established, the designer should present a number of different options that will fit them. The feasibility of each option should be examined, and its advantages and disadvantages should be listed and compared to the other alternatives. Because the lowest capital cost system is not always the most economical system, an LCCA will then be made for each of the different design alternatives, taking into account the following considerations: Capital investment costs, operating costs, and maintenance costs. As a final stage of the preliminary design effort, a coal flow schematic as shown in figure 5-1 will be prepared showing each process and piece of equipment the coal is moved through before reaching the plant storage bunkers.

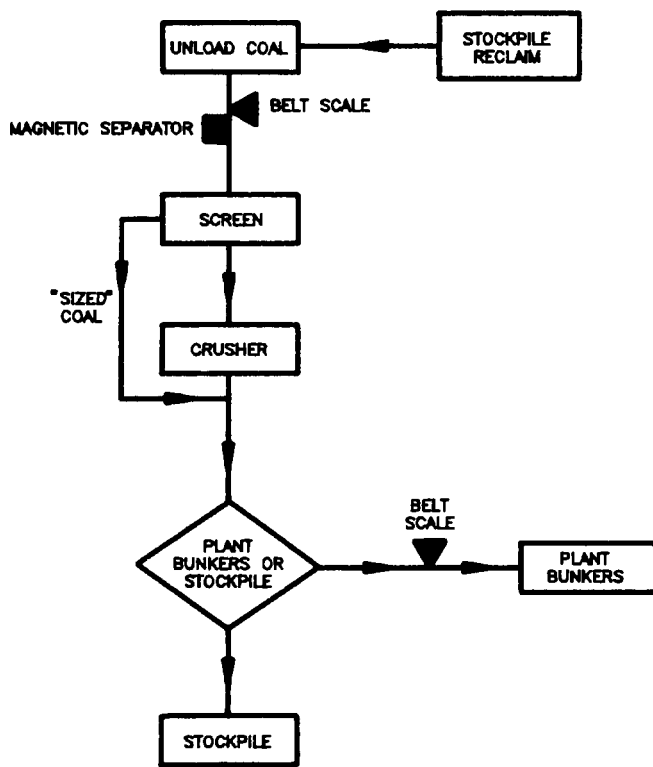


Figure 5-1. Typical Coal Flow Schematic.

b. Climatic conditions. Annual temperature extremes, rainfall, seismic zone and wind conditions will all affect coal handling equipment selection. Hostile equipment environments can dictate what type of conveying system is to be selected.

c. Coal conveying rate. The design conveying rate of the coal handling system depends on the maximum daily coal burn rate of the steam plant, including future increases in coal requirements due to plant expansion. Maximum daily coal requirement is computed by using the maximum continuous ratings of all the boilers and conservative values for boiler efficiency and coal heating values. Once the maximum daily coal burn rate is established, the maximum allowable operating time per day must be defined to arrive at the design conveying rate. It is general industry practice to select the design conveying rate of the coal handling system so it can transport the maximum daily coal requirements to the steam plant in a single eight hour shift allowing seven hours of actual operation time. This criteria allows coal to be handled during the daylight hours and provides adequate time for maintaining the equipment in good operating condition. The amount of running time for an Army Ammunition Plant (AAP) should not be confined to the eight-hour per day limitation. The amount of time that the AAP would be operating at the full mobilization condition has historically been for relatively short periods of time

over the life of the plant. One and one-half shifts per day of running time for a coal handling system at full mobilization would be a reasonable criteria to use.

(1) The conveyor should be operating with the belt fully loaded and at minimum speed for the required amount of material to be handled per hour. There is no advantage to be gained by running conveyors at high speed while only partly loaded.

(2) The full load on the belt will be considered as approximately 80 percent of the cross sectional load area of the conveyor belt which must take into account that load carrying width is several inches narrower than the actual belt width.

(3) Maximum belt speed for 24, 30 and 36 inch wide conveyors will not exceed 600 fpm and maximum 800 fpm for 42, 48, 54 and 60 inch wide belts and maximum 1,100 fpm for 72-inch wide belts that carry coal. Wider belts should be limited to 600 fpm if possible. Conveyor belts smaller than 24 inches wide will not be used.

d. Coal characteristics and constituents. Designing for a single homogeneous coal type is generally no longer feasible. Where multiple coals will be burned, the conveyer designer must consider the worst case for his or her design based on coal ranking (according to ASTM standards), particle size and shape (sieve analysis), coal density, moisture content, corrosiveness and abrasiveness, sulphur content, angles of repose and surcharge, safe angle of incline, and coal grindability index. Each factor or combination of factors can dictate the type or size of crusher, transfer chute or conveyor that can safely be used to handle the material. The physical and chemical characteristics of coal make it one of the more difficult bulk solids to handle. Care must be taken by the designer to make sure that he is fully aware of the properties of the coal that is to be handled. A system designed for a western subbituminous coal will not be suitable for an eastern coal, and due to the variable constituents, each different type of coal will have a direct influence on air pollution devices, boiler and equipment design and material handling equipment design.

e. Conveying western coal. Because of the increasing use of western, low-sulfur coal in recent years, the designer must take into account that equipment sized to handle a given quantity of eastern coal cannot usually handle the same quantity of western coal, even though the conveyor has been sized to handle the lower density and surcharge angles of western coals. This is partly due to the vastly different range of flow characteristics that are inherent in western coal. A rule of thumb for sizing conveyors for western coal is to go one

belt size larger than recommended i.e. if a conveyor is sized at 30 inches wide to handle a certain capacity, then use a 36-inch wide belt. Conveyor speeds in excess of 700 fpm are not recommended for western type coal.

5-6. Coal delivery.

a. General. The method of delivering coal to the plant can be a significant cost in the delivered price of the coal and will affect the design, operation and cost of the coal receiving system. The delivery mode depends on such factors as, plant location, distance from mine to plant, daily "burnrate" under full load conditions, available coal storage area and the cost of competitive transportation methods. The ability to receive coal by either truck or rail can be advantageous and create a competitive pricing atmosphere. The ability to accommodate 10-15 railcars or higher multiple car shipments can enable the user to obtain lower shipping rates and reduce demurrage on the railcars due to the amount of time a car spends at the plant. Enough track must be provided at the plant site to allow for the loaded and empty railcars and the unloading area. The economic justification for a loop track or spur track rail storage system can be made as a result of savings in freight rates, if space permits.

b. Truck delivery. Trucks are an extremely convenient form of coal transportation, but due to the high manpower and fuel costs, this type of transportation has become expensive. Over-the-road trucks vary in net carrying capacity from 10 to 40 tons. Trucking coal more than 150 to 200 miles to a plant site usually increases the delivered price of coal to a cost that is financially unacceptable for efficient operation. Truck delivery of coal can usually be incorporated into the design of a railcar unloading hopper. If trucks are the sole method of coal delivery, the designer should investigate the economics of a covered shed over the unloading hopper. Truck hopper should be a minimum of 12 feet by 12 feet with a steel grating covering the dump area. Maximum grating opening should be 6 inches square. Grating should be designed to withstand the loads imposed by the fully loaded truck. Truck weighing scales are optional subject to both economics and justification.

c. Railroad car delivery. This is the most common form of coal delivery to the boiler plant. If a plant has good access to a rail network, the delivery of coal in 70-100 ton railcars is usually more efficient and economical than delivery by trucks. The most common size of railcar is the 100 ton capacity car. The designer should also take into consideration any requirements for the smaller 50

and 80 ton capacity cars which are more popular at smaller sized plants.

5-7. Railcar unloading system components.

a. Railcar scales. Railcar scales are optional for large plants if their use can be justified. These scales are usually not installed in a coal handling system.

b. Railcar haulage. The designer can select from capstan type, drum type, or hydraulic type car pullers. Cost is dependent upon the type of car puller arrangement and accessories provided. The capstan type puller is the cheapest, and is used where one or two cars have to be moved. The capstan puller can only be used on level track, and has very limited capabilities. An alternative for very small systems where three to four cars are moved per week, a front end loader fitted with a railcar moving device should be considered. Drum or reversible type railcar pullers provide more versatility and are becoming the most commonly selected units. The operator makes one connection to a "string" of railcars and pulls them backward or forward, up or down grades, and around curves with a car puller. The designer will ensure that the operator and control panel is well protected from the railcar pulling rope. A railcar string is usually one to twelve fully loaded cars. Hydraulic car pullers are usually the most expensive. They are used at larger plants where high volume railcar moving is required. In making a selection, the designer must take number of loaded railcars, track grade, radius of curvature of track (straight preferred), track condition (new or old), operating temperature, and amount of travel distance required into consideration. The designer should consult a railcar manufacturer for final equipment selection.

c. Railcar shaker. Railcar shakers are used to vibrate the railcar for fast removal of coal from the railcar without the operator having to get inside the car and manually clear the material out, thus reducing unloading time and manpower requirements. Car shakers can be the overhead or side mounted type. Side mounted car shakers require a foundation outside of the rails, and this becomes a problem if there are two or more railroad tracks spaced close together. This type of shaker is more expensive than the overhead type. The overhead shaker is the more common of the two types of shaker, having been in proven use for many years. The designer must ensure that suitable electrical interlocks are provided for the hoist and shaker to prevent incorrect use.

d. Railcar thawing. If the plant is located in a geographical area where the coal would be subject to extreme freezing conditions either from stockpiling the coal, travel time of coal in railcars, or railcars parked on rail sidings for extended periods of time, the designer should make an economic cost comparison to justify whether a railcar thawing system is viable. The car thaw system is used to melt frozen coal from the walls and the bottom of railcars. The thaw system is not intended to completely thaw the entire amount of coal inside the railcar, but rather loosen the bond between the railcar sides and the contents.

(1) *Methods.* There are two very distinct methods used for railcar thawing. The more expensive method is to spray a chemical freeze conditioning agent onto the coal as it is being loaded into the railcar at the mine site. The other method that is employed is electric or gas infrared radiant energy generation. A combination chemical treatment and thawing system is often used, but this is usually very expensive. Direct flame against the side of the rail cars or the use of explosive charges to dislodge coal inside the railcar, will definitely be avoided. A steam thawing system may be required at an AAP due to the explosive atmosphere, where any naked flame or infrared heating device would be prohibited. Steam thawing is not very efficient and can only be effectively used when large amounts of steam are readily available. This type of system should be avoided where possible.

(2) *Design considerations.* The car thaw system should be provided with an enclosure or shed around the thawing area. The shed should be at least long enough to accommodate one heating and one soak zone, when using stationary bottom dump railcars. The shed length should be increased to handle in motion or unit trains. The car thaw heaters are located between the rails and along the walls of the shed. Reflecting side panels may also be utilized to deflect radiant heat into the railcar.

e. Unloading hoppers. The coal hopper must be sized to accommodate the unloading capacity of the delivery system regardless if the coal is delivered by rail or truck. The hopper should have enough capacity to hold at least 100 tons of coal from a stationary positioned railcar, without the coal spilling over the tracks. The actual unloading schedule of the railcars or trucks is very important and should be timed to prevent overloading a limited capacity hopper. If railcars are to be unloaded quickly or on the move, the sequencing of the railcars, the track hopper size, and the size of the track hopper conveyor must all be coordinated together so that a choking condition does not

occur.

(1) *Sizing.* A double hopper arrangement, approximately 28 feet long by 14 feet wide will allow a 100 ton capacity railcar to be placed over the unloading hopper without respotting the car.

(2) *Design considerations.* The structure will be designed to support the fully loaded railcar and a fully loaded hopper. Bar grating will be provided to protect against personnel and vehicles falling into the hopper. Grating will support the weight of a truck or front end loader. Grate spacing should be a maximum of 6 inches square. The slope angle of all sides of the hoppers will not be less than 65 degrees from horizontal. The angle of the hopper where two sides meet or valley angle will not be less than 60 degrees from horizontal. Provide capped poke holes at the hopper outlets for use if the hopper becomes plugged.

(3) *Materials.* A number of track hopper construction options exist and these should be evaluated by the designer for each particular application and the type of coal used. The more common construction materials include three types. The first is A588 also known as weathering steel with minimum 3/8-inch plate thickness. This type material should not be used for high sulfur coal. The second type is A-36 mild steel minimum 3/4-inch plate thickness, with minimum 3/4-inch thick type 304 stainless steel bolted or plug welded liners or studs. This type should not be used for high sulfur coal. The third type is solid stainless steel, minimum 1/2-inch plate thickness. The type of material used for hopper construction will be determined by the type of coal being handled. Solid stainless steel hoppers are not usually installed due to the extremely high cost of the material.

5-8. Belt conveyors.

a. Conveyor design. Belt conveyors are used most extensively in coal handling systems. They have high handling capacities and offer unlimited possible combinations of length, speed, and capacity. Operating costs and power requirements are low and they are reliable and quiet. Belt conveyors can be designed for practically any desired path of travel limited only by the strength of the belt, conveyor incline or decline, or the space available for installation. Troughed belt conveyors normally require more space than other types of conveying equipment. The designer must make sure that all conveyor components are suitable for use in a coal dust atmosphere as described by the NFPA and NEMA.

b. Angle of conveyor incline and belt width.

(1) The angle of repose of a material can indicate to the designer how a material reacts while being conveyed on a running conveyor belt. This angle will affect both the capacity and incline limitations of the conveyor. The inclined angle of a belt conveyor should be limited to 15 degrees, with 18 degrees used as an absolute maximum for coal. High angle conveyors are currently being used by various companies, and the designer should investigate these before a final design is accepted. High angle conveyors use another belt to “sandwich” the material for higher conveying angles. Belt replacement on high angle, flexible sidewall and pocket conveyors is more expensive than conventional belts. High angle type conveyors have more carryback. Conveyor design must consider dirty conditions. Pocket conveyor life is approximately 10 years, while smooth conveyor expected life is 15 years.

(2) The width of the conveyor belt is determined by several factors: the type of material being conveyed, size of lumps, percentage of lumps to fines, the angle of repose of the material and the required belt capacity or conveying rate.

c. Walkways. All conveyors will be provided with a walkway of at least 30 inches in width, including a handrail. Conveyors that are larger than 36 inches wide will also have an additional 18 inch minimum width maintenance walkway on the opposite side.

(1) Walkway construction may be welded bar grating or serrated type expanded metal grating, but wooden walkways will not be used.

The designer will provide adequate access walkways for all conveyors and equipment. Provide adequate width stairways to and from platforms and walkways.

(2) The distance from the conveyor belt line to the top of the conveyor walkway should be between 36 and 42 inches.

d. Weather covers. For open truss conveyors, the belts must be protected from rain and freezing and dust must be prevented from escaping to the atmosphere.

(1) Full or three-quarter cover type, hinged weather covers will be used to protect the belts, yet allow maintenance of the conveyor belt and idlers from the walkway.

(2) The truss will be covered with a continuous deck plate. A typical open truss conveyor is shown in figure 5-2.

(3) For more extreme climates where freezing conditions are a hazard or when airborne dust must be totally eliminated, a totally enclosed type gallery as shown in figure 5-3, should be considered. This type of gallery is far more expensive than the open truss conveyor. Enough room must be allowed around each conveyor in the gallery for maintenance. Tube type galleries are more easily built, insulated and lagged, and washed.

e. Safety escapes. Conveyors will include means of egress that comply with all applicable codes. In no case will the distance from any location on the conveyor to a safety escape to grade level exceed 200 feet.

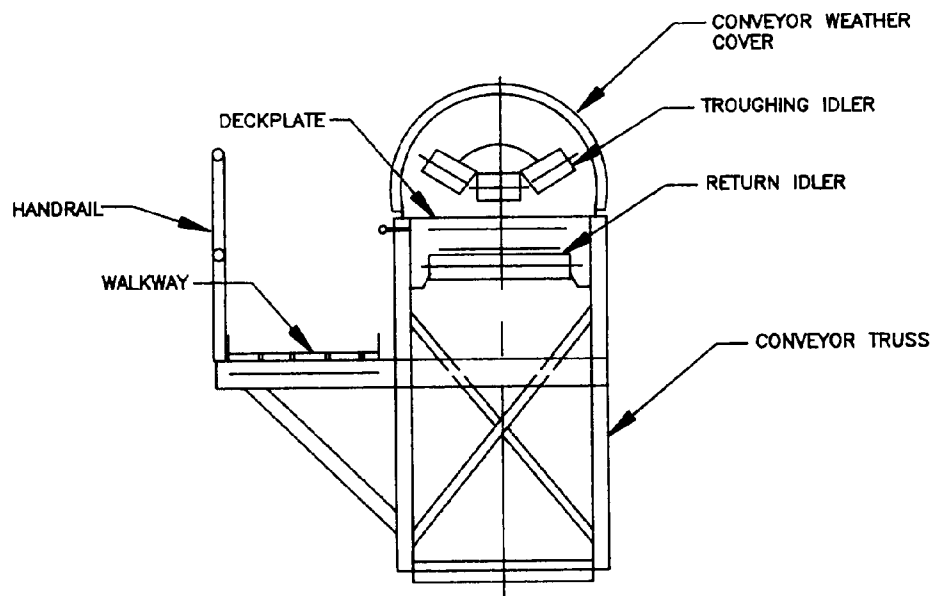


Figure 5-2. Open Truss Type Conveyor.

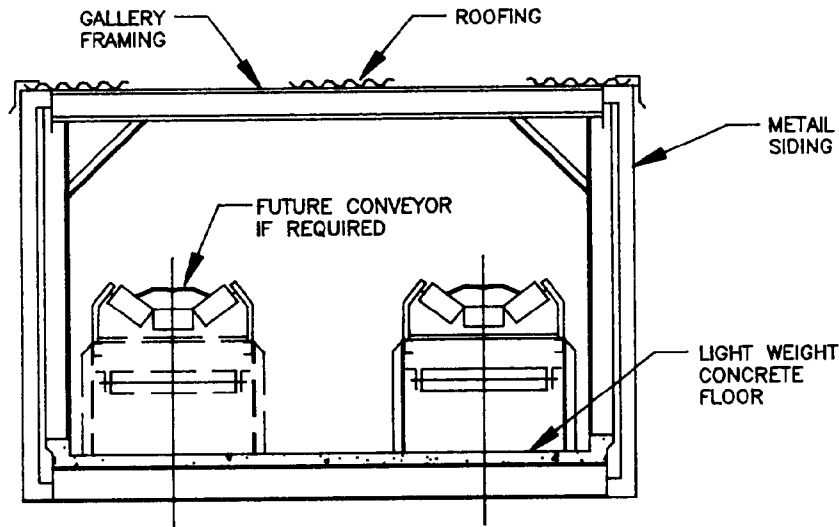


Figure 5-3. Enclosed Gallery Conveyor.

f. *Idlers.* Idlers will be selected for a specific condition since they provide the support and protection for the belt and material load and also influence the overall design of the conveyor. Improper idler selection directly affects the belt tensions and thus the final horsepower requirements.

(1) Troughing idlers will have a minimum of three 5-inch diameter equal length interchangeable rolls, with the two outside rolls inclined at 35 degrees from the horizontal.

(2) At least 3 rubber type impact idlers, spaced a maximum of one foot apart or urethane bar loading sections will be placed under each conveyor belt loading point. As an alternative, cradles composed of energy absorbing bars may be used under the loading zone to cushion the impact. In installations where more than one cradle is required to cover the length of the loading zone, an impact idler will be placed between the cradles to assure proper belt carriage.

(3) Self aligning carrying and return idlers should be placed at 80-foot centers along the length of the conveyor.

(4) All idlers will have a single point grease lubrication system that is accessible from the walkway side of the conveyor.

(5) Idler construction, selection and spacing will be based upon Conveyor Equipment Manufacturers Association (CEMA) standards.

g. *Belt take-ups.* Belt take-ups are necessary to maintain the proper belt tensions for the drive pulley traction and to maintain correct amount of belt sag between idlers. Gravity type take-ups should be provided on all conveyors with adjust-

ment of at least three percent of the conveyor terminal centers.

(1) Counterweight will be adjustable ± 20 percent from the calculated weight. Counterweight will be designed to limit conveyor belt sag to 2 percent and provide adequate traction for the drive pulley. Loading zone belt sag will be maximum 1 percent.

(2) Screw type takeups are satisfactory for conveyors less than 40 feet in length, but should be avoided if at all possible.

h. *Conveyor belt selection.* One of the most important design considerations is the selection of the conveyor belt. The belt has to withstand both the initial start up and operating tensions that are encountered within the system, be impact resistant and be suitable for the material being conveyed.

(1) The conveyor belt selection must be capable of transmitting the maximum belt tension in the conveyor, include the minimum number of belt plies to support the load, pulley series, take into account the type of material to be conveyed, and minimize belt cost to cover the above items.

(2) Conveyor minimum belt cover thicknesses will be $\frac{1}{16}$ -inch thick bottom cover (belt side which contacts the idlers and pulleys) and $\frac{1}{8}$ -inch thick top cover (belt side in contact with the material).

(3) The conveyor belt selected must be capable of withstanding all startup and operating tensions that will be encountered within the conveyor. For a multiple ply conveyor belt, the unit tension is expressed in pounds per inch belt width (piw) or pounds per ply inch (ppi). A 30-inch wide,

3 ply belt with a maximum calculated operating tension of 5000 pounds, will have a unit tension of: $\frac{5000}{30} = 167$ piw or 56 ppi

(4) Conveyor belt sag between carrying idlers should be limited to two percent, except at load zones limited to 1 percent.

(5) Belt tension will not exceed 70 percent of the Rubber Manufacturers Association (RMA) tension ratings under normal operating conditions with a vulcanized splice.

(6) Conveyor belt will be fire and oil resistant conforming to United States Bureau of Mines Standards.

(7) Consideration should be given in applications of limited takeup or long conveyors to provide a mechanical splice when the belt is first installed so initial stretch can be taken out before doing the vulcanized splice. In these cases run-in time will be long enough to eliminate manufacturer's stretch. Vulcanized belt splices generally last close to the life of the belt. Mechanical splices last two to three years.

i. Skirtboards. Skirtboards will be provided at all conveyor loading points. Coal handling system design, especially when handling lignite or western coal requires examination of flow velocity differences between conveyors, vertical drop at transfer points, and angular relationship of conveyors. The width of the skirtboards will be maximum $\frac{3}{4}$ belt width.

(1) Skirtboard length will be at least 2 feet for every 100 fpm of belt speed plus 3 feet at tail end. Minimum skirt length will be 8 feet. The skirtboard will terminate above an idler roll, not between.

(2) Skirtboard rubber strips with easy adjustable clamps will be provided on the lower edge of the skirtboards to prevent the escape of fines. Wearable liners inside the chute will be installed as a dam to keep the material load off the rubber, so it can effectively serve as a fines barrier. Provide continuous skirtboards on feeder conveyors.

j. Belt cleaners. Belt cleaner units on a troughed conveyor belt will consist of a primary scraper on the face of the head pulley and one or more secondary arm and blade type multiple blade cleaner to scrape and remove the material that bypasses the primary cleaner. Each belt cleaner will be held in an easily serviceable mounting system allowing fast and easy blade replacement. The cleaners will be held in position against the belt by means of a tensioner which rotates the blades against the belt yet which allows for relief when mechanical splices or other obstructions pass. Do

not use counter-weighted type cleaning devices on conveyors faster than 350 fpm or larger than 36-inch as they become ineffective very quickly. V type belt cleaners will be provided on the clean side of the belt before belt take ups and tail pulleys.

5-9. Other conveying methods.

a. Bucket elevators. These are used to elevate coal to overhead storage or conveyors, where there is little available space for a belt conveyor. Malleable iron, steel, stainless steel, aluminum or plastic buckets can be selected depending on the material conveyed. Care should be taken when selecting nonmetallic type buckets for use in a combustible environment, due to their ability to retain a static electrical charge. Capacity of the bucket elevator will be based upon buckets filled to 75 percent theoretical capacity for loading. Drive horsepower will be based upon 100 percent full buckets. There are two common types of elevator used for coal handling: centrifugal and continuous.

(1) *Centrifugal type.* Centrifugal discharge elevators are the most frequently used type for free flowing, fine or small lump materials. Buckets should be type A or AA as designated by CEMA, spaced at intervals to chain or belt. Buckets are loaded by a combination of material flowing into the buckets and material that is scraped up by the digging action as the buckets pass around the tail pulley. Speeds are relatively high and the centrifugal action controls the discharge from the buckets. Capacities range from 5 to 80 tons per hour (tph). Elevator will be completely self supporting. Centrifugal type elevators are used extensively in grain service and other free flowing materials. Centrifugal elevators tend to create more dust and cause breaking of friable material, which creates problems with boiler requiring a particular size distribution. Centrifugal elevators if used should be vented, and include a filter to relieve the "air pumping" phenomena at discharge.

(2) *Continuous type.* Continuous bucket elevators are recommended for high capacity heavy duty service. The buckets are steel, continuously space on single or double strand chain or on a belt. At the head, the discharge from each bucket is over the back of the preceding bucket which forms a chute to lower the material to the fixed discharge spout. This method of discharge, plus the slow speed, minimizes breakage of fragile material. These types of elevator are not the self digging type, so a loading leg must be used, requiring a deeper pit than that needed for a centrifugal discharge elevator. Capacities from 15 to 300 tph are available. Elevator will be completely self

supporting. Bucket elevators are usually high maintenance items and should only be used where space restrictions apply. Manufacturers have to take particular care when designing the track and load shoe.

b. Apron conveyors. Apron and pan conveyors consist of overlapped steel pans which are supported between two strands of chain that pass around head and tail sprockets. This type of conveyor is usually short, slow speed, and used for removing granular or lumpy material from under the track hopper. An apron conveyor is a very high maintenance item and should be avoided when possible. Maximum conveyor incline is usually up to 25 degrees or 45 degrees with pusher plates. One distinct advantage of this type of conveyor is they can carry hot materials.

c. Screw conveyors. Screw conveyors are an economical short, low tonnage type of conveyor which can be used in areas with low headroom. Screw conveyors are not usually used when their capacities exceed 50 tph. They are used to handle pulverized, granular or noncorrosive materials where product agitation or degradation can be tolerated. Where mixing or blending is required, numerous conveyor screw configurations are available. The conveyor is completely enclosed with only one moving part and can be fitted with multiple or single discharge openings. Extreme caution must be taken when handling abrasive materials, as excessive wear will lead to premature equipment failure. As the screw conveyor is inclined, the carrying capacity decreases. Trough loading should not exceed 30 percent of the trough cross sectional area for coal, even though higher loading is possible.

d. Flight conveyors. Flight conveyors are used to move granular, lumpy or pulverized material along both horizontal and inclined paths. Inclines are limited to approximately 40 degrees, with capacity decreasing as incline increases. One percent of capacity should be deducted for each degree of incline over 30 degrees. Flight conveyor is a high wear, very noisy and high maintenance item. With abrasive materials, the trough design should provide for renewal of the bottom plate without disturbing or removing the side plates or flights. A method of compensating for unequal chain wear or stretching must be incorporated into the design. Flight conveyors are well suited to conveying bottom ash from boilers and sludge from tanks and ponds.

5-10. Drive units and couplings.

a. Conveyor drive units. The conveyor drive unit should be located at the discharge or head end of

inclined and horizontal conveyors. The designer may find it preferable to locate the drive internally or at the tail end of the conveyor if required by accessibility or maintenance, but should be avoided if possible. The drive arrangement should be designed with the minimum amount of compact components as possible. Reducers, couplings and motors should be the same size as far as practical for ease of maintenance and to reduce spare parts inventories. On conveyor drives over 300 hp the designer should investigate the economical justification of dual drives. This type of drive allows the conveyor to be operated at reduced capacity when one of the drive units fails. V belts will not be used.

b. Reducers. The conveyor drive reducer will be American Gear Manufacturers Association (AGMA) rated using a service factor of 1.5 of the input motor design hp. The thermal hp rating of the reducer will not be less than the full load hp of the motor. Bearings will be Anti Friction Bearing Manufacturers Association (AFBMA) 100,000 hour L-10 minimum life. All conveyor drives will be capable of starting under full loaded conditions. V belts will not be used.

c. Couplings. Power from the reducer drive low speed shaft is transmitted to the conveyor head or drive pulley by the use of a flexible coupling. The coupling will be capable of withstanding parallel, axial and angular misalignment of the drive shafts. The coupling will be incapable of transmitting axial loading and the use of torque limiting couplings will not be permitted. Couplings will be rated using a minimum service factor of 2.0 for the input hp.

d. Fluid couplings. Fluid coupling will be provided between the drive motor and the reducer which allows a controlled amount of slip to occur without causing excessive tension and shock loading to the drive components and conveyor belt. A fluid coupling will allow the motor to run rapidly up to full speed, but will allow the conveyor a smooth controlled acceleration start curve when starting from rest when either empty or fully loaded. This type of coupling is also beneficial in extremely cold climates where a controlled acceleration start is required to prevent coal from back-sliding on inclined conveyors. Fluid couplings permit the use of standard motors with across-the-line starting capabilities which allows the use of less expensive motors.

5-11. Belt scales.

a. Scales. General Belt scales are used to constantly measure the rate at which a bulk material is being delivered to the plant on a moving conveyor belt, and to make a record of the delivered amount

for inventory purposes. It is important to weigh the coal as it is delivered to the plant, and again before it is burned.

b. Type. A belt scale of the weighbridge type which incorporate electronic precision strain gauge load cell and microprocessor based technology with automatic calibration capabilities should be selected. The belt scale, including weighbridge assembly will be capable of withstanding at least 250 percent material overload without damage to any mechanical or electrical components.

c. Scale accuracy. If a belt scale is to be used for basis-of-payment contracts between the coal supplier and the plant, the coal supplier may require a scale with 0.125 or 0.25 percent repeatability accuracy. For general plant inventory purposes, a 0.5 percent accuracy is usually acceptable. If a scale is used for billing purposes or invoicing freight, approval and certification by the weighing bureau which has jurisdiction for that particular geographical area must be obtained.

d. Readout. The scale can be connected to a computer or a printer to provide a readout of the quantity of material delivered to the plant. The readout will be easily readable by the operator and be such that he does not have to do any manual calculations to find the amount of coal received.

5-12. Sampling system.

a. General. When a given consignment of coal is delivered to the plant, it may be advantageous to the plant to determine by laboratory analysis some of the characteristics of the delivered coal. Sampling is used to take a representative sample from the complete coal consignment lot and provide a quality evaluation of that sample. Because of the variability of the chemical composition of the coal, the analytical results from a sampling system can be used to determine coal contract rates, reliable and efficient quality assurance, plant operating efficiency and compliance with environmental standards.

b. Design conditions. Each sampling system will be designed for a specific location and on an individual plant basis. One sampling system cannot necessarily be used for another similar system. Depending on the capacity of system, one or more sampling stages may be required to obtain the volume of the final sample required for analysis. ASTM standards establish the requirements of the final sample for each particular system. A good rule of thumb for selection is a three stage system is used for flow rates which exceed 2000 tph and when product size is greater than 3 inches, while a two stage system is used where flow rates are

below 2000 tph and product size is below 3 inches. Sample system manufacturers will provide help with system sizing and requirements. Due to the complexity and high cost of sampling system, the designer must decide if a sample system is a justifiable piece of equipment to meet the end results.

c. Sweep type sampling. Sweep type (or hammer type) are relatively new and have different design conditions than given above. This type takes less sample than a cross stream type, usually from 1/3 to 1/6 less, depending on conveyor speed, material size and flow rate. This allows two stage sampling systems to be employed with virtually any flow rate using sweep samplers for the first and second stages. Also, for low capacity installations of approximately 50 tph and below, a single sweep sampler with sample collector can be used to meet ASTM D 2234. At these low flow rates, a manageable amount of sample is collected for laboratory analysis with a minimal capital investment.

5-13. Magnetic separators and detectors.

a. Magnetic separators. Magnetic separators are installed to remove potentially damaging magnetic tramp iron from the material on the conveyor belt. Tramp iron is removed from the conveyed material by the separator and can be automatically or manually discharged to a collection hopper. A single unit mounted ahead of the crusher on the conveyor is usually all that is required to protect a complete conveying system. A small piece of tramp iron can put an expensive crusher out of action very easily. The separator will also protect the conveyor belts from being ripped by large pieces of tramp iron. A separator is a relatively inexpensive and necessary method for protecting crushing machinery, conveyors and the plant boilers.

b. Detectors. Detectors are used to detect both magnetic and nonmagnetic tramp iron and are usually installed in conjunction with a magnetic separator to provide additional protection for all downstream equipment. When tramp metal is detected, the unit automatically die marks the location and shuts down the conveyor before any damage is done. The operator has to manually remove the foreign material before restarting the conveyor.

c. Magnetic pulleys. Magnetic pulleys can also be used to remove tramp iron, but are usually not as effective as a magnetic separator, and are seldom used in coal handling systems.

5-14. Coal crushing equipment.

a. General. Stoker fired or pulverized coal boiler plants install crushers for use when a larger and

more coarse ROM coal has been purchased for use in the boiler plant. A separate crusher bypass chute should be provided to divert coal around the crusher when properly sized coal is purchased and no crushing is required. The separate bypass chute is also advantageous when maintenance work has to be performed, requiring the shutdown or removal of the crusher from the coal handling system. In boiler plants that have both pulverized coal and stoker fired boilers, all the coal supplied is sized to suit the stokers, with coal going to pulverizers when required. This simplifies the storage and handling facilities required for the system. The crusher will be selected to handle the hardest material that may be encountered in the system. A stationary or vibrating grizzly screen placed ahead of the crusher reduces the crusher size. This can be part of the feed chute to the crusher.

b. Crusher sizing. Generally, crusher drive motor sizing is 1/2 hp per tph for roll crushers, granulators and hammermills and one hp per tph is used for sizing impactors.

c. Coal reduction methods. Reducing coal to smaller size can be separated into the two categories of breaking and crushing. Breakers reduce raw mine coal into a manageable size, while crushers break the coal down to small manageable particles. Rotary breakers are used to crush or size run-of-mine coal by gravity impact and are often used to clean debris from coal which has already been sized. This type of breaker is usually used at the mine site and not at the boiler plant location. When used at a boiler plant, a built in hammer mill is included.

d. Crusher types.

(1) *Roll crushers.* Roll crushers compress the coal between a roll and a breaker plate. Teeth on the roll help to split the coal through impact and toward the bottom of the breaker plate, the teeth shear the coal, which minimizes product fines and reduces power demand. Adjustable clearance between the breaker plate and roll determine the finished product size. The breaker plate is usually spring loaded for protection against uncrushable debris and adjustable from outside the machine. Roll crushers are well suited for western coal due to control on minimum size of product.

(2) *Hammermills.* Hammermills break the coal by the impact of rotating hammers throwing the coal against breaker bars and then dragging the coal against the screen bars. This type of crusher is used as a primary reduction of dry or friable material where uniform product size is required and large amounts of fines are not objectionable. Hammermill crushers must be provided with a vent arrangement because of the air being displaced by

the high speed rotating hammers.

(3) *Granulators.* Granulators crush coal with a slow, positive rolling action which produces a granular product with a minimum amount of fines. Power plants particularly choose this type of crusher for its high reduction ratio and high capacity. The product size is externally adjusted by changing the clearance between the case assembly and the ring hammers.

(4) *Impactors.* Impactors break the material by dropping it centrally into the path of the rotating hammers. The material then impacts against breaker plates and rebounds back into the rotating hammers. A variety of product sizes can be attained by adjustment of the breaker plates. Impactors are usually recommended for secondary and tertiary crushing applications where high reduction ratios, high capacity and a well shaped and graded product are required.

5-15. Vibrating feeders.

a. General. Vibrating pan feeders consist of a pan or trough to which is imparted a vibrating motion so that material moves in a controlled flow. Feeders are instantly adjustable for capacity and controllable from any near or remote point. Feeders are normally positioned under track hopper openings, the bottom of a bin or under a storage pile to induce and regulate the flow of material onto a belt conveyor or other means of moving coal. Vibrating feeders are used for handling practically all kinds of bulk materials, but will be avoided where the material has a tendency to stick to the pan. The feed rate in tons per hour of the feeder is a function of bulk density, material size, material angle of repose, angle of decline, frequency of vibration, trough stroke and feeder length.

b. Feeder design. Feeders will be the electro mechanical type which employ easily adjustable, rotating eccentric weights driven by a heavy duty electric motor which transmits power to the feeder pan through heavy duty springs, which in turn induces the material to flow. Electromagnetic type feeders will be avoided where possible. These type of feeders have an extremely high noise level when installed in underground pits and tunnels, and have trouble meeting explosionproof atmosphere requirements.

(1) Each feeder will be designed and sized for nonflushing operation.

(2) Hopper design and inlet arrangement to the vibrating feeder are very important in obtaining the required capacity and preventing overloading and choking of the pan. An adjustable depth

limiting gate will be provided to control the depth of material on the feeder pan.

(3) Maximum recommended feeder angle of slope is 10 degrees down from the horizontal. Larger slopes are possible, but care must be taken to prevent the material from “flushing” (self emptying), when the feeder is shut down.

(4) The more common type of primary feeder supports consist of steel cable or bar hangers supported from the hopper or roof support steel above, with spring type shock absorbers in each hanger. A support frame can be used to support the feeder from below if the feeder cannot be supported from the hopper or overhead support steel. The feeder will be provided with at least two safety slings to prevent the feeder from falling in the event of a primary support failure. Application of suspended feeders will take into account “back out” action of the feeder.

c. Feeder construction. Feeder pan will be constructed from a minimum of 3/8-inch thick, type 304 solid stainless steel plate. Replaceable stainless steel liner plates can be used, but are far more expensive to install. Plastic type liner plates should be investigated when a sticky material is being handled.

d. Controls. There are two common types of control systems which are used to control the vibrating feed rate; Silicon Controlled Rectifier and Variable Auto-Transformer. The control system will be capable of adjusting the feed rate from 0 to 100-percent of the vibrating feeder capacity.

(1) *Silicon Controlled Rectifier (SCR).* This is the more commonly preferred method of vibrating feeder control. The SCR is a solid state, variable voltage, soft start control device that can be used for both local and remote operation where a manual or electronic process control signal input is used. A full voltage start circuit is recommended to protect against full inrush starting current.

(2) *Variable auto transformer.* This is a variable voltage device that is used for local, manual control of the feeder feedrate. The auto transformer requires that a servo device be used for dial adjustment. This type of control is being replaced by the solid state circuitry of the SCR, which is capable of both local and remote control.

