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MIL-HDBK-1003/7

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MILITARY HANDBOOK

STEAM POWER PLANTS - FOSSIL FUELED

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ABSTRACT

Basic design guidance is presented for fossil-fueled, steam-powered plants generating electricity or cogenerating electricity and steam. Criteria and design requirements are given for sizing plants, load shedding, use of cogeneration, environmental regulations and permitting, electric and steam generators, steam condensers and cooling water systems, auxiliary equipment, coal and ash handling, water supply, makeup and treatment, controls and instrumentation, testing, pollution control, corrosion, safety and fire protection, and various miscellaneous items.

FOREWORD

THIS HANDBOOK SHALL NOT BE USED AS A REFERENCE DOCUMENT FOR PROCUREMENT OF FACILITIES CONSTRUCTION. IT IS TO BE USED IN THE PURCHASE OF FACILITIES ENGINEERING STUDIES AND DESIGN (FINAL PLANS, SPECIFICATIONS, AND COST ESTIMATES). DO NOT REFERENCE IT IN MILITARY OR FEDERAL SPECIFICATIONS OR OTHER PROCUREMENT DOCUMENTS.

Beneficial comments (recommendations, additions, deletions) and any pertinent data that may be of use in improving this document should be addressed to: Commanding Officer (Code 111C), Naval Energy and Environmental Support Activity, Port Hueneme, CA 93043, by using the self-addressed Standardization Document Improvement Proposal (DD Form 1426) appearing at the end of this document or by letter.

MECHANICAL ENGINEERING CRITERIA MANUALS

Criteria Manual	Title	PA
DM-3.01	Plumbing Systems	WESTDIV
MIL-HDBK-1003/2	Incinerators	WESTDIV
DM-3.03	Heating, Ventilating, Air Conditioning and Dehumidifying Systems	WESTDIV
DM-3.04	Refrigeration Systems for Cold Storage	WESTDIV
DM-3.05	Compressed Air and Vacuum Systems	WESTDIV
MIL-HDBK 1003/6	Central Heating Plants	NEESA
MIL-HDBK-1003/7	Steam Power Plants - Fossil Fueled	NEESA
MIL-HDBK-1003/8	Exterior Distribution of Utility Steam, HTW, CHW, Fuel Gas and Compressed Air	WESTDIV
DM-3.09	Elevators, Escalators, Dumbwaiters, Access Lifts, and Pneumatic Tube Systems	WESTDIV
DM-3.10	Noise and Vibration Control for Mechanical Equipment (Tri-Service)	ARMY
MIL-HDBK-1003/11	Diesel Electric Generating Plants	WESTDIV
MIL-HDBK-1003/12	Boiler Controls	NEESA
MIL-HDBK-1003/13	Solar Heating of Buildings and Domestic Hot Water	NCEL
DM-3.14	Power Plant Acoustics	ARMY
MIL-HDBK-1003/17	Industrial Ventilation Systems	NEESA
DM-3.18	Central Building Automation Systems	ARMY
MIL-HDBK-1003/19	Design Procedures for Passive Solar Buildings (Tri-Service)	NCEL

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Section 1. INTRODUCTION

1.1 Scope. This handbook contains data and information as criteria that shall govern the design of fossil fueled steam power plants that are used to generate electricity or cogenerate electricity and steam.

1.2 Cancellation. This handbook, Steam Power Plants - Fossil Fueled, does not cancel or supersede any existing design handbooks.

1.3 Policy. Power plants shall be provided when a crucial need exists which cannot be satisfied economically or reliably with purchased power. When a power plant is required, it shall be designed and constructed with the lowest overall cost to own and operate; that is, the lowest overall life cycle costs for ownership, operation, maintenance, and fuel consumption during its life span.

Section 2. BASIC DATA

2.1 Economic Analysis. The economic analysis for all new or modified plant construction projects shall consider all suitable alternative methods to determine the most cost-effective method of accomplishment. All economic analyses shall follow the policy and procedures as outlined in SECNAVINST 7000.14, Economic Analysis and Program Evaluation for Navy Resource Management. For information, formatting, and guidance in performing a detailed cost analyses refer to NAVFAC P-442, Economic Analysis Handbook or National Bureau of Standards Handbook 135, Life-Cycle Cost Manual for the Federal Energy Management Programs.

2.1.1 Present Value Analysis. All cost analyses for power plant investments shall be computed by using the present value (discounting) technique. In this method all benefits and costs accruing throughout the life of the facility are compared on a present value basis. The cost investments for each year of the economic life of the facility are converted to present values by applying a discount factor.

2.1.2 Cost Elements. The cost elements of an economic analysis will include non-recurring (capital cost of construction) and recurring operational and maintenance costs. The recurring costs which are tabulated for each year of the facility useful life will include the sum of the following items:

a) Fuel Costs. Consider various fuels and fuel combinations.

b) Electrical Costs.

c) Water Costs.

d) Chemical Costs.

e) Operating and maintenance material costs (other than fuel).

f) Operating and maintenance labor.

g) Any other costs related to the facility.

Insurance is not charged because the Government is self-insured. Taxes are not charged because the Government does not pay taxes.

2.1.3 Analysis Format. The cost elements described above shall be summarized and tabulated for each year of the economic life of the facility and should be prepared for each alternative proposal under consideration. The annual costs shall then be summarized to determine the total project cost for each alternative proposal.

2.1.4 Discount Factor. In determining the present value of future expenditures the appropriate discount factor (interest rate) is applied to each annual tabulated expenditure. Discount factors are based on a 10 percent interest rate.

2.1.5 Economic Life. A maximum economic life of 25 years shall be used in cost analyses of utility investments.

2.1.6 Uniform Annual Cost. The method of project accomplishment shall be the alternative which has the lowest uniform annual cost. The uniform cost is determined by dividing the total project cost by the factor in NAVFAC P-442, Table B, for the end year of the project.

2.2 Economic Studies

2.2.1 Factors to be Analyzed

a) Actual loads, such as electric, heat, refrigeration, etc.

b) Duration of loads.

c) Mobilization requirements.

d) Future expansion.

e) Sensitivity of the establishment to hazards.

f) Permanence of the power plant.

g) Standby requirements.

h) Emergency requirements.

i) Fuel selection.

2.2.2 Method of Satisfying Load Demands

2.2.2.1 Objective. Provide the necessary utilities such as electricity, steam, and compressed air, at lowest overall owning and operating cost, with sufficient standby to preclude irreparable loss to personnel or national security, or large financial loss.

2.2.2.2 Guidelines. Consider the following.

a) Interservice possibilities; for example, one power plant to service more than one installation.

b) Only new or future costs of a project; "A sunk cost is a past expenditure or an obligation already incurred, which must be ignored as having nothing to do with a choice between two alternatives for the future." Grant. E. L, Principles of Engineering Economy, Wiley & Sons, New York, NY.

c) Continuous integrity of utility service.

d) Past experiences with other power plants.

2.2.2.3 Plausible Methods. Consider all plausible, alternate methods of satisfying the load demands, including:

a) Rehabilitation.

b) Replacement.

c) New installation.

d) Consolidation.

e) Modernization.

f) Cogeneration.

g) Types and combinations of drivers, such as steam condensing turbines, extraction condensing turbines, back pressure turbines, gas turbines, and diesel engines.

2.2.3 Comparative Cost of Alternate Methods

2.2.3.1 Load Duration Curves. For electric generating plants, block out each method of satisfying electric and export steam demands on a load duration graph (with a curve for electricity and each export steam condition), as shown in Figures 1, 2, 3, and 4 for a particular job. The example is for a plant generating electricity and exporting steam at three different conditions: 135 pounds per square inch (psig) (930 kPa gage), 35 psig (241 kPa gage), and 6 psig (41 kPa gage).

2.2.3.2 Comparative Owning and Operating Costs. Estimate and tabulate the owning and operating costs for the alternate methods. Tabulate total annual costs for each project year in Format A or Format A-1 of SECNAVINST 7000.14, and apply discount factor for discounted annual cost.

2.2.3.3 Choice of Individual Components. The same economic analysis can be applied to individual components within a utility system. Since the only variables will be initial cost and energy, only these factors need be considered in the analysis.

2.3 Source of Power. Each naval activity shall normally be provided with three sources of electric power: primary, standby, and emergency. For further information on power sources, see MIL-HDBK-1004/1, Electrical Engineering Preliminary Design Considerations.

2.4 Private Versus Government Ownership

2.4.1 Private Ownership. Private or commercial facilities shall be utilized unless it can be demonstrated that it is necessary, or more economical, for the Government to perform the services.

2.4.2 Government Ownership. The Government shall operate utility services only if justified by any of the following factors:

a) A lack of reliable, available private facilities with sufficient capacity to meet the load demand. First, however, the possibility of inducing private industry to undertake the operation or to provide the facility must be examined.

b) Substantial savings to the Government resulting from owning and operating a plant, provided the true cost basis (including all allocable items of overhead and personnel) is used in evaluating government ownership. For additional data, see Section 2. Only those costs which would remain unchanged, regardless of whether the services were owned or purchased, may be neglected.

c) The necessity for meeting current and mobilization requirements at any emergency, particularly where an abnormal or fluctuating military demand discourages private investment. This factor shall apply to the essential load only.

d) The need for training military personnel for advanced base or overseas operations where nonmilitary personnel are not available for the particular work or service.

e) A demand for complete command control, in order to avoid compromise of highly classified security information.

f) The necessity for protecting the plant and personnel in areas of unusually hazardous operations.

g) The need for a complete demilitarization, prior to final disposal, of certain types of military equipment.

h) Any other items clearly demonstrating a particular Government owned operation to be in the public interest.

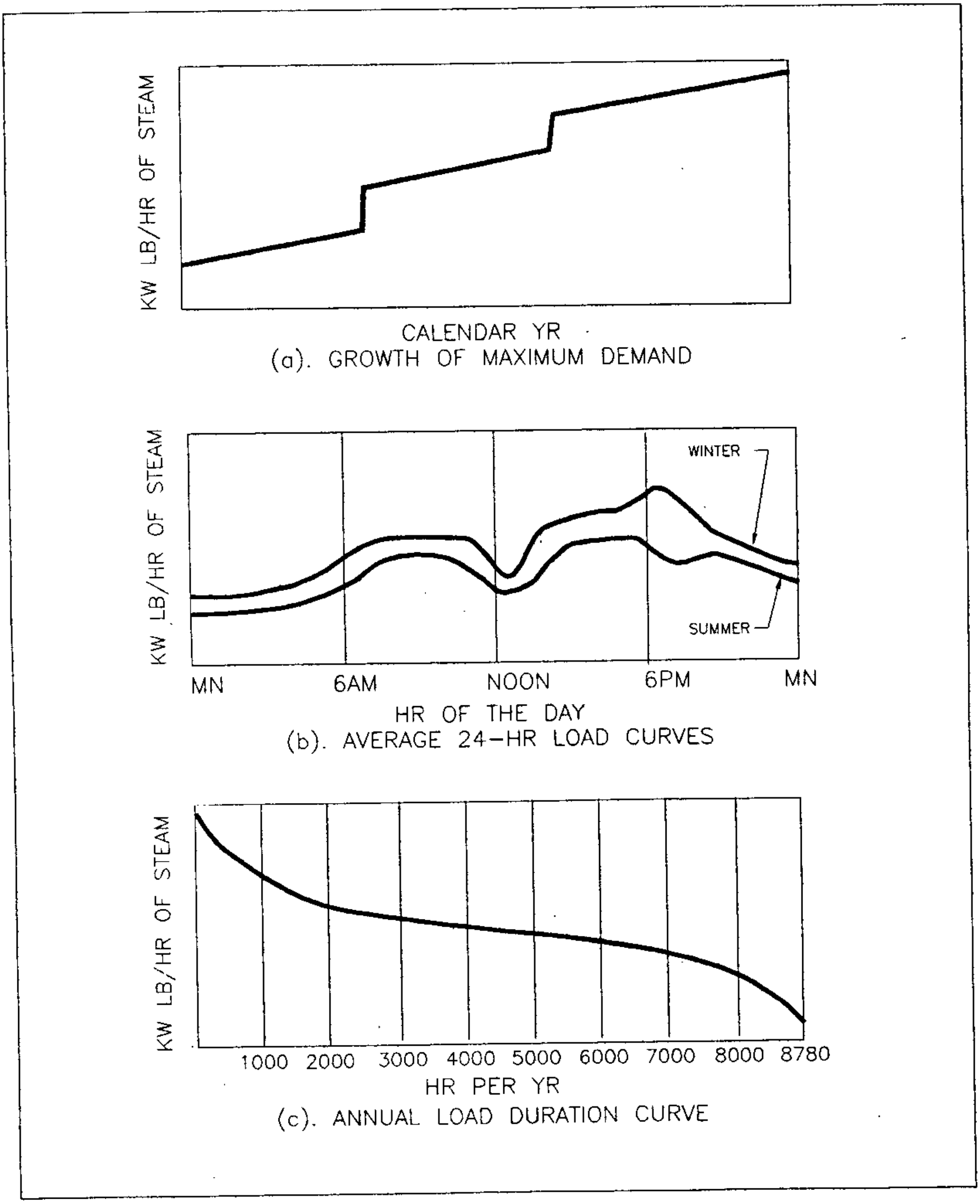

Figure 1
Typical Steam and Electric Load Curves

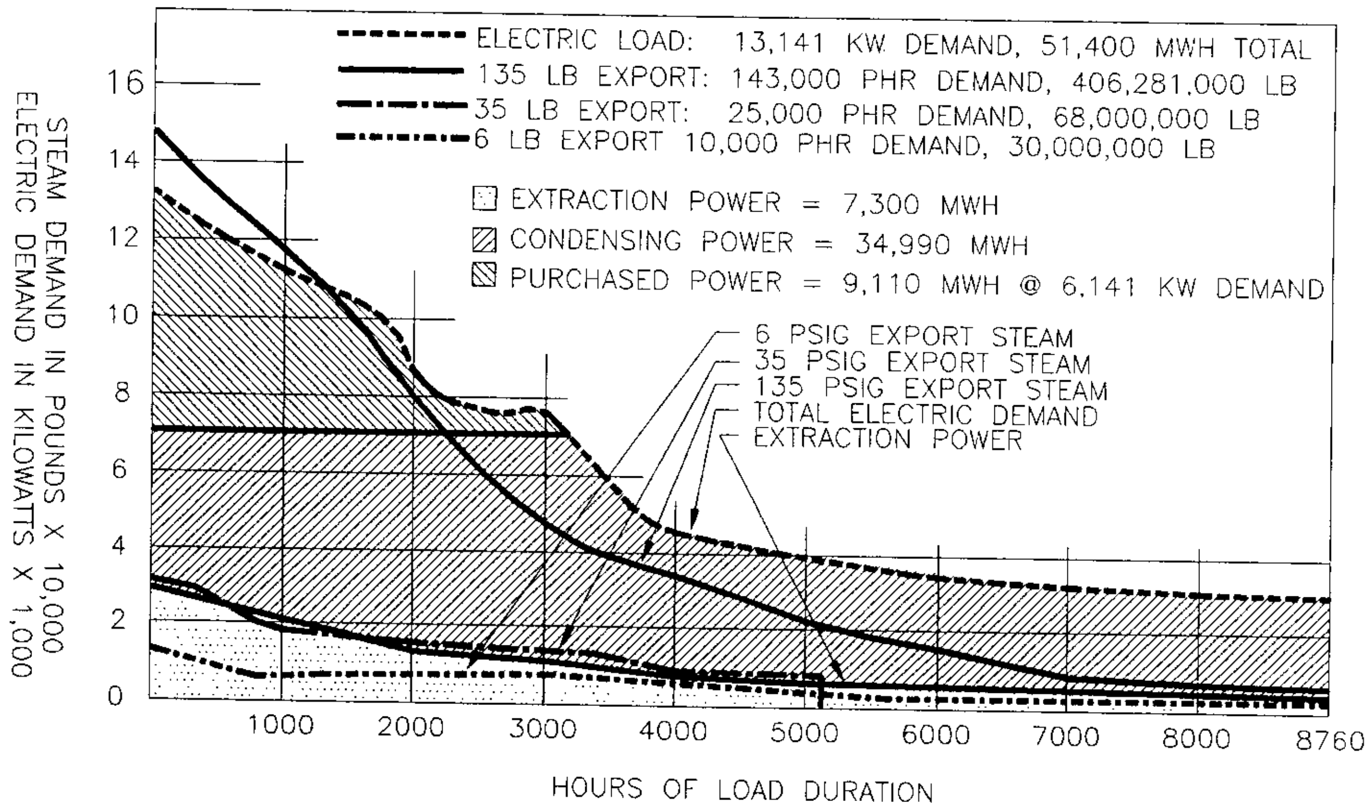

Figure 2
Typical Load Duration Curve -- Base Load on Power Plant, Swings on Purchased Power, All Export Steam from Power Plant

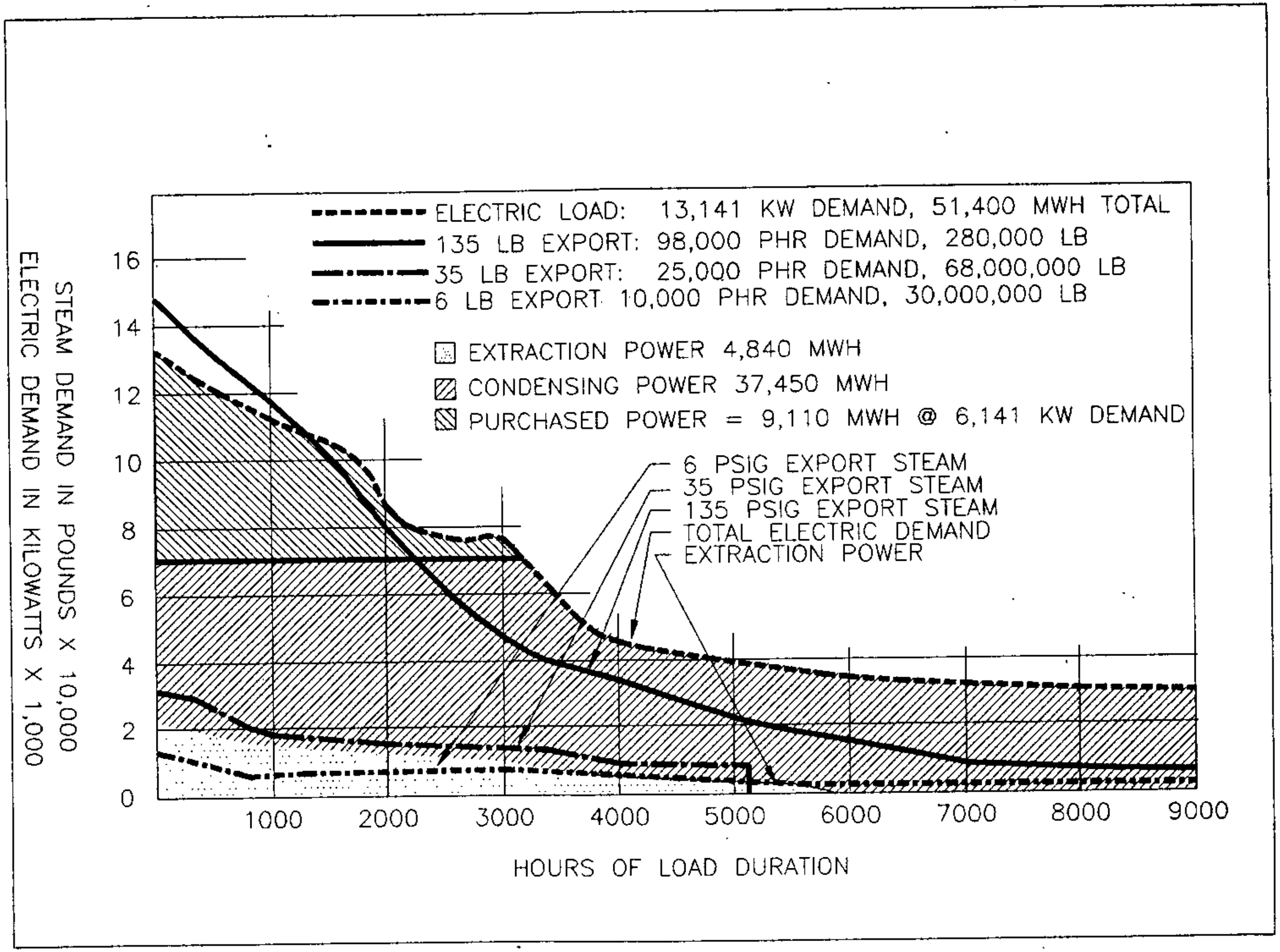

Figure 3

Typical Load Duration Curve -- Base Load on Power Plant, Load Swings on Purchased Power, Portion of Export Steam on Central Heating Plant

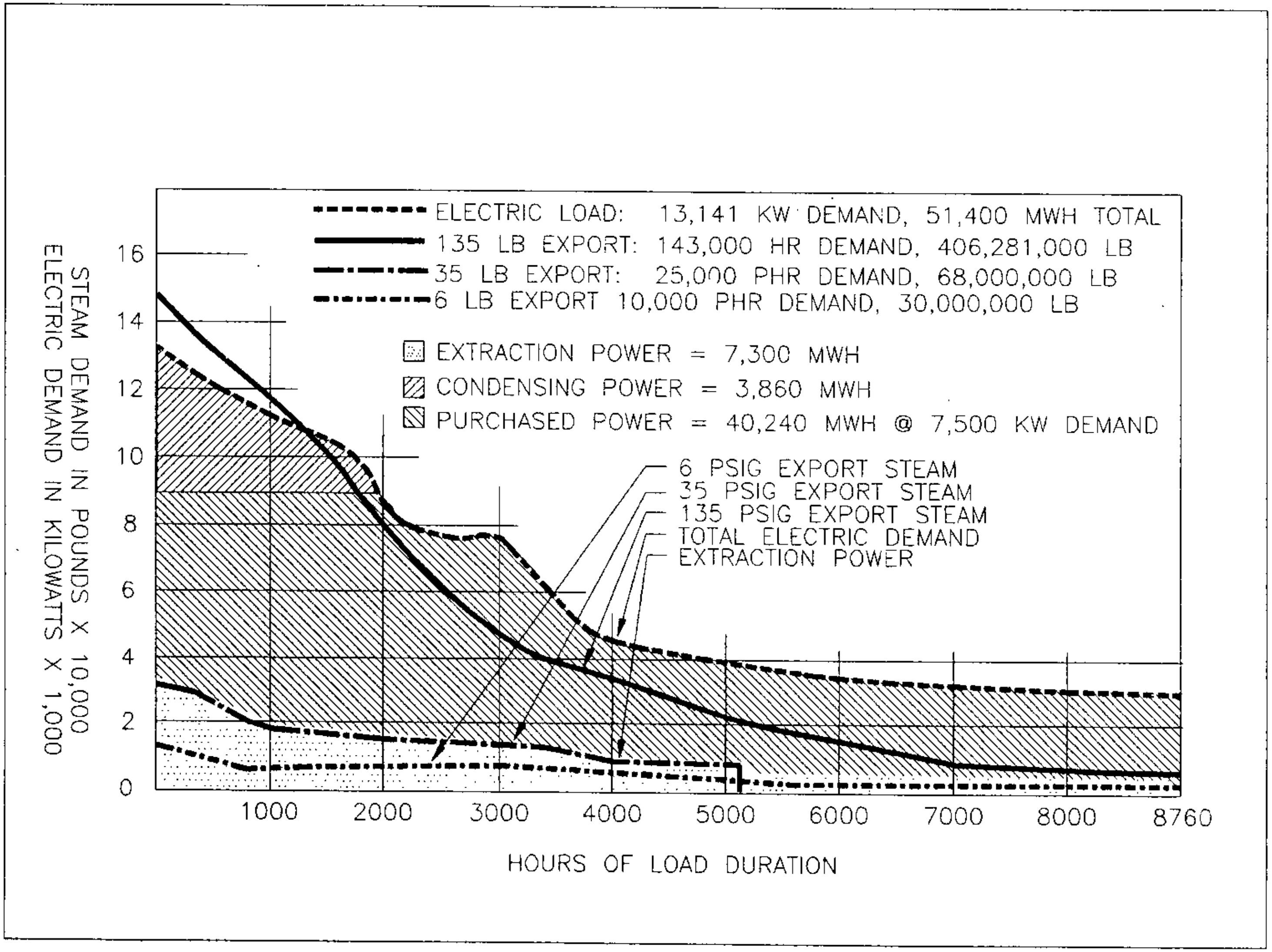

Figure 4
Typical Load Duration Curve – Load Priority as Follows:
(a) Extraction Generation, (b) Purchased Power, (c) Condensing Generation

2.4.3 Hospitals, Communications, and Other Services. Activities which cannot withstand an outage of more than four hours must be protected. Where normal electric connections between hospitals, for instance, and the normal source of power may be broken by a catastrophe, provide an emergency power plant of sufficient capacity to handle the essential load, arranged to operate automatically with the failure or restoration of normal current.

2.5 Expansion, Rehabilitation, and Replacement of Existing Plants

2.5.1 Plant Additions. Expansion of an existing power plant should be considered when additional electric generating capacity, including reserve capacity, is needed to provide for future loads. An economic study must show that modifications and additions to an existing plant, to serve additional loads, will be more economical than the construction of another power plant.

Compliance pollution control and elimination of safety deficiencies shall be included for any significant plant modifications.

2.5.2 Rehabilitation Versus Replacement. If an existing plant has deteriorated to the point where numerous outages occur, does not perform in compliance with air pollution regulations, or is becoming a safety hazard, its rehabilitation or replacement should be considered. The choice between rehabilitation of the existing plant or replacement with a new modern plant shall be determined by a life cycle economic analysis. New capacity as needed to handle additional projected load shall be included in the considerations.

Necessary equipment and systems for air pollution regulation compliance and elimination of other operating, safety, or maintenance deficiency must be included in either the rehabilitated or replacement plant.

2.6 Fuel Selection

2.6.1 Selection. Refer to Department of Defense MIL-HDBK-1190, Facility Planning and Design Guide, NAVFACINST 10343.1A, On-Shore Use of Navy Special, Navy Distillate and Marine Diesel Fuel Oils, NAVFACINST 10340.4C, Coal Requirements and requisitions, OPNAVINST 4100.6, Energy Financing and Source selection Criteria for Shore Facilities, and Navy policy on selection of fuels. Select fuels that are within the national guidelines and that produce the required performance at lowest life cycle costs, consistent with availability and pollution control. The fuel policy has been to use a solid domestically produced fuel as a primary fuel for power plants of medium size and above except where use of a solid fuel is not feasible because of geographic considerations. Existing plants burning fuel oil or gas may continue to burn fuel oil or gas, but new or replacement boilers in plants with design input over the threshold minimum established by government policy are required to burn solid fuel. Capability of burning another fuel shall be provided to be used when the primary fuel is not available and where it is critical to keep the power plant in operation on an emergency basis.

Interruptible gas service will require a secondary oil fuel backup.

2.6.2 Characteristics. For properties of various fuels, handling equipment, firing equipment, and controls, refer to MIL-HDBK-1003/6, Central Heating Plants, Section 5, "Fuel and Combustion Systems". When oil is to be used, the plant shall be capable of pumping and burning grades No. 2 through No. 6 oil.

2.6.3 Types. Type of fuels to be considered are coal/oil, oil, gas/oil, wood, waste, and other combinations.

2.7 Codes and Regulations

2.7.1 Conformance. It is mandatory for the Federal Government to conform to Federal, state, and local air and water pollution abatement codes.

2.7.2 Environmental Regulations and Permitting. See Section 18.

2.7.3 Pollution Control. See Section 17.

2.7.4 National Industry Codes. Where applicable, design shall conform to the industry codes including the following:

a) American Society of Mechanical Engineers (ASME), Boiler and Pressure Vessel Code.

b) American National Standards Institute (ANSI) Standards.

c) American Petroleum Institute (API).

d) National Board of Boiler and Pressure Vessels (NBBPV), Inspection Code.

e) American Society of Heating, Refrigerating and Air Conditioning Engineers (ASHRAE).

f) American Society for Testing and Materials (ASTM).

g) American Welding Society (AWS).

h) American Institute of Plant Engineers (AIPE).

i) National Association of Power Engineers (NAPE).

j) National Association of Corrosion Engineers (NACE).

k) National Fire Protection Association (NFPA).

l) Air and Waste Management Association (AWMA).

m) American Institute of Chemical Engineers (AICHE).

n) Institute of Electrical and Electronics Engineers (IEEE).

o) American Institute of Mining, Metallurgical, and Petroleum Engineers (AIME).

2.7.5 Safety Regulations and Requirements. See Section 14, "Safety Protection" and Section 15, "Fire Protection".

2.8 Plant Location Factors. Power plant location should be determined after evaluating the factors listed in Table 1.

Table 1
Plant Location Factors

Item	Subitem	Comment
Climate	------------	Will determine type of architecture of building, wall and roof U factors, heating, and ventilating
	Max. and min. dry bulb; max. wet bulb temperature heating and cooling degree days	Affects export heating load
	Max. and min. wind velocities	Affects heating load and structural loading
Topography	Grades	Affects architecture and floor levels, fuel handling, fuel storage, and drainage
	Soil - Bearing value Water table	Determines structural foundations, drainage, and underground pipe distribution

Table 1 (Cont.)
Plant Location Factors

Item	Subitem	Comment
	Max. high water level	Affects floor levels, pumps, suction lifts, and foundations
	Frost line	Determines depth of water and sewer lines
	Cathodic analysis	Determines cathodic protection
	Seismic zone	Determines structural reinforcement
	Future Expansion	Affects allocation of space in plant for expansion
Altitude	Height above sea level	Affects air density and stack height
Orientation	Load Center	---------------
	Air Field	Determines maximum stack heights and hazards
	Docks, railroads, and roads	Affects transportation of fuel and materials
Water supply	Condenser cooling, jacket cooling, makeup water, domestic water	Affects plant location, water treatment, filtering
Local material	---------------	May determine materials of construction
Local rules and regulations	Air pollution Water Sewers Landfill	Obtain permits
	Fuel storage	Allot space, note fire protection requirements

Table 1 (Cont.)
Plant Location Factors

Item	Subitem	Comment
Skills and availability of local labor	---------------	Determine construction and operating manpower
Master plan	---------------	Make sure plant is consistent with Master Plan for activity development
Architectural requirements		Must be compatible with surrounding buildings

2.9 Types of Power Plants

2.9.1 Design. Power plant design varies to suit the various combination of electrical power generation and export heat requirements.

2.9.2 Primary Power Plants. Primary power plants must have adequate capacity to meet all peacetime requirements. Types of plants for installations not requiring export steam or heat:

a) Purchased electric power.

b) Diesel engine-generator rated for continuous duty.

c) Steam boilers with turbine generators of matched capacity. Turbines can be straight condensing, or combination condensing and back pressure, as required to suit plant steam usage.

Types of plants for installations requiring export steam:

a) Purchased electric power and steam plus steam heating boiler.

b) High pressure steam boilers with back pressure steam turbines of matched capacity. Steam heating boilers can be used to supplement the requirements of the export steam load.

c) High pressure steam boilers with automatic extraction condensing turbines. Steam heating boilers can be used to supplement the requirements of the export steam load.

d) Diesel generator with heat recovery boilers for low pressure steam distribution and supplementary boilers as required for steam export.

Section 3. ADMINISTRATIVE PROCEDURE TO DEVELOP A POWER PLANT

3.1 Power Plant Loads

3.1.1 Electric Loads. To determine plant capacity, the data shown in Table 2 must be obtained using the demand coincidence and load factors discussed in MIL-HDBK-1004/1.

3.1.2 Steam Loads. Determine steam loads as indicated in Table 2.

Table 2
Power Plant Loads for Design

Types of Electric Load	Loads to be determined in kW (Determine winter and summer loads separately)
Export	See MIL-HDBK-1004/1
Plant	See MIL-HDBK-1004/1
Switchgear	See MIL-HDBK-1004/1
Line losses	12% of subtotal (unless more accurate data is available).
Total present load	Total of above.
Total ultimate load	See MIL-HDBK-1004/1 (may be estimated by extending current load trend).
Minimum continuous	See MIL-HDBK-1004/1 (as for a summer night).
Emergency load	See MIL-HDBK-1004/1 (demand of services that cannot tolerate a 4 hour interruption).
Types of Steam Load	Loads to be Determined in KBtu/hr (Determine winter and summer and winter loads separately)
Condensing turbine	Rated kW x Heat Rate
Auto-extraction turbine	Rated kW x Heat Rate
Plant auxiliaries	Steam jet air ejector Feedwater heating. Fuel oil heating.
Export	Space heating (radiation) Use diversity factor of 1.0. Space heating (ventilation). Use diversity factor of 0.8.

Table 2 (Cont.)
Power Plant Loads for Design

Export (Cont.)	Utilities (hot water and laundry). Use diversity factor of 0.65. For kitchen use factor of 1.0. Refrigeration (turbine drive). Refrigeration (absorption type). Process. Distribution loss.
Total present load	Total of above steam loads.
Total ultimate load (including projected future load)	Maximum expected steam load for present and additional future electrical power generation plant steam requirements and export steam loads.
Minimum continuous	Same as distribution loss.
Emergency load	Demand of services that cannot tolerate a 4-hour interruption.

3.1.3 Typical Load Curves. For an example of a typical load curve, see Figure 1.

3.1.3.1 Growth Curves. In (a) of Figure 1, note the normal trend growth of total steam and electric demands and the additional loads when new buildings or processes are added. This curve is useful in timing power plant additions of equipment.

3.1.3.2 Load Curves. The average of daily steam and electric demands, (b) of Figure 1, for the season or year under consideration for each hour of a 24 hour day is also important. Such curves are useful in determining load factors and duration of certain demands, and in dividing the total load among the plant units. Refer also to Appendix B, Load Shedding.

3.1.3.3 Load Duration Curves. Plot the number of hours duration of each load during a year for present and future load conditions of steam and electricity usage for the Naval activity. See (c) of Figure 1. This type of curve is useful in determining load factors and in sizing units of power plant equipment.

Load duration curves for various conditions are shown on Figures 2, 3, 4, and 5.

3.2 Steam Power Plant Design

3.2.1 Steam Conditions. For selection of steam pressures and temperatures for inlet conditions to the turbine, see Section 5, Steam Turbine Design. Going slightly beyond a range bracket (as above 400 psig (2758 kPa gage) and 750 degrees F (399 degrees C)) will result in price increases and a less economical design. For boiler outlet conditions, see Section 4, Power Plant Steam Generation. The export steam conditions depend on the distribution system and the consuming equipment.

3.2.2 Heat Balances. Typical extraction condensing, back pressure and automatic extraction cycles are shown in Figures 6, 7, and 8. For collateral reading on steam cycles and heat balances, see Steam Turbines and Their Cycles, Salisbury 1974, Modern Turbines, L. E. Newman 1944, Mechanical Engineers Handbook, Marks 1978, and Power Plant Engineering, Morse 1943. A typical heat balance for an extraction condensing cycle is shown on Figure 9.

3.3 Plant Design Factors. Power plant design should consider and evaluate the factors listed in Table 3.

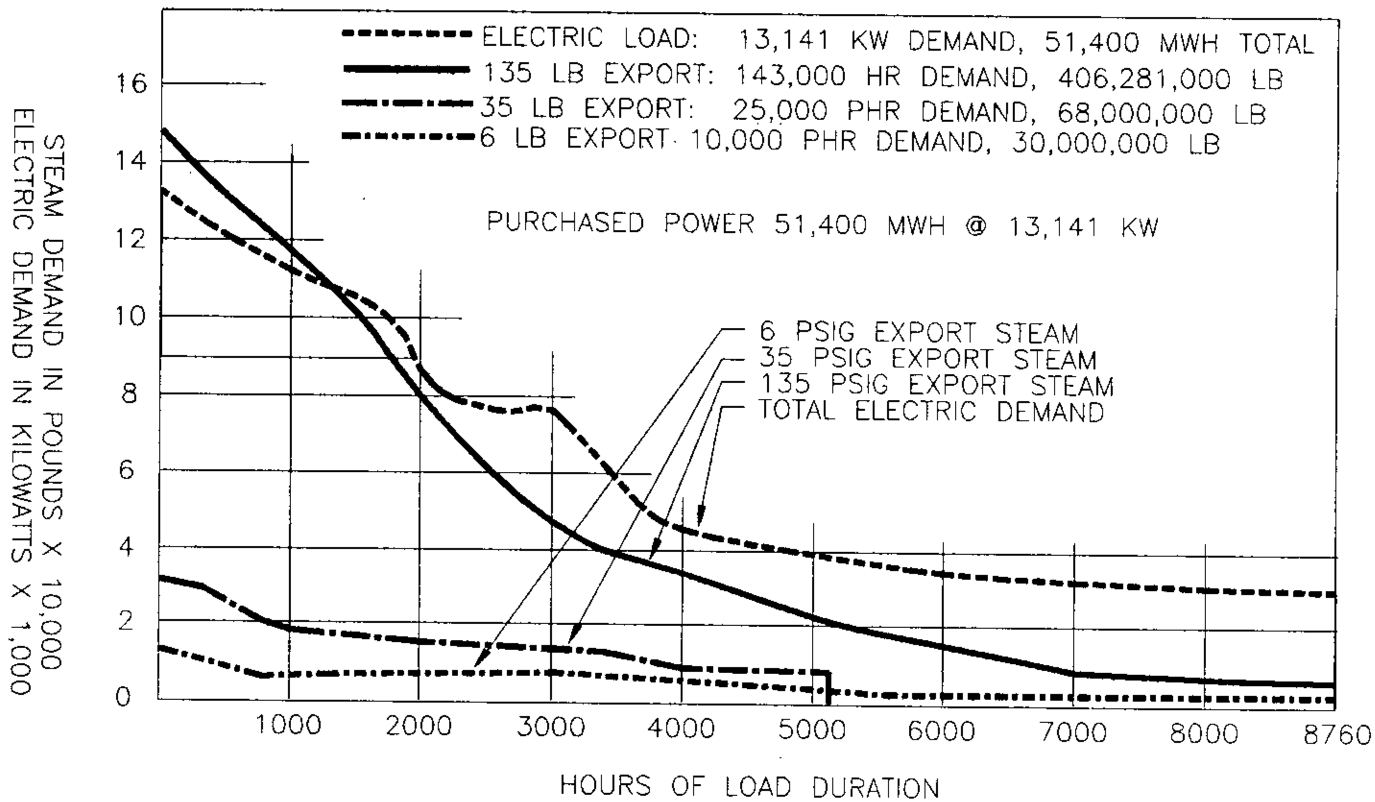

Figure 5

Typical Load Duration Curve — All Power Purchased

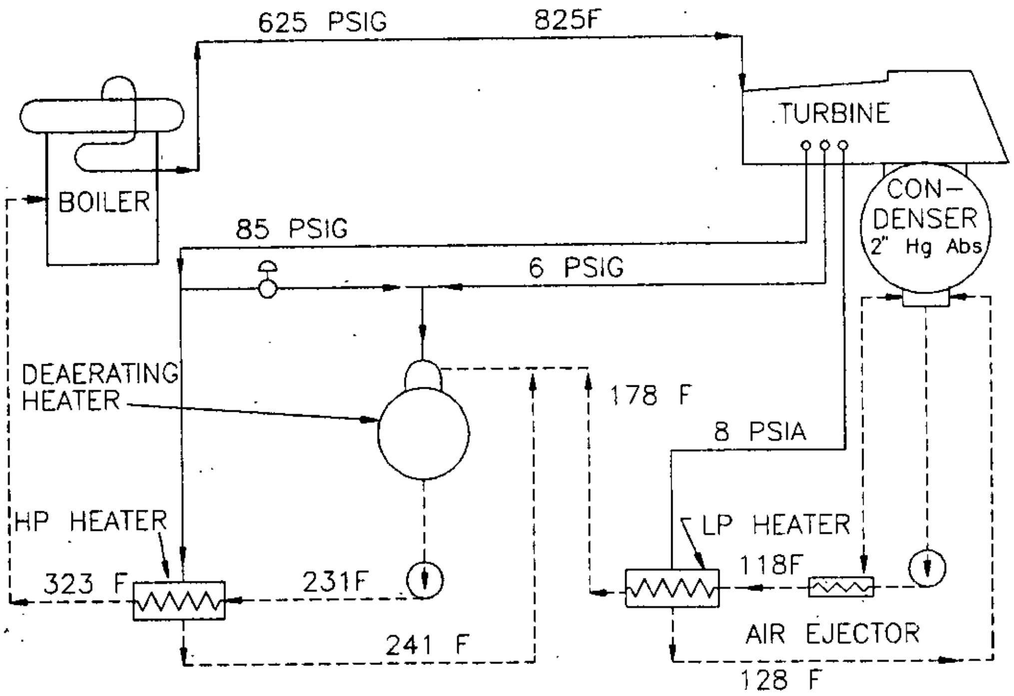

Figure 6
Typical Extraction Condensing Cycle

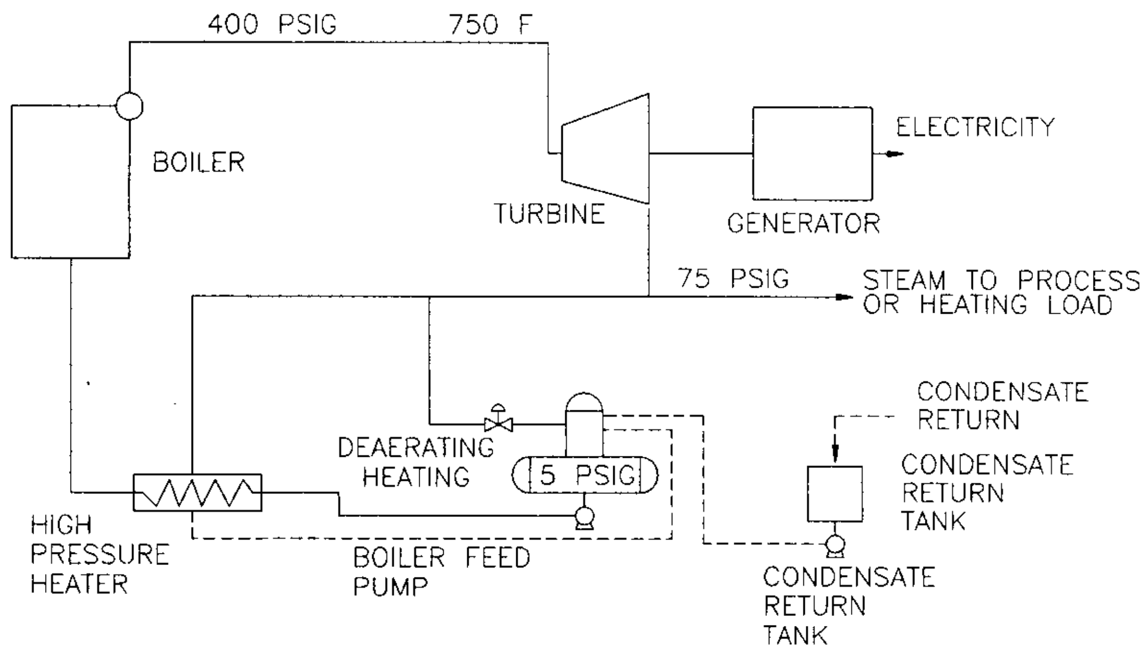

Figure 7
Typical Back Pressure Cycle

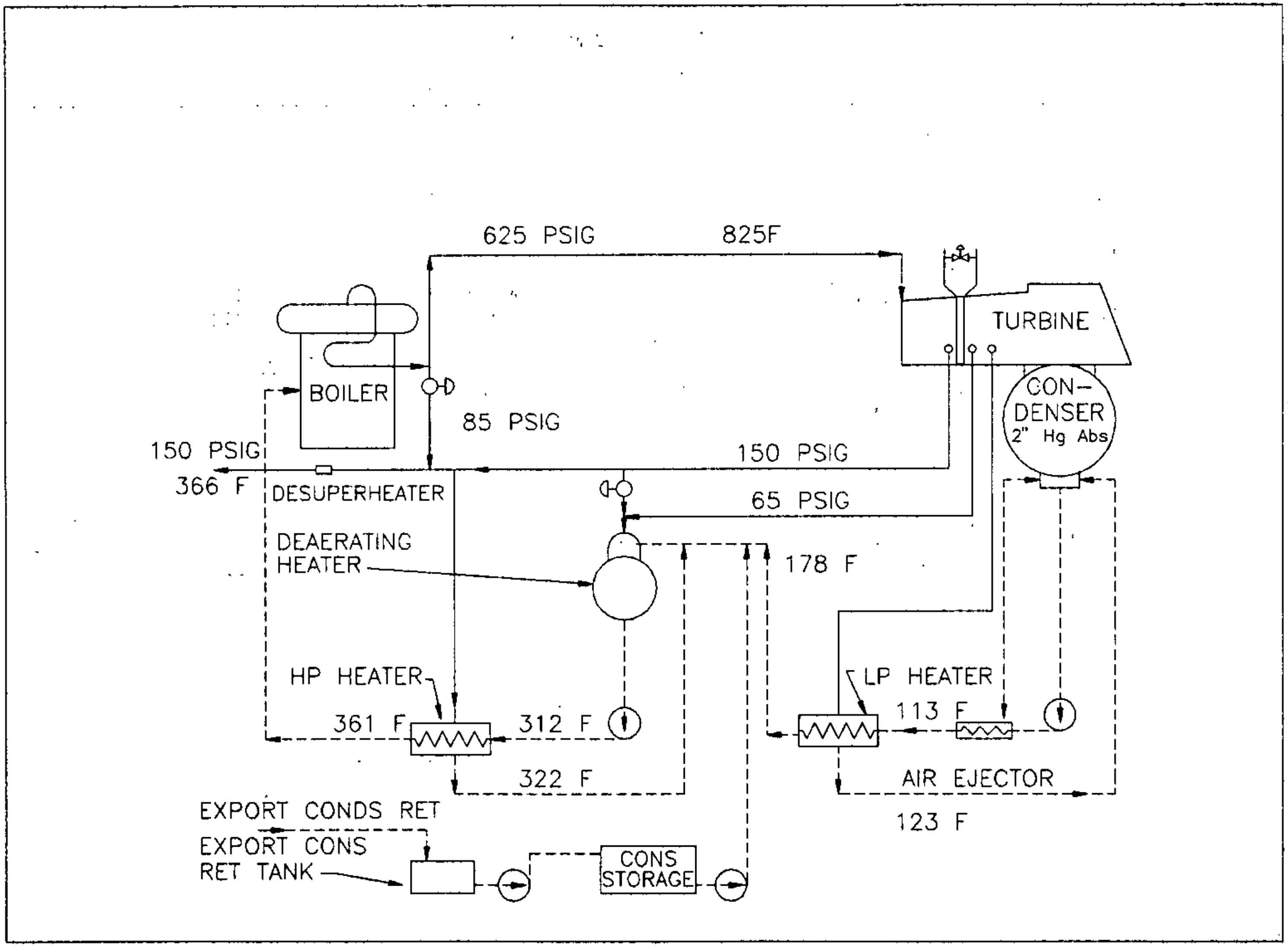

Figure 8

Typical Automatic Extraction Condensing Cycle

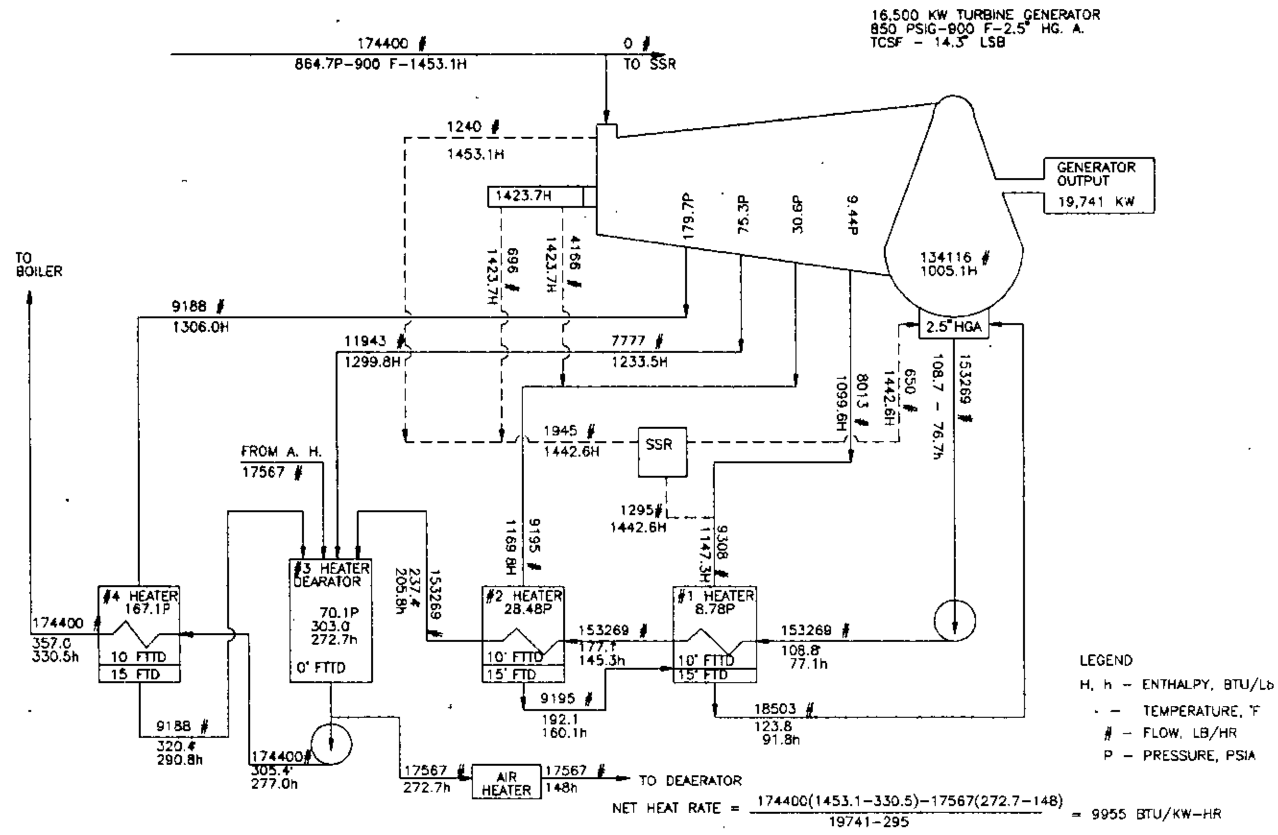

Figure 9

Typical Extraction Condensing Cycle Heat Balance

Table 3
Information Required for Design of Power Plants

Principal Item	Subitem	Required Data	Comments
Plant steam load	Maximum continuous load. Consider diurnal loads and hourly loads.	Export load: Heating (not auto. control) diversity 0.8-0.9. Heating (auto control), diversity 0:7-0.8	Obtain loads separately for summer and winter. Determine Heating loads by criteria in NAVFAC DM-3.03 and ASHRAE Handbook Fundamentals Chapter 25, "Heating Loads"
		Utilities hot water, kitchen laundry, diversity 0.5 - 0.7.	Use factors to obtain diversified load.
		Process, diversity varies.	Determine ratio of sum of utility and process loads to total load.
		Distribution loss. Total summer load. Total winter load.	
	Maximum ultimate load.	Add future load to present load.	
	Minimum continuous load.	Distribution loss and night utility load.	
	Essential load.	Diversified load in all buildings where no cutback can be tolerated. Minimum permissible heating and ventilating load where cutback can be tolerated. Minimum heating load to avoid freeze-up.	
Export fluid conditions	Steam	Maximum pressure required by consumer. Maximum allowable	See criteria in MIL-HDBK-1003/8, Exterior

Table 3 (Cont.)
Information Required for Design of Power Plants

Principal Item	Subitem	Required Data	Comments
		pressure in distribution system and in consumer equipment. Maximum pressure drop through distribution system.	Distribution of Utility Steam, HTW, CHW, Gas, and Compressed Air.
		Purity for ship usage	Use demineralized water for makeup. See MIL-HDBK-1025/2, Dockside Utilities for Ship Service, for other criteria.
	Condensate return	Condensate flow, pressure, and temperature at condensate storage/ return tank	Add simultaneous pumping rates of all condensate return pumps.
		Ratio of condensate return to steam	
Fuels	Availability	Reserves for life of plant	See Section 2 for policy.
	Natural gas	Heating value, ultimate analysis, specific gravity, moisture content, pressure at meter, delivered cost per million Btu	Determine who supplies meter, meter house, valving arrangement and gas piping on site.
	Liquid petroleum gas	Heating value, ultimate analysis, delivered cost per million Btu	Determine if gas supply is firm or interruptible.
	Fuel oils	Grade, heating	Ascertain supply,

Table 3 (Cont.)
Information Required for Design of Power Plants

Principal Item	Subitem	Required Data	Comments
		value, ultimate analysis, delivered cost per million Btu	if other gas fuel is not available for burner ignition. Determine how delivered, unloaded, and stored.
	Coal	Source, heating value, ultimate analysis, proximate analysis, delivered cost per million Btu.	Determine how delivered, unloaded, stored, and handled.
	Wood	Source, heating value, ultimate analysis, delivered cost per million Btu.	Determine how delivered, unloaded stored, and handled.
	Refuse (municipal)	Source, heating value, composition	Determine how delivered by municipality or private haulers and how stored and handled. Determine pollution abatement.
	Ash	Cost of disposal	Determine disposal by fill on site or by trucking away. Determine pollution abatement. Determine if secure landfill area is necessary to prevent contamination of ground water.
Water	Availability	Domestic use. Cooling and tempering pumps and coolers. Condensing	

Table 3 (Cont.)
Information Required for Design of Power Plants

Principal Item	Subitem	Required Data	Comments
		water, makeup water for heating plant, fire protection, construction purposes.	
	Composition and Source	Chemical analysis	Determine type of water treatment
	Discharge	Determine discharge temperature and composition. Environmental restraints. Inlet temperature.	
Electric service (available and required)	Normal service	Substation capacity and voltage available. Energy and demand charges.	
	Alternate service	Alternate source in case of normal service failure.	
	Emergency service	Power required, size of electric generator	Determine if continuous.
Plant location factors			See Table 1
Economic studies	Comparison of various types of generating equipment for full and partial load generation	Capital costs and operating expense, including utility costs	See Section 2 for policy. Use most economical system in accord with National energy policy.