5-16. Trippers.

a. General. Trippers are used in conjunction with a horizontal belt conveyor to discharge material from the belt at points along its length. Trippers can be stationary or fixed position, arranged with suitable chutework to discharge material to either side of the conveyor or back onto the conveyor belt.

b. Stationary type. Stationary trippers are used to discharge material at a specific fixed location into a bin or silo, or direct the material back onto the conveyor belt to the next point of discharge.

c. Motor driven. Motor driven movable trippers have the tripper frame mounted on wheels, which engage parallel rails supported on either side of the belt. This type of tripper can remain in a specific location for a short time or locked in position for longer periods. Provide a cable reel or festoon cable system to provide power to controls and motor drives. The designer must provide safety devices at each end of the tripper travel to reverse or stop the tripper car. Dust seals will be provided near the lower end of the discharge chutes to prevent the escape of dust from the covered bins or hoppers. For a clean operation hoppers or bins must be vented to release air displaced by incoming coal. Belt propelled tripper cars will be avoided. Traveling trippers are installed in stream plants where material is discharged into multiple bins, hoppers or silos.

d. Winch type. Winch trippers have positive drives using cable connected to both ends of the conveyor, and looped up through winch. No power is required on the tripper. Winch trippers should be used when conveyor would be exposed to weather. Wind can fold the belt which could cause a self-propelled tripper to come off the tracks. Rain or handling material that absorbs moisture could make the rails slippery, which would not adversely affect a positive drive unit such as a winch tripper.

5-17. Conveyor chutework.

a. Chutework design. Design of conveyor transfer and headchutes depends upon the accurate prediction of the material trajectory path as it discharges over the end of the pulley. The curvature of the material trajectory is dependent on the material depth on the conveyor belt, the belt speed, the angle of the conveyor, pulley size and the force of gravity on the material. All the above factors should be considered during the design stage to prevent the material from choking or plugging the chutework and causing material spillage.

b. Chute slope. For good coal flow all chutework side plates will be as steep as possible but will have a slope no less than 55 degrees off horizontal. For western coal slope will be minimum 60 degrees, preferably 70 degrees. The designer must eliminate offsets, turns or changes in direction of chutework as much as possible.

c. Chute liners. Stainless steel or Ultra High Molecular Weight (UHMW) liner plates will be installed on all surface subject to wear or slide, such as “dribble” from belt scrapers landing on

chute back plates. Impact type liners or bars will be installed at material discharge impact points.

d. Construction. Headchutes and transfer chutes will be totally enclosed to reduce spillage and fugitive dust. Rubber dust curtains and seals will be provided around the conveyor belt as it enters and exits the headchute. Conveyor headchutes will have at least 2 inches clearance between the edge of the head pulley and the inside of the chute. For belt widths up to 42-inch and 48-inch through 72-inch clearance will be 3-inch. Headchute construction should have provisions to remove the entire pulley assembly and frame so maintenance can be done in the shop. Chutework will be flanged and bolted design with externally mounted bearings and hinged access doors for ease of maintenance. Provide hinged, access doors on both sides or front (above material impact point) of headchutes.

e. Chute pluggage detectors. A tilt type plugged chute detector will be furnished at each transfer point to protect the conveyor from damage. Pressure or resistance type plug chute switches are not as reliable as the tilt type switches and will not be used.

5-18. Coal reclaim.

a. General. Reclaim systems can be classified into two categories, below grade and above grade coal reclaim systems. Small size steam plants usually cannot economically justify the types of reclaim systems employed by the larger power plants such as the above grade reclaimers, bucket wheels, boom mounted bucket wheels, barrel and bridge reclaimers, and the below grade system such as V-shaped slot bunkers, glory holes and underground reclaim tunnels with vibratory or rotary plow devices. These type of reclaim devices require a very large capital outlay. Smaller plants usually employ a combination of both the above and below grade systems.

b. Reclaim hopper. This is the cheapest and simplest form of reclaiming coal from long term storage. In this method an above ground bulldozer moves coal from the storage pile to a below grade reclaim hopper. The hopper will be approximately 12 foot square and covered with a steel grizzly or grillage with maximum 6-inch square openings. The hopper and grillage will be designed for a fully loaded hopper and the weight of a bulldozer, front-end loader or truck. A vibrating apron or belt feeder under the hopper outlet and a manually adjustable strike off gate on the hopper regulate the amount of coal loaded onto the reclaim conveyor. This method of coal reclaim is solely dependent on the front-end loader or bulldozer to move coal to

the hopper. There is no "live" reclaim ability with this method.

c. Drawdown hopper. A more expensive method of reclaiming coal is with the use of a vibrating drawdown hopper or pile discharger. The drawdown hopper is located directly under the coal storage pile and is designed to operate on a timed cycle basis, which transmits controlled vibration energy into the coal pile, generating fracture lines, causing the control column of flow to be drawn down into the hopper and onto the conveyor belt. This method of coal reclaim can provide the plant with a certain amount of "live" reclaim from the coal pile minimizing the use of mobile coal moving machinery.

5-19. Wet and dry dust control.

a. General. Whenever a dry material such as coal is moved or changes its direction during a process, the result is fugitive airborne dust. Fugitive dust emissions can be significantly reduced by the addition of an effective dry dust collection system, wet suppression system or combination of both. With the evolution of more stringent air pollution control regulations, coal handling systems are being required to meet these standards for the geographical area they are located in. Federal, State or local clean air codes can rule out the use of one or the other types of dust control systems.

b. Wet dust suppression system. Wet dust suppression system is usually used where the dust producing area is complex, large and unconfined, such as stockpiles or track hoppers.

(1) This type of system uses a proprietary water soluble, surface active, proportioned chemical additive, to dampen and agglomerate fugitive dust particles at the source making them too heavy to be airborne.

(2) The effectiveness of wet suppression systems can range from total suppression in warm weather to questionable operation in cold subfreezing temperatures. Additional moisture can cause coal to stick together complicating the flow characteristics of the material being conveyed, and can reduce the burning characteristics of the coal and are only as effective as the amount of dust that is contacted by the suppressing agent.

(3) A wet suppression system is a simple solution to dust control, that does not require the use of costly or elaborate enclosures or hoods, are cheaper to install and require far less space than a dry dust collection system. Changes or alterations required after startup can be made with the minimum of expense and system downtime.

(4) Foam suppression is simple and efficient. Foaming chemicals have to be purchased. It is ideal where low moisture is necessary. Foam type systems typically add less than 1/2 percent moisture as compared to up to 4 percent with standard water spray systems. One foam unit is needed for each central application location. No electricity is required. Water and compressed air are required.

c. *Dry dust collection systems.* Dry dust collection systems utilize dry type bag filters which are designed to remove dust-laden air from unloading areas and transfer points throughout the coal handling system, as well as to provide ventilation for bins, storage silos or bunkers. The main advantage of this type of system is that it can be operated in both warm and cold climates.

(1) A dry dust collection system requires a large amount of space for equipment and ductwork, which makes it more expensive to install than a wet type dust suppression system. Operating and maintenance costs are compounded as the size of the system increases. Changes or alterations required after startup are virtually impossible without completely modifying the entire system. Filter bag replacement for the dust collector units

is very time consuming and costly.

(2) The collected dust from the dust collector must be returned to the material flow which allows reentrainment of the dust at the next pick-up point location.

(3) Table 5-1 shows a comparison of dry dust collection versus wet dust suppression systems.

5-20. Conveyor safety and safety devices.

a. *General.* Conveying system safety begins with good design which, as far as is practical, tries to protect the operator from dangerous or hazardous areas associated with conveyors. Safety should be considered in all phases of conveyor design, manufacture, installation, operation and maintenance procedures. Conveyor operators must be properly trained and made aware of possible recognizable equipment hazards, safety procedures and devices, before they become involved in an accident. Conveyor safety is covered in ANSI B20.1. In addition, the following safety devices will be included for all conveyors:

Table 5-1. Comparison of Dry Dust Collection Versus Wet Dust Suppression Systems.

	Dry dust collection	Wet dust suppression	Foam suppression
When recommended	Enclosed hoppers, bins, silos, transfer/crusher houses. Silo, bunker or bin venting Enclosed track hopper buildings	Open coal storage piles Open or enclosed track hopper buildings. Open or enclosed conveyor. Transfer points	Stock piles Crushers
Enclosed transfer points			
<i>Note:</i> Where an item is listed under both dry dust collection and wet suppression, an LCCA should be conducted to determine which system should be used.			
Disadvantages	More expensive. High operating and maintenance costs. Changes or alteration to system are costly. Time consuming filter bag replacement. Large amount of space required. Collected dust must be returned to the material flow.	Chemical additive be purchased. Questionable cold-weather operation. Moisture is added to coal. Requires a water supply. Requires freeze protection supply.	Foaming chemicals must be purchased
Advantages	Can be operated in warm and cold climates. Does not add moisture to coal. Can be used for bin or silo venting,	Less expensive. Does not require costly or elaborate enclosures. Small space required for installation. Changes to system easily made.	Same advantages as wet dust suppression.

b. Safety devices. Each conveyor in a conveying system will incorporate electrical safety devices to provide protection to the operating personnel as well as to prevent damage to the conveyors' mechanical components.

(1) All electrical safety devices will be electrically interlocked so that when a "trip" signal is received from the device at the point of failure, all the downstream conveyors and feed devices, such as crushers and feeders, back to the initial conveyor feed source will shut down immediately.

(2) No conveyor can be started until the safety device has been checked and put back into proper service. Only then can the complete conveying system be put back into operation.

c. Emergency stop switches. Pull cord switches and pull cords will be located along all walkways or areas that are accessible to conveyors to protect personnel from falling into any rotating or moving machinery. Once "tripped" these switches have to be manually reset before the conveyor can be restarted.

d. Belt overtravel switches. Belt misalignment switches will be provided on both sides of the belt at the head and tail end of each conveyor and the tripper, to detect conveyor belt misalignment, which can result in serious damage to expensive belts, drive equipment and structures. Extra switches will be installed at selected intervals, no more than 500 feet apart on long conveyors.

e. Conveyor zero speed switch. A zero speed switch will be provided for each conveyor in the system. They are installed on a nondrive pulley, preferably the tail pulley to detect a decrease in conveyor belt speed, from a given set value.

f. Plug chute switches. A plug chute switch will be installed at each conveyor transfer point. They operate when a plugged chute condition occurs, and are arranged to stop the downstream equipment from continuing to feed the plugged chute. Similar type switches are used in hoppers, bins, silos and chute discharge points. Tilt type switches are the most common type used.

g. Warning horns. Horns are used prior to the conveyor start sequence to warn operating or maintenance personnel that the equipment is being placed into operation. Horns will be operated for at least 15 seconds, before starting any conveyor. Provide enough horns to cover all conveyor areas in the plant.

h. Guards. Rotating or moving machinery which provides a safety hazard to the operator will be provided with a guard or guards to warn the operator that a particular hazard does exist. ANSI B20. 1 gives the conveyor designer guidance on conveyor safety guards.

i. Conveyor backstops. A backstop is a mechanical device which allows a conveyor or bucket elevator drive shaft to rotate in one direction only. An automatic backstop will be installed on all conveyors or bucket elevators subject to reversal under loaded conditions. Backstop will be sized according to conveyor drive motor stall torque, and be provided with a removable torque arm. The backstop will be installed on the conveyor drive pulley shaft and not in the drive reducer.

j. Methane detectors. Install methane detectors and vent system anywhere that coal is stored in an enclosure.

5-21. Spontaneous combustion of coal.

a. General. A major problem with the bulk storage of coal is its ability to release enough heat, through slow oxidation, to raise its temperature gradually until self-ignition or spontaneous combustion occurs. The tendency of stockpiled or stored coal to self ignite increases as the coal ranking decreases.

b. Coal ranking. Lower rank coals tend to be very fragile, resulting in faster degradation and particle size reduction during the handling process. Anthracite type coals, which are the highest ranking coals have few problems and are very easy to handle. Lignite and subbituminous type coals tend to degrade quickly leading to spontaneous combustion.

(1) When these types of coal are stored, provisions must be made to monitor the conditions in the silo, bunker or stockpile to reduce the occurrence of spontaneous combustion.

(2) Precautions must be taken so that material in a silo, bunker or stockpile can be evacuated in the event of material self ignition. Without oxygen, the oxidation process cannot take place, so it is important that the total coal surface exposure to air be as low as possible. Coal should be stored so that air cannot infiltrate or move through the storage pile. Spontaneous combustion usually only results from careless storage procedures. Where coal is properly stored, this likelihood is remote.

5-22. Coal bunkers.

a. General. In the design of bunkers, careful consideration will be given to the capacity, shape, bunker material, and bunker location within the steam plant.

b. Storage capacity. Bunker will be sized for a minimum of 30 hours supply for maximum boiler capacity.

c. Shape. The shape of the bunkers are usually a compromise between space restrictions and optimum design for coal flow. The more common

bunker designs are the square upside down pyramid and silo types. Cantenary, straight, or parabolic type bunkers will not be used because the flow of coal from all outlets is not uniform which creates dead pockets and causes a spontaneous combustion hazard. Cylindrical or silo type bunkers are used to reduce danger of spontaneous ignition of coals. To reduce stagnation and coal segregation, separate bunkers will be provided for each boiler. At least the bottom of each bunker should be in the building to preclude bottom freezing. Discharge hoppers will be sloped at least 55 degrees. An emergency discharge chute will be provided for each bunker to remove coal from the bunker in emergency situations. Silo design type bunkers are more frequently used because they have been found to be less susceptible to rat holing and hangups than other shapes.

d. Material. The designer will carefully analyze the type of material being used for the bunker, to insure the material is compatible with the type of coal being stored.

e. Location. Coal bunkers should be located to provide a coal flow which is as vertical as possible. Current trend is to replace plant storage bunkers with inside silos which require less building volume and structural support steel. On the average, it has been determined that the silo and related support steel structure were less expensive than a bunker of the same capacity. The cylindrical shape of a silo has an inherent strength advantage. A properly designed bunker generally can match a silo's flow efficiency, therefore such factors as moisture content, temperature and storage time have the greatest influence on the type of silo or bunker that is selected.

5-23. Long term coal storage.

a. General. The long term coal storage pile is created for the sole purpose of having an adequate supply of coal on hand to supply coal to the boilers in the event of an interruption of coal supplies to the plant.

(1) The reserve or long term coal storage pile should be maintained at the boiler plant. Refer to TM 5-848-3 for the criteria for determining the quantity of coal to be stored.

(2) The method of storing and reclaiming coal in an outside storage pile should be determined to satisfy regulatory environmental restraints. Drainage and collection of rainwater runoff, treatment, coal water separation and neutralizing effluent will be included in design. Local, State and Federal environmental regulations will determine limits for suspended solids and pH of coal pile

runoff water and leachate. Treatment facilities will be provided if required.

(3) Care must be taken in the method of constructing the coal pile. Coal is placed in maximum 18-inch thick layers and then compacted with the use of a front-end loader or rubber tired dozer to eliminate air spaces within the pile.

(4) The designer will take into account the "weathering" process or loss of coal heating value, that takes place with long term storage of coal.

(5) Coal handling personnel will be assigned to check a long term storage pile on a daily basis, to guard against localized hot spots caused by spontaneous combustion.

(6) A liner may be required underneath the coal pile to prevent coal pile runoff from being absorbed by surrounding subsoil. Soil permeability tests will be taken in the area where the coal pile is to be located.

b. Environmental regulations. Local and State Regulation Agencies may have environmental regulations which prohibit open storage of coal, because of fugitive dust emissions and runoff. In this case the designer should investigate the use of outside coal storage silos or covered barn structures. Both silos and barns are high capital expense items. Some agencies will allow open storage of coals with wet suppression.

5-24. Fire protection and prevention.

a. General. Fire protection and prevention for a conveying system and its related structures, requires that the designer ensure careful planning during the initial design stage to reduce coal dust. Fire protection systems are playing a more important role in the design of conveying systems. New code standards developed by the NFPA and industry requirements are forcing designers to reexamine coal handling system design and the suitability of the fire protection system. A fire protection system can make a difference between minor damage and total destruction.

(1) Western subbituminous type coals are less dense, more susceptible to spontaneous combustion than the eastern coals. The amount of fire protection required for any system largely depends on the type of coal to be burned at the facility. Some coals can be stored in bunkers for years without any spontaneous combustion generated fires, while other coals such as some types of western subbituminous C type coals cannot be left in a bunker for a period over 30 days. An emergency bunker unloading system will be included in the design to enable the bunkers to be emptied. Western coals tend to produce a higher

percentage of fines during the handling, conveying and stockpiling process, thus causing particles to become airborne, creating a more dusty environment. Coal dust can impair the operation of coal conveying equipment and create an unhealthy working environment which increases the risk of fires and explosions. Methane detectors and a vent system should be installed in coal storage enclosures to reduce danger of explosion.

(2) Conveyor fires are usually started by friction between seized idlers and the conveyor belt, seized bearings or improperly aligned or maintained equipment. If a fire on a conveyor should occur, the conveyor, the upstream and downstream conveyors, auxiliary feed equipment such as crushers and dust collectors must all be stopped immediately.

b. Design. The following items will be given consideration when designing a conveyor fire protection system:

(1) An automatic wet or dry pipe sprinkler system should be installed along conveyors, to protect the carrying and return belts, conveyor drives, underground tunnels and control areas.

(2) Automatic deluge systems require large flow rates to protect the conveyor and the conveyor galleries. The water supply system will be investigated to see if it can support the required flow rates when a fire protection system is determined to be necessary.

(3) Adequate means of removing fire protection water from below grade tunnels must be provided to ensure that personnel can be evacuated before a hazardous water build up occurs.

(4) A dry pipe or preaction type system, which employ a fusible link or glass bulb sprinkler heads, are usually used in areas that are subject to freezing conditions. This type of system is the more popular type of fire protection system.

(5) A wet pipe system, which is basically the same as dry pipe, except that water is in the system piping at all times, is usually suitable for areas not subject to freezing.

(6) A fire detection and evacuation alarm system will be provided throughout all facilities with pull stations at all exterior exits and sufficient evacuation alarms to overcome the normally higher level of noise found in power plants. The fire detection and evacuation alarms will give indication in main and auxiliary control rooms and into the plant main fire alarm system.

(7) Adequate fire hydrant protection will be provided for all coal piles and consideration will be given to the long term methods of coal pile storage to minimize spontaneous combustion.

(8) Draft barriers or fire walls will be provided at each end of conveyor galleries.

(9) Safety escapes. Conveyors will include means of egress that comply with all applicable codes. In no case will the distance from any location on the conveyor to a safety escape to grade level exceed 200 feet.

(10) Carbon dioxide, or steam protection should be considered for bunkers, bins and silos. A method of transporting coal from a silo to a remote yard area in the event of a fire will be considered in the design.

(11) There are numerous types of fire detection sensors and detectors such as heat, continuous thermal sensor, fixed temperature spot sensor, fusible thermal wire, pneumatic rate of rise, series thermal detector, smoke detectors, ionization detectors, flame, ultraviolet, infrared and numerous others. There is no single, all purpose sensor or detector for a fire protection system and a well designed system usually requires a wide range of sensors for maximum system protection. Matching the specific type and configuration of the detector or sensor to a particular hazard is very difficult and a professional fire protection systems engineer who has experience with the design and operation of coal handling fire protection systems should be consulted.

5-25. Control system.

a. General. Control of the individual conveying system operations should be conducted from a single control room. The following items should be considered:

(1) The control system will be capable of providing a local manual, remote manual or fully automatic control of the conveying system.

(2) Conveyor controls will be interlocked to prevent coal spills in the event of a system malfunction and to shut the conveying systems down in a set sequence. The controls will provide a foolproof sequential method of starting and stopping upstream and downstream equipment in the conveying system.

(3) A locked remote control panel will be located next to each piece of equipment they control, so that the equipment can be locally operated by maintenance personnel. Local panels will be interlocked with main control panel so that both panels cannot be operated at the same time.

(4) Each system will be adequately monitored with alarm and control devices so that the operating status of the system can be determined from indicating lights on the control room graphic or mimic display panel.

(5) Indicating lights will be provided on a separate annunciator panel for belt misalignment, plugged chute, drive motor overload, emergency stop, zero speed, or any other safety device. The

lights tell the operator at the control panel which piece of equipment has tripped and also the reason.

(6) Motor operated gates and valves will be provided in locations requiring frequent operation, and properly interlocked for starting and stopping in the proper sequence.

b. Computerized control systems. A computerized control system such as a programmable controller (PC) is the most cost effective where logic functions must be accomplished. Advances in micro technology make the cost of computer type controls more economical than the relay based control systems. Field changes to the logic in a PC system can be made without wiring changes. Most units allow a program simulation mode, whereby the PC will diagnose the program and check the logic that has been entered. The computerized system is the preferred method of control.

5-26. En masse conveying system.

a. General. This type of system uses a conveying chain which utilizes the skeletal flight as opposed to a paddle flight, which can greatly reduce the horsepower requirements for the conveyor. The conveyor chain runs in a completely enclosed and sealed trough. The effective conveying capacity can reach as high as 90 percent of the cross sectional area. These conveyors have the ability to convey horizontally, inclined or vertically, which makes them extremely versatile.

(1) En masse type conveyors require approximately twice as much horsepower as a regular belt conveyor to move the same amount of material the same distance. They are also very susceptible to foreign material, which is not the case with belt conveyors. Special care has to be taken when handling abrasive or corrosive materials.

(2) En masse conveyors are advantageous for overbunker distribution systems, offering totally enclosed, multiple or individual discharges which do not require complicated or extensive chutework at the discharge points.

b. Chain. Use short pitch, drop forged alloy steel, carburized or case hardened to 500-600 Brinell Hardness Number (BHN). Each link should be easily removable without cutting any part.

c. Trough. Provide symmetrical panels for wear and maintenance. Sides and bottom plates will be

abrasion resistant and bolted for easy replacement.

d. Return rails. Hardness of rails will match the hardness of the conveying chain.

e. Drive sprockets. Provide a segmental type with reversible teeth sections, so that the complete drive shaft assembly does not have to be removed for maintenance. Teeth hardness will match chain hardness.

5-27. Pneumatic conveying systems.

a. General. Pneumatic conveying involves the movement of powdered, granular or other free flowing bulk materials along the pipeline with the aid of compressed air. Pneumatic conveying can be very basically categorized into two areas—dense phase and dilute phase. Suitable materials that can become fluid-like or fluidized are usually only suitable for pneumatic conveying. The product size can also restrict the use of this type of conveying medium. This type of system is sometimes used for moving small tonnages, up to about 50 tph.

(1) Materials that have a high moisture content, such as wet coal are difficult if not impossible to handle in a pneumatic type system.

(2) Pneumatic conveying systems are extremely inefficient when comparing tonnage moved to hp required to move the material with energy consumption as much as five times that of a belt conveyor.

(3) Exotic auxiliary equipment and very costly control components have to be compared with the minimal room requirements and ease of installation for this type of system.

b. Advantages and disadvantages.

(1) Advantages of pneumatic conveying systems are that they require little maintenance, take up less space than belt conveying equipment, are usually automatic (eliminating manual operations) and are totally enclosed, thus avoiding environmental fugitive emission problems, spillage and dust.

(2) Disadvantages of pneumatic systems are that they usually have a higher operating cost than belt conveying systems because compressed air is used to convey the material and there is a limitation on the maximum size material and the amount of fines that can be conveyed. Coal fines in excess of 40 percent will cause pluggage problems in the conveying pipe. Pneumatic conveying tends to create additional coal fines.

CHAPTER 6

ASH HANDLING

6-1. General.

This chapter addresses the requirements for the ash handling system for a coal fired boiler plant.

a. Design criteria. Ash handling systems were relatively simple prior to the enactment of stringent environmental regulations during the past twenty years. The ash was commonly quenched in wet ash pits and hydraulically discharged through ash sluice trenches to a sump pit and from there were pumped to an ash fill area. Bottom ash, pulverizer or mill pyrite rejects (pulverized coal fired plants only), economizer ash and fly ash are sometimes handled by individual, independent systems in plants now being designed.

b. Methods. A well accepted method of handling bottom ash and fly ash today is by the use of pneumatic conveying systems in stoker fired boilers. Ash is pneumatically conveyed to a storage silo without coming in contact with steam or liquid. Figure 6-1 shows a typical bottom ash and fly ash conveying system. Ash dust control conditioners have been developed to mix water with dry bottom ash and fly ash in the proper proportions to reduce the fugitive dust emissions during the transfer of ash from the storage silo to either trucks or railcars. Because of higher furnace temperatures and larger ash quantities in pulverized coal fired boilers, bottom ash has been water quenched and hydraulically conveyed. Dry bottom ash systems have been limited in quantity because of dry gravity flow. Continuous removal dry bottom ash systems are becoming available and allow reconsideration of dry bottom ash handling. Water filled bottom ash storage hoppers have been designed to accommodate large ash quantities. Bottom ash is periodically removed from the bottom ash hopper and hydraulically sluiced to an ash pond or to dewatering bins. Quantity and characteristics of ash produced in a coal fired boiler, and the ratio of fly to bottom ash depends on the coal being used, steaming rate, and method of burning. These factors, along with a LCCA of available ash handling systems will determine equipment selection. This chapter will consider hydraulic, mechanical and pneumatic ash handling systems.

6-2. System design.

a. General. There are many considerations involved in selecting an ash handling system for a coal fired boiler plant. These are as follows:

b. Boiler design and configuration. The boiler determines the amount of coal to be burned, and the percentage of fly ash to bottom ash. In a pulverized coal-fired boiler approximately 80 percent of all ash is fly ash and the remainder 20 percent is bottom ash. In a stoker fired boiler approximately 20 to 30 percent of the total ash content in the coal is fly ash with the remaining amount being bottom ash. The versatility of the boilers to burn a wide range of coals should be considered to determine the highest ash production rate when sizing the system conveying capacity.

c. Disposal conditions. Disposal to an ash pond or, alternatively, to storage bins or silos is a factor in selection of equipment. Ash ponds require large areas of land and must meet environmental regulatory restrictions. Ash storage bins require less space and are environmentally more compatible than ash ponds; however, the ash must ultimately be removed from the bin and disposed.

d. Water availability. The availability of water as a source for conveying ash, its pH rating and other chemical characteristics must be considered. If the water is not recycled, the environmental regulations of the discharged water must be considered. In most localities, untreated overflow is not permitted.

e. Type of coal. The type of coal to be burned, its ash content, sulfur content and its chemical constituents have an effect on the selection of the ash handling system. The coal with the highest ash content at the maximum continuous boiler steam output rating will be anticipated to assure adequate ash handling capacity. Ash from some coals with high calcium oxide content, such as western subbituminous coal, has a tendency to solidify when it comes in contact with water and should be handled dry to the disposal areas where it can be blown underwater from a closed bed truck.

f. Design capacity. The design criteria for selection of conveying capacity will be made to require the system to operate no more than 50 percent of the time or four hours in an eight hour shift. The remaining time is used for maintenance or catch up time on the ash handling system. The conveying time is based on the coal with the highest ash content which can be used in the boilers and with a 10 percent reserve margin on the estimated percent fly ash and bottom ash.

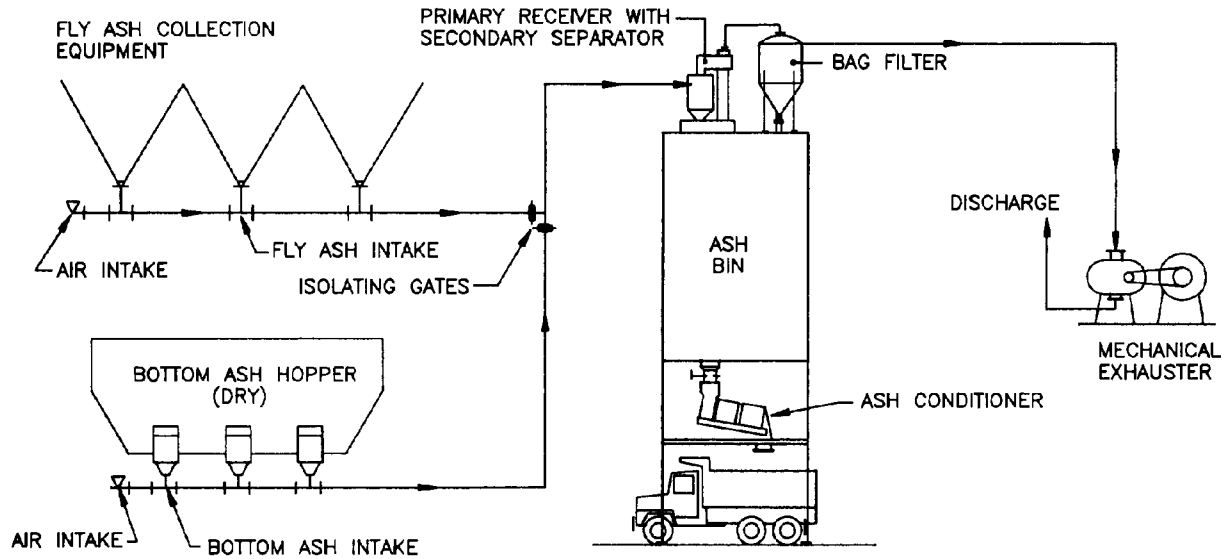


Figure 6-1. Pneumatic Conveyor—Bottom Ash and Fly Ash Mechanical Exhauster.

6-3. Bottom ash hydraulic conveying systems.

a. General. Hydraulic conveying systems are generally used for only bottom ash handling systems. Bottom ash is collected in a water impounded refractory lined steel hopper, which will be sized to store a minimum of twelve hours production of ash under the worst coal conditions at maximum continuous boiler steam output rating. The water impounded bottom ash hopper allows ash to fall through a clinker grinder or crusher where the ash is ground to a predetermined size prior to entry into a hydraulic ejector or in some instances to material handling pumps. The ash is sluiced from the plant to ash ponds or to dewatering bins. Figure 6-2 shows a typical sluice conveyor arrangement. The ash slurry is conveyed by a system of ash sluice centrifugal pumps. Ash handling pumps are discussed in paragraph 7-13. Most hydraulic ejectors are jet pumps requiring high pressure ash sluice centrifugal pumps to supply the water that is used to convey the ash to the storage area. This arrangement eliminates the need for a downstream transfer tank and the use of pumps to convey the abrasive ash slurry as shown in figure 6-3. The high pressure ash sluice pumps are also used for hopper washdown nozzles. Low pressure ash sluice centrifugal pumps supply water for bottom ash hopper furnace sealing and for coaling the refractory lined hoppers, and inspection windows.

b. Ash ponds. The ash ponds receive the ash slurry from the bottom ash hopper. Ash ponds must be sealed to prevent seepage into ground water. Ash ponds can be constructed in a manner to allow the water to be stored and returned to the plant for

reuse. The ash ponds which act as a solid liquid separator must have a considerable area since retention time is the only means to allow ash to settle and separate from the conveying water. If fly ash is conveyed to the ash pond, the pond must be greatly enlarged because of the extremely slow settling rate.

c. Dewatering bins. Dewatering bins receive the ash water slurry and drain the water from the accumulated ash. Dewatering bins, like the ash ponds, can work in a closed system or an open system where water is allowed to drain to waste. In most cases the discharge of water is not allowed by regulation, so a closed recycling dewatering system will be discussed. After passing through the bottom ash hopper the ash is pumped to two dewatering bins. While one bin receives ash slurry the other bin is draining or decanting to separate the solids and liquids. The dewatered bottom ash is discharged from the bin to trucks or railcars as shown in figure 6-4. Each dewatering bin will be sized for at least 36 hour storage for a total of 72 hours storage for long weekends when trucks or rail service is not available. The dewatering bins will be designed with a 30-degree angle of repose for the ash at the top of the bins. The dewatering bins will be designed to hold the determined ash capacity at an ash/water density of 62.4 pounds per cubic foot (pcf) and be designed structurally for an ash/water density of 110 pcf. From the dewatering bins which act as the solid/liquid separator, the decanted water with some entrained ash fines flows by gravity into a settling tank for the second stage of separating the ash from the sluicing water. The settling tank

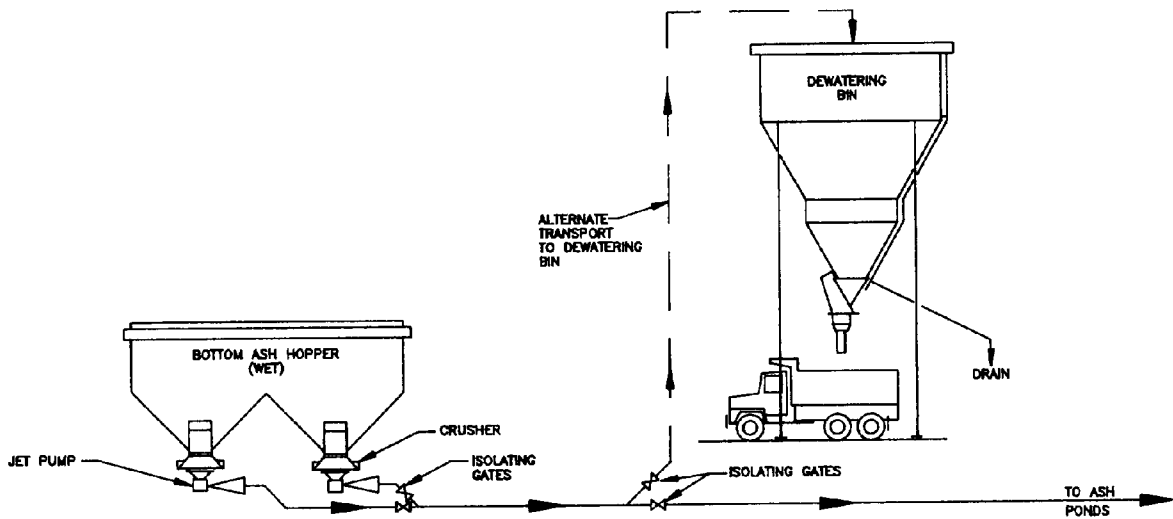


Figure 6-2. Sluice Conveyor—Bottom Ash.

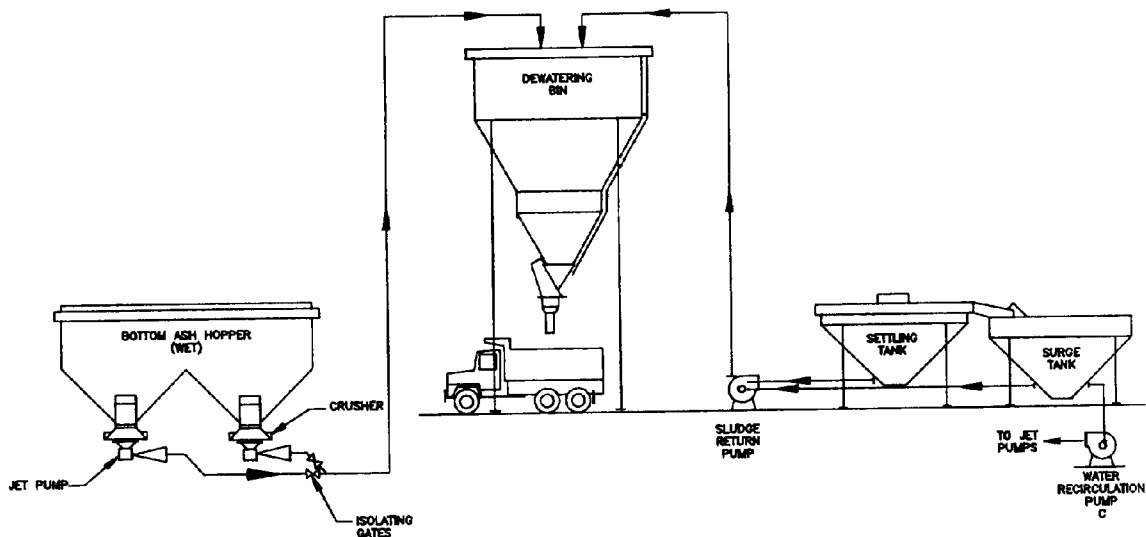


Figure 6-3. Recirculating Sluice Conveyor Jet Pump Transfer—Bottom Ash.

overflows into a surge tank which is the third and final stage of the closed recirculation system. The surge tank is sized to accommodate the overall coaling and conveying water demands of the bottom ash system. The decanted ash sluice water is returned to the ash conveying system for recycling. The ash sludge which is collected in the settling and surge tanks are returned to the dewatering bins by the use of sludge return pumps. A dewatering system is much more compact but usually more expensive to purchase and operate

than an ash pond system. Climatic conditions may require this system to be enclosed and piping heat traced to avoid freeze up problems.

6-4. Bottom ash handling system alternatives.

a. *Submerged drag chain mechanical transport system.* Mechanical transport systems collect bottom ash in a water impounded hopper. The hopper includes a water seal to prevent escape of the boiler furnace flue gases into the environment and to prevent ambient air from entering the boiler. The

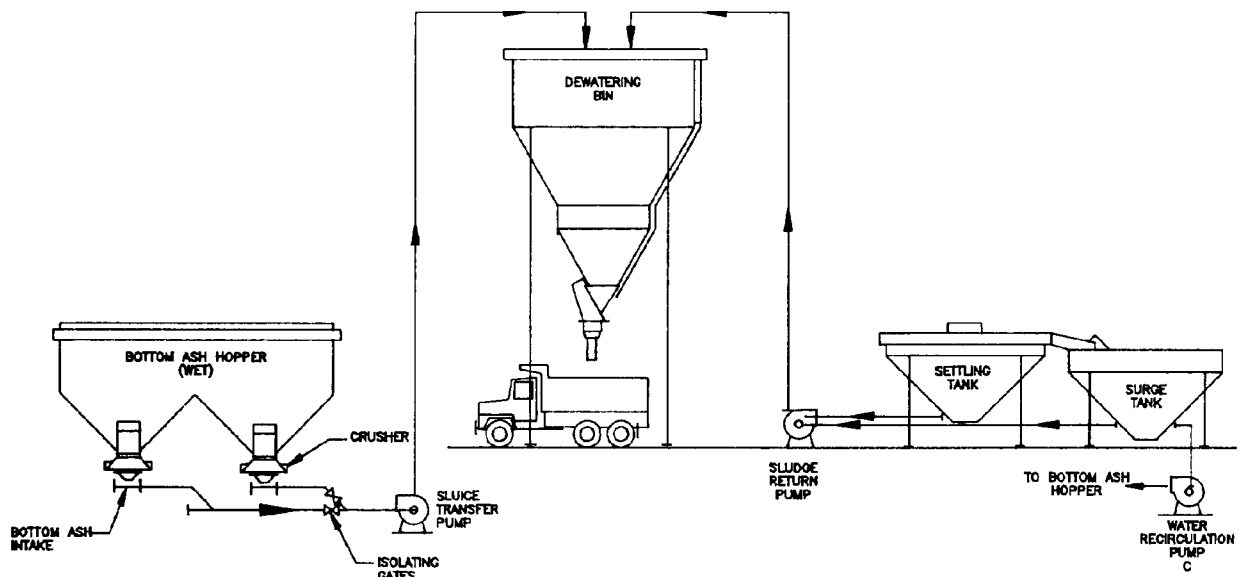


Figure 6-4. Recirculating Sludge Conveyor Mechanical Pump Transfer—Bottom Ash.

ash is continuously removed by a submerged scraper conveyor. The ash is then conveyed to either a storage bin with a capacity of up to three days or to a bunker for front end loader/truck removal. The water is recirculated into and out of the submerged trough to maintain a temperature below 140 degrees F. Overflow water from the trough is filtered through tanks before it is recirculated into the system. Surge tanks are small compared to the dewatering system tanks.

b. Sizing. The submerged scraper conveyor must be sized so that the rate of ash removal will be at least as great as ash production at maximum continuous boiler steam output rating under worst fuel conditions. Mechanical transport has several advantages over hydraulic transport. The ash removed is dewatered, it requires a lower boiler setting height and reduces power and water consumption. However, ash storage in a submerged scraper conveyor is limited and maintenance must be done in a relatively short period of time. Expensive standby conveyors and transition hoppers are often needed to provide time to perform maintenance. The submerged scraper conveyor is not commonly used in the United States because the reliability of the system in past years has been too low. There is some renewed interest by industry in the use of this type of system because of the recent improvements in the reliability and its wider acceptance in the European countries. Also in current use in Europe is a continuous dry removal system utilizing moving stainless steel belting and introduction of additional air to complete combustion and cool the ash.

6-5. Fly ash pneumatic systems.

a. Pneumatic systems. This type of system is usually used to transport fly ash from the fly ash collection equipment storage hoppers to the ash storage silo. The tendency of some types of fly ash to form scale inside hydraulic fly ash conveying lines and its extremely slow settling rate in water when coupled with the environmental liquid discharge limitations have severely restricted the use of the wet type fly ash conveying system. An advantage of pneumatic systems is they can be applied to both fly ash and bottom ash for stoker fired or fluidized bed boilers simplifying ash conveying and storage as shown in figure 6-5. Pneumatic systems are either vacuum or pressure types of system. A vacuum system pulls ash from the fly ash storage hoppers by means of mechanical, steam or water powered exhausters and a filtering system. Vacuum systems, depending on capacity requirements, line configuration and plant altitude may be designed for vacuum levels ranging from 8 to 20 inches Mercury (Hg). Vacuum systems are generally preferable to pressure systems because the system piping joint leaks pull air into the system leaving a cleaner environment. A vacuum system is recommended for capacities of less than 60 tph per system. If the conveying distance is at a remote location of over 800 feet from the boiler plant an evaluation will be made to determine whether a vacuum or pressure system is more feasible. A comparison of vacuum systems and pressure systems are shown in table 6-1.

b. Pressure systems. A pressure system engages a positive displacement blower producing pressures

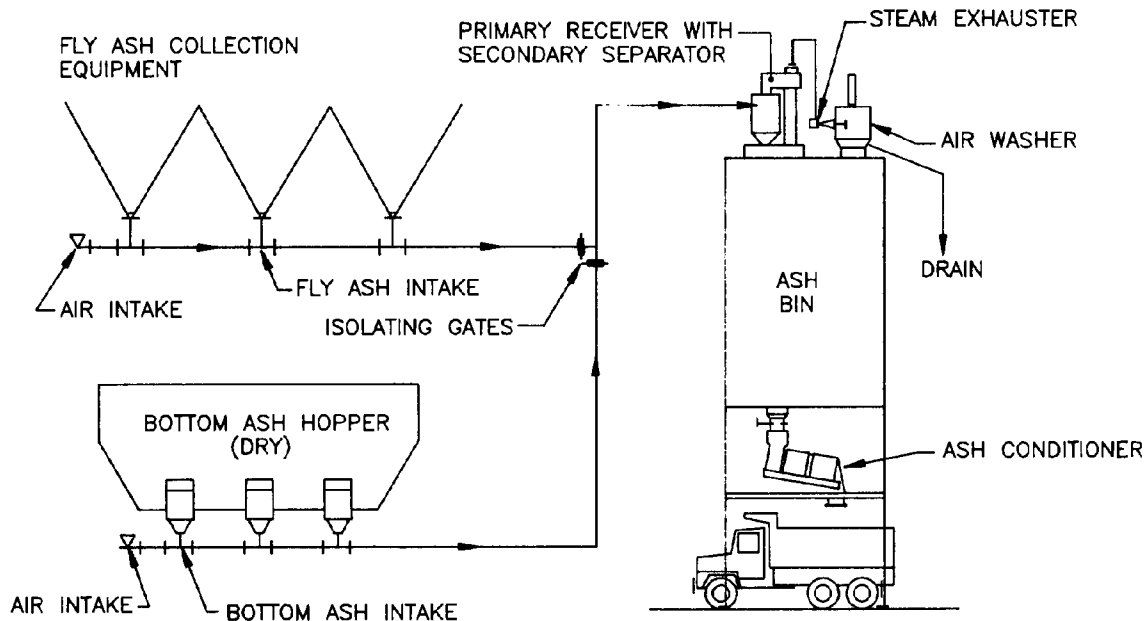


Figure 6-5. Pneumatic Conveyor—Bottom Ash and Fly Ash Steam Exhauster.

up to 20 psig for the conveying system as shown in figure 6-6. System capacity and long conveyor distances sometimes require higher blower pressures. Pressure systems may be used in lieu of vacuum systems because of higher capacities or longer conveying distances. Pressure type system should be avoided where possible because leaks of fine ash particles usually occur at the piping joints. Silo storage design is the same for a pressure system as for a vacuum system except that ash collectors are not required at the silo and fly ash is redeposited directly into the silo. There are two types of pressure systems, the dilute phase and dense phase. The dilute phase system usually has an ash to air volumetric ratio of 15 to 1 and sometimes it is as high as 30 to 1. A dense phase system has an ash to air ratio of 40 to 50 to 1 and is sometimes as high as 80 to 1. Vacuum systems are classified as dilute phase. A comparison of pressure dilute phase and dense phase systems is shown in table 6-2. The dilute phase pressure system is the more widely used pressure system. Dense phase pressure systems utilize a fluidizing transporter, a vessel in which air and ash is mixed, fluidizing the ash so that flow characteristics resemble that of a liquid.

c. *Vacuum/pressure systems.* In some rare cases, it may be more economical to combine a vacuum system with a pressure system where distance rules out the use of a vacuum system alone. Figure 6-7 shows a typical vacuum/pressure system. The vacuum system, with its simplified controls, removes ash at an optimum rate. The pressure

system, reduced to one transfer point with a minimum of controls, then delivers collected ash to any terminal point at a distance of several thousand feet. The vacuum pressure system provides the least complex controls of any long distance pneumatic conveying system.

d. *Ash storage silos.* Storage silos are usually constructed of carbon steel because of its lower cost and durability. Hollow concrete stave construction or reinforced concrete construction are sometimes used. The bottom of ash storage silos are equipped with aeration stones to fluidize the ash and induce flow from the silo to the discharge outlets. Silos will be designed for a minimum of sixty hours of storage, based on the design and production rate, utilizing an ash density of 60 pcf. The actual ash density can vary from 60 pcf depending on the coals being fired. The silo support structure will be designed for a full silo with fly ash density 100 pcf.

6-6. Controls

a. *General.* Programmable type control systems are used for both automatic and semi-automatic control. Older systems used electromechanical type control systems, many of which are still in operation.

b. *Types.*

(1) Programmable controllers (PC) have been applied to ash handling systems with good success during the last fifteen years and are the

Table 6-1. Comparison of Pneumatic Vacuum Versus Pressure Ash Conveying Systems.

	Vacuum Systems	Pressure Systems
<i>When Recommended</i>	Convey systems less than 60 TPH per system. Reasonable conveying distance.	High system capacity. Long conveying distances (greater than 1000 to 2000 feet).
<i>Advantages</i>	Less maintenance at hoppers. System leaks inward for cleaner environment. Multiple collecting points. Simpler control scheme.	Relative unlimited capacity. Relative unlimited conveying distance. No separating equipment. Clean air blowers multiple disposal points.
<i>Disadvantages</i>	Requires separating equipment and process bag filter. Blower life dependent on separating equipment reliability.	Double gates required with air lock. Air lock pressurizing and venting requires additional piping and valving. Ash leaks outward into the plant. Higher maintenance costs.

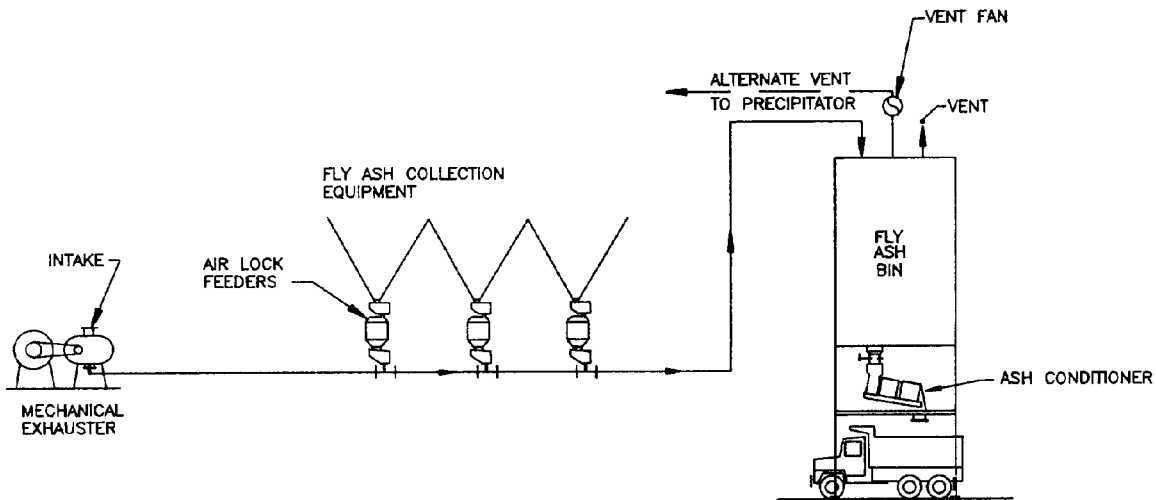


Figure 6-6. Pneumatic Conveyor—Pressure System Fly Ash.

most preferable type of control. The PC's ability to perform relay logic, timing, counting, and sequencing functions, provides a way to perform the tasks required for ash handling system control. A number of higher level PC's also offer more enhanced capabilities such as instruction, sophisticated report generation and off-line programming. The PC performs all ash handling controls and allows flexibility in control schemes giving the user many benefits. The PC has a memory and is programmable, providing the user with the ability to change the ash handling sequence

and timing and gives him the ability to troubleshoot, modify and expand with the system.

(2) Before the advent of the PC, both the bottom ash and fly ash made extensive use of the drum sequencer, electromagnetic timers and counters, and relay logic. The disadvantage of the electromechanical system is the large amount of relay control required for the drum sequencer; the periodic maintenance required for the drum sequencer, the large amount of panel area required; the extensive wiring; and the inflexibility of the system when changes are required.

Table 6-2. Comparison of Pressure Dilute Phase and Dense Phase Pneumatic Ash Conveying Systems.

	Dilute Phase	Dense Phase
<i>Design Criteria</i>	Evenly loaded single conveying line. Loading ratio (5 to 22) lbs. of ash to lb. of air. 10 to 30 psig operating pressure. 2000 to 3500 ft per mm starting velocity.	Typically multiple convey lines. Loading ratio (20 to 200) lbs. of ash to lb. of air. 30 to 100 psig operating pressure. 600 to 3000 ft per min starting velocity.
<i>When Recommended</i>	High conveying capacity (greater than 30 TPH) Long conveying distances (greater than 1000 ft).* Multiple disposal points. Minimum collection points.	Short conveying distances (200 to 500 ft).* Medium capacities (10 to 50 TPH). Minimum collection points. Minimum disposal points.
<i>Advantages</i>	Greater capacities and distances with single line. Not affected by material changes with gravity flow. Stable velocity range provides material re-entrainment. Transfer stations normally not required. Low initial cost air handling equipment Components subjected to lower pressure.	Smaller conveyor lines, bag filters and hoppers. Lower conveying velocity. Normally lower horsepower. Carbon steel pipe.
<i>Disadvantages</i>	Higher airflow, larger pipe, and hoppers. Often higher horsepower. Components subjected to higher velocity, Special pipe required-alloy pipe or ceramic lined pipe.	Material consistency greatly affects conveying parameters and granular material remains in airlock with top exist. Positive sealing high differential discharge valve is critical to system performance. Transfer stations normally required. Parallel compressed air lines required to free line plugs. Multiple conveyor lines. Expensive initial cost air compressors. Components subject to higher pressure.

*An evaluation should be made for conveying distances of 500 to 1000 ft to determine whether Dilute Phase or Dense Phase pneumatic ash conveying systems are more feasible.

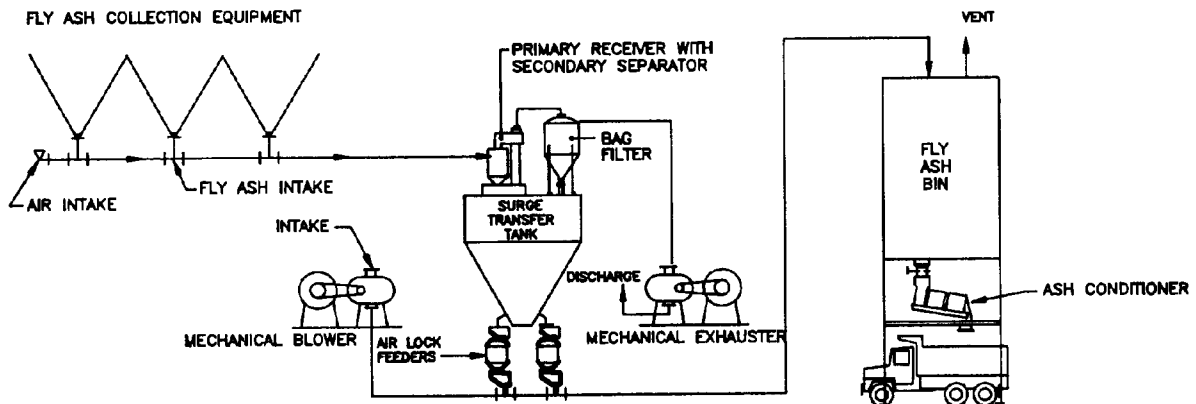


Figure 6-7. Pneumatic Conveyor—Vacuum System and Pressure System Fly Ash.

CHAPTER 7

MECHANICAL AUXILIARY EQUIPMENT

7-1. General.

This chapter addresses the criteria for the major steam plant auxiliary equipment.

7-2. Closed feedwater heat exchangers (CFHE).

a. Applications. CFHE may be used to raise feedwater temperature to the plant economizer and thus maintain the exit flue gas temperature above the acid dew point during low load operation. This application is possible for plant design in all size ranges. Other methods for keeping the exit flue gas temperature above the acid dew point are bypassing flue gas around the economizer or bypassing a portion of feedwater around the economizer which needs to be avoided. Bypassing the feedwater around the economizer at low load operation creates a potential for steam formation in the economizer. The CFHE is the most positive approach to maintaining the exist flue gas temperature. An evaluation will be made to determine the economic practicality of each method.

b. CFHE design. Each CFHE will be a U-tube type heater to minimize stresses caused by thermal expansion. Tube material selection is dependent on the quality of the water. Tubes of stainless steel construction will minimize the possibility of corrosion and erosion. High quality water will allow the use of 90/10 and 70/30 copper nickel (CuNi) material tubing.

c. CFHE design criteria. Data listed in table 7-1 are necessary to size CFHE.

Table 7-1. Closed Feedwater Heat Exchanger Design Parameters.

<i>Parameter</i>	<i>Engineering Units</i>
Feedwater flow	pph
Feedwater inlet temperature	degrees F
Feedwater outlet temperature	degrees F
Maximum feedwater velocity	fps
Maximum allowable tube side pressure drop	psi
Maximum tube side operating pressure	psig
Maximum shell side operating pressure	psig

Minimum recommended feedwater temperatures to the economizer are shown in figure 7-1. Minimum feedwater velocities are shown in figure 7-2.

7-3. Steam deaerators.

a. General. The steam deaerator (DA) heats boiler feedwater to improve plant efficiency and lowers dissolved oxygen and gasses that are corrosive to internal metal surfaces of the boiler. The standards of the Heat Exchange Institute (HEI), 1992, Fifth Edition, state that a DA should be guaranteed to remove all dissolved oxygen in excess of 0.005 cc/i.

b. Deaerator types. There are several types of steam DA with three acceptable types being: spray/tray type, atomizer or scrubber spray type and recycle type. DA heater should be counterflow design. Although some tray and recycle type DA's have a higher first cost, they will operate properly under rapid load changes and only require a 10 to 30 degrees F rise across the DA (inlet water temperature 10 to 30 degrees F lower than the DA outlet water temperature). Spray or atomizing type DA's can be used when steam loads are steady and the temperature rise across the DA is 30 to 50 degrees F or greater. Because of this performance limitation, tray or recycle type DA's will be used unless there is a steady steam load and the temperature rise in the DA is 50 degrees F or greater. If the latter conditions exist, the DA selection will be decided by a LCCA.

c. Deaerator design criteria. Deaerating heaters and storage tanks will comply with the ASME Unfired Pressure Vessel Code, ASME Power Test Code for Deaerators, Heat Exchange Institute, American National Standards Institute, and National Association of Corrosion Engineers Recommendations. One steam plant DA can be sized for multiple boiler units. At full load conditions, the water from the DA will have a temperature sufficiently high to prevent acid dew point corrosion of the economizer. In no case will the temperature rise in the DA be less than 20 degrees F or the minimum storage capacity at normal operating level be less than 10 minutes at the DA's maximum continuous load rating or less than 12 minutes full. Information contained in table 7-2 will be specified after a heat balance around the DA has been determined at full load conditions.

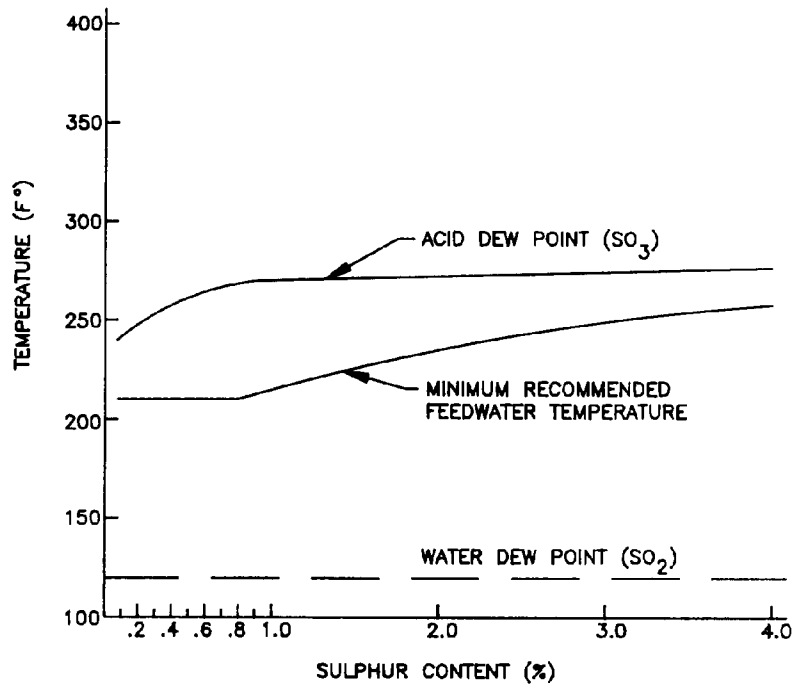


Figure 7-1. Minimum Recommended Feedwater Temperatures.

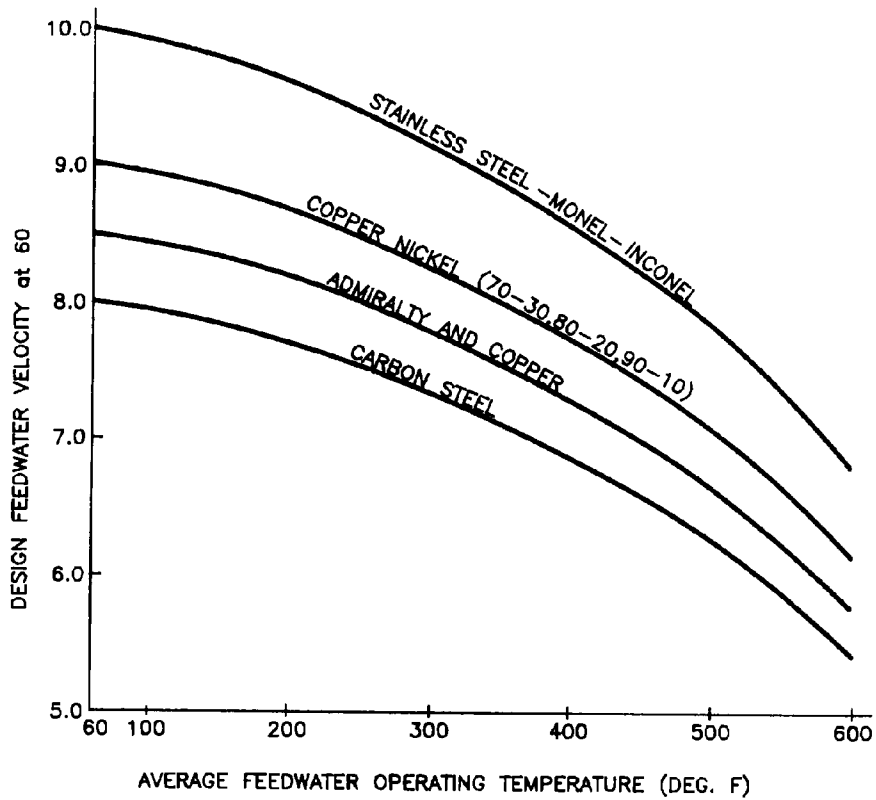


Figure 7-2. Design Feedwater Velocity at 60 Degrees F.

Table 7-2. Specified Deaerator Information.

Item	Engineering Units
Maximum plant capacity	pph
Maximum DA outlet capacity	pph
Make-up water temperature	degrees F
Condensate temperature	degrees F
Make-up water flow	pph
Condensate flow	pph
Steam temperature to DA	degrees F
Steam pressure to DA prior to control valve	psig
DA design pressure	psig
DA outlet water temperature	degrees F
DA outlet water flow	pph

7-4. Boiler feed pumps.

a. *General.* Boiler feed pumps convey water from the DA to the boiler.

b. *Design requirements.* Boiler feed pumps will comply with the latest revisions of Hydraulics Institute (HI) and ANSI. A minimum of one pump per boiler and one backup pump will be provided for all cases. The ASME Boiler and Pressure Vessel Code requires that coal fired boiler plants in this size range be provided with at least two means of feeding water. For stoker fired boilers, one source will supply sufficient water to prevent boiler damage during an interruption. A steam turbine driven pump is one method that is frequently used to meet this requirement. Multiple pumps permit backup capacity for individual pump failures or scheduled maintenance and increase efficiency of pump operations at reduced loads. Multiple pumps are usually more cost effective for boilers subjected to large daily load swings. This arrangement allows the pumps to operate in a more efficient range and gives the system more flexibility. The use of multiple pumps will provide for between 50 and 100 percent of additional capacity beyond the expected operating loads.

c. *Steam turbine drives vs electric motor drives.* Steam turbine drives provide a more thermally efficient system, but in this size range they can be less economical on a LOCA than electric motor drives. However, as noted above, the ASME Boiler and Pressure Vessel Code requires that both steam turbine and motor drives be used in stoker fired boiler plants with capacities of 35,000 pph and above. Steam turbine drives will not be used exclusively. An electric motor drive makes it easier to bring a boiler on line from a cold start.

d. *Boiler feed pump sizing.* Boiler feed pumps will be sized to deliver the desired flow and pressure to the boilers from the DA. A 10 percent flow margin for wear allowance will be included when sizing the pump. These conditions are determined by first defining the items listed in table 7-3.

Table 7-3. Boiler Feed Pumps Capacity Criteria.

Item	Engineering Units
Boiler steam outlet pressure	psig
Boiler water side pressure losses	psi
Water temperature entering pump	degrees F
Piping losses	psi
DA operating pressure	psig
Pump elevation relative to boiler and DA	ft
Net positive suction head required (NPSHR)	ft

(1) Calculation of net positive suction head available (NPSHA). Determining the NPSHA is an important design consideration for boiler feed pumps because they take water from the DA at saturated conditions. To prevent cavitation of a pump operating at elevated temperatures, the DA is elevated to increase the static pressure at the pump suction and overcome the vapor pressure. The boiler feed pump vapor pressure is equal to the DA operating pressure and cancel out each other. Thus, boiler feed pump NPSHA is the head of water from the DA to the pump inlet minus the pipe friction loss. A safety margin of at least one foot of head will be subtracted from the calculated NPSHA to obtain the net positive suction head required (NPSHR).

(2) Discharge head calculation. The boiler feed pump discharge head will be designed to overcome the boiler drum pressure, valve and piping losses within the boiler and external to the boiler as well as the head of the water column.

e. *Pump construction.* The boiler feed pumps will be constructed to provide continuous operation for the expected plant life. Pump manufacturers should be consulted regarding specific features of construction for a particular application. In general, lower pressures and flows could use vertical in-line pumps with stainless steel shaft, impellers, and impeller casings. Suction and discharge chambers on vertical pumps will be cast iron. For higher pressure and flow applications casings will be 11 to 13 percent chrome steel, split on the horizontal centerline with suction nozzles, discharge nozzles and feet on the lower half of the casing so the top half of the casings can be removed without

disturbing the main piping. These applications will also include shafts constructed of stainless steel, containing not less than 11 percent chrome. The impellers will be of the closed type, cast in one piece. All internal parts of the pumps including impellers, sleeves and wearing rings, will be constructed of stainless steel containing not less than 11 percent chrome.

7-5. Condensate pumps.

a. General. The condensate pumps convey condensate from condensate return storage tank to the DA.

b. Design requirements. A minimum of two condensate pumps will be used, each sized for at least two thirds of the maximum steam plant demand. This configuration will provide backup capacity for individual pump failures or scheduled maintenance and will increase pump operation efficiency at reduced loads. Steam turbine driven pumps may be more economical than electric motor driven pumps. However, one electric motor driven pump facilitates cold start-up of the boiler plant. A LCCA will be made to determine the most practical combination of condensate pumps.

c. Condensate pump sizing. The condensate pump discharge head needs to be designed to overcome the water static head to the DA, the piping losses and the DA operating pressure. A 10 percent flow margin for wear allowance will be included when sizing the pump. The condensate pump discharge head and suction head available will be determined when the operating conditions are defined, an arrangement of the equipment has been made, and a pipe size and routing has been made.

d. Pump construction. Pumps will be constructed so they will provide continuous operation for the expected plant life. Pump manufacturers should be consulted regarding specific features of construction for a particular application. The pump impellers will be split ring key type. Bearings will be of the water lubricated sleeve type. The baseplate, outer barrel, inner column and discharge head will be carbon steel. The impeller will be bronze and the pump bearings graphalloy. The stage bowl will be cast iron. The shaft, shaft sleeves and wearing rings will be 11 to 13 percent chrome stainless steel. When the pump design conditions do not require a vertical can type pump as described above, the pump may be centrifugal, horizontal end suction, top discharge type as described below. The pump impellers will be totally open type, screw mounted directly to the shaft with O-ring seal and constructed of ductile iron. Impellers will be dynamically balanced to the

maximum rated speed. The pump construction will include antifriction bearings that operate in an oil bath. Pump and bearing frame and housing will be constructed of cast iron. Casing will be constructed of ductile iron. Minimum casing thickness will be ½ inch with an additional 1/8 inch corrosion allowance. The shaft, shaft sleeves and wearing rings will be 316 stainless steel.

e. Turbine drives. The turbine drives will be sized to match the runout hp of the pump. Turbine drives will be horizontal split case construction. The steam chest will be case iron or cast steel. The rotor shaft will be annealed carbon steel and the rotor disc a high strength alloy steel.

7-6. Air compressors.

a. Applications. Two compressor applications are used in a steam plant: plant air and instrument air. Plant air is the dry air used to atomize fuel oil, blow soot deposits from the boiler furnace and heat recovery equipment, run plant pneumatic tools, and perform other general plant functions. Instrument air is oil free, dry air supplied to instruments and pneumatic controls control valves and control drives. Instrument air is also used to clean fly ash baghouse filter bags.

b. Compressor types. Compressors are available in two types. The first type is positive displacement, such as the reciprocating piston compressor. The second type is dynamic, such as the centrifugal compressor. Each type can be furnished with single stage or multiple stage design. Reciprocal and centrifugal compressors are the industry standard for compressors used in boiler plants. Centrifugal compressors are usually considered for selection when the compressed air demand is uniform and is equal to or above 400 standard cubic feet per minute (scfm). Otherwise reciprocating compressors are usually used.

c. Instrument air compressor sizing criteria.

(1) *Required volume of air.* The required volume of air needed is found by adding all simultaneous air usages together. With instrument air, the highest usages generally occur during boiler start up when lighters are inserted or when fly ash baghouse filter bags are being cleaned.

(2) *Outlet pressure.* The compressor outlet pressure will be sufficient to supply air at the required pressure, after line losses, to the device requiring the highest pressure in the instrument air system. Pressure regulators will limit the pressure to devices operating at lower pressures.

d. Plant air compressor sizing criteria.

(1) *Required volume of air.* The required volume of air needed is found by adding all simultaneous air usages together. One of the highest

usages of plant air occurs when air soot blowers are used in the boiler. Steam soot blowers may be used eliminating the need for air soot blowers. Other usages which must be considered are air tool demand and cleaning coal handling dust bags.

(2) *Outlet pressure.* The compressor outlet pressure will be sufficient to supply air at the required pressure, after line losses, to the device requiring the highest pressure in the plant air system. Pressure regulators will limit the pressure to devices operating at lower pressures.

e. Compressor auxiliaries.

(1) *Aftercoolers/intercoolers.* Intercoolers are used on any compressor having more than one stage, and all compressors will have aftercoolers. Aftercoolers will be pipeline type units with air-in-tube, water-in-shell construction and designed with a 20 degrees F approach.

(2) *Air dryers.* All air compressors will have air dryers installed immediately downstream of the aftercoolers. The dryers will be designed to maintain a dew point at line pressure which is lower than any ambient temperature to which pressurized air lines are exposed.

(3) *Receivers.* Receivers will be sized based upon a timed usage of a volume of air. The required tank volume will be determined using equation 7-1:

$$T = \frac{V \times (P_1 - P_2)}{C \times P_0} \quad (\text{eq 7-1})$$

T = time in minutes receiver will supply air from upper to lower pressure limits (use 15 seconds)

V = volume of tank, in cubic feet

P₀ = absolute atmospheric pressure, psia

P₁ = maximum tank pressure, psia (compressor discharge pressure)

P₂ = minimum tank pressure, psia (pressure required to operate tool)

C = amount of cubic feet of free air needed per minute, cfm (air at ambient temperature and pressure)

f. General design criteria.

(1) The total air capacity will be increased by a factor of 1.1 to 1.2 to account for leakage.

(2) Both the instrument air and the plant air systems will consist of two compressors tied to a common header. Backup capacity of 100 percent will be provided so maximum compressed air demand can be satisfied with one compressor out of service.

(3) The headers for instrument air and plant air will have an emergency cross-connection equipped with oil removal equipment to protect the instrument air system.

(4) Plant air compressor will be designed to be loaded 50 percent of the time at maximum load. Instrument air compressor is to be sized for 40 percent loading at maximum load. Centrifugal compressors can be loaded 100 percent of the time.

(5) Provisions will be made to allow drainage of water from all coolers and receivers by means of traps or manual valving.

(6) Separate receivers will be placed near area of large air demands. It may be more economical to supply separate air systems for air soot blowers and baghouse cleaning systems.

7-7. Boiler feedwater treatment.

a. General. Feedwater treatment is necessary to prevent corrosion of metals, formation of deposits and to minimize boiler water solids carryover. Boiler water treatment guidelines are discussed in AR 42049. For boilers operating at 400 psig, constituents in the feedwater must be controlled so that the maximum water limits for boiler feed-water and boiler water shown in tables 7-4 and 7-5 can be maintained with minimal boiler blow-down, since the higher the blowdown rate, the greater the thermal loss. An evaluation will be made to determine the costs of thermal losses due to blowdown versus the costs of high quality treated water.

Table 7-4. Boiler Feedwater Limits.

Drum Pressure (psig)	Iron (ppm Fe)	Copper (ppm Cu)	Total hardness Calcium carbonate (ppm CaCO ₃)
0-300	0.100	0.050	0.300
3010-450	0.050	0.025	0.300

Table 7-5. Boiler Water Limits.

Drum pressure (psig)	Silica silicon dioxide (ppm SiG)	Total Alkalinity calcium carbonate (ppm CaCO ₃)	Specific conductance (micromhos./cm)
0-300	150	700	7000
301-450	90	600	6000

b. Design requirements. Before a plant water treatment system is designed, a thorough raw water analysis will be obtained as shown in table 7-6.

The raw water condition can vary widely even within a small regional area and can greatly effect the options and economics available for water treatment equipment. Also, the purity and quantity

of condensate available as feedwater is to be established. From this information the actual feedwater constituents to be treated can be determined. The water treatment requirements for the plant can then be identified based on the allowable boiler water limits and the desired amount of continuous boiler blowdown (use 1 percent of boiler maximum continuous rating as a starting blow-down value).

Table 7-6. General Raw Water Analysis.

Water properties	Milligrams/Liter As the ion or as Shown
Calcium	64.5
Silica	9.1
Magnesium	20.7
Sodium	70.0
Sulfate	182.0
Chloride	23.3
Bicarbonate	211.0
Nitrate	4.0
Total hardness	248.0
Carbonate hardness	173.0
Noncarbonate hardness	73.0
Total alkalinity	166
Conductivity - microseim per per centimeter	731
pH	8.2

Note: Water characteristics will vary by location.

c. *Treatment.* Water treatment is generally categorized by external treatment or internal treatment. External treatment dampens, softens, or purifies raw water prior to introducing the water into the feedwater system. Internal methods introduce chemicals directly into the feedwater or boiler

water where they regulate the undesirable effects of water impurities. Blowdown is used in the evaporative process to control the concentration of dissolved and suspended solids. Methods of water treatment include filtration (reverse osmosis), deaeration (para 7-3 above) and degasification, cold or hot lime softening, sodium zeolite ion exchange, chloride cycle dealkalization, demineralization, internal chemical treatment, and blowdown. Several internal treatment methods commonly used to treat boiler water include phosphate hydroxide or conventional treatment method, chelent method, polymer method (feedwater < 1.0 ppm Ca as Ca CO₃), and coordinated phosphate/pH (high purity ≤ 15 mirohms conductivity). These chemical internal treatment methods can be used in conjunction with external treatment methods. After a raw water analysis has been made, a water treatment specialist should be consulted and an evaluation should be made on the practicability of a combination of internal and external treatment methods. It is usually more cost effective to externally pretreat the feedwater as much as practical. This discussion concerns boiler feedwater treatment equipment. It is assumed that water delivered to the feedwater equipment is of a pretreated, clear, potable quality free of organic materials.

d. *Boiler feedwater treatment equipment.* The industry standards for reducing water constituents in boilers with an operating pressure of 400 psig are reverse osmosis, ion exchangers, or combinations of the two.

(1) Reverse osmosis (RO) is a filtration method which removes approximately 90 percent of all inorganic dissolved solids from the feedwater. Reverse osmosis can be used alone, as shown in figure 7-3, but is more generally used with regenerative ion exchange equipment (demineralizer) as shown in figure 7-4. The viability of using reverse osmosis will be determined by a LCCA.

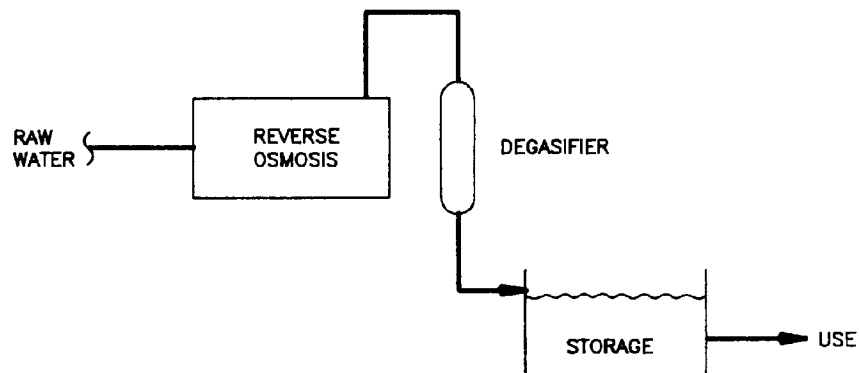


Figure 7-3. Boiler Feedwater Treatment with Reverse Osmosis Only.

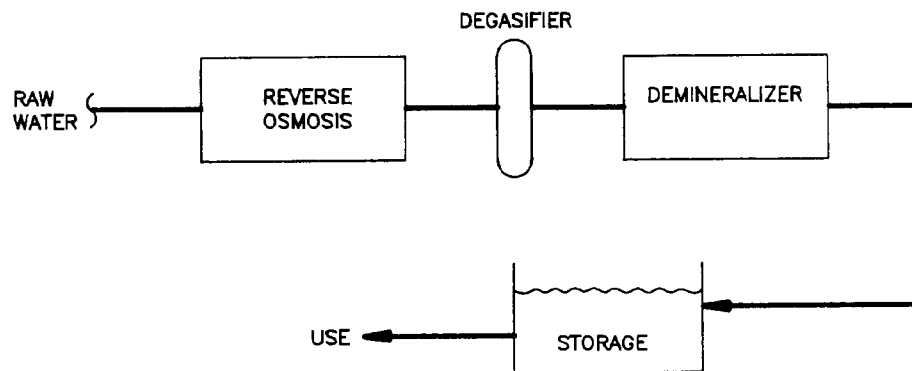
(2) Sodium zeolite (NaZ) softeners are used to remove calcium (Ca) and magnesium (Mg) from the feedwater. NaZ softeners do not remove silica, bicarbonate, or carbonate, and should be used alone when these constituents are not a problem in the boiler feedwater. A typical NaZ softener is shown in figure 7-5.