Table 3 (Cont.)
Information Required for Design of Power Plants

Principal Item	Subitem	Required Data	Comments
	Choice of operating pressure and temperature	Electrical demand loads. Reliability and cost of purchased power. Heating loads, production requirements, lines losses energy costs.	Make life cycle cost analysis to determine most economical system. Consider first cost and operating costs including distribution energy loss costs.

Section 4. POWER PLANT STEAM GENERATION

4.1 Steam Generators (Boilers). For collateral reading and further detailed information, see (1) Steam/Its Generation and Use, by Babcock & Wilcox, 1978 and (2) Combustion/Fossil Power Systems, by Combustion Engineering, Inc, 1981.

4.2 Steam Pressures and Temperatures

4.2.1 Rated Pressure and Temperature. The boiler shall be specified for the maximum operating steam pressure required at the superheater outlet for operation of the turbine generator. The specified operating pressure is the maximum operating pressure at the turbine throttle valve inlet plus the main steam line pressure drop (between the superheater outlet and turbine throttle valve inlet at the maximum continuous rating of the boiler) rounded to the next higher unit of 5 psi (34 kPa gage). Based on the specified operating pressure, the boiler manufacturers will design the boiler parts and safety valve pressure settings in accordance with the ASME Boiler and Pressure Vessel Code, Section 1, Power Boilers.

The boiler shall be specified for the maximum steam temperature required at the superheater outlet for operation of the turbine generator. The specified temperature is equal to the sum of the operating temperature at the turbine throttle valve inlet plus the main steam temperature drop (between the superheater outlet and turbine throttle valve inlet) with the sum rounded out to the next higher unit of 5 degrees F.

4.2.2 Maximum Allowable Working Pressure. The maximum allowable working pressure (MAWP) of a boiler is an absolute limit of pressure in psig at which a boiler is permitted to operate. The ASME Boiler and Pressure Vessel Code states that no boiler shall be operated at a pressure higher than the MAWP except when the safety valve or valves are discharging (blowing).

4.2.2.1 Safety Valves and Safety Relief Valves. In accordance with the rules of the ASME Boiler and Pressure Vessel Code, one or more safety valves on the boiler shall be set at or below the MAWP. If additional safety valves are used, the highest pressure setting shall not exceed the MAWP by more than 3 percent. The capacity of all safety valves or safety relief valves for each boiler shall be such that the valves will discharge all the steam that can be generated without allowing the pressure to rise more than 6 percent above the highest pressure at which any valve is set and in no case higher than 6 percent above the MAWP.

4.2.2.2 Normal Operating Pressure. In order to avoid excessive use and wear of safety or safety relief valves, the maximum boiler operating pressure in the boiler steam drum or at the superheater outlet is usually not greater than 95 percent of the lowest set pressure of the relief valves at these points.

This allows operation of the boiler below the blowdown range of the safety valves, which is usually 3 to 4 percent of the set pressure.

4.3 Natural Gas Firing. For natural gas characteristics and application, see NAVFAC MIL-HDBK-1003/6, Sections 5 and 9.

4.4 Fuel Oil Firing. For fuel oil characteristics, application, handling, storage, and burning, see MIL-HDBK-1003/6, Sections 5 and 9.

4.5 Coal Firing. For characteristics, application, handling, and storage of coal, see MIL-HDBK-1003/6.

4.5.1 Definitions of Boiler and Stoker Criteria.

4.5.1.1 Stoker Grate Burning Rate. Burning rate is the higher heating value (in Btu) of the type of coal used; multiplied by the number of pounds of coal burned per hour to obtain the rated boiler capacity; divided by the total active burning area, in square feet, of the stoker grate. The maximum values shown are based on the assumption that furnace walls are water cooled, that there is adequate furnace volume, and that the most desirable type of coal for the unit is used; in the absence of these conditions, values should be reduced to ensure satisfactory combustion.

4.5.1.2 Velocities in Convection Sections of Boilers. To prevent undue erosion of boiler convection tubes, the gas velocities through the convection section shall not exceed velocities shown in Table 4 for the specific boiler, stoker, and fuel combination.

4.5.1.3 Furnace Volume. For water-tube boilers, furnace volume is defined as the cubical volume between the top grate surface (coal) or the floor (gas, oil) and the first plane of entry into or between the tubes. If screen tubes are utilized, they constitute the plane of entry.

4.5.1.4 Effective Radiant Heating Surface. Effective radiant heating surface is defined as the heat-exchange surface within the furnace boundaries and, in solid-fuel furnaces, above the grate surface that is directly exposed to radiant heat of the flame on one side and to the medium being heated on the other. This surface consists of plain or finned tubes and headers and plain surfaces, which may be bare, metal-covered, or metallic-ore-covered. Refractory-covered surfaces should not be counted. The surface shall be measured on the side receiving heat.

Computations of effective radiant heating surface for water tube boilers shall be based on the following:

a) Bare, metal-covered, or metallic-ore-covered tubes and headers: projected area (external diameter times length of tube) of the tubes or header.

Table 4
Maximum Velocities (ft/sec) in Convection Sections
for Coal, Wood, or Solid Waste Boilers

Stoker Type	Single Pass Water Tube			Multi-Pass Water Tube
	Coal	Wood	Solid Waste	Coal
Underfeed stoker	75			60
Spreader stoker Traveling grate (with reinjection)	60	50		50
Spreader stoker Traveling grate (without reinjection)	60	50		50
Traveling grate (front gravity feed)	75			60
Solid waste			30	

b) Extended surface (metal and metallic surfaces extending from the tubes or headers): sixty percent of the flat projected area, except that metal blocks not integral with tubes or headers, extended surfaces less than 1/4 inch (6.35 mm) thick or more than 1-1/4 inches (31.75 mm) in length, and the part of the extended surface which is more than one tube or header radius from the tube of header from which it extends are not included.

c) Furnace exit tubes: the projected areas of those portions of the first two rows of exit tubes receiving radiant heat from the fire.

4.5.2 Types of Stokers Used in Power Plants

4.5.2.1 Front Gravity Feed Traveling Grate Stoker. For plant capacities in the 25,000 pounds of steam per hour (pph) (11400 kg/hr) to 160,000 pph (7260 Kg/hr) range, the traveling grate stoker method of firing can be used for moderately changing wide load swings. It will handle fuels that have widely varying characteristics, from low volatile anthracite, coke breeze to high and medium volatile bituminous. It is particularly efficient with free-burning type coals in the Mid-West producing areas and can handle lignite and subbituminous coals. The type of furnace configuration, including long rear arches, are important when using the traveling grate stoker to burn very low volatile fuels, such as anthracite or coke breeze. Front arches are used with the high volatile and free-burning Mid-Western type coals. The feature of the traveling grate stoker that provides for the utilization of such a wide variety of fuel types is the undergrate air zoning. These units normally have from five to nine individual air zones which can control the amount of air admitted to the fuel bed as it travels from the free end of the stoker to the discharge. This provides the stoker operation with tremendous flexibility to obtain complete combustion with the various sizes and types of fuel. Since the fuel bed on the traveling grate stoker is not agitated by vibration as the bed usually 4 inches (101.6 mm) to 6 inches (152.4 mm) depth is moving from the feed end toward the discharge end, the amount of particulate fluidization is very low. This means that the traveling grate stoker has a low particulate pollution characteristic as compared to other fuel burning stokers. Chain grate stokers are not recommended except to burn low fusion coals with high clinkering tendencies.

4.5.2.2 Overfeed Spreader Stoker with Traveling Grate. The spreader stoker is characterized by a thin bed and partial burning of coal particles in suspension. Suspension burning gives rapid response to load changes which is an important characteristic for many industrial process steam plants that need rapid changes in steam production. This characteristic, together with a nonclinkering thin bed on the grate, provides a unit capable of firing a wide range of coal grades and types. The spreader stoker has high availability, ease of operation, and good efficiency. The suspension burning causes a high particulate loading of the burning gases within the furnace which, without fly ash reinjection, would result in a high carbon loss in the fly ash. Front discharge traveling grates are commonly used with spreader stokers. (Dump, vibrating, reciprocating, and oscillating grates are also available). With a high particulate loading, the spreader stoker requires the use of electrostatic precipitator or baghouse collectors to prevent particulate pollution.

4.5.3 Stoker Criteria. See Table 5, Stoker Selection Criteria, for information necessary for proper selection of a stoker type. Information included in the table are average criteria gathered from several boiler-stoker manufacturers' recommendations.

4.5.4 Pulverized Coal

4.5.4.1 Coal Feeders. For use with each pulverizer, the coal feeding function can be accomplished by the use of a separate rotary feeder or combined with the weighing function (see para. 4.5.6, Coal Scales), using a volumetric or gravimetric feeder. Pulverizers, depending on type, may operate with either a negative or positive internal pressure and will also contain hot circulating air. Coal feeders cannot act as a seal for the pulverizer air, therefore, a height (head) of coal must be provided and maintained above the feeder inlet to prevent pulverizer air backflow. See also MIL-HDBK-1003/6, Section 5.

Table 5
Stoker Selection Criteria

Unit Size Range PPH	Type of Stoker: Type of Feed	Type of Stoker: Type of Grate	Fuel Requirements: Size	Fuel Requirements: Characteristics
25,000-160,000	Front Gravity	Traveling	1" to 0" top size with maximum 60% though 1/4" round hole screen	Free burning to medium caking (free swelling index less than 6) ash 6 to 15% volatile matter 28 to 40%. Ash fusion (reducing atmosphere H = 1/2W) minimum 2750 deg. F minimum Btu/lb 11,500
25,000-160,000	Overfeed spreader	Traveling	1-1/4" to 3/4" X 0" with maximum 40% through 1/4" round hole screen	Bituminous A & B subbituminous or lignite volatile matter 25% to 40% ash 6 to 15% ash fusion (reducing atmosphere H = 1/2W) minimum 2750 deg. F minimum Btu/lb 11,500

Unit Size Range PPH	Type of Stoker: Type of Feed	Type of Stoker: Type of Grate	Maximum Stoker Grate Burning Rates Btu/ft^2/Hr	Btu/Hr ft^3 of furnace Volume	Btu/Hr ft^2 of Radiant Heating Surface	Combustion limited (turndown)
25,000-160,000	Front Gravity	Traveling	450,000	35,000	100,000	6 to 1
25,000-160,000	Overfeed spreader	Traveling	700,00	300,000	100,000	2.8 to 1 3.5 to 1

Notes:
1. The underfeeds and chain grate stokers are not generally applicable to widely fluctuating loads, i.e., process type loads which may vary in capacity more than 50% during any 30 minute period. For applications of swing loads with less than the 30 minute period, use spreader stoker.

2. Where availability of proper coal suitable for a particular type stoker is

indeterminate, consideration should be given to the spreader type stoker.

3. For definitions of stoker grate burning rates, furnace volume and radiant heating surface, see the section.

4. For smokeless condition, the minimum burning rate for tangent tube or membrane furnace wall construction is 250,000 Btu/ft^2/hr active stoker grate area which equates to 2/3 - 1 maximum boiler turndown, with a tube and tile (spaced tubes backed by refractory) or refractory furnace. This release rate can be reduced to 200,000 Btu/ft^2/hr which equates to 3.5 - 1 maximum boiler turndown

5. All grate heat release rates are based on maximum continuous rating (MCR) with allowance for 110% rating for 2 hour emergency peak per 24 hours.

6. Coal with volatile content less than indicated should not be applied, as loss of ignition could result.

7. Some chain grate designs are applicable for anthracite coal firing.

8. Further turndown beyond that indicated under Note 4 may be obtainable dependent upon allowable emission requirements and/or pollution abatement equipment applied.

9. For excess air requirements at the boiler outlet over the boiler/stoker limits operating range, see MIL-HDBK-1003/6. Consult boiler and stoker manufacturers for predicted excess air requirements at various loads.

10. In cases where coal quality is less than in above tables, consult NAVFAC headquarters Code 04 for direction.

4.5.4.2 Pulverizers. Pulverizers are used to reduce crushed coal to a powder-like fineness usually in the order of 70 percent passing through a 200 mesh screen. To facilitate the pulverizing and pneumatic circulation of the coal fuel within the pulverizer, hot air (up to 650 degrees F (343 degrees C)) is introduced into the pulverizer for the purpose of drying the coal. A pulverizer fan is used either as a blower or exhauster which either forces or draws hot primary air through the pulverizer and through the discharge coal-air piping to the burners. If a blower is used, one pulverizer will usually furnish coal directly to several burners. If an exhauster is used, a distributor located beyond the fan discharge is used to distribute the coal-air mixture to several burners.

a) Types of Pulverizers. The principal types of pulverizers are as follows:

(1) Ball and race

(2) Roll and race
(3) Ball tube
(4) Attrition

The various types are described in detail in the following boiler manufacturers' literature: (1) Babcock & Wilcox, 1978, (2) Combustion Engineering, Inc, 1981.

b) Turndown Ratio. The operating range of all types of pulverizers, without reducing the number of burners fed from the pulverizer(s) is approximately 35 percent to 100 percent of the maximum pulverizer coal capacity. This is usually stated as not more than 3 to 1 turndown range or ratio.

c) Pulverizer Sizing. Base pulverizer selection on coal feed is required at maximum boiler load plus 10 percent for load pickup and continuous boiler output at maximum steam load. Pulverizer output varies with coal grindability index and fineness (percent through 200 mesh) of grind. These factors must also be taken into account in selecting number and size of pulverizers. Emergency loss of one pulverizer must be considered and the remaining pulverizer capacity must be sufficient to carry maximum boiler steam load. The minimum boiler load will depend on the number of pulverizers and burners installed and primary air velocities in the coal-air piping and coal burners. It is desirable to have at least a 3 to 1 turndown on automatic control with all burners and pulverizers in service. During boiler startup, the firing rate may be further reduced by reducing the number of pulverizers and number of burners per pulverizer in service. Sizing of pulverizers must be coordinated with the boiler manufacturer and usually requires the development of a set of coordination curves of the various factors involved such as shown on Figure 10.

d) Coal Feed Size. Crushed coal is used as the feed stock for pulverizers. The maximum coal feed size is dependent upon pulverizer size. The larger the pulverizer size, the larger is the coal size which can be accommodated. Coal feed size ranges from 3/4" (19.05 mm) x 0" to 1-1/2" (38.1 mm) x 0" with 3/4" x 0" being a size which is commonly used.

4.5.5 Pulverized Coal Firing vs. Stoker Coal Firing. The choice between the use of pulverizers or stokers can only be determined by making an economical evaluation of life cycle costs which include cost of equipment and installation, fuel, maintenance labor and parts, operating labor, electrical energy, electrical demand, and supplies. For many years, for industrial power applications, the boiler size breakpoint was approximately 300,000 pph (136 000 kg/hr) with pulverizers predominantly used at this boiler load and above. Presently there is a downward trend and the breakpoint for boiler size is approximately 250,000 pph (113 000 kg/hr). Pulverized coal systems are of high installation costs, high power costs to drive mills, more rigid coal specifications, and need highly trained personnel.

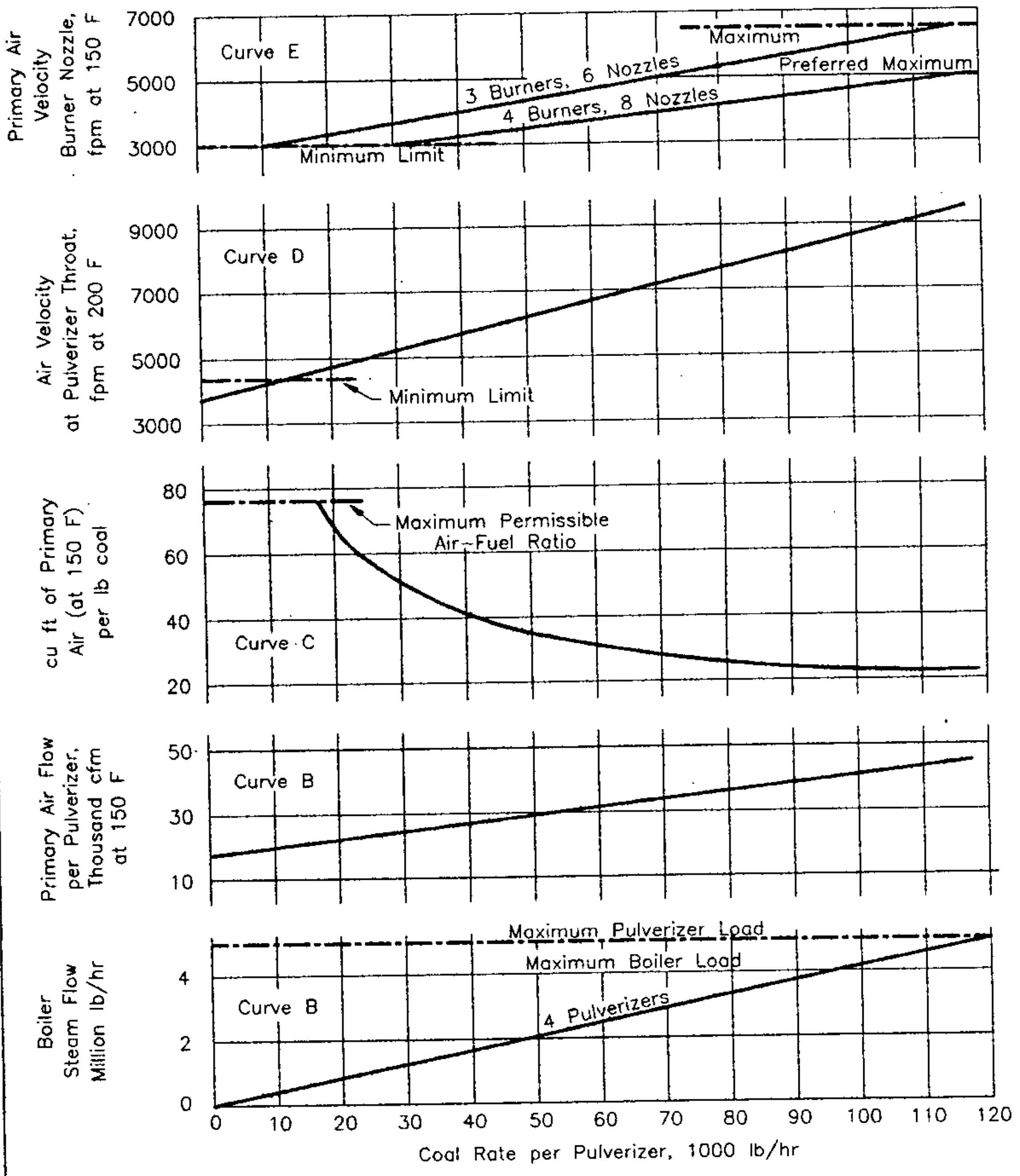

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Figure 10
Pulverizer - Burner Coordination Curves

4.5.6 Coal Scales. See MIL-HDBK-1003/6, regarding the use of rail car scales and the use of truck scales for coal delivery. Coal scales are also used to measure coal feed to stokers or pulverizers. These are located at the in-plant bunker outlet and may be of the batch weigh bucket, volumetric (volume rate of flow measurement) belt, or gravimetric (weight rate of flow measurement) belt type.

4.6 Wood Firing. Combustion systems for wood are usually designed specifically for the material and mixture of fuels to be burned. When the moisture content is high, over 60 to 65 percent, supplemental firing of coal, oil, or gas can be used or the wood must be mixed with low-moisture fuels so that enough energy enters the boiler to support combustion. Dry wood may have a heating value of 8,750 Btu/lb (20 353 kJ/kg); but at 80 percent moisture, a pound of wet wood has a heating value of only 1,750 Btu/lb (4071 kJ/kg). The usual practice when burning wood is to propel the wood particles into the furnace through injectors, along with preheated air, with the purpose of inducing high turbulence in the boiler. The wood is injected high enough in the combustion chamber so that it is dried, and all but the largest particles are burned before they reach the grate at the bottom of the furnace. Spreader stokers and cyclone burners work well for this application. For burning wood as a fuel to produce steam or high temperature water (HTW), methods should be researched thoroughly and their successful operation, adequate source of fuel, and economics evaluated.

4.6.1 Suspension Burning. Small wood chips or saw dust are blown into the furnace chamber and burned in suspension. The ash or unburned particles are collected on traveling grate and transported to ash pit. In wood burning applications, heat releases have been as high as 1,000,000 Btu/ft^2/hr. (11 357 373 kJ/m^2/hr) of active grate area.

4.7 Soot Blowers. Soot blowers are required for No. 6 fuel oil, coal, and wood and may or may not be required for No. 2 fuel oil. Additional information regarding soot blowers and blowing mediums are presented in MIL-HDBK-1003/6.

4.8 Economizers. Economizers are located in the boiler flue gas outlet duct and are used to heat the incoming feedwater by reducing the flue gas temperature. The result is an increase in boiler efficiency. For application and design considerations, see MIL-HDBK-1003/6.

4.9 Air Heaters. Air heaters should be used to burn bark and wood chips and may be used for other fuels if economically justified or required for combustion. For additional information see MIL-HDBK-1003/6.

4.10 Forced Draft Fans. For forced draft fan size, types, drives, and general requirements, refer to MIL-HDBK-1003/6.

4.11 Induced Draft Fans. For induced draft fan size, types, drives and general requirements, refer to MIL-HDBK-1003/6. When flue gas scrubbers are used, the induced draft fans must be able to accommodate the boiler full test steam load when the scrubbers are not in operation. In addition, allowances must be made for leakage and pressure requirements for air pollution control equipment.

4.12 Primary Air Fans. Primary air fans may be used on large pulverized coal fired boilers in lieu of pulverizer blowers or exhausters. Primary air fans usually provide both hot and cold air which can be tempered before being introduced into the pulverizers. The cold air is atmospheric air supplied from the fan discharge. Part of the fan discharge goes through a section of the air heater or separate air heater which in turn raises the temperature to 500 degrees F (260 degrees C) or 600 degrees F (315 degrees C). The hot air is then ducted and tempered with the cold air to provide the motive and drying air to the pulverizers at the proper temperature.

4.13 Overfire Air Fans. Overfire air fans are used on stoker fed coal fired boilers to reduce smoke and to improve combustion efficiency by mixing with unburned gases and smoke. The quantity of overfire air is usually between 5 and 15 percent of the total air needed for combustion of the coal fuel. The pressure and volume of overfire air must be sufficient to produce the proper turbulence for efficient burnup of the unburned gases and suspended fuel particles. Fan size is determined by the boiler manufacturer and furnished with the boiler.

4.14 Cinder Return Fans. Cinder return fans are used on some stoker fed coal fired boilers for reinjection of fly ash from last pass hoppers and mechanical dust collectors. Fan size is determined by the boiler manufacturer and furnished with the boiler.

4.15 Stacks. For description and sizing of stacks, see MIL-HDBK-1003/6.

4.16 Blowdown Equipment. For information relative to boiler blowdown and blowdown equipment, refer to MIL-HDBK-1003/6, Section 7, "Water Treatment".

4.17 Essential Plant Equipment

4.17.1 Steam Drive Auxiliaries. On coal stoker-fired installations, steam driven boiler feed pumps, with total pumping capacity to suit the ultimate plant capacity, are required to satisfy the ASME Boiler and Pressure Vessel Code (Section 1, Paragraph PG-61) requirement of two means of feeding water. These pumps shall be primarily connected to the boiler feed header from the deaerator and also to the treated water line for an emergency water source for the boilers.

4.18 Equipment Selection. For design information and requirements needed to design boiler plants, see Table 6.

Table 6
Equipment Selection For Boiler Plants

Equipment	Size or Type	Pertinent Information
Water tube boiler (shop assembled)	10,000 to 25,000 pph	Coal/oil or coal/oil/gas or coal fired
Water tube boiler (field erected)	30,000 to 160,000 pph	Coal/oil or coal fired. Gas can be used if allowed by current energy policy. Casing to withstand not less than 20 inches W.G. Maximum casing surface temperature not to exceed 150 degrees F.
Air heater	Tubular or regenerative	Use for wood firing, some coal firing where required for proper combustion or when economically justified. Keep outlet gas temperature above dew point. Maximum temperature of combustion air shall not exceed 350 deg F for coal stoker or wood chip firing; pulverized coal firing may use temperatures up to 600 deg F. Minimum flue gas temperature range is 300 to 350 degrees F.
Economizer (part of boiler unit)	Bare tube or cast iron covered tube for coal or high sulfur oil.	Use where economically justified. Keep outlet gas temperature above dew point.
	Finned tubes for No. 2 fuel oil, gas.	Keep water inlet temperature from 230 deg F to 250 degrees F depending on sulfur content of fuel.
Superheater (part of boiler)		Drainable

Table 6 (Cont.)
Equipment Selection For Boiler Plants

Equipment	Size or Type	Pertinent Information
Forced draft fan MIL-F-18523, Fan, Centrifugal Draft Forced and Induced	Backward inclined or backward curved single thickness blade	Safety factor for test block ratings same as for ID fans.
Induced draft fan MIL-F-18523	Straight radial with shrouds or radial tip (forward curved-backward inclined)	Safety factor for test block ratings. Coal, 20% excess pressure; oil and gas, 10 to 15% excess volume, 20 to 25% excess pressure. Add 25 deg F to temperature of gas.
Wet scrubber		Flue gas desulfurization for fuel sulfur content up to 4.5%
Baghouse	Pulse jet cleaning up to 50,000 actual cubic cubic feet per minute (ACFM). Reverse air cleaning over 100,000 ACFM. Either pulse jet or reverse air between 50,000 and 100,000 ACFM.	Particle removal from flue gas. Do not use for oil firing because of bag blinding or for wood chip or solid waste firing be cause of fire hazard. Use with fuel with sulfur content in compliance with air pollution regulation or with a dry scrubber.
Mechanical cyclone dust collector	Multiple tube, high efficiency	Flue gas large particulate removal, 60 to 80% efficiency is common minimum protection for ID fan. Use upstream of baghouse.
Electrostatic precipitator	Rigid frame	Particulate removal from flue gas. Use with fuel which is in compliance with air pollution control regulations for sulfur.

Table 6 (Cont.)
Equipment Selection For Boiler Plants

Equipment	Size or Type	Pertinent Information
Soot blowers	Compressed air or steam operated	Required for burning No.6 fuel oil and coal and possibly for No. 2 fuel oil. Not required for gas firing.
Condensate receiver	60 to 180 minute storage capacity at ultimate plant capacity.	Steel plate tank with corrosion resistant liner suitable for 250 degrees F. For automatic extraction plant use 180 minutes. For straight condensing plant use 60 to 90 minutes.
Deaerating heater and tank MIL-H-17660C, <u>Heater, Fluid, Deaerating</u>	15 to 20 minutes storage capacity at ultimate plant capacity	Tray type to be used. Use with multiport back pressure relief valve.
Boiler feed pumps (centrifugal) MIL-P-17552 horizontally split, multistage, high alloy pumps	Coal fired plants and oil or gas fired boilers: one motor driven pump per boiler. Pump to be 1.25 x boiler steaming capacity; plus two steam driven pumps 1.25 x half of ultimate plant capacity.	For adequate minimum pump flow, use automatic flow control valve or automatically controlled discharge system for each pump. Discharge water to deaerator storage tank. Consider variable speed drive if over 10 HP. Consider dual motor drive and steam turbine drive with clutch to permit instantaneous changeover from one drive to the other.
Condenser condensate pumps	Two per condenser. Size each for 1.25 x condenser maximum flow rate.	Horizontal split case or vertical can type pumps.

Table 6 (Cont.)
Equipment Selection For Boiler Plants

Equipment	Size or Type	Pertinent Information
Condensate transfer pumps MIL-P-17552	Two motor driven pumps per boiler. Each pump to be 1.25 x boiler steaming capacity. Consider one steam turbine driven pump in lieu of one of the motor driven pumps.	Provide bypass orifice at each pump. Discharge of bypass to go to condensate tank. Consider variable speed drive if over 10 HP. Horizontal split case or vertical can type pumps.
Feedwater regulators	Two element (steam flow/drum level) pump control or three element (drum level, steam flow, water-flow) pump control.	Use three element pump control where boilers are operated simultaneously or have severely fluctuating loads.
Steam Turbines for Mechanical Drive MIL-T-18246, <u>Steam Turbines for Mechanical Drive</u>	Size for maximum horsepower required under all possible operating conditions	Can be used for condensate transfer pump, boiler feed pump, forced draft fan, induced draft fan, over fire fan. Use to reduce electric consumption of heating plant. Assure sufficient electric auxiliaries to preclude atmospheric exhaust during low-load periods. Consider both motor drive and steam turbine drive with overrunning clutch or units to permit instantaneous changeover from one drive to the other.

Section 5. STEAM TURBINE DESIGN

5.1 Typical Plants and Cycles

5.1.1 Definition. The cycle of a steam power plant is the group of interconnected major equipment components selected for optimum thermodynamic characteristics, including pressures, temperatures, and capacities, and integrated into a practical arrangement to serve the electrical (and sometimes by-product steam) requirements of a particular project. Selection of the optimum cycle depends upon plant size, cost of money, fuel costs, non-fuel operating costs, and maintenance costs.

5.1.2 Steam Turbine Prime Movers

5.1.2.1 Smaller Turbines. Turbines under 1,000 kW may be single stage units because of lower first cost and simplicity. Single stage turbines, either back pressure or condensing, are not equipped with extraction openings.

5.1.2.2 Larger Turbines. Turbines for 5,000 kW to 30,000 kW shall be multi-stage, multi-valve units, either back pressure or condensing types.

a) Back Pressure Turbines. Back pressure turbine units usually exhaust at pressures between 5 psig (34 kPa gage) and 300 psig (2068 kPa gage) with one or two controlled or uncontrolled extractions. However, there is a significant price difference between controlled and uncontrolled extraction turbines, the former being more expensive. Controlled extraction is normally applied where the bleed steam is exported to process or district heat users.

b) Condensing Turbines. Condensing units exhaust at pressures between 1 inch of mercury absolute (Hga) and 5 inches Hga, with up to two controlled, or up to five uncontrolled extractions.

5.1.3 Selection of Cycle Conditions. The function or purpose for which the plant is intended determines the conditions, types, and sizes of steam generators and turbine drives and extraction pressures.

5.1.3.1 Simple Condensing Cycles. Straight condensing cycles or condensing units with uncontrolled extractions are applicable to plants or situations where security or isolation from public utility power supply is more important than lowest power cost. Because of their higher heat rates and operating costs per unit output, it is not likely that simple condensing cycles will be economically justified for a military power plant application as compared with that associated with public utility purchased power costs. A schematic diagram of an uncontrolled extraction-cycle is shown in Figure 11.

5.1.3.2 Controlled Extraction-Condensing Cycles and Back Pressure Cycles. Back pressure and controlled extraction-condensing cycles are attractive and applicable to a cogeneration plant, which is defined as a power plant simultaneously supplying either electric power or mechanical energy and heat energy. A schematic diagram of a controlled extraction-condensing cycle is shown in Figure 12. A schematic diagram of a back pressure cycle is shown in Figure 13.

5.1.3.3 Topping Cycle. A schematic diagram of a topping cycle is shown in Figure 14. The topping cycle consists of a high pressure steam boiler and turbine generator with the high pressure turbine exhausting steam to one or more low pressure steam turbine generators. High pressure topping turbines are usually installed as an addition to an existing lower pressure steam electric plant.

5.1.4 General Economic Rules. Maximum overall efficiency and economy of the steam turbine power cycle are the objectives of a satisfactory design. Higher efficiency and a lower heat rate require more complex cycles which are accompanied with higher initial investment costs and higher operational and maintenance costs but lower fuel costs. General rules to consider to improve the plant efficiency are listed hereinafter.

a) Higher steam pressures and temperatures increase the turbine efficiencies, but temperatures above 750 degrees F (399 degrees C) usually require more expensive alloy piping in the high pressure steam system.

b) Lower condensing pressures increase turbine efficiency. However, there is a limit where lowering condensing (back) pressure will no longer be economical, because the costs of lowering the exhaust pressure is more than the savings from the more efficient turbine operation.

c) The use of stage or regenerative feedwater cycles improves heat rates, with greater improvement corresponding to larger numbers of such heaters. In a regenerative cycle, there is also a thermodynamic crossover point where lowering of an extraction pressure causes less steam to flow through the extraction piping to the feed water heaters, reducing the feedwater temperature. There is also a limit to the number of stages of extraction/feedwater heating, which may be economically added to the cycle. This occurs when additional cycle efficiency no longer justifies the increased capital cost.

d) Larger turbine generator units are generally more efficient than smaller units.

e) Multi-stage and multi-valve turbines are more economical than single stage or single valve machines.

f) Steam generators of more elaborate design and with heat saving accessory equipment are more efficient.

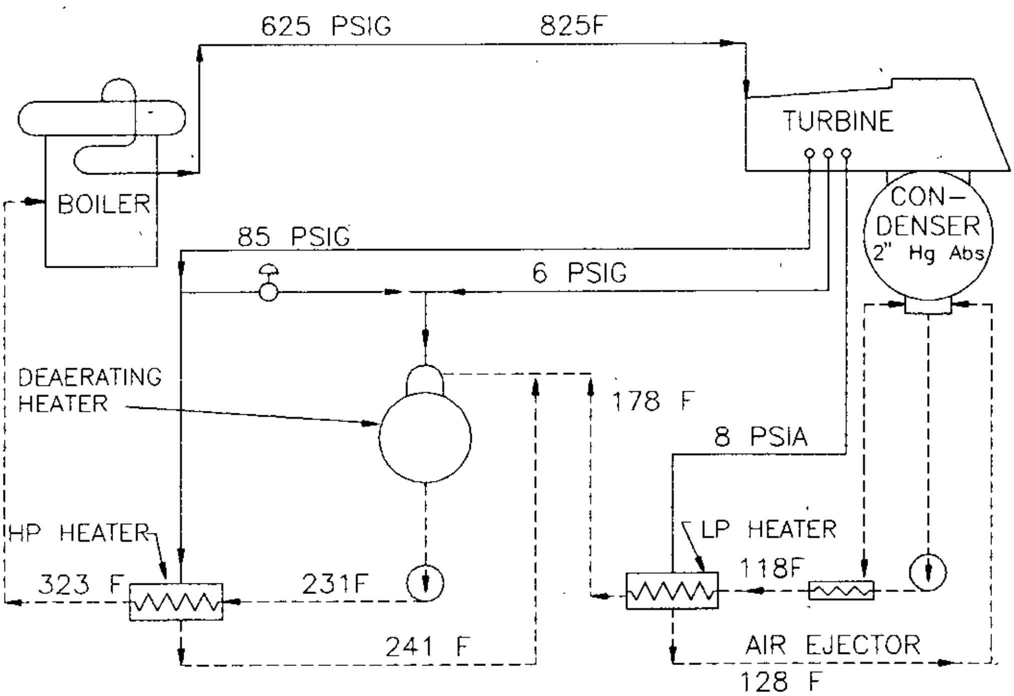


Figure 11
Typical Uncontrolled Extraction - Condensing Cycle

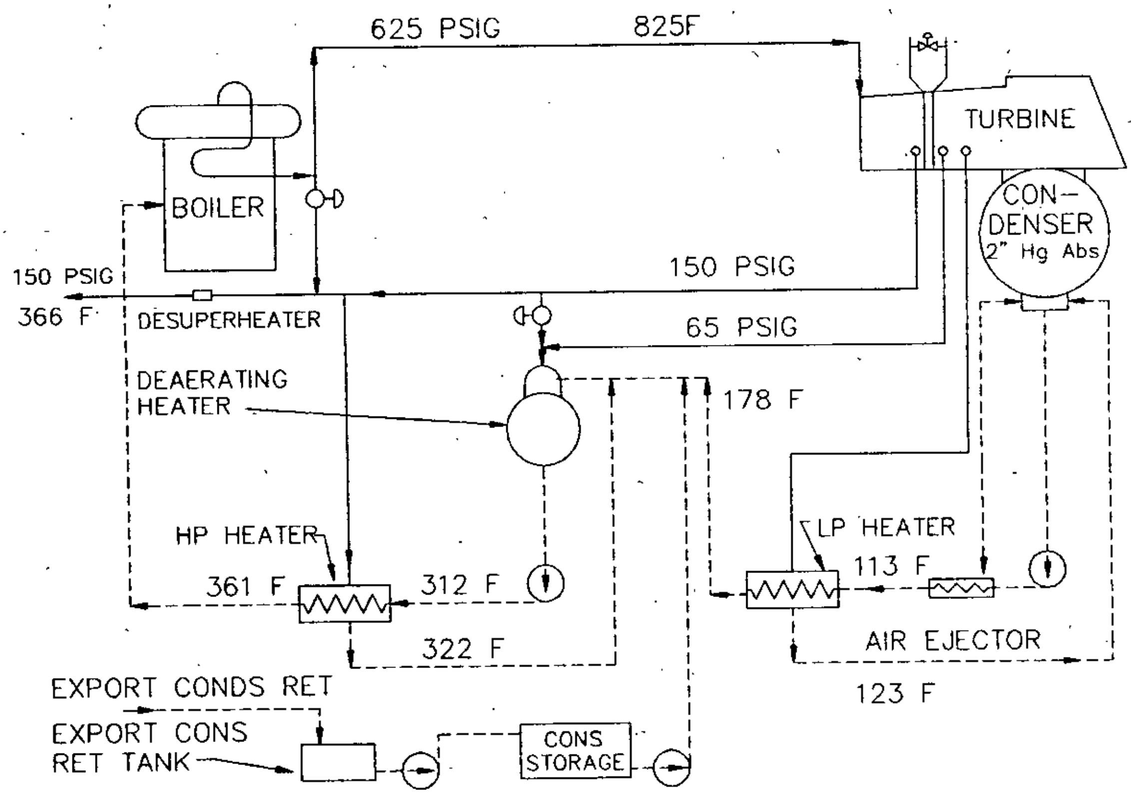


Figure 12
Typical Controlled Extraction - Condensing Cycle

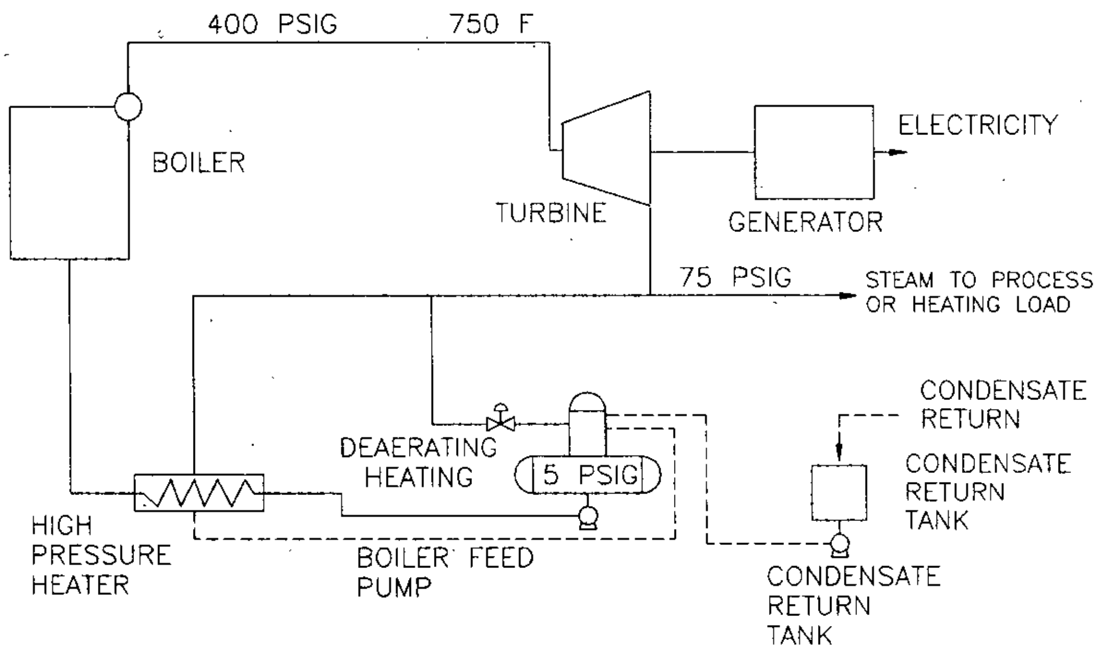


Figure 13

Typical Back Pressure Cycle

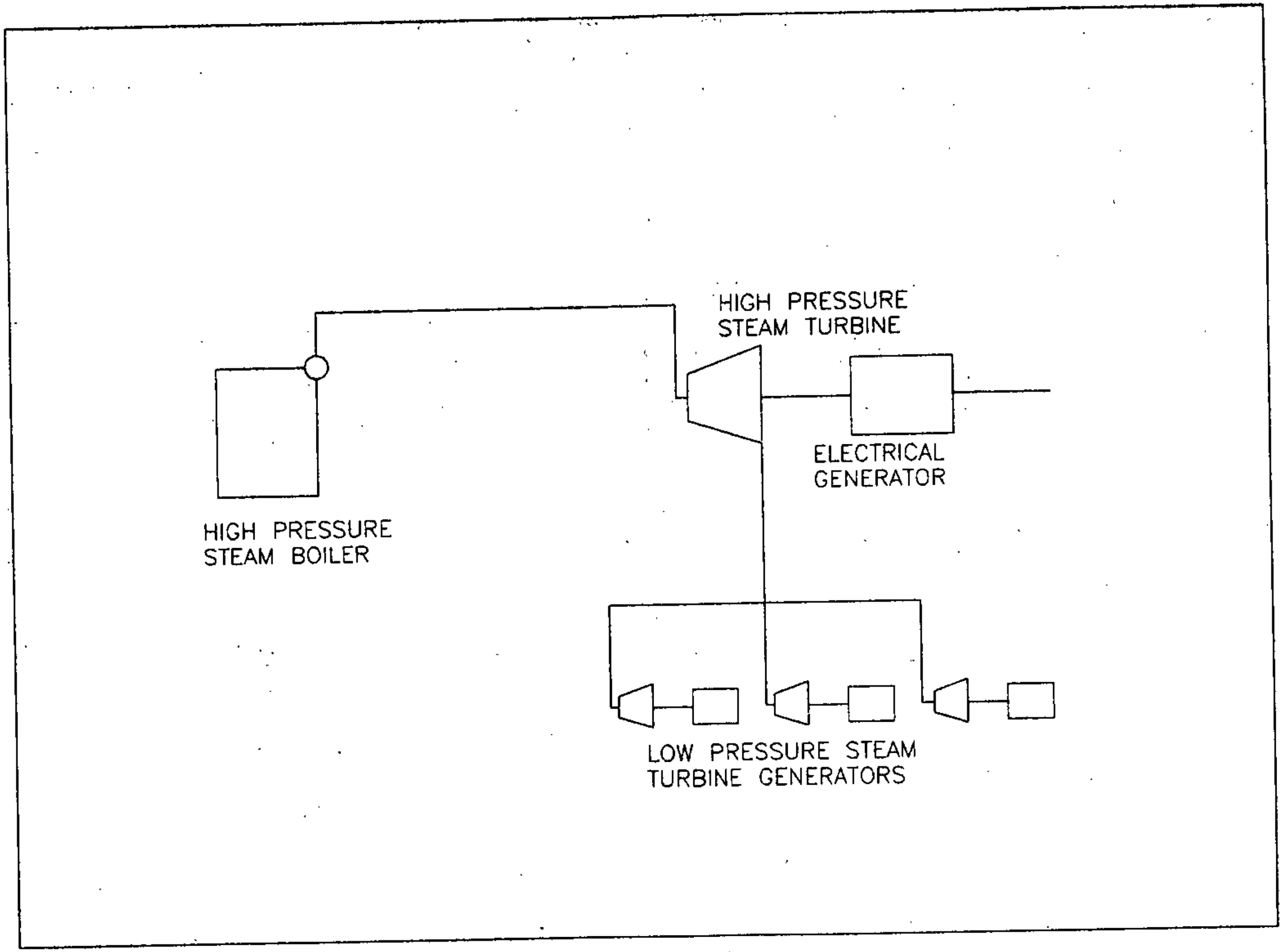


Figure 14
Typical Topping Cycle

5.1.5 Selection of Cycle Steam Conditions

5.1.5.1 Balanced Costs and Economy. For a new or isolated plant, the choice of initial steam conditions should be a balance between enhanced operating economy at higher pressures and temperatures, and generally lower first costs and less difficult operation at lower pressures and temperatures. Realistic projections of future fuel costs may tend to justify higher pressures and temperatures, but such factors as lower availability, higher maintenance costs, more difficult operation, and more elaborate water treatment shall also be considered.