(3) A split stream softener with degasifier should be used when it is necessary to remove hardness (Ca, Mg) and carbon dioxide (CO₂) formed from bicarbonate and carbonates. A typical split stream system is shown in figure 7-6. The use of split stream versus other options will be decided by means of a LCCA and an evaluation of applicable safety restrictions. This particular type system will result in a reduction of total dissolved solids (TDS).

(4) Chloride anion exchangers

(dealkalizer) may be used in conjunction with NaZ softener to remove carbonate, bicarbonate and CO₂. Used in this manner, the dealkalizer takes the place of a hydrogen cycle softener and degasifier in the split stream system. A dealkalizer application is shown in figure 7-7. This particular type system will not reduce TDS.

(5) A weak cation exchanger, regenerated with acid, followed by a strong acid cation exchanger, salt regenerated, can be used in conjunction with a degasifier. The weak acid exchanger will remove the alkalinity and the hardness associated with alkalinity, and the salt regenerated strong acid cation exchanger will remove the balance of the hardness. This balance will depend on the hardness to alkalinity ratio of the raw water. The degasifier will be used to strip the CO₂ formed in the weak acid exchange process.



Boiler feedwater treatment with reverse osmosis and demineralizer.

Figure 7-4. Boiler Feedwater Treatment with Reverse Osmosis and Demineralizer.

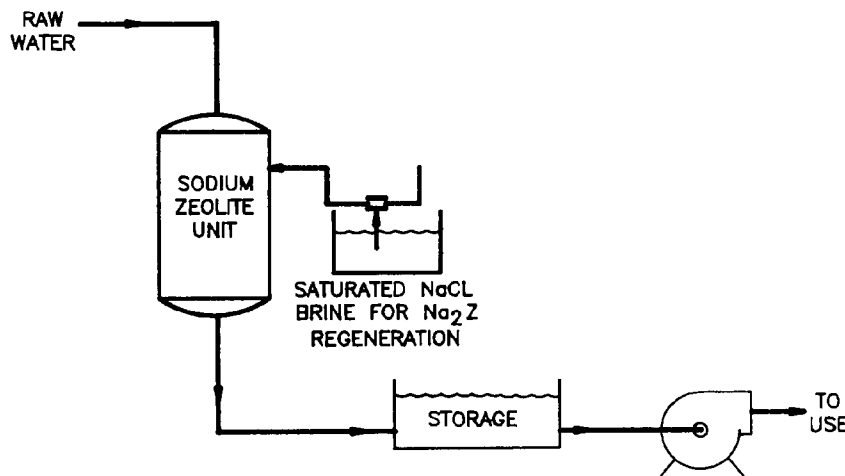


Figure 7-5. Sodium Zeolite Unit.

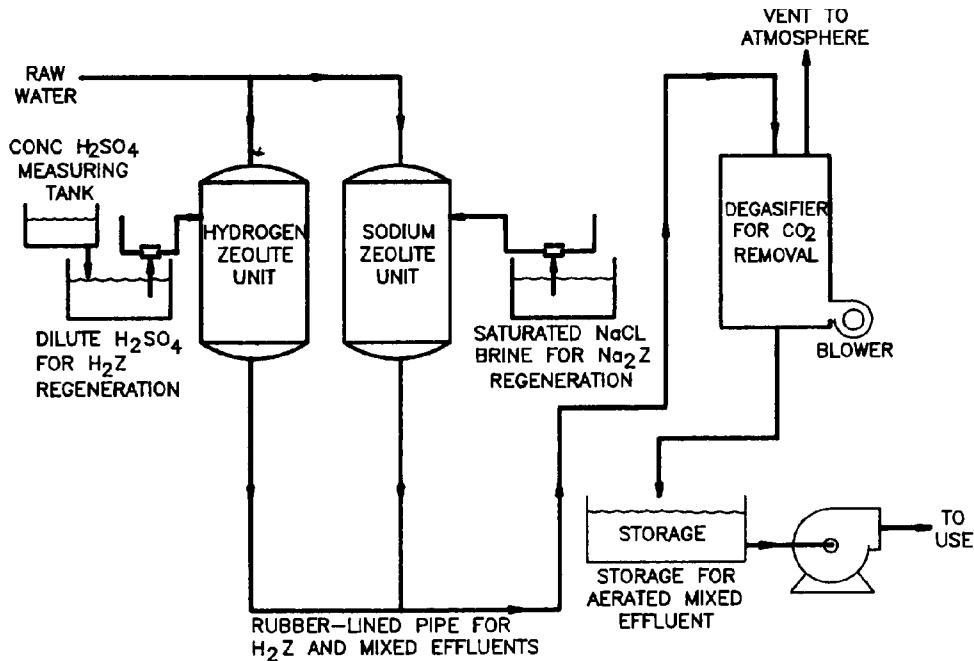


Figure 7-6. Hydrogen and Sodium Zeolite Units in Parallel.

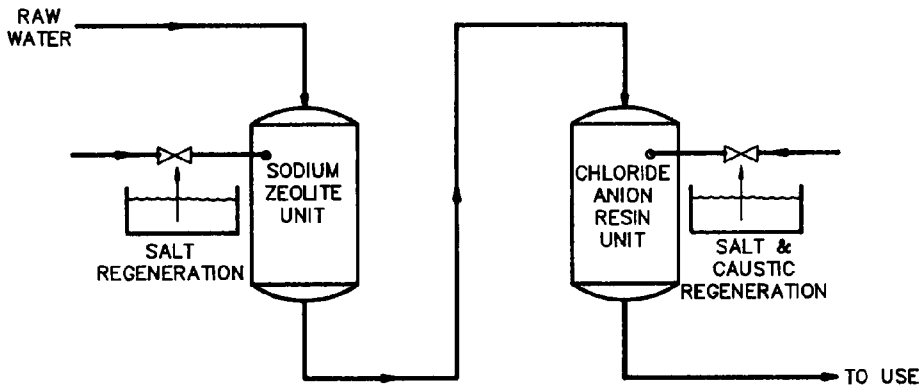


Figure 7-7. Sodium Zeolite-Chloride Ion Exchanger.

(6) Demineralizers produce very high quality water—higher than is generally required for a boiler operating at 400 psig.

7-8. Blowdown tank.

a. *Application.* Pure water vapor is generated in a boiler and the impurities (dissolved solids) of the boiler feed water remain and become concentrated. The concentration of dissolved solids can be controlled by withdrawing the boiler water with a high concentration of dissolved solids as blowdown and discharging it safely to waste through a blowdown tank. Every boiler - system has two types of blowdowns. The upper blow-down of

either intermittent or continuous operation is used to control concentrations of dissolved solids. It is connected to the steam drum of a water tube boiler in such location as to minimize the inclusion of feedwater, chemical feed and steam entrainment. The other blowdowns from the mud drum or the water walls are intermittent or mass blowdowns which removes accumulated solids and sludge from stagnated areas of the boiler, usually at reduced steam loads. A blowdown tank allows the hot water to flash to steam leaving the concentrated impurities to be more safely drained to waste. The flashed steam can be vented to atmosphere or can be used in a heat recovery system.

b. *Design.*

(1) Blowdown tanks will be designed and constructed in accordance with the ASME Boiler and Pressure Vessel Code, Section VIII. The amount of boiler blowdown capacity is determined to be a percentage of the boiler firing rate. The percent of boiler blowdown is governed by the allowable concentration ratio (CR) or the number of times a dissolved solid may be concentrated over the amount of dissolved solid in the feedwater. The allowable concentration ratios are determined by a chemical analysis of the boiler feedwater and by the type of makeup water treatment. The continuous blowdown rate can be determined using equation 7-2:

$$R = \frac{B}{A-B} \times Q \quad (\text{eq 7-2})$$

- R = Blowdown rate (pph)
- A = Predetermined boiler water concentration as total solids (ppm)
- B = Total solids in feedwater to boiler (ppm)
- Q = Steam output (pph)

A boiler operated on exceptionally high quality feedwater will have very little blowdown. The size of the blowdown tank will be determined from table 7-7. Blowdown, steam and water connection sizes are shown in table 7-7. The tank will have openings to allow cleaning and inspection. The blowdown tank should have a blowdown inlet connection, a water outlet connection, a vent connection, a cold water supply line, a drain connection, a thermometer connection, and a pressure gauge.

Table 7-7. Blowdown Tank Size.

Boiler Design Pressure (psig)	*Blowdown Size (Inches)	Cold Steam Vent Size (Inches)	Water Inlet Size (Inches)	Water Outlet Size (Inches)	**Blowdown Tank Size (Dia x Ht.)
20 to 50	3/4	2	3/4	1 1/2	14" x 5'6"
	1	2	1	1 1/2	14" x 5'6"
	1 1/2	2	1 1/4	2 1/2	14" x 5'6"
	1 1/2	2 1/2	1 3/4	2 1/2	14" x 5'6"
	2	3	2	4	18" x 6'0"
51 to 100	2 1/2	4	2	4	20" x 6'0"
	3/4	2	1	1 1/2	14" x 5'6"
	1	2 1/2	1 3/4	2	14" x 5'6"
	1 1/4	3	1 1/2	3	18" x 6'0"
	1 1/2	4	2	4	18" x 6'0"
101 to 150	2	5	2 1/2	4	24" x 6'0"
	2 1/2	6	2 1/2	5	30" x 6'6"
	3/4	2 1/2	1	2	14" x 5'6"
	1	3	1 1/4	3	14" x 5'6"
	1 1/4	4	1 1/2	3	20" x 6'0"
151 to 200	1 1/2	5	2	4	24" x 6'0"
	2	6	2 1/2	4	30" x 6'6"
	2 1/2	8	2 1/2	4	39" x 6'6"
	3/4	3	1	2	14" x 5'6"
	1	4	1 1/4	2 1/2	18" x 6'0"
201 to 300	1 1/4	5	2	3	24" x 6'0"
	1 1/2	6	2	4	30" x 6'6"
	2	8	2 1/2	4	39" x 6'6"
	2 1/2	8	3	5	48" x 6'6"
	3/4	4	1 1/4	2	18" x 6'0"
301 to 400	1	5	1 1/2	2 1/2	24" x 6'0"
	1 1/4	6	2	4	30" x 6'6"
	1 1/2	6	2 1/2	4	36" x 6'6"
	2	8	3	5	48" x 6'6"
	2 1/2	10	3	6	54" x 7'0"
400	3/4	4	1 1/4	2 1/2	20" x 6'0"
	1	5	1 1/2	3	24" x 6'0"
	1 1/4	6	2	4	33" x 6'6"
	1 1/2	8	2 1/2	4	42" x 6'6"
	2	10	3	5	54" x 7'0"
	2 1/2	10	4	6	66" x 7'0"

Table 7-7. Blowdown Tank Size. (Continued).

Boiler Design Pressure (psig)	*Blowdown Size (inches)	Cold Steam Vent Size (Inches)	Water inlet Size (Inches)	Water Outlet Size (inches)	**Blowdown Tank Size (Dia x Ht.)
401 to 500	3/4	4	1/4	2 1/2	20" x 6'0"
	1	5	1 1/2	3	27" x 6'6"
	1 1/4	8	2	4	39" x 6'6"
	1 1/2	8	2 1/2	4	48" x 6'6"
	2	10	3	5	60" x 7'0"
	2 1/2	12	4	8	72" x 7'0"
501 to 600	3/4	5	1/4	2 1/2	24" x 6'0"
	1	6	1 1/2	3	30" x 6'6"
	1 1/4	8	2 1/2	4	42" x 6'6"
	1 1/2	10	2 1/2	5	54" x 7'0"
	2	12	3	6	66" x 7'0"
	2 1/2	12	4	8	72" x 7'0"
601 to 800	3/4	5	1/4	2 1/2	27" x 6'6"
	1	6	1 1/2	3	36" x 6'6"
	1 1/4	8	2	4	48" x 6'6"
	1 1/2	10	2 1/2	5	60" x 7'0"
	2	12	3	6	72" x 7'0"
	2 1/2	12	4	8	72" x 7'0"
801 to 1000	3/4	6	1/4	2 1/2	30" x 6'6"
	1	8	1 1/2	3	42" x 6'6"
	1 1/4	10	2 1/2	4	54" x 7'0"
	1 1/2	10	3	5	66" x 7'0"
	2	12	4	6	72" x 7'0"
1001 to 1500	3/4	8	1/4	2 1/2	36" x 6'6"
	1	8	2	4	48" x 6'6"
	1 1/4	10	2 1/2	4	66" x 7'0"
	1 1/2	12	3	5	72" x 7'0"
1505 to 2000	3/4	8	1/4	2 1/2	42" x 6'6"
	1	10	1 1/2	4	48" x 6'6"
	1 1/4	10	2 1/2	5	66" x 7'0"
	1 1/2	12	3	5	72" x 7'0"
2001 to 2500	3/4	8	1 1/2	4	48" x 6'6"
	1	10	2	4	66" x 7'0"
	1 1/4	12	2 1/2	5	72" x 7'0"
	1 1/2	12	3	6	72" x 7'0"

*Size of blow-off connection on boiler or size of blow-off header, whichever is larger.

**The sizes tabulated are based on the minimum diameter and minimum volume that can be used. Larger diameter tanks with equivalent or larger volume may be used.

(2) The pressure for which the tank should be designed is shown in table 7-8. The blowdown tank will have a wear plate between the tank water level and the top of the tank. The blowdown will enter tangentially and the wear plate attached to the shell at the point of impact from the blowdown. The wear plate will be the same thickness of the tank and extend approximately one-third of the tank circumference. The blowdown tank vent will allow steam to escape from the highest possible location on the tank and will be as direct as possible to the outside atmosphere without intervening stop valves. The water discharge

temperature should not exceed 140 degrees F. The pressure of the blowdown leaving any type of blowdown equipment will not exceed 5 psig. The Boiler Law and Rules & Regulations Code administered by the Bureau of Safety & Regulation in Lansing, Michigan can be used as a guide in designing blowdown tanks. Each state will be consulted to determine their design criteria.

7-9. Slowdown heat recovery.

a. *Application.* A LCCA will be conducted to determine if a slowdown heat recovery system is a justifiable capital investment.

Table 7-8. Blowdown Tank Pressure.

Maximum Allowable Boiler Pressure, psig	Blowdown Tank Design Pressure, psig
50	25
100	50
200	70
300	90
500	125
750	165
1000	200
1500	275
2250	325
2500	400

b. Design. Heat is recovered in a blowdown heat recovery system by passing the blowdown water from the blowdown tank through a heat exchanger to recover the sensible heat of the water and transferring blowdown tank steam to the DA. The heat exchanger will be sized to reduce the temperature of the blowdown main to 20 degrees F above the inlet temperature of the fluid being heated, typically feedwater heating, makeup water heating, building heating, oil heating or process steam generation. The blowdown tank for a heat recovery system will be smaller to allow the blowdown drain water to be hotter for an effective heat recovery system. If flash steam is used in the DA, the blowdown tank will be designed to minimize carryover. A normal blowdown system consisting of a large blowdown tank venting to atmosphere and draining directly to waste may have to be available to allow maintenance on the heat recovery equipment during operation. There are several package blowdown heat recovery systems available consisting of blowdown tanks, heat exchangers, flow control valves, thermostatic control valves, sample coolers and high level float switches.

7-10. Steam coil air heater.

a. Application. The steam coil air heater preheats the combustion air before it enters the main air heater. The heat dries the air and reduces corrosion of the air heater tube metals.

b. Design. The installation will be designed for reasonable air velocities with pressure loss not to exceed one inch of water. The heating coils will be designed in multiple elements to maintain average cold and metal temperatures of the air heater surfaces above 180 degrees F at all loads up to 15 percent above full rated load. The uncorrected air heater gas outlet temperature should be used to determine the average cold end metal temperature. A typical steam coil would have seamless type 321

stainless steel tubes, outer tubes 1 inch outside diameter and 0.049-inch minimum wall thickness and inner tubes 5/8-inch outside diameter and 0.022-inch minimum wall thickness. The supply and return connections are to be on the same end of the coil. Tubes will be pitched to the drain. The coil should be removable in a manner that does not disturb connecting ends of breeching. The coil outer casing is typically 10 gauge steel welded into an airtight structure. The core header plate will be gasket sealed to the casing.

7-11. Steam coil drain tank.

a. Application. The steam coil drain tank will collect the condensate from the steam coil air heater for transfer to the DA.

b. Design. The steam coil drain system must be sized large enough to drain the maximum expected steam flow rate to the air heater and to maintain a reasonable condensate level allowing proper operation of the steam coil drip return pumps (if included). Another consideration is the possibility of freezing. The steam coil tank should be located indoors, if possible, and sized small enough that outdoor drain piping is not allowed to fill with condensate. The steam coil drain tank is normally equipped with a level controller, gauge glass and high level alarm. The steam coil drain tank will be designed and constructed in accordance with the ASME Boiler and Pressure Vessel Code, Section VIII.

7-12. Fans.

a. Applications. Boiler furnaces are either pressurized or have balanced draft for combustion. Gas and oil fired boilers are normally of the pressurized furnace design. Modern coal fired boilers have balanced draft type furnaces. Balanced draft type boilers use FD fans to supply combustion air to the furnace and ID fans exhaust the products of combustion or flue gas. The furnace is kept at a slightly negative pressure ranging from 0.1 to 0.25-inches w.g., by the ID fan which is located downstream of the particulate removal equipment.

b. Forced draft fans. FD fans operate with reasonably clean, cool or warm air and will be designed for quietness and efficiency. This source of combustion air is frequently taken from within the steam plant to promote ventilating and to take advantage of the higher ambient temperatures. Inlets for the fans will have silencers with screens to attenuate entrance noises and to keep birds and other objects from entering the system. The static pressure of the FD fan will be calculated for the pressure drop through the inlet air duct, steam coil air heater, air heater (if used), air metering devices, dampers or vanes, air ducts, static fuel bed or

burners and any other resistance between the fan and the furnace at the air flow rate required for proper combustion. The volume of the air to be handled is dependent on the air pressure (elevation), moisture content if moisture exceeds 1 or 2 percent by weight, temperature and excess air required. Factors of safety to be added to the air flow requirements to obtain test blockrating are 20 percent excess volume and 32 percent excess pressure for coal fired boilers. Add 25 degrees F to temperature of the air being handled as a safety factor.

(1) FD fan will be airfoil type to provide lower power consumption. Airfoil fans will have inlet vane controls to provide low part load power consumption.

(2) FD fan design will include the following features. Shafts will be designed to have critical speeds not less than 1.4 times the operating speed. Bearings will be antifriction type with L10 life of 100,000 hours. Wheel stresses should not exceed 50 to 60 percent of yield strength while using finite difference methods and 75 percent of yield strength at operating temperature while using finite element methods. Stress rupture should be considered for elevated temperature. Variable speed fan fatigue life should be evaluated to avoid premature failure due to low cycle fatigue. An impact response test should be performed to avoid high cycle fatigue due to resonance. Resonance speed of fan support system should not be less than 1.2 times operating speed.

c. *Induced draft fans.* ID fans can operate under erosive conditions even though these fans are located downstream of the particulate (fly ash) collection equipment. Erosion is controlled by using abrasion resistant material and limiting top speed. The ID fans move the gas from the furnace, through the superheater if required, boiler bank, economizer, ductwork, scrubbers, baghouse and stack. Corrosion must be considered if temperatures of flue gas are within 30 degrees F of the dew point. The type of fan is usually straight radial with shrouds (modified radial) or radial tip design (forward curved, backward inclined) with wearing strips when dust burden is high. Maximum speed should be 1200 revolutions per minute (rpm). Even when flue gases are normally cleaned through a baghouse before they reach the fan dirty gases can be bypassed around the baghouse and impinge on the fan blades or wheel. Therefore, the fan must be constructed to resist fly ash and dust buildup and to give better wear resistance. Factors of safety to be added to the air flow requirements to obtain test block rating are 20 percent excess volume and 32 percent excess pressure for coal fired boilers. Add a minimum of 25 degrees F to the temperature of

entering gas being handled as a safety factor. ID fan type will be selected based on grain loading according to table 7-9.

Table 7-9. ID Fan Type.

Grains/actual cubic feet	ID fan type
0.1 to 0.2	Airfoil
>0.2	Radial tipped, backward inclined, or radial bladed

ID fan control type will be selected based on temperature and grain loading according to table 7-10.

Table 7-10. ID Fan Control Type.

Temperature	Grains/actual cubic foot	Type ID fan control
≤500 F	≤0.2	inlet vane
>500 F	>0.2	inlet box dampers

ID Fan design will include the following features. Shafts will be designed to have critical speeds not less than 1.4 to 1.5 times the operating speed. Bearings shall be antifriction type with L10 life of 100,000 hours. Partial liners will be included for airfoil or backward curved fans. Partial or full width liners will be included for other blade types based on dust loading and velocities. Housings will be provided with liners or replaceable heavier scroll for fans with severe dust loading. Wheel stresses should not exceed 50 to 60 percent of yield strength while using finite difference methods and 75 percent of yield strength at operating temperature while using finite element methods. Stress rupture should be considered for elevated temperature. Variable speed fan fatigue life should be evaluated to avoid premature failure due to low cycle fatigue. An impact response test should be performed to avoid high cycle fatigue due to resonance. Resonance speed of fan support system should not be less than 1.25 times operating speed.

d. *Fan control methods.*

(1) Dampers are used on the fan discharge at either the stoker plenum, the boiler outlet or in ducting and function to raise system resistance, thus raising operating points higher on the fan curves and altering fan output. Input power can decrease somewhat on decreased volume output if fan efficiency increases. Dampers are closed on startup of the boiler to reduce the starting load on the motor.

(2) Variable inlet vanes are used to change characteristic curves of FD fans. Vanes impart a prespin to the gas and by the alteration of the pitch

of the vanes, fan discharge volume and pressure are changed to give new system operating points. With fixed speed motors, power usage only slightly diminishes as air volume is reduced; this system will operate economically if air volume is 75 percent or above the design volume. Movement of vanes is non linear so they have to move more at low loads.

(3) Two speed motors, generally of speed ratios of 4:3 or 3:2 with variable inlet vanes will provide economical operation down to 40 percent of the design volume.

(4) Variable speed drive on ID fan, two speed or variable speed motor on FD fan, with variable inlet vanes on boiler outlet damper, are generally required for most efficient operation of heating plant boiler systems with power drive requirements in excess of 10 hp. The benefits of a variable speed drive are greater when the boiler is operated at lower loads. A life cycle cost analysis (LCCA) should be performed based on the number of hours at each load to justify the use of a variable speed drive. The variable speed gives an infinite series of fan curves from which the points of highest system efficiency can be chosen. Fans with both adjustable speed capability and control inlet vanes provide the most energy efficient operation. Control dampers may be provided for multiple coal fired units with auxiliary oil firing for startup of boiler and adjustment of air flow. If oil is fired in a boiler designed for coal firing, excessive dampering may set up objectionable vortexing of the air currents in the breeching and ductwork unless variable speed drives are used in the system.

e. Fan motors. Motors will be selected for the maximum duty required by the fan under most severe anticipated operating conditions. Motor selection is discussed in chapter 10.

7-13. Hydraulic ash handling pumps.

a. Application. Bottom ash can be conveyed hydraulically from a bottom ash hopper by means of mechanical pumps. Hydraulic ash handling systems are discussed in chapter 6.

b. Ash sluice pump.

(1) *Application.* The ash sluice pump pumps recycle sluice water through the bottom ash hopper outlet to be disposed.

(2) *Sizing.* Two 100 percent capacity pumps will be used to provide full backup. The capacity of the ash sluice pumps will depend on the hydraulic ash handling system demands. The discharge head of the ash sluice pump will be designed to overcome the piping losses and static head to a dewatering bin or surge tank. A jet pump hydraulic system will demand higher pressure pumps to allow the jet pump to function properly. A surge tank is

required to make available adequate NPSH for an effective pump.

(3) *Construction.* The pumps will be constructed in a horizontal split case configuration with a heavy duty slurry type enclosed impeller. Replaceable shaft sleeves, suction sideplates and rear sideplates will be provided. The pump will include oil lubricated bearings and a stuffing box packing for external clean water injection.

(4) *Pump materials.* Ash sluice pumps will be designed of abrasion resistant alloys to provide an acceptable life.

c. Bottom ash pump.

(1) *Application.* The bottom ash pump transfers the slurry from the bottom ash hopper discharge to a disposal area, either dewatering bins or ash handling ponds. The bottom ash pump is not needed if the ash sluice pumps are designed to pump the water through the hopper discharge to the disposal system.

(2) *Sizing.* The bottom ash pump is most generally used with a surge tank downstream of the ash hopper offering a controlled NPSH. Two 100 percent capacity pumps will be used to provide full backup. The capacity of the bottom ash pumps depend on the hydraulic ash handling system demands. The capacity must be greater than the ash sluice pump capacity. The discharge head of the bottom ash pump will be designed to overcome the piping losses and static head to a dewatering bin.

(3) *Construction.* The pumps will be constructed in a horizontal, vertical split case, end suction back pullout configuration with a heavy duty, slurry type enclosed impeller. Replaceable shaft sleeves, suction sideplates and rear side-plates will be provided. The pump will include oil lubricated bearings and a stuffing box packing for external clear water injection.

(4) *Pump materials.* Bottom ash pumps will be designed of abrasion resistant alloys to provide an acceptable life.

d. Ash sluice water recirculation pumps.

(1) *Application.* Ash sluice water recirculation pumps are used for returning ash pond water to a surge tank for the ash sluice pump suction.

(2) *Sizing.* Two 100 percent capacity pumps will be used to provide full backup. The capacity of the recirculation pumps must exceed the ash sluice pump capacities. The NPSH available will be the atmospheric pressure of the ash pond plus the depth of the impeller minus the resistance of the suction bell piping. The discharge head of the recirculation pumps must overcome piping losses and the surge tank static head.

(3) *Construction.* The pumps will be vertical shaft configuration with bottom suction. Replaceable suction sideplates and rear sideplates will be provided.

(4) *Pump materials.* The ash sluice water recirculation pumps will be designed of abrasion resistant alloys to provide an acceptable life.

e. Sludge return pump.

(1) *Application.* The sludge pump is used on a hydraulic ash handling system using a dewatering bin. A tank or series of tanks collect and store the water discharge from the dewatering bins. Remaining ash particles settle in these conical shaped tanks and are pumped from the tank bottom back to the dewatering bins by sludge return pumps.

(2) *Design.* The sludge return pumps have the same design characteristics as the bottom ash pumps.

7-14. Bearing cooling water pumps.

a. Application. Bearing cooling water pumps will supply cooling water to all plant equipment with a cooling water demand. Typical equipment requiring cooling water are pulverizers, pump bearings and seals, air compressors and after coolers, fan drives, lube oil coolers and chemical feed sample coolers, boilers access doors and scanning fire detectors. Smaller boiler plants may have processed water available and may not require cooling water pumps. Boiler plants with a plentiful water supply will sometimes allow cooling water to be discharged without recirculation.

b. Design. Two 100 percent capacity pumps will be used to provide full backup. The required flow rate needed is found by adding all equipment coincident demands. The future expansion of the plant will also be considered. The cooling water system may be an open (once through) or closed (recirculating) type of system depending on the availability of clear water. The system head required must be determined by adding the system piping friction losses and the static head required. When the flowrate and total head required are known, add 10 percent to the total head for wear allowance. This will be the rated capacity and total dynamic head for the pump selection.

c. Construction. The pumps will be motor driven, horizontal, vertical split case, end suction, centrifugal type, back pullout configuration, single stage design.

7-15. Bearing cooling water heat exchangers.

a. Application. Bearing cooling water heat exchangers are required for a closed loop system in which clean water is not available in unlimited quantities. A heat exchanger will transfer heat

absorbed by the clean bearing cooling water and transfer it to a circulating water system. The circulating water system may use river water, lake water, or a cooling tower system where absorbed heat can be discharged. An evaluation must be made to determine the feasibility of using a heat exchanger versus using a cooling tower where bearing water is directly pumped through the cooling system. A plentiful supply of dirty water from a lake or river may make a heat exchanger more economical. Consideration will be given to water treatment as a cooling tower bearing water system would have to be constantly monitored and treated as water is made up for evaporation.

b. Design. The heat exchanger must be sized to transfer all the heat generated from the fully operational plant at the maximum continuous rating. Two heat exchangers will be used so one can be removed from service, each having 100 percent of the flow capacity. The heat exchanger will be designed to conform to the ASME Boiler and Pressure Vessel Code, Section VIII. The heat exchanger manufacturer must be given the information for both the shell side and the tube as shown in table 7-11. The amount of cooling water required depends on the equipment cooling water demand. The equipment manufacturers will be asked how many gallons of cooling water per minute is required for equipment cooling at a given inlet temperature of 95 degrees F allowing the outlet temperature to be no more than 10 degrees F higher. The heater cooling water rated flow capacity will be the total equipment demand of all equipment to be operating simultaneously plus a 20 percent design margin. The circulating water rated flow capacity will be twice the cooling water rated flow capacity.

c. Construction. The coolers will be designed and constructed to conform with the ASME Boiler and Pressure Vessel Code, Section VIII. The

Table 7-11. Heat Exchanger Design Information.

	Typical Values	
	Shell Side Cooling Water	Tube Side Water
Number of passes	.1	1
Temperature in, degrees F	115	85
Temperature out, degrees F	95	95
Flow gpm.	demand	demand
Maximum pressure drop, psi	2	5
Design pressure, psig	150	75
Fouling factor	.0005	.001
Maximum velocity, fps	3.0	5.0

construction of the coolers will allow the circulating water or dirtier water to pass through the tubes allowing more practical cleaning. The cooler tubing and tube sheet material selection will be based on water quality. Materials can be admiralty, copper nickel, or for corrosive applications stainless steel. The coolers will be the straight tube type with fixed tubesheet, removable channel construction. The shell will be carbon steel and the channel heads will be fabricated steel. The shell will have 150 pound raised face flanged or 3000 pound screwed connections. The channel will have 150 pound flat faced flanged or 3000 pound screwed connections. The coolers will be manufactured with shell, channel vent and drain connection.

7-16. Ignitor fuel oil pumps.

a. Design. Ignitor fuel oil pumps will be rotary screw type pumps. Two pumps will be provided, each rated at 100 percent capacity, with one pump used for backup service. A fuel oil unloading pump will be applied if required and will have the same characteristics as the ignitor fuel oil pumps. No. 2 fuel oil is more commonly used for ignitor systems and will be assumed herein. The pumps will be able to pump oil with a viscosity of 200 Saybolt Seconds Universal (SSU) against the design discharge pressure at the design capacity. Fuel oil viscosity will be expected to vary between 33 and 200 SSU. Pump motors will be totally enclosed and explosionproof.

b. Types. Unlike a centrifugal pump, a rotary screw pump is a positive displacement pump, that will displace its capacity to the point of failure regardless of the resisting pressure. A fuel oil recirculation system will be designed to allow the pump to recirculate the fuel oil as the ignitor fuel oil is modulated according to demand. In a fuel oil loading system the fuel oil is not modulated and a recirculation system is not necessary. In sizing the fuel oil pump, the pressure to overcome will be calculated from piping losses and elevation change to get the required pump discharge pressure. The ignitor fuel oil pump capacity is determined from maximum fuel oil demand plus 20 percent for pump wear and safety factor.

7-17. Nitrogen system.

a. Application. The nitrogen system is used to purge the boiler for protection from corrosion between hydrostatic test and initial operation and after chemical cleaning periods and outages.

b. Design. The boiler steam parts are filled with treated water until overflowing and then capped off with 5 psig of nitrogen according to the recom-

mendations of the boiler manufacturer. Depending on the boiler and down period, such steam parts filled with treated water or a nitrogen purge are the economizer, water walls, superheater, reheater, feedwater heater (tube side-water; shell side-nitrogen) and drum. In some cases freezing may be a problem and treated water can be replaced with nitrogen. The amount of nitrogen required, for boiler purging will be given by the boiler manufacturer or can be calculated from the volume of the steam parts. The nitrogen system is a low pressure system. However, the nitrogen is stored in high pressure cylinder bottles and the piping will be connected to a high pressure boiler. A pressure regulator and high pressure valving will be required.

7-18. Carbon dioxide (CO₂) system.

a. Application. A carbon dioxide system in a boiler plant is most commonly used to extinguish fires in coal bunkers. A CO₂ system can also be used to extinguish electrical hazards, such as transformers, oil switches and circuit breakers, and rotating equipment. CO₂ extinguishes fire by reducing the concentration of oxygen and the gaseous phase of the fuel in the air to the point where combustion stops.

b. Design. The CO₂ systems are classified as automatic, manual or automatic-manual. Fires or conditions likely to produce fires may be detected by visual (human senses) or by automatic means. In the case of coal bunkers, methane detectors can be used to alarm a fire or actuate the CO₂ system and an alarm. CO₂ can be stored in cylinder bottles and pipes through a pressure regulated system to discharge nozzles at the area of combustion. The amount of CO₂ in the system will be at least sufficient for the largest single hazard protected or group of hazards to be protected simultaneously. The CO₂ system will be designed and erected in accordance with NFPA 12 of the National Fire Codes.

7-19. Chemical feed pumps.

a. Application. Chemical feed pumps are small capacity pumps used to inject chemicals into the condensate, feedwater and steam system at a controlled rate. Most chemical feed pumps are specified and purchased as a chemical feed unit that includes a pump, tank, mixer and piping. Typical chemical systems used in a boiler plant are hydrazine, morpholine, phosphate and a metal surface passivating agent.

b. Design. The pump selection will have the capacity and discharge head to inject the chemical into the system. Pumps are rated by capacity in

gallons per hour (gph), discharge head in psig and piston strokes per minute. The chemical feed pumps will be positive displacement metering type. The pumps will have hydraulically balanced diaphragms, mechanically actuated air venting; all rotating parts to run in an oil bath with roller bearings; double ball check valves with Teflon O-ring seats on both suction and discharge. The pumps will have micrometer capacity adjustment from 0—100 percent while the pump is running and to have metering accuracy within plus or minus 1 percent.

c. Chemical feed unit. Chemical feed tanks for the mentioned chemicals will be 16 gage type 304 stainless steel with agitator, gage glass and low level alarm system. Piping will be stainless steel and valves will have Teflon seats. The chemical feed system will include a back pressure valve to insure accurate and consistent metering at all flows and will include a safety valve.

7-20. Laboratory.

a. General. A laboratory is needed in every boiler plate to assist in analyzing chemical treatment and in early detection of problems. Samples of water and steam are taken from various systems and parts of systems to evaluate the system's condition.

b. Sample coolers. Sample coolers are required to condense steam and cool water to be handled. Sample coolers are heat exchangers that will be sized to maintain the temperature at 77 degrees F.

Coolers for individual samples are either double-tube helical coils with cooling water counterflow cooling or submerged helical coils properly baffled to effect counterflow cooling. If a coil type of exchanger or a coil and condenser type of exchanger are used, they will meet the intention of ASTM D 1192. If a multicircuit heat exchanger is used, it will meet the requirements of Section VIII, ASME Boiler and Pressure Vessel Code.

7-21. Sump pumps.

a. Application. Sump pumps are required in several applications at a boiler plant. Sump pumps primarily are used for storm water removal but also are used for ash hopper water overflow or any condition requiring removal of water from a sump.

b. Design. The pump will be sized for one and one-half times the maximum amount of expected drain rate. Two 100 percent capacity pumps will be used to supply full backup if overflow is dangerous. The suction line between the suction vessel and the pump must be properly designed to prevent air pockets and cavitation. Sufficient NPSH must be available at the pump suction flange.

c. Construction. The pumps will be motor driven, vertical shaft configuration with bottom suction and open impeller. The pump will include a flanged column, discharge pipe flanged over soleplate, bearing lubrication piping and connections on the soleplate to support the pump and motor.

CHAPTER 8

PIPING SYSTEMS

8-1. General.

This chapter addresses the criteria for the steam plant piping systems. The design of the steam plant piping will be in accordance with the ASME B31.1. Gas piping will be in accordance with ASME B31.8. Reference table 8-1 for piping system design notes.

8-2. System descriptions.

a. Main steam. The main steam system delivers steam from the boiler outlet connections to the process. The main steam system consists of: piping from each boiler outlet connection, superheating equipment (superheated boilers only), a common main steam line headered to the individual boiler outlets, and piping which transports the steam to the process. On superheated steam units the superheating equipment, which is an integral part of the boiler, consists of a primary superheater section, a desuperheater, and a secondary superheater. The system diagram is shown in figure 8-1.

b. Low pressure steam. The low pressure steam system provides steam for use within the steam plant. These uses include deaerator (DA) pegging steam, sootblowing steam, steam coil air preheaters, boiler feed pump turbine drives, and feedwater heaters. The low pressure steam system consists of: steam pressure reducing station, DA, sootblowers, steam coils, turbine drives, feedwater heaters, and interconnecting piping. The system diagram is shown in figure 8-2.

c. Feedwater. The feedwater system collects returning process condensate, treats raw water for makeup to the boiler, collects returning condensate from in-plant processes, conditions the condensate and makeup to remove corrosive gases, heats the water, and delivers it to the boiler economizer. The feedwater system consists of: water treatment equipment to condition raw water for makeup to the boiler, a treated water and condensate storage tank, treated water and condensate pumps to deliver water to the DA, a blowdown recovery heat exchanger, a DA to remove the entrained corrosive gases from the water, boiler feed pumps to increase the pressure of the water and deliver it to the boiler, feedwater heaters to heat the water and protect the boiler economizer against acid condensation of the flue gas at low loads, flow regulating stations, and interconnecting piping. The system

diagram is shown in figure 8-3.

d. Fuel gas. The fuel gas system reduces gas pressure from the supplier's pipeline, totalizes flow to the plant, removes impurities from the gas, allows manual isolation of the plant from the supply, provides visual indication of plant gas pressure, and electrically isolates the plant piping from the buried supply piping.

e. Fuel oil. The fuel oil system includes pumps to move oil from outdoor storage tanks to the plant header. The functions performed by the fuel oil system are similar to those listed for the gas system. Since oil is stored on site and since there is recirculation back to the fuel oil storage tank, more than one totalizing flow meter is needed to calculate the amount of oil burned.

f. Blowdown heat recovery. The blowdown heat recovery system recovers part of the heat available in boiler blowdown water and discharges the unusable high-solids content water. The blowdown heat recovery system consists of: blowdown regulation equipment, a flash tank, a blowdown recovery heat exchanger, and interconnecting piping. The system diagram is shown in figure 8-4.

g. Instrument air. The instrument air system supplies air to the pneumatic instruments and control devices throughout the plant. The instrument air system consists of: instrument air compressors, aftercoolers, air drying equipment, instrument air receiver, baghouse air receiver (when required), and interconnecting and distribution piping. The system diagram is shown in figure 8-5.

h. Plant air. The plant air system supplies air for pneumatic tools, maintenance uses, and other uses throughout the plant. Plant air may also be used for sootblowing and igniter atomizing purposes when required. The plant air system consists of: plant air compressors, aftercoolers, oil separating equipment on crosstie to instrument air system, plant air receiver, sootblower air receiver (when required), atomizing air regulating station (when required), and interconnecting piping. The system diagram is shown in figure 8-6.

i. Boiler vents and drains. Boiler vents and drains provide the means by which the boiler is vented and drained during startup and maintenance operations. The system consists of piping from the vent and drain connections on the boiler to the appropriate disposal points.

Table 8-1. Piping Design Notes,

<i>System</i>	<i>Origin</i>	<i>Termination</i>	<i>Typical Design Press. & Temp.</i>	<i>Design Notes</i>
Main steam (Saturated)	Boiler outlet	Process	400 psig 450 degrees F	Slope pipe ¼" per 100 ft. Thermal expansion compensation required. Traps and drains required. Insulate for thermal efficiency.
Main steam (superheated)	Boiler outlet	Process	400 psig 750 degrees F	Slope pipe ¼" per 100 ft. Thermal expansion compensation required. Traps and drains required. Insulate for thermal efficiency.
Auxiliary (low pressure) steam	Pressure reducing station	Deaerator, feed-water heaters steam coils BFP turbine soot-blowers	150 psig 375 degrees F	Slope pipe ¼" per 100 ft. Thermal expansion compensation required. Traps and drains required. Insulate for thermal efficiency.
Steam coil steam supply	Auxiliary steam header	Steam coil inlet	150 psig 375 degrees F	Slope pipe ¼" per 100 ft. Thermal expansion compensation required. Insulate for thermal efficiency. Traps and drains required.
Building heat	Auxiliary steam system (reducing station)	Building heating equipment	150 psig 375 degrees F	Slope pipe ¼" per 100 ft. Thermal expansion compensation required. Traps and drains required. Insulate for thermal efficiency.
Boiler feed pump discharge	Boiler feed pump	Boiler economizer	450 psig 230 degrees F	Check valve required on each pump. Insulate for thermal efficiency.
Boiler feed pump suction	Deaerator storage tank	Boiler feed pump	5 psig 225 degrees F	Strainer required on each pump. Insulate for thermal efficiency.
Boiler feed pump recirculation	Boiler feed pump discharge	Deaerator	450 psig 230 degrees F	Breakdown orifice required for each pump. Insulate for thermal efficiency.
Main steam desuperheater	Boiler feed pump discharge	Main steam desuperheater	450 psig 230 degrees F	Insulate for thermal efficiency.
Sootblower steam	Auxiliary steam system (reducing station)	Sootblowers	150 psig 375 degrees F	Slope pipe ¼" per 100 ft. Thermal expansion compensation required. Traps and drains required. Insulate for thermal efficiency.
Boiler continuous blowdown	Boiler drum	Flash tank	400 psig 450 degrees F	Compensation for thermal expansion and boiler movement required. Insulate for thermal efficiency.
Instrument air	Instrument air compressors	Instrument air piping system	100 psig 100 degrees F	No insulation required.
Plant air	Plant air compressors	Plant air piping system	100 psig 100 degrees F	No insulation required.
Atomizing air	Plant air system	Ignitors	100 psig 100 degrees F	No insulation required.
Boiler drains and vents	Boiler drum mud drum, waterwall headers	Atmosphere, drain	400 psig 450 degrees F	Compensation for boiler movement required. Insulate for burn protection.
Steam coil drain & vent	Steam coil outlet	Deaerator (drain) atmosphere (vent)	10 psig 240 degrees F	Insulate for thermal efficiency.
Deaerator vents	Deaerator	Atmosphere	5 psig 220 degrees F	Insulate for burn protection.
Safety valve vents	Safety valve outlets	Atmosphere	As required bends or turns.	Use drip pan elbows on steam safety valves. Avoid
Condensate makeup pump discharge	Condensate makeup pump	Deaerator	10 psig 100 degrees F	Check valve required on each pump. Insulate for thermal efficiency.
Condensate makeup pump suction	Condensate storage tank	Condensate makeup pump	5 psig 100 degrees F	Strainer required on each pump. Insulate for thermal efficiency.

Table 8-1. Piping Design Notes. (Continued)

<i>Typical Design System</i>	<i>Origin</i>	<i>Termination</i>	<i>Press. & Temp.</i>	<i>Design Notes</i>
Condensate makeup pump recirculation	Condensate makeup pump discharge	Condensate storage tank	10 psig 100 degrees	Breakdown orifice required for each pump.
Treated water	Water treatment system	Condensate storage tank	10 psig 60 degrees F	No insulation required.
Condensate return	Process	Condensate storage tank	As required	Insulate for thermal efficiency.
Potable water	Water main	Restrooms, lockers, drinking fountains, etc.	50 psig 60 degrees F	Piping must be sanitized before use. No insulation required.
Service water	Water main	Air compressors, aftercoolers	50 psig 60 degrees F	No insulation required.
Trap return	Steam traps	Waste or drain	150 psig 375 degrees F	Insulate for burn protection.
Fire protection	Water main or service water	Sprinklers and hose stations	150 psig 60 degrees F	No insulation required. All valves OS&Y type FM approved.
Floor and roof drains	Drain hubs	Within 15 feet outside building	50 psig 60 degrees F	Slope pipe ¼" per 100 ft. Provide cleanouts, use lateral fittings, avoid sharp turns. Coat where buried.
Sanitary drains	Restrooms, lockers, drinking fountains, etc.	Drainage	100 psig 60 degrees F	Slope pipe ¼" per 100 ft. Provide cleanouts, use lateral fittings, avoid sharp turns.
Ash sluice water	Ash pond	Bottom ash hopper	60 degrees F	No insulation required.
Bottom ash water	Bottom ash hopper	Ash handling equipment	150 psig 100 degrees F	No insulation required.
Nitrogen	Nitrogen bottle manifold	Boiler drums	150 psig 60 degrees F	No insulation required.
Coal bunker & pulverizer inerting gas	Gas bottle manifold	Coal bunkers & pulverizers	150 psig 60 degrees F	No insulation required.
Ignitor fuel	Fuel oil storage tank	Ignitors	As required	No insulation required.
Chemical feed	Chemical feed pumps	Boiler drum, deaerator	450 psig (boiler drum) 10 psig (deaerator) 60 degrees F	Strainers on pump suction and check valves on pump discharge required. No insulation required.
Samples	Boiler drum, deaerator feedwater	Water analysis equipment	400 psig (boiler drum main steam) 450 psig FW 450 degrees F boiler drum 230 degrees F DA FW	Sample coolers required on boiler drum.
Fly ash	Fly ash hoppers	Ash handling	As required	Insulate where cooler climates may develop condensation in pipe.

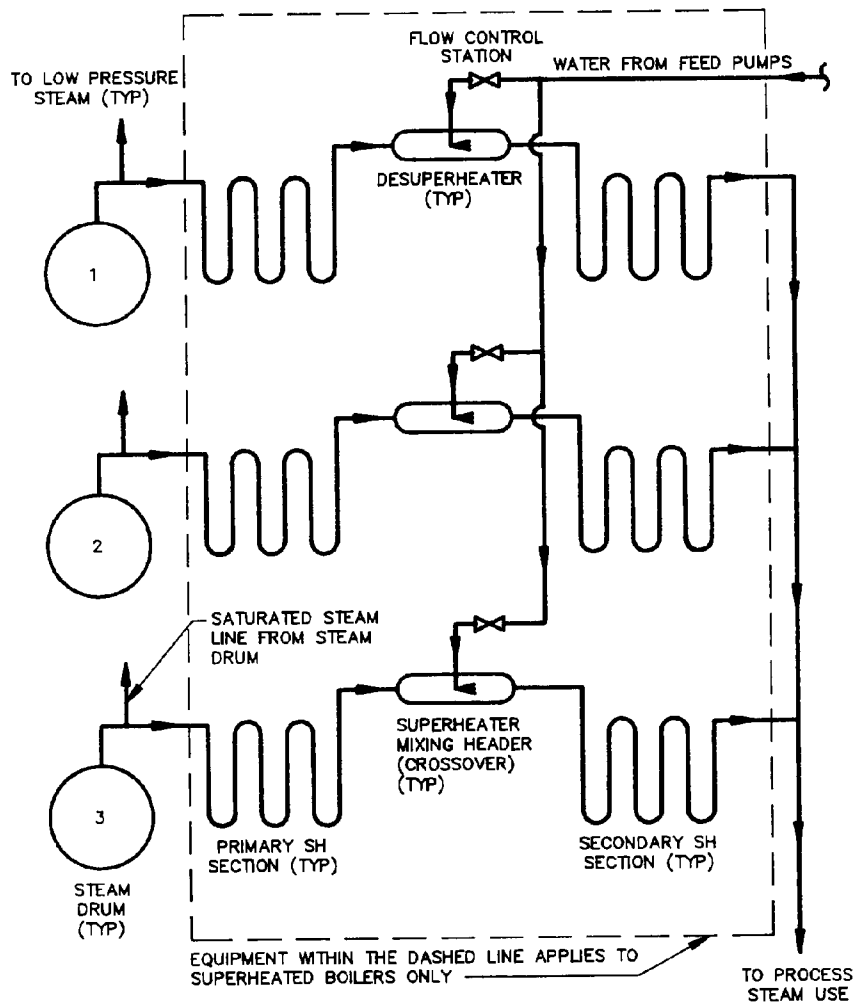


Figure 8-1. High Pressure Main Steam Flow.

j. *Deaerator vent.* The DA vent piping provides the means by which the entrained gases removed by the DA are vented to the atmosphere. The system will contain an orifice sized for the venting requirements determined from operating conditions and DA design.

k. *Safety valve vents.* Safety valve vent piping provides for the safe discharge of fluids from safety valves. Water safety valves require piping from the safety valve outlet to drain. Air and gas safety valves require piping from the safety valve outlet to atmosphere or to a safe location. Steam safety valves require piping from the safety valve outlet to a safe location that is outside the building. Steam safety valve vents also require provisions for removal of water condensed under the safety valve seat and in the vent piping itself. Safety valve

piping must be designed to pass the required flow without adversely effecting safety valve operation.

l. *Miscellaneous water systems.* Miscellaneous water systems include service and potable water and ash sluice water. The service and potable water system will provide water for the various cooling requirements in the plant, such as air compressor intercoolers and aftercoolers, and will provide water for personnel usages. The ash sluice water system is required when a hydraulic bottom ash system is used. Ash sluice water provides the water for ash jet pumps and bottom ash hopper filling and sealing water requirements.

m. *Miscellaneous gas systems.* Miscellaneous gas systems include nitrogen system and coal bunker and pulverizer inerting systems. The nitrogen system is used to fill any of the boilers

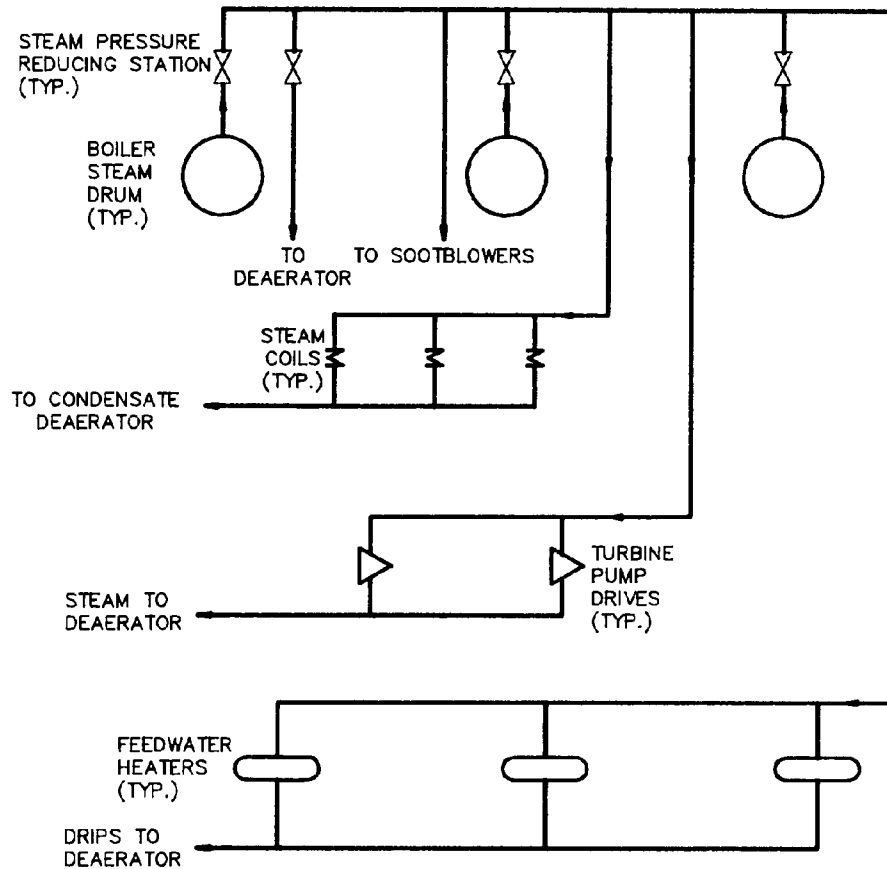


Figure 8-2. Low Pressure Steam Flow.

with nitrogen when it is to be out of service for an extended period. The system consists of nitrogen bottles, manifold, and interconnecting piping. The coal bunker and pulverizer inerting system is used to fill coal bunkers and pulverizers with an inert gas, usually 002 when fires are detected in the equipment or when the equipment is to be out of service for an extended period. The system consists of gas bottles, manifold, and interconnecting piping.

n. Ignitor fuel. The ignitor fuel system provides fuel for burner ignitors. Ignitors are used on gas, oil, pulverized coal, and ACFB boilers. The ignition fuel may be oil, natural gas or liquified petroleum gas based on the type of ignitors used. The system consists of pressure regulating stations and interconnecting piping.

o. Chemical feed. The chemical feed system supplies chemicals to the feedwater system at the DA storage tank to maintain water quality. The system consists of chemical feed tanks for mixing and storage of chemical solutions; positive displacement metering type chemical feed pumps; and stainless

steel piping or tubing for interconnection of system components and the DA storage tank.

p. Samples. The samples system collects samples from various points in the plant for use in determining chemical feed requirements based on water quality. Sample points will include boiler drum, feedwater, and condensate. The system consists of sample coolers (boiler drum) and tubing from the sample point to a central location when desired.

8-3. Valves.

a. General. All valves installed in piping systems must be suitable for the pressure and temperature of the piping system in which they are installed. Valves will be selected based on type of service (throttling or isolation), type of process fluid (water, steam, air), and special conditions (corrosive or abrasive process). Consideration must be given to materials of construction and packing materials. Table 8-2 summarizes the types of valves and their application.

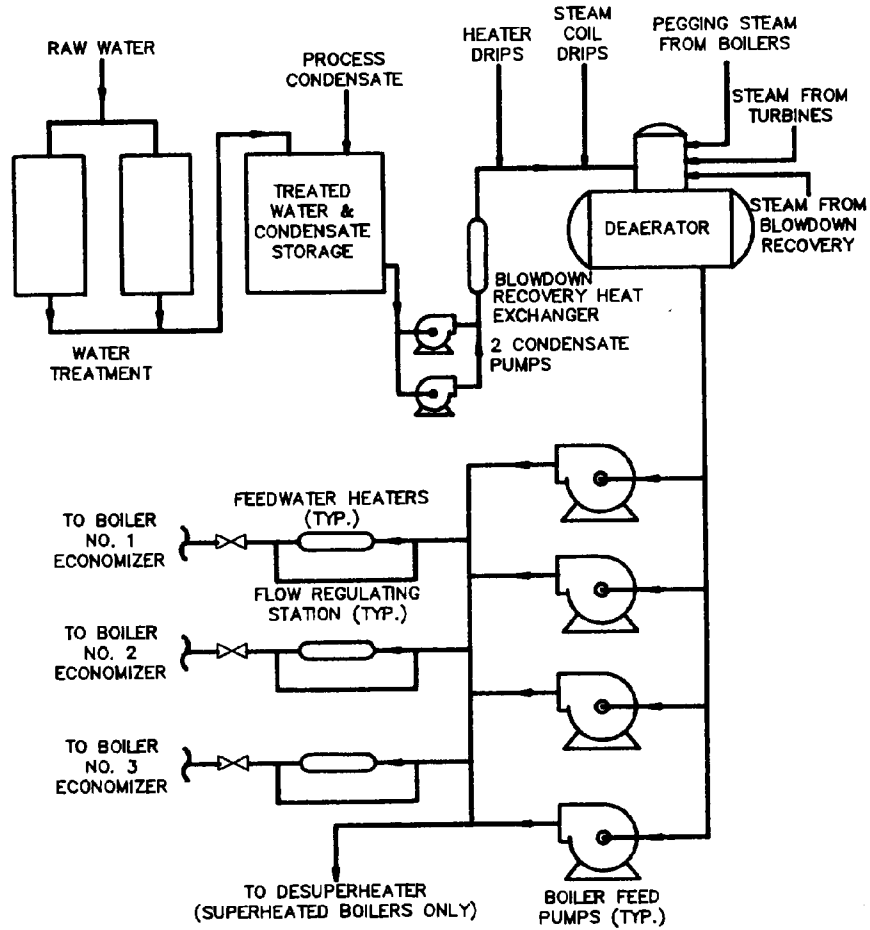


Figure 8-3. Feedwater Flow.

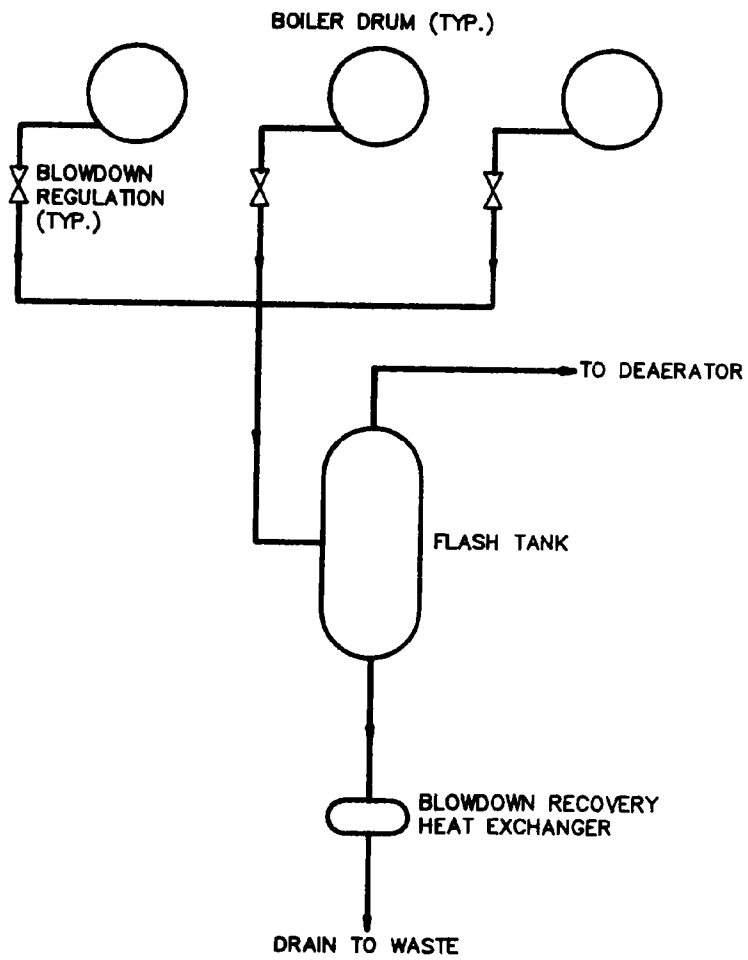


Figure 8-4. Blowdown Heat Recovery.

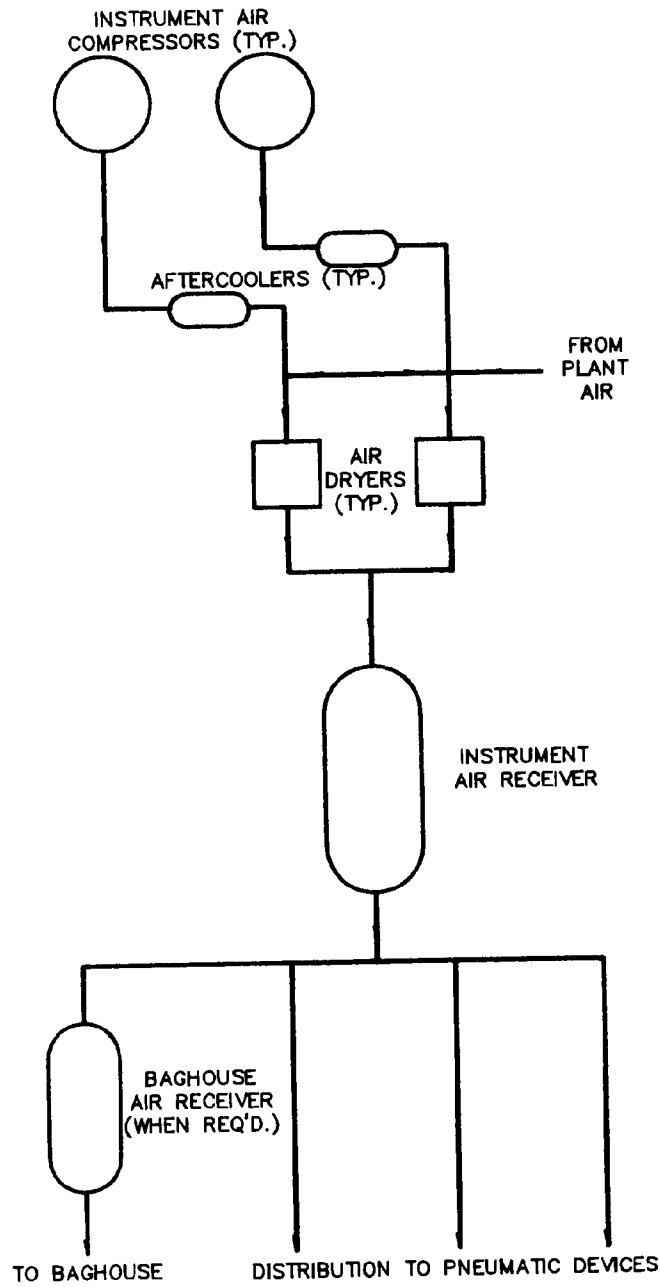


Figure 8-5. Instrument Air.

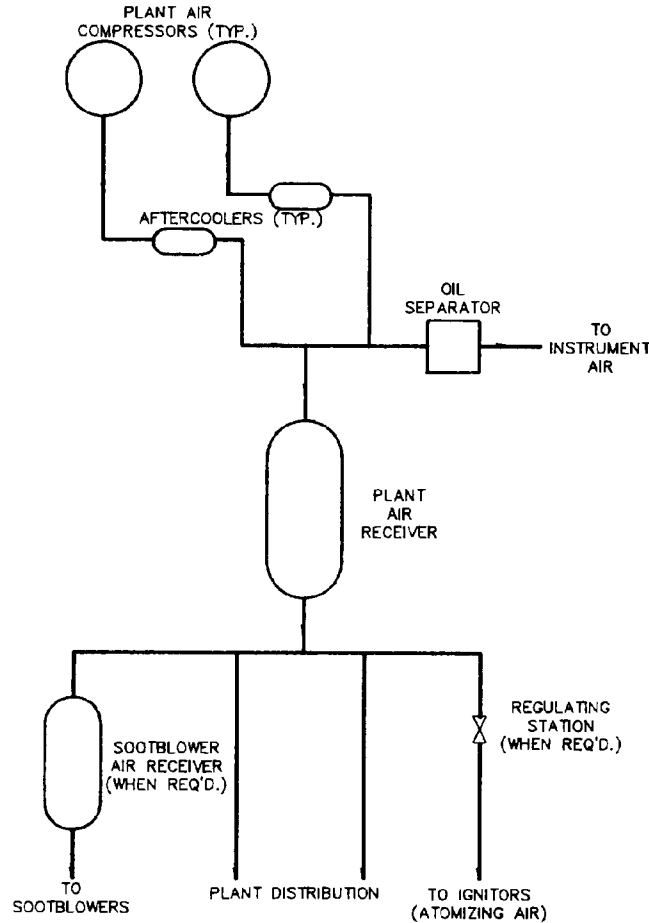


Figure 8-6. Plant Air.

Table 8-2. Valve Types.

Valve Type	Application	Fluid
Globe	Throttling and flow regulation service, control valves	Steam, water, air, gas, oil
Gate	Isolating nonthrottling service	Steam, water, air, gas suitable for high temperature and pressure
Butterfly	Isolating service, intermittent throttling, limited control valve application	Low pressure and temperature water and other fluids
Plug	Isolating service, intermittent throttling	Natural gas, fuel oil and other viscous fluids
Ball	Isolating service, intermittent throttling	Water, air, gas—low pressure applications
Check	Allows flow in one direction only, pump discharge piping	Steam, water, air, gas, oil
Diaphragm	Provide flow control and leaktight closure	Corrosive, abrasive and solids in suspension
Pinch	Isolating service for large amounts of solids in suspension	Low pressure and temperature, noncorrosive fluids
Needle	Volume control valve used in small instrument, gage and meter lines	Water, air, gas
Relief or safety	Prevents excessive overpressure in process and piping	Steam, water, air, gas system

TM 5-810-15

b. *Valve types.* Numerous types of valves are available including globe, gate, butterfly, plug, ball and check valves. Valves can be furnished with flanged, butt welded, socket welded, or screwed end connections.

c. *Valve construction.* Valves must be constructed of suitable materials for the pressures, temperatures, and fluids for which they will be used. Table 8-3 summarizes body and packing materials and their application. Consideration will be given to special disc and seat materials and valve bonnet types when required by special process conditions.

8-4. Pipe insulation.

a. *Acceptable types.* Table 8-4 shows the acceptable types of insulation material.

b. *Applications.*

(1) *Burn protection.* Where applicable, insulation will be sufficiently thick to provide burn protection as required by OSHA regulations.

Table 8-3. Valve Construction.

Application	
<i>Body Material:</i>	
Cast Iron	Pressure up to 250 psi, temperature up to 267 degrees F, water, oil, gas
Steel	Pressure up to 9000 psi, temperature up to 800 degrees F, water, oil, gas, steam
Stainless Steel	Pressure up to 9000 psi, temperature up to 1200 degrees F, corrosive fluids
Bronze	Pressure up to 300 psi, temperature up to 400 degrees F, water, air gas
<i>Packing Material:</i>	
Teflon	Temperature up to 450 degrees F, water, oil, gas
Graphite	Temperature up to 1000 degrees F, water, oil, gas, steam

Table 8-4. Acceptable Insulation Types.

Insulation Type	Advantages	Disadvantages
Asbestos free calcium silicate ASTM C 533 and expanded silica (perlite)	Inexpensive, easy to handle, numerous manufacturers, for use from 100 degrees F to 1500 degrees F.	Deteriorates in moist conditions, not very compressible, unsuitable for direct buried applications.
Fiberglass ASTM E-84	Inexpensive, easy to handle, numerous manufacturers, for use from -40 degrees F to 1200 degrees F.	Loses insulating value in moist conditions, unsuitable for direct buried applications.
Cellular Glass	Impervious to moisture, easy to handle, for use from -40 degrees F to 1200 degrees F can be used above and below ground.	Not compressible, few manufacturers.

*Insulation systems using composite of two or more acceptable insulations may also be acceptable.

(2) *Thermal efficiency.* For purposes of efficiency, the ~~recommended economic~~ thickness of pipe insulation shall meet or exceed the requirements of ASHRAE 90.1.

Table 8-5. Recommended Economic Thickness for Pipe Insulation.

Nominal Pipe size, in.	Temperature of pipe F										
	100-199	200-299	300-399	400-499	500-599	600-699	700-799	800-899	900-999	1000-1099	1100-1200
UTILITY - STEAM GENERATION											
1/2 and less	1	1	1	1 1/2	1 1/2	1 1/2	2	2 1/2	2 1/2	2 1/2	3
2	1	1	1	1 1/2	1 1/2	1 1/2	2	2 1/2	1 1/2	2 1/2	3
2 1/2	1	1	1 1/2	1 1/2	2	2	2 1/2	2 1/2	3	3	3 1/2
3	1	1	1 1/2	1 1/2	2	2	2 1/2	2 1/2	3	3	3 1/2
3 1/4	1	1 1/2	1 1/2	2	2	2 1/2	3	3	3	3 1/2	4
4	1	1 1/2	1 1/2	2	2	2 1/2	3	3	3 1/2	3 1/2	4
4 1/2	1	1 1/2	1 1/2	2	2	2 1/2	3	3	3 1/2	3 1/2	4
5	1	1 1/2	1 1/2	2	2 1/2	2 1/2	3	3 1/2	3 1/2	4	4
6	1	1 1/2	2	2	2 1/2	2 1/2	3	3 1/2	3 1/2	3 1/2	4

Table 8-5. Recommended Economic Thickness for Pipe Insulation. (Continued)

Nominal Pipe size, in.	Temperature of pipe F										
	100-199	200-299	300-399	400-499	500-599	600-699	700-799	800-899	900-999	1000-1099	1100-1200
UTILITY — STEAM GENERATION											
7	1½	1½	2	2	2½	2½	3	3½	3½	4	4
8	1½	1½	2	2	2½	2½	3½	3½	4	4	4½
9	1½	1½	2	2½	2½	3	3½	3½	4	4	5
10	1½	1½	2	2½	3	3	3½	4	4	4	5
11	1½	1½	2	2½	3	3	3½	4	4	4½	5
12	1½	1½	2	2½	3	3	3½	4	4	4½	5
14 and up	1½	1½	2	2½	3	3	4	4	4½	4½	5

1/1 8-5. Pipe hangers, anchors and supports.

a. *Design.* Hangers, anchors and pipe supports will be designed to meet ASME B31.1 requirements where applicable. Pipe hangers will be in accordance with MSS SP-69.

b. *Spacing.* Guidelines for pipe support spacing and carrying capacities are provided in ASME B31.1

8-6. Pipe expansion compensation.

a. *Design.* The thermally induced expansion of piping materials can be compensated for with normal pipe bends and the proper placement of anchors. The thermal expansion of common piping materials is shown in Appendix B of the ASME B31.1.

b. *Expansion devices.* When piping system design is unable to compensate for pipe expansion, expansion bends or expansion joints will be used. Expansion joints and bends will conform to ASME standards.

8-7. Pipe sizing.

a. *General.* Selection of the proper pipe size for any particular application is dependent upon numerous variables. Pipe sizing is based on velocity, pressure loss, and friction loss calculations.

b. *Data requirements.* In order to properly size piping, pertinent data must be organized for use in the required calculations. This data includes pipe material (friction factor), process fluid, flow requirements, design pressures and temperatures, allowable pressure drop, velocity requirements, and preliminary piping layout.

c. *Velocity guidelines.* General guidelines for allowable velocities in piping systems are shown in table 8-6.

d. *Pipe sizing philosophy.* Piping will be sized to obtain a maximum velocity that corresponds to the allowable pressure drop for the system. It is desirable to keep velocities as high as possible

Table 8-6. Piping Velocity Guidelines.

Fluid	Application	Velocity
Steam	Superheated steam, boiler leads	150-333 fps
	Auxiliary steam, exhaust lines	100-250 fps
	Saturated and low pressure steam	100-167 fps
Water	Centrifugal pump suction lines	3-5 fps
	Feedwater	8-15 fps
	General service	4-10 fps
	Potable water	Up to 7 fps

without exceeding maximum allowable velocities or causing excessive pressure drops.

e. *Sizing calculations.* Empirical equations and charts have been devised to calculate pressure drops with reasonable accuracy. The Darcy Equation has been shown to produce accurate results.

8-8. Steam traps.

a. *Application.* Steam traps are devices that are used to accomplish the following functions:

(1) Allow condensate resulting from loss of latent heat in steam to flow from the steam system to a lower pressure system or to atmosphere.

(2) Vent air and other gases from the steam system to maintain steam temperature and reduce corrosion.

(3) Prevent escape of steam from the steam system.

b. *Selection.* The factors to be considered when selecting the proper steam trap include condensate load, continuous or intermittent operation, system pressure, constant or variable pressure and load, indoor or outdoor installation, failure mode (open or closed), air and noncondensable gas venting, and resistance to water hammer.

c. *Design.* Trap selection and sizing depends on many factors. The condensate load on a trap involves range of load as well as rate of change. Nearly all traps service a long range. A trap will be

sized for the maximum expected condensate load and a safety factor. Oversizing a trap can increase losses, both for good traps as well as traps that fail open. It is recommended that a safety factor of 2:1 be used to size a trap in a constant pressure usage and safety factor of 3:1 be used if the pressure varies. The major steam loss from a trap is at a failed-open condition and can cost thousands of dollars a year if not detected. However, a failed close trap may cause extensive damage because of corrosion or water hammer from condensate that is not discharged. Selection of the failure mode depends on the design conditions and maintenance practices. All traps are subject to freezing, particularly due to condensate flow blockage. Of all types of traps, float traps are most subject to freezing. Steel bodied traps resist freezing better than iron. Trap cost is an important consideration as initial expense may not justify selection because of maintenance characteristics and life span. The inverted bucket type of trap has the longest life, followed by the float trap, thermostatic trap and the thermodynamic trap consecutively for long life.

d. Types. There are four basic types of steam traps: inverted bucket, float, thermostatic and thermodynamic.

(1) *Inverted bucket.* This type of steam trap is the most widely used. When properly sized, steam loss is kept to a minimum. The inverted bucket trap contains an inverted bucket inside the trap body. The inverted bucket is fastened to a linkage in such a manner that it will close the trap outlet when steam enters from beneath the bucket. As the steam cools and condenses (assisted by a bucket vent), the bucket loses its buoyancy and the trap opens releasing the condensate. Gases mixed with the steam pass through the inverted bucket trap partly by way of the bucket vent and partly in any steam discharged by the trap. The discharge from the inverted bucket trap is intermittent and requires a differential pressure between the inlet and discharge of the trap to lift the condensate from the bottom of the trap to the discharge connection. They are resistant to water hammer, operate well at low loads, and fail open. Bucket traps may be subject to damage from freezing and have only fair ability to handle start-up air loads. Inverted bucket traps are well suited for draining condensate from steam lines or equipment where an abnormal amount of air is to be discharged and where dirt may drain into the trap.

(2) *Float.* A float trap has a small chamber containing a float and linkage that multiplies the float's buoyancy. The condensate will cause the

float to open the trap until it is drained and the float loses buoyancy. A float trap does not have to be primed as an inverted bucket trap does. However, buildup of solids and sludge in the trap body can prevent the float from sinking and closing the valve. The discharge from the float trap is generally continuous. This type is used for draining condensate from steam headers, steam heating coils, and other similar equipment. When a float trap is used for draining a low pressure steam system, it will be equipped with a thermostatic air vent.

(3) *Thermostatic.* The thermostatic trap opens and closes by means of a force developed by a temperature sensitive actuator. A basic problem for all thermostatic traps is keeping the actuating temperature close to the saturation temperature so the condensate will be hot, but not allow live steam to blow out the trap. If the actuating temperature is not close to the saturation temperature, there is a possibility that O₂ and CO₂ may dissolve in the water, and also, that the condensate may back up to an unacceptable level. The discharge from this type of trap is intermittent. Thermostatic traps are used to drain condensate from steam heating coils, unit heaters and other similar equipment. Strainers are normally installed on the inlet side of the steam trap to prevent dirt and pipe scale from entering the trap. The thermostatic trap is the most common of all trap types used for two pipe steam heating systems. When this type of trap is used for a heating system, at least 2 feet of pipe will be provided ahead of the trap to cool the condensate. This permits condensate to cool in the pipe rather than in the coil, and thus maintains maximum coil efficiency. Thermostatic traps are recommended for low pressure systems up to a maximum of 15 psi. When used in medium or high pressure systems, they must be selected for the specific design temperature. In addition, the system must be operated continuously at that design temperature.

(4) *Thermodynamic disc traps.* Thermodynamic disc traps are used for intermittent service, where they operate well under variable pressure conditions, are resistant to damage from freezing and water hammer, and fail open. A disadvantage of the thermodynamic trap or disc trap is poor gas handling. The pressure drop when air or O₂ are flowing in the trap resembles that of steam, so that large amounts of air will close the trap. Therefore, another air removal method is necessary for startup of a steam system. Thermodynamic disc traps will not be used where high back pressures, or low load conditions might occur. They are best suited for

use on high pressure superheated steam mains and steam tracer lines.

8-9. Piping accessories.

a. Strainers. Strainers are a filtering device used to remove solids from liquid piping systems and to protect equipment. Strainers are normally placed in the line at the inlet to pumps, control valves or other types of equipment that are to be protected against damage.

(1) *Y-type strainers.* Y-type strainers are used in small piping for protection of in-line devices such as steam traps. Y-type strainers may also be used in pump suction lines on small pumps such as chemical feed pumps. Y-type strainers utilize a screen mesh to remove solids and will have a blow-off valve and a means for removing the screen for cleaning.

(2) *T-type strainers.* T-type strainers are used in large piping on pump suction lines to protect the pump. T-type strainers will utilize a perforated basket to remove solids and will have inlet and outlet pressure gauges or a differential pressure gauge to indicate when the basket requires cleaning. Strainers for pump protection should be not

less than 40 mesh. Screen material will be suitable for liquid or gas in line. Strainer body will be equal to material specified for the valves in the same service.