5.1.5.2 Extension of Existing Plant. Where a new steam power plant is to be installed near an existing steam power or steam generation plant, careful consideration shall be given to extending or paralleling the existing initial steam generating conditions. If existing steam generators are simply not usable in the new plant cycle, it may be appropriate to retire them or to retain them for emergency or standby service only. If boilers are retained for standby service only, steps shall be taken in the project design for protection against internal corrosion.

5.1.5.3 Special Considerations. Where the special circumstances of the establishment to be served are significant factors in power cycle selection, the following considerations may apply:

a) Electrical Isolation. Where the proposed plant is not to be interconnected with any local electric utility service, the selection of a simpler, lower pressure plant may be indicated for easier operation and better reliability.

b) Geographic Isolation. Plants to be installed at great distances from sources of spare parts, maintenance services, and operating supplies may require special consideration of simplified cycles, redundant capacity and equipment, and highest practical reliability. Special maintenance tools and facilities may be required, the cost of which would be affected by the basic cycle design.

c) Weather Conditions. Plants to be installed under extreme weather conditions require special consideration of weather protection, reliability, and redundancy. Heat rejection requires special design consideration in either very hot or very cold weather conditions. For arctic weather conditions, circulating hot water for the heat distribution medium has many advantages over steam, and the use of an antifreeze solution in lieu of pure water as a distribution medium should receive consideration.

5.1.6 Steam Power Plant Arrangement

5.1.6.1 General. Small units utilize the transverse arrangement in the turbine generator bay, while the larger utility units are very long and require end-to-end arrangement of the turbine generators.

5.1.6.2 Typical Small Plants. Figures 15 and 16 show typical transverse small plant arrangements. Small units less than 5,000 kW may have the condensers at the same level as the turbine generator for economy, as shown in Figure 15. Figure 17 indicates the critical turbine room bay clearances.

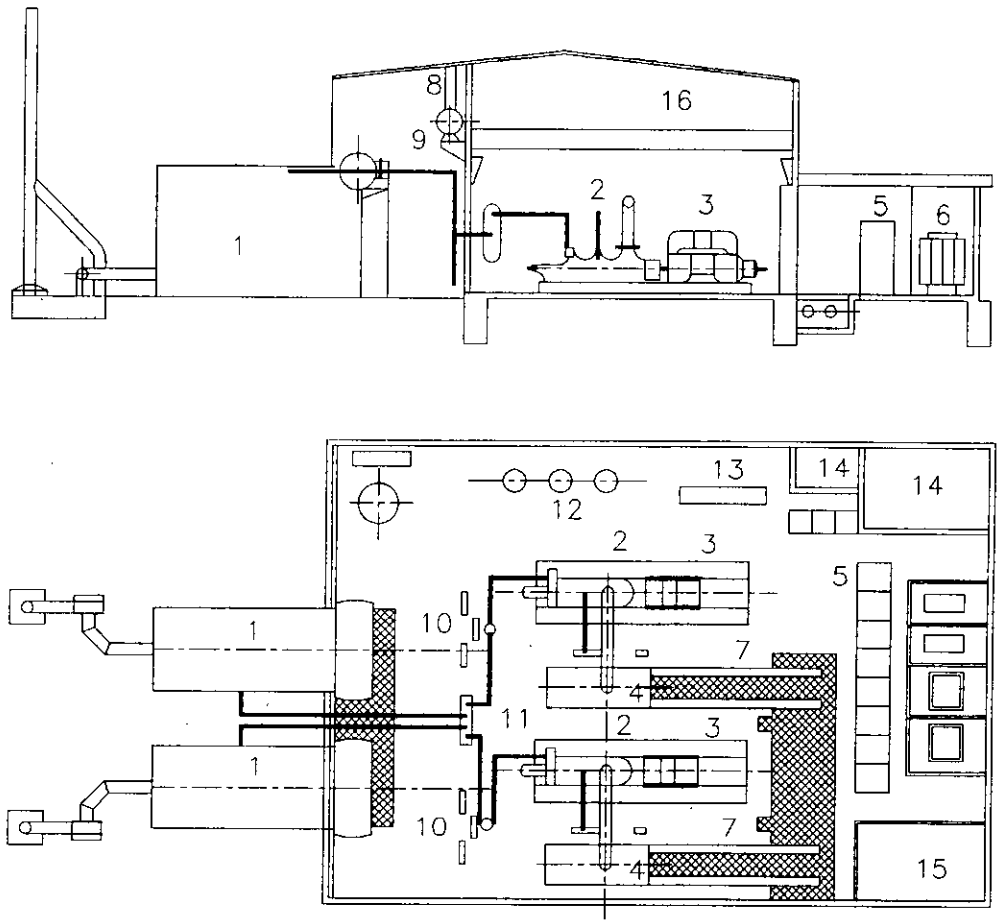
5.1.7 Heat Rates. The final measure of turbine cycle efficiency is represented by the turbine heat rate. It is determined from a heat balance of the cycle, which accounts for all flow rates, pressures, temperatures, and enthalpies of steam, condensate, or feedwater at all points of change in these thermodynamic properties. Heat rate is an excellent measure of the fuel economy of power generation.

5.1.7.1 Heat Rate Units and Definitions. The economy or efficiency of a steam power plant cycle is expressed in terms of heat rate, which is total thermal input to the cycle divided by the electrical output of the units. Units are Btu/kWh.

a) Conversion to cycle efficiency, as the ratio of output to input energy, may be made by dividing the heat content of one kWh, equivalent to 3412.14 Btu by the heat rate, as defined. Efficiencies are seldom used to express overall plant or cycle performance, although efficiencies of individual components, such as pumps or steam generators, are commonly used.

b) Power cycle economy for particular plants or stations is sometimes expressed in terms of pounds of steam per kilowatt hour, but such a parameter is not readily comparable to other plants or cycles and omits steam generator efficiency.

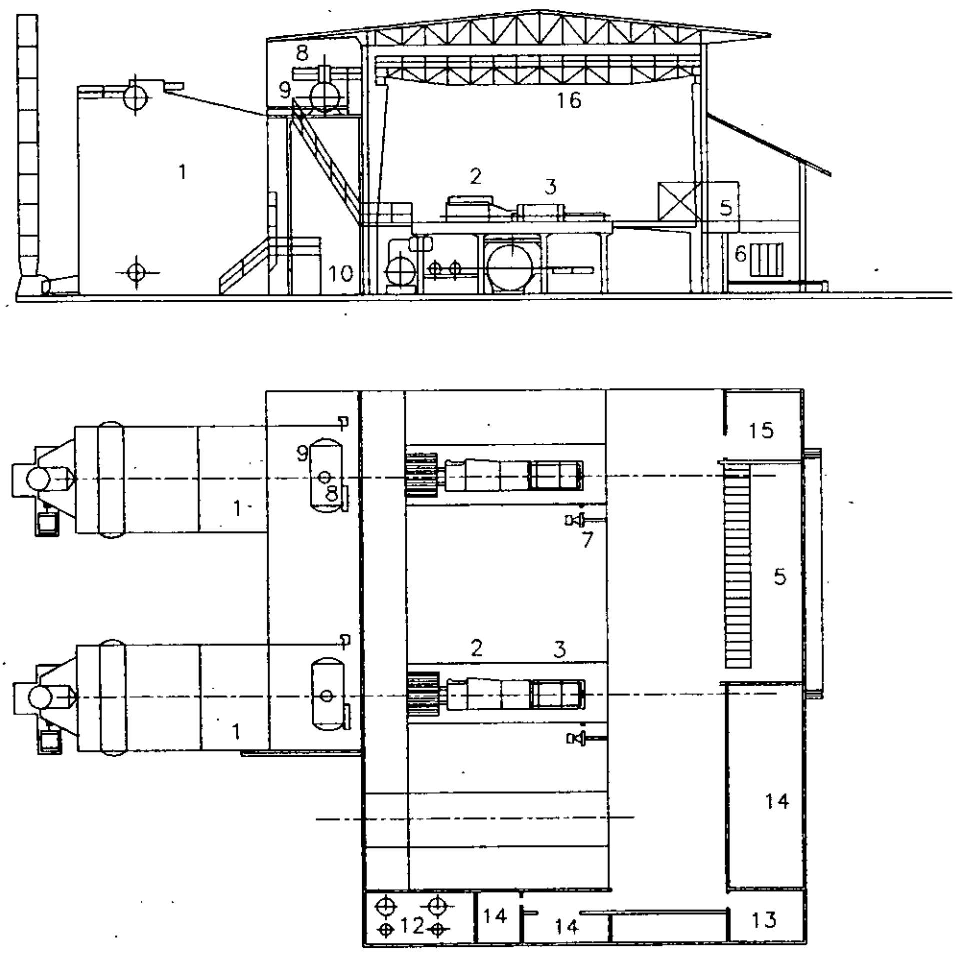
c) For mechanical drive turbines, heat rates are some times expressed in Btu per hp-hour, excluding losses for the driven machine. One horsepower hour is equivalent to 2544.43 Btu.



1 – BOILER, OIL-FIRED
2 – TURBINE
3 – GENERATOR
4 – CONDENSER
5 – SWITCHGEAR
6 – TRANSFORMERS
7 – COOLING WATER PUMP
8 – DEAERATOR
9 – FEEDWATER TANK
10 – BOILER FEED PUMPS
11 – INDUCED DRAFT FAN
12 – WATER TREATMENT
13 – START UP DIESEL
14 – STORE ROOM
15 – OFFICE
16 – TURBINE HOUSE CRANE

U.S. Army Corps of Engineers

Figure 15
Typical Small 2-Unit Power Plant (Less than 5 MW)
Condenser on Same Level as Turbine



1 – BOILER, OIL FIRED
2 – TURBINE
3 – GENERATOR
4 – CONDENSER
5 – SWITCHGEAR
6 – TRANSFORMERS
7 – COOLING WATER PUMP
8 – DEAERATOR
9 – FEEDWATER TANK
10 – BOILER FEED PUMPS
11 – INDUCED DRAFT FAN
12 – WATER TREATMENT
13 – CHEMICAL LABORATORY
14 – OFFICES
15 – STORE ROOM
16 – TURBINE HOUSE CRANE

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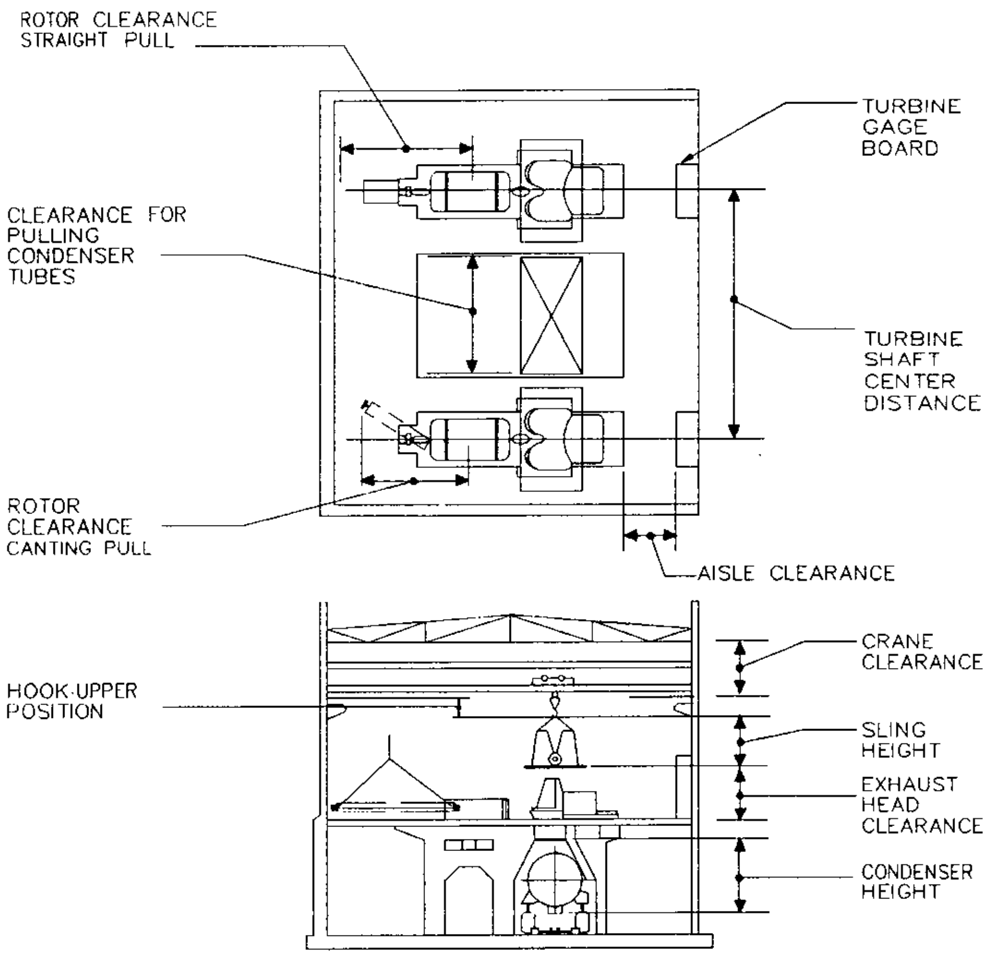
Figure 16
Typical 2-Unit Power Plant with Condenser Below Turbine



NOTE : ABOVE TURBINE ROOM BAY DIMENSIONS VARY ACCORDING TO TURBINE AND CONDENSER SUPPLIERS SELECTED

U.S. Army Corps of Engineers

Figure 17
Critical Turbine Room Bay Clearances

5.1.7.2 Turbine Heat Rates

a) Gross Turbine Heat Rate. The gross heat rate is determined by dividing the heat added in the boiler between feedwater inlet and steam outlet by the kilowatt output of the generator at the generator terminals. The gross heat rate is expressed in Btu per kWh. For reheat cycles, the heat rate is expressed in Btu per kWh. For reheat cycles, the heat added in the boiler includes the heat added to the steam through the reheater. For typical values of gross heat rate, see Table 7.

Table 7
Typical Gross Turbine Heat Rates

Turbine Generator Rating, kW	Throttle Pressure psig	Throttle Temp. F	Reheat Temp. F	Pressure in. Hg Abs.	Cond. HeatRate Btu/kWh
11,500	600	825	-	1 1/2	10,423
30,000	850	900	-	1 1/2	9,462
60,000	1,250	950	-	1 1/2	8,956
75,000	1,450	1,000	1,000	1 1/2	8,334
125,000	1,800	1,000	1,000	1 1/2	7,904

b) Net Turbine Heat Rate. The net heat rate is determined the same as for gross heat rate, except that the boiler feed pump power input is subtracted from the generator power output before dividing into the heat added in the boiler.

c) Turbine Heat Rate Application. The turbine heat rate for a regenerative turbine is defined as the heat consumption of the turbine in terms of "heat energy in steam" supplied by the steam generator, minus the "heat in the feedwater" as warmed by turbine extraction, divided by the electrical output at the generator terminals. This definition includes mechanical and electrical losses of the generator and turbine auxiliary systems, but excludes boiler inefficiencies and pumping losses and loads. The turbine heat rate is useful for performing engineering and economic comparisons of various turbine designs.

5.1.7.3 Plant Heat Rates. Plant heat rates include inefficiencies and losses external to the turbine generator, principally the inefficiencies of the steam generator and piping systems; cycle auxiliary losses inherent in power required for pumps and fans; and related energy uses such as for soot blowing, air compression, and similar services.

a) Gross Plant Heat Rate. This heat rate (Btu/kWh) is determined by dividing the total heat energy (Btu/hour) in fuel added to the boiler by the kilowatt output of the generator.

b) Net Plant Heat Rate. This heat rate is determined by dividing the total fuel energy (Btu/hour) added to the boiler by the difference between power (kilowatts/hour) generated and plant auxiliary electrical power consumed.

5.1.7.4 Cycle Performance. Both turbine and plant heat rates, as above, are usually based on calculations of cycle performance at specified steady state loads and well defined, optimum operating conditions. Such heat rates are seldom achieved in practice except under controlled or test conditions.

5.1.7.5 Long Term Averages. Plant operating heat rates are actual long term average heat rates and include other such losses and energy uses as non-cycle auxiliaries, plant lighting, air conditioning and heating, general water supply, startup and shutdown losses, fuel deterioration losses, and related items. The gradual and inevitable deterioration of equipment, and failure to operate at optimum conditions, are reflected in plant operating heat rate data.

5.1.7.6 Plant Economy Calculations. Calculations, estimates, and predictions of steam plant performance shall allow for all normal and expected losses and loads and should, therefore, reflect predictions of monthly or annual net operating heat rates and costs. Electric and district heating distribution losses are not usually charged to the power plant but should be recognized and allowed for in capacity and cost analyses. The designer is required to develop and optimize a cycle heat balance during the conceptual or preliminary design phase of the project. The heat balance depicts, on a simplified flow diagram of the cycle, all significant fluid mass flow rates, fluid pressures and temperatures, fluid enthalpies, electric power output, and calculated cycle heat rates based on these factors. A heat balance is usually developed for various increments of plant load such as 25, 50, 75, 100 percent and VWO (valves, wide open). Computer programs have been developed which can quickly optimize a particular cycle heat rate using iterative heat balance calculations. Use of such a program should be considered.

5.1.8 Steam Rates

5.1.8.1 Theoretical Steam Rate. When the turbine throttle pressure and temperature and the turbine exhaust pressure (or condensing pressure) are known, the theoretical steam rate can be calculated based on a constant entropy expansion or can be determined from published tables. See Theoretical Steam Rate Tables, The American Society of Mechanical Engineers, 1969. See Table 8 for typical theoretical steam rates.

Table 8
Theoretical Steam Rates
LB/KWH

Pin, PSIG Tin, F	100 Sat.	200 Sat.	250 550	400 750	600 825	850 900	1250 950	1450 1000	1600 1000
Exhaust. P									
1" HGA	10.20	9.17	8.09	6.85	6.34	5.92	5.62	5.43	5.40
2" HGA	11.31	10.02	8.78	7.36	6.76	6.28	5.94	5.73	5.69
3" HGA	12.12	10.62	9.27	7.71	7.05	6.53	6.16	5.93	5.89
0 PSIG	22.73	17.52	14.57	11.19	9.82	8.81	8.10	7.72	7.62
5 PSIG	26.07	19.35	15.90	11.99	10.42	9.29	8.49	8.07	7.96
10 PSIG	29.52	21.10	17.15	12.71	10.96	9.71	8.83	8.38	8.26
15 PSIG	33.20	22.83	18.35	13.38	11.44	10.08	9.14	8.66	8.52
20 PSIG	37.17	24.56	19.53	14.02	11.90	10.43	9.42	8.91	8.76
25 PSIG	41.56	26.31	20.70	14.63	12.34	10.76	9.68	9.14	8.98
50 PSIG	74.8	35.99	26.75	17.56	14.31	12.22	10.80	10.15	9.94
100 PSIG		66.6	42.40	23.86	18.07	14.77	12.65	11.78	11.46
150 PSIG			71.8	31.93	22.15	17.33	14.35	13.26	12.79
200 PSIG				43.51	26.96	20.05	16.05	14.72	14.08
300 PSIG					40.65	26.53	19.66	17.74	16.70
400 PSIG					78.3	35.43	23.82	21.10	19.52
500 PSIG						49.03	28.87	25.03	22.69
600 PSIG						73.1	35.30	29.79	26.35

The equation for the theoretical steam rate is as follows:

EQUATION: $$T.S.R. = 3413/(h_1 - h_2) \quad (1)$$

where:

T.S.R. = theoretical steam rate of the turbine, lb/kWh
h_1 = throttle enthalpy at the throttle pressure and temperature, Btu/lb
h_2 = extraction or exhaust enthalpy at the exhaust pressure based on isentropic expansion, Btu/lb.

5.1.8.2 Turbine Generator Engine Efficiency. The engine efficiency is an overall efficiency and includes the entire performance and mechanical and electrical losses of the turbine and generator. The engine efficiency can be calculated using the following equation:

EQUATION: $$n_e = (h_1 - h_e)n_t n_g/(h_1 - h_2) \quad (2)$$

where:

n_e = Turbine generator engine efficiency
h_1 and h_2 = (see Equation 1)
h_e = Actual extraction or exhaust enthalpy, Btu/lb
nt = Turbine mechanical efficiency
n_g = Generator efficiency

Engine efficiency is usually obtained from turbine generator manufacturers or their literature. Therefore, it is not usually necessary to calculate engine efficiency.

Typical turbine generator engine efficiencies are provided in Figure 18.

5.1.8.3 Actual Steam Rate. The actual steam rate of a turbine can be determined by dividing the actual throttle steam flow rate in pounds per hour by the actual corresponding kilowatts, at the generator terminals, produced by that amount of steam. The resulting steam rate is expressed in pounds of steam per kWh. The actual steam rate can also be determined by dividing the theoretical steam rate by the engine efficiency of the turbine generator.

EQUATION: $$A.S.R. = T.S.R./n_e \qquad (3)$$

where:

A.S.R. = actual steam rate of the turbine, lb/kWh.

5.2 Cogeneration in Steam Power Plants. Cogeneration in a steam power plant affects the design of the steam turbine relative to the type of cycle used, the exhaust or extraction pressures required, the loading of the steam turbine, and the size of the steam turbine. Appendix C presents a further discussion on steam plant cogeneration.

5.2.1 Definition. In steam power plant practice, cogeneration normally describes an arrangement whereby high pressure steam is passed through a turbine prime mover to produce electrical power, and thence from the turbine exhaust (or extraction) opening to a lower pressure steam (or heat) distribution system for general heating, refrigeration, or process use.

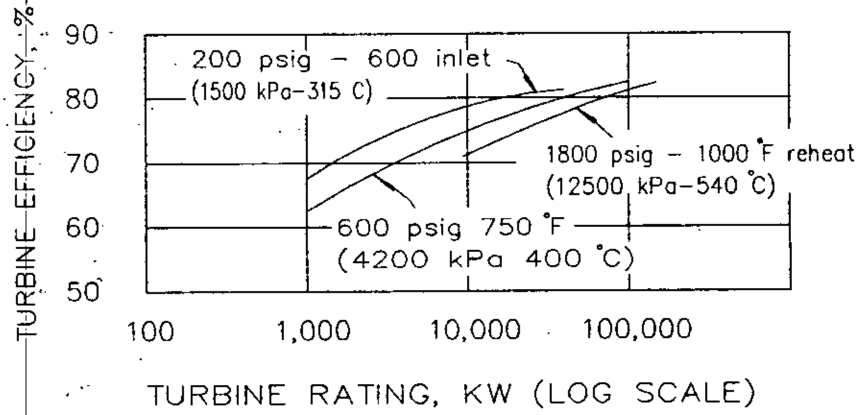


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Figure 18
Turbine Efficiencies vs Capacity

5.2.2 Common Medium. Steam power cycles are particularly applicable to cogeneration situations because the actual cycle medium, steam, is also a convenient medium for area distribution of heat.

a) The choice of the steam distribution pressure should be a balance between the costs of distribution, which are slightly lower at high pressure, and the gain in electrical power output by selection of a lower turbine exhaust or extraction pressure.

b) Often, the early selection of a relatively low steam distribution pressure is easily accommodated in the design of distribution and utilization systems, whereas the hasty selection of a relatively high steam distribution pressure may not be recognized as a distinct economic penalty on the steam power plant cycle.

c) Hot water heat distribution may also be applicable as a district heating medium with the hot water being cooled in the utilization equipment and returned to the power plant for reheating in a heat exchange with exhaust (or extraction) steam.

5.2.3 Relative Economy. When the exhaust (or extraction) steam from a cogeneration plant can be utilized for heating, refrigeration, or process purposes in reasonable phase with the required electric power load, there is a marked economy of fuel energy because the major condensing loss of the conventional steam power plant (Rankine) cycle is avoided. If a good balance can be attained, up to 75 per cent of the total fuel energy can be utilized, as compared with about 40 percent for the best and largest Rankine cycle plants and about 25 to 30 percent for small Rankine cycle systems.

5.2.4 Cycle Types. The two major steam power cogeneration cycles, which may be combined in the same plant or establishment, are the back pressure and extraction-condensing cycles.

5.2.4.1 Back Pressure Cycle. In a back pressure turbine, the entire flow to the turbine is exhausted (or extracted) for heating steam use. This cycle is more effective for heat economy and for relatively lower cost of turbine equipment, because the prime mover is smaller and simpler and requires no condenser and circulating water system. Back pressure turbine generators are limited in electrical output by the amount of exhaust steam required by the heat load and are often governed by the exhaust steam load. They, therefore, usually operate in electrical parallel with other generators.

5.2.4.2 Extraction-Condensing Cycle. Where the electrical demand does not correspond to the heat demand, or where the electrical load must be carried at times of very low (or zero) heat demand, then condensing-controlled extraction steam turbine prime movers, as shown in Figure 12, may be applicable. Such a turbine is arranged to carry a specified electrical capacity either by a simple condensing cycle or a combination of extraction and condensing. While very flexible, the extraction machine is relatively complicated, requires complete condensing and heat rejection equipment, and must always pass a critical minimum flow of steam to its condenser to cool the low pressure buckets.

5.2.5 Criteria For Cogeneration. For minimum economic feasibility, cogeneration cycles will meet the following criteria:

5.2.5.1 Load Balance. There should be a reasonably balanced relationship between the peak and normal requirements for electric power and heat. The peak/normal ratio should not exceed 2:1.

5.2.5.2 Load Coincidence. There should be a fairly high coincidence, not less than 70 percent, of time and quantity demands for electrical power and heat.

5.2.5.3 Size. While there is no absolute minimum size of steam power plant which can be built for cogeneration, a conventional steam (cogeneration) plant will be practical and economical only above some minimum size or capacity, below which other types of cogeneration, diesel, or gas turbine become more economical and convenient.

5.2.5.4 Distribution Medium. Any cogeneration plant will be more effective and economical if the heat distribution medium is chosen at the lowest possible steam pressure or lowest possible hot water temperature. The power energy delivered by the turbine is highest when the exhaust steam pressure is lowest. Substantial cycle improvement can be made by selecting an exhaust steam pressure of 40 psig (276 kPa gage) rather than 125 psig (862 kPa gage), for example. Hot water heat distribution should also be considered where practical or convenient, because hot water temperatures of 200 to 240 degrees F (93 to 116 degrees C) can be delivered with exhaust steam pressure as low as 20 to 50 psig (138 to 345 kPa gage). The balance between distribution system and heat exchanger costs, and power cycle effectiveness should be optimized.

5.3 Turbine Types

5.3.1 Condensing Types

5.3.1.1 High Pressure Extraction Type. Turbines with throttle pressures generally above 400 psig (2758 kPa gage) are considered high pressure machines; however, the exact demarcation between high, intermediate, and low pressure turbines is not definite. Turbines built with provisions for extraction of steam from the turbine at intermediate pressure points below the throttle pressure are called extraction turbines. The extracted steam may be used for process systems, feed water heating, and environmental heating. A typical cycle using a high pressure extraction type turbine is shown in Figure 12.

5.3.1.2 High Pressure Non-Extraction Type. The high pressure non-extraction type of turbine is basically the same as the extraction type described in 5.3.1.1 above, except no steam is extracted from the turbine. High pressure steam enters the turbine throttle and expands through the turbine to the condenser. The condenser pressure is comparable to that with high pressure extraction machines.

5.3.1.3 Automatic Extraction Type. Automatic extraction turbines usually operate with high pressure, high temperature throttle steam supply to a high pressure turbine section. The exhaust pressure of the high pressure turbine is held constant by means of automatic extraction gear (valve) that regulates the amount of steam passing to the low pressure turbine. Single automatic extraction turbines provide steam at a constant pressure from the automatic extraction opening, usually in the range of 50 to 150 psig (345 to 1034 kPa gage). Double automatic extraction turbines consist of a high, intermediate, and low pressure turbine section and provide steam in the range of 50 to 150 psig (345 to 1034 kPa gage) at one automatic extraction opening and 10 to 15 psig (69 to 103 kPa gage) at the other automatic extraction opening. Automatic extraction turbine generators operating automatically meet both automatic extraction steam and electrical demands by adjusting the flow of steam through the low pressure turbine. A typical automatic extraction cycle is shown in Figure 19.

Automatic extraction turbines may be either condensing (condenser pressure 1.0 to 4.0 inches of Hg Abs.) or noncondensing (usually 5 to 15 psig (34 to 103 kPa gage) back pressure).

5.3.1.4 Mixed Pressure or Induction Type. The mixed pressure or induction type turbine is supplied with steam to the throttle and also to other stages or sections at a pressure lower than throttle pressure. This type of machine is also called an admission type. The steam admitted into the lower pressure openings may come from old low pressure boilers, or it may be the excess from auxiliary equipment or processes. The mixed pressure turbine is the same as an automatic extraction turbine described in 5.3.1.3 above, except steam is admitted instead of extracted at the automatic controlled opening.

5.3.1.5 Low Pressure Type. Low pressure turbines are those with throttle pressures generally below 400 psig (2758 kPa gage). However, the pressure dividing point varies, depending on the manufacturer and type of turbine (industrial, mechanical drive, etc.) The variations as described in 5.3.1.1, 5.3.1.2, and 5.3.1.3 above are also applicable to low pressure turbines.

5.3.2 Noncondensing Types

5.3.2.1 Superposed or Topping Type. Refer to para 5.1.3.3, and Figure 14 in this handbook for a description of topping turbine and cycle.

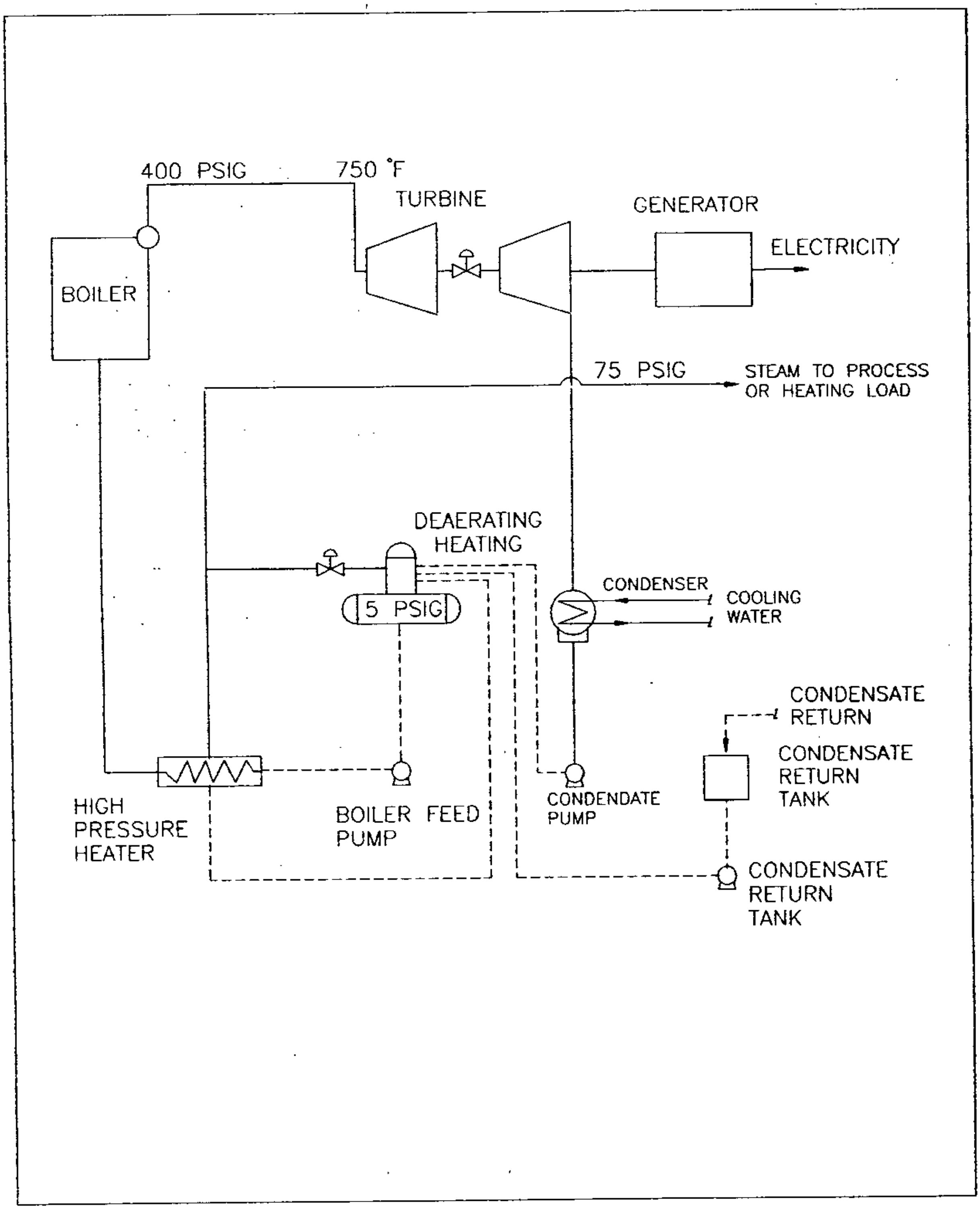


Figure 19
Typical Automatic Extraction Cycle

5.3.2.2 Back Pressure Type. Back pressure turbines usually operate with high pressure, high temperature throttle steam supply, and exhaust at steam pressures in the range of 5 to 300 psig (34 to 2068 kPa gage). Uncontrolled steam extraction openings can be provided depending on throttle pressure and exhaust pressures. Two methods of control are possible. One of the methods modulates the turbine steam flow to be such as to maintain the turbine exhaust pressure constant and, in the process, generate as much electricity as possible from the steam passing through the turbine. The amount of electricity generated, therefore, changes upward or downward with like changes in steam demand from the turbine exhaust. A typical back pressure cycle is shown in Figure 13. The other method of control allows the turbine steam flow to be such as to provide whatever power is required from the turbine by driven equipment. The turbine exhaust steam must then be used, at the rate flowing through the turbine, by other steam consuming equipment or excess steam, if any, must be vented to the atmosphere.

5.3.2.3 Atmospheric Exhaust. Atmospheric exhaust is the term applied to mechanical drive turbines which exhaust steam at pressures near atmospheric. These turbines are used in power plants to drive equipment such as pumps and fans.

5.4 Turbine Generator Sizes. See Table 9 for nominal size and other characteristic data for turbine generator units.

5.4.1 Noncondensing and Automatic Extraction Turbines. The sizes of turbine generators and types of generator cooling as shown in Table 9 generally apply also to these types of turbines.

5.4.2 Geared Turbine Generator Units. Geared turbine generator units utilizing multistage mechanical drive turbines are available in sizes ranging generally from 500 to 10,000 kW. Single stage geared units are available in sizes from 100 kW to 3,000 kW. Multistage units are also available as single valve or multi-valve, which allows further division of size range. Because of overlapping size range, the alternative turbine valve and stage arrangements should be considered and economically evaluated within the limits of their capabilities.

5.5 Turbine Throttle Pressure and Temperature. Small, single stage turbines utilize throttle steam at pressures from less than 100 psig (689 kPa gage) and saturated temperatures up to 300 psig and 150 (66 degrees C) to 200 degrees F (93 degrees C) of superheat. Steam pressures and temperatures applicable to larger multistage turbines are shown in Table 10.

5.5.1 Selection of Throttle Pressure and Temperature. The selection of turbine throttle pressure and temperature is a matter of economic evaluation involving performance of the turbine generator and cost of the unit including boiler, piping, valves, and fittings.

Table 9
Direct Connected Condensing Steam Turbine Generator Units

Turbine Type and Exh. Flow[1]	Nominal Last Stage Blade Length, In.	Nominal Turbine Size, kW	Typical Generator Cooling
Non-Reheat Units			
	Industrial Sized		
SCSF	6	2,500	Air
SCSF	6	3,750	Air
SCSF	7	5,000	Air
SCSF	7	6,250	Air
SCSF	8.5	7,500	Air
SCSF	10	10,000	Air
SCSF	11.5	12,500	Air
SCSF	13	15,000	Air
SCSF	14	20,000	Air
SCSF	17-18	25,000	Air
SCSF	20	30,000	Hydrogen
SCSF	23	40,000	Hydrogen
SCSF	25-26	50,000	Hydrogen
	Utility-Sized		
TCDF	16.5-18	60,000	Hydrogen
TCDF	20	75,000	Hydrogen
TCDF	23	100,000	Hydrogen
Reheat Units (Reheat is never offered for turbine-generators of less than 50 MW).			
TCSF	23	60,000	Hydrogen
TCSF	25-26	75,000	Hydrogen
TCDF	16.5-18	100,000	Hydrogen

1. SCSF - Single Case Single Flow Exhaust
TCSF - Tandem Compound Single Flow Exhaust
TCDF - Tandem Compound Double Flow Exhaust

Table 10
Turbine Throttle Steam Pressures and Temperatures

Unit Size, kW	Pressure Range, psig	Temperature Range, deg F
2,500 to 6,250	300 - 400	650 - 825
7,500 to 15,000	500 - 600	750 - 825
20,000 to 30,000	750 - 850	825 - 900
40,000 to 50,000	1,250 - 1,450	825 - 1,000
60,000 to 125,000	1,250 - 1,450	950 - 1,000 and 1,000 Reheat

5.5.2 Economic Breakpoints. Economic breakpoints exist primarily because of pressure classes and temperature limits of piping material that includes valves and fittings. General limits of steam temperature are 750 F (399 degrees C) for carbon steel, 850 degrees F (454 degrees C) for carbon molybdenum steel, 900 degrees F (482 degrees C) for 1/2 to 1 percent chromium - 1/2 percent molybdenum steel, 950 degrees F (510 degrees C) for 1-1/4 percent chromium - 1/2 percent molybdenum steel, and 1,000 degrees F (538 degrees C) for 2-1/4 percent chromium - 1 percent molybdenum. Throttle steam temperature is also dependent on moisture content of steam existing at the final stages of the turbine. Moisture content must be limited to not more than 10 percent to avoid excessive erosion of turbine blades. Traditional throttle steam conditions which have evolved and are in present use are shown in Table 11.

5.6 Turbine Exhaust Pressure. Typical turbine exhaust pressure is as shown in Table 12. The exhaust pressure of condensing turbines is dependent on available condenser cooling water inlet temperature. See Section 7, Steam Condenser, this manual.

Table 11
Typical Turbine Throttle Steam Pressure-Temperature Conditions

Pressure, psig	Temperature, degrees F
250	500 or 550
400	650 or 750
600	750 or 825
850	825 or 900
1,250	900 or 950
1,450	950 or 1,000
1,600	1,000

Table 12
Typical Turbine Exhaust Pressure

Turbine Type	Condensing In. Hg Abs.	Non-Condensing psig
Multivalve multistage	0.5 - 4.5	0 - 300
Superposed (topping)	--	200 - 600
Single valve multistage	1.5 - 4.0	0 - 300
Single valve single stage	2.5 - 3.0	1 - 100
Back pressure	--	5 - 300
Atmospheric pressure	--	0 - 50

5.7 Lubricating Oil Systems

5.7.1 Single Stage Turbines. The lubricating oil system for small, single stage turbines is self-contained, usually consisting of water jacketed, water-cooled, rotating ring-oiled bearings.

5.7.2 Multistage Turbines. Multistage turbines require a separate pressure lubricating oil system consisting of oil reservoir, bearing oil pumps, oil coolers, pressure controls, and accessories.

a) The oil reservoir's capacity shall provide a 5 to 10 minute oil retention time based on the time for a complete circuit of all the oil through the bearings.

b) Bearing oil pump types and arrangement are determined from turbine generator manufacturers' requirements. Turbine generators should be supplied with a main oil pump integral on the turbine shaft. This arrangement is provided with one or more separate auxiliary oil pumps for startup and emergency backup service. At least one of the auxiliary oil pumps shall be separately steam turbine driven or DC motor driven. For some hydrogen cooled generators, the bearing oil and hydrogen seal oil are served from the same pumps.

c) Where separate oil coolers are necessary, two full capacity, water cooled oil coolers shall be used. Turbine generator manufacturers' standard design for oil coolers is usually based on a supply of fresh cooling water at 95 degrees F (35 degrees C) at 125 psig (862 kPa gage). These design conditions shall be modified, if necessary, to accommodate actual cooling water supply conditions. Standard tube material is usually inhibited admiralty or 90-10 copper-nickel. Other tube materials are available, including 70-30 copper-nickel, aluminum-brass, arsenical copper, and stainless steel.

5.7.3 Oil Purifiers. Where a separate turbine oil reservoir and oil coolers are used, a continuous bypass purification system with a minimum flow rate per hour equal to 10 percent of the turbine oil capacity shall be used. Refer to ASME Standard LOS-1M, ASTM-ASME-NEMA Recommended Practices for the Cleaning, Flushing, and Purification of Steam and Gas Turbine Lubricating Systems. The purification system shall be either one of the following types.

5.7.3.1 Centrifuge With Bypass Particle Size Filter. See Figure 20 for arrangement of equipment. Because of the additives contained in turbine oils, careful selection of the purification equipment is required to avoid the possibility of additive removal by use of certain types of purification equipment such as clay filters or heat and vacuum units. Both centrifuge and particle size filters are suitable for turbine oil purification. Particle filters are generally sized for not less than 5 microns to avoid removal of silicone foam inhibitors if present in the turbine oil used. The centrifuge is used periodically for water removal from the turbine oil. The particle filter, usually of the cellulose cartridge type, is used continuously except during times the centrifuge is used.

5.7.3.2 Multistage Oil Conditioner. See Figure 21 for arrangement of equipment. The typical multistage conditioner consists of three stages: a precipitation compartment where gross free water is removed by detention time and smaller droplets are coalesced on hydrophobic screens, a gravity filtration compartment containing a number of cloth-covered filter elements, and a storage compartment which contains a polishing filter consisting of multiple cellulose cartridge filter elements. The circulating pump receives oil from the storage compartment and pumps the oil through the polishing filter and back to the turbine oil reservoir. The storage compartment must be sized to contain the flowback oil quantity contained in the turbine generator bearings and oil supply piping. The oil conditioner in this type of purification system operates continuously.

5.7.4 Lubricating Oil Storage Tanks. As a minimum, provide one storage tank and one oil transfer pump. The storage tank capacity should be equal to, or greater than the largest turbine oil reservoir. The transfer pump is used to transfer oil between the turbine oil reservoir and the storage tank. The single tank can be used to receive oil from, or return oil to the turbine oil reservoir. Usually a separate portable oil filter press is used for oil purification of used oil held in the storage tank. Two storage tanks can be provided when separate tanks are desired for separate storage of clean and used oil. This latter arrangement can also be satisfied by use of a two-compartment single tank. Only one set of storage tanks and associated transfer pump is needed per plant. However, it may be necessary to provide an additional oil transfer pump by each turbine oil reservoir, depending on plant arrangement.

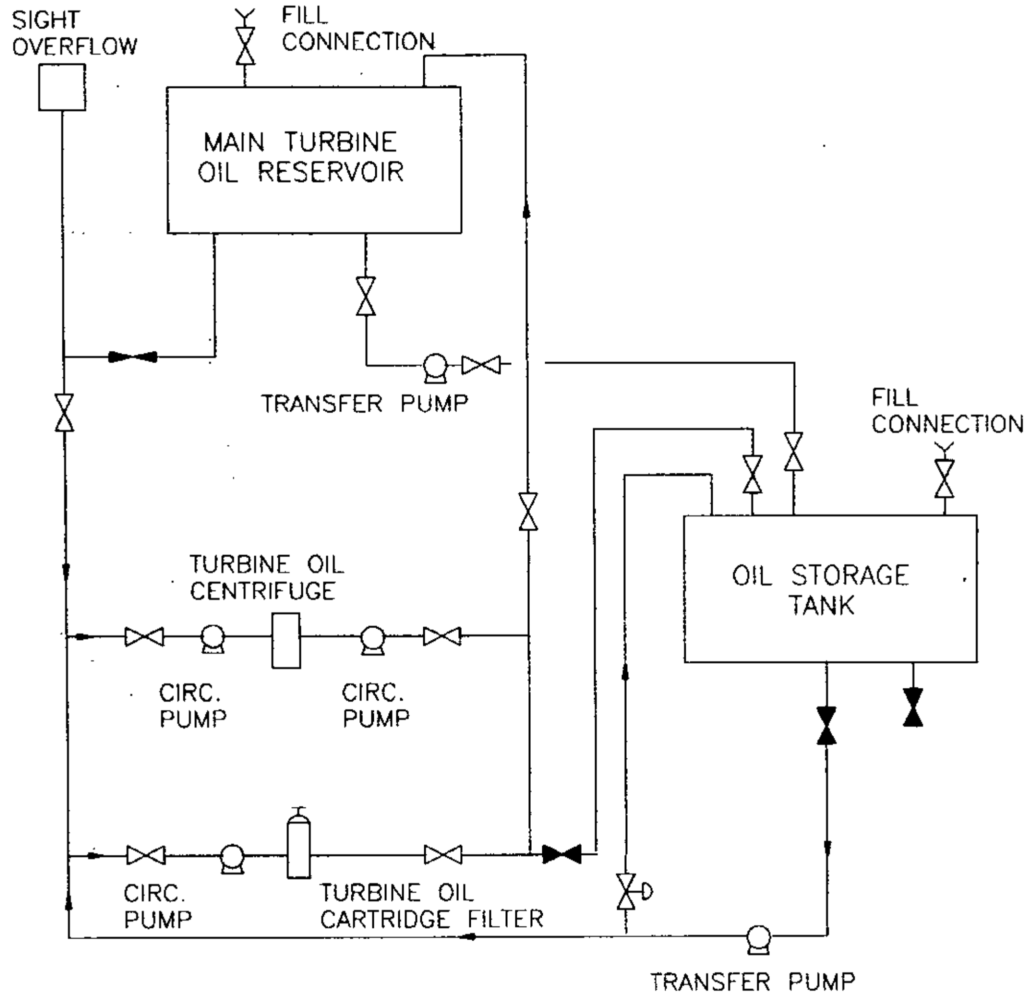


Figure 20
Oil Purification System with Centrifuge

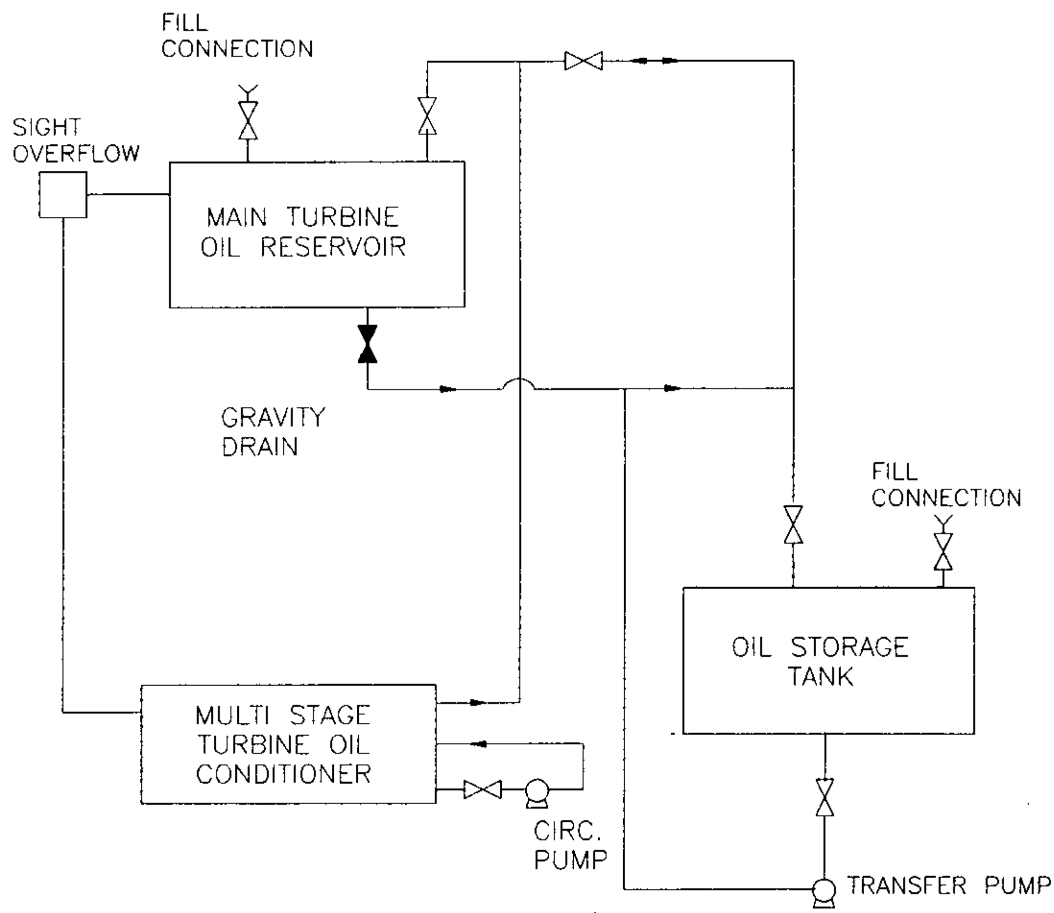


Figure 21
Oil Purification System with Multistage Conditioner

5.7.5 Lubricating Oil System Cleaning. Refer to ASME Standard LOS-1M.

5.8 Generator Types. Generators are classified as either synchronous (AC) or direct current (DC) machines. Synchronous generators are available for either 60 cycles (usually used in U.S.A.) or 50 cycles (frequently used abroad). Direct current generators are used for special applications requiring DC current in small quantities and not for electric power production.