(3) *Duplex strainers.* Duplex strainers are used on low pressure systems and contain two sections which can be individually cleaned while the process is in operation. One section is operable while the other section is isolated. Duplex strainers will have inlet and outlet pressure gauges or a differential pressure gauge to indicate when a basket requires cleaning.

b. Safety valves. Safety valves must be provided in accordance with the ASME Boiler and Pressure Vessel Code. Safety valves are pre-set to open fully at a certain pressure and to pass a certain flow capacity. The pressures and capacities are determined from code requirements. Safety valves on the boiler proper are normally provided by the boiler manufacturer. Other equipment requiring safety valves includes the DA, feedwater heater shell, feedwater heater channel, and air receivers. Pressures and capacities for this equipment is also determined from code requirements.

CHAPTER 9

INSTRUMENTS AND CONTROLS

9-1. General.

This chapter addresses the criteria for the selection of instruments and controls to meet the requirements of the steam plant.

a. Pneumatic controls. Most control system manufacturers have discontinued production of pneumatic controls systems. Replacement parts and qualified service for the equipment are difficult to procure. For these reasons pneumatic controls should not be used for new installation.

b. Electronic controls. Electronic systems have been made obsolete by the microprocessor based control systems. Manufacturers no longer make electronic control systems and they should not be specified for new installations.

c. Microprocessor based controls. Microprocessor based control systems can provide sequential logic control and modulating control in one control device. This capability makes available boiler control systems, which use both sequential logic and modulating control, that are more flexible and reliable as well as more cost effective. Processing units can be utilized as single loop controllers or more powerful processing units can be applied to individual control subsystems, such as combustion control of ash handling control.

(1) Inputs from and outputs to field devices may be multiplexed. Data highways connect all processing units to data storage and acquisition components, cathode ray tube (CRT) displays and operator consoles, loggers, and printers, providing communication among all components. Communications between modulating control devices and sequential logic flow freely and are not subject to the restrictions inherent with analog and mechanical relay electronic systems which require hard-wiring between components. Data acquisition and operator interface for control may be accomplished using CRT's, keyboards and printers or through control stations indicators and recorders mounted on an operator console. When CRT's, keyboards and printers are utilized redundant microprocessors are sometimes utilized depending on unit size.

(2) Program logic can be changed or expanded readily with limited hardware revisions. System selection can range from programmable controller systems to fully distributed digital control systems. The criteria for selection of the proper microprocessor based system will include unit size, the amount and type of modulating control and sequential logic required, operator interface re-

quirements, system security requirements, and LCCA.

(3) Distributed control systems include the process input output sensors and actuators which are connected to the termination units which condition and multiplex the signals for communication to the microprocessor unit controllers where the logic resides for control of the process variable. All microprocessor unit controllers communicate with each other and to a data highway which includes nodes for the operator interface station, engineering work station, and programmable logic controllers for balance of plant controls.

(4) The distributed control system logic for the controls and the I/O for the process are located in the vicinity of the process. This process controller will communicate with other process controllers, engineers work station, data acquisition system and the operator interface. The control system will be configured to allow the process controller to continue to function upon loss of communication with the operator interface, data acquisition system and other process controllers.

d. Control system reliability. The methods used to ensure control system reliability will be based on unit size, importance to plant operation, and the cost of control system failure versus the cost of backup hardware.

(1) *Power sources.* Power to the control system must have a backup supply. Microprocessor based systems must have a backup power supply either from a separate ac source or an uninterruptable power supply (UPS). Loss of either the primary power source or the backup power service must be detected and alarmed. Loss of either supply alone must not affect operation of the controls. Distributed control systems will include power supplies which are redundant or backed up so that loss of any power supply will not cause loss of power to the control logic. Loss of power supply should be alarmed.

(2) *Control system safeguards.* Microprocessor based controls are highly reliable but safeguards must be provided to limit the effects of component failure. Microprocessor based control systems require grounding to a ground mat with an impedance of three ohms or less for protection of system components to reduce forced plant outages. Spare circuit cards for critical components are to be available at the boiler plant, as well as spare microprocessing units that can be

substituted for faulty units which are encountered during start-up and operation of the plant. For critical subsystems consideration should be given to redundant microprocessors with automatic switching of inputs and outputs from one microprocessor to another. The data highway should be looped or redundant so that failure of a segment of the data highway will not result in the loss of communications. Control elements should be designed to fail in a safe condition upon loss of the electric or pneumatic power to the actuators or input signal. The loss of power at the component or subsystem levels must cause the associated auto/manual stations to switch to the manual mode of operation. The control logic should have continuous self diagnostic capability and, upon detection of component failure, transfer to manual and indicate the cause of the failure. Microprocessors are to contain nonvolatile memory which will not be erased on power failure.

e. Control system expansion. The control system architecture should allow expansion at all levels of the system. The 110 can be expanded by installing additional cards or racks with signal conditioning for communication to the control system processing units. Additional nodes can be added to the data highway to allow additional processing units, engineering work stations, and operator interface CRT's to be added to the control system.

f. Data link. The process 110 signals are connected to the termination units and through signal conditioners to the microprocessor controllers. The control system data highway for exchange of data between microprocessor based controllers and between microprocessor based controllers, data acquisition systems, operator interface and engineering work stations will be redundant. The data highways will utilize coax, twines of fiber optic cabling. The speed of data transmission is increasing and should be investigated prior to

writing specifications. Data rates of approximately 1 mega baud are available.

9-2. Combustion controls.

a. General. The purpose of combustion control systems is to modulate the quantity of fuel and combustion air inputs to the boiler in response to a load index or demand (steam pressure or steam flow) and to maintain the proper fuel/air ratio for safe and efficient combustion for the boiler's entire load range.

b. System types. Three types of combustion control systems are available: series, parallel, and series-parallel. Each of these types are schematically represented in figure 9-1.

(1) *Series control.* A series control system as shown in figure 9-1(a) uses variation in the steam header pressure (or any other master demand signal) from the setpoint to cause a change in the combustion air flow which, in turn, results in a sequential change in fuel flow. The use of series control is limited to boilers of less than 100,000 pph that have a relatively constant steam load and a fuel with a constant Btu value.

(2) *Parallel control.* A parallel control system as shown in figure 9-1(b) uses a variation from setpoint of the master demand signal (normally steam pressure) to simultaneously adjust both the fuel and combustion air flows in parallel. This type of system is applicable to stoker-fired boilers, pulverized coal fired boilers, gas/oil fired boilers and atmospheric circulating fluidized bed (ACFB) boilers.

(3) *Series-parallel control.* A series-parallel control system as shown in figure 9-1(c) should be used to maintain the proper fuel/air ratio if the Btu value of the fuel varies by 20 percent or more, if the Btu input rate of the fuel is not easily monitored, or if both of these conditions are present. These conditions normally exist on pulver-

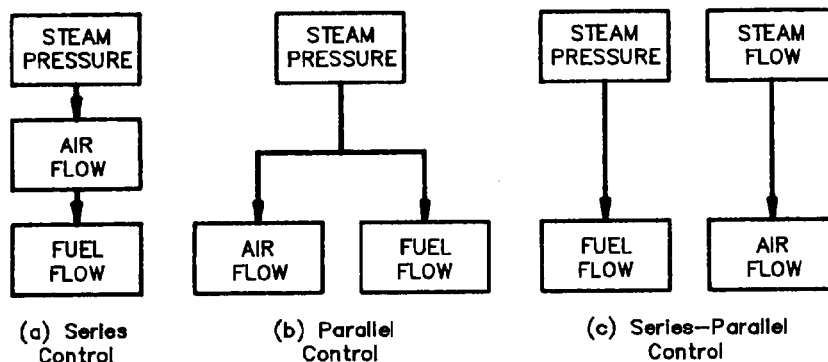


Figure 9-1. Types of Combustion Controls.

ized coal fired and ACFB boilers. Variations in the steam pressure setpoint adjust the fuel flow input. Since steam flow is directly related to heat release of the fuel, and because a relationship can be established between heat release and combustion air requirements, steam flow can be used as an index of required combustion air. Note however that this relationship is true only at steady load conditions.

c. *System categories.* Combustion controls can be further divided into two categories within the basic types: positioning control and metering control, as shown in figure 9-2.

(1) *Positioning control.* Positioning systems require that the final control elements move to a preset position in response to steam pressure variations from a setpoint. Series positioning control will not be covered here since it is only used on very small boilers operating at constant loads. Parallel positioning systems that use a mechanical jackshaft to simultaneously position fuel feed and air flow from a single actuator apply to packaged type gas/oil fired boilers in the 20,000 to 70,000 pph size and is shown in figure 9-2a. This system

allows the operator to load the boiler over its complete operating range. The fuel valves and air damper are operated by the same drive through a mechanical linkage. The gas and oil valves include cams which are adjusted at start up to maintain proper fuel air ratio over the operating range of the boiler. Parallel positioning systems with fuel/air ratio control as shown in figure 9-2(b) are suitable for use on gas/oil and stoker fired units. This system allows the operator to adjust the fuel/air ratio for the entire load range of the boiler. The addition of steam flow correction of air flow to parallel positioning with fuel/air ratio control creates a system suitable for use on ACFB, gas/oil and pulverized coal fired units as shown in figure 9-2(c). This system uses variation of steam pressure from a setpoint to initially control fuel and air inputs. The system recorrects combustion air flow using steam flow as a setpoint for air flow, since steam flow is a function of fuel Btu input (inferred fuel flow). This system relates directly to a series-parallel type control with the addition of a feed-forward signal from the steam pressure controller to the combustion air control.

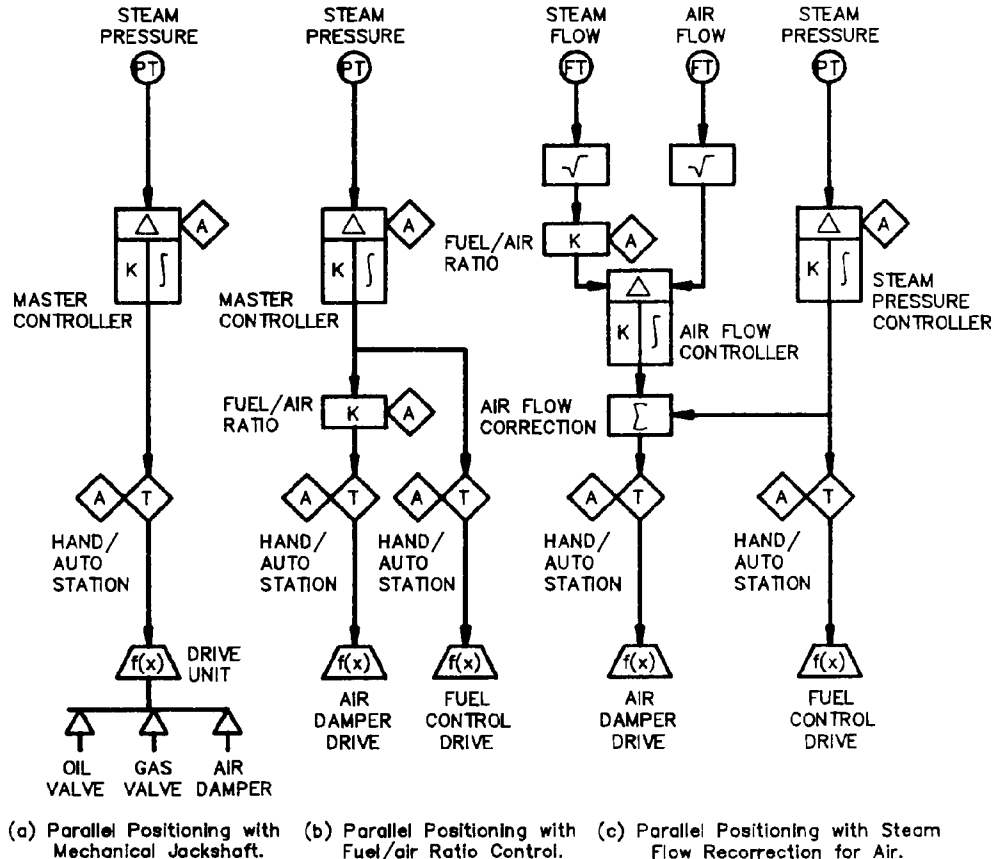


Figure 9-2. Positioning Controls.

(2) *Metering control.* Metering control systems regulate combustion based on metered fuel and air flows as shown in figure 9-3. The master demand developed from steam pressure error establishes the setpoints for fuel and combustion air flows at the controllers. The controllers drive the final control elements to establish proper fuel and flows which are fed back to the controllers. Maximum and minimum signal selectors are used to prevent the fuel input from exceeding available combustion air on a boiler load increase and to prevent combustion air from decreasing below fuel flow requirements on load reduction. This system is a cross-limiting flow tie back system with air leading fuel on load increase and fuel leading air on load reduction. This system is applicable to gas and oil, pulverized coal, and ACFB fired units.

d. *System selection.* Table 9-1 summarizes the combustion control systems discussed and their application to the various types of boilers.

e. *Stoker system controls.*

(1) *Fuel flow control.* The components of a stoker system must respond to the fuel flow demand signals generated by the combustion control system. For spreader stokers the coal feed to the overthrow rotor will vary with the demand signal. Grate speed on traveling grate and traveling chain grate stokers will respond to the demand signal. The frequency and duration of vibration cycles on vibrating grate stokers will vary with the demand signal. In all cases the relationship between fuel flow and unit load will be determined for use in the combustion control system to properly control fuel flow in response to the demand signal.

(2) *Combustion air control.* The combustion air flow is normally controlled at the FD fan. Two methods that are commonly used are control of inlet vanes on the FD fan or control of the FD fan inlet damper. If a metering control system is used the combustion air flow should be measured down

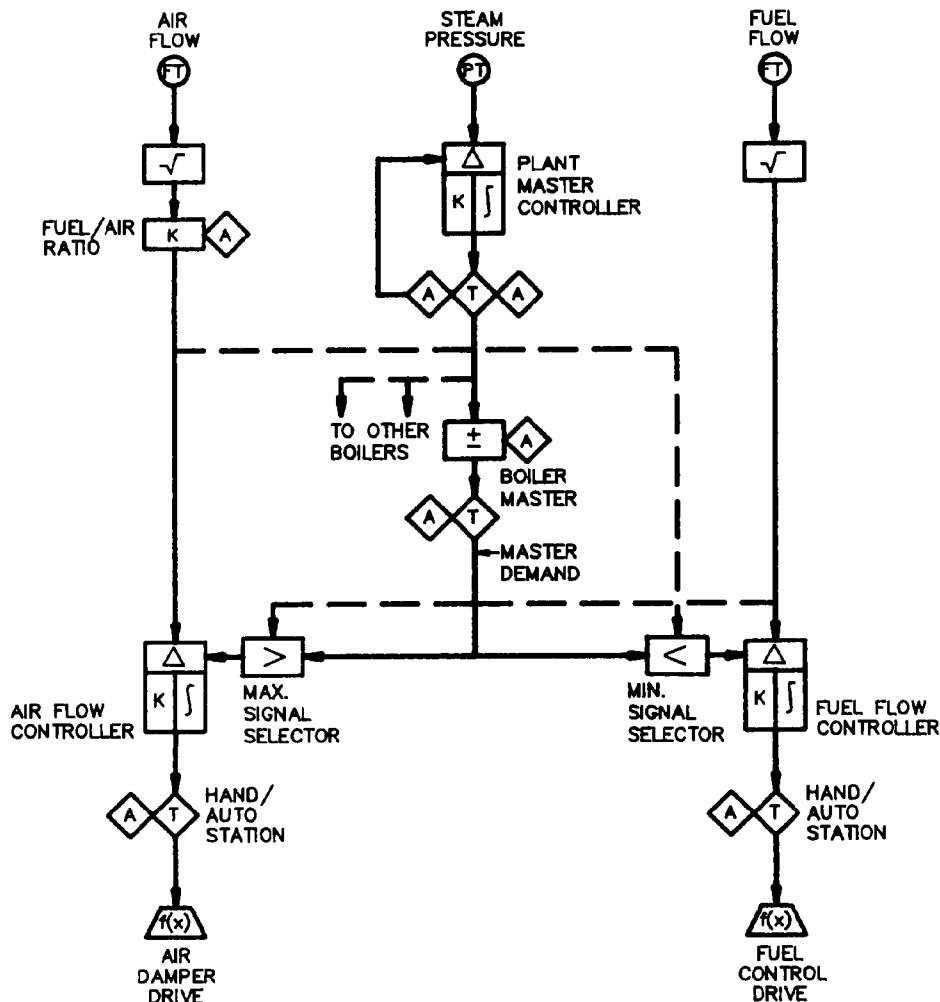


Figure 9-3. Metering Controls.

Table 9-1. Combustion Control System Selection Guide.

Control System	Boiler Type				
	Gas/Oil	Stoker	Pulverized Coal (PC)	Multiple Burner PC	ACFB
Jackshaft positioning	X*				
Series control	X**	X**			
Parallel positioning	X	X			
Parallel positioning with steam flow correction of air	X	X	X		
Parallel metering with cross limiting and flow tie-back	X		X	X	

X Recommended Application

*Restricted to use on boilers 70,000 pph and under.

**Restricted to use on boilers under 100,000 pph with constant load and constant Btu value fuel.

stream from the fan outlet. The relationship between inlet vane or damper position and air flow will be determined for use in the combustion control system or for characterizing the final control element. Overfire air flow on stoker fired units normally is not measured. If overfire air is to be controlled the air flow demand signal will be used to control overfire air in parallel with combustion air.

(3) *Combustion air flow measurement.* Accurate combustion air flow measurement is extremely important in combustion control systems for stoker fired boilers. A venturi section of air foil flow element should be provided in the ductwork between the FD fan and the stoker or a Piezometer ring may be installed at the FD fan inlet. The flow element will be designed to provide a design differential pressure across the flow element of not less than 2 inches wg at full load conditions. The flow transmitter selected for combustion air flow will be a differential pressure transmitter that is accurate in the range of differential pressure developed by the flow element.

f. *Pulverized coal system controls.*

(1) *Fuel flow control.* Fuel flow in pulverized coal systems is established by coal feeder inputs to the pulverizer. Coal feeder speed controls the fuel flow to the pulverizer. The volumetric rate of coal flow delivered to the pulverizer is directly related to feeder speed. Feeder speed varies with fuel flow demand.

(2) *Combustion air control.* Combustion air flow in pulverized coal systems consists of primary air flow and secondary air flow. Primary air is the air which transports the pulverized coal to the burner or burners. Secondary air is the air delivered by the FD fan to the boiler to support combustion. Total air flow is the sum of secondary air flow and all primary air flows. Secondary air is measured downstream of the FD fan and controlled by positioning FD fan inlet vanes or inlet damper. Primary air can be supplied by the FD fan or by a primary air fan. Primary air is normally measured on each pulverizer.

(3) *Combustion air flow measurement.* Accurate combustion air flow measurement is essential for combustion control systems of pulverized coal fired boilers. Secondary air flow will be measured with a venturi section or air foil flow element in the ductwork between the FD fan and the boiler windbox. The flow element should be designed to provide a design differential pressure across the flow element of not less than 2-inches wg at full load conditions. Primary air flow will be measured on each pulverizer with a venturi section or pilot tube between the primary air fan and the pulverizer. The design pressure differential pressure across the primary air flow elements should not be less than 2-inches wg at full load. The transmitters selected for primary air flow and secondary air flow will be differential pressure transmitters that are accurate in the range of differential pressure developed by the flow elements.

(4) *Pulverizer controls.* Figure 9-4 shows one multiple pulverizer control scheme. In this arrangement the firing rate demand is compared to total fuel flow, which is the sum of all feeders to develop the demand to the pulverizer master. The pulverizer master demand signal is applied in parallel to all pulverizers which have duplicate controls. If an upset occurs in the fuel/air ratio such that total air flow is low, an error signal from air flow control reduces the firing rate demand to the pulverizer master to restore the proper fuel/air ratio. Since coal flow to the burner is a function of primary air flow the primary air damper and coal feeder speed control receive the same demand signal. If an error develops between demand and measured primary air flow or coal feeder speed, the controllers adjust the primary air flow or feeder speed to eliminate the error. If primary air flow is less than feeder speed demand, the feeder speed demand is made equal to the primary air flow by the low select auctioneer. A minimum pulverizer loading and a minimum primary air flow limit should be used to maintain the pulverizers above the minimum safe operating load to maintain adequate burner nozzle velocities and to maintain

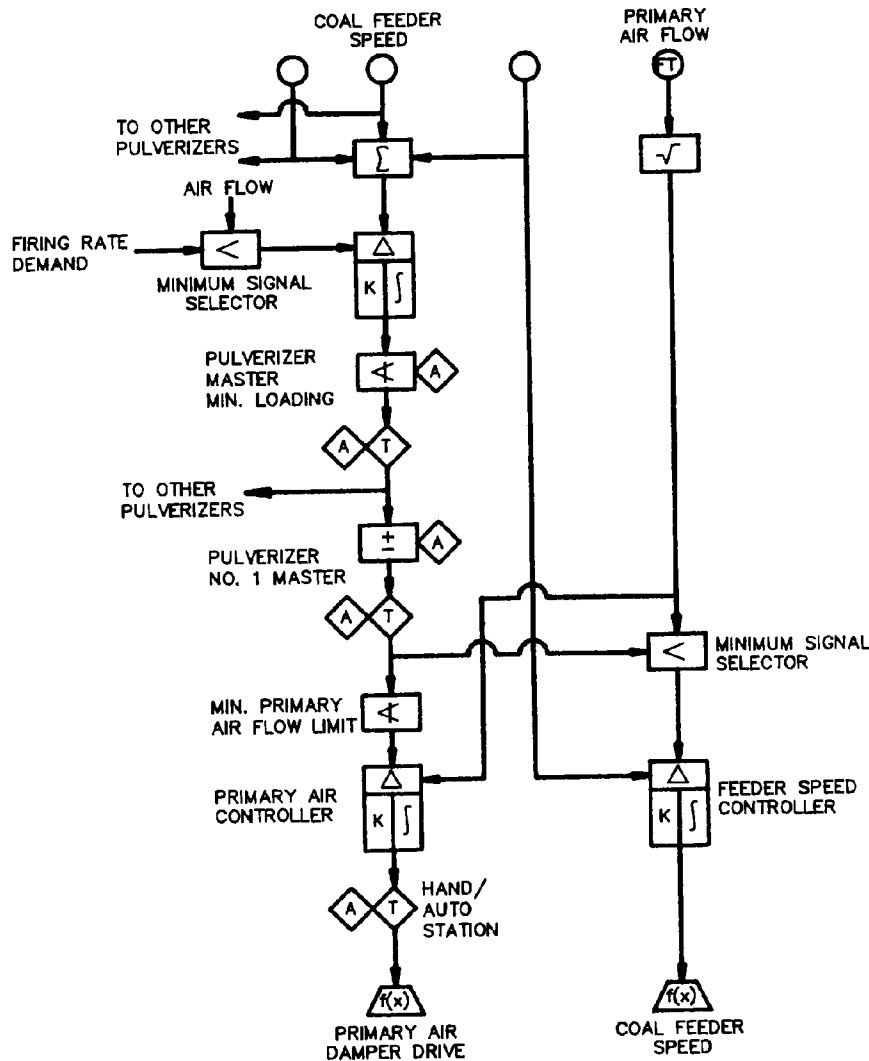


Figure 9-4. Pulverizer Controls.

the primary air to fuel ratio above a minimum level for all pulverizer loads.

g. Gas/oil system controls.

(1) *Fuel flow control.* Fuel flow in gas/oil fired boilers is controlled by operation of gas or oil control valves in the supply lines to the burners. The gas or oil control valves are modulated to control fuel flow based on the demand signal generated by the combustion control system. Gas flow to the burner is measured by taking the differential pressure across an orifice. Oil flow to the burners will be measured by a rotating disk type meter. Metering type control systems utilize the fuel flow and unit load in the combustion control

system to properly modulate fuel flow in response to the system demand.

(2) *Combustion air control.* The combustion air is normally controlled at the FD fan. Air flow for package boilers is normally controlled by outlet dampers at the FD fan. Other methods that are used include control of the FD fan inlet vanes or control of the FD fan inlet damper. The relationship between inlet vane or damper position and air flow will be determined for characterizing the final control element. When a metering type control system is used air flow is measured downstream of the FD fan or a piezometer may be installed at the FD fan inlet.

(3) *Combustion air flow measurement.* Accurate combustion air flow measurement is also important in metering type combustion control systems for gas/oil fired boilers. A venturi section or air foil flow element should be provided in the ductwork between the FD fan and the burner windbox or a piezometering may be installed at the FD fan inlet. The flow element will be designed to provide a design differential pressure across the flow element of not less than 2 inches wg at full load conditions. The flow transmitter selected for combustion air flow will be a differential pressure transmitter that is accurate in the range of differential pressure developed by the flow element.

(4) *Oil atomization.* The oil to the burner will be atomized utilizing steam or compressed air. A control valve installed in the atomizing steam or air line will be controlled to maintain the atomizing medium pressure above the oil supply pressure to the burner.

h. Atmospheric circulating fluidized bed (ACFB) boiler.

(1) *Fuel flow control.* Main fuel flow in an ACFB system is established by fuel flow through the feeder to the combustor. The volumetric rate of fuel flow is directly related to feeder speed. The coal feed demand speed utilizes the lower of the total air flow or firing rate demand as the set point and compares the set point to total fuel flow

to develop the demand signal for the feeder master. The feeder master demand signal is applied to all feeders which have duplicate controls. Therefore, as firing rate demand is increased or decreased the feeder speed is increased or decreased. Coal chute air flow compares measured air flow to load flow to operate the coal chute air damper. A feed forward signal based on rate of change is also used to modulate the coal chute air control damper. Coal feeder and coal chute air damper control is shown in figure 9-5.

(2) *Combustion air control.* Combustion air flow in ACFB systems consists of primary air flow, overfire air flow, stripper cooler air flow, and main fuel chute air flow. Primary air is introduced below the bed and keeps the fuel and bed in suspension. Overfire air is delivered by the FD fan and is utilized at loads above 50 percent to control furnace exit gas temperature. The stripper cooler air flow is utilized to cool the excess bed material which is removed in the stripper section. Main fuel chute air flow is utilized to sweep the fuel tube to the combustor. Total air flow is the sum of primary air, overfire air, stripper cooler air, and coal chute air flow. All air can be supplied by the FD fan or separate primary air and FD fans may be utilized. The primary air, overfire air and stripper cooler are controlled by positioning the appropriate damper.

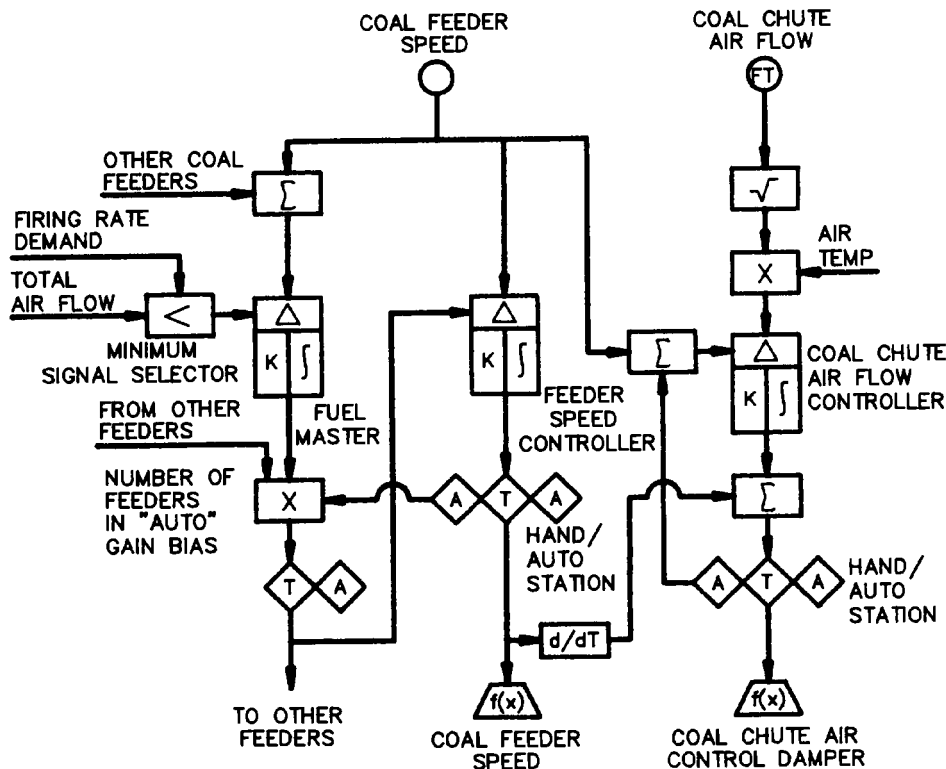


Figure 9-5. Coal Feeder Speed and Coal Chute Air Damper Controls.

Air supply is maintained by modulating the FD fan and primary air fan inlet vanes or dampers to maintain pressure in the FD fan outlet duct.

(3) *Combustion air flow measurement.* Accurate combustion air flow measurement is also important in combustion control systems for ACFB boilers. Measurement of primary air flow, overfire air flow, stripper cooler air flow, and coal chute air flow will be measured with a venturi section or air flow element in the ductwork to the various equipment. The design pressure differential pressure across the air flow elements will be not less than 2-inches wg at full load. The transmitters selected for primary air flow and secondary air flow will be differential pressure transmitters that are accurate in the range of differential pressure developed by the flow elements.

(4) *Primary and overfire air flow control.* Figure 9-6 shows the primary and overfire air flow. The firing rate demand signal serves as an index for air flow demand. The fuel feed signal and firing rate demand signal are cross limited by a high selector to serve as the setpoint for the total air flow controller. The output of the total air flow controller becomes the setpoint for the primary and overfire air flow controllers. The setpoint is

characterized based on load to obtain the proper primary-to-overfire air flow ratio. The upper overfire air dampers are closed below 50 percent load. The primary air controller setpoint is low limited by a minimum primary air setpoint. Each primary and upper air flow controller compares measured air flow to setpoint. The controller output becomes the demand to its respective air flow control damper. All air flow measurements should be temperature corrected. Furnace exit gas temperature should be monitored and at high temperature alarmed to allow the operator to make the proper air flow adjustment to bring the temperature back to normal. A bias adjustment normally is provided for each controller.

(5) *Furnace bed inventory control and solids cooler temperature, air flow and spray water control.* Furnace bed inventory control requires removal of excess bed material from the furnace. The solids cooler cools the excess bed material to a temperature which allows it to be disposed of via the ash system. Solids are removed from the furnace either by operator action or automatically on high furnace plenum pressure. The furnace bed static pressure, total furnace differential pressure,

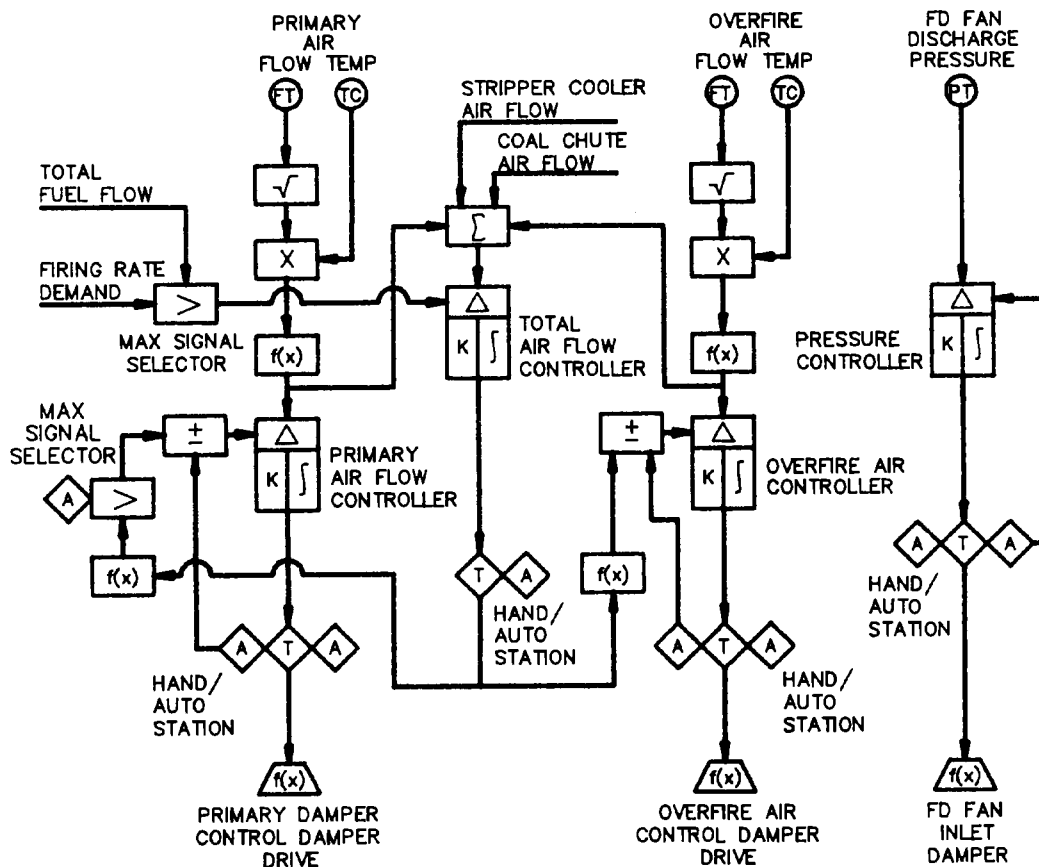


Figure 9-6. FD Fan Discharge Pressure, Primary and Overfire Air Controls.

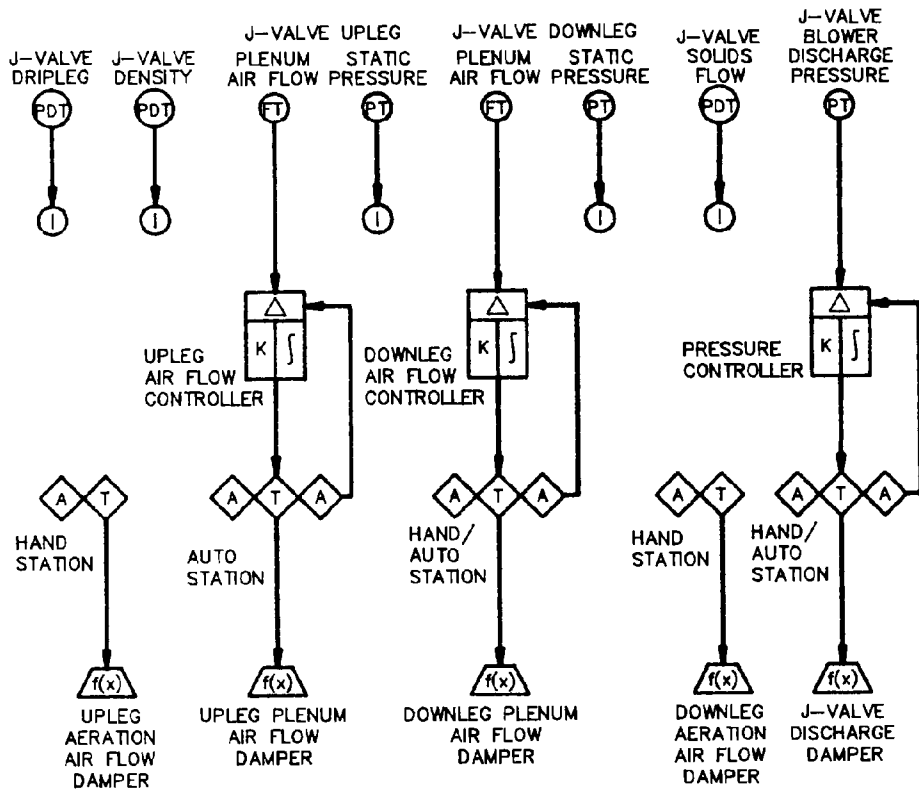


Figure 9-8. J-valve Controls.

the aeration valves. The aeration control is normally only required during start-up and are manually controlled.

(7) *Sorbent (limestone) feeder control.*

The sorbent feeder control provides the proper amount of sorbent to capture the SO₂ generated in the combustion process. The sorbent feeder control is shown in figure 9-9. Sorbent feeder speed controls the sorbent flow to the combustor. The volumetric rate of sorbent delivered to the combustor is directly related to feeder speed. Feeder speed setpoint is based on SO₂ in the stack flue gases, modified by oxygen in the flue gas, total fuel flow and a correction factor. The SO₂ measurement is provided by a flue gas analyzer or analyzers, total fuel flow is taken from the main fuel feeders and oxygen from the flue gas O₂ analyzer. The setpoint value is compared to the actual sorbent (limestone) flow. A low limit is applied to the controller output to prevent the value from falling below a minimum value.