5.9 Generator Cooling

5.9.1 Self Ventilation. Generators, approximately 2,000 kVA and smaller, are air cooled by drawing air through the generator by means of a shaft-mounted propeller fan.

5.9.2 Air Cooled. Generators, approximately 2,500 kVA to 25,000 kVA, are air cooled with water cooling of air coolers (water-to-air heat exchangers) located either horizontally or vertically within the generator casing. Coolers of standard design are typically rated for 95 degrees F (35 degrees C) cooling water at a maximum pressure of 125 psig (862 kPa gage) and supplied with 5/8-inch minimum 18 Birmingham wire gage (BWG) inhibited admiralty or 90-10 copper-nickel tubes. Design pressure of 300 psig (2068 kPa gage) can be obtained as an alternate. Also, alternate tube materials such as aluminum-brass, 70-30 copper-nickel, or stainless steel are available.

5.9.3 Hydrogen Cooled. Generators, approximately 30,000 kVA and larger, are hydrogen cooled by means of hydrogen to air heat exchangers. The heat exchangers are similar in location and design to those for air-cooled generators. Hydrogen pressure in the generator casing is typically 30 psig (207 kPa gage).

5.10 Turbine Generator Control. For turbine generator control description, see Section 11,"Controls and Instrumentation" of this handbook.

5.11 Turning Gear. In order to thermally stabilize turbine rotors and avoid rotor warpage, the rotors of turbine generators size 12,500 kW and larger are rotated by a motor-driven turning gear at a speed of approximately 5 rpm immediately upon taking the turbine off the line. The rotation of the turbine generator rotor by the turning gear is continued through a period of several hours to several days, depending on the size of the turbine and the initial throttle temperature, until the turbine shaft is stabilized. The turning gear and turbine generator rotor are then stopped until the turbine generator is about to be again placed in service. Before being placed in service, the turbine generator rotor is again stabilized by turning gear rotation for several hours to several days, depending on the turbine size.

Turbine generators smaller than 12,500 kW are not normally supplied with a turning gear, since the normal throttle steam temperature is such that a turning gear is not necessary. However, should a turbine be selected for operation at higher than usual throttle steam temperature, a turning gear would be supplied.

During turning gear operation, the turbine generator bearings are lubricated by use of either the main bearing oil pump or a separate turning gear oil pump, depending on size and manufacturer of the turbine generator.

5.12 Turbine Generator Foundations. Turbine generator foundations shall be designed in accordance with MIL-HDBK-1002/2, Loads, para.6.4.

5.13 Auxiliary Equipment. For description of steam jet air ejectors, mechanical air exhausters, and steam operated hogging ejectors, see Section 7, Steam Condensers, of this handbook.

5.14 Installation. Instructions for turbine generator installation are definitive for each machine and for each manufacturer. For turbine generators, 2,500 kW and larger, these instructions shall be specially prepared for each machine by the turbine generator manufacturer and copies (usually up to 25 copies) shall be issued to the purchaser.

The purchase price of a turbine generator shall include technical installation, start-up, and test supervision furnished by the manufacturer at the site of installation.

5.15 Cleanup, Startup, and Testing

5.15.1 Pipe Cleaning

5.15.1.1 Boiler Chemical Boil out. Chemical or acid cleaning is the quickest and most satisfactory method for the removal of water side deposits. Competent chemical supervision should be provided, supplemented by consultants on boiler-water and scale problems during the chemical cleaning process. In general, four steps are required in a complete chemical cleaning process for a boiler.

a) The internal heating surfaces are washed with an acid solvent containing a proper inhibitor to dissolve the deposits completely or partially and to disintegrate them.

b) Clean water is used to flush out loose deposits, solvent adhering to the surface, and soluble iron salts. Any corrosive or explosive gases that may have formed in the unit are displaced.

c) The unit is treated to neutralize and "passivate" the heating surfaces. The passivation treatment produces a passive surface or forms a very thin protective film on ferrous surfaces so that formation of "after-rust" on freshly cleaned surfaces is prevented.

d) The unit is flushed with clean water as a final rinse to remove any remaining loose deposits.

The two generally accepted methods in chemical cleaning are continuous circulation and soaking.

e) Continuous Circulation. In the circulation method, after filling the unit, the hot solvent is recirculated until cleaning is completed. Samples of the return solvent are tested periodically during the cleaning. Cleaning is considered complete when the acid strength and the iron content of the returned solvent reach equilibrium indicating that no further reaction with the deposits is taking place. The circulation method is particularly suitable for cleaning once-through boilers, superheaters, and economizers with positive liquid flow paths to assure circulation of the solvent through all parts of the unit.

f) Soaking. In cleaning by the soaking method after filling with the hot solvent, the unit is allowed to soak for a period of four to eight hours, depending on deposit conditions. To assure complete removal of deposits, the acid strength of the solvent must be somewhat greater than that required by the actual conditions, since, unlike the circulation method, control testing during the course of the cleaning is not conclusive, because samples of solvent drawn from convenient locations may not truly represent conditions in all parts of the unit. The soaking method is preferable for cleaning units where definite liquid distribution to all circuits by the circulation method is not possible without the use of many chemical inlet connections or where circulation through all circuits at an appreciable rate cannot be assured, except by using a circulating pump of impractical size.

5.15.1.2 Main Steam Blowout. The main steam lines, reheat steam lines, auxiliary steam lines from cold reheat and auxiliary boiler, and all main turbine seal steam lines shall be blown with steam after erection and chemical cleaning until all visible signs of mill scale, sand, rust, and other foreign substances are blown free. Cover plates and internals for the main steam stop valves, reheat stop, and intercept valves, shall be removed. Blanking fixtures, temporary cover plates, temporary vent and drain piping, and temporary hangers and braces to make the systems safe during the blowing operation shall be installed.

After blowing, all temporary blanking fixtures, cover plates, vent and drain piping, valves, hangers, and braces shall be removed. The strainers, valve internals, and cover plates shall be reinstalled. The piping systems, strainers, and valves shall be restored to a state of readiness for plant operation.

a) Temporary Piping. Temporary piping shall be in stalled at the inlet to the main turbine and the boiler feed pump turbine to facilitate blowout of the steam to the outdoors. Temporary piping shall be designed in accordance with the requirements of the Power Piping Code, ANSI/ASME B31.1. The temporary piping and valves shall be sized to obtain a cleaning ratio of 1.0 or greater in all permanent piping to be cleaned. The cleanout ratio is determined using the following equation.

EQUATION: $$R = (Q_c/Q_m)^2 \times [(P_v)_c/(P_v)_m] \times (P_m/P_c] \qquad (4)$$

where:

- R = Cleaning ratio
- Q_c = Flow during cleaning, lb/h
- Q_m = Maximum load flow, lb/h
- $(P_v)_c$ = Pressure-specific volume product during cleaning at boiler outlet, ft^3/in^2.
- $(P_v)_m$ = Pressure-specific volume product at maximum load flow at boiler outlet, ft^3/in^2
- P_m = Pressure at maximum load flow at boiler outlet, psia
- P_c = Pressure during cleaning at boiler outlet, psia

This design procedure is applicable to fossil fuel-fired power plants, And is written specifically for drum (controlled circulation) type boilers but may be adapted to once-through (combined circulation) type boilers by making appropriate modifications to the procedure. The same basic concepts for cleaning piping systems apply to all boiler types.

b) Blowout Sequence. Boiler and turbine manufacturers provide a recommended blowout sequence for the main and reheat steam lines.

The most satisfactory method for cleaning installed piping is to utilize the following cleaning cycle:

(1) Rapid heating (thermal shock helps remove adhered particles).

(2) High velocity steam blowout to atmosphere.

(3) Thermal cool down prior to next cycle.

The above cycle is repeated until the steam emerging from the blowdown piping is observed to be clean.

5.15.1.3 Installation of Temporary Strainers. Temporary strainers shall be installed in the piping system at the suction of the condensate and boiler feed pumps to facilitate removal of debris within the piping systems resulting from the installation procedures. The strainers shall be cleaned during the course of all flushing and chemical cleaning operations. The temporary strainers shall be removed after completion of the flushing and chemical cleaning procedures.

5.15.1.4 Condenser Cleaning. All piping systems with lines to the condenser should be completed and the lines to the condenser flushed with service water. Lines not having spray pipes in the condenser may be flushed into the condenser. Those with spray pipes should be flushed before making the connection to the condenser. Clean the interior of the condenser and hot well by vacuuming and by washing with an alkaline solution and flushing with hot water. Remove all debris. Open the condensate pump suction strainer drain valves and flush the pump suction piping. Prevent flush water from entering the pumps. Clean the pump suction strainers.

5.15.1.5 Condensate System Chemical Cleaning. Systems to be acid and alkaline cleaned are the condensate piping from condensate pump to deaerator discharge, boiler feedwater piping from deaerator to economizer inlet, feedwater heater tube sides; air preheat system piping, and chemical cleaning pump suction and discharge piping. Systems to be alkaline cleaned only, are the feedwater heater shell sides, building heating heat exchanger shell sides, and the feedwater heater drain piping. The chemicals and concentrations for alkaline cleaning are 1000 mg/L disodium phosphate, 2,000 mg/L trisodium phosphate, non-foaming wetting agent as required, and foam inhibitors as required. The chemicals and concentrations for acid cleaning are 2.0 percent hydroxyacetic acid, 1.0 percent formic acid, 0.25 percent ammonium bifluoride, and foaming inhibitors and wetting agents as required.

a) Deaerator Cleaning. Prior to installing the trays in the deaerator and as close to unit start-up as is feasible, the interior surfaces of the deaerator and deaerator storage tank shall be thoroughly cleaned to remove all preservative coatings and debris. Cleaning shall be accomplished by washing with an alkaline service water solution and flushing with hot service water. The final rinse shall be with demineralized water. After cleaning and rinsing, the deaerator and deaerator storage tank shall be protected from corrosion by filling with treated demineralized water.

b) Cycle Makeup and Storage System. The cycle makeup and storage system, condensate storage tank, and demineralized water storage tank shall be flushed and rinsed with service water. The water storage tanks should require only a general hose washing. The makeup water system should be flushed until the flush water is clear. After the service water flush, the cycle makeup and storage system shall be flushed with demineralized water until the flushing water has a clarity equal to that from the demineralizer.

c) Condensate-Feedwater and Air Preheat Systems. The condensate-feedwater and air preheat systems (if any) shall be flushed with service water. The condensate pumps shall be used for the service water flushing operations. Normal water level in the condenser should be maintained during the service water flushing operation by making up through the temporary service water fill line. After the service water flush, the condensate-feedwater and air preheat systems shall be flushed with demineralized water.

After the demineralized water flush, the condensate-feedwater and air preheat systems shall be drained and refilled with demineralized water.

d) Alkaline Cleaning. The condensate-feedwater and air preheat water systems shall be alkaline cleaned by injecting the alkaline solution into circulating treated water, preheated to 200 degrees F (93.3 degrees C) by steam injection, until the desired concentrations are established. The alkaline solution should be circulated for a minimum of 24 hours with samples taken during the circulation period. The samples should be analyzed for phosphate concentration and evidence of free oil. The feedwater heaters and drain piping shall be alkaline cleaned by soaking with hot alkaline cleaning solution in conjunction with the condensate-feedwater and air preheat water system alkaline cleaning. The heater shells and drain piping should be drained once every six hours during the circulation of the alkaline cleaning solution through the condensate-feedwater and air preheat water systems. After the alkaline cleaning is completed, flush the condensate-feedwater, air preheat water, feedwater heater, and drain piping systems with demineralized water.

e) Acid Cleaning. Acid cleaning of the condensate feedwater and air preheat water systems shall be similar to the alkaline cleaning, except that the circulation period shall only be six hours. The condensate-feedwater and air preheat water system shall be heated to 200 degrees F (93 degrees C) and hydrazine and ammonia injected into the circulating water to neutralize the acid solution. The systems shall then be flushed with demineralized water until all traces of acid are removed.

5.15.1.6 Turbine Lube Oil Flush and Recirculation. The lubricating and seal oil systems of the turbine generator shall be cleaned as recommended by the manufacturer. Oil samples shall be tested to determine contamination levels. The cleaning shall be a cold flushing of the system and cleaning of the oil reservoir. This shall be followed by cycling of circulating hot and cold oil until the system is clean.

5.15.2 Equipment Startup

5.15.2.1 Preliminary Checks. Preliminary checks and inspection, and any required corrective work shall be performed on all equipment in accordance with the equipment manufacturer's recommendations.

a) Shaft Alignment. All bearings, shafts, and other moving parts shall be checked for proper alignment.

b) Linkage Alignment. Manual set of all linkages shall be performed, ensuring open and close limit adjustment. Operational linkage adjustment shall be performed as required.

c) Safety Equipment. All coupling guards, belt guards, and other personnel safety items shall be installed.

d) Piping. All power actuated valves shall be checked for correct valve action and seating and the actuators and converters shall be given initial adjustment. All manual valves shall be operated to ensure correct operation and seating. All safety valves shall be checked for correct settings.

All piping shall be nondestructively tested, hydrostatically tested, leak tested, or air tested, as applicable, and shall be flushed or blown clean. All temporary shipping braces, blocks, or tie rods shall be removed from expansion joints. All spring type pipe hangers shall be checked for proper cold settings.

e) Pits. All pump suction pits shall be free of trash.

f) Lubrication. Each lubricating oil system shall be flushed and the filters inspected. All oil tanks, reservoirs, gear cases, and constant level type oilers shall be checked for proper oil levels. All points requiring manual lubrication shall be greased or oiled as required.

g) Belts, Pulleys, and Sheaves. All belts, pulleys, and sheaves shall be checked for correct alignment and belt tension.

h) Cooling and Sealing Water. All cooling and sealing water supplies shall be flushed and checked for proper operation.

i) Pump Suction Strainers. All pump suction strainers shall be installed.

j) Stuffing Boxes and Packing. All stuffing boxes shall be checked for correct takeup on the packing.

k) Mechanical Seals. All mechanical seals shall be removed as required to ensure clean sealing surfaces prior to starting. Seal water piping shall be cleaned to the extent necessary to ensure no face contamination. Seal adjustments shall be performed as required by the manufacturer.

l) Tanks and Vessels. All tanks and vessels shall be thoroughly inspected internally before securing.

5.15.2.2 Initial Plant Startup. The following steps shall be followed for plant startup:

a) Operate demineralizer and fill condensate storage/return tank.

b) Fill boiler, deaerator, and condenser.

c) Start boiler feed pumps.

d) Warm up boiler using manufacturer's recommendations.

e) Start cooling water system pumps.

f) Start condensate pumps.

g) Start condenser exhauster (air ejectors).

h) Start turbine lubricating oil system.

i) Roll turbine using manufacturer's startup procedures.

5.15.3 Testing. For testing requirements, see Section 19 this handbook.

5.16 Operation

5.16.1 Trial Operation. After all preliminary checks and inspections are completed, each piece of equipment shall be given a trial operation. Trial operation of all equipment and systems shall extend over such period of time as is required to reveal any equipment weaknesses in bearings, cooling systems, heat exchangers, and other such components, or any performance deficiencies which may later handicap the operation of main systems and the complete plant. All rotating equipment shall be checked for overheating, noise, vibration, and any other conditions which would tend to shorten the life of the equipment.

5.16.2 Main System Operation. Main systems should be trial operated and tested after each individual piece of equipment has been trial operated and ready for operation. All functional and operational testing of protective interlocking, automatic controls, instrumentation, alarm systems, and all other field testing should be conducted during initial plant startup. All piping should be visually inspected for leaks, improper support adjustment, interferences, excessive vibration, and other abnormal conditions. Steam traps should be verified for proper operation and integral strainers cleaned.

5.16.3 Operation Control. A system of control to protect personnel and equipment as the permanent plant equipment and systems are completed and capable of energization, pressurization, or being operated, should be established. The system should consist of placing appropriate tags on all equipment and system components. Tags should indicate status and the mandatory clearances required from designated personnel to operate, pressurize, energize, or remove from service such equipment or systems. The controls established should encompass the following phases.

a) Equipment or systems completed to the point where they may be energized, pressurized, or operated, but not yet checked out, shall be tagged.

The sources of power or pressure shall be turned off and tagged.

b) Equipment and systems released for preoperational check-out shall be so tagged. When a request to remove from service is made, all controls and sources of power or pressure shall be tagged out and shall not be operated under any circumstances.

Section 6. GENERATOR AND ELECTRICAL FACILITIES DESIGN

6.1 Typical Voltage Ratings and Systems

6.1.1 Voltages

6.1.1.1 General. Refer to ANSI Standard C84.1, Electric Power Systems and Equipment - Voltage Rating, for voltage ratings for 60 Hz electric power systems and equipment. In addition, the standard lists applicable motor and motor control nameplate voltage ranges up to nominal system voltages of 13.8 kV.

6.1.1.2 Generators. Terminal voltage ratings for power plant generators depend on the size of the generators and their application. Generally, the larger the generator, the higher the voltage. Generators for a power plant serving an installation will be in the range from 4160 volts to 13.8 kV to suit the size of the unit and primary distribution system voltage. Generators in this size range will be offered by the manufacturer in accordance with its design, and it would be difficult and expensive to get a different voltage rating. Insofar as possible, the generator voltage should match the distribution voltage to avoid the installation of a transformer between the generator and the distribution system.

6.1.1.3 Power Plant Station Service Power Systems

a) Voltages for station service power supply within steam electric generating stations are related to motor size and, to a lesser extent, distances of cable runs. Motor sizes for draft fans and boiler feed pumps usually control the selection of the highest station service power voltage level. Rules for selecting motor voltage are not rigid but are based on relative costs. For instance, if there is only one motor larger than 200 hp and it is, say, only 300 hp, it might be a good choice to select this one larger motor for 460 volts so that the entire auxiliary power system can be designed at the lower voltage.

b) Station service power requirements for combustion turbine and internal combustion engine generating plants are such that 208 or 480 volts will be used.

6.1.1.4 Distribution System. The primary distribution system with central in-house generation should be selected in accordance with MIL-HDBK-1004/1.

6.1.2 Station Service Power Systems

6.1.2.1 General. Two types of station service power systems are generally in use in steam electric plants and are discussed herein. They are designated as a common bus system and a unit system. The distinction is based on the relationship between the generating unit and the auxiliary transformer supplying power for its auxiliary equipment.

a) In the common bus system the auxiliary transformer will be connected through a circuit breaker to a bus supplied by a number of units and other sources so that the supply has no relationship to the generating unit whose auxiliary equipment is being served. In the unit system the auxiliary transformer will be connected solidly to the generator leads and is switched with the generator. In either case, the auxiliary equipment for each generating unit usually will be supplied by a separate transformer with appropriate interconnections between the secondary side of the transformers.

b) The unit type system has the disadvantage that its station service power requirements must be supplied by a startup transformer until the generating unit is synchronized with the system. This startup transformer also serves as the backup supply in case of transformer failure. This arrangement requires that the station service power supply be transferred from the startup source to the unit source with the auxiliary equipment in operation as a part of the procedure of starting the unit.

c) The advantages of the unit system are that it reduces the number of breakers required and that its source of energy is the rotating generating unit so that, in case of system trouble, the generating unit and its auxiliaries can easily be isolated from the rest of the system. The advantage of switching the generator and its auxiliary transformer as a unit is not very important, so the common bus system will normally be used.

6.1.2.2 Common Bus System. In this system, generators will be connected to a common bus and the auxiliary transformers for all generating units will be fed from that common bus. This bus may have one or more other power sources to serve for station startup.

a) Figure 22 is a typical one-line diagram for such a system. This type system will be used for steam turbine or diesel generating plants with all station service supplied by two station service transformers with no isolation between auxiliaries for different generating units. It also will be used for gas turbine generating plants. For steam turbine generating plants the auxiliary loads for each unit in the plant will be isolated on a separate bus fed by a separate transformer. A standby transformer is included, and it serves the loads common to all units such as building services.

b) The buses supplying the auxiliaries for the several units shall be operated isolated to minimize fault current and permit use of lower interrupting rating on the feeder breakers. Provision shall be made for the standby transformer to supply any auxiliary bus.

6.1.2.3 Unit Type System. The unit type station service power system will beused for a steam electric or combustion turbine generating station serving

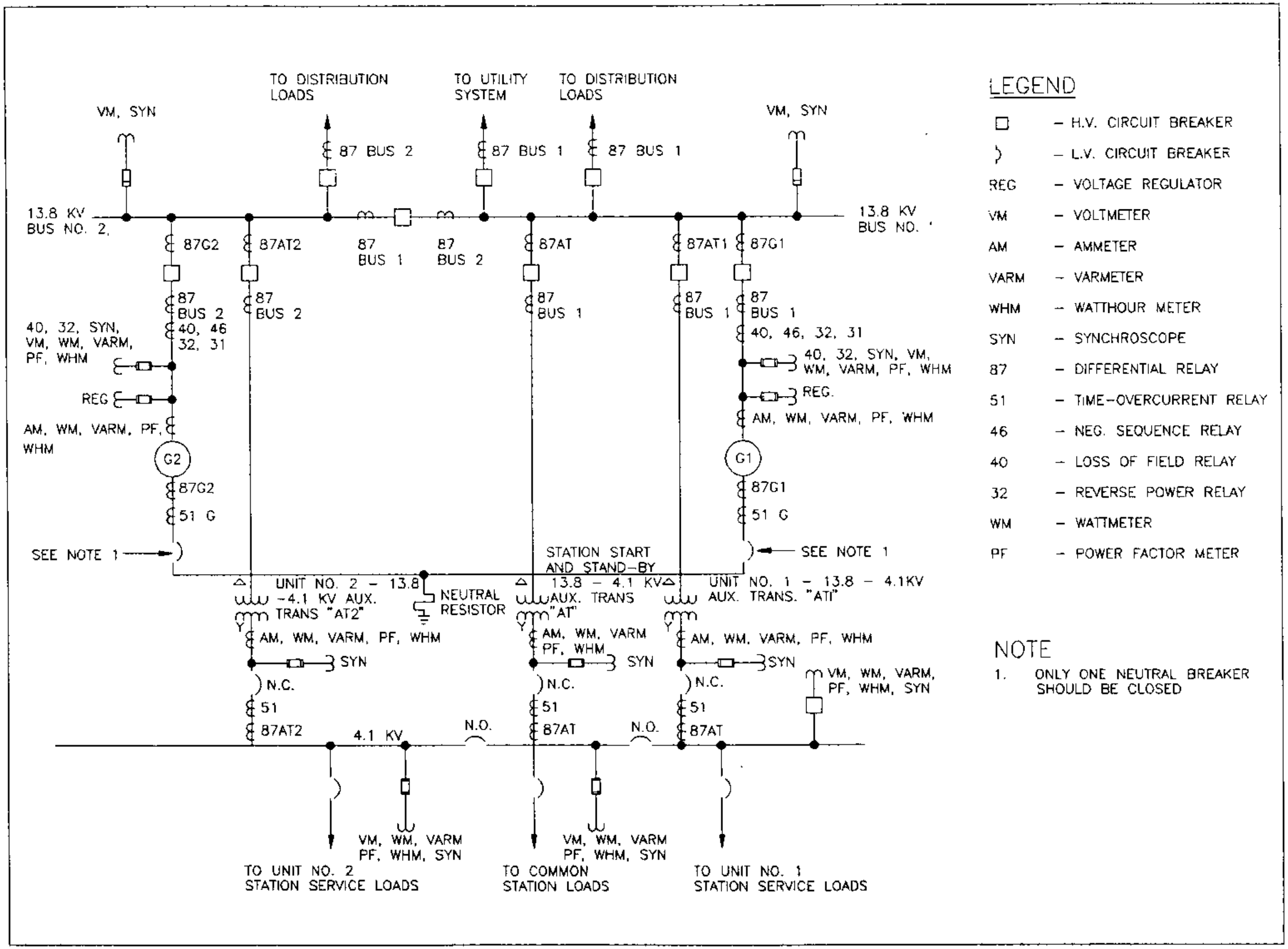


Figure 22

Station Connections, 2-Unit Stations Common Bus Arrangement a utility transmission network. It will not be, as a rule, used for a diesel generating station of any kind, since the station service power requirements are minimal.

The distinguishing feature of a unit type station power system is that the generator and unit auxiliary transformer are permanently connected together at generator voltage and the station service power requirements for that generating unit, including boiler and turbine requirements, are normally supplied by the auxiliary transformer connected to the generator leads. This is shown in Figure 23. If the unit is to be connected to a system voltage that is higher than the generator voltage, the unit concept can be extended to include the step-up transformer by tying its low side solidly to the generator leads and using the high side breaker for synchronizing the generator to the system. This arrangement is shown in Figure 24.

6.1.2.4 Station Service Switchgear. A station service switchgear lineup will be connected to the low side of the auxiliary transformer; air circuit breakers will be used for control of large auxiliary motors such as boiler feed pumps, fans, and circulating water pumps which use the highest station service voltage, and for distribution of power to various unit substations and motor control centers to serve the remaining station service requirements. Figure 25 is a typical one-line diagram of this arrangement. If the highest level of auxiliary voltage required is more than 480 volts, say 4.16 kV, the auxiliary switchgear air circuit breakers will only serve motors 250 hp and larger, and feeders to unit substations. Each unit sub station will include a transformer to reduce voltage from the highest auxiliary power level to 480 volts together with air circuit breakers in a lineup for starting of motors 100 to 200 hp and for serving 480-volt motor control centers. The motor control centers will include combination starters and feeders breakers to serve motors less than 100 hp and other small auxiliary circuits such as power panels.

6.1.2.5 Startup Auxiliary Transformer. In addition to the above items, the unit auxiliary type system will incorporate a "common" or "startup" arrangement which will consist of a startup and standby auxiliary transformer connected to the switchyard bus or other reliable source, plus a low voltage switchgear and motor control center arrangement similar to that described above for the unit auxiliary system. The common bus system may have a similar arrangement for the standby transformer.

a) This common system has three principal functions:

(1) To provide a source of normal power for power plant equipment and services which are common to all units; e.g., water treating system, coal and ash handling equipment, air compressors, lighting, shops, and similar items.

(2) To provide backup to each auxiliary power system segment if the transformer supplying that segment fails or is being maintained.

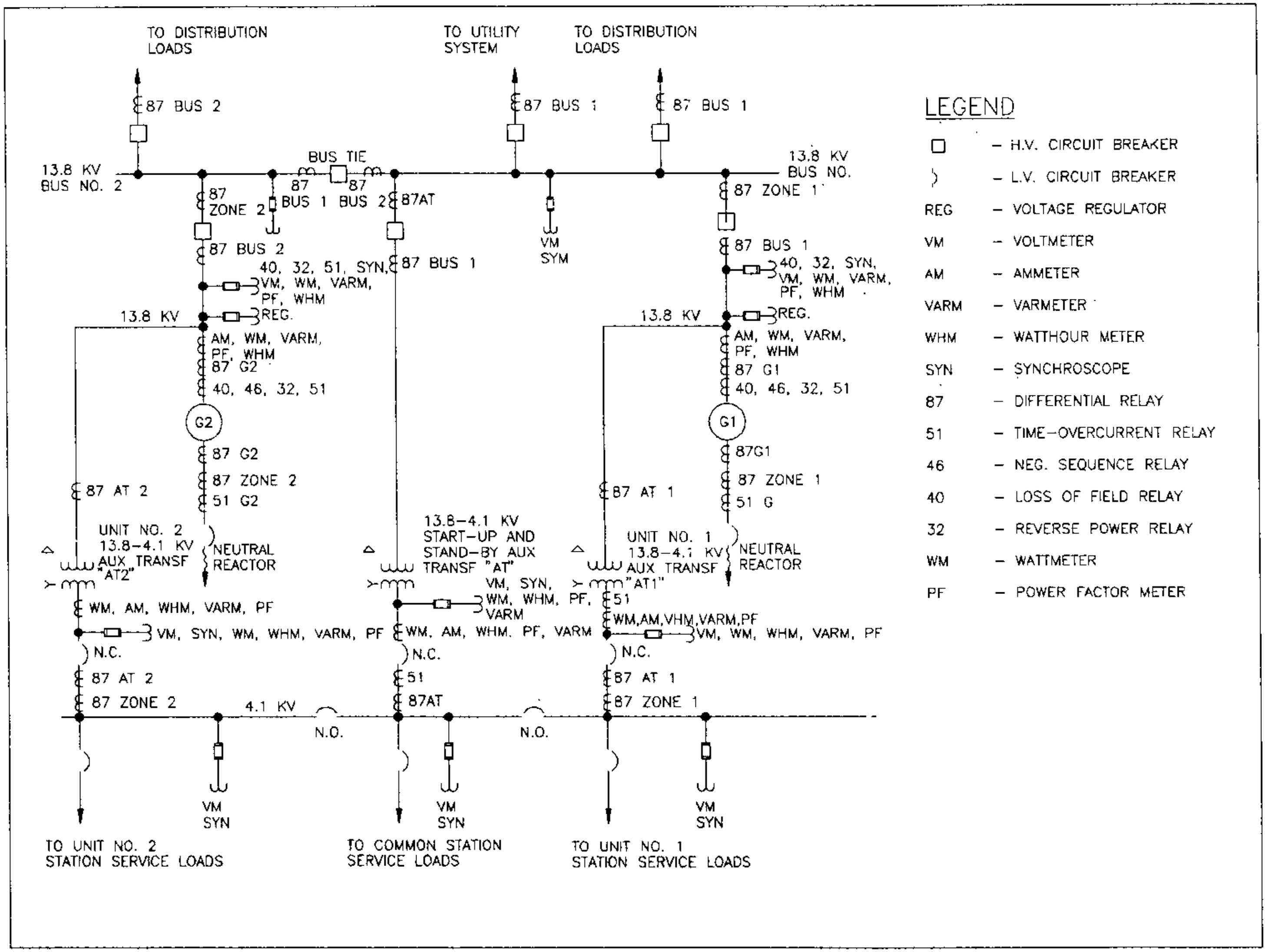


Figure 23
Station Connections, 2-Unit Stations,
Unit Arrangement Generation at Distribution Voltage

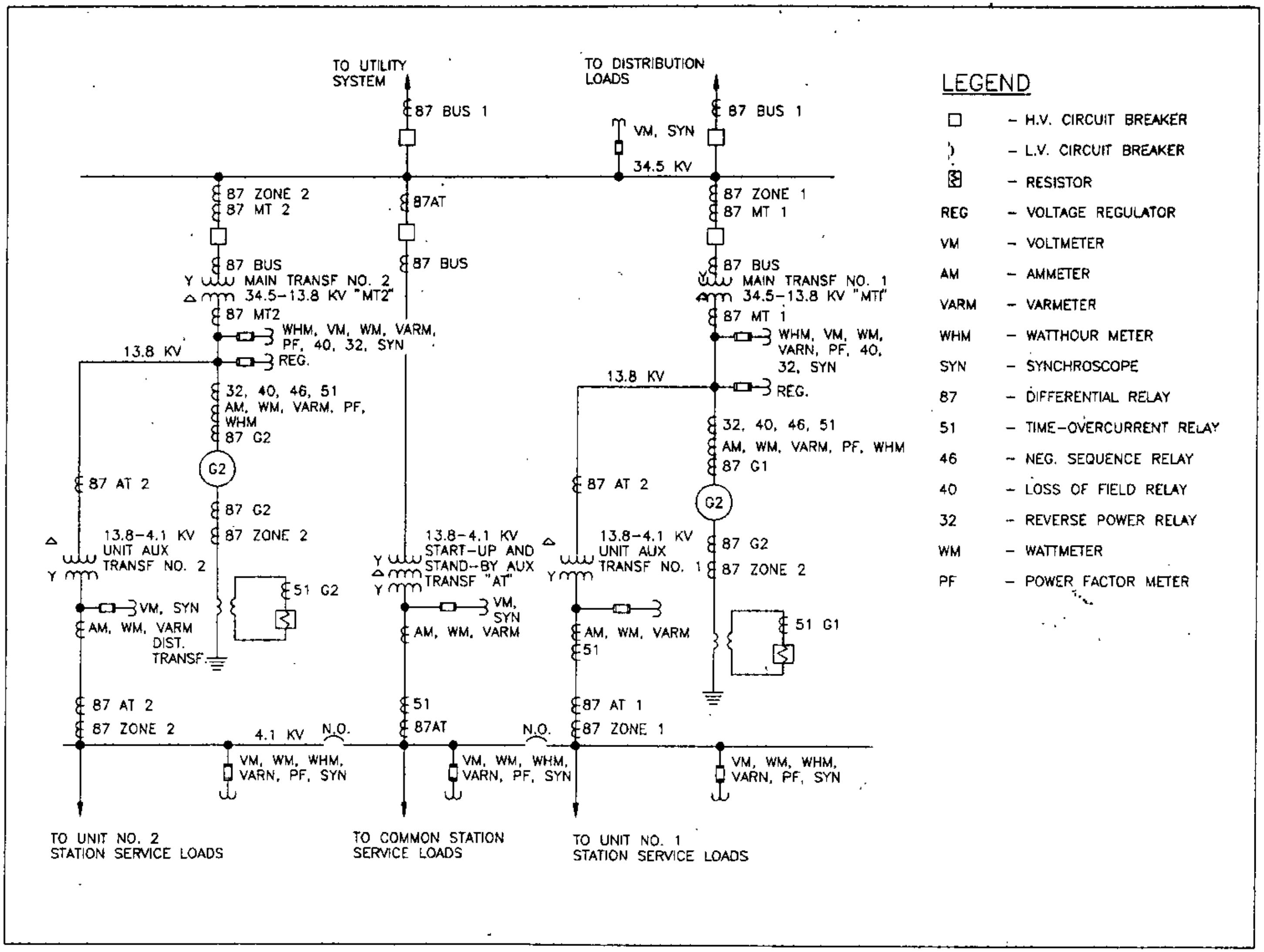


Figure 24
Station Connections, 2-Unit Stations, Unit Arrangement Distribution Voltage Higher than Generation

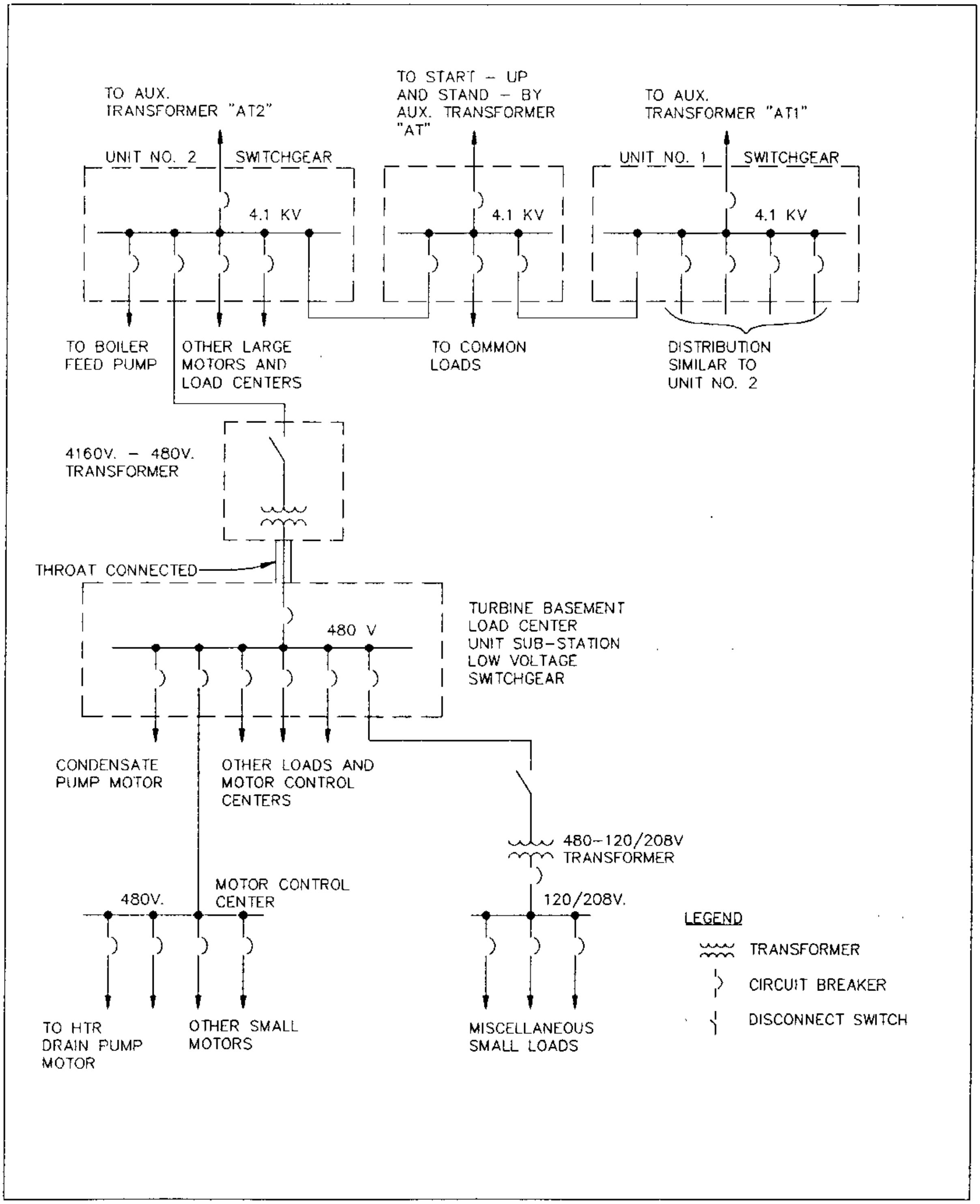


Figure 25
One-Line Diagram Typical Station Service Power Systems

(3) In the case of the unit system, to provide startup power to each unit auxiliary power system until the generator is up to speed and voltage and is synchronized with the distribution system.

b) The startup and standby transformer and switchgear will be sized to accomplish the above three functions and, in addition, to allow for possible future additions to the plant. Interconnections will be provided between the common and unit switchgear. Appropriate interlocks will be included, so that no more than one auxiliary transformer can feed any switchgear bus at one time.

6.2 Generators

6.2.1 General Types and Standards

6.2.1.1 Type: Generators for power plant service can be generally grouped according to service and size.

a) Generators for steam turbine service rated 5,000-32,000 kVA, are revolving field, non-salient, two-pole, totally enclosed, air-cooled with water cooling for air coolers, direct connected, 3,600 rpm for 60 Hz frequency (sometimes connected through a gear reducer up to 10,000 kVA or more). Self-ventilation is provided for generators larger than 5,000 kVA by some manufacturers, but this is not recommended for steam power plant service.

b) Similar generators rated 5,000 kVA and below are revolving field, non-salient or salient pole, self-ventilated, open drip-proof type, sometimes connected through a gear reducer to the turbine with the number of poles dependent on the speed selected which is the result of an economic evaluation by the manufacturer to optimize the best combination of turbine, gear, and generator.

c) Generators for gas turbine service are revolving field, nonsalient or salient pole, self-ventilated, open drip-proof type, sometimes connected through a gear reducer, depending on manufacturer's gas turbine design speed, to the gas turbine power takeoff shaft. Non-salient pole generators are two-pole, 3,600 rpm for 60Hz, although manufacturers of machines smaller than 1,500 kVA may utilize 1,800 rpm, four-pole, or 1,200 rpm, six-pole, salient pole generators. Generators may be obtained totally enclosed with water cooling, if desired, because of high ambient temperatures or polluted atmosphere.

d) Generators for diesel service are revolving field, salient pole, air-cooled, open type, direct connected, and with amortisseur windings to dampen pulsating engine torque. Number of poles is six or more to match low speeds typical of diesels.

6.2.1.2 Standards. Generators shall meet the requirements of ANSI C50.10, C50.13, and C50.14. These are applicable as well as the requirements of National Electrical Manufacturers Association (NEMA) SM 23, Steam Turbines for Mechanical Drive Service, and SM 24, Land Based Steam Turbine Generator sets 0 to 33,000 KW.

a) ANSI C84.1 designates standard voltages as discussed in Section 1.

b) Generator kVA rating for steam turbine generating units is standardized as a multiplier of the turbine kW rating. Turbine rating for a condensing steam turbine with controlled extraction for feedwater heating is the kW output at design initial steam conditions, 3.5 inches Hg (12 kPa) absolute exhaust pressure, three percent cycle makeup, and all feedwater heaters in service. Turbine rating for a noncondensing turbine without controlled or uncontrolled extraction is based on output at design initial steam conditions and design exhaust pressure. Turbine standard ratings for automatic extraction units are based on design initial steam conditions and exhaust pressure with zero extraction while maintaining rated extraction pressure. However, automatic extraction turbine ratings are complicated by the unique steam extraction requirements for each machine specified. For air-cooled generators up to 15,625 kVA, the multiplier is 1.25 times the turbine rating, and for 18,750 kVA air-cooled and hydrogen-cooled generators, 1.20. These ratings are for water-cooled generators with 95 degrees F (35 degrees C) maximum inlet water to the generator air or hydrogen coolers. Open, self-ventilated generator rating varies with ambient air temperature; standard rating usually is at 104 degrees F (40 degrees C) ambient.

c) Generator ratings for gas turbine generating units are selected in accordance with ANSI Standards which require the generator rating to be the base capacity which, in turn, must be equal to or greater than the base rating of the turbine over a specified range of inlet temperatures. Non-standard generator ratings can be obtained at an additional price.

d) Power factor ratings of steam turbine driven generators are 0.80 for ratings up to 15,625 kVA and 0.85 for 17,650 kVA air-cooled and 25,600 kVA to 32,000 kVA air/water-cooled units. Standard power factor ratings for gas turbine driven air-cooled generators usually are 0.80 for machines up to 9,375 kVA and 0.90 for 12,500 to 32,000 kVA. Changes in air density, however, do not affect the capability of the turbine and generator to the same extent so that kW based on standard conditions and generator kVA ratings show various relationships. Power factors of large hydrogen cooled machines are standardized at 0.90. Power factor for salient pole generators is usually 0.80. Power factor lower than standard, with increased kVA rating, can be obtained at an extra price.

e) Generator short circuit ratio is a rough indication of generator stability; the higher the short circuit ratio, the more stable the generator under transient system load changes or faults. However, fast acting voltage regulation can also assist in achieving generator stability without the heavy expense associated with the high cost of building high short circuit ratios into the generator. Generators have standard short circuit ratios of 0.58 at rated kVA and power factor. If a generator has a fast acting voltage regulator and a high ceiling voltage static excitation system, this standard short circuit ratio should be adequate even under severe system disturbance conditions. Higher short circuit ratios are available at extra cost to provide more stability for unduly fluctuating loads which may be anticipated in the system to be served.

f) Maximum winding temperature, at rated load for standard generators, is predicated on operation at or below a maximum elevation of 3,300 feet; this may be upgraded for higher altitudes at an additional price.

6.2.2 Features and Accessories. The following features and accessories are available in accordance with NEMA standards SM 12 and SM 13 and will be specified as applicable for each generator:

6.2.2.1 Voltage Variations. Unit will operate with voltage variations of plus or minus 5 percent of rated voltage at rated kVA, power factor and frequency, but not necessarily in accordance with the standards of performance established for operation at rated voltage; i.e., losses and temperature rises may exceed standard values when operation is not at rated voltage.

6.2.2.2 Thermal Variations

a) Starting from stabilized temperatures and rated conditions, the armature will be capable of operating, with balanced current, at 130 percent of its rated current for 1 minute not more than twice a year; and the field winding will be capable of operating at 125 percent of rated load field voltage for 1 minute not more than twice a year.

b) The generator will be capable of withstanding, without injury, the thermal effects of unbalanced faults at the machine terminals, including the decaying effects of field current and DC component of stator current for times up to 120 seconds, provided the integrated product of generator negative phase sequence current squared and time (I_2^2t) does not exceed 30. Negative phase sequence current is expressed in per unit of rated stator current, and time in seconds. The thermal effect of unbalanced faults at the machine terminals includes the decaying effects of field current where protection is provided by reducing field current (such as with an exciter field breaker or equivalent) and DC component of the stator current.

6.2.2.3 Mechanical Withstand. Generator will be capable of withstanding, without mechanical injury any type of short circuit at its terminals for times not exceeding its short time thermal capabilities at rated kVA and power factor with 5 percent over rated voltage, provided that maximum phase current is limited externally to the maximum current obtained from the three-phase fault. Stator windings must withstand a normal high potential test and show no abnormal deformation or damage to the coils and connections.

6.2.2.4 Excitation Voltage. Excitation system will be wide range stabilized to permit stable operation down to 25 percent of rated excitation voltage on manual control. Excitation ceiling voltage on manual control will not be less than 120 percent of rated exciter voltage when operating with a load resistance equal to the generator field resistance, and excitation system will be capable of supplying this ceiling voltage for not less than 1 minute. These criteria, as set for manual control, will permit operation when on automatic control. Exciter response ratio as defined in ANSI/IEEE 100, Dictionary of Electrical & Electronic Terms, will not be less than 0.50.

6.2.2.5 Wave Shape. Deviation factor of the open circuit terminal voltage wave will not exceed 10 percent.

6.2.2.6 Telephone Influence Factor. The balanced telephone influence factor (TIF) and the residual component TIF will meet the applicable requirements of ANSI C50.13.

6.2.3 Excitation Systems. Rotating commutator exciters as a source of DC power for the AC generator field generally have been replaced by silicon diode power rectifier systems of the static or brushless type.

a) A typical brushless system includes a rotating permanent magnet pilot exciter with the stator connected through the excitation switchgear to the stationary field of an AC exciter with rotating armature and a rotating silicon diode rectifier assembly, which in turn is connected to the rotating field of the generator. This arrangement eliminates both the commutator and the collector rings. Also, part of the system is a solid state automatic voltage regulator, a means of manual voltage regulation, and necessary control devices for mounting on a remote panel. The exciter rotating parts and the diodes are mounted on the generator shaft; viewing during operation must utilize a strobe light.

b) A typical static system includes a three-phase excitation potential transformer, three single-phase current transformers, an excitation cubicle with field breaker and discharge resistor, one automatic and one manual static thyristor type voltage regulators, a full wave static rectifier, necessary devices for mounting on a remote panel, and a collector assembly for connection to the generator field.

6.3 Generator Leads and Switchyard

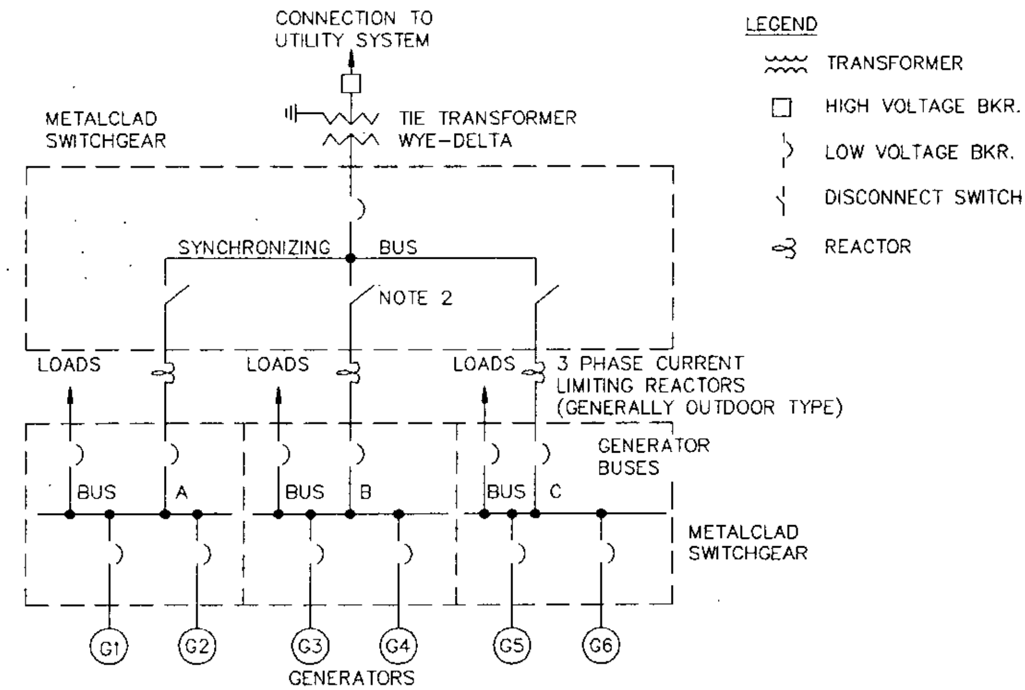
6.3.1 General. The connection of the generating units to the distribution system can take one of the following patterns:

a) With the common bus system, the generators are all connected to the same bus with the distribution feeders. If this bus operates at a voltage of 4.16 kV, this arrangement is suitable up to approximately 10,000 kVA. If the bus operates at a voltage of 13.8 kV, this arrangement is the best for stations up to about 25,000 or 32,000 kVA. For larger stations, the fault duty on the common bus reaches a level that requires more expensive feeder breakers, and the bus should be split.

b) The bus and switchgear will be in the form of a factory fabricated metal clad switchgear as shown in Figure 22. For plants with multiple generators and outgoing circuits, the bus will be split for reliability using a bus tie breaker to permit separation of approximately one-half of the generators and lines on each side of the split.

c) A limiting factor of the common type bus system is the interrupting capacity of the switchgear. The switchgear breakers will be capable of interrupting the maximum possible fault current that will flow through them to a fault. In the event that the possible fault current exceeds the interrupting capacity of the available breakers, a synchronizing bus with current limiting reactors will be required. Switching arrangement selected will be adequate to handle the maximum calculated short circuit currents which can be developed under any operating routine that can occur. All possible sources of fault current; i.e., generators, motors, and outside utility sources, will be considered when calculating short circuit currents. In order to clear a fault, all sources will be disconnected. Figure 26 shows, in simplified single line format, a typical synchronizing bus arrangement. The interrupting capacity of the breakers in the switchgear for each set of generators is limited to the contribution to a fault from the generators connected to that bus section plus the contribution from the synchronizing bus and large (load) motors. Since the contribution from generators connected to other bus sections must flow through two reactors in series fault current will be reduced materially.

d) If the plant is 20,000 kVA or larger, and the area covered by the distribution system requires distribution feeders in excess of 2 miles, it may be advantageous to connect the generators to a higher voltage bus and feed several distribution substations from that bus with step-down substation transformers at each distribution substation as shown in Figure 24.



MULTIPLE GENERATORS CONNECTED TO COMMON BUSES (TWO GENS. PER BUS) WITH FEEDS TO DISTRIBUTION SYSTEM AT GENERATOR VOLTAGE

NOTE 1. IF NO UTILITY CONNECTION IS REQUIRED, THE SYNCHRONIZING BUS STILL FUNCTIONS TO CONNECT BUSES A, B, AND C.

NOTE 2. IN DRAWOUT TYPE METALCLAD SWITCHGEAR THESE DISCONNECTS CAN BE DUMMY BREAKERS TO PERMIT INSPECTION AND MAINTENANCE OF REACTORS AT MINIMUM COST. CIRCUIT BREAKERS ARE NOT REQUIRED.

Figure 26
Typical Synchronizing Bus

e) The configuration of the high voltage bus will be selected for reliability and economy. Alternative bus arrangements include main and transfer bus, ring bus, and breaker and a half schemes. The main and transfer arrangement, shown in Figure 27, is the lowest cost alternative but is subject to loss of all circuits due to a bus fault. The ring bus arrangement, shown in Figure 28, costs only slightly more than the main and transfer bus arrangement and eliminates the possibility of losing all circuits from a bus fault, since each bus section is included in the protected area of its circuit. Normally it will not be used with more than eight bus sections because of the possibility of simultaneous outages resulting in the bus being split into two parts. The breaker and a half arrangement, shown in Figure 29, is the highest cost alternative and provides the highest reliability without limitation on the number of circuits.

6.3.2 <u>Generator Leads</u>

6.3.2.1 <u>Cable</u>

a) Connections between the generator and switchgear bus where distribution is at generator voltage, and between generator and step up transformer where distribution is at 34.5 kV and higher, will be by means of cable or bus duct. In most instances more than one cable per phase will be necessary to handle the current up to a practical maximum of four conductors per phase. Generally, cable installations will be provided for generator capacities up to 25 MVA. For larger units, bus ducts will be evaluated as an alternative.

b) The power cables will be run in a cable tray, separate from the control cable tray, in steel conduit suspended from ceiling or on wall hangers, or in ducts, depending on the installation requirements.

c) Cable terminations will be made by means of potheads where lead covered cable is applied, or by compression lugs where neoprene or similarly jacketed cables are used. Stress cones will be used at 4.16 kV and above.

d) For most applications utilizing conduit, cross-linked polyethylene with approved type filler or ethylene-propylene cables will be used. For applications where cables will be suspended from hangers or placed in tray, armored cable will be used to provide physical protection. If the cable current rating does not exceed 400 amperes, the three phases will be triplexed; i.e., all run in one steel armored enclosure. In the event that single-phase cables are required, the armor will be nonmagnetic.

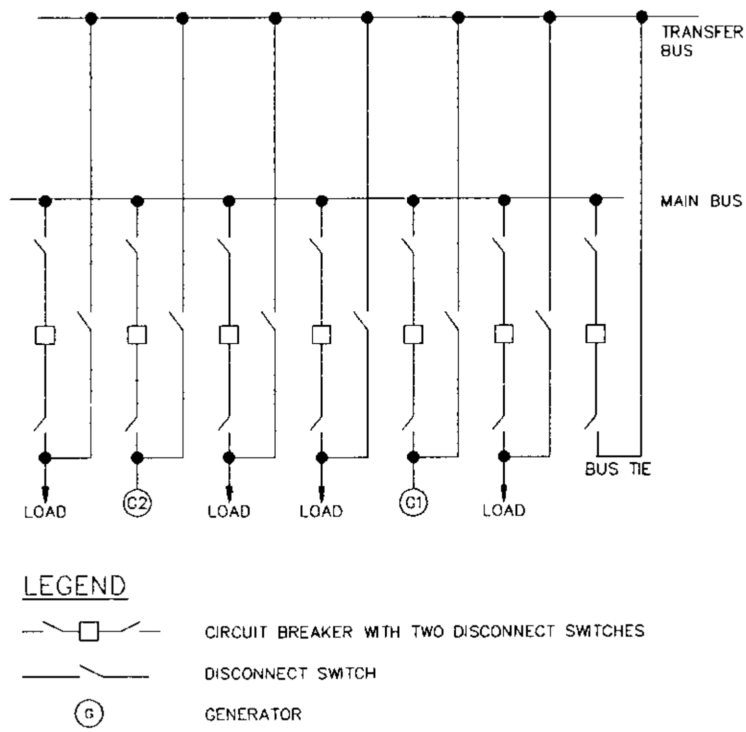


Figure 27
Typical Main and Transfer Bus

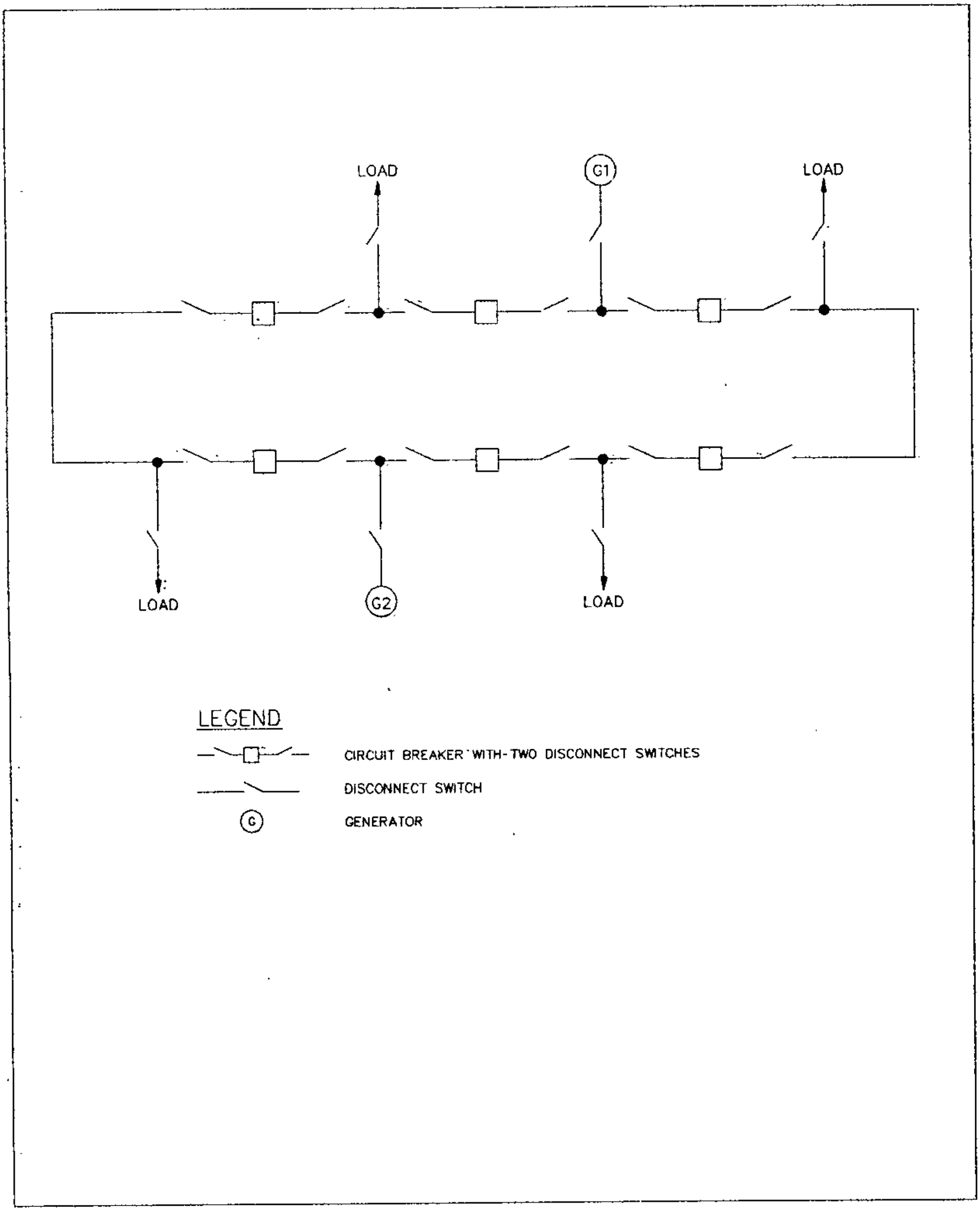


Figure 28
Typical Ring Bus

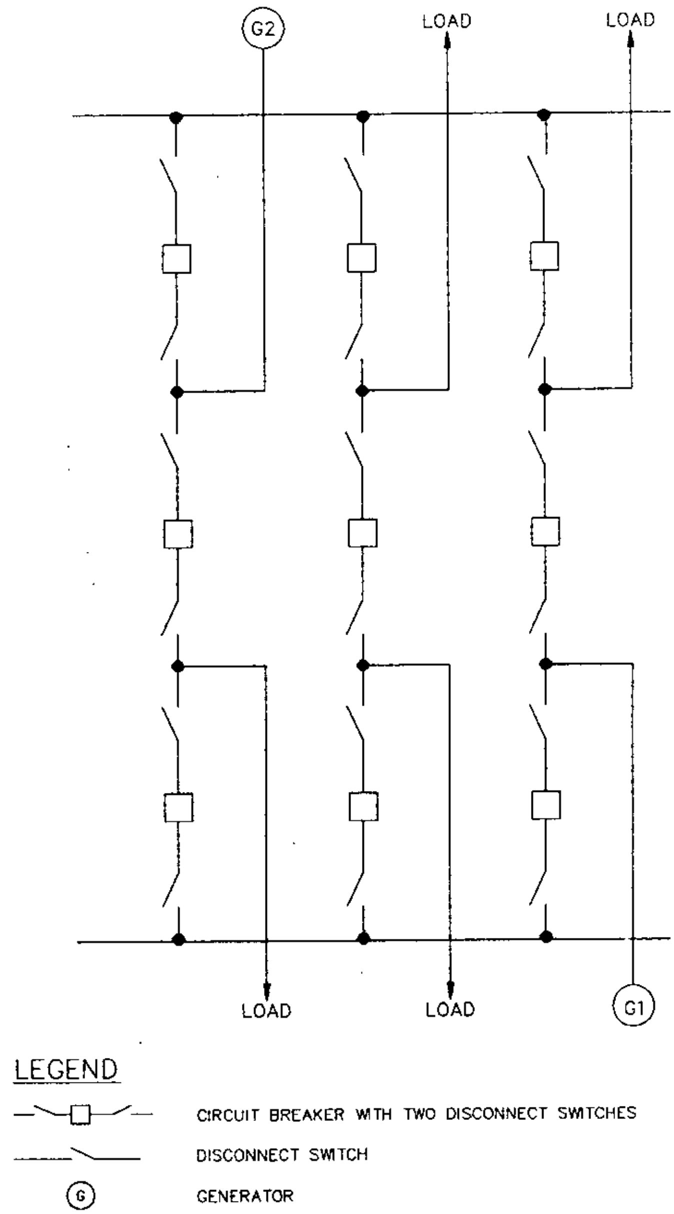


Figure 29
Typical Breaker and a Half Bus

e) In no event should the current carrying capacity of the power cables emanating from the generator be a limiting factor on turbine generator output. As a rule of thumb, the cable current carrying capacity will be at least 1.25 times the current associated with kVA capacity of the generator (not the kW rating of the turbine).

6.3.2.2 Segregated Phase Bus

a) For gas turbine generator installations the connections from the generator to the side wall or roof of the gas turbine generator enclosure will have been made by the manufacturer in segregated phase bus configuration. The three-phase conductors will be flat copper bus, either in single or multiple conductor per phase pattern. External connection to switchgear or transformer will be by means of segregated phase bus or cable. In the segregated phase bus, the three bare bus-phases will be physically separated by nonmagnetic barriers with a single enclosure around the three buses.

b) For applications involving an outdoor gas turbine generator for which a relatively small lineup of outdoor metal clad switchgear is required to handle the distribution system, segregated phase bus will be used. For multiple gas turbine generator installations, the switchgear will be of indoor construction and installed in a control/switchgear building. For these installations, the several generators will be connected to the switchgear via cables.

c) Segregated bus current ratings may follow the rule of thumb set forth above for generator cables, but final selection will be based on expected field conditions.

6.3.2.3 Isolated Phase Bus

a) For steam turbine generator ratings of 25 MVA and above, the use of isolated phase bus for connection from generator to step up transformer will be used. At such generator ratings, distribution seldom is made at generator voltage. An isolated phase bus system, utilizing individual phase copper or aluminum, hollow square or round bus on insulators in individual nonmagnetic bus enclosures, provides maximum reliability by minimizing the possibility of phase-to-ground or phase-to-phase faults.

b) Isolated phase bus current ratings should follow the rule of thumb set forth above for generator cables.

Section 7. STEAM CONDENSERS

7.1 Condenser Types

7.1.1 Spray Type. Spray condensers utilize mixing or direct contact of cooling water and steam. Cooling water is distributed inside the condenser in the form of a fine spray that contacts and condenses the steam. This type has application where dry cooling towers are used. Part of the condensate from the condenser is circulated through dry cooling towers and returned to and sprayed into the condenser. The balance of the condensate, which is equal to the steam condensed, is pumped separately and returned to the feedwater cycle.

7.1.2 Surface Type. Surface condensers are basically a shell and tube heat exchanger consisting of water boxes for directing the flow of cooling water to and from horizontal tubes. The tubes are sealed into fixed tube sheets at each end and are supported at intermediate points along the length of the tubes by tube support plates. Numerous tubes present a relatively large heat transfer and condensing surface to the steam. During operation at a very high vacuum, only a few pounds of steam are contained in the steam space and in contact with the large and relatively cold condensing surface at any one instant. As a result, the steam condenses in a fraction of a second and reduces in volume ratio of about 30,000:1.

7.1.2.1 Pass Configuration. Condensers may have up to four passes; one and two pass condensers are the most common. In a single pass condenser, the cooling water makes one passage from end to end, through the tubes. Single pass condensers have an inlet water box on one end and an outlet water box on the other end. Two pass condensers have the cooling water inlet and outlet on the same water box at one end of the condenser, with a return water box at the other end.

7.1.2.2 Divided Water Box. Water boxes may be divided by a vertical partition and provided with two separate water box doors or covers. This arrangement requires two separate cooling water inlets or outlets or both to permit opening the water boxes on one side of the condenser for tube cleaning while the other side of the condenser remains in operation. Operation of the turbine with only half the condenser in service is limited to 50 percent to 65 percent load depending on quantity of cooling water flowing through the operating side of the condenser.

7.1.2.3 Reheating Hotwell. The hotwell of a condenser is that portion of the condenser bottom or appendage that receives and contains a certain amount of condensate resulting from steam condensation. Unless the condenser is provided with a reheating hotwell (also commonly called a deaerating hotwell), the condensate, while falling down through the tube bundle, will be subcooled to a temperature lower than the saturation pressure corresponding to the condenser steam side vacuum. For power generation, condenser subcooling is undesirable since it results in an increase in turbine heat rate that represents a loss of cycle efficiency. Condenser subcooling is also undesirable because the condensate may contain noncondensible gases that could result in corrosion of piping and equipment in the feedwater system. Use of a deaerating hotwell provides for reheating the condensate within the condenser to saturation temperature that effectively deaerates the condensate and eliminates subcooling. Condensers should be specified to provide condensate effluent at saturation temperature corresponding to condenser vacuum and with an oxygen content not to exceed 0.005cc per liter of water (equivalent to 7 parts per billion as specified in the Heat Exchange Institute (HEI), Standards for Steam Surface Condenser, 1970.

7.1.2.4 Air Cooler Section. The condenser tubes and baffles are arranged in such a way as to cause the steam to flow from the condenser steam inlet toward the air cooler section. The steam carries with it the noncondensible gases such as air, carbon dioxide, and ammonia that leave the air cooler section through the air outlets and flow to air removal equipment. Any residual steam is condensed in the air cooler section.

7.2 Condenser Sizes. The proper size of condenser is dependent on the following factors:

a) Steam flow to condenser.

b) Condenser absolute pressure.

c) Cooling water inlet temperature.

d) Cooling water velocity through tubes.

e) Tube size (O.D. and gauge).

f) Tube material.

g) Effective tube length (active length between tube sheets).

h) Number of water passes.

i) Tube cleanliness factor.

7.2.1 Condenser Heat Load. For approximation, use turbine exhaust steam flow in pound per hour times 950 Btu per pound for non-reheat turbines or 980 Btu per pound for reheat turbines.

7.2.2 Condenser Vacuum. Condenser vacuum is closely related to the temperature of cooling water to be used in the condenser. For ocean, lake, or river water, the maximum expected temperature is used for design purposes. For cooling towers, design is usually based on water temperature from the tower and an ambient wet bulb that is exceeded not more than 5 percent of the time. The condenser performance is then calculated to determine the condenser pressure with an ambient wet bulb temperature, that is exceeded not more than 1 percent of the time. Under the latter condition and maximum turbine load, the condenser pressure should not exceed 4 inches Hg Abs. Using the peak ambient wet bulb of record and maximum turbine load, the calculated condenser pressure should not exceed 4-1/2 inches Hg Abs. The turbine exhaust pressure monitor is usually set to alarm at 5 inches Hg Abs, which is near the upper limit of exhaust pressure used as a basis for condensing turbine design.

7.2.3 Cooling Water Temperatures

7.2.3.1 Inlet Temperature. Economical design of condensers usually results in a temperature difference between steam saturation temperature (t_s) corresponding to condenser pressure and inlet cooling water temperature (t_1) in the range of 20 degrees F (11 degrees C) to 30 degrees F (17 degrees C). Table 13 shows typical design conditions:

Table 13
Typical Design Conditions for Steam Condensers

Cooling Water Temp. F(t_1)	Condenser Pressure In. Hg Abs	$t_s - t_1$ Degrees, F
50	1.0	29.0
55	1.0 - 1.25	24.0 - 30.9
60	1.0 - 1.5	19.0 - 31.7
65	1.5 - 1.75	26.7 - 31.7
70	1.5 - 2.0	21.7 - 31.1
75	2.0 - 2.25	26.1 - 30.1
80	2.0 - 2.5	21.1 - 28.7
85	2.5 - 3.0	23.7 - 31.1
90	3.0 - 3.5	25.1 - 30.6

7.2.3.2 Terminal Difference. The condenser terminal difference is the difference in temperature between the steam saturation temperature (t_s) corresponding to condenser pressure and the outlet cooling water temperature (t_2). Economical design of condenser will result with t_2 in the range of 5 degrees F (2.8 degrees C) to 10 degrees F (5.6 degrees C) lower than t_s. The HEI Conditions limits the minimum terminal temperature difference that can be used for condenser design to 5 degrees F (2.8 degrees C).

7.2.3.3 Temperature Rise. The difference between inlet and outlet cooling water temperatures is called the temperature rise that will be typically between 10 degrees F (5.6 degrees C) and 25 degrees F (13.9 degrees C).

7.2.4 Tube Water Velocity. The maximum cooling water velocity through the tubes is limited by erosion of the inlet ends of the tubes and by the water side pressure drop (friction loss). Velocities in excess of 8 feet per second are seldom used. The normal tube water velocity ranges from 6 to 8 feet per second. Higher velocities provide higher heat transfer but will cause increased friction loss. Where conditions require the use of stainless steel tubes, the tube water velocity should be at least 7 feet per second to ensure that the tubes are continually scrubbed with oxygen for passivation of the stainless steel and maximum protection against corrosion. As a general rule, 7.5 feet per second water velocity is used with stainless steel tubes. When using admiralty tubes, water velocities should be limited to about 7 feet per second to prevent excessive erosion. Previous studies indicate that varying cooling water tube velocities from 6.8 to 7.6 feet per second has very little effect on the economics or performance of the entire cooling water system.

7.2.5 Tube Outside Diameter and Gauge. Condenser tubes are available in the following six outside diameters: 5/8-inch, 3/4-inch, 7/8-inch, 1-inch, 1-1/8 inch, and 1-1/4 inch. For power plants, 3/4-inch, 7/8-inch, and 1-inch OD tubes are the most prevalent sizes. As a general rule, 3/4-inch tubes are used in small condensers up to 15,000 square feet, 7/8-inch tubes are used in condensers between 15,000 and 50,000 square feet. Condensers larger than 50,000 square feet normally use at least 1-inch tubes. Condenser tubes are readily available in 14, 16, 18, 20, 22, and 24 gauge. For inhibited Admiralty or arsenical copper, 18 BWG tubes are normally used. For stainless steel tubes, 22 BWG tubes are normally used.

7.2.6 Tube Length. The length of tubes is important because of its direct relation to friction loss and steam distribution over the tube bundle. The selection of tube length depends on condenser surface required, space available for the installation, and cooling water pump power required. Normally, economical tube length for single pass condensers will fall in the ranges as shown in Table 14. Two pass condensers will normally have shorter tube lengths.

Table 14
Typical Condenser Tube Length vs. Surface

Tube Length Feet	Condenser Surface Sq.Ft.
16 - 24	Less than 20,000
22 - 30	20,000 to 50,000
30 - 36	50,000 to 100,000
32 - 44	100,000 to 500,000

7.2.7 Number of Water Passes. A single pass condenser is commonly used where the water is supplied from natural sources such as rivers or oceans. If the source of circulating water is at all limited, a two pass condenser will probably be the best selection since a single pass condenser requires more cooling water per square foot of condenser surface and per kilowatt of electrical generation. Usually, a two pass condenser is used with cooling towers or a cooling lake. Plant layout and orientation with respect to cooling water source may also dictate the use of a two pass condenser. If sufficient water is available, the most economical condenser is a single pass. A single pass condenser is normally smaller in physical size than the equivalent two pass unit. Typical condenser sizes and cooling water flows for a given turbine generator capacity are given in Table 15.

Table 15
Typical Condenser Size and Cooling Water Flow

Turbine Generator Kw	Condenser Surface ft^2		Cooling Water Gpm		Tube Length Feet	Tube O.D. Inch
	Single Pass	Two Pass	Single Pass	Two Pass		
5,000	3,836	5,147	6,607	4,433	20	3/4
7,500	5,754	7,721	9,911	6,650	20	3/4
10,000	7,096	9,522	12,223	8,201	20	3/4
20,000	12,728	17,079	21,924	14,701	20	3/4
30,000	18,486	24,637	32,301	21,525	24	7/8
40,000	24,071	33,290	36,051	24,929	28	7/8
50,000	30,704	43,211	42,921	30,202	30	7/8
60,000	34,705	46,889	57,205	38,645	30	1
80,000	38,706	52,295	63,800	43,100	30	1
100,000	48,180	65,096	79,418	53,650	30	1

Note: Based on use of Admiralty tubes, 85 degrees F (29.4 degrees C) cooling water inlet, 2-1/2 inch Hg Abs. condensing pressure, 85 percent cleanliness factor, 6.5 ft/sec tube water velocity, and 18 BWG tube wall thickness.

7.2.8 Tube Cleanliness Factor. Design tube cleanliness can vary from 70 to 95 percent depending on tube water velocity, cooling water cleanliness, and cooling water scale-formation characteristics. As condenser tubes become dirty, the heat transfer coefficient is reduced and the condenser vacuum is decreased. When the cooling water is clean or is chlorinated, a factor of 0.85 is normally used. For bad water conditions, a lower value should be used. If the cooling water conditions are very good, a value of 0.90 or 0.95 could be used. For a cooling tower system with stainless steel condenser tubes, it is practical to use a value of 0.90. For a cooling tower system with Admiralty condenser tubes, a tube cleanliness factor of 0.85 should probably be used because of lower tube water velocities through the tubes. In general, with all types of cooling water (river, ocean, lake, cooling tower) a factor of 0.85 is commonly used for copper alloy tubes and 0.90 is commonly used for stainless steel tubes.

7.2.9 Surface. The condensing surface may be calculated by use of Equation 5.

EQUATION: $$A = Q/Um \qquad (5)$$

where:

A = condensing surface (outside active tube area), ft^2.
Q = condenser heat load = $W \times Hr$, Btu/h
W = exhaust steam from turbine, lb/h
Hr = heat rejected latent heat of exhaust steam, 950 Btu/lb for nonreheat unit, 980 Btu/lb for reheat unit
U = heat transfer coefficient = $C \times V^{0.5} \times C_1 \times C_2 \times C_f$
V = velocity of cooling water through tubes, fps
$C \times V^{0.5}$ = heat transfer coefficient at 70 deg F, (see Figure 30)
C_1 = correction factor for inlet water temperatures other than 70 degrees F, (see Figure 30)
C_2 = correction factor for tube material and thickness other than No. 18 BWG Admiralty (see Figure 30)
C_f = correction factor for tube cleanliness, (see para. 7.2.8)
m = logarithmic mean temperature difference
= $(t_2 - t_1)/\{\log_e[(t_s - t_1)/(t_s - t_2)]\}$
t_2 = cooling water outlet temperature, degrees F
t_1 = cooling water inlet temperature, degrees F
t_s = saturation temperature, degrees F of exhaust steam corresponding to condenser pressure

7.2.10 Cooling Water Flow. May be calculated by use of Equation 10.

EQUATION: $$G = Q/500(t_2 - t_1) \qquad (10)$$

where:

G = Condenser cooling water flow, gpm

7.3 Condenser Materials. Typical materials of construction for condenser shell, water boxes, tube sheets, and tubes are listed in HEIS. Recommended tube, tube sheet, and water box materials are shown in Table 16.

7.3.1 Shell. The condenser shell is usually welded steel construction reinforced against collapsing forces resulting from high vacuum. Carbon steels ASTM A283 Grade C, Specification for Low and Intermediate Tensile Strength Carbon Steel Plates, Shapes, Shapes, and Bars, ASTM A285 Grade C, Specification for Pressure Vessel Plates, Carbon Steel, Low and Intermediate Tensile Strength, and ASTM A516 Grade 70, Specification for Pressure Vessel Plates, Carbon Steel, for Moderate and Lower Temperature Service, are commonly used without preference of one type over the others. NEI standards require 1/32-inch corrosion allowance and 1/16-inch corrosion allowance is usually specified.

7.3.2 Tube Support Plates. Tube support plates are located at periodic intervals along the length of the tubes to steady and prevent vibration of the tubes that could otherwise result from impingement of high velocity steam or possibly from cooling water flow. Carbon steel plate, either ASTM A283 Grade C or ASTM A285 Grade C material is usually used. Tube support plates should not be less than 3/4 inch thick. The spacing of the tube support plates shall be in accordance with HEI standards. The maximum spacing for 1-inch, 22 gauge Type 304 stainless steel tubes shall not be greater than 48 inches.

7.3.3 Tubes. Recommended condenser tube gauge, water velocity, and application are shown in Table 17. The relative resistance to various failure mechanisms of most widely used materials is shown in Table 18. A final choice of tube material should not be made without a thorough understanding of the effects and problems related to the following:

a) Tube metal corrosion.

b) Tube metal erosion.

c) Tube water velocity.

d) Cooling water scaling characteristics.

e) Foreign body contamination, particularly seashells.

f) Biofouling.

g) Chemical attack.

h) Galvanic corrosion and protection.

i) Dealloying such as dezincification.

j) Stress corrosion cracking.

k) Tube impingement and vibration.

l) Cooling water characteristics such as freshwater, seawater, brackish water, polluted water, concentrated cooling tower water, etc.

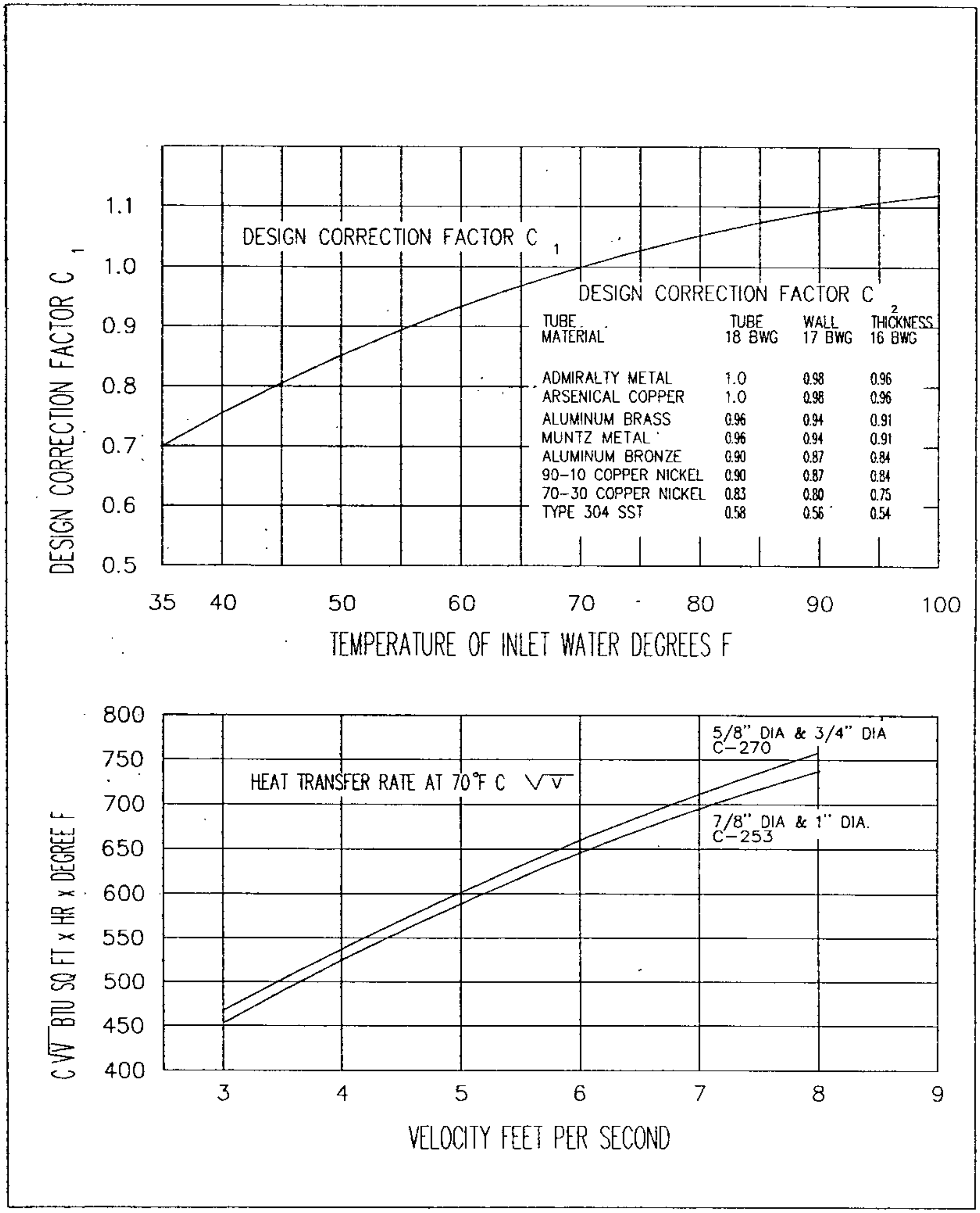


Figure 30
Heat Transfer Through Condenser Tubes

TABLE 16
Recommended Tube, Tube Sheet and Water Box Materials

Water Type	Specific Conductance/ Chlorides[1] ms/cm	mg/L	Tube Material	Tube Sheet Material	Interior Water Box Material	Water Box Coating	Cathodic Protection Type
Fresh-water	2,000	250	304 ss, ASTM A 249	Carbon Steel ASTM A283 Gr C	Carbon Steel[2]	None	None
Fresh-water	6,000	1,000	304 SS, ASTM A 249	Carbon Steel ASTM A283 Gr C	Carbon Steel[2]	None	Sacrificial Anodes
Fresh-water	9,000	1,500	304 SS ASTM	Carbon Steel ASTM A283 Gr C	Carbon Steel[2]	Yes	Sacrificial Anodes
Brackish water and High TDS Freshwater	9,000	1,500	90-10 Cu-Ni,	Aluminum Bronze (Alloy D) C61400	Carbon Steel[2]	Yes	Impressed Current
Clean Seawater	30,000	15,000	90-10 Cu-Ni, C70600	Aluminum Bronze (Alloy D) C61400	Carbon Steel[2]	Yes	Impressed Current
Polluted Seawater[3]	30,000	15,000	Titanium, ASTM B 338 Gr	Aluminum Bronze (Alloy D), C61400	Carbon Steel[2]	Yes	Impressed Current

[1]Other chemical characteristics of the cooling water must be considered, such as ph and iron and manganese concentration. Full classification of the cooling water must be on a project by project basis.

[2]ASTM A 285 Gr C or ASTM A 283 Gr C.

[3]Polluted seawater includes water with sulfide related content. Sulfides and sulfide related compounds may be found in cooling waters other than seawater.

Table 17
Recommended Tube Gauge, Water Velocity, and Application

			Possible Applications		
Freshwater Alloys	Gauge BWG	Velocity FPS	Main Body	Air Removal Section	Periphery
Once-Through System					
Admiralty Brass	18	8 max	X		
90-10 Copper Nickel	20	10 max	X	X	X
70-30 Copper Nickel	18,20	15 max		X	X
304 Stainless Steel	22	5 min	X	X	X
Recirculating System					
90-10 Copper Nickel	20	10 max	X	X	X
70-30 Copper Nickel	18,20	15 max		X	X
304 Stainless Steel[1]	22	5 min	X	X	X
Once-Through System					
90-10 Copper Nickel	18,20	8 max	X	X	X
85-15 Copper Nickel		20 max	X	X	X
70-30 Copper Nickel	18,20	15 max	X	X	X
"Super" Stainless Steel	22	5 min	X	X	X
Titanium	22	5 min	X	X	X

1. Low chloride content waters only.
2. Recommendations are the same for a once-through system or a recirculating system.

Source: Olin Fineweld Condenser and Heat Exchanger Tube Symposium.

Table 18
Relative Resistance of Most Widely Used Tube Materials to Failure

Failure Mechanism	Admiralty	90-10 Cu-Ni	70-30 Cu-Ni	Stainless Steel	Titanium
General Corrosion	2	4	4	5	6
Erosion Corrosion	2	4	5	6	6
Pitting (Operating)	4	6	5	4	6
Pitting (Stagnant)	2	5	4	1	6
High Water Velocity	3	4	5	6	6
Inlet End Corrosion	2	3	4	6	6
Steam Erosion	2	3	4	6	6
Stress Corrosion	1	6	5	1	6
Chloride Attack	3	6	5	1	6
Ammonia Attack	2	4	5	6	6

NOTE: Numbers indicate relative resistance to the indicated cause of failure on a scale of 1 (lowest) to 6 (highest).

7.3.3.1 Freshwater Service. The most commonly used tube materials for freshwater service are Type 304 stainless steel (ss), 90-10 copper nickel and, to a lesser extent, Admiralty metal. Stainless steels, both type 304 and 316, provide excellent resistance to all forms of corrosion in fresh water. However, stainless steels are susceptible to biofouling, and scale buildup can also be a problem. Almost all failures of stainless steel tubes, because of corrosion, can be traced to the problem of tube fouling (including seawater applications). Type 304 stainless steel is a good selection for freshwater makeup cooling tower systems. Stainless steel provides a good resistance to sulfide attack, but the chloride levels must be kept low. For 304 stainless steel, chlorides less than 1500 mg/L should be acceptable.

Copper alloys have also been used successfully in freshwater applications. Their main advantage over stainless steels is better resistance to biofouling. Admiralty and 90-10 copper-nickel have been used in both once-through and recirculating freshwater cooling systems. Admiralty provides good corrosion resistance when used in freshwater at satisfactory velocities (less than 8 fps), good biofouling resistance, good thermal conductivity and strength, and some resistance to sulfide attack. Admiralty is susceptible to stress corrosion cracking if ammonia is present. Admiralty should not be used in the air removal sections. Admiralty is also susceptible to dezincification. Because copper alloys are susceptible to ammonia based stress corrosion cracking, to blockage induced erosion/corrosion, and to deposit related attack, stainless steel (Type 304) is the best tube material for freshwater once-through or recirculating cooling water systems.

7.3.3.2 Brackish Water Service. Brackish water is defined as any water with chlorides in the range of 1500 mg/L to 12000 mg/L and associated high concentrations of total dissolved solids. Brackish water also refers to the recirculating systems with freshwater makeup where the cycles of concentration produce high chlorides and total dissolved solids.

In spite of overall excellent corrosion resistance, stainless steels have not been used extensively in brackish or seawater. Type 316 stainless has been used successfully in a few instances and where special care was taken to keep the tubes free of fouling. Because of stringent preventive maintenance requirements and procedures, Type 316 stainless steel is not considered the best tube material for use in brackish water applications. For condenser cooling water with high chloride concentration, increased attention is being given to newly developed austenitic and ferritic stainless steels. It is generally accepted that for austenitic stainless steel to resist corrosion, the molybdenum content should be 6 percent with a chromium content of 19 to 20 percent. For ferritic steels, the molybdenum content should be at least 3 percent and the chromium content should probably be 25 percent or more.

Copper alloys, including aluminum brass, aluminum bronze, and copper-nickel have been used extensively in brackish water applications. Because of overall failure rate experience, 90-10 copper-nickel is the recommended tube material for use with brackish water in the main body of tubes with 70-30 copper-nickel in the air removal sections. When inlet end infringement and erosion attack due to water flow is a potential problem, 85-15 copper-nickel should be considered. However, if the brackish cooling water is also characterized by high sulfide concentrations, consideration for use of the "super" stainless steels is recommended.

7.3.3.3 Seawater Service. Seawater materials are considered wherever the chlorides in the cooling water are greater than 15,000 ppm. Seawater also includes cooling tower systems where brackish water is concentrated and high chlorides and total dissolved solids result. As long as the seawater is relatively clean and free of pollution, the recommendations for brackish water materials are applicable.

Titanium tubes are being used with increasing frequency for seawater application. Titanium is essentially resistant to all oxidizing media by virtue of the stable, protective oxide film. The major problems with titanium tubes include its high fouling rate in low water velocity systems, its susceptibility to hydrogen embrittlement, and its low modulus of elasticity. Where scale formation or micro-biological slimes can possibly occur, an on-line mechanical tube cleaning system is required to maintain a high tube cleanliness factor. Careful attention must also be given to support plate spacing to avoid vibration when using thin walled titanium tubes and extra support plates are needed.

Because of the expense and potential problems with titanium tubes, 90-10 copper-nickel and 70-30 copper-nickel tubes are considered better selections for clean seawater applications. When the seawater is also characterized by a high sulfide concentration, the new austenitic and ferritic stainless steel condenser tube alloys should be considered since 90-10 copper-nickel and 70-30 copper-nickel are highly susceptible to sulfide pitting attack.

7.3.3.4 Polluted Water Service. Polluted water materials should be used whenever sulfides, polysulfides, or elemental sulfur are present in the cooling water. Sulfides produce and accelerate corrosion of copper alloys. Therefore, copper based alloy tubes are not considered feasible polluted water materials. Stainless steel is also not acceptable since the polluted water is usually brackish or seawater. This leaves titanium and the new austenitic and ferritic stainless steels. The most acceptable of these tube materials is titanium based mainly on its greater experience. However, the "super" stainless steels, which were created predominantly for use with polluted cooling water, are less expensive than titanium and are not expected to experience any of the problems with cathodic protection systems that are possible with titanium tubes. The majority of installations using these new "super" stainless materials are located in coastal areas with polluted cooling water. To date, the results have been favorable for the "super" stainless steels used in this application.

7.3.4 Tubesheets. In order to prevent galvanic action between tubes and tubesheets, the obvious selection of tubesheet material for new units is the use of same material as the tubes. However, this may be prohibitively expensive. The next best choice is to use materials that are as close as possible to one another in the galvanic series (see Figure 31) or ensure satisfactory performance by using coatings or cathodic protection.

7.3.4.1 Freshwater Service. Tubesheet material compatible with stainless steel tubes are carbon steel and stainless steel. Carbon steel has been used successfully for tubesheet material. Since it is less expensive than stainless steel, it is the obvious tubesheet material selection for use with stainless steel tubes. Muntz metal is the most widely used tubesheet material with copper-nickel tubes. Muntz metal is also suitable for use with Admiralty tubes.

7.3.4.2 Brackish and Seawater Service. Because of their relatively high yield strengths, aluminum bronze and silicon bronze provide good tube-to-tubesheet joint integrity and good pull-out strength. The materials are compatible with all copper alloy tubes. Even if titanium tubes are used, aluminum bronze is the most common choice for tubesheet material involving welded tubes. (Cathodic protection is required, however.) Silicon bronze tubesheets are not widely used. Aluminum bronze is the preferred tubesheet material for copper-nickel installations since silicon bronze is not easily weldable and since Muntz metal does not provide as much strength. Also, as a

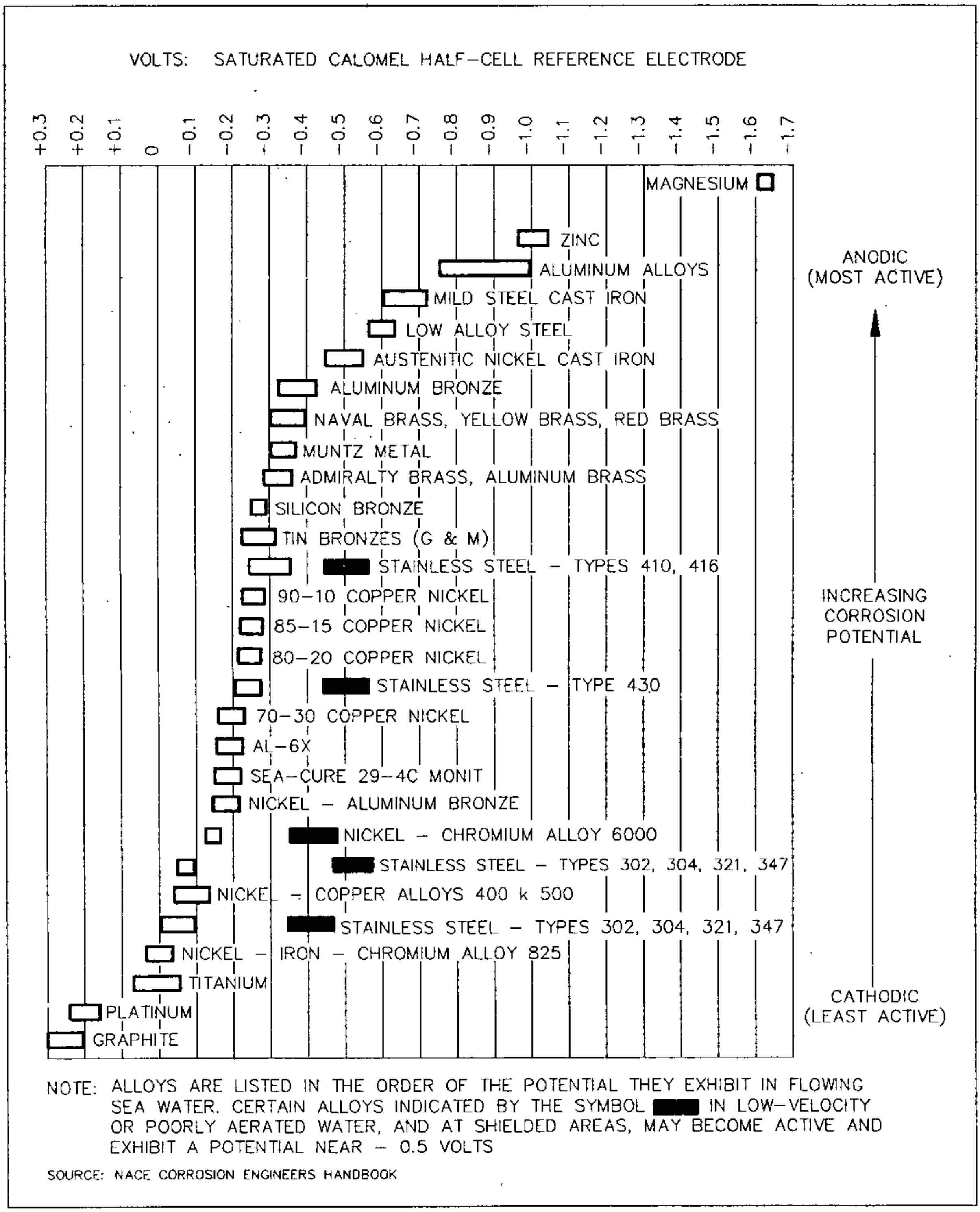


Figure 31
Galvanic Series of Metals and Alloys in Flowing Seawater

tubesheet material, aluminum bronze is significantly less susceptible to galvanic corrosion than Muntz metal. The cost difference between aluminum bronze and silicon bronze is slight. The actual material cost of silicon bronze is slightly lower but the added thickness or supports required for high pressure designs negates any material savings. Muntz metal is not the best material since it does not have the strength required to ensure adequate tube-to-tubesheet integrity. However, as with freshwater, Muntz metal tube-sheets are often used with copper-nickel tubes.

New condenser tubesheet materials are under consideration as a result of the ever increasing use of the new austenitic and ferritic stainless steel condenser tube materials. Stainless steels such as Type 316L and other proprietary alloys are similar to Type 304 stainless steel but with the addition of molybdenum that offers increased resistance to general corrosion, pitting, and crevice corrosion attack. Galvanic corrosion between the new "super" stainless steel condenser tubes and these tubesheet materials is minimized because their similar compositions places them relatively close on the galvanic series chart. The 316L and similar tubesheet materials are also slightly cathodic to the "super" stainless steel tube alloys. This is desirable since whatever corrosion takes place, if any, will occur on the thicker tubesheet instead of the thinner walled tubes.

7.3.4.3 Polluted Water Service. Aluminum bronze is the preferred tubesheet material for titanium tubes. For extremely polluted water, a titanium tubesheet (or titanium cladded tubesheet) should be considered. This arrangement would prevent any potential galvanic corrosion of the aluminum bronze as well as eliminate any problem with corrosion due to the sulfides. A properly designed cathodic protection system should protect the aluminum bronze tubesheet.

Recommended tubesheet materials for use with tubes made of the new austenitic and ferritic stainless steels are the same as described under brackish water.

7.3.5 Water Boxes

7.3.5.1 Freshwater Service. Use carbon steel ASTM A285 Grade C or ASTM A283 Grade C with copper alloy or stainless steel tubes.

7.3.5.2 Brackish and Seawater Service. Water box materials include carbon steel, stainless steel, and 90-10 copper-nickel. In brackish water, there is no advantage to using stainless steel over carbon steel since stainless steel is more expensive and is also susceptible to corrosion. A feasible alternative is 90-10 copper-nickel but it is significantly more expensive than carbon steel. Carbon steel is an acceptable choice assuming that the interior of the water box is properly coated and that some form of cathodic protection for the water box is provided.

7.3.5.3 Polluted Water. Coated carbon steel water boxes with cathodic protection is the recommended choice for use with titanium or the new austenitic and ferritic stainless steel tubes.

7.3.6 Exhaust Neck. The connection piece extending from the turbine exhaust flange to the main body of the condenser and often referred to as the condenser neck is made of the same material as the condenser shell.

7.3.7 Expansion Joints

7.3.7.1 Exhaust Neck. For bottom supported condensers, an expansion joint made of copper, stainless steel, or rubber is located between the turbine exhaust flange and the main body of the condenser, either as a part of the exhaust neck of the condenser or separate component. Corrosion of copper joints has caused the use of this material to be essentially discontinued. The use of stainless steel is satisfactory but expensive. The majority of all condensers are now furnished with a rubber (dogbone type) expansion joint. The rubber dogbone type is preferred because it can more easily be replaced as compared to a stainless steel joint.