(8) *Warmup burner control.* A gas/oil fired burner or in-bed lances are utilized to warm the bed material to the value where main fuel combustion occurs. When gas/oil fire burners are utilized they normally are placed in the primary air duct. Fuel flow is regulated by a controller comparing primary

air temperature at the burner outlet to the selected temperature. A low limit select limits the fuel to the available primary air flow through the duct burner. When in-bed lances are utilized the fuel flow setpoint is compared to the actual fuel flow to modulate the burner valve. Position of the fuel valve is limited by a low selector to the available air flow to the combustor. The warmup burner and in-bed lance control is shown in figure 9-10.

i. Oxygen trim. Boiler efficiency can be improved by minimizing excess air levels. Excess air is required to ensure complete combustion and optimum heat release from the fuel. However excess air adds to heat loss and reduces boiler thermal efficiency. Oxygen trim controls are used to operate the boiler at low excess air levels. An oxygen analyzer is installed to monitor the amount of oxygen in the boiler flue gas. The signal from the analyzer is used to correct the combustion air flow to maintain the proper oxygen level in the flue gas exiting the boiler. The boiler manufacturer's recommendations for flue gas oxygen content versus boiler load for optimum boiler efficiency should be used to establish the proper oxygen content in the flue gas at all boiler loads. Oxygen trim controls applied to a parallel metering system

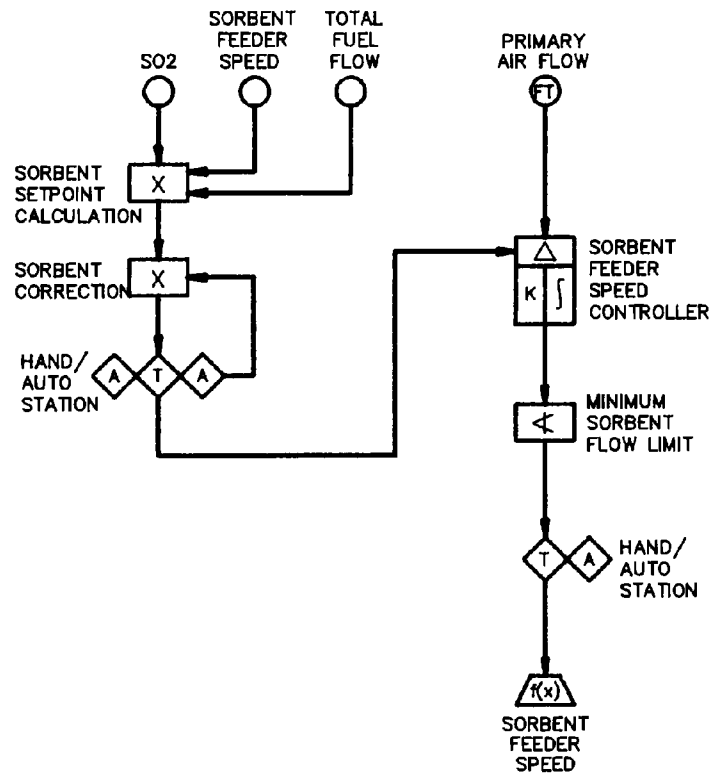


Figure 9-9. Sorbent Feeder Controls.

are shown in figure 9-11. The oxygen setpoint is calculated from boiler load by a characterizing function generator applied to steam flow. Signal limiters are used to establish minimum and maximum corrections to the fuel/air ratio since major excursions are possible due to malfunctions of the oxygen analyzer. Automatic oxygen trim controls should not be used on stoker fired units. Since the fuel bed on a stoker cannot be increased or decreased quickly the firing rate on a stoker is varied primarily by changes in combustion air flow. Changes in combustion air flow will cause similar changes in flue gas oxygen content. Automatic oxygen trim would attempt to correct the air flow and would cause unstable operation during load changes. Stoker fired units should be provided with manual oxygen trim.

9-3. Boiler controls.

a. Furnace safety system.

(1) *General requirements.* The main function of a furnace safety system is to prevent unsafe conditions to exist in the boiler including prevention of the formation of explosive mixtures of fuel and air in any part of the boiler during all phases of

operation. The system must be made to comply with the appropriate NFPA regulations and the recommendations of the boiler manufacturer.

(2) *Purging and interlocks.* The specific purging and interlock requirements will depend on whether the boiler is gas/oil fired, stoker fired, pulverized coal fired or ACFB fired. Regardless of the type of firing system, certain functions must be included in the furnace safety system. These functions include a prefiring purge of the furnace, establishment of permissives for fuel firing, emergency shutdown of the firing system when required, and a post firing purge. Pulverized coal, ACFB and gas/oil firing require additional functions such as establishment of permissives for firing the ignition system and continuous monitoring of firing conditions. The prefiring purge is required to ensure that all unburned fuel accumulated in the furnace is completely removed and is accomplished by passing a minimum of 25 to 30 percent air flow through the furnace for five minutes. The conditions that would cause an emergency shutdown (trip) for pulverized coal, gas/oil and ACFB boilers are shown in table 9-2. The furnace safety system can be either deenergize-to-trip to

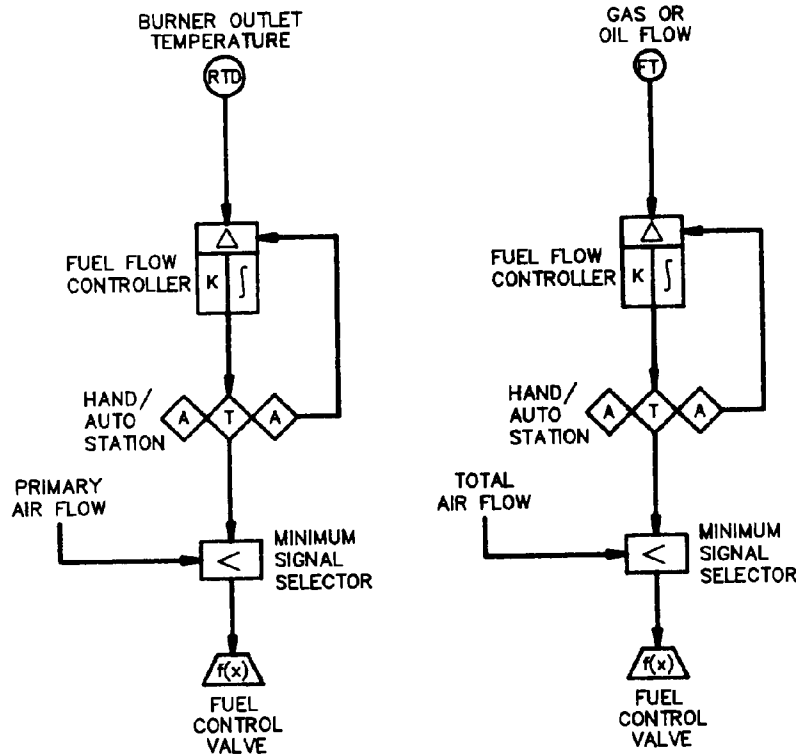


Figure 9-10. Bed Warm-up Controls.

energize-to-trip. The energize-to-trip philosophy is more desirable since it reduces nuisance trips, is operable on loss of power, and is more reliable.

(3) *Flame detection and management.* Stoker fired boilers do not utilize flame detection or flame management. Pulverized coal and gas/oil fired systems do require flame detection, which is the key to proper flame management. The basic requirements of flame detectors are detection of the high energy zone of a burner flame, ability to distinguish between ignitor and main flames, and discrimination between the source flame, adjacent flames, and background radiation. Ultraviolet (UV) detectors are suited for flame detection of gas or light oil ignitor and main gas flames. Infrared (IR) detectors are used for pulverized coal flames. Self checking or redundant detectors should be used to ensure reliability. Location of the flame detectors is critical to proper flame management and must be given careful consideration. Flame detection systems will be on-off type based on the presence or absence of flame.

(4) *Burner controls.* Burner controls are the permissives, interlocks, and sequential logic which are required for safe startup and operation of pulverized coal, ACFB and gas/oil burners. Burner controls range from manual to fully automatic.

Regardless of the level of automation incorporated into the burner controls, the system logic must insure that the operator commands are performed in the correct sequence with intervention only when required to prevent a hazardous condition. Pulverized coal burner controls must provide the proper sequential logic to completely supervise burner startup and operation including coal feeders, pulverizers, air registers, ignitors, and flame detectors. Gas/oil burner controls must provide the proper sequential logic to completely supervise burner startup and operation including gas/oil fuel valves, air registers, ignitors and flame detectors. The ACFB boiler includes utilizing a main gas burner or gas lances and ignitor system to warm the boiler and bed temperature above minimum required for solid fuel firing. This burner operation is identical to a gas/oil burner operation. The ACFB boiler does not have a main fuel burner; however, the introduction of fuel is completely supervised to provide the proper sequence for purge, ignitors, warm-up burners, flame detection, coal feeders, sorbent feeders and bed temperature monitoring. Note the bed temperature monitor insures that adequate temperature is present to ignite the solid fuel. Adequate bed temperature

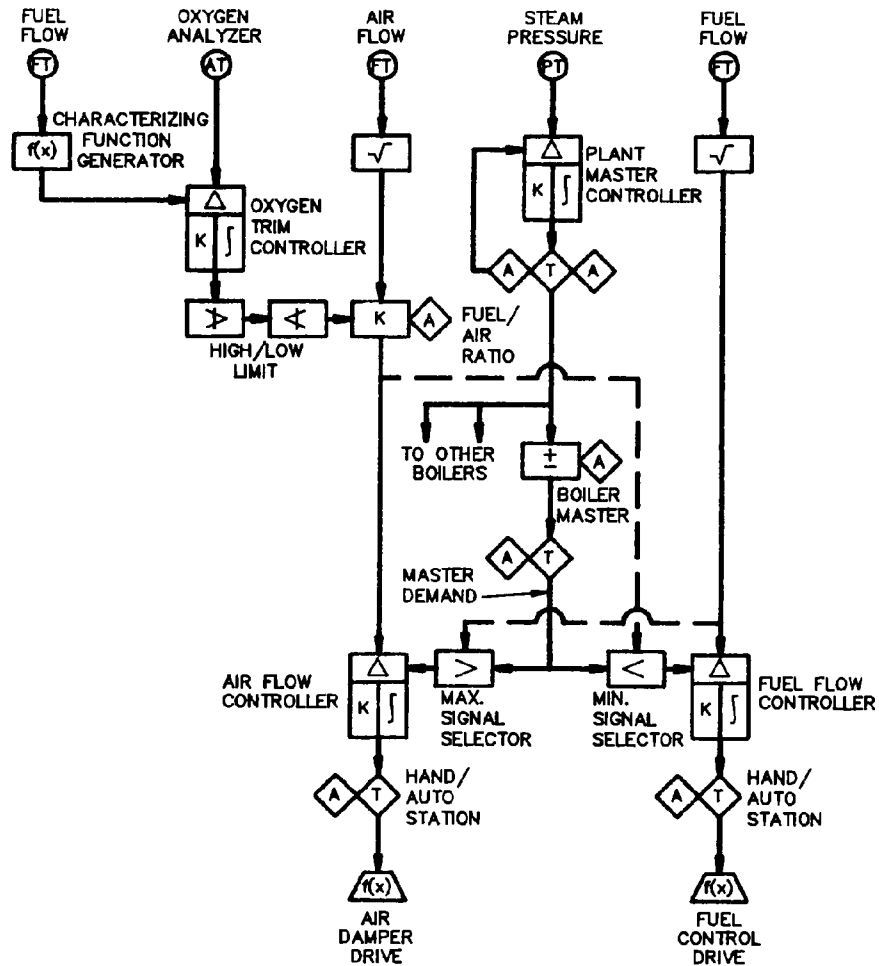


Figure 9-11. Oxygen Trim Controls for Parallel Metering Control.

Table 9-2. Emergency Trip for Boilers.

Item	Pulverized Coal	Gas/Oil	ACFB
Loss of all FD fans	X	X	X
Loss of all ID fans (if used)	X	X	X
High-low drum level	X	X	X
High steam pressure	X	X	X
High furnace pressure or draft	X	X	X
Low air flow	X	X	X
Loss of power to safety system	X	X	X
Flame failure	X	X	
Gas or oil pressure/temperature out of limits		X	
High cyclone level			X
All solids fuel feeders trip	X		X
Bed temperature greater than maximum			X
Bed temperature less than minimum			X
Emergency trip pushbutton	X	X	X
Trips recommended by boiler supplier	X	X	X

allows a hot restart which bypasses the purge, ignitors and warm burners and allows the introduction of solid fuel provided certain conditions are met. Figure 9-12 shows sequential logic for burner control.

b. Feedwater flow and drum level control.

(1) *Two element control.* Two element feedwater control systems as shown in figure 9-13(a) are characterized by the use of steam flow as a feed-forward signal to reduce the effect of shrink

and swell of the boiler drum level during load changes. Without the steam flow feed-forward signal, load changes will momentarily cause the drum level to change in a direction opposite to the load change. The feed-forward signal provides the correct initial response of the feedwater valve.

(2) *Three element control.* Three element feedwater control as shown in figure 9-13(b) uses feedwater flow in addition to steam flow to improve drum level control. In this system feedwater

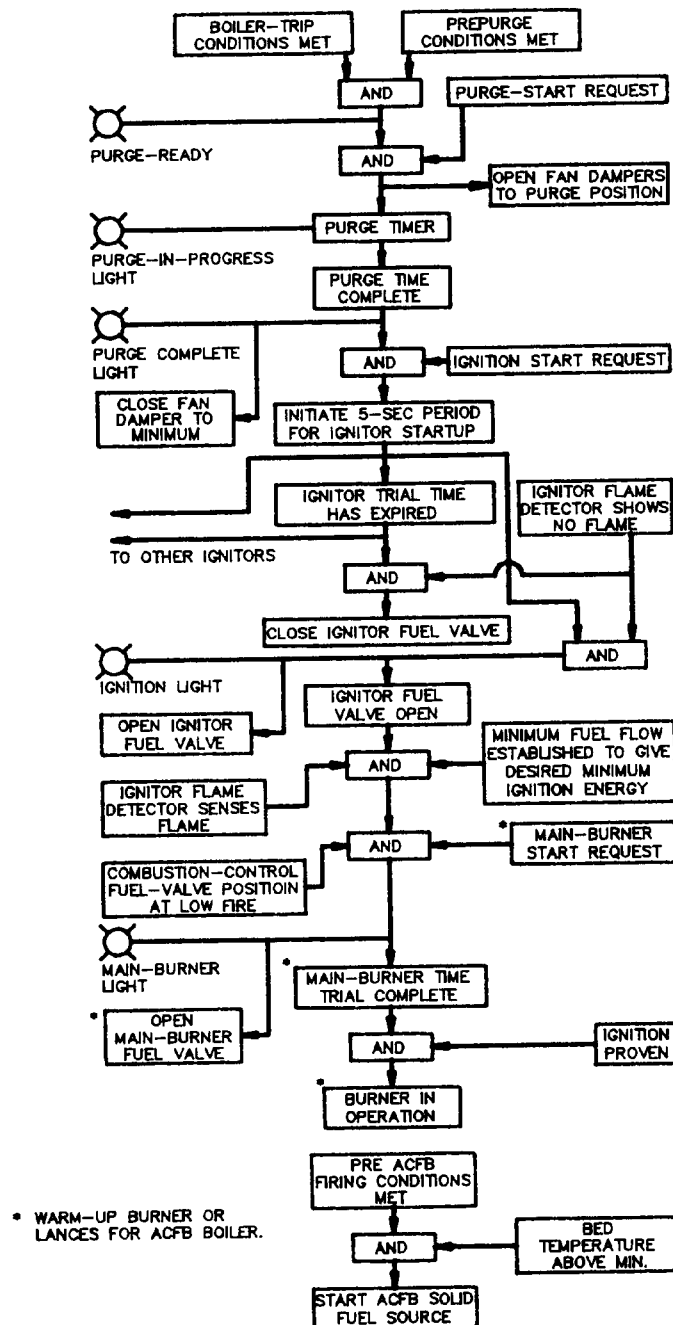


Figure 9-12. Burner Control Sequence.

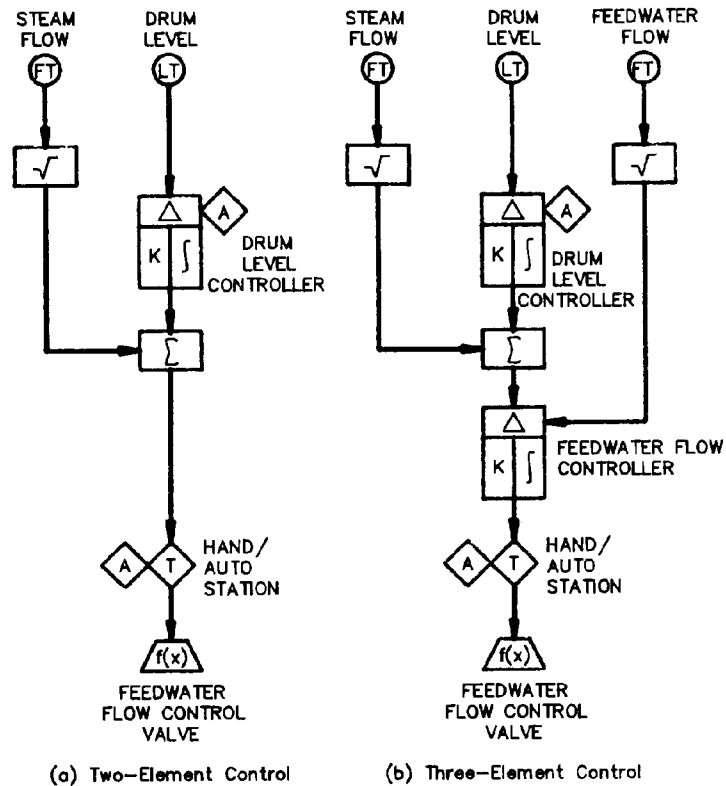


Figure 9-13. Feedwater Control System.

flow to the boiler is metered and the feedwater valve is positioned by summing steam flow and drum level error through a controller. This system should be used when multiple boilers are connected to a common feedwater supply system since feedwater flow is a metered feedback signal and the control system demands a feedwater flow.

(3) *System selection.* Table 9-3 summarizes the types of feedwater control systems and the parameters which should be used for selection of the proper system.

c. *Furnace pressure controls.*

(1) *Single element control.* Furnace pressure controls are primarily single element type. The final control element is the ID fan inlet damper, ID fan inlet vanes or adjustable speed drive for ID fan. The control loop shown in figure 9-14 also uses a feed-forward demand signal that is representative

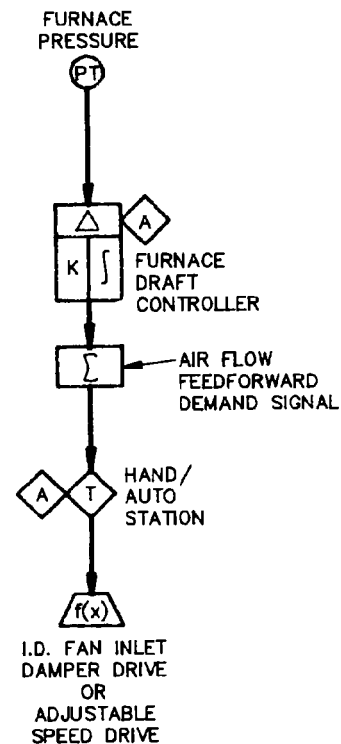


Figure 9-14. Single Element Furnace Pressure Controls.

Table 9-3. Feedwater Control System Selection Guide

Control System	Boiler Requirements		
	Steady-State Load	Swinging Load	Multiple Boiler
Two-element	X	X	
Three-element		X	X

of boiler air flow demand. This feed-forward signal may be fuel flow, boiler master, or other demand index, but will not be a measured air flow signal.

(2) *Furnace implosion protection.* Boilers that have a large capacity and large draft losses due to air quality control equipment may require ID fans with a head capacity large enough to exceed design pressure limits of the furnace and ductwork. If this possibility exists, the furnace pressure control system must include furnace implosion protection. The furnace implosion protection system will comply with the guidelines established by NFPA 85G. These guidelines include redundant furnace pressure transmitters and transmitter monitoring system, fan limits or run-backs on large furnace draft error, feed-forward action initiated by a main fuel trip, operating speed requirements for final control elements, and interlock systems.

d. *Steam controls.*

(1) *Steam pressure control.* Steam pressure is controlled by boiler firing rate. As discussed in combustion control, steam pressure is used to establish the master demand signal that controls fuel and combustion air flow.

(2) *Steam flow control.* Steam flow is a function of boiler load demand. Steam flow is also a function of fuel Btu input and can be used to trim combustion air flow as discussed in combustion control. Steam flow is also used to calculate boiler load for use in oxygen trim controls and as a feed-forward signal in feedwater controls.

(3) *Steam temperature control.* Boilers that produce saturated steam do not require steam temperature controls. Boilers that produce superheated steam require a control loop to maintain superheater outlet temperature. A single element loop with feedback as shown in figure 9-15 is normally adequate for control of steam temperature.

e. *Blowdown controls.*

(1) *Continuous blowdown.* Continuous blowdown is the continuous removal of concentrated water from the boiler. The rate of blowdown is controlled by manually adjusting the setting of the continuous blowdown control valve. Continuous blowdown can be used on boilers of any capacity and permits heat recovery of the blowdown. The use of continuous blowdown heat recovery is dependent upon life cycle cost evaluation.

(2) *Automatic blowdown.* Automatic blowdown systems as shown in figure 9-16 continuously monitor the boiler water and adjust the rate of blowdown to maintain the conductance of the boiler water at the proper level. Control action can be two-position or modulating. The use

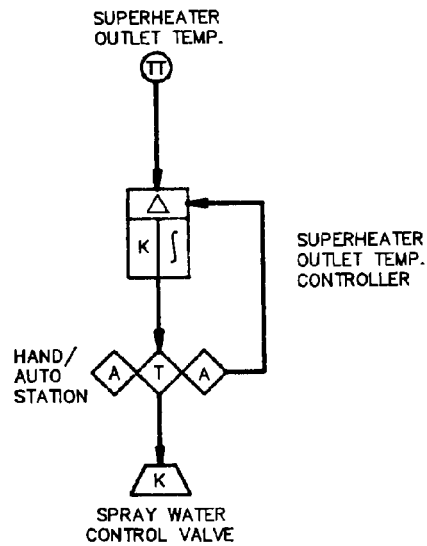


Figure 9-15. Single Element Steam Temperature Controls.

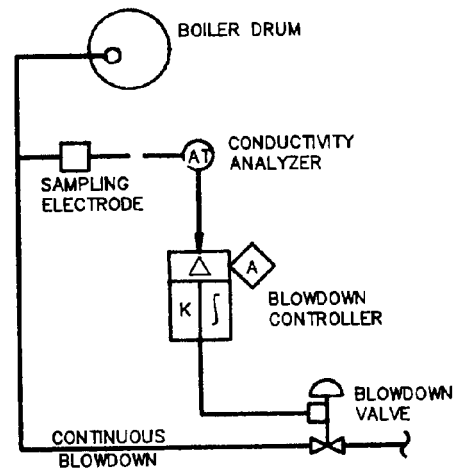


Figure 9-16. Automatic Blowdown Controls.

of automatic blowdown will be dependent on whether blowdown heat is to be recovered and a LCCA.

f. *Sootblower control.* Sootblower control should be an operator-initiated automated sequence control. After the start command the system should step through the sequence for all sootblowers including opening the valve for the sootblowing medium, timing the length of the blow and closing the valve. The system should automatically move to the next sootblower and continue the sequence until all sootblowers have been completed.

9-4. *Nonboiler controls.*

a. *Low pressure steam controls.*

(1) *Turbine drives.* The boiler feed pump turbine drive is controlled by feedwater header pressure. The steam control valve on the turbine drive inlet is controlled by a pressure transmitter on the feedwater header acting through a controller as shown in figure 9-17. The setpoint pressure will be lower than the normal operating feedwater pressure to prevent turbine drive operation during normal operating conditions.

(2) *Sootblowers.* Sootblower steam controls are normally a pressure control system to maintain the proper steam pressure at the sootblower inlet. If remote indication of the sootblower steam header pressure is desired a transmitter and controller will be used as shown in figure 9-18(a). If remote indication is not required a pressure controller mounted on the control valve can be used as shown in figure 9-18(b).

(3) *Steam coil air heater.* The steam coil air heater controls are based on maintaining the flue gas leaving the air heater above the acid dew point temperature. This is accomplished by using an average cold end temperature control system as shown in figure 9-19. Air heater average inlet air temperature and average gas outlet temperature are calculated. These two signals are averaged to arrive at the average cold end temperature, which is used to control the steam coil control valve. Also, the control system should include an interlock that opens the steam coil control valve 100 percent when the ambient air is below a set temperature, usually 35 degrees F.

(4) *Deaerator.* The DA steam controls are a pressure control system to maintain DA pressure. A single element loop with feedback as shown in figure 9-20 is adequate for controlling DA pressure.

(5) *Feedwater heater.* The feedwater heater controls as shown in figure 9-21 are used to protect the economizer against acid condensation. The economizer outlet gas temperature and economizer inlet feedwater temperature are averaged. The average is used to control the feedwater temperature by regulating the steam input to the feedwater heater.

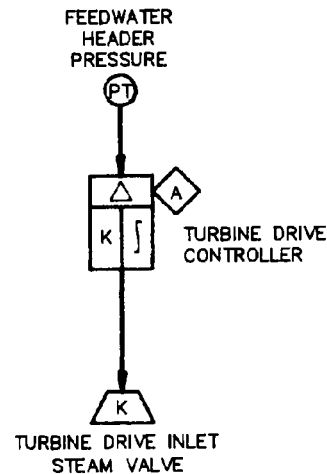


Figure 9-17. Turbine Drive Controls.

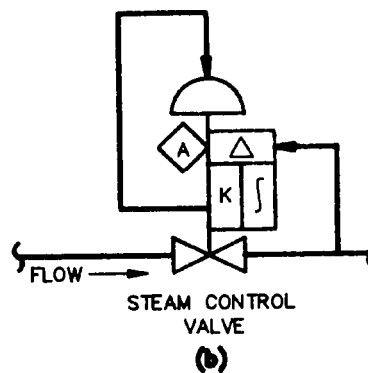
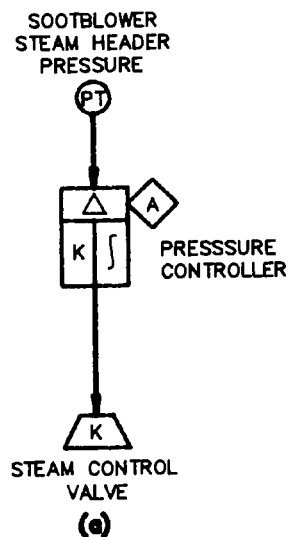


Figure 9-18. Sootblower Steam Controls.

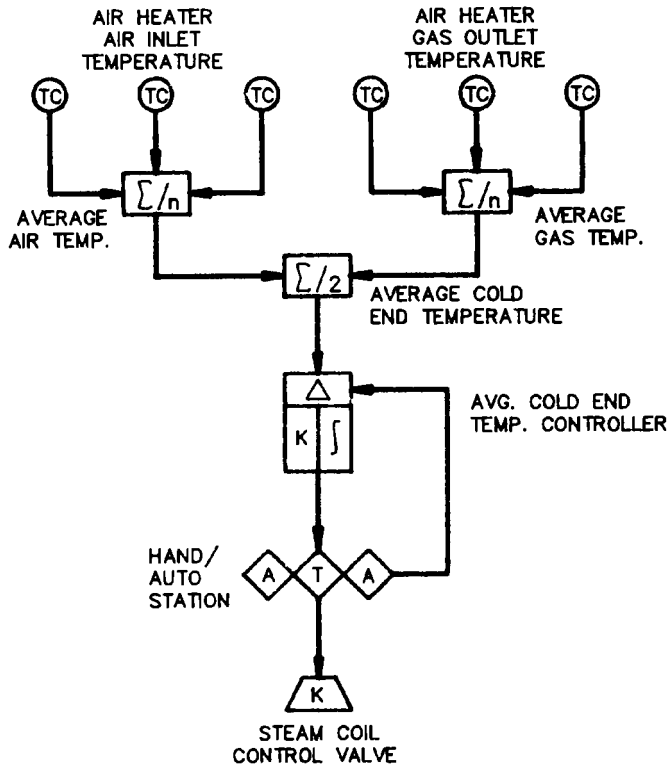


Figure 9-19. Steam Coil Airheater Controls.

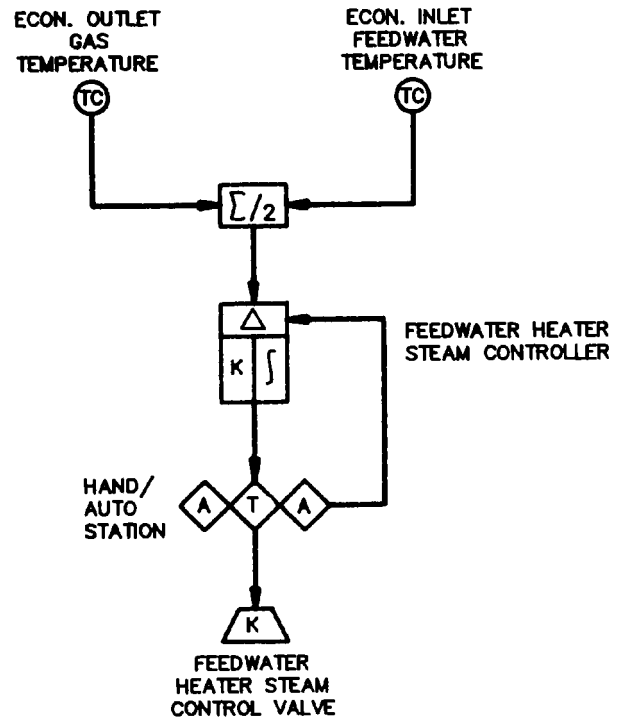


Figure 9-21. Feedwater Heater Controls.

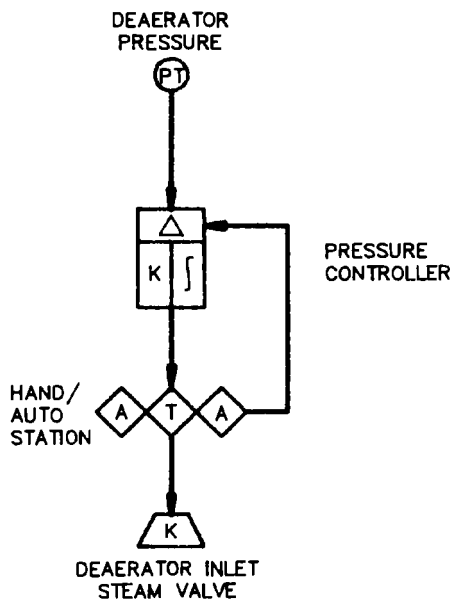


Figure 9-20. Deaerator Steam Controls.

b. Deaerator level controls.

(1) *Two element control.* A two element DA level control system as shown in figure 9-22(a) uses feedwater flow as a feedwater signal to make the system responsive to load changes. A two element system for DA level control can be used for most multiple unit installations that operate under steady load conditions.

(2) *Three element control.* A three element DA level control system as shown in figure 9-22(b) uses a metered condensate flow feedback signal in a cascaded control loop. This system will maintain DA level on units that operate under swinging load conditions.

c. Pump recirculation control. Pump recirculation controls are necessary to maintain the minimum flow through a pump when required by the manufacturer. A breakdown orifice plate sized to pass the required minimum flow can be installed in a line from the pump discharge to the pump suction source. Since this system is a constant recirculation type, it is a source of lost pump hp. The lost hp can be eliminated by using automatic pump recirculation controls. This system requires pump flow to be metered and an automatic valve to open when pump flow is at or below the minimum flow requirement. Automatic recirculation control will be used only when justified by LCCA evaluation.

9-5. Control panels.

a. Control room. A control room isolated from the plant environment complete with heating and air conditioning should be provided for all boiler plants. The boiler panels and auxiliaries may be located at the boiler front for packaged boilers up to 70,000 pph and for stoker fired units. A recorder panel should be located in the control room. The

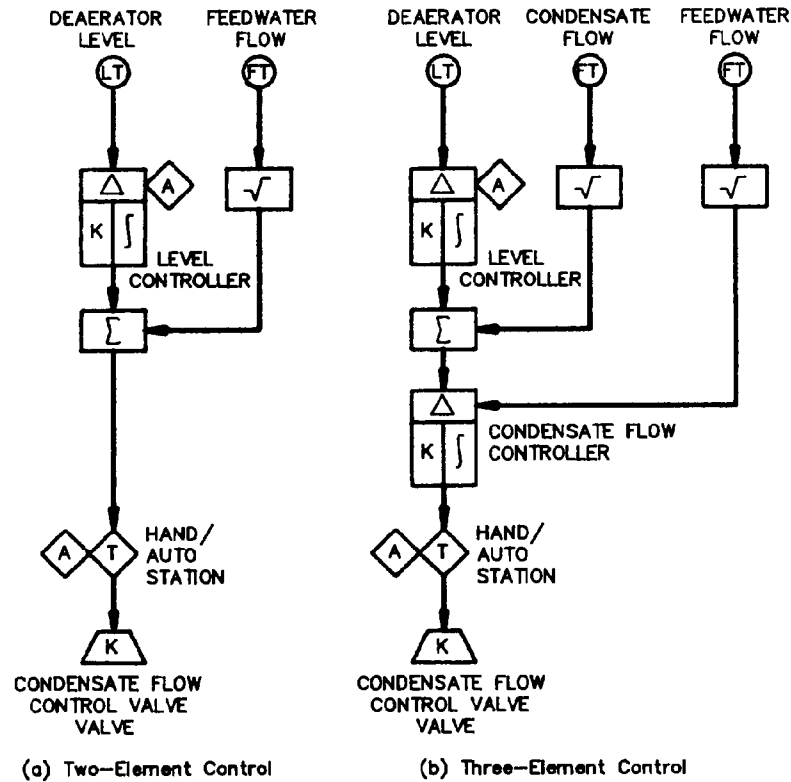


Figure 9-22. Deaerator Level Controls.

control room will be located at a central location in the plant to allow operating personnel good access to the boilers and the auxiliary equipment. The control room will be large enough for the operator interface for the boiler and auxiliaries and also allow room for a desk to be used by operating personnel.

b. Operator interface. The operator interface to the boiler and auxiliaries may be via CRT's and printer housed in a control console or operator stations, recorders, indicators, annunciators and start/stop controls mounted on a control panel.

(1) *Distributed control system.* Operator interface via CRT and printers are normally used on larger units and are part of the distributed control system. This system should always utilize redundant microprocessors, CRT's and printers. The system will automatically switch to the back-up system and annunciate failure of a component. The system will be utilized to perform combustion control, data acquisition and trending, boiler efficiency calculations, graphic displays, boiler control motor start/stop and ash system controls. An auxiliary panel will also be required to mount critical controls and monitoring equipment.

(a) *I/O racks.* The system will include remote mounted input/output racks with redundant microprocessors for control. The information at the I/O rack will be multiplexed to allow communica-

tion with other I/O racks and the central control console. Redundant communication links should be provided to allow communication when one link is lost. All field wiring entering or leaving the I/O racks is to be connected to terminal blocks with spare terminals provided. The equipment in the 110 racks will be designed for installation in a dusty atmosphere with maximum ambient temperatures of 50 degrees C.

(b) *Operator interface.* The control console will include the appropriate number of CRT's and printers required by the size and complexity of the system. A minimum of two CRT's and two printers should be installed. The CRT's and keyboard or other means of operation will be mounted in a console which allows the operators to access and operate the controls while sitting at a chair in front of the CRT.

(c) *Auxiliary panel.* Auxiliary panel construction must conform to the requirements of the National Electrical Code, the National Fire Protection Association, and NEMA standards. It will be constructed of steel plate with adequate internal reinforcement to maintain flat surfaces and to provide rigid support for the instrumentation to be installed. The panel interior will have adequate bracing and brackets for mounting of equipment to be installed within the panel. Electrical outlets will be provided in the panel. No pressure piping of

process fluids is to be run in control panels. All field wiring entering or leaving control panels is to be connected to terminal blocks with spare terminals provided. The items to be mounted in the auxiliary panel will include hardwired main fuel trip (MFT) pushbutton, fan trips, drum level indication, soot blower controls and annunciation of critical items. The annunciator should include items listed below.

1. Main fuel trip (MFP)
2. Drum level high-low.
3. Furnace pressure high.
4. Boiler FW pressure low.
5. Control system power failure.

(2) *Panel mounted control system.* The control and auxiliaries panel where used will include operator stations, recorders, indicators, equipment start-stop controls and annunciation. The arrangement of the panel will not be addressed here since panel arrangements are normally based on the preferences of operating personnel and management.

(a) *Control panel construction.* Control panel construction must conform to the requirements of the National Electrical Code, the National Fire Protection Association, and NEMA standards. Panels will be constructed of steel plate with adequate internal reinforcement to maintain flat surfaces and to provide rigid support for the instrumentation to be installed. The panel interior will have adequate bracing and brackets for mounting of equipment to be installed within the panel. A walk-in door for access to the panel interior will be provided on both ends of the panel where possible and on at least one end of the panel. Electrical outlets will be provided in the panel. No pressure piping of process fluids is to be run in control panels. All field wiring entering or leaving control panels is to be connected to terminal blocks with spare terminals provided.

c. *Instrumentation requirements.* The boiler and auxiliaries panel or control console will provide operator interface required to properly control and monitor the operation of the boilers and auxiliary equipment in the steam plant. This will include operator interface to stations, recorders or trending, indication, equipment start/stop controls, and annunciation. Table 9-4 summarizes the instrumentation requirements for the operator interface.

(1) *Operator stations.* Operator stations are to be provided as shown in table 9-4. Operator stations on control consoles will be accessed through the CRT or through individual operator station on control panels. Hand automatic operator stations will provide bumpless transfer from hand to automatic and automatic to hand without manual

balancing for transfer; and have antireset windup characteristics. Operator stations with set point will indicate set point in engineering units. Operator stations with ratio or bias are to indicate the magnitude of the ratio or bias at all times. Operator stations are to indicate the measured variable on a continuously in engineering units and will indicate station output continuously in percent. The indications on a station should be consistent with all other stations such that all final control elements move closed to open from zero to 100 percent. For hardwired operator stations, the position of final control elements will not change when an operator station is disconnected from or reconnected to its plug-in cable. Changes in ratio or bias settings will not cause a process upset.

(2) *Records.* Records will be kept for the parameters indicated in table 9-4. Records will be stored on floppy disks when a control console is used. The operator will have access through the CRT to display trends for parameter for which records are kept. When the operator interface utilizes boiler and auxiliaries panels recorders will be used. Recorders may be strip chart recorders or circular chart recorders. The recorders will have scale markings consistent with the measured variables and associated field transmitters. The use of circular chart recorders will be restricted to steam pressure, steam flow, air flow, and exit gas temperature. Circular chart recorders will not be used when conservation of panel space is critical or desirable. Allowances should be made to provide spare pens for future use.

(3) *Indicators.* Indicators will be provided for the parameters shown in table 9-4. When a control console is utilized the parameter will be displayed on the CRT. The display may be digital or graphic and the displays should have scale markings consistent with the measured variable and associated field transmitter. When indicators are located on a panel the indicators may be digital indicators or analog indicators. Digital indicators will have Light Emitting Diode (LED) uniplaner numerals, zero instrument zero drift with time, and 0.1 percent Full Scale (FS) or less span drift per year. Analog indicators will have vertical edgewise scales, plus or minus 2 percent full scale accuracy, and scale markings consistent with the measured variable and the associated field transmitter. Integrators are shown in table 9-4 and should include the signal converters necessary to provide scaled integrated readings. Integrators will have at least six digit readout.