7.3.7.2 Shell. Depending upon the type of tube to tubesheet joining, there can be and usually is a difference in expansion between the shell and tubes during operation. Suitable means must be incorporated in the design of the condenser to provide for this differential expansion. Both flexing steel plate and U-bend type have been used; however, the majority of condensers are furnished with a steel U-bend type that is usually located adjacent to one of the tube sheets.

7.4 Condenser Support

7.4.1 Bottom Support. Bottom support is the simplest method and consists of mounting the condenser rigidly on its foundation. The condenser dome, turbine exhaust extension piece, or condenser neck as it is commonly called is attached to the turbine exhaust flange by bolting or welding and contains an expansion joint of stainless steel, copper, or rubber.

7.4.2 Spring Support. The condenser is bolted directly to the turbine exhaust flange and supported at the bottom feet by springs to allow for expansion. This avoids the use of an expansion joint in the condenser neck. However, all piping connected to the condenser for auxiliaries must be provided with expansion joints to permit free movement of the condenser. This method is seldom used.

7.4.3 Rigid Support. The condenser is bolted to and supported from the turbine exhaust. The center of gravity of the condenser must be centered on the turbine exhaust. As with the spring support method, all auxiliary piping must be provided with expansion joints. The use of this method is restricted to small turbine generator units.

7.5 Condenser Air Removal

7.5.1 Continuous Air Removal. Continuous air removal is accomplished by use of either a steam jet air ejector or mechanical air exhausters (vacuum pumps). Recommended capacities of air removal (venting) equipment for single shell condensers should not be less than shown in Table 19. For other condenser arrangements refer to complete tables presented in HEIS.

Table 19
Venting Equipment Capacities For Single Shell Condenser

Turbine Exhaust Steam Flow lb/h	Steam/Air Mixture SCFM
Up to 25,000	3.0
25,001 to 50,000	4.0
50,001 to 100,000	5.0
100,001 to 250,000	7.5
250,001 to 500,000	10.0
500,001 to 1,000,000	12.5

7.5.2 Hogging Air Removal. For evacuating steam space, when starting up to a condenser pressure of about 10-inch Hg Abs., a steam operated hogging ejector or mechanical air exhausters (the same equipment as used for continuous air removal) must be used. Hogger capacities as shown in HEIS are shown in Table 20.

Table 20
Hogger Capacities

Turbine Exhaust Steam Flow lb/hr	Dry Air SCFM[1] (at 1.0" Hg Abs suction pressure)
Up to 100,000	50
100,001 to 250,000	100
250,001 to 500,000	200
500,001 to 1,000,000	350

1. SCFM - 14.7 psia and 70 F

Section 8. AUXILIARY EQUIPMENT

8.1 Condensate Storage and Transfer. About 0.5 percent of the steam flow to the turbine is lost from the cycle. These losses occur at points such as the deaerator continuous noncondensibles and steam vent, pump glands, valve packing leaks, continuous boiler blowdown, and continuous water and steam samples. Demineralized water is also required for filling the boiler/turbine generator unit system initially prior to startup and during times of boiler or cycle maintenance and chemical cleaning. The condensate storage and transfer equipment is illustrated in Figure 32.

8.1.1 Condensate Storage Tank. For normal operation, the excess or deficiency of cycle water caused by load changes is usually handled by providing a condensate storage tank which can accept and hold excess condensate or provide condensate makeup for cycle water deficiency. A tank sized for twice the cycle water swell volume will usually provide sufficient capacity for normal condensate makeup and dump requirements. Condenser vacuum is normally used as the motive force to draw condensate from the storage tank to the condenser through makeup control valves. Condensate dump from the cycle to the storage tank usually is made from the condensate pump discharge through dump control valves. For cogeneration plants, the function of condensate return from heating and other processes is usually combined with the function of condensate storage using a single tank.

8.1.2 Deionized or Demineralized Water Storage Tank. Water required for filling the cycle or boiler either initially, for maintenance or for chemical cleaning, is usually stored in separate tanks which contain deionized or demineralized water. The amount of storage required is about 1,000 gallons per MW of installed electric generating capacity which is usually divided into not less than two tanks. Provide two pumps for transfer of water as needed from these tanks to the condensate storage/return tank. If an evaporator is used for cycle water makeup, a similar amount of 1,000 gallons per MW storage capacity is necessary. For additional requirements see MIL-HDBK-1003/6.

8.1.3 Condensate Receivers and Pumps Sizing. For sizing of condensate receivers and associated pumps, see Section 4, Power Plant Steam Generation.

8.1.4 Condensate Pumps. Condenser condensate pumps are used for pumping condensate from the turbine condenser to the deaerator through the low pressure feedwater heaters, the steam jet air ejector, and the turbine gland steam condenser (if any). Two condenser condensate pumps, each capable of handling full load operation, shall be provided of either the horizontal split case or vertical can type. The vertical can type pumps are often used because the construction and installation provides for net positive suction head (NPSH) requirements without the use of a pit for pump location.

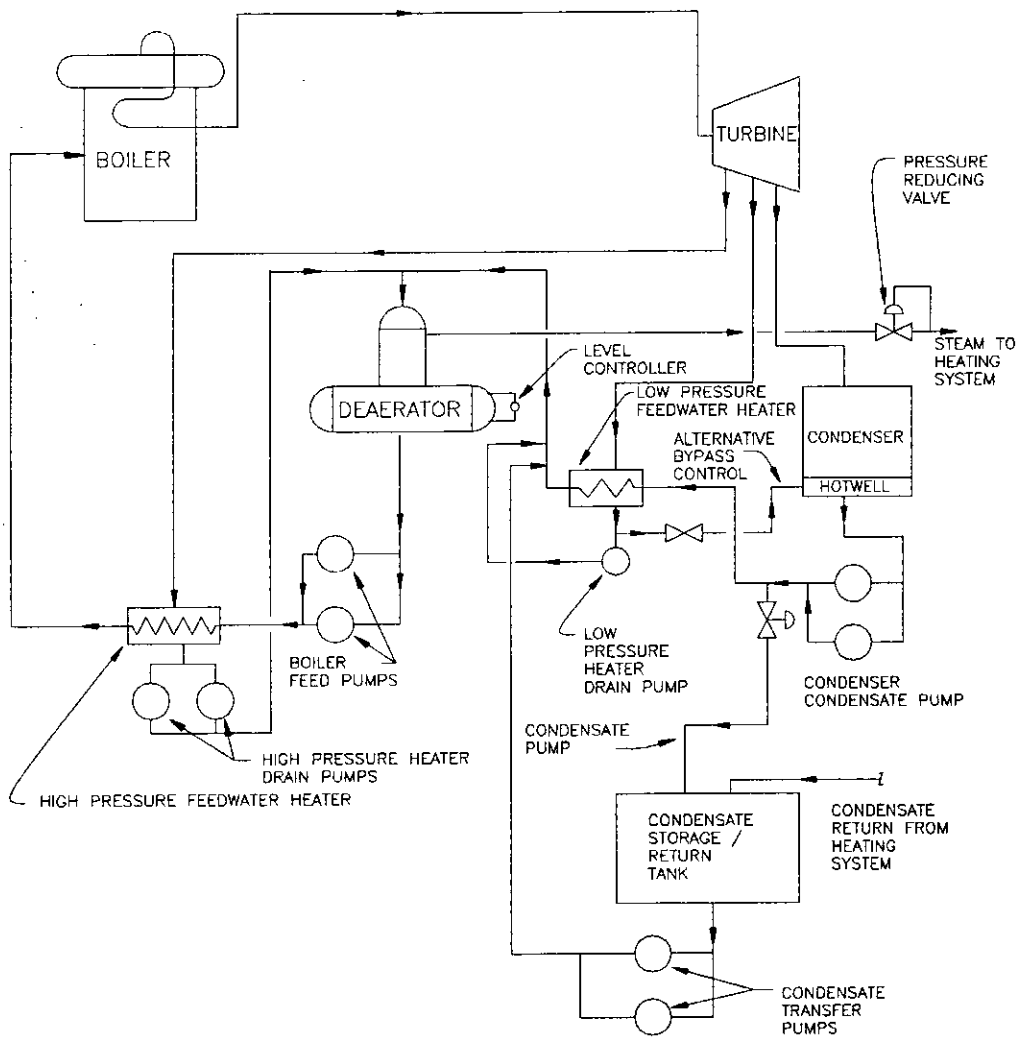


Figure 32
Typical steam plant Flow Diagram

8.1.5 Condensate Transfer Pumps. Condensate transfer pumps are used to pump condensate from the main condensate storage/return tank to the deaerator. Two condensate transfer pumps, each capable of handling full load operation, shall be provided of either the horizontal split case or vertical can type. The standby condensate transfer pump can be used for boiler fill, emergency condensate makeup to the deaerator, and initial fill of the condenser.

8.1.6 Condensate Cleaning. Oil and other undesirable matter should be removed from condensate returned from the process and fuel oil tubular heat exchangers. Oil will cause foaming and priming in the boilers as well as scale.

8.1.6.1 Wastage. Condensate containing oil should be wasted.

8.1.6.2 Filtration. Where the amount of oil-contaminated condensate is so great that it would be uneconomical to waste it, provide cellulose, diatomite, leaf filters, or other acceptable methods to clean the condensate.

8.2 Feedwater Heaters. Low pressure feedwater heaters are used in the condensate system between the condensate pump discharge and boiler feed pumps, and utilize low pressure turbine extraction or auxiliary turbine exhaust steam for heating the condensate. High pressure feedwater heaters are used in the feedwater system between the boiler feed pump discharge and the boiler, and utilize high pressure turbine extraction steam for heating the feedwater. The condensate or feedwater temperature increase for each feedwater heater will be in the range of 50 to 100 degrees F (28 to 56 degrees C) with the actual value determined by turbine manufacturer's stage location of steam extraction nozzles. Depending on turbine size, some turbines offer alternate number of extraction nozzles with usually a choice of using the highest pressure extraction nozzle. The selection, in this case, of the total number of feedwater heaters to use should be based on economic evaluation. The feedwater heater equipment is illustrated in Figure 32.

8.2.1 Low Pressure Heater(s). Use one or more low pressure feedwater heaters to raise the temperature of condensate from condensate pump discharge temperature to the deaerator inlet temperature. The heater drains are cascaded from the higher pressure heater to the next lower pressure heater with the lowest pressure heater draining to the condenser.

8.2.2 High Pressure Heater(s). Use one or more high pressure feedwater heaters to raise the temperature of feedwater from deaerator outlet temperature to the required boiler economizer inlet temperature. The heater drains are cascaded from heater to heater, back to the deaerator in a fashion similar to the heater drain system for the low pressure heaters.

8.3 Heater Drain Pumps

8.3.1 Low Pressure Heater Drain Pump. Low pressure heater drain pumps may be used for pumping drains from the lowest pressure heater to a point in the condensate piping downstream from the heater in lieu of returning the drains to the condenser. Pumping of the heater drains in this fashion provides recovery of heat which would other wise be lost to the condenser. The use of low pressure heater drain pumps can be decided by economic evaluation. Use only one pump and provide alternate bypass control of drains to the condenser for use when the drain pump is out of service.

8.3.2 High Pressure Heater Drain Pumps. High pressure heater drain pumps are required, when high pressure heater drains are cascaded to the deaerator, in order to overcome the elevation difference between the lowest high pressure heater and deaerator. Use two full capacity pumps with one of the two pumps for standby use.

8.4 Deaerators. Provide at least one deaerator for the generating plant. The deaerator usually is arranged in the cycle to float in pressure with changes in extraction pressure (which changes with turbine load). Deaerator(s) for power plants usually heat the condensate through a range of 50 to 75 degrees (28 to 42 degrees C). See Section 4, Table 6: and MIL-HDBK-1003/6, for further requirements.

8.4.1 Deaerator Function. The primary function of the deaerator is to remove dissolved oxygen from the condensate in excess of 0.005 cc of oxygen per liter of condensate at all loads. In addition, the deaerator will normally perform the following functions:

a) Heat the condensate in the last stage of condensate system prior to the boiler feedwater system.

b) Receive the boiler feed pump recirculation.

c) Provide the boiler feed pumps with the required net positive suction head.

d) Receive water from the condensate system and provide surge capacity in the storage tank.

e) Provide hot water for air preheating and combustion gas reheating (if any) and/or other auxiliary heat requirements.

f) Receive drains from high pressure heaters.

g) Receive high pressure trap drains.

The deaerator functions are illustrated in Figure 33.

8.4.2 Deaerator Design Pressure

a) Turbine manufacturers indicate that the extraction pressure quoted on the heat balances may vary as much as plus or minus 10 percent. Considering operation with extraction heaters out of service, the manufacturers recommend that the deaerator be designed for a possible 15 percent increase in the pressure from that shown on the manufacturer's heat balance.

b) Safety valve manufacturers recommend that a suitable margin be provided between the maximum operating pressure in a vessel and the set pressure of the lowest set relief valve. This prevents any undesirable operation of the relief device. They suggest that this margin be approximately 10 percent above the maximum operating pressure or 25 psi, whichever is greater.

c) The deaerator design pressure shall be specified with a design pressure equal to maximum extraction pressure x 1.15 plus allowance for safety valve. The allowance for safety valve shall equal maximum extraction pressure x 1.15 x 0.1 or 25 psi, whichever is greater. The design pressure should be rounded up to the nearest even 10 psi.

The maximum allowable working pressure shall be assumed to be equal to the design pressure.

d) If the deaerator design pressure is 75 psi or greater, the deaerator shall also be designed for full vacuum (thereby eliminating the need for a vacuum breaker.)

8.4.3 Deaerator Storage Volume. The deaerator storage volume, elevation, and boiler feed pump net positive suction head (NPSH) are related as outlined in Rodney S. Thurston's paper "Design of Suction Piping: Piping and Deaerator Storage Capacity to Protect Feed Pumps," Journal of Engineering for Power, Volume 83, January 1961, ASME pp 69-73. The boiler feed pump NPSH is calculated using the following equation:

EQUATION: $$NPSH = (P_a + P_s - P_v) \times (144/D) + h_s - f \qquad (11)$$

where:

P_a = Atmospheric pressure, psia
P_s = Steam pressure in deaerator, psig
P_v = Vapor pressure of boiler feedwater at boiler feed pump suction, psia
D = Density of boiler feedwater, lb/cu. ft.
h_s = Static head between deaerator water level and centerline of boiler feed pump, ft
f = Friction loss in piping from deaerator to boiler feed pump suction, ft

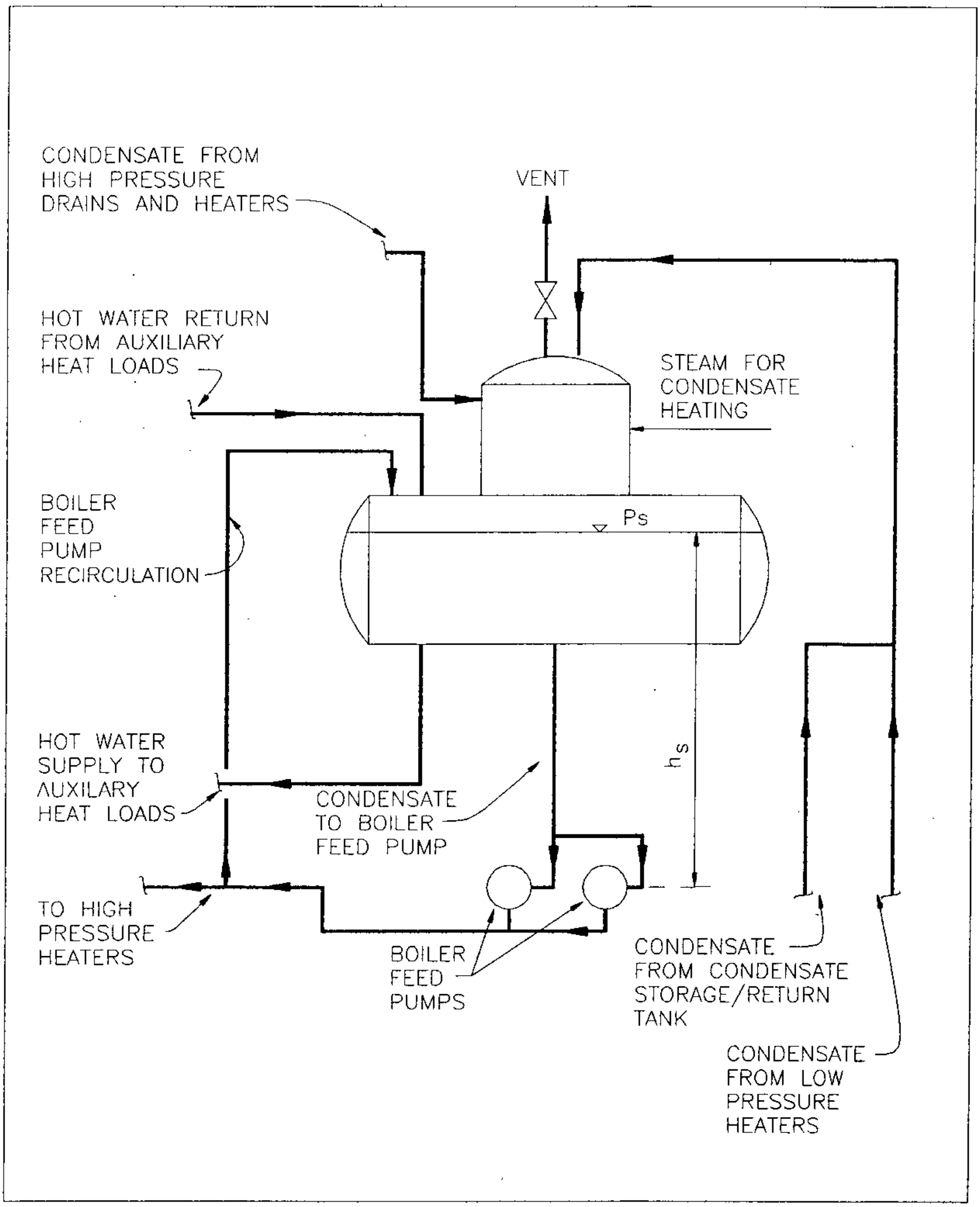


Figure 33
Deaerator Functions

a) Deaerator storage volume should be not less than the volume of feedwater equivalent to 10 minutes of feedwater flow at full turbine load.

b) The deaerator is usually located at the same elevation as the boiler main upper drum.

8.4.4 Deaerator Rating

8.4.4.1 Rated Capacity. The rated capacity of a deaerator is the quantity of deaerated water in pounds per hour delivered to the boiler feed pumps by the deaerating unit and includes all of the steam used for heating in the deaerator.

8.4.4.2 Oxygen Removal. Deaerators should be specified to provide condensate effluent, at all loads, at saturation temperature corresponding to deaerator pressure and with an oxygen content not to exceed 0.005cc of oxygen per liter of condensate.

8.5 Boiler Feed Pumps. For design and other data relative to boiler feed pumps and feedwater pumping systems, see Section 4, Table 6, and MIL-HDBK-1003/6.

8.6 Pressure Reducing and Desuperheating Stations. A pressure reducing and desuperheating station is shown in Figure 34.

8.6.1 Pressure Reducing Stations. Typical use of pressure reducing control valves are as follows:

a) Boiler drum steam supply to auxiliary steam system supplying building heating equipment, fuel oil heaters, and deaerator standby steam supply.

b) Main steam supplemental and standby supply to export steam.

c) High pressure extraction bypass to deaerator.

d) Main steam supply to steam jet air ejector, if used.

For load variations of 3:1 and larger, use two parallel pressure reducing stations with a common valved bypass; use one for one-third of total load and the other for two-thirds load instead of single pressure reducing valve, or station.

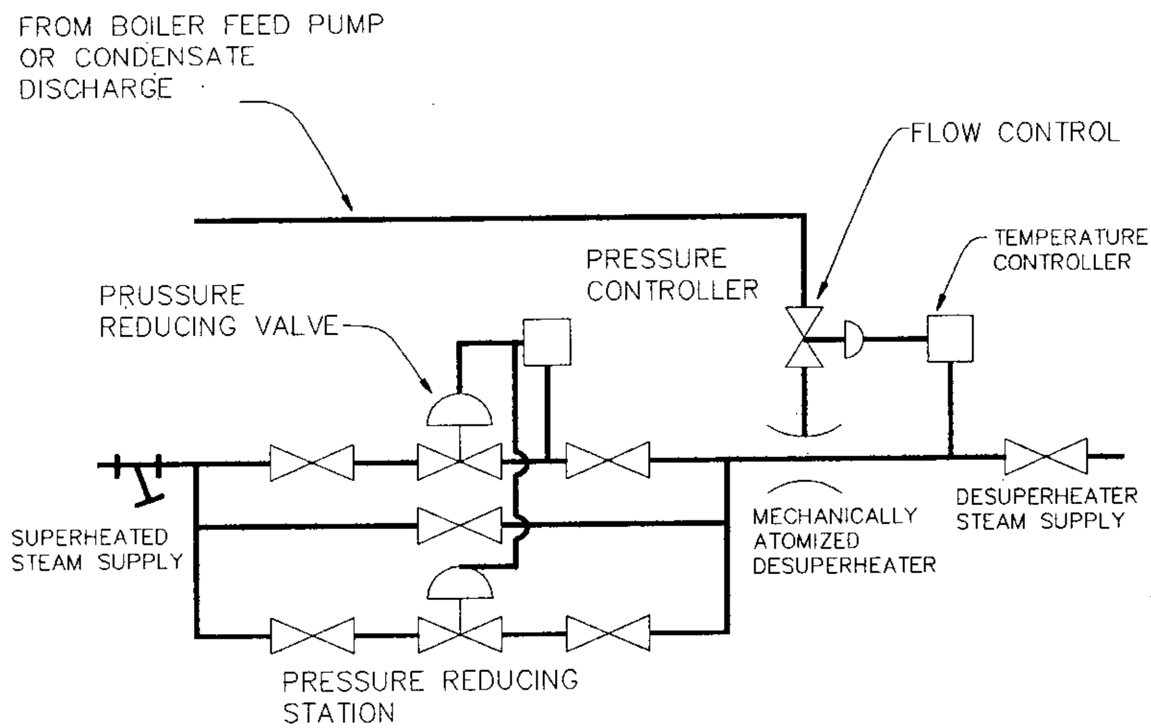


Figure 34
Typical Pressure Reducing and Desuperheating Stations

8.6.2 Desuperheating Stations. Desuperheating stations usually consist of a control valve station which is used to regulate the flow of desuperheating water (from boiler feed pumps or condensate pumps discharge, depending upon the reduced pressure of export steam) to the desuperheater. Water used for tempering must be of demineralized water or good quality condensate to avoid mineral deposits on the desuperheater. Desuperheaters may be of the steam or mechanically atomized type. Desuperheaters may also be used on the boiler steam headers for main steam temperature control, depending upon the design of the boiler.

8.7 Compressed Air System

8.7.1 Applications. The major uses of compressed air for power plants are for plant service which includes boiler fuel oil atomizing, soot blowing, and instrument air supply. The use of compressed air for fuel oil atomizing should be economically evaluated versus steam or mechanical atomization. The use of compressed air versus steam blowing for soot blowers should also be economically evaluated.

8.7.2 Equipment Description, Design, and Arrangement. For description of types, design requirements, and arrangement of air compressors, aftercoolers, receivers, and air dryers, see MIL-HDBK-1003/6 and NAVFAC DM-3.05, Compressed Air and Vacuum Systems.

8.8 Auxiliary Cooling Water System. A closed circulating cooling water system shall be provided for cooling the bearings of auxiliary equipment such as pumps and fans, for air compressor jackets and aftercoolers, turbine oil coolers, generator air or hydrogen coolers, and sample cooling coils. The system shall consist of two shell and tube heat exchangers, two water circulating pumps, one head tank, and necessary valves and piping. A typical auxiliary cooling water system is illustrated in Figure 35.

The auxiliary cooling water head tank is used as an expansion tank, to provide head on the system and to provide a still volume to permit release of air from the system. The normal operating water level of the head tank should be approximately 70 percent of the tank capacity. To provide for expansion from cold to operating temperatures, a volume equal to approximately one percent of the volume of the system should be provided between the normal operating level and the high water alarm. The tank should be provided with an overflow piped to drain. The tank should be located above the highest piece of equipment being cooled by the auxiliary cooling water system. This will assure a positive pressure throughout the system both during normal operation and in the shutdown mode.

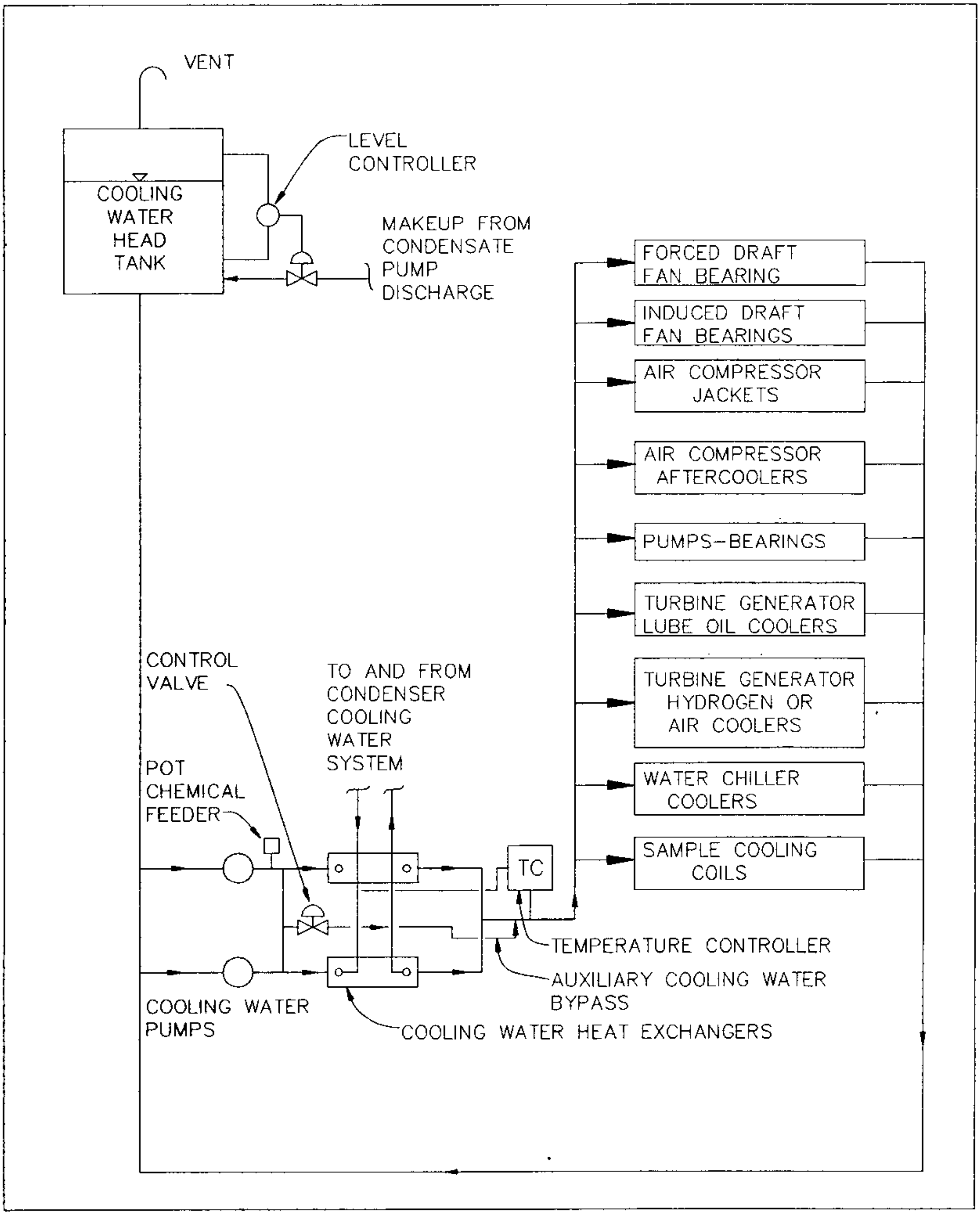


Figure 35
Typical Auxiliary Cooling Water Station

The temperature of auxiliary cooling water from the heat exchangers should be maintained constant by use of an automatic temperature control system which regulates a control valve to bypass auxiliary cooling water around the cooling water heat exchangers.

The auxiliary cooling water in the system is treated initially upon filling with chemical additives to prevent corrosion throughout the system. Chemical concentration of water contained in the system is maintained during plant operation by periodic injection of chemicals. This is accomplished by means of a pot feeder located on the discharge of the auxiliary cooling water pumps.

Section 9. COAL HANDLING

9.1 Unloading Systems. See MIL-HDBK-1003/6, Section 5, for railroad and truck delivery and coal handling. Unloading systems are required at the plant site for removing or discharging coal from the primary carrier. The unloading system is an integral part of the overall coal handling system for a power plant.

9.1.1 Barge. Barge unloaders are required for river barges (195 feet long x 35 feet wide x 12 feet side, 1,500 ton capacity each) and for ocean barges (462 feet long x 82 feet wide x 28 feet side and combing, 13,000 to 18,000-ton capacity each depending upon allowable draft).

9.1.1.1 River Barge Unloader. Unloaders for river barges are usually of the continuous bucket ladder type. Unloaders of this type range in capacity from 1,500 to 5,000 tons per hour. The unloader supports one or two bucket elevator type digging elements as shown in Figure 36. The unloader may be arranged to either lower and raise the elements relative to the barge or swing into and out of the barge from a pivot at the upper end. Barges are moved under the unloader by use of a barge haul system especially designed for this type of machine. The haul system consists of a hauling winch, return winch, sheaves, and wire rope cable. The hauling winch is designed to move the barge at an adjustable speed from approximately 5 to 50 feet per minute. The return winch is designed to move the barge at faster rates of speed. Each winch must be designed to exert a retarding torque during barge unloading in order to keep the cables tight and prevent barge drift. With the continuous ladder type of unloader, the barge being unloaded must be kept in alignment with the dock face.

The barge unloading procedure used with the continuous ladder unloader will vary with the size of barge being unloaded and number of digging elements. For a 195-foot x 35-foot standard hopper barge, a "two pass" unloading procedure is generally used with a single digging element and a "three pass" unloading procedure is generally used with twin digging elements.

9.1.1.2 Ocean Barge Unloader. Unloaders for ocean barges are usually of the clamshell bucket type; however, the continuous bucket ladder type has also been used. Clamshell bucket unloaders range in size from 400 tons per hour to 2,000 tons per hour. The capacity of a clamshell unloader is specified in tons per hour-free digging rate based on a mean duty cycle. The mean duty cycle is based on the average travel and lift of the bucket required for a barge of specified dimensions.

The tower structure of the unloader may be either stationary or movable. The stationary type requires a system of hauling and breasting winches and cables to move and position the barge along the dock relative to the unloader tower structure and boom. Ocean barges have four or more

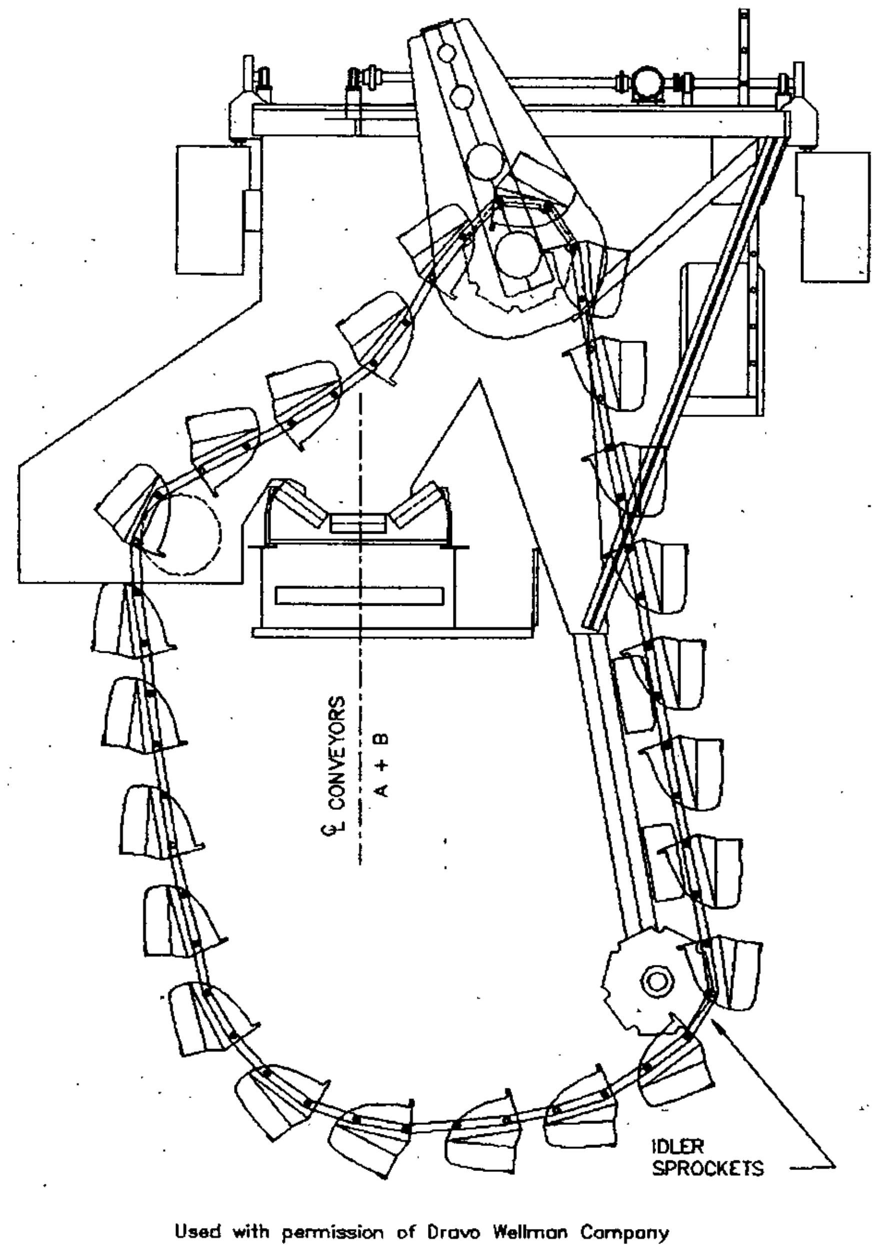


Figure 36
Arrangement of Continuous Bucket Ladder for Unloading Barges

separate compartments with each compartment provided with a large hatch cover. Hatch covers are moved to the open position by means of cables attached to the unloader bucket. These cables are also used to lower a bulldozer into each compartment for final cleanup of coal.

The unloader boom may be extended on both sides of the tower structure, which allows the unloader to be used also for coal reclaim from an onshore stockpile. The boom may also be provided with a movable operating cab which can be positioned to serve at either end of the boom.

The unloader bucket is supported by cables from a trolley that moves back and forth along the boom. The unloader mechanism includes a holding hoist to raise, lower, and hold the bucket, a closing hoist that opens and closes the bucket, a trolley winch that moves the trolley, and a tower drive (if the tower is of the movable type).

The tower structure supports a machinery house that contains DC motor driven hoisting and trolley movement equipment, motor generator sets, and electrical control equipment. Coal is dropped into a receiving hopper from which it is discharged to a yard belt conveyor.

9.2 Coal Crushing. If unsized coal such as run of mine is delivered to the plant, a coal crusher must be provided to reduce the coal to uniform lump size suitable for storage and firing or pulverizing.

In climates where frozen coal may be a problem, a coal cracker for breaking up frozen lumps, should be provided on the conveyor system feeding plant bunkers or silos.

For additional information relative to coal crushing equipment, see MIL-HDBK-1003/6.

9.3 Coal Storage. Storage shall be as required in MIL-HDBK-1003/6, under paragraph titled "Fuel Handling," except that the outside storage reserve stockpile shall be designed to store 90 days usage of coal at full plant capacity.

9.4 Coal Reclaiming. Coal reclaiming is usually done by means of bull dozing the coal from the reserve stockpile into a separate reclaim hopper which shall include a feeder and a conveyor that transports the reclaimed coal onto an unloading belt or bucket elevator.

9.5 Plant Bunker or Silo Storage. In-plant bunkers and silos are used for storage of coal for day-to-day operation of feeding the boiler coal burning system. The amount of coal for this storage should be equivalent to 96 hours of plant operation at full load. Separate bunkers or silos should be provided for each boiler. For additional information see MIL-HDBK-1003/6.

9.6 Bunker or Silo Filling Systems. The bunker or silo filling system will consist of a bucket elevator or belt conveyor that is used to elevate the coal from reclaim hopper discharge to top of bunker/silo coal gallery. The coal gallery will contain a coal distribution system consisting of a belt tripper flight conveyor or cascading belts. The bunker/silo fill system capacity should be equivalent to twice the maximum coal burn rate plus 15 percent. For description of system components and requirements see MIL-HDBK-1003/6.

9.7 Coal Scales. Railroad track scales and truck scales are optional for use in measuring the amount of coal received; however, if an unloading belt conveyor is used, the use of belt type scales is more economical than track or truck scales. Conveyor belt type scales can also be used to measure the amount of coal stockpiled or delivered to the in-plant bunkers or silos.

9.8 Magnetic Separators. Magnetic separators shall be used in coal conveying systems to separate tramp iron (including steel) from the coal. Basically, two types are available. One type incorporates permanent or electromagnets into the head pulley of a belt conveyor. The tramp iron clings to the belt as it goes around the pulley drum and falls off into a collection hopper or trough after the point at which coal is discharged from the belt. The other type consists of permanent or electromagnets incorporated into a belt conveyor that is suspended above a belt conveyor carrying coal. The tramp iron is pulled from the moving coal to the face of the separating conveyor, which in turn holds and carries the tramp iron to a collection hopper or trough. Magnetic separators shall be used just ahead of the coal crusher, if any, and/or just prior to coal discharge to the in-plant bunker or silo fill system.

9.9 Coal Sampling. Coal sampling is done when there is a need to determine or verify the analysis or content of some constituent in the coal either on an as-received or as-fired basis. Sampling of coal may be done either manually or automatically. In either case, the method of sampling must provide a representative sample of a relatively large amount of coal without bias. If moisture content determinations are to be made, the sample must be collected in a container which can be immediately sealed following the sample collection. The major components of automatic sampling systems are as follows:

a) In-line, spoon-type primary and secondary sample cutters with electric or hydraulic drive assemblies.

b) Motor-driven, rotary tertiary sample cutters.

c) Flanged belt sample feeders with rubber-lagged head pulleys and variable speed drives.

d) Sample crushers with adjustable breaker plates or screen bars to permit control of product size and compensate for wear.

e) Automatic rotary sample collectors.

f) Means of returning sample rejects to coal conveyor.

The method of sampling and coal sampling system must conform to ASTM D2234, Standard Methods for Collection of Gross Sample of Coal and ASTM D2013, Standard Method of Preparing Coal Samples for Analysis.

Section 10. ASH HANDLING

10.1 Ash Handling Systems. See MIL-HDBK-1003/6 Section 4, Paragraph titled "Ash Handling", for requirements. Ash handling systems are required for removal of bottom ash and fly ash from coal fired boilers. Ash production rates can be determined using the known ash content (from proximate or ultimate analysis) and firing rates of the coal. The typical distribution of ash from combustion of coal is shown in Table 21.

Table 21
Typical Distribution of Boiler Ash

	Eastern Bituminous Percent	Western Sub-Bituminous Percent
Stoker Coal Boiler:		
Bottom ash	35	35
Fly ash	60	60
Last pass or economizer hoppers	5	5
Pulverized Coal Boiler:		
Bottom ash	20	30
Fly ash	75	65
Last pass or economizer hoppers	5	5

Bottom ash is collected in the boiler bottom ash hopper. For a stoker coal fired boiler, bottom ash also includes ash which falls through the grate into the siftings hopper. Fly ash is collected in the boiler, last pass hoppers or hoppers below an economizer, hoppers below an air heater, mechanical dust collector hoppers, electrostatic precipitator hoppers, or bag house filter hoppers. The removal and handling of bottom ash and fly ash from collection hoppers is accomplished by the use of one of several systems which are described as follows. Also see ash handling equipment manufacturers' reference manuals for detailed descriptions of arrangement, operation, and control of ash handling components and systems.

10.1.1 Pneumatic. Pneumatic ash handling systems are available as a complete vacuum system, complete pressure system or a combination vacuum-pressure system.

10.1.1.1 Vacuum System. Vacuum for conveying bottom ash or fly ash is produced hydraulically by the use of a water jet pump, thermally by the use of a steam jet pump, or mechanically by the use of motor driven rotary exhausters. Air is admitted into the end of the conveyor pipe and ash is admitted at intermediate points through ash intake fittings or automatic valves. The ash is then conveyed to a storage silo through primary and secondary cyclone type air and ash separators. Ash is dumped from the separators into the storage silo through air lock type automatic gates. Air from the secondary separator is passed through a bag filter for residual ash removal prior to the air being admitted to the vacuum producing exhausters.

10.1.1.2 Pressure System. Compressed air for conveying fly ash is produced by motor driven positive displacement rotary blowers. An air lock tank type feeder is located at each fly ash hopper outlet or discharge. The feeder discharge is attached to the conveyer pipeline. The feeder is closed to the conveyor pipe and opened to the ash hopper during the feeder loading cycle. When full, the feeder is closed to the ash hopper, pressurized with compressed air, and then opened to the conveyor pipe allowing the fly ash to discharge into the conveyor pipe air stream. The air-entrained fly ash is then conveyed by the pipeline and discharged into the storage silo. The silo air vent shall have an exhaust fan which discharges the vented air to the boiler flue gas dust collector, or a separate bag filter may be used to clean the silo vented air. A pressure system should be used when the fly ash conveying distance is greater than can be served by a vacuum system. Pressurized conveyors can be used to convey fly ash several thousand feet.

10.1.1.3 Vacuum-Pressure System. A combination of vacuum and pressure conveying of fly ash should be considered where conveying distances rule out the use of vacuum alone. This type of system permits the use of vacuum to remove fly ash from hoppers at a high rate to a collecting point nearby where the fly ash is continuously transferred to a pressurized conveyor for discharge at a remote terminal point.

10.1.2 Hydraulic. Hydraulic ash removal systems, using high pressure water as the conveying medium for bottom ash, are used only for utility type boilers and will not be considered for most Navy installations. In this system, bottom ash hoppers are fitted with ash discharge gates each followed by a crusher which in turn discharges to a centrifugal materials handling pump or a hydraulic ejector utilizing high pressure water as the motive force and ash conveying medium. The ash is conveyed in a slurry (approximately 20 percent ash by weight) to a disposal area or pond, or to dewatering bins. Dewatering bins allow storage of bottom ash up to several days. After the water is drained from one of the dewatering bins, ash is discharged into trucks, rail cars or barges for final disposal.

10.1.3 Dense Phase. In the dense phase system, material is pushed through a pipeline as a fluidized slug at higher ash to air ratios than conventional dilute phase conveying. The dense phase system requires fine, dry, fluidizable material such as fly ash. Coarse or damp material cannot be conveyed by this method. Because of the associated history of line plugging and other mechanical difficulties, there have been only a limited number of successful installations of dense phase systems in the United States. Need for further developmental work is indicated and is ongoing. Careful investigation should be made before considering the use of a dense phase system.

10.2 Bottom Ash Hoppers

10.2.1 Stoker Firing. The bottom ash hopper should be sized to provide not less than 8 hours, preferably 12 hours of storage at the maximum bottom ash production rate. For bulk density of bottom ash, use 45 lb/ft^3 for eastern bituminous coal and 35 lbs/ft^3 for western sub-bituminous coal. Sizing of the bottom ash hopper volume should also consider that the bottom ash will contain unburned coal in the amount of 5 to 12 percent of the bottom ash. Design structural loads shall be based on 70 pounds per cubic foot. Discharge gates shall be air-cylinder operated with intermediate positioning capability.

10.2.2 Pulverized Coal Firing. For a water impounded bottom ash hopper, the hopper volume should be sized to provide 8 hours of storage at the maximum production rate, or 12 hours of storage based on the maximum expected amount of ash to be produced for any 12-hour period. The bulk densities of bottom ash as given above under stoker coal firing may be used also for pulverized coal firing.

10.3 Clinker Crushers

10.3.1 Stoker Coal Firing. On bottom ash handling systems, motor driven clinker crushers shall be installed below the hopper outlets and above the pneumatic ash intakes.

10.3.2 Pulverized Coal Firing. For pulverized coal firing, each bottom ash hopper discharge gate is provided with a clinker crusher. In order to avoid clinker crusher plugging problems, pulverizer pyrites rejects should be discharged to a separate holding tank and not to the bottom ash hopper.

10.4 Ash Storage. Silos are used for storage of pneumatically conveyed bottom ash and fly ash. The use of silos facilitates the disposal of ash by truck or rail cars. Minimum silo storage capacity should be 72 hours based on maximum ash production rate. Motor driven rotary dustless unloaders (conditioners) shall be used to unload the silo into trucks or railroad cars. For additional requirements, see MIL-HDBK-1003/6.

Section 11. CONTROL AND INSTRUMENTATION

11.1 Types of Controls and Control Systems. There are basically three types of industrial instrumentation systems for power plant control: analog, microprocessor, and computer.

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

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

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

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

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

11.1.4 Pneumatic Control Systems. Pneumatic control systems should only be considered when adding to an existing power plant already equipped with pneumatic control instruments.

11.1.5 Types of Control Systems Available.

a) On-off controls.

b) Single point positioning system.

c) Parallel positioning system.

d) Parallel metering system.

e) Parallel metering system with oxygen trim. CO trim w/coal.

f) Steam flow/air flow metering system. Boilers should have oxygen trim in order to optimize fuel usage. CO trim should be considered for larger boiler installations as an adjunct to oxygen trim for increased efficiency, especially for coal firing.

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

11.2 Steam Power Plant Controls. Steam power plant controls are shown in MIL-HDBK-1003/6, Section 6 and Table 13.

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

a) For the metering type (proportioning plus reset plus rate action), see Figure 37.

b) Combustion safeguard. See Military Specification MIL-B-18796, Burner, Single, Oil, Gas, And Gas/Oil Combination, and MIL-B-18797, Burners, Oil, Mechanical-Draft, Automatic.

c) Refer to the ASME Boiler and Pressure Vessel Code Section VII subsection C6 for minimum basic instruments required for proper, safe, efficient operation.

d) Refer to Tables 13 and 15 in MIL-HDBK-1003/6, Section 6.

e) See Tables 22, 23, and 24 for typical lists of instruments.

11.2.2 Steam Temperature Control. Steam temperature control shall be as listed in MIL-HDBK-1003/6, Section 6, Table 13. Critical temperatures should be recorded and also alarmed. An automatic fuel-trip device is required for steam temperature out of normal range. See Table 23 for temperature sensing devices.

11.2.3 Feedwater Control. Feedwater control shall be as listed in MIL-

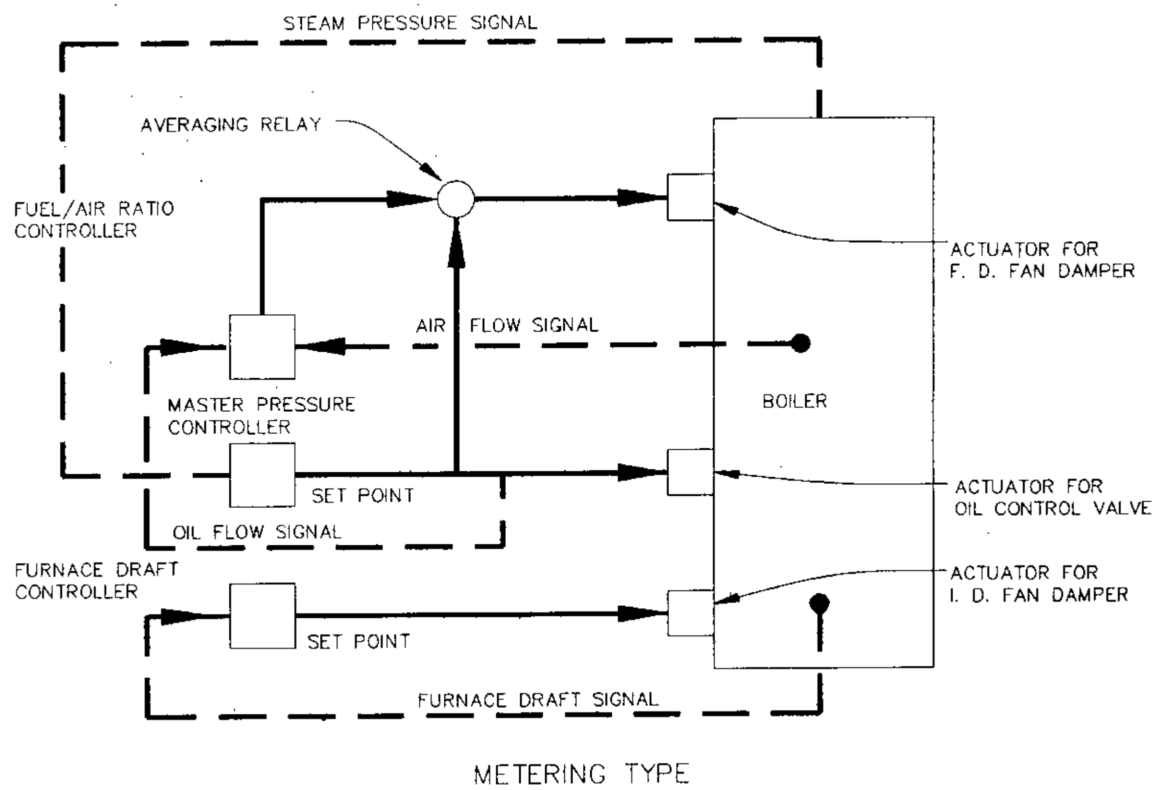


Figure 37
Typical Combustion Control System

TABLE 22

List of Instruments on Control Panels

Sensing Element	Location of Sensing Element	Indicator	Recorder	Totalizer
Pressure	Steam boiler drum	A		
	Superheated steam outlet		A	
	Main steam header		A	
	Feedwater header	A		
	Fuel oil header	A		
	Gas fuel header	A		
	Steam at Turbine (extraction or condensing)	A	C	
	Steam at turbine first stage	A		
	Steam at turbine No. 1 extraction	A		
	Steam at turbine No. 2 extraction	A		
	Steam at turbine No. 3 extraction	A		
	Steam at turbine exhaust	A		
	Instrument air	A		
	House service air	A		
	House service water	A		
	Auxiliary steam	A		
Draft	Forced draft fan discharge	A		
	Burner or stoker windbox	A		
	Furnace draft	A		
	Boiler gas outlet	A		
	Air heater or economizer gas outlet	A		
	Dust collector outlet, or I.D. fan inlet	A		
	Air heater air discharge	A		
	Flyash return fan	A		
Temperature	Superheated steam		A	
	Boiler outlet gas		A	
	Air heater or economizer outlet gas	A	B	
	Air heater outlet air	A	A	
	Economizer water outlet	A	B	
	Feedwater header	A		

Table 22
List of Instruments on Control Panels (cont.)

Sensing Element	Location of Sensing Element	Indicator	Recorder	Totalizer
Temperature Cont.	Steam to extraction turbine		A	
Vacuum flow	Absolute pressure at turbine exhaust	A		
	Steam	A		A
	Air		A	
	Feedwater		D	
	CO_2 (alternate to air flow)		E	
	Fuel Oil			A
	Gas fuel		A	A
	Coal weight			A
	Steam to extraction turbine		A	A
	Extraction steam from extraction turbine		A	A
Level	Boiler drum		A	
	Coal bunker - pilot lights	A		
	Fuel oil tank	A		
	Deaerator storage section	A		
Flame safeguard	Safeguard panel	A		
Control instruments	Combustion control	A		
Hand Automatic selector stations with indicators for remote or automatic operation.	Combustion control:			
	Fuel control	A		
	Forced draft damper	A		
	Induced draft damper	A		
	Feedwater control	A		
Conductivity	Condenser Hotwells		A	
	Sample coolers		A	

Table 22.
List of Instruments on Control Panels (cont.)

Sensing Element	Location of Sensing Element	Indicator	Recorder	Totalizer
Alarms	Annunciator	A		
O_2	Stack Percent		A	
CO	Stack Percent (coal)		A	

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

Table 23
Sensing Elements for Controls and Instruments

Element	Type		Common Applications: Control	Common Applications: Instrument
Flow	Mechanical	Batch Totalizing	Eilling containers	Weighing containers Totalizing positive displacement water and gas meters
	Variable differential pressure with constant area	Continuous and totalizing	Proportioning large flows	Orifice, flow nozzle, and Venturi nozzle meters. V-slot
	Variable differential pressure with constant area	Combustion	Control valves	Air and gas flow
	Constant differential pressure with variable area	Tapered tube and float	Proportioning small flows	Rotameter

Table 23
Sensing Elements for Controls and Instruments (cont.)

Element	Type		Common Applications: Control	Common Applications: Instrument
	Variable differential with variable velocity anemometer	Pitot tube	Airflow	Airflow
		Velocity Electric resistance of hot wire affected by Velocity of flow		Potentiometer
	Vortex-linear volumetric flow	Batch, continuous and totalizing	Filling containers, proportional flow, control valves, air flow, liquid flow, steam flow	Vortex flowmeter 16 to 1 turndown,
Tempera-ture	Solid expansion	Bimetal	On-off thermostats	Dial thermometer 100 to 1000 deg. F
	Fluid expansion	Mercury or alcohol		Glass thermometer 38 to 750 deg. F
		Mercury in coil	Temperature regulators	Dial thermometer 38 to 1000 deg. F
		Organic liquid		125 to 500 deg. F
		Organic vapor liquid		40 to 600 deg. F
		Gas		400 to 1000 deg. F
	Gas expansion	Nitrogen gas	Temperature regulators	Recorders, and transmitters 350 to 1400 deg. F
	Thermocouples	Copper-constantan	Temperature regulators	Low voltage 300 to 600 deg. F
		Iron-constantan		0 to 1400 deg. F
		Chromel-alumel		600 to 2100 deg. F
		Platinum-Platinum rhodium		1300 to 3000 deg. F

Table 23
Sensing Elements for Controls and Instruments (cont.)

Element	Type		Common Applications: Control	Common Applications: Instrument
Temperature	Elec resistance of metals	Copper	Temperature regulators	Potentiometer 40 to 250 deg. F
		Nickel		300 to 600 deg. F
		Platinum		300 to 1800 deg. F
	Optical pyrometer	Comparative rad energy		850 to 5200 deg. F
	Radiation pyrometer	Radiant energy on thermocouples	Flame safeguard Surf. temp. regulation	Potentiometer 200 to 7000 deg. F
	Fusion			Pyrometric Cones 1600 to 3600 deg. F Crayons 100 to 800 deg. F
Pressure	Mechanical	Bourdon tube	Pressure, draft and vacuum	Pressure gauge
		Bellows or diaphragm Manometers	vacuum regulators	Low pressure, draft and vacuum gauges, Barometer
	Variable electric resistance due to strain	Pressure transducer	Process pressure regulator	Potentiometer: 100 - 50,000 p.s.i.
	Variable electric resistance due to vacuum	Thermocouple	Vacuum regulator	High vacuum 1-700 microns Hg.
	Variable electronic resistance to vacuum	Vacuum tube	Vacuum regulator	High vacuum down to 0.1 micron Hg.
	Variable capacitance	Capacitance	Pressure regulators	Indicators and recorders - 1" H_2O to 1,200 psig
	Variable frequency	Frequency transducer	Pressure regulators	Indicators and recorders - 1" H_2O to 1,200 psig
Level	Visual			Gauge stick, Transparent tube

Table 23
Sensing Elements for Controls and Instruments (cont.)

Element	Type		Common Applications: Control	Common Applications: Instrument
Level	Float	Buoyant float	Mechanical level regulator	Tape connected to float
		Displacement	Pneumatic level regulator	Torque
	Differential pressure	Manometer	Level regulator	Remove level gauge
	Hydrostatic	Diaphragm in tank bottom	Level regulator	Tank levels with viscous fluids
Motion	Centrifugal		Speed governs	Tachometer
	Vibrating read			Tachometer
	Relative motion			Stroboscope
	Photo-electric cell		Limit control	Counter
Chemical	Flue gas analysis		Combustion control	Orsat
	Water analysis		Water Treatment	Water constituents
	Fuel analysis			Ultimate analysis of fuels
Physical	Specific gravity			Hydrometer for liquids
	Weight			Scales for solids
	Humidity			Hygrometer
	Smoke density			Ringelman chart
	Gas density		Combustion	CO_2 meter
	Heat	Combination of water flow and temp. diff.	Combustion	Btu meter
Electric and electronic	Photo-conductivity		Flame safeguard	Photo-electric cell
				Smoke density
	Elec conductivity	Probes	Alarm	pH of water
				Oil in condensate

Table 24
Locally Mounted Instrumentation

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

A - necessary

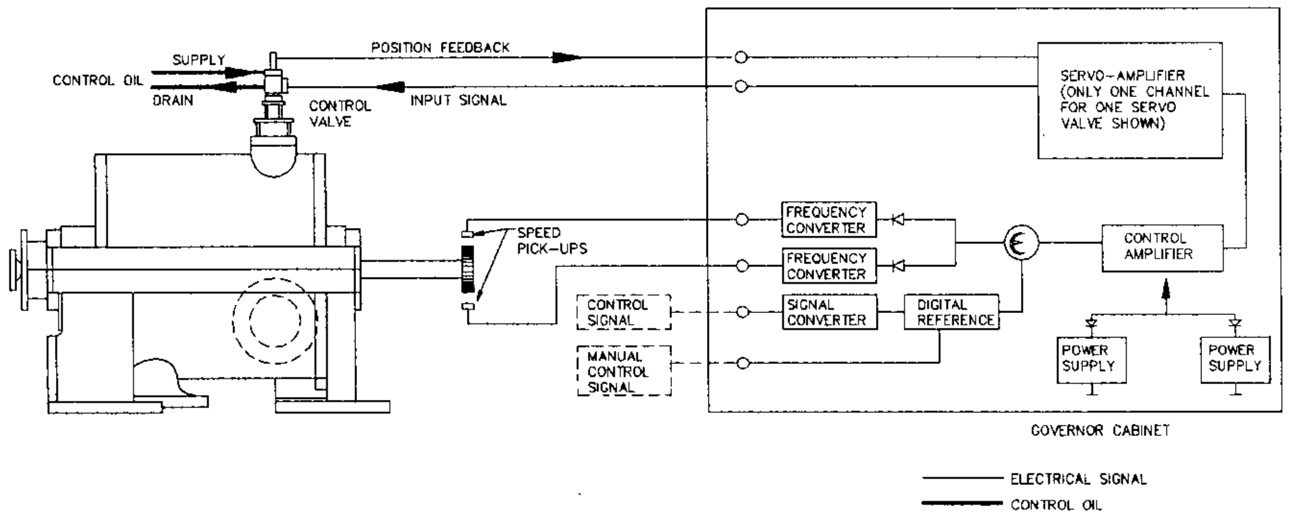


Figure 38
Electro-Hydraulic Control System

HDBK-1003/6 Section 6, Table 13. For small packaged boilers and boilers with constant loads a single or two element feedwater control system will suffice. Larger boilers and boilers with widely fluctuating loads should use a three element type. An automatic fuel trip device is required for low drum water level.

11.2.4 Steam Turbine Generator Control. Steam turbine controls should be supplied by the turbine manufacturer. With the rapid advancement of electronics, an electro-hydraulic control (EHC) system is desirable over an all mechanical system. The EHC system is more versatile and faster responding, which gives improvement in control reliability and accuracy which is manifested in improved turbine performance. See Figure 38 for a typical EHC system. The Mechanical Hydraulic Control System (MHC) has not been used since the late 1970's. Many are still in use but they are for the most part not a currently manufactured unit. Automatic startup and shutdown is easily done with microprocessor based control equipment. A standard EHC system is comprised of four primary functions:

a) Speed control

b) Load control

c) Flow control

d) Trip

11.3 Safety Devices and Interlocks. Safety devices such as boiler shutdown devices, startup and shutdown interlocks, and alarms should be installed as recommended by the equipment manufacturer. See Table 14 in MIL-HDBK-1003/6 Section 6 for selection factors and reasons for use. Coal, oil, and gas fired boilers can have different shutdown safety trips. Check boiler manufacturer's recommendations and ASME Boiler and Pressure Vessels Code Section VII for standard trip conditions.

Safety controls for boilers are needed for protection against explosions and implosions. Criteria for protection against boiler explosions have been well established. Protection against boiler implosions is not so well understood. For a boiler, implosion would be the result of a negative pressure excursion of sufficient magnitude to cause structural damage. Boiler implosions are caused by one of two basic mechanisms: (1) The induced draft fan of a balanced draft boiler is capable of providing more suction head than the boiler structure is capable of withstanding and (2) the so-called flame collapse or flameout effect.

Implosion concerns have resulted in many new control-system developments. Each steam generator manufacturer has recommendations and the National Fire Protection Association has issued NFPA 85-G on the subject. For a detailed discussion of boiler implosions, see also Combustion Engineering, Inc, 1981.

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

11.4.1 Pressure. Pressure control loops may be used for control of boiler pressure, deaerator pressure, auxiliary steam pressure, building heating steam pressure, and fuel oil pressure. For control of boiler pressure the final control element regulates fuel flow to the boiler in response to boiler drum steam pressure. For other pressure applications the final control element is usually a pressure reducing control valve which regulates in response to downstream pressure. A typical pressure control loop is shown in Figure 39a.

11.4.2 Temperature. Temperature control loops may be used for control of steam temperature from boilers or desuperheaters and fuel oil temperature from fuel oil heaters. A typical temperature control loop is shown in Figure 39b.

11.4.3 Level. Liquid level control loops may be used for control of boiler drum water level, condenser hotwell water level, feedwater heater drain cooler water level, and deaerator storage tank water level. A typical liquid level control loop is shown in Figure 39c.

11.5 Flow meters. Flow meters, particularly differential pressure type, have remained unchanged over the past decade. There have been several new types of flow meters added to the flow measurement arena. The new meters such as vortex, ultrasonic, and Doppler have added improved accuracy, linear signals, and rangeability as high as 16:1. With the improvements in electronic transmitters over the past decade there has been an improvement in their overall specifications. However, the differential pressure type flow meters have remained the same; accuracy 2-3 percent and rangeability of 4:1 maximum. Cost of electronic transmitters are now lower than pneumatic counterparts and should be used except for all pneumatic systems. For types of flow meters see Table 25; for applications see Table 23; and for a listing of required flow measurements for steam power plants, refer to MIL-HDBK-1003/6.

11.6 Pressure Gauges. Pressure gauges are usually direct-connected and field-mounted. Size and ranges are specified by user. Local-mounted gauges give a "backup" reading and also help operators in determining if equipment or pressure systems are working satisfactorily. Accuracy is normally 0.5 to 1 percent of span. For test and calibration purposes use 0.25 to 0.5 percent gauges. Refer to MIL-HDBK-1003/6 for required pressure measurements and instrument selector factors.

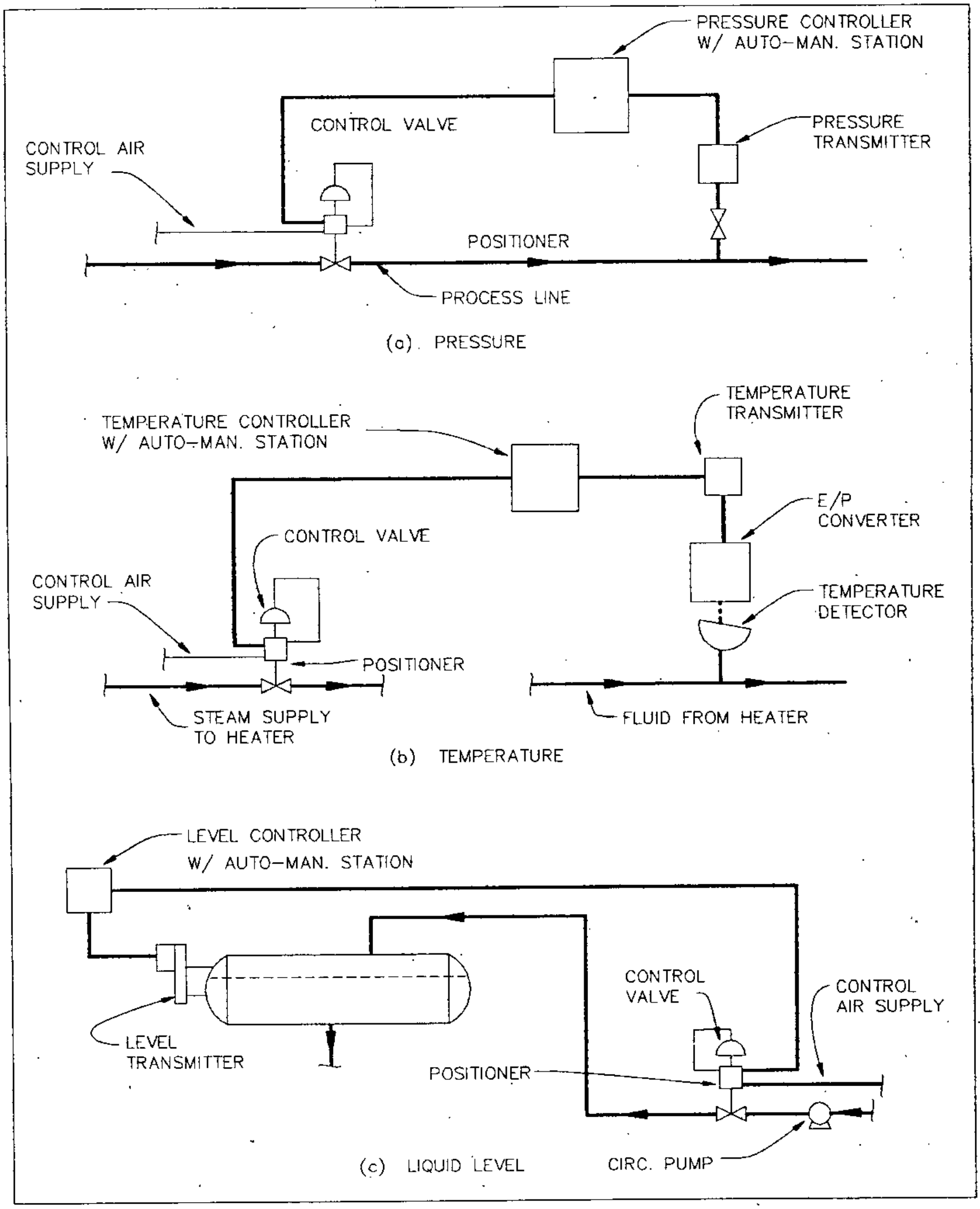


Figure 39
Typical Controls Loops

11.7 Temperature Sensors. The basic types of temperature sensors are thermometers, thermocouples, and resistance temperature detectors.

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

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

11.7.3 Resistance Temperature Detector. Resistance temperature detectors offer a temperature range about the same as a copper-constantan thermocouple with detection of temperature changes of 0.03 degrees F (0.02 C). The resistance detector does not have a reference junction, as a thermocouple, since it operates on the measured change in the resistance of a metal or semiconductor (thermistor) with temperature. Platinum, because of its inherent stability and linearity is becoming the standard of the industry with some copper and nickel still being used. Copper is quite linear but nickel is quite nonlinear. Resistance detectors can be used with pneumatic and electronic transmitters or can also be direct-connected to some instruments. See Table 23 for ranges and use.

11.8 Transmitters. Transmitters are primarily used to transmit an analog output (pneumatic or electronic) proportional to its measured signal. The American Petroleum Institute Recommended Practice 550 suggests for general service applications that the pneumatic tubing length from transmitter to controller to control valve not exceed 400 feet. Neither run should exceed 250 feet. Standard output signal for pneumatic transmitter is 3-15 psi with a 20 psi air supply and 4-20 mA DC for electronic transmitters with a nominal 30 VDC power supply. There are options for other output signals depending upon the manufacture.

Recent electronic enhancements have made most electronic transmitters much more accurate, reliable, and smaller in size, weight, and less expensive than its pneumatic counterpart. Electronic signals are easier to adapt to microprocessor and computer based systems and should therefore be given prime consideration over pneumatics.

Materials of construction is of prime importance when selecting a transmitter. Many options are available and should be selected on the basis of need or life expectancy and cost. Most transmitters are field-mounted near point of measurement. Most electronic transmitters are the two wire type. Sensing line lengths longer than 50 feet are not usually recommended and should be used only when absolutely necessary. Where transmission line length (pneumatic) poses a problem in a flow loop, use a volume booster, or mount the controller near the valve.

Table 25
Flowmeter Selection Table

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

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

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

a) Federal and state requirements.

b) Equipment manufacturer recommendations.

c) Accounting purposes.

d) Safety requirements.

e) Operator requirements.

Recorders are available in different sizes, shapes, (roll, fold, circular) and number of recording points. The selection of types should be based on suitability to needs and, in particular, the number of points being recorded. Trend recording is becoming more popular since it allows the selection of a large number of inputs to be recorded and for time periods as desired by the operator. Trend recording also allows for recording of critical points during startup. Most panel-mounted recorders are the 4-inch strip chart type because of space requirements. Most field-mounted recorders are the 12-inch circular large case type because they usually meet NEMA Type 3 or better protection, see NEMA, Standard Publication/No. 250, Enclosures for Electrical Equipment (1000 volts Maximum). See Table 22 for selection of signals to be recorded. Recorders are normally supplied with 115 V, 60 cycle, or 24 VDC for the chart drives, some can be supplied with a pneumatic impulse or mechanical chart drives.

11.10 Controllers. Controllers can be used in either closed loop (feedback) or open loop control configurations. In a closed loop control configuration, a measurement is made of the variable to be controlled, and is compared to a reference or set point. If a difference or offset exists between the measured variable and set point, the automatic controller will change its output in the direction necessary for corrective action to take place. See Figure 40a.

Open loop control simply does not have a measurement sensor to provide an input to the controller for a comparison. See Figure 40b. Open loop control can also occur when an automatic controller is placed in its manual position; saturation of the controller output at zero or 100 percent of scale; or failure of the final operator, when it can no longer be changed by its input signal.

Feed-forward control is relatively new and in most cases it is also used in closed loop control configurations. While feedback control is reactive in nature and responds to the effect of an upset which causes an offset between the measured variable and set point of the controller, feed forward schemes respond directly to upsets and, thus, offer improved control. See Figure 40c. There are also several types of control units available such as:

a) Ratio control.

b) Cascade control.

c) Auto-selector control.

d) Nonlinear control.

These units can be analog type and either electronic or pneumatic; however, additional pieces of instrumentation may be required to actually do the above types of control. With the new microprocessor-based control stations they can perform most of the types of control listed above without additional devices and still provide 18 or so control algorithms. For standard controller action see Figure 41. For a controller to operate correctly, the controller must be properly tuned. Each controller must be tuned for its control loop--seldom are two alike. This can be time consuming, but it is necessary to have correct controller response to process changes. Some new microprocessor controllers have "Self Tuning" capability. This is a major addition for exact tuning of the control parameters to match the process dynamics.

The new microprocessor-based controllers should be given first consideration as they are less expensive, state of the art, and can perform many more functions than a standard analog controller without additional pieces of equipment. These new units should also be considered for retrofit work as they can easily replace old electronic and pneumatic analog controllers and other devices. Some of the new microprocessor-based controllers are configured from push buttons located on the controller face plate. Special calibrators or mini-computers are not required to configure these stand alone controllers.

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

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

11.11.2 Electric Operators. Electric operators are used prevalently in heating, ventilating, and air conditioning systems.

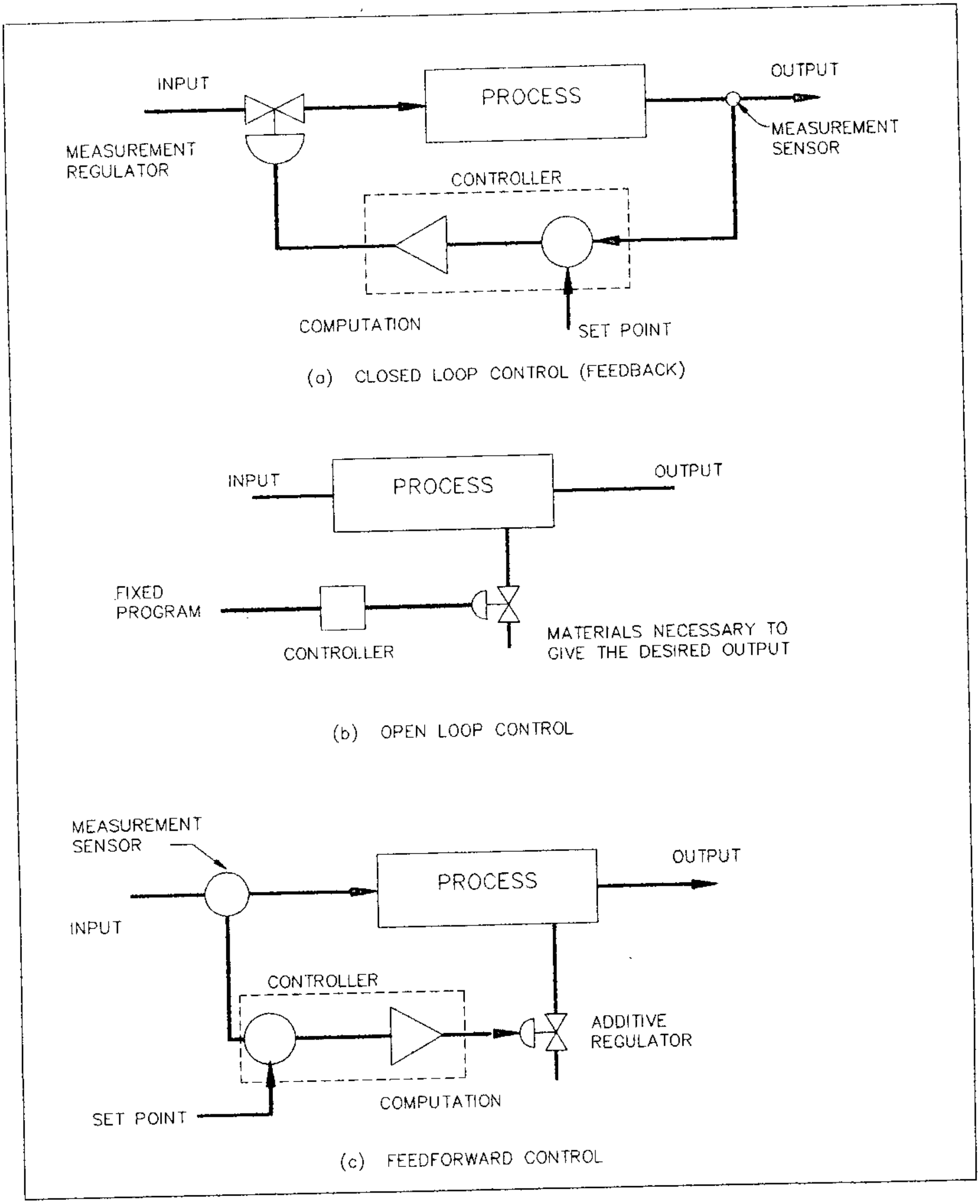


Figure 40
Typical Controls

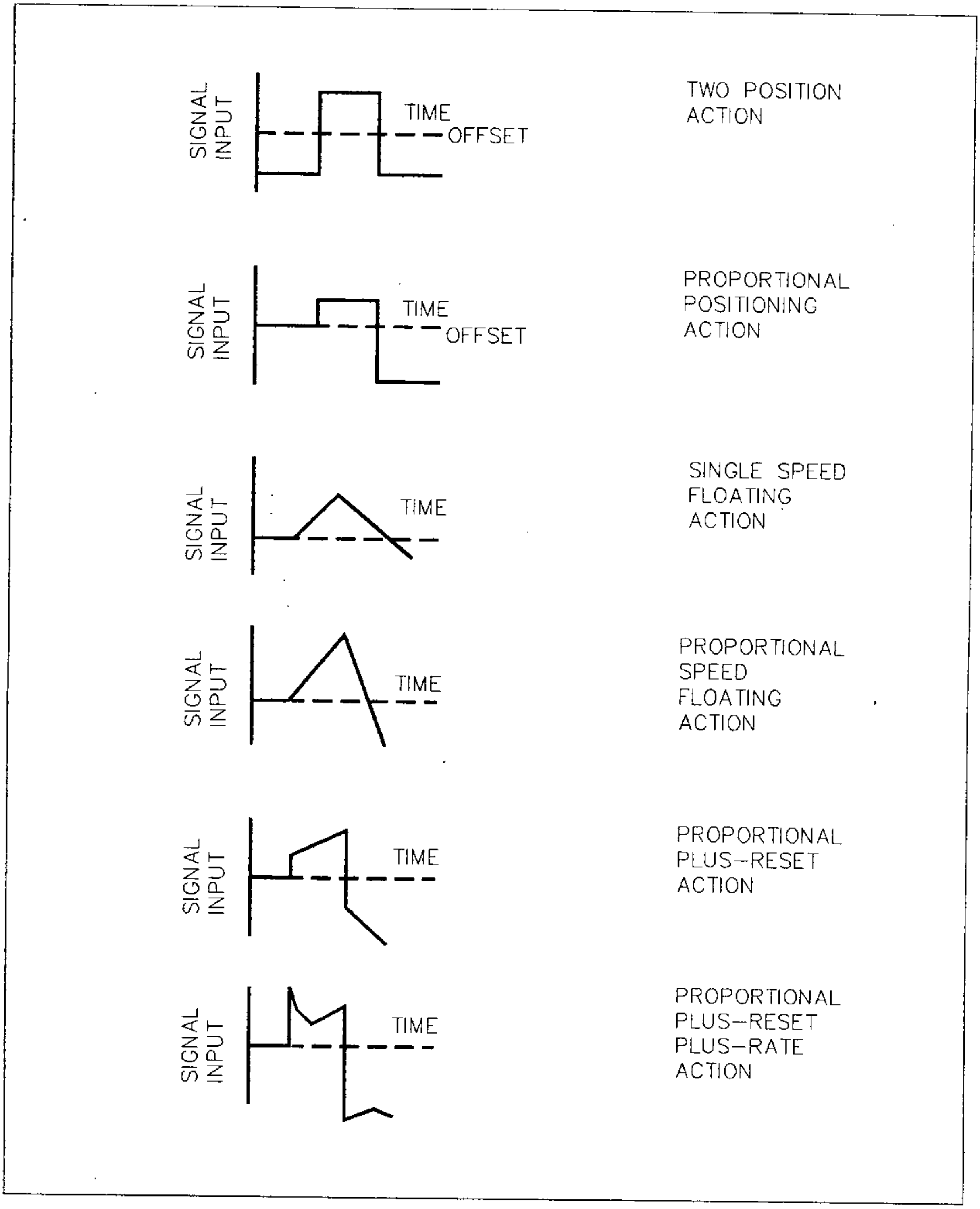


Figure 41
Types of Automatic Controller Action

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

11.12 Positioners. Positioners are used on control valves to force the stem and valve plug to move to a position as called for by the control signal. Positioners are used primarily to overcome valve stem friction, to compensate for long pneumatic transmission lines, or when extreme or variable line pressure can offset the valve plug. Every control valve exhibits from 2 to 10 percent hysteresis unless it is equipped with a positioner. The effect of valve position hysteresis is indicated in Figure 42.

A positioner should be used for liquid level, volume (as in blending), and weight (as in blending) whenever a two mode controller (proportional plus integral) is used. For temperature control, a positioner will be helpful but not essential. As a general rule, use a positioner on control systems that have a relatively slow response such as liquid level, blending, and temperature control loops. Do not use a positioner on control systems which have a relatively fast response such as liquid pressure, most flow, and some pressure control loops.

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

a) Clean dry atmosphere.

b) Relatively constant temperature and humidity.

c) No vibration.

d) Adequate light.

e) Reliable electric power, free of surges in voltage and frequency.

f) Clean, dry air of adequate pressure and capacity (for pneumatic instruments).

g) Air conditioning (a necessity for electronic distributive control systems and computers).

See Tables 22 and 23 for typical lists of analog instruments.

With the new microprocessor-based control systems, the operator

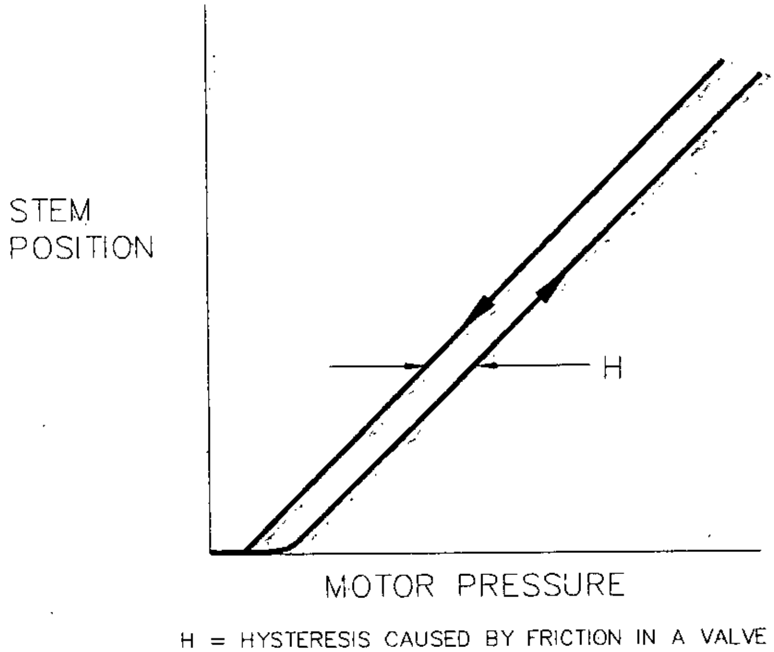


Figure 42
Hysteresis Caused by Friction in a Valve

interface can be a color or black and white cathode ray tube (CRT) monitor, thus eliminating the need for panels. The operator can control the boiler plant from a single CRT with redundant CRTs located elsewhere if desirable.

Field inputs and outputs should be done through the floor or ceiling of the control room. All field measurements should come into one central control room.

Section 12. WATER SUPPLY, MAKEUP, AND TREATMENT

12.1 Water Supply. Raw water is required for supply to water treatment equipment for boiler-turbine cycle water fill and makeup, water treatment equipment backwash, plant service water, domestic (potable) water, ash conditioning, cooling tower system fill and makeup, and fire protection. Consider the use of a raw water storage tank if necessary to back up any uncertainties in water supply or for fire fighting. Provide in-plant overhead tank or outdoor elevated tank for pressurization of distribution system, or consider the use of a pneumatic ground floor level pressurized system. For additional information see MIL-HDBK-1003/6, MIL-HDBK-1005/7, Water Supply Systems.

12.2 Water Makeup

12.2.1 Cycle Makeup. Boiler-turbine cycle water makeup is a requirement and continuous demand when the boiler-turbine cycle is in operation. Normal operation of the power plant will usually require an actual condensate makeup rate to the cycle of about 0.5 percent plus the makeup required for steam atomization of oil burners, steam operated soot blowers, and condensate losses in a process or facility heating system which is supplied with steam from the boiler-turbine cycle. The design of the makeup system should be based on a demand of 1.5 percent of the main steam flow to the turbine to provide for condensate losses from the cycle, plus steam usage for oil atomization and steam soot blowers, plus process or heating system steam and condensate losses. For additional information, see MIL-HDBK-1003/6.

12.2.2 Cooling Tower Makeup. Makeup water to a cooling tower cooling water system is required to replace losses from evaporation, drift, and blowdown. Drift loss from a mechanical draft tower will range from a minimum of 0.03 percent to a maximum of 0.2 percent of the cooling water flow rate. The blowdown rate will depend on the number of concentrations of total dissolved solids to be maintained in the cooling water. The relationships of these variables are as follows:

EQUATION:

$$\text{Drift} + \text{Blowdown} = \text{Evaporation} / (\text{No. of Concentrations} - 1) \quad (12)$$

EQUATION:

$$\text{Makeup} = \text{Evaporation} + \text{Drift} + \text{Blowdown} \quad (13)$$

For additional information relative to cooling towers, see para 12.7.

12.3 Water Treatment. Water treatment equipment will be required to provide cycle water fill and makeup of suitable quality. The final quality will depend on the operating pressure of the boiler. Water treatment of raw water may also be required in conjunction with cycle water makeup treatment and/or to provide potable water for domestic use, all depending on the quality of the raw water supply. Where a demineralizer is used for cycle water makeup, it shall be sized as follows:

EQUATION:

$$\text{Gallons/day} = (0.015 \times F \times 24 \times 60 + SA + SB + P) / 500 \qquad (14)$$

where:

F = Maximum boiler steam flow, lb/h
SA = Atomizing steam requirements, gal/day
SB = Soot blower steam requirements, gal/day
P = Process or heating steam and condensate losses, gal/day

The demineralizer should be sized to produce the amount of water as determined by Equation 14 by operating the demineralizer 18 hours per day, leaving 6 hours per day for demineralizer regeneration. The sizing should also be such that it should not be necessary to regenerate the demineralizer more than once per day. For additional information see MIL-HDBK-1003/6.

12.4 Cooling Water Systems

12.4.1 Once-Through System. Once-through systems have an intake structure including screens, cooling water pumps to provide for water static and dynamic head losses, a condenser, conduits to carry the water, and a discharge or outfall structure located so that significant recirculation of warm water will not occur.

12.4.2 Recirculating System

12.4.2.1 Evaporative Wet Cooling. This system utilizes cooling towers (natural or mechanical draft) or basins.

12.4.2.2 Non-evaporative Dry Cooling. Cooling water is pumped through a closed circuit passing through the condenser where heat is absorbed, then through a water-to-air heat exchanger, and finally back to the cooling water pumps for recycling.

12.4.2.3 Combination Wet and Dry Cooling. This system uses a combination of wet and dry systems as described above. The cooling tower combines a water to air heat exchanger section with an evaporative type cooling section. The advantages of the wet/dry tower as compared to the wet tower are lower water consumption and reduced water vapor (plume) discharge.

12.5 Intake Structures. The intake structure, usually made of concrete, shall contain stationary and mechanical traveling screens that are used to remove debris from the cooling water before entering the pumps.

12.5.1 Location. Locate the intake structure as close to the water source as possible in order to limit the hydraulic losses to the pump suction and to eliminate the possibility of a sand silt buildup in the wells of the structure. Connect the structure with the power plant through suitable pipes or reinforced concrete flumes or tunnels. The intake structure shall be provided with access roads and power wiring.

12.5.2 Arrangement. Provide at least two parallel sets of wells in the structure to permit alternate operation when one set is being cleaned. Each set shall contain an entry well, with a trash rack in front and a sluice gate (or stop logs) at its outlet; a screen well, with a traveling water screen; and a crossover well with sluice gates to permit closing off the screen well and directing the water flow from either set of wells to a selected pump flume or pump well.

The pump chamber may be combined with the intake structure when the power plant is some distance away or they may be separated by flume or pipe when they are close by and the pumps are installed near the condensers. In the combination intake structure and pump chamber, vertical centrifugal pumps are usually installed above a wet well, whereas horizontal centrifugal pumps may be installed in a dry well below low water level. A determination of extreme low and high water levels of the water source must be made.

12.5.3 Trash Racks. Inlet ports to the entry wells should be covered with trash racks as a rough screen for such items as logs, sticks, leaves, and ice. They should be designed to pass maximum velocities of 2 feet per second at extreme low water levels and arranged for manual raking from the outside.

12.5.4 Traveling Water Screen

a) Use screen approach water velocities of 0.5 to 0.75 feet per second to avoid entrapment of fish.

b) The maximum water velocity through the net screen area when passing the circulating pump capacity should not exceed 2.5 feet per second at extreme low water level. The net screen area is one-half of the waterway area, after deducting for the screen frame and boot interference. Manufacturers will guarantee a maximum 2 feet head loss under the above conditions.

c) One or two speed drives are available, the higher speed for intermittent operation when debris is light and the lower speed for continuous operation when the debris is heavy.

d) Select screen size and material to suit water conditions. Provide a trash trench, backwash pump and dewatering bin for cleaning the screens. Trash cannot be pumped back into water, but is disposed of either by incineration or in a landfill.

e) The flow area below the extreme low water level and the extreme high water level determines the height of the traveling screen.

f) In the extreme case of large quantities of water plants and algae, it may be necessary to back up the traveling screen with a fine stationary screen that can be lifted out for cleaning.

12.5.5 Pumps. Each condenser circulating pump should be sized to serve half of a condenser plus the water quantity required for turbine lubricating oil coolers, generator air coolers, and closed cooling water system. Oversizing these pumps will result in wasted power and in premature wear from operating continuously at pumping heads less than the design point. Pump materials should be suitable for the water conditions.

12.5.5.1 Vertical pumps. Use vertical pumps for large differences in extreme high and low water levels and obtain manufacturers' recommendations on installation. Design the suction chamber in accordance with Figures 43 through 46, because these pumps are very sensitive to poor distribution of flow at suction bell entrances. Note that the distance of the bell from the bottom of the well is critical.

12.5.5.2 Horizontal Pumps. Where economically justified, use horizontally split centrifugal pumps in a dry well below extreme low water level to avoid the necessity of foot valves and priming, as they are not as sensitive as vertical pumps to inlet flow conditions. Where horizontal circulating pumps are located away from the intake structure but above the suction flume, provide a means of priming the pumps.

12.5.5.3 Backwash Pump. The backwash pump for a traveling screen should be of the horizontally split centrifugal type and should take its suction from the circulating pump discharge. Where the intake structure and the circulating pump chamber are separated, it will be necessary to install a vertical backwash pump in the traveling screen well after the screen and to lengthen the intake structure accordingly.

A fire pump, where required, may be installed in the crossover well of the intake structure.

Provide space for pump motor controllers, traveling screen, and backwash pump on top of the structure.

12.5.6 Water Treatment

12.5.6.1 Chlorination. Provide chlorinator and storage for one ton chlorine containers for chlorination of the circulating water, if needed to control sea life growth. Chlorine concentration should be closely controlled and monitored to avoid injury to fish and/or loss of fish life.

12.5.6.2 Cathodic Protection. Provide all equipment necessary to protect exterior surfaces of the water screens, pumps, and piping below the water from corrosion by cathodic protection, as covered in MIL-HDBK-1004/10.

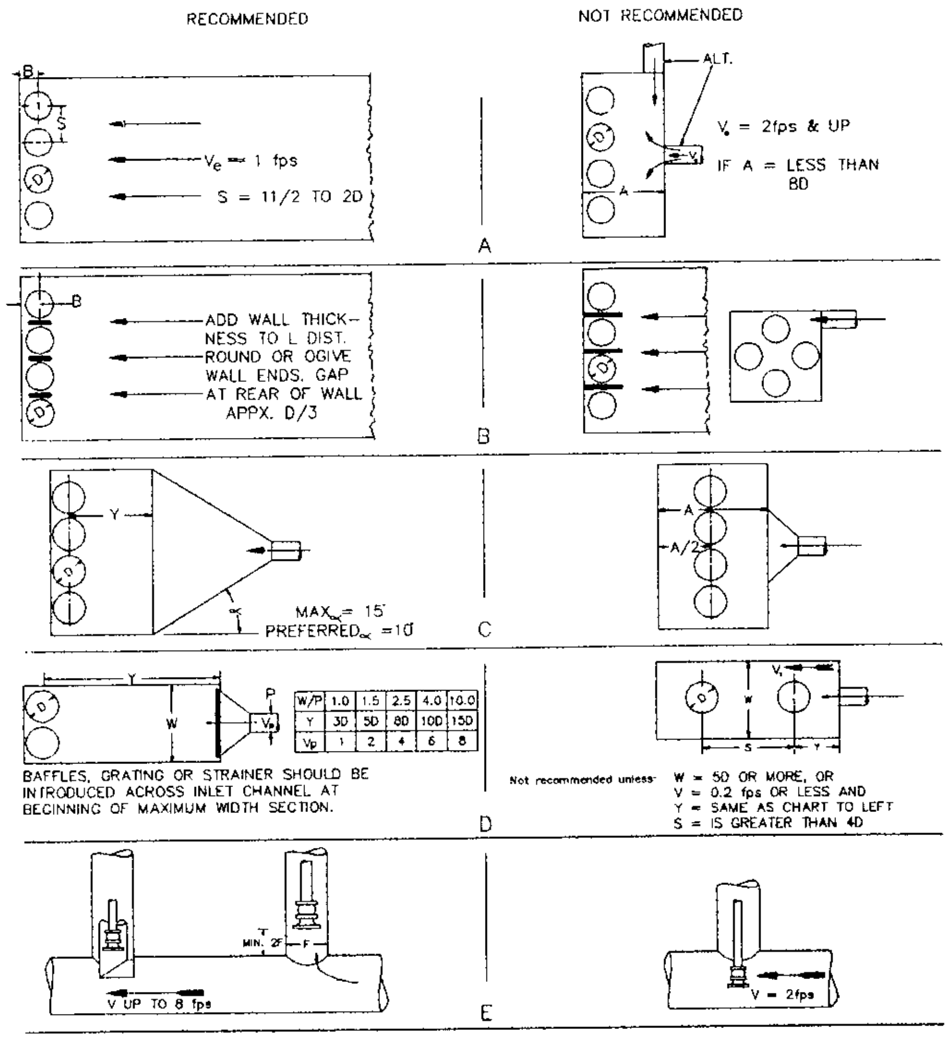
12.5.7 Housing. For unfavorable weather conditions, house the equipment on top of the structure, provide roof hatches over the screens and pumps to enable removal of the pumps, and include an inside crane. For outdoor installations, the screens and pumps must be raised by some other means of hoisting such as a traveling gantry crane, temporary rigging and hoist, or mobile boom hoist or cranes.

12.6 Outfall Structures. Discharge of cooling water from the condenser is made through conduits terminating at an outfall structure (usually made of concrete) located at the shore of an ocean, lake, basin, or river. The purpose of the outfall structure is to control the discharge of cooling water in such a manner to avoid bank or bottom erosion of the main body of water. Because of its location at the end of the discharge conduit, the outfall structure can also be used to provide the necessary seal for cooling water systems operating with a siphon.

12.6.1 Location. Locate the end or ends of the discharge conduit down stream from or as far from the intake structure as feasible, in order to reduce the possibility of recirculation of the warm discharge water.

Where economically justified, consider bypassing some of the discharge water to the intake structure for controlling ice formations or sea life growth.

12.6.2 Seal Wells. Where the top of the condenser water box is above extreme low water level of the cooling water source, advantage may be taken of the siphon effect to reduce the total pumping head. In order to start and maintain the siphon, the discharge end of the cooling water conduit must be maintained below water in order to provide and maintain a seal between the water in the conduit and the atmosphere. The maximum practical differential elevation between the extreme low water level of the source and the top of the condenser water box is usually between 28 and 30 feet. The actual value is limited by the vapor pressure of the cooling water corresponding to the actual maximum temperature of the cooling water at the point of maximum vacuum (resulting from the siphon). If, during operation, this limit should be



The Dimension D is generally the diameter of the suction bell measured at the inlet. This dimention may vary depending upon pump design. Refer to the pump manufacturer for specific dimensions.

Note: Figures apply to sumps for clear liquid. For fluid–solids mixtures refer to the pump manufacturer.