(4) *Equipment start/stop controls.* Equipment start/stop controls will be provided for all major

equipment as shown in table 9-4. Start/stop controls on a control console will be performed utilizing the ORT. Indication of motor operation should be indicated on the CRT. Start/stop controls will be indicating control switches or indicating push button when boiler and auxiliary panels are used for the operator interface.

(5) *Annunciator.* Annunciators will be provided on the boiler and auxiliaries panel for visual and audible indication of alarm conditions. Annunciator windows will have alarm legends etched on the windows and will be backlighted in alarm or test state. Each window will have at least two parallel connected bulbs and front access for ease of bulb replacement. All annunciator circuits will be solid state and compatible with microprocessor based controls. The annunciator will have an adjustable tone and volume horn. Split windows will be avoided unless conservation of panel space is critical. The annunciator system will have one of the alarm sequences specified in Instrument Society of America (ISA) S18.1. Test and acknowledge pushbuttons will be provided on the panel. All alarms, except for critical alarms, will be displaced on the ORT and printed on the printer when CRT's are utilized as the operator interface.

d. Ash handling control for stoker, pulverized coal and ACFB boilers.

(1) *General requirements.* Control of the fly ash system will be from the control room via ORT or control panel. A bottom ash panel will be located near the boilers. The control of the bottom ash system may also be controlled from the control room. The operator interface will contain all devices required to properly control and monitor the operation of the ash handling system. This will include start/stop control, selector controls, indication, and annunciator.

(2) *Start/stop controls.* Controls will include start/stop controls for the vacuum producing equipment, initiation of system operation, emergency stop, selection of manual or automatic system operation and manual operation of hopper valves and vibrators. This control may be through a CRT or panel mounted indicating control switches or indicating pushbuttons, pushbuttons and selector switches.

(3) *Indicators.* Indication of system vacuum, primary and secondary bag filter pressures and temperature and vacuum pumps inlet temperature, valve position, bag filter operation, system operation and hopper being emptied should be displayed in the control room. The display may be via CRT or panel mounted indicators and indicating lights.

(4) *Annunciation.* Alarm conditions of the ash handling system should be audible and visually annunciated in the control room. Annunciation may be via CRT and printer or a panel mounted annunciator of the same type described in c(5) above.

f. Air quality control system for stoker, pulverized coal and ACFB boilers.

(1) *General requirements.* Control of the air quality control equipment will be from the control room via CRT or control panel. The operator interface will contain all devices required to control and monitor the operation of the air quality control system. This will include start/stop controls, selector controls, indication and annunciation.

(2) *Start-stop controls.* Start/stop controls will be provided for manual operation of baghouse cleaning via the CRT or panel mounted control switches.

(3) *Selection controls.* Selection controls will be provided for selection of manual, pressure initiated, or time sequenced baghouse cleaning. Operation of compartment isolation dampers and baghouse bypass dampers will be provided. The control will be via CRT or panel mounted selector switches.

(4) *Indication.* Indication will be provided for compartment pressures and temperatures, baghouse inlet pressures and temperatures, and baghouse outlet pressures and temperatures. The indication will be via CRT or panel mounted indicators.

(5) *Annunciation.* Alarm conditions of the air quality control system should be audible and visually annunciated in the control room. Annunciation may be via CRT and printer or a panel mounted annunciator as described in c(5) above.

g. Continuous emissions monitoring systems controls. The continuous emissions monitoring system (CEMS) controls will be located in an air conditioned and heated environment. The controls will be microprocessor based and include all printers, displays and equipment necessary to save all data and generate reports required by the EPA. Malfunction of equipment will be annunciated in the control room.

9-6. Field Instrumentation.

a. General. Transmitters, control drives, control valves and piping instrumentation will be provided to sense the process variables and allow the control system to position the valves and dampers to control the process. All field devices shall be designed to operate in a dust laden atmosphere with temperature conditions varying from 20 to 160 degrees F.

b. Field transmitters.

(1) *General.* Electronic transmitters should produce a 4-20 mA dc signal that is linear with the measured variable. Electronic transmitters will be the two wire type except when unavailable for a particular application. Encapsulated electronics are unacceptable in any transmitter. Transmitters will be selected such that the output signal represents a calibrated scale range that is a standard scale range between 110 and 125 percent of the maximum value of the measured process variable. Transmitters will be designed for the service required and will be supplied with mounting brackets. Purge meters and differential regulators will be used on transmitters for boiler gas service or coal-air mixture service. A change in the load on a transmitter within the transmitter load limits will not disturb the transmitted signal. The load limits of the transmitter will be a minimum of 600 ohms. Transmitters can be supplied with local indicators, either integral or field mounted, if desired. Transmitters used for distributed control systems should be the "smart" type which have duplex digital communications ability transparent to the analog signal. Smart transmitters may be remotely calibrated via a hand held terminal. Data available at the hand held terminal should include programmed instrument number, instrument ID or serial number, instrument location, date of last calibration, calibrated range and diagnostics.

(2) *Flow transmitters.* Numerous types of flow transmitters are available. These include differential pressure with square root extractor, turbine flowmeters, nutating disk type transmitter, ultrasonic flow transmitters, and magnetic flowmeters. The most common method for measuring flow is to measure differential pressure across an orifice, flow nozzle, venturi, pitot tube, or piezometer ring. Square root extraction is necessary to linearize the output signal. Differential pressure measurement should be used for most steam plant flow applications. Nutating disk with pulse to 4-20 mA transmitters are normally used for fuel oil flow measurement. Flow transmitters will be accurate within 0.5 percent of span from 20 to 100 percent span with ambient temperature effect not to exceed 1.0 percent per 100 degrees F variation.

(3) *Level transmitters.* Measuring elements for level transmitters will be diaphragm, bellows, bourdon tube, strain gage transducer, caged float, or sealed pressure capsule. Level transmitters will be accurate within 0.5 percent of span with ambient temperature effect not to exceed 1.0 percent of span per 100 degrees F variation. The output signal will be linear with the sensed level.

(4) *Pressure transmitters.* Measuring elements for pressure transmitters will be diaphragm, bellows, bourdon tube, or strain gage transducers. Pressure transmitters will be accurate within 0.5 percent of span with ambient temperature effect not to exceed 1.0 percent of span per 100 degrees F variation. Measuring elements for pressure differential transmitters will be diaphragm, bellows, or sealed pressure capsule. Pressure differential transmitters will be accurate within 0.25 percent of span with ambient temperature effect not to exceed 1.0 percent of span per 100 degrees F variation. Output signals for pressure and pressure differential transmitters will be linear with the sensed pressure or differential pressure.

(5) *Temperature sensors.* Several types of sensors can be used for temperature measurement. Thermocouples sense temperature by a thermoelectric circuit which is created when two dissimilar metals are joined at one end. A wide variety of thermocouples are available for temperature sensing. Type J (iron-constantan) and type K (chromel-alumel) are the most common types of thermocouples for boiler plant applications. Type J thermocouples can be used for temperatures from 32 to 1382 degrees F. Type K thermocouples can be used for temperatures from -328 to 2282 degrees F. The type of thermocouple to be used, Type J or Type K, will be selected based upon the temperatures to be sensed. All thermocouples in the boiler plant will be of the same type. Resistance Temperature Detectors (RTD) sense temperature based upon the relationship between the resistivity of a metal and its temperature. The most common RTD used in boiler plant applications is a platinum RTD with a resistance of 100 ohms at 0 degrees C. Sealed bulb and capillary sensors detect temperature by sensing the change in volume due to changes in temperature of a fluid in a sealed system.

(6) *Temperature transmitters.* Measuring elements for temperature transmitters should be thermocouple, RTD, or sealed bulb and capillary. Temperature transmitters will be accurate within 0.5 percent of span with ambient temperature effect not to exceed 1.0 percent of span per 100 degrees F degree variation. Output signals for temperature transmitters will be linear with the sensed temperature.

(7) *Oxygen analyzers.* Oxygen analyzers will be direct probe type utilizing an in situ zirconium sensing element. The element will be inserted directly into the gas stream and will directly contact the process gases. The sensing element will be provided with a protective shield to prevent direct

impingement of fly ash on the sensing element. The analyzer should be equipped to allow daily automatic calibration checks without removing the analyzer from the process. The cell temperature in the analyzer will be maintained at the proper temperature by a temperature controller. The analyzer will be certified for "in stack" analysis technique in accordance with the Factory Mutual (FM) approval guide. The analyzer will be furnished with all accessories necessary for a complete installation.

(8) *Opacity monitors.* Opacity monitors use the principal of transmissometry to indicate level of particulate emissions. A beam of light is projected across the flue gas stream and a detector registers variations in the light transmittance caused by the particulate in the flue gas.

(9) *Flue gas monitors.* Flue gas monitors will be provided for all items required for EPA reports. Flue gas monitors are either in situ or extractive. In situ monitors are attached directly to the stack or breeching and access for maintenance should be provided. Extractive systems are wet, dry or diluted. Wet extractive system sample line should be heated to avoid corrosion. Dry systems utilize a cooler to remove water. Dilution systems utilize clean dry air to dilute the sample eliminating the need to heat the sample lines or dry the sample. Either in situ or extractive flue gas monitors should be used and not a mixture of the two for the various gases to be analyzed. All analyzers should be provided with self calibration features and have contact outputs for control room annunciation.

c. Control drives. Control drives will be used for positioning of control dampers, isolating dampers, and other devices requiring mechanical linkages. Control drives may be pneumatic or electric and are either open-shut type or modulating type depending on the application. Modulating drives may include position transmitters. Control drives will have adjustable position limit switches wired to terminal blocks, handwheels or levers for manual operation, hand locks or be self locking, position indicators, and adjustable limit stops at maximum and minimum positions. Drive arms and connecting linkages will be supplied with the damper drives. Control drives will have stroking times as required by the service and by NFPA recommendations.

(1) *Pneumatic control drives.* Pneumatic control drives should consist of a double acting air cylinder with rigid support stand and weatherproof enclosure. Pneumatic control drives for outdoor service will have thermostat controlled space heaters installed and wired to terminal blocks. Pneumatic control drives for modulating service will

have positioners with characterizable cams. Open/shut control drives should have internally mounted four-way solenoid valves. Control drives will be designed to provide the rated torque with a maximum 50 psig air supply. The control drive will be sized to provide 150 percent of the torque required to drive controlled device.

(2) *Electric control drives.* Electric control drives will consist of an electric motor, gear box, rigid support stand, and wiring termination enclosure. Electric control drives will be weatherproof. The gear box will be dust tight, weather tight, and totally enclosed. Electric control drives will be self-locking on loss of control or drive power. Drives for outdoor installation will be designed to operate with ambient conditions of -20 degrees F and a 40 miles per hour wind. Drives will have adjustable torque limit switches and position limit switches. Electric drives will be supplied with motor starters, position controllers, speed controllers, characterizable positioners, transformers, and other accessories as required. The control drive will be sized to provide 150 percent of the torque required to drive the controlled device.

d. Control valves.

(1) *Valve bodies.* Control valve bodies will be constructed in accordance with the applicable ANSI codes. Control valves will be globe type unless otherwise required for the particular process. Butterfly valves may be used in low pressure water systems. Globe valves will have a single port designed to meet the design conditions. Restricted ports should be used when necessary for stable regulation at all loads. Special consideration will be given to valves which pass flashing condensate to assure adequate port and body flow area. The valve body size may be smaller than the line size if the plug guide is sufficiently rugged to withstand the increased inlet velocity, but valve body size will not be smaller than one half the line size. End preparations will be suitable for the applicable piping system. Valves will have teflon packing for temperatures not exceeding 450 degrees F. Bonnet joints will be flanged and bolted type and designed for easy disassembly and assurance of correct valve stem alignment. Valve trim will be cage guided and removable through the top after bonnet removal. Seat rings will be easily replaceable. Flow direction should be flow opening unless otherwise required.

(2) *Valve operators.* Control valve operators will be pneumatic diaphragm actuated type except where piston actuators are required. Valve operators will be adequate to handle unbalanced forces that occur from flow conditions or maximum differential. Allowances for stem force based on seating

surface will be made to assure tight seating. Diaphragms will be molded rubber and diaphragm housing will be pressed steel. Piston operators will use cast pistons and cylinders with O-ring seals. Each valve operator will have an air supply pressure filter regulator. Valve operators for modulating service valves in fast response control loops, such as flow control or pressure control, will have electropneumatic valve positioners. Limit switches will be provided if needed for remote indication or control logic.

(3) *Control valve sizing.* Proper control valve sizing requires careful analysis of the process and piping system in which each valve is to be used. It is necessary to calculate the required valve flow coefficients based upon flow, valve inlet pressure, valve outlet pressure, and process fluid conditions. Calculations will be based on ISA S75.01. Valve flow coefficients will be calculated at the maximum, intermediate, and minimum process flow conditions. The control valves will be selected such that the maximum flow coefficient occurs at a valve travel between 70 and 80 percent. The minimum flow coefficient will occur at a valve travel between 10 and 20 percent. Control valves will be selected with a flow characteristic which provides uniform control loop stability over the range of process operating conditions. A quick opening flow characteristic provides large changes in flow at small valve travels and should primarily be used for on-off service applications. With a linear flow characteristic, the flow rate is directly proportional to valve travel. Valves with linear flow characteristics will be used for liquid level control where the ratio of the maximum valve pressure differential to the minimum valve pressure differential is less than five to one. Linear flow characteristic valves will also be used for pressure control of compressible fluids and for flow control when the flow rate varies but the valve pressure differential is constant. With an equal percentage flow characteristic, equal increments of valve travel produce equal percentage changes in the existing flow rate. Equal percentage flow characteristic valves will be used for liquid level control when the ratio of the maximum valve pressure differential to the minimum valve pressure differential is greater than or equal to five to one. Equal percentage flow characteristic valves will also be used for pressure control of liquids and for flow control when the valve pressure differential varies but the flow rate is constant. Special inner valve trim characteristics are required on applications where flashing or cavitation exist in liquid service and for noise control in steam or gas service.

(4) *Control valve stations.* Control valve stations are used to install control valves in piping systems and to provide a means of isolating and bypassing the control valve for maintenance purposes. Control valve stations will conform to the recommendations of ISA RP 75.06. Control valve stations consist of a control valve, isolating valves, bypass valve, and bypass line. Since control valves are normally smaller than the line size, reducers are required and can be integral to the control valve on valves with butt weld end connections. Isolation valves are required to isolate the control valve for repair, removal, or calibration and will be installed on the inlet and outlet sides of the control valve. Isolation valves will be gate valves or other non-throttling type valves. A bypass valve is necessary to provide a means of controlling the process when the control valve is not operable. The bypass valve will be identical to the control valve except it will be manually operated. Using an identical valve on the bypass provides better control during manual operation since the valve will have the proper flow coefficient and special valve trim. The bypass line which contains the bypass valve must be smaller than the main line size. The bypass line may be the same size as the bypass valve but in no case will the bypass line be smaller than one half the main line size.

e. Piping instrumentation.

(1) *Pressure switches.* Pressure switches are used to monitor pressures for remote indications, interlocking functions, and alarm conditions. Pressure switches may have snap acting switch contacts or mercury switch contacts. Shutoff valves of the same pressure and temperature rating as the process piping will be provided on each switch for isolation purposes. Snubbers will be provided on switches when the pressure connection is located within 15 pipe diameters of a pump or compressor discharge.

(2) *Pressure gauges.* Pressure gauges are used to provide local and remote indication of process pressures. Scale ranges will be selected such that the normal operating pressure is at approximately mid-scale. Shutoff valves of suitable rating will be provided on each gauge for isolation purposes. Snubbers will be provided on gauges when the pressure connection is located within 15 pipe diameters of a pump or compressor discharge. Siphons will be provided on pressure gauges for steam service. Pressure gauges will be provided on the discharge of all pumps and compressors, all boiler drums, all main process headers, and other locations as required to monitor equipment and process operation.

(3) *Thermometers.* Thermometers are used to provide local indication of process temperatures. Thermometers are normally the bimetallic type for most applications. Scale ranges will be selected such that the normal operating temperature is at approximately mid-scale. Thermometers will be provided with thermowells so the thermometer sensing element is not inserted directly into the process. Thermowells will be designed to withstand the pressure, temperature, and fluid velocities of the process in which they are inserted. Thermowells installed in piping will be long enough to extend to approximately the pipe centerline. Thermowells will have extensions to clear insulation and lagging.

(4) *Thermocouples.* Thermocouples are used to provide remote indication and control of process temperatures. Type J or Type K thermocouples are normally suitable for steam plant applications as discussed in paragraph 9-6b(5). Thermocouples will be provided with thermowells or protection tubes of suitable rating. Thermowell or protection tube length will be sufficient to provide the necessary insertion length plus the desired nipple length. Thermocouple assemblies will also include insulators and terminal head with cover.

(5) *Temperature switches.* Temperature switches are used to monitor temperatures for remote indications, interlocking functions, and alarm conditions. Temperature switches may have snap acting switch contacts or mercury switch contacts and may be bulb and capillary type or direct insertion type. Thermowells of suitable rating will be supplied so the sensing element is not inserted directly into the process.

(6) *Pressure controllers.* Pressure controllers will be pneumatic with bourdon tube or bellows sensing element. The sensing element will be suitable for the pressure and temperature of the process fluid to be controlled and will be an integral part of the controller assembly. The sensing element will have adequate sensitivity and be able to withstand the maximum pressure under all conditions. Pressure controllers will have adjustable proportional and reset control action, control point adjustment, calibrated pressure setting dial, air supply filter regulator, and gauges which indicate air supply and controller output pressures. Pressure controllers will be mounted on the operator of the valve to be regulated.

Table 9-4. Operator Interface Instrumentation Requirements.

Gas/Oil Fired Boilers		Stoker Fired Boilers		Pulverized Coal Fired Boiler	
<i>Operator Stations:</i>					
1. Boiler Master	R	1. Boiler Master	R	1. Boiler Master	R
2. Air Flow	X	2. Air Flow	R	2. Air Flow	R
3. Fuel flow	X	3. Fuel Flow	R	3. Pulverizer Master	X
4. Drum Level	R	4. Drum Level	R	4. Pulverizers	R
5. Oxygen Trim	X	5. Oxygen Trim	X	5. Primary Air	R
6. Furnace Pressure		6. Furnace Pressure	R	6. Drum Level	R
7. Steam Temperature (SH only)	R	7. Steam Temperature (SH only)	R	7. Oxygen Trim	R
8. Deaerator Pressure	X	8. Deaerator Pressure	X	8. Furnace Pressure	R
9. Deaerator Level	X	9. Deaerator Level	R	9. Steam Temperature (SH only)	R
10. Feedwater Heater	X	10. Feedwater Heater	X	10. Deaerator Pressure	X
		11. Steam Coil Preheater	R	11. Deaerator Level	R
				12. Feedwater Heater	X
				13. Steam Coil Preheater	R
<i>Recorder Requirements:</i>					
1. Steam Pressure	R	1. Steam Pressure	R	1. Steam Pressure	R
2. Steam Flow	X	2. Steam Flow	R	2. Steam Flow	R
3. Fuel Flow	X	3. Steam Temperature (SH only)	R	3. Steam Temperature (SH only)	R
4. Drum Level	R	4. Feedwater Flow	R	4. Feedwater Flow	R
5. Percent Oxygen	R	5. Feedwater Temperature	X	5. Feedwater Temperature	X
6. Steam Temperature (SH only)	R	6. Deserator Pressure	K	6. Deaerator Pressure	X
7. Deaerator Pressure	X	7. Deaerator Level	X	7. Deaerator Level	K
8. Deaerator Level	K	8. Drum Level	R	8. Drum Level	R
9. Feedwater Temp	X	9. Air Flow	R	9. Total Air Flow	R
10. Exit Gas Temp	R	10. Percent Oxygen	R	10. Percent Oxygen	R
11. Feedwater Flow	R	11. Fuel Flow	K	11. Total Fuel Flow	K
12. Air Flow	X				

Table 9-4. Operator Interface Instrumentation Requirements. (Continued)

<i>Gas/Oil Fired Boilers</i>		<i>Stoker Fired Boilers</i>		<i>Pulverized Coal Fired Boiler</i>	
		12. Combustion Air Temperatures	X	12. Combustion Air Temperatures	X
		13. Exit Gas Temperatures	R	13. Exit Gas	R
<i>Indicators:</i>					
1. Steam Pressure	R	1. Steam Pressure	R	1. Steam Pressure	R
2. Drum Level	R	2. Drum Level	R	2. Drum Level	R
3. Furnace Pressure	R	3. Furnace Pressure	R	3. Furnace Pressure	R
4. Combustion Air Pressure	R	4. Combustion Air Pressures	R	4. Combustion Air Pressures	R
5. Exit Air Pressures	R	5. ExitGas Pressure	R	5. ExitGas Pressures	R
6. Feedwater Pressures	R	6. Feedwater Pressures	R	6. Feedwater Pressures	R
7. Feedwater Temperature	R	7. Feedwater Temperature	R	7. Feedwater Temperature	R
8. FD Fan Amps	R	8. ID Fan Amps	R	8. Pulverizer Outlet Temperature	R
9. Boiler Feed Pump Amps	R	9. FD Fan Amps	R	9. ID Fan Amps	R
10. Sootblower Pressure	X	10. Boiler Feed Pump Amps	R	10. FD Fan Amps	R
11. Gas Pressure	X	11. Sootblower Pressure	K	11. PA Fan Amps	R
12. Oil Pressure	X			12. Boiler Feed Pump Amps	R
				13. Sootblower Pressure	X
<i>Integrators:</i>					
1. Steam Flow	X	1. Steam Flow	X	1. Steam Flow	X
2. Fuel Flow	X	2. Fuel Flow	X	2. Fuel Flow	X
3. Feedwater Flow	X	3. Feedwater Flow	K	3. Feedwater Flow	X
<i>Equipment start-stop controls:</i>					
1. FDFans	R	1. ID Fans	R	1. IDFans	R
2. Boiler Feed Pumps	R	2. FD Fans	R	2. FD Fans	R
		3. Boiler Feed Pumps	R	3. PA Fans	R
				4. Boiler Feed Pumps	R
				5. Pulverizers	R
				6. Coal Feeders	R
ACFB Fired Boilers					
<i>Indicators:</i>					
1. Furnace pressure	R	23. Fuel flow			R
2. J-valve outlet static pressure	R	24. Sorbent (limestone) flow			R
3. J-valve inlet static pressure	R	25. Steam temperature			R
4. J-valve discharge pressure	R	26. Furnace exit gas temperature			R
5. Over furnace bed static pressure	R	27. Solids cooler stripper section temperature			R
6. Furnace plenum pressure	R	28. Solids cooler cooler cooler section temperature			R
7. Steam pressure	R	29. J-valve fluid temperature			R
8. Spray water pressure	K	30. Furnace bed individual TC temperature			X
9. J-valve dipleg (diff press)	R	31. Furnace bed average temperature			R
10. J-valve density (duff press)	R	32. Furnace plenum temperature			R
11. Valve solids flow (diff press)	R	33. Feedwater temperature			K
12. Bed differential pressure	R	34. Oxygen			R
13. Total furnace differential pressure	R	35. SO ₂			R
14. Primary air flow	R	36. Drum level			R
15. Overfire air flow	R	37. Deasrator pressure			X

Table 9-4. Operator Interface Instrumentation Requirements. (Continued)

<i>ACFB Fired Boilers</i>				
16. J-valve plenum air flow upleg	R	38.	Deaerator level	X
17. J-valve plenum air flow downleg	R	39.	Cyclone level (uses diff press transmitters)	R
18. Total air flow	R	40.	Chute air flow	R
19. Steam flow	R			
20. Spray water flow	X			
21. Feedwater flow	R			
22. Gas flow	R			
Operator Stations:				
1. Boiler master	R	14.	J-valve plenum air control	R
2. Primary air flow	R	15.	Sorbent (limestone) feed	R
3. Overfire air flow	R	16.	Furnace bed inventory control	R
4. Oxygen trim	R	17.	Drum level	R
5. Fuel master	X	18.	Steam temperature (SH only)	R
6. Fuel flow	R	19.	Warm-up burner control	R
7. Airflow	R	20.	Deaerator pressure	X
8. Furnace pressure	R	21.	Deaerator level	R
9. FD fan discharge pressure	R	22.	Feedwater heater	X
10. Stripper cooler air flow	R	23.	Steam coil preheater	R
11. Solids cooler spray water	R			
12. J-valve blower discharge pressure	R			
13. J-valve aeration control	R			
Recorder Requirements:				
1. Furnace pressure pressure	R	29.	J-valve fluid temperature	R
3. J-valve inlet static pressure	R	30.	Furnace bed individual TC temperature	X
4. J-valve discharge pressure	R	31.	Furnace bed average temperature	R
5. Over furnace bed static pressure	R	32.	Furnace plenum temperature	R
6. Furnace plenum pressure	R	33.	Finish SH inlet temperature	X
7. Steam pressure	R	34.	Feedwater temperature	X
8. Spray water pressure	X	35.	Oxygen	R
9. J-valve diplet (duff press)	R	36.	SO ₂	R
10. J-valve density (duff press)	R	37.	Drum level	R
11. Valve solids flow (duff press)	R	38.	Deaerator pressure	X
12. Bed differential pressure	R	39.	Deaerator level	X
13. Total furnace differential pressure	R	40.	Cyclone level (uses duff press transmitters)	R
14. Primary air flow	R	41.	FD fan discharge pressure	R
15. Overfire air flow	R	42.	Solids cooler stripper airflow	R
16. J-valve plenum air flow upleg	R	43.	Solids cooler solids air flow	R
17. J-valve plenum air flow downleg	R	44.	Drum pressure	R
18. Total air flow	R	45.	Warmup burner discharge temperature	R
19. Steam flow	R	46.	Air heater inlet air temperature	R
20. Spray water flow	X	47.	Air heater gas temperature	R
21. Feedwater flow	R	48.	Air heater cold end temperature	R
22. Gas flow	R	49.	ID fan amps	R
23. Fuel flow	R	50.	FD fan amps	R
24. Sorbent (limestone) flow	R	51.	Boiler feed pump amps	R
25. Steam temperature	R	52.	Sootblower pressure	X
26. Furnace exit gas temperature	R			
27. Solids cooler stripper section temperature	R			
28. Solids cooler cooler section temperature	R			

Table 9-4. Operator Interface Instrumentation Requirement. (Continued)

<i>ACFB Fired Boilers</i>			
<i>Integrator</i>		<i>Equipment Start-Stop Controls</i>	
1. Steam flow	R	1. ID fans	R
2. Fuel flow	R	2. FD fans	R
3. Feedwater flow	R	3. PA fans	R
4. Sorbent flow	R	4. Boiler feed pumps	R
		5. Coal feeders	R
		6. Sorbent (limestone) feeders	R
		7. -valve blowers	R
R - Required			
X - Optional			

CHAPTER 10

ELECTRIC SYSTEMS

This chapter addresses the criteria for the electric power system in a steam plant.

a. Design requirements. The electrical requirements for the steam plant are the same as those for the steam generating equipment of an electric power generating station as covered by TM 5-811-6.

b. The following sections of chapter 4 of TM 5-811-6 are applicable to the design of the steam boiler plant electrical requirements:

(1) *Station service power system (section VI).* Station service power systems for a 200,000 pph boiler addition is about the equivalent to a 20,000 kw power plant steam turbo-generator addition. Steam generators of 200,000 pph and above will require a 4.16 kv auxiliary bus to supply the larger motors—particularly boiler draft fans. Boilers below 200,000 pph can be accommodated with a 480 volt power supply.

(2) *Emergency power system (section VII).* Emergency power system applies to the steam boiler plant with the exception that the battery requirements will be less because the system will not be required to supply emergency power to any lube oil pumps.

(3) *Motors (section VIII).* This section covers the motor requirements to be used in the steam boiler plant design.

(4) *Communication systems (section IX).* This section covers the communication system requirements to be used in the steam boiler plant design.

APPENDIX A

REFERENCES

Government Publications.

29 CFR 1910	Part 1910: Occupational Safety and Health Standards
Department of the Army. AR 420-49	Heating, Energy Selection and Fuel Storage, Distribution, and Dispensing Systems
TM 5-805-1	Standard Practice for Concrete Military Structures
TM 5-805-4	Noise Control for Mechanical Equipment
TM 5-805-9	Power Plant Acoustics
TM 5-809-1	Load Assumptions for Buildings
TM 5-809-10	Seismic Design for Buildings
TM 5-810-1	Mechanical Design/Heating, Ventilating and Air Conditioning
TM 5-811-6	Electric Power Plant Design
TM 5-815-1	Air Pollution Control Systems Boilers and Incinerators
TM 5-848-3	Ground Storage of Coal

Non-Government Publications.

American Association of State Highway and Transportation Officials, (AASHTO) 444 North Capital Street, N.W., Suite 249 Washington, DC 20001	
American Boiler Manufacturers Association (ABMA) 950 N. Glebe Road, Suite 160 Arlington, VA 22203	
American Concrete Institute (ACI) P. O. Box 19150, Redford Station Detroit, MI 48219-0150	
ACI 301	(1989) Structural Concrete for Buildings
ACI 318	(1989; Rev 1992; Errata) Building Code Requirements for Reinforced Concrete
American Gear Manufacturers Association (AGMA) 1500 King Street, Suite 201 Alexandria, VA 22314	
American National Standards Institute, Inc. (ANSI) 11 West 42nd Street New York, NY 10036	
ANSI B20.1	(1990) Safety Standards for Conveyors and Related Equipment
American Railway Engineering Association (AREA) 50 F Street, N.W., Suite 7702 Washington, DC 20001	
American Society of Heating, Refrigerating and Air-Conditioning Engineers (ASHRAE) Publication Dept. 1791 Tullie Circle, N.E. Atlanta, GA 30329	
ASHRAE (1991) Handbook, HVAC Applications	
ASHRAE (1992) Handbook, HVAC Systems and Equipment	
ASHRAE (1993) Handbook, Fundamentals	
ASHRAE (1990) Handbook, Refrigeration Systems and Applications	

TM 5-810-15

American Society of Mechanical Engineers (ASME)

22 Law Drive
Box 2300
Fairfield, NJ 07007.2300

Boiler and Pressure Vessel Code, and Interpretations:

ASME	Section I: Power Boilers (1992; Addenda Dec 1992)
ASME 08	Section VIII: Pressure Vessels, Division 1 (1992; Addenda Dec 1992)
ASME B31.1	(1992; b31.1a) Power Piping
ASME B31.8	(1992) Gas Transmission and Distribution Piping Systems

American Society for Testing and Materials (ASTM)

1916 Race Street

Philadelphia, PA 19103

ASTM A 36	(1991) Structural Steel M-Grades
ASTM A 48	(1990) Gray Iron Castings
ASTM A 536	(1984) Ductile Iron Castings
ASTM A 588	(1991a) High-Strength Low-Alloy Structural Steel with 50 ksi (345 MPa) Minimum Yield Point to 4 in. (100 mm) Thick
ASTM D 395	(1988) Ferritic Ductile Iron Pressure-Retaining Castings for Use at Elevated Temperature
ASTM D 1192	(1970; R 1977) Equipment for Sampling Water and Steam
ASTM D 1857	(1989) Test Method for Fusibility of Coal and Coke Ash
ASTM D 2234	(1989) Test Methods for Collection of a Gross Sample of Coal
ASTM D 3174	(1989) Test Method for Ash in the Analysis Sample of Coal and Coke from Coal
ASTM D 3176	(1989) Practice for Ultimate Analysis of Coal and Coke

Anti-Friction Bearing Manufacturers Association (AEBMA)

1101 Connecticut Ave., NW, Suite 700
Washington, DC 20036

Boiler Law and Rules and Regulations

The Bureau of Safety and Regulation

7150 Harris Drive
P O Box 30015
Lansing, MI 48909

Conveyor Equipment Manufacturers Association (CEMA)

932 Hungerford Dr., No. 36
Rockville, MD 20850

Factory Mutual Engineering and Research (FM)

1151 Boston-Providence Turnpike
PO Box 9102
Norwood, MA 02062-9957

Heat Exchange Institute (HEI)

1300 Sumner Ave.
Cleveland, OH 44115-2851

Hydraulic Institute (HI)

9 Sylvan Way, Suite 180
Parsippany, NJ 07054-3802

Instrument Society of America (ISA)

P.O. Box 3561
Durham, NC 27702

ISA S18.1	(1979; R1992) Annunciator Sequences and Specification
ISA S75.01	(1985) Control Valve Sizing Equations
ISA RP 75.06	(1981) Control Valve Manifold Designs

Manufacturers Standardization Society of the Valve and Fittings Industry (MSS)

127 Park Street, NE
Vienna, VA 22180
MSS SP-69

(1991) Pipe Hangers and Supports-Selection and Application

National Association of Corrosion Engineers (NACE)

P O Box 218340
Houston, TX 77218-8340

National Electric Code

P0 Box 9146
Quincy, MA 02269

National Electrical Manufacturers Association (NEMA)

2101 L St., NW
Washington, DC 20037

National Fire Protection Association (NFPA)

P.O. Box 9146
Quincy, MA 02269
NFPA 85G

(1987) Prevention of Furnace Implosions in Multiple Burner Boiler-Furnaces

Rubber Manufacturers Association

1400 K Street NW
Washington, DC 20005

GLOSSARY

AAP Army Ammunition Plant	CaCO₃ CO ₃ Calcium Carbonate
AASHTO American Association of State Highway and Transportation Officials	CaO Calcium Oxide
ACFB Atmospheric Circulating Fluidized Bed	CaSiO₃ Calcium Silicate
ACI American Concrete Institute	CEMA Conveyor Equipment Manufacturers Association
AEI Architectural and Engineering Instructions	CEMS Continuous Emissions Monitoring Systems
AEL Allowable Emissions Limit	CFHE Closed Feedwater Heat Exchangers
AFBMA Anti Friction Bearing Manufacturers Association	cfm Cubic feet per minute
AGMA American Gear Manufacturers Association	CO₂ Carbon Dioxide
Al₂O₃ Aluminum Oxide	CPU Central Processing Unit
ANSI American National Standards Institute	CR Concentration Ratio
APHA American Public Health Association	CRT Cathode Ray Tube
AREA American Railway Association Standards	Cu Copper
ASHREA American Society of Heating, Refrigeration and Air Conditioning Engineers	CuNi Copper Nickel
ASME American Society of Mechanical Engineers	DA Deaerator
ASYM American Society for Testing and Materials	DAS Data Acquisition System
BHN Brinell Hardness Number	EHE External Heat Exchanger
BOD Biochemical Oxygen Demand	EPA Environmental Protection Agency
BOOS Burner Out of Service	F Fahrenheit
Btu British thermal units	FAC Free Available Chlorine
C Centigrade	Fe Iron
Ca Calcium	FeO₃ Ferric Oxide
CAAA Clean Air Act Amendments of 1990	FD Forced Draft
	FGD Flue Gas Desulfurization

TM 5-810-15

FGR

Flue Gas Recirculation

FM

Factory Mutual

fpm

Feet per minute

fps

Feet per second

FS

Full Scale

FT

Fluid Temperature

FW

Feedwater

gph

Gallons per hour

HEI

Heat Exchange Institute

HEMA

Heat Exchanger Manufacturers Association

HI

Hydraulics Institute

Hg

Mercury

hp

Horsepower

HRA

Heat Recovery Area

HY

Hemispherical Temperature

HVAC

Heat, Ventilating and Air Conditioning

ID

Induced Draft

IES

Illuminating Engineers Society

IR

Infrared

ISA

Instrument Society of America

IT

Initial Deformation Temperature

K₂O

Potassium Oxide

kv

Thousand volt

lb

Pound

lb/ft³

Pounds per cubic foot

LCCA

Life Cycle Cost Analysis

LEA

Low Excess Air

LED

Light Emitting Diode

LNB

Low NO_x burner

LOI

Loss on ignition

LPG

Liquified Petroleum Gas

mA

Milliamp

MB

Million Btu

MFT

Main Fuel Trip

Mg

Magnesium

MgO

Magnesium Oxide

Na₂Si^O₃

Sodium Silicate

NaZ

Sodium Zeolite

NEMA

National Electrical Manufacturers Association

NFPA

National Fire Protection Association

NO

Nitric Oxide

NO₂

Nitrogen Dioxide

N₂O

Nitrous Oxide

NO_x

Oxides of Nitrogen

NPDES

National Pollutant Discharge Elimination System

NPSH

Net Positive Suction Head

NPSHA

Net Positive Suction Head Available

NPSHR

Net Positive Suction Head Required

Glossary-2

O₂
Oxygen

OFA
Overfire Air

OSHA
Occupational Safety and Health Act

PA
Primary Air

PC
Personal Computer

PC
Programmable Controller

PC
Pulverized Coal

PCB
Polychlorinated Biphenyl

pcf
Pounds per cubic foot

piw
Pounds per inch width

pph
Pounds per hour

ppi
Pounds per ply inch

ppm
Parts per million

psf
Pounds per square foot

psi
Pounds per square inch

psig
Pounds per inch gauge

RA
Relative Accuracy

RATA
Relative Accuracy Test Audit

RDF
Refuse Derived Fuel

RMA
Rubber Manufacturers Association

RO
Reverse Osmosis

ROM
Run-of-mine

rpm
Revolutions per minute

RTD
Resistance Temperature Detector

scfm
Standard cubic feet per minute

SCR
Selective Catalytic Reduction Silicon Controlled Rectifier

SH
Superheat

SiO₂
Silica Dioxide

SNCR
Selective Noncatalytic Reduction

SO₂
Sulfur Dioxide

SSU
Saybolt Seconds Universal

ST
Softening Temperature

TDS
Total Dissolved Solids

TiO₂
Titanium Dioxide

tph
Tons per hour

TSS
Total Suspended Solids

UHMW
Ultra High Molecular Weight

UPS
Uninterruptable Power Supply

uv
Ultraviolet

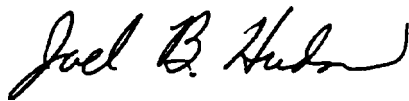
wg
Water gauge

The proponent agency of this publication is the Office of the Chief of Engineers, United States Army. Users are invited to send comments and suggested improvements on DA Form 2028 (Recommended Changes to Publications and Blank Forms) to HQUSACE (CEMP-ET), WASH DC 20314-1000.

By Order of the Secretary of the Army:

DENNIS J. REIMER
General, United States Army
Chief of Staff

Official:



JOEL B. HUDSON
*Acting Administrative Assistant
to the Secretary of the Army*

Distribution:

To be distributed in accordance with DA Form 12-34-E, Block 1685, requirements for TM 5-810-15.