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Figure 43
Multiple Pump Pits

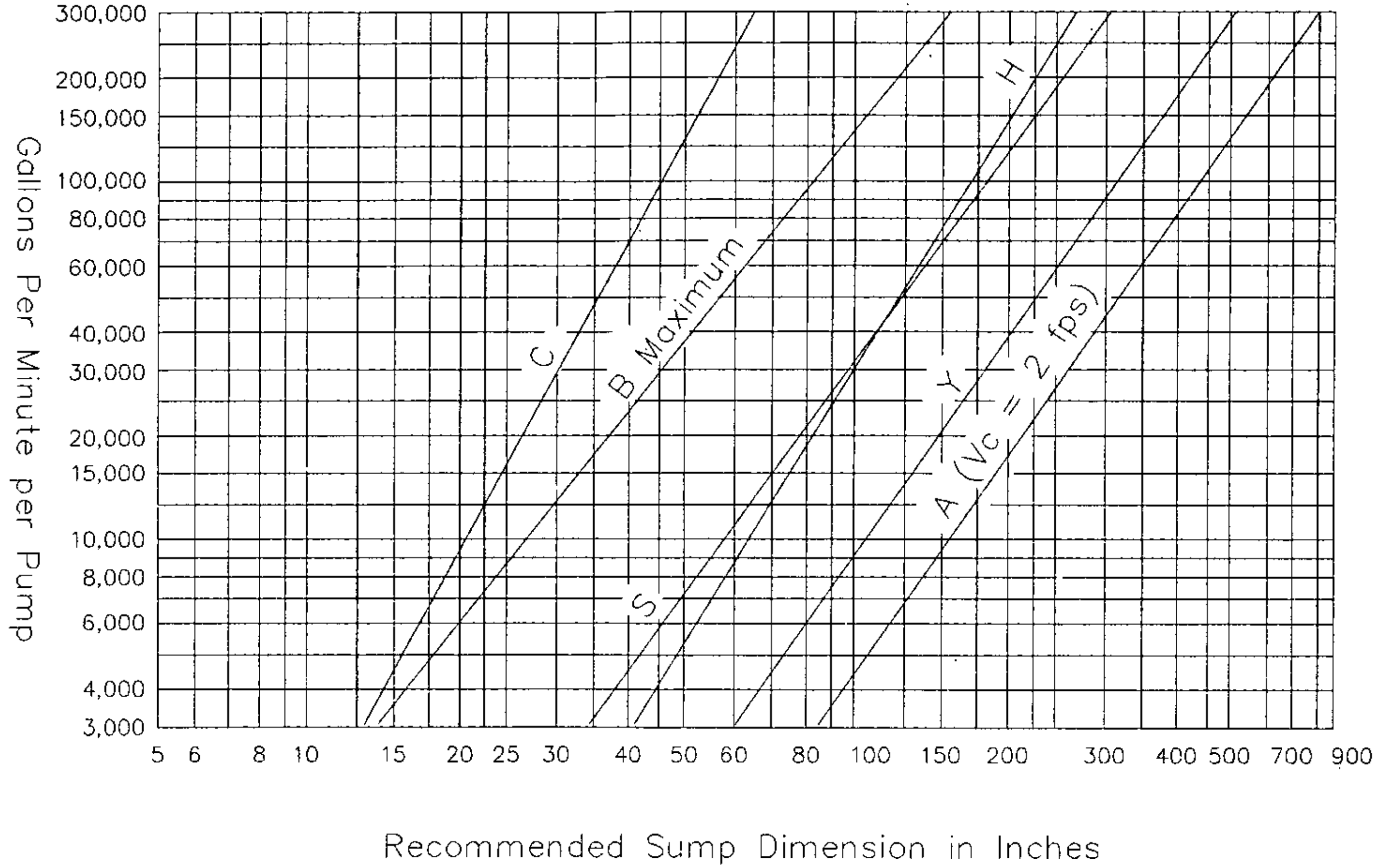

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Figure 44
Sump Dimensions Versus Flow

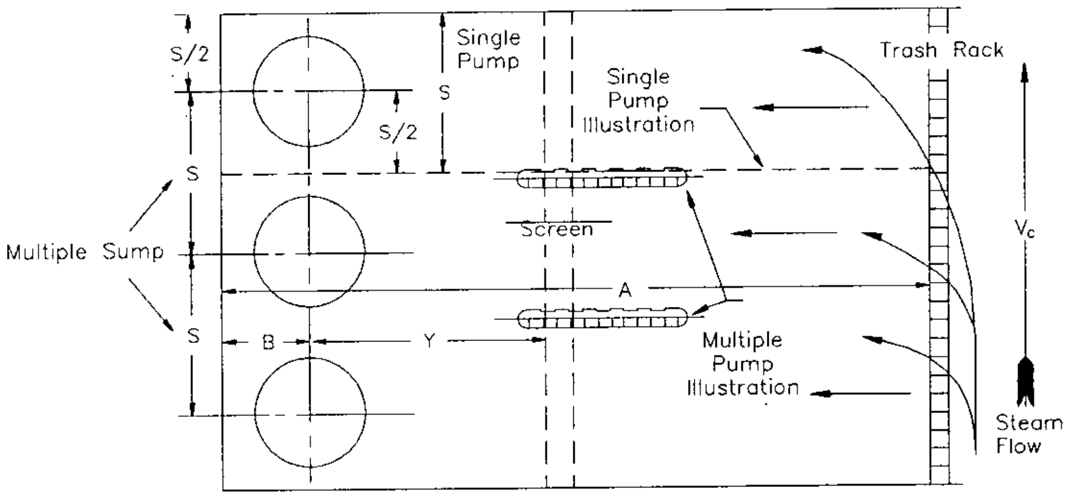

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Figure 45
Sump Dimensions Plan View

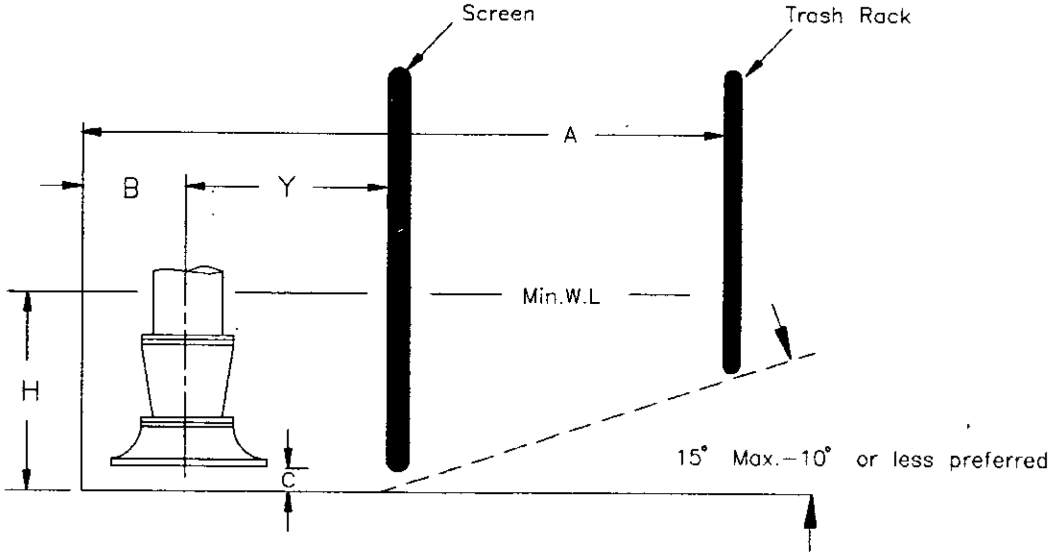

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Figure 46
Sump Dimensions Elevation View

exceeded as a result of higher vacuum or higher water temperature, the cooling water at this point will partially flash into vapor (steam) and the siphon will collapse.

Where the maximum allowable siphon is exceeded because of difference in elevation between the water level of the source and top of the condenser water box, a seal well with an adjustable discharge weir must be provided at the end of the discharge conduit to limit the siphon head. The adjustable weir is made up of stop logs that are installed by the operators as necessary to obtain the maximum possible head recovery, which can be afforded by the maximum practical siphon.

12.7 Cooling Towers. Cooling towers consist of a structure, some type of fill to break the warm water into droplets, warm water distribution system, air circulation system, and basin for collection of cooled water. For a detailed description of construction and theory of operation of cooling towers, see American Society of Heating, Refrigerating, and Air Conditioning Engineers, ASHRAE Handbook, HE Equipment Volume.

12.7.1 Mechanical Draft Towers

12.7.1.1 Induced Draft Wet Type. This type utilizes propeller fans with exhaust velocity recovery fan cylinders, which are mounted at the top of the cooling tower at the fan deck. Typical fan size for power plant use would be 28-foot diameter and powered with a 200 hp motor (single or two-speed) through a right angle gear reducer. Atmospheric air is drawn in through louvers or grating, through the falling water and fill, through drift eliminators, and out through the fans and fan cylinders.

12.7.1.2 Induced Draft Wet/Dry Type. This type combines a wet type as described above with a finned tube heat exchanger. The warm water to the tower usually flows first through the heat exchanger and then is distributed over the fill of the wet section. Atmospheric air is drawn in through the heat exchangers in parallel with air through the wet section. The addition of the heat exchanger reduces water consumption and water vapor discharge.

12.7.1.3 Induced Draft Dry Type. This combines induced draft fans and finned tube heat exchanger surface. Water flows through the coils while air is drawn across the outside of the finned tubes.

12.7.2 Natural Draft Towers. Natural draft cooling towers are generally economical for use only with very large scale power generating plants.

12.8 Cooling Water System Chemical Treatment

12.8.1 Chemical Analysis. The chemical analysis, the source, and the physical analysis of the raw water should be examined to determine what treatments are necessary.

12.8.2 Selection Factors. See Table 26 for a general guide to avoiding circulating water troubles. For collateral reading on the problem, see ASHRAE Handbook, Systems Volume, Corrosion and Water Treatment, and National Association of Corrosion Engineers (NACE), Cooling Water Treatment Manual.

Table 26
Cooling Water Treatments

Water Problem	Treatment for Systems	
	Once-through	Open recirculating
Scale	Polyphosphates pH control. Manual cleaning.	Continuous blowdown. Polyphosphates. pH control. Softening.
Corrosion	Corrosion resistant materials. Coatings. Corrosion inhibitors. pH control.	Corrosion resistant materials. Coatings. Corrosion inhibitors. pH control.
Erosion	Erosion resistant materials. Velocity limit. Removal of abrasives.	Erosion resistant materials. Velocity limit. Removal of abrasives.
Slime and algae	Chlorination. Chemicals, algaecides, and slimicides.[1] Manual cleaning.	Continuous blowdown. Chemical algaecides. Velocity. Manual cleaning.
Delignation of wood	None	pH control
Fungus rot	None	Pretreatment of wood

1. Biodegradable materials should be used to avoid environmental damage to streams, rivers, lakes, etc.

Section 13. CORROSION PROTECTION

13.1 Justification. Corrosion exists in every metallic substance to some degree and in many cases to a severe degree. A corrosion protection program against severe corrosion conditions must be justified on the basis of economy, necessity, and hazards.

13.1.1 Economy. The investment cost plus operating and maintenance costs of a program should be less than the sum of the following:

a) Direct loss or damage costs resulting from corrosion of metal structures.

b) Direct maintenance costs attributed to corrosion, including indirect losses, such as leakage-loss of tank contents.

c) Increased costs for over design to allow for strength losses resulting from corrosion.

d) Costs of shutdown, power failures, labor losses, and other items.

13.1.2 Operational Necessity. Military facilities must be maintained in a state of readiness at all times, with the importance and mission determining the degree of necessity for corrosion protection.

13.1.3 Hazards in Handling Materials. Corrosion preventive measures are necessary where deterioration of structures, and containers and piping serving fluids or gases may cause danger of fire and explosion.

13.2 Causes. For power plants, corrosion is caused primarily by oxidation, galvanic action, or chemical attack. For more detailed information see MIL-HDBK-1003/6.

13.3 Corrosion Controls. The control of corrosion involves the selection of appropriate materials, use of metallic, organic, inorganic, or plastic coatings, and cathodic protection systems. For additional detailed information, see MIL-HDBK-1003/6. For description and design of cathodic protection systems, see MIL-HDBK-1004/10.

Section 14. SAFETY PROTECTION

14.1 Personnel

14.1.1 OSHA Standards. All federal installations must comply with the Code of Federal Regulations, Title 29, Chapter XVII, Occupational Safety and Health Administration, Department of Labor, Part 1910 - Occupational Safety and Health Standards, Safety requirements, including those not covered by OSHA standards, should be the latest most stringent standards and practices followed by industrial organizations. Special attention shall be given to platforms, railings, occupational noise exposure, means of egress, safety signs, color code and markings, fire protection, safety relief valves, and control valves.

14.1.1.1 Equipment Guards. Guards shall be provided to cover all exposed rotating shafts, couplings, flywheels, belt sheaves, and driven belts. Safety cages and guards shall be provided for conveyor belt takeups.

14.1.1.2 Platforms and Stairs. Provide access platforms for operation and maintenance of all equipment and valves more than 8 feet 0 inches above the floor level. Handrails and toe guards shall be provided on platforms and floor openings. Stairs shall be provided where possible in lieu of ladders; landings shall be provided when stair run is in excess of 12 feet 0 inches. Stairs shall be constructed with abrasive treads or nosings and, preferably, closed risers.

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

14.1.2 National Industrial Safety Codes. The following codes shall apply:

a) ANSI A12 - Safety Requirements for Floor and Wall Openings, Railings, and Toe Boards.

b) ANSI A14.3 - Fixed Ladders, Safety Requirements.

c) ANSI/ASME B15.1 - Mechanical Power Transmission Apparatus.

d) ANSI/ASME B20.1 - Conveyors and Related Equipment.

e) ANSI/ASME B30.2 - Overhead and Gantry Cranes.

f) ANSI/ASME B30.6 - Derricks.

g) ANSI B30.11 - Monorails and Underhung Cranes.

h) ANSI B30.16 - Overhead Hoists (Underhung).

i) ANSI C2 - National Electrical Safety Code.

j) NAVFAC P-309 - Color for Naval Shore Facilities.

k) ANSI Z83.3 - Gas Utilization Equipment in Large Boilers.

l) ANSI Z358.1 - Eyewash and Shower Equipment, Emergency.

m) ANSI/NFPA 31 - Installation of Oil Burner Equipment.

n) ANSI/NFPA 37 - Combustion Engines and Gas Turbines.

o) ANSI/NFPA 70 - National Electrical Code.

p) ANSI/NFPA 85F - Installation and Operation of Pulverized Fuel Systems.

14.1.3 Hearing Conservation. NAVOSH Standards for noise exposure, and hearing conservation including protection requirements, are presented in Chapter 18 of OPNAVINST 5100.23B, Navy Occupational Safety & Health Program.

14.1.3.1 Permissible Noise Exposure. In accordance with NAVOSH Standards, protection against the effects of noise exposure shall be provided when sound levels exceed those shown in Table 27.

Table 27
Permissible Noise Exposures

Sound level Duration per day, Hours	dBA slow response
8	84
6	85
4	88
3	91
2	96
1-1/2	101
1	112

When the daily noise exposure is composed of two or more periods of noise exposure of different levels, their combined effect should be considered, rather than the individual effect of each. If the sum of the following fractions: C1/T1+C2/T2+...Cn/Tn exceeds unity, then, the mixed exposure should be considered to exceed the limit value. Cn indicates the total time of exposure at a specified noise level, and Tn indicates the total time of exposure permitted at that level.

Exposure to impulsive or impact noise should not exceed 140 dB peak sound pressure level.

14.1.3.2 Equipment Design Sound Levels. All equipment which produces noise as a side effect of operation shall be specified for noise level not in excess of 84 dBA (A scale rated sound pressure level referenced to 0.0002 microbar) when measured 5 feet above the mounting floor level and 3 feet from the equipment base. Equipment which cannot meet this specification shall be provided with appropriate silencers or enclosed as necessary to contain or direct the emanating sound.

14.1.3.3 Space Design Sound Levels. Power plant areas which require air conditioning usually require consideration of sound level also. These areas include central control rooms, offices, and laboratories. The acoustical design goals for these areas is the achievement of background sound levels which will not interfere with the occupancy requirements. For complete information relative to design, control, and testing of sound, see the American Society of Heating, Refrigerating, and Air Conditioning Engineers (ASHRAE) Handbooks, Fundamentals and Systems Volumes.

14.1.4 Handling of Toxic and Hazardous Substances

14.1.4.1 Hazard Communication Standard. OSHA standards for hazard communications are presented in Title 29, CFR Part 1910, Subpart Z, paragraph 1910.1200.

14.1.4.2 Local Exhaust. For design guidance of local exhaust systems for mixing tanks, local feed systems, test bench hoods, etc., see MIL-HDBK-1003/17 Industrial Ventilation Systems, and ACGIH Industrial Ventilation Manual.

14.1.4.3 Storage. For design criteria pertaining to storing of all types of toxic and hazardous substances, see MIL-HDBK-1032/2, Covered Storage.

14.1.4.4 Dry Chemicals. Provide storage per manufacturer's recommendations or instructions.

14.1.4.5 Liquid Chemicals. Provide curbed area around liquid storage or mixing tanks and chemical feed equipment. Volatile toxic chemicals will require special ventilation and adequate personnel protective clothing; included in this category are chemicals such as acids, morpholine, hydrazine, etc. For design criteria, refer to ACGIH Industrial Ventilation Manual.

14.1.4.6 Gaseous Chemicals. See 29 CFR 1910, Subpart H - Hazardous Materials and Subpart Z - Toxic and Hazardous Substances.

14.1.4.7 Emergency Shower and Eye Wash Fountain. Provide an emergency shower and eye wash fountain, meeting ANSI Z358.1, within any work area in which personnel eyes or body may be accidentally exposed to injurious corrosive materials.

14.2 Piping and Equipment

14.2.1 Piping. Provide safety relief valves on piping in accordance with ANSI/ASME B31.1, Power Piping (ASME Code for Pressure Piping).

14.2.2 Boilers and Pressure Vessels. Provide safety relief valves on boilers, receivers, heat exchangers, and other pressure vessels in accordance with the ASME Boiler and Pressure Vessel Code.

14.2.3 Air Compressors and Positive Displacement Pumps. Provide safety valves as necessary to protect air compressors and positive displacement pumps in the event a discharge valve is closed with the equipment in operation.

14.2.4 Equipment Enclosures. To protect both equipment and personnel, provide enclosures for batteries, machine shop, and laboratory equipment. Battery rooms shall be provided with forced ventilation exhaust type fans.

14.3 Air Navigation. To determine if any part of the power plant, such as the stack, presents an obstruction to air navigation, refer to Title 14 Code of Federal Regulations, Part 77. See also Federal Aviation Administration advisory circular AC 70/7460-1F, Obstruction Marking and Lighting; FAA 150/5345-43c, Specification for Obstruction Lighting Equipment; MIL-HDBK-1023/1, Airfield Lighting; and NAVAIR 51-50AAA-2, General Requirements for Shorebased Airfield Marking and Lighting.

14.4 Security. See NAVFAC DM-5.12, Fencing, Gates, and Guard Towers, for security fencing.

Section 15. FIRE PROTECTION

15.1 General Requirements. See MIL-HDBK-1190 and MIL-HDBK-1008, Fire Protection for Facilities Engineering, Design and Construction. The designer shall be governed by the above Navy criteria. Where Navy criteria do not address a particular subject, applicable Factory Mutual Engineering Loss Prevention Data Sheets and National Fire Protection Codes shall be consulted. All questions concerning fire protection should be directed to the fire protection branch. For additional requirements, see MIL-HDBK-1003/6.

15.2 Fuel. For fire protection of coal facilities, see MIL-HDBK-1003/6. For fire protection requirements for oil fuel, see NFPA 30, Flammable and Combustible Liquids Code and NFPA 31, Oil Burning Equipment, Installation of.

15.3 Transformers. Outdoor generator step up transformers and outdoor auxiliary transformers shall be protected by automatic, dry pilot, deluge water spray fire protection equipment.

15.4 Lubricating and Hydrogen Seal Oil Equipment. The turbine lubricating oil reservoir and conditioner, and hydrogen seal oil unit, if any, shall be protected by automatic, dry pilot, deluge water spray fire protection equipment.

15.5 Standpipe and Fire Hose Stations. Standpipe and fire hose stations shall be strategically located at various levels of the power plant and at various locations on each floor.

15.6 Portable Hand-Held Extinguishers. Portable hand-held fire extinguishers shall be provided at all standpipe hose stations and other strategic locations. The extinguishing agent shall be selected based on the fire hazards encountered in the immediate area.

15.7 Typical Fire Protection Systems for Power Plants. Table 28 lists the various areas or pieces of power plant equipment that should be considered relative to the need for fire protection. Whether or not an area or piece of equipment requires the installation of fire protection equipment depends on the initial costs of buildings and equipment being considered and the relative cost of the fire protection system. The criticality of an area or piece of equipment to the mission of the power plant must also be considered. Table 28 also lists the recommended type of fire suppression system, type of detection, and operation.

Table 28
Typical Fixed Fire Detection and Suppression Systems

Location	Type of Fire Suppression System	Type of Detection	Operation
Administration Area (excluding Halon protected areas)	Wet pipe sprinkler	Fixed temperature quartzoid bulb	Automatic
Plans and records storage room	Halon 1301	Cross-zoned ionization and photo-electric smoke detection system	Automatic
Control room (below ceiling)	Not applicable	Ionization smoke detection	Alarm only
Control room (above ceiling)	Not applicable	Ionization smoke detection	Alarm only
Control room (main control panel)	Not applicable	Ionization smoke detection	Alarm only
Control equipment room	Halon 1301	Cross-zoned ionization and photo-electric	Automatic
Cable spreading room	Wet pipe sprinkler	Fixed temperature quartzoid bulb	Automatic
	--	Ionization smoke detection	Alarm only
Turbine underfloor area, grade and mezzanine level	Dry pipe sprinklers	Fixed temperature quartzoid bulb	Automatic
Turbine generator bearings	Preaction spray	Fixed temperature	Manual
Boiler feed pump turbine	Deluge spray	Dry pilot	Automatic

Table 28 (Cont.)
Typical Fixed Fire Detection and Suppression Systems

Location	Type of Fire Suppression System	Type of Detection	Operation
Warm-up guns and igniters	Preaction spray	Fixed temperature	Automatic
Igniter oil pumps	Deluge spray	Dry pilot	Automatic
Hydrogen seal oil unit	Deluge	Dry pilot	Automatic
Turbine lube oil reservoir and conditioner	Deluge spray	Dry pilot	Automatic
Main generator and auxiliary transformers	Deluge spray	Dry pilot	Automatic
Reserve auxiliary transformers	Deluge spray	Dry pilot	Automatic
Switchgear areas and major motor control center	None	Smoke detection only	Alarm
Coal conveyors within generation building	Dry pipe sprinklers	Fixed temperature quartzoid bulb	Automatic
Air heaters	Deluge spray	Infrared hot spot detectors	Manual
Coal pulverizers	Steam inerting	Carbon monoxide monitoring	Manual
	Waterwash		Manual (for B&W only)
Coal dust collectors	Preaction sprinkler	Thermistor wire	Automatic

Table 28 (Cont.)
Typical Fixed Fire Detection and Suppression Systems

Location	Type of Fire Suppression System	Type of Detection	Operation
Coal silos	Low pressure CO_2	--	Automatic on master fuel trip or manual for fires
Silo fill galleries and plant conveyor gallery	Dry pipe sprinklers	Fixed temperature quartzoid bulb	Automatic
Coal feeders	Provisions for CO_2 inerting or for water hose streams	--	Manual

Section 16. MISCELLANEOUS

16.1 Piping. For design of power plant piping and selection of piping materials, see ANSI/ASME B31.1, Power Piping (ASME Code for Pressure Piping). See also MIL-HDBK-1003/8, Exterior Distribution of Utility Steam, High Temperature Water (HTW), Chilled Water (CHW), Fuel Gas, and Compressed Air.

16.2 Insulation, Lagging, and Jacketing

16.2.1 Insulation. Insulation shall be non-asbestos composition and shall be applied to piping, equipment, and ductwork to conserve energy and for comfort and safety. Thickness for energy conservation shall be dictated by an economic comparison of the value of heat energy saving versus the cost of additional thickness of insulation.

For additional information, see MIL-HDBK-1003/6.

16.2.2 Lagging. Metal lagging is used to cover insulation applied to breeching, ductwork, scrubbers, baghouse filters, electrostatic precipitators, large fans, and other equipment having large flat surfaces. Lagging can be aluminum, aluminized steel, galvanized steel, or stainless steel in a variety of profiles with the selection depending on the application and exposure. Lagging can be plain, corrugated, embossed, unpainted, or painted with a variety of finishes.

Lagging surface temperature shall not exceed 150 degrees F (66 degrees C).

16.2.3 Jacketing. All insulated piping and equipment should be completely covered with aluminum or stainless steel jacketing. Aluminum jacketing should not be used for piping in trenches or buried directly in the ground.

To prevent galvanic corrosion, avoid permanent contact of aluminum jacketing with copper, copper alloys, tin, lead, nickel, or nickel alloys including Monel metal.

16.3 Freeze Protection. Piping that is subject to freezing shall be protected with electric heating cable. Follow manufacturer's recommendations and instructions for application.

16.4 Pipe Supports. Use rigid (rod or roller) or spring type pipe hangers for supporting overhead piping. Piping located near floors, platforms, or other suitable surfaces is often supported from below by rigid floor stands. See Federal Specification WW-H-171E, Hangers and Supports, Pipe, for type selection. See also MIL-HDBK-1003/8.

Locate anchors to control heat pipe movement or to limit movements of branch takeoffs from a main line.

Provide adequate flexibility (by use of change in pipe direction, expansion loops, or expansion joints) in all steam or hot liquid piping. Perform formal piping flexibility and hanger support calculations to make certain that pipes will be adequately and properly supported, that pipe stresses will not exceed limitations permitted by ANSI/ASME B31.1, and that piping reactions and movements at equipment piping connection or piping anchors will not be excessive. For piping hanger and flexibility calculations, refer to publications such as Piping Handbook, Sabin Crocker or Piping Design and Engineering, ITT Grinnell, Inc. Providence, RI. Computer programs for analyzing piping flexibility (stress, forces, and moments) such as ADLPIPE can also be used.

16.5 Heating, Ventilating, and Air Conditioning. Refer to MIL-HDBK-1003/6 and NAVFAC DM-3.03, Heating, Ventilating, Air Conditioning and Dehumidifying Systems for boiler plant requirements.

16.5.1 Heating. Heating systems shall be provided for boiler room, turbine room, pump and equipment rooms, shcps, warehouses, and administration areas if required for comfort or for freeze protection. Heat from boiler and equipment operation shall not be taken as a credit.

16.5.2 Ventilating. Provide adequate forced ventilation for the boiler room and the turbine room by use of roof-mounted exhauster fans. Central control rooms and offices should utilize air handling units with duct systems for air distribution. Other areas to be ventilated include shops, tunnels, enclosed coal galleries, toilets and washrooms, locker rooms, lunch rooms, and other areas where personnel are expected to operate or maintain equipment. Exhaust air from areas with suspended particulate shall be cleaned sufficiently to satisfy environmental regulations.

16.5.3 Air Conditioning. Use air tempering (heating and cooling) for central control rooms and for areas such as offices where air conditioning for comfort is justified. Include humidification where necessary for comfort. In dry climate regions, humidification of the boiler and turbine rooms may also be necessary for personnel comfort.

16.6 Cranes and Hoists

16.6.1 General. Refer to NAVFAC DM-38.01, Weight-Handling Equipment.

16.6.2 Cranes. Provide turbine room crane for erection and maintenance of turbine generators.

16.6.3 Hoists. Provide hoists and supports for maintenance on water intakes, pumps, compressors, fans, and other heavy equipment. Provide a beam into the plant, and provide steel above an opening between floors to hoist large equipment to an upper level.

16.7 Metering. Meters shall be provided on fuel lines, electrical and water services to the buildings, and to the major equipment and boilers in the building. Steam output metering of the header and at each steam generator shall be provided for periodic reports and testing.

16.8 Drainage. Refer to MIL-HDBK-1003/6, under Drainage and NAVFAC DM-3.1, Plumbing Systems.

16.9 Seismic Design Criteria

16.9.1 Power Plant Buildings. Power plant buildings shall be in accordance with Seismic Design for Buildings, NAVFAC P-355.

16.9.2 Piping. All piping systems shall be designed to permit freedom of movement of the pipes in all directions. Pipe penetration through building walls and floors shall be made through pipe sleeves and with swing joints or other means of permitting independent pipe movements.

All piping critical to the operation of the power plant shall be steel, if possible, in lieu of a brittle material.

Cast-iron or cement-asbestos pipe shall not be used for condenser cooling waterlines.

16.9.3 Equipment. All mechanical equipment and tanks shall be securely anchored to their foundations. Supports for equipment shall be steel in lieu of cast iron.

16.9.4 Controls. Control systems shall be designed so that loss of the control media (air or electricity) will leave the control in a fail-safe position.

16.10 Architectural Criteria

16.10.1 Outdoor and Semi-Outdoor Plants. Boiler plants and generators, completely outdoors, may be feasible in warm and temperate climates, thereby reducing construction costs. Proper measures against freezing of stationary water must be made.

Definitive steam electric-generating plants have semi-outdoor boilers. Weatherproofing equipment for outdoor service saves a good part of building construction. However, weatherproofing equipment makes operation and maintenance more difficult.

An economic study should decide whether indoor or outdoor housing should be used.

16.10.2 Arrangements. Architectural arrangements should provide for:

a) Minimum total building volume.

b) Centralization of electrical equipment and controls.

c) Sufficient aisle and laydown space.

d) Adaptability to various makes of equipment.

e) Adaptability to definitive designs.

f) Localization of operations.

g) Ease of replacing equipment and extending a plant.

h) Loading and unloading fuel and equipment.

i) Parking.

j) Toilets, lockers, work shops, offices, storage, and control rooms.

k) Equipment platforms with access.

16.10.3 Criteria Source. For general architectural design criteria, see MIL-HDBK-1003/6, under Architectural Criteria.

16.11 Structural Criteria

16.11.1 Foundations. Power plant foundations require careful design because a site is frequently on marsh or filled ground close to the sea. Where low water levels are anticipated, a detailed subsurface study is necessary.

a) Extra piling may be required for stack foundations, turbine generators, boilers, fuel oil tanks, coal silos, and other heavy equipment. Seismic conditions at the site should be investigated.

b) Where heat from a furnace is transmitted to a boiler foundation, it should be separated from other foundations and floor slabs, and an expansion joint at floor slab level installed around its periphery.

c) Equipment foundations should be designed in accordance with manufacturers' instructions.

16.11.2 Platform and Ladders. Provide platforms for all systems more than 4 feet above the ground floor requiring access for operation and cleaning. Connect the platforms to two means of exit.

a) Systems and access doors for inspection need only ladders.

b) Platforms shall have toe guards and railings.

16.11.3 Typhoon or Hurricane Considerations. Exterior mechanical equipment and systems should be anchored, braced, or guyed to withstand the wind velocity specified for design of structures (see MIL-HDBK-1002/2, Loads). Designs for construction, installation, and anchorage of the typical mechanical features, as listed below, shall be given special attention to ensure minimum damage due to typhoon or hurricane phenomena:

16.11.3.1 Miscellaneous. Coal silos and conveying systems, cooling towers, evaporative condensers and coolers, boiler stacks, outside boilers, duct work, and roof-mounted heating and air conditioning units.

16.11.3.2 Exterior Piping Systems. Steam, water, compressed air, and fuel distribution lines mounted above ground on structural supports.

16.11.4 Collateral Reading. See MIL-HDBK-1003/6.

16.12 Electrical Criteria. Refer to MIL-HDBK-1003/6, under Electrical Criteria.

16.13 Operation and Maintenance Manuals. Each power plant shall be provided with a complete set of operating and maintenance manuals covering the plant, each process system and subsystem, and each piece of equipment. Preparation of operating and maintenance manuals shall be in accordance with the latest revision of Military Specification MIL-M-38784, Manuals, Technical: General Style and Format Requirements.

16.13.1 Plant Operation and Maintenance Manual. The plant operation and maintenance manual shall be divided into volumes separating mechanical and electrical systems. The manual shall be composed of sections or parts, each covering a complete operating system. Each section or part shall be formatted as follows:

16.13.1.1 System designation

16.13.1.2 Description of system and associated major equipment. Include pictures as necessary. List special tools or test equipment that are needed or furnished with equipment. Describe system function. Reference Equipment Data Manual for each piece of equipment. List all valves, state valve function, and state normal valve position (open, closed, or throttled). Include pipeline listing of pipeline section description, pipe material, and thickness and type of insulation. List and describe all electrical components.

16.13.1.3 Operation. Operation of system including procedures for prestart, starting, shutdown, post-shutdown, and monitoring. Include list of monitor description, location, units (such as ON/OFF), status, and alarm.

16.13.1.4 Maintenance. Maintenance of system including safety precautions, preparation, maintenance procedures (refer to data contained in Equipment Data Manual wherever possible). List maintenance actions, frequency (monthly, quarterly, semi-annually, annually, etc.) and Equipment Data Manual reference. Include description of each maintenance action by steps.

16.13.1.5 Troubleshooting. Troubleshooting of system including safety precautions, preparations, and troubleshooting. List troubleshooting activity by equipment piece including reference to Equipment Data Manual. Include list of trouble, probable cause, and corrective action for each piece of equipment.

16.13.1.6 Drawings. Foldout drawings including system descriptive drawings, schematic diagrams, flow diagrams, piping and instrument diagrams, heat balances, electrical one-line diagrams, control panel layouts, and reduced copies of sheets of construction plans, as necessary.

16.13.2 Equipment Data Manual. The Equipment Data Manual shall consist of one or more volumes, as necessary, to contain manufacturer's literature and data covering operation and maintenance procedures. This data manual should be indexed and sectioned by major pieces of equipment, including original equipment manufacturer's accessories. Equipment data should include the following information:

a) Master equipment list including equipment identification or tag number, name of item of equipment, location of item, name of supplier/manufacturer, other identifying characteristics such as capacity or type, and data location in the manual.

b) Manufacturer's data for each piece of equipment including:

(1) General description.

(2) Sequence of operation (startup, operating, and shutdown).

(3) Operational checks and tests.

(4) Adjustments.

(5) Maintenance, lubrication, and inspection procedures and intervals.

(6) Parts lists, including price list.

(7) Recommended spare parts.

(8) Manufacturer's data report for boilers, pressure vessels, and heat exchangers.

(9) Manufacturer's certified pump performance curves and factory test data sheets.

(10) Piping and wiring diagrams.

(11) Original equipment manufacturer's data for associated auxiliary or accessory equipment.

Section 17. POLLUTION CONTROL

17.1 Air Quality Control

17.1.1 Pollutant Production. As a fossil fuel is burned, air pollutants such as sulfur dioxide (SO_2), nitrogen oxides (NOx), and particulate matter are produced. The amount of each formed is dependent upon many factors, the most important of which are fuel type and fuel burning equipment. Data on emissions of pollutants produced while burning a fossil fuel in a boiler are given in TM-5-815-1/AFR 19-6, Air Pollution Control Systems for Boilers and Incinerators.

17.1.2 Emission Limits. The amount of the pollutants produced in the boiler that are allowed to pass out of the stack as emissions is governed by Federal, state, and local regulations. A discussion of emission limits as they relate to fossil fueled steam power plants is contained in Section 18, Environmental Regulations and Permitting.

17.1.3 Equipment Selection. Examples of particulate matter removal equipment include mechanical cyclones, wet scrubbers, electrostatic precipitators, and fabric filters (baghouses). Sulfur dioxide is normally removed with wet or dry scrubbers. The basic operation, application, design considerations, and selection of air pollution control equipment are contained in TM-5-815-1/AFR 19-6.

Nitrogen oxides are not normally removed from the exhaust; rather, the pollutant production in the boiler is minimized. Various techniques such as fuel changing, load reduction, and combustion modifications can be employed. However, recently there has been much development work performed with techniques for reducing NOx emissions with the use of Urea, Ammonia or Selective Catalytic Reduction. These systems have been installed on many recent boilers and combustion turbines. Details of NOx reduction techniques are given in TM-5-815-1/AFM 19-6.

17.1.4 Monitoring and Reporting. Point source emission rate tests are a necessary part of the environmental impact assessment required for all new Government-funded facilities. In the upgrading of existing installations, compliance is determined through point source emission rate tests. Revisions to the regulations regarding air pollution test requirements for federal installations appear in the Federal Register.

The point source emission rate test methods and requirements approved by the EPA are published in the Code of Federal Regulations. The techniques included are for testing for particulate, SO_2, NOx, and visible emissions and are listed in Table 29.

Table 29
EPA Emission Sampling Techniques[1]

EPA Method	To determine:
#1	Sampling site and the minimum number of sampling points required for the extraction of a representative sample of flue gas from a stationary source.
#2	Velocity and volumetric flow rate of flue gas.
#3	Concentration by volume of carbon dioxide (CO_2), carbon monoxide (CO), and oxygen (O_2) in flue gas.
#4	Moisture content of flue gas.
#5	Particle emissions from stationary sources.
#6	Sulfur dioxide (SO_2) concentration in flue gas.
#7	All nitrogen oxides (NOx) in flue gas except nitrous oxide (NO).
#8	Sulfur dioxide and sulfuric acid (H_2SO_4) mist concentrations in flue gas..
#9	Opacity of visible emissions.

[1]40 CFR 60, Appendix A.

Sampling ports will be approximately 4 inches in diameter, extend out approximately 4 inches from the stack, and have a flanged removable cover. On double wall stacks, sampling ports may consist of a 4-inch diameter pipe extending from 4 inches outside the stack to the inner edge of the inner stack wall. Sampling ports will be accessible and located so that the cross-sectional area of the stack or flue can be traversed to sample the flue gas. The sampling ports shall be provided and located in accordance with the applicable current Federal or state regulations for fuel-burning equipment.

17.2 Water Quality Control

17.2.1 Waste Streams. The number and source of wastewater streams associated with a fossil-fueled steam power plant are dependent upon such factors as fuel type, methods of ash handling, SO_2 removal method, and overall water usage and conservation measures. Possible wastewater sources are listed hereinafter.

a) Chemical wastes resulting from water treatment, backwash, and drainage.

b) Chemical feed area and storage area drains.

c) Laboratory drains.

d) Boiler tube chemical cleaning wastes.

e) Sanitary wastewater. This waste source consists of sanitary wastes originating from plant buildings with sanitary facilities (e.g., restroom toilets and sinks).

f) Steam boiler blowdown. This wastewater is released from the boiler drums to maintain a sufficient water quality in the boiler.

g) Cooling tower water blowdown. This source is present only if cooling towers are employed to remove heat from the steam cycle. This wastewater is released from the cooling water tower to maintain water quality.

h) Plant drains. This source is a result of pump seal water overflows and miscellaneous equipment water drains.

i) Area washdown drains. This wastewater results when plant personnel use hoses to wash down certain equipment and areas in and around plant buildings. For example, floors such as in the scrubber, turbine, and service buildings may be periodically flushed.

j) Oily waste treatment system. Wastewater from this source is a result of treating washdown water from such areas as fuel oil storage, lube oil storage, transformers, service buildings, and turbine building.

k) Ash handling system (from bottom ash removal transport system). Any discharge requires pretreatment for clarification and neutralization.

l) Flue gas desulfurization (FGD). Under normal conditions, process water within the scrubber system is recirculated. At times, however, water quality may degrade to a point where some must be released as a wastewater.

m) Storm water runoff.

n) Runoff from coal storage areas and solid waste storage areas. The wastewater must be pretreated before discharge.

17.2.2 Discharge Standards. Newly constructed plants may be designed as zero discharge facilities. Zero discharge means that although a plant may use water, it does not have a discharge of water. Hence, for this case, discharge standards do not apply. Many facilities do discharge water from the sewage treatment plant, the cooling water system, or from storm water runoff. If there is any water discharge, discharge standards apply. Environmental regulations and permitting associated with wastewater discharge are discussed in Section 18, Environmental Regulations and Permitting.

17.2.3 Treatment and Disposal Methods. Wastewaters generated by a power plant should be reused as much as practical to conserve water.

17.2.3.1 Recycle Basin. A common method of wastewater handling at a power plant involves the use of a recycle basin (also called a reclaim pond). The wastewater streams, properly treated, flow to the recycle basin.

17.2.3.2 Chemical Wastewater. Wastes from steam condensate treatment, chemical feed and storage area drains, laboratory drains, and metal cleaning wastewater are corrosive and should be collected in a separate piping system from other plant drains. These wastes are normally directed to a treatment tank where they are mixed with the proper chemicals until the entire solution is no longer corrosive (i.e., neutralized). The neutralized wastewater can then be discharged to the recycle basin or to the sanitary sewer.

17.2.3.3 Sanitary Wastewater. Sanitary wastewater is typically directed to a sewage treatment plant located on site. The treatment plant processes the sanitary wastes and discharges either to the streams or to the recycle basin.

17.2.3.4 Storm Water Runoff. Roof and yard drain storm water runoff is reasonably clean and discharged with the storm system without treatment.

17.2.3.5 Leachate and Runoff From Coal Storage Areas. Discharge waters from coal storage areas and solid waste storage require treatment, which includes settlement, clarification, and neutralization, to satisfy local regulations for wastewater discharge of storm water.

17.2.3.6 Oily Wastewater. Oil-contaminated wastewater must be treated before being allowed to enter a recycle basin. This treatment is normally accomplished through use of an oil separator. This device operates by allowing the oil and wastewater to separate naturally (because of their difference in densities). The separated oil is directed to waste oil storage containers while the de-oiled wastewater is discharged to the recycle basin.

17.3 Oil Spill Control

17.3.1 Possible Sources of Spills

17.3.1.1 Bulk Oil Storage Tanks. Spills may originate from tank rupture, overflow, or valve and pipe leakage. In addition, the process of filling the tanks from a barge, a railroad tank car, or a truck may cause an oil spill.

17.3.1.2 Lube Oil Tanks. Lubricating oil tanks are normally located indoors. Spills may originate from tank rupture, valve and pipe leakage, or lube oil drippings from equipment which, if unconfined, may be sources of oil spills.

17.3.1.3 Oil-Filled Transformers. Most large electrical transformers are filled with oil for purposes of cooling. Their location can be indoors or outdoors and ground level or elevated. For example, transformers for electrostatic precipitators are typically located atop the precipitator structure itself. Spills may originate as a result of rupture or seal leakage.

17.3.2 Methods of Prevention. According to oil spill regulations and permitting, appropriate containment and diversionary structures or equipment to prevent discharged oil from reaching a navigable watercourse should be provided. The following systems or its equivalent should be used as a minimum.

a) Dikes, berms, or retaining walls.

b) Curbing.

c) Oil/water separators.

d) Gravel-filled retention area under transformers.

For example, the area surrounding fuel oil storage tanks shall be provided with dikes with controlled water discharge to confine oil spills and to collect rainwater runoff that may be contaminated with oil. Oil/water separators may be required on the water discharge control to satisfy some state requirements. See NAVFAC DM-22, Petroleum Fuel Facilities, for additional information.

17.3.3 Methods of Cleanup. If a spill occurs, appropriate cleanup action must be taken. Confined spills above ground may be cleaned up through use of oil-absorbent materials. Permeated soils shall be removed, and uncontaminated soils shall be used as a replacement. If the plant is located near a navigable watercourse, appropriate clean up equipment must be on hand for spills on such a water surface.

Additional information concerning oil spill prevention and cleanup can be found in the Code of Federal Regulations.

17.4 Solid Waste Disposal

17.4.1 Solid Waste Production. The sources and amounts of solid waste produced by a fossil-fueled steam power plant are dependent mainly on the fuel type, fuel burn rate, and degree of pollutant removal from the boiler exhaust. Other factors, such as fuel-burning equipment, may also affect the solid waste production rate. Solid wastes produced at a plant burning fossil fuel include fly ash, bottom ash, pulverizer rejects (if pulverized coal is burned), and flue gas desulfurization scrubber solids (if an FGD device is employed).

17.4.1.1 Fly Ash. Fly ash consists of the fine ash particles that are entrained in the boiler exhaust gases. For further information, see Combustion Engineering, Combustion Fossil Power Systems, and Boiler Emissions in TM-5-815-1/AFR 19-6. Particulate emissions from natural-gas-fired boilers are negligible and thus are not a source of solid waste.

17.4.1.2 Bottom Ash. Bottom ash consists of the large particles of solid combustion products (ash) and unburned carbon that fall out in the bottom of the boiler.

17.4.1.3 Pulverizer Rejects. Pulverizer rejects consist of a variety of coarse, heavy pieces of hard rock or slate and iron pyrite that are separated from coal during pulverization. The amount produced varies with the particular coal being pulverized. A reasonable estimate can be made, however, if it is assumed that rejects comprise 0.5 percent of the coal fired.

17.4.1.4 FGD Scrubber Solids. Solids from an FGD device consist of sulfate and sulfite reaction products resulting from the absorption of sulfur dioxide from the boiler exhaust. The particular solids formed depend on the scrubber type. See MIL-HDBK-1003/6, Section 7.4, for details of scrubber waste products for various types of SO_2 scrubbers. The quantity of scrubber solids produced vary with the amount of SO_2 removed from the boiler exhaust and with the type of solids produced. Generally, a mass balance calculation is required to determine the quantity of scrubber solids generated.

17.4.2 Methods of Treatment and Disposal

17.4.2.1 Requirements. At this time, the solid wastes produced at a fossil-fueled steam power plant are not categorized as hazardous by the Environmental Protection Agency. Therefore, according to the Resource Conservation and Recovery Act (RCRA) of 1976, the wastes may be landfilled utilizing environmentally acceptable practices. Since RCRA requires that a landfill not contaminate an underground drinking water source beyond the solid waste boundary, leachate control must be incorporated. This is usually accomplished through the use of liners, either clay or a synthetic membrane.

17.4.2.2 Fly Ash. Details of fly ash handling, intermediate storage, and conditioning are covered in Section 10, Ash Handling, of this design manual. If not sold to an outside party such as cement or concrete block manufacturers, fly ash can be disposed of as a solid waste in a landfill. Details of solid waste disposal can be found in NAVFAC DM-5.10, Solid Waste Disposal. Additional information on solid waste management can be found in NAVFAC MO-213, Solid Waste Management.

17.4.2.3 Bottom Ash. Bottom ash handling and intermediate storage are discussed in Section 10, Ash Handling, of this design manual. This waste product is generally disposed of in either settling ponds or a landfill. The choice of which to use depends on economics, space availability, and compatibility with the bottom ash removal system. For example, if the bottom ash is removed dry (i.e., mechanically) the preferred disposal method is a landfill. However, if the waste is hydraulically removed and plant space is available, a bottom ash pond may be preferred. If space is limited, the bottom ash could be dewatered and then landfilled. Consideration of these factors and others in a detailed study is recommended before deciding on a specific disposal system. Additional information on solid waste disposal and its management can be found in NAVFAC DM-5.10 and NAVFAC MO-213.

17.4.2.4 Pulverizer Rejects. In most cases, the pulverizer rejects are transferred either hydraulically, mechanically, or pneumatically to the bottom ash handling system. The combined waste product is then disposed of as discussed in Bottom Ash above.

17.4.2.5 SO_2 Scrubber Solids. Treatment and disposal of this waste product can be the most complicated and expensive of the four discussed. To choose a method, consideration must be given to the type of scrubber system employed, chemical composition of waste product, and availability of disposal space. A discussion of various waste products from FGD systems can be found in MIL-HDBK-1003/6, along with information on alternative disposal methods for scrubber waste products. Additional discussions of FGD waste can be found in TM-5-815-1/AFR 19-6.

17.4.3 Hazardous Waste Considerations. The U.S. Environmental Protection Agency (EPA) has interpreted the fossil fuel combustion waste exemption from hazardous classification to extend to other wastes that are produced in conjunction with the combustion of fossil fuel, are necessarily associated with the production of energy, and are mixed with and co-disposed or co-treated with fly ash, bottom ash, or FGD wastes. Wastes which the EPA has specifically indicated would fall under this co-disposal/co-treatment interpretation include (but are not limited to) boiler cleaning solutions, boiler blowdown, demineralization regenerant, pyrites, and cooling tower blowdown. Therefore, the production of hazardous waste from a fossil-fueled steam power plant should be prevented through proper design choices.

Section 18. ENVIRONMENTAL REGULATIONS AND PERMITTING

18.1 Air Quality Regulations. Air pollution emissions from a fossil fueled steam power plant are regulated by the Federal Government under the Clean Air Act (42 USC & 7401 et seq.). Each of the states also regulates air pollution emissions. All facilities must comply with both Federal regulations and state (and local) regulations. The facility will have to be designed to meet the most stringent requirements.

Stack emissions are limited by direct emission limits. This is the pollutant concentration in the flue gas emissions measured in the stack. Stack emissions may also be limited by ambient air quality limitations. These are standards based on measured or calculated pollutant concentrations at ground level off the site of the pollutant source.

The stack emissions of major concern in a fossil fueled steam power plant are sulfur dioxide (SO_2), nitrogen oxides (NOx), and particulate matter. Of lesser concern are carbon monoxide (CO) and various trace elements such as mercury and beryllium. The formation of the major pollutants and their control is discussed in Section 17 of this handbook.

18.1.1 National Ambient Air Quality Standards. The National Ambient Air Quality Standards (NAAQS) are established by the U.S. Environmental Protection Agency (EPA). The entire United States. is supposed to have air quality at least as good as the NAAQS. Any place where the air quality is worse than the NAAQS is said to be a "nonattainment" area. An area can be a nonattainment area for one pollutant and an attainment area for another. Each pollutant is characterized separately. The NAAQS is important to stack emissions because a new facility will not be permitted if calculations (modeling) show that the NAAQS would be exceeded at any point off the facility site. To find out if the NAAQS would be exceeded, the existing pollution level (background) must be known. The modeled impacts of the proposed facility are added to the background. It may be necessary to limit the emissions from a new source so that the NAAQS are protected.

The NAAQS values for all six "criteria" pollutants are given in Table 30. These six pollutants include the three major pollutants discussed above; SO_2, NOx, and particulate matter. The primary standard is established at the level requisite to protect the public health and allowing an adequate margin of safety. The secondary standard is established at the level requisite to protect the public welfare (such as vegetation) from any known or anticipated adverse effects associated with the presence of such pollutants in the ambient air.

Table 30
Primary and Secondary Ambient Air Quality Standards
(micrograms/m^3 except where otherwise noted)

	Primary Standard	Secondary Standard
Sulfur Dioxide		
3-hour concentration (a)	--	1,300
24-hour concentration (a)	365	--
Annual concentration	80	--
Particulate Matter PM10 (c)		
24-hour concentration (a)	150	150
Annual concentration	50	50
Carbon Monoxide		
1-hour concentration (a)	40 mg/m^3	40 mg/m^3
8-hour concentration (a)	10 mg/m^3	10 mg/m^3
Ozone		
1-hour concentration (b)	235	235
Nitrogen Dioxide		
Annual concentration	100	100
Lead		
Calendar quarter	1.5	1.5

(a) Not to be exceeded more than once per year.
(b) Not to be exceeded more than an average of one day per year over 3 years.
(c) Since 1987, the standard has been based on particulate matter with an aerodynamic diameter of 10 microns and less (PM10). Prior to that date, the standard was based on total suspended particulate (TSP).

Even if the area is currently nonattainment, a new facility may be permitted. But to receive a permit, other sources of pollution must be reduced. These "offsets" are part of the permitting process. The amount of offsets available can affect the amount of stack emissions permitted from a new source.

Each state has also established ambient air quality standards. Most states have adopted the NAAQS. A few have more restrictive standards. The most restrictive standards will apply.

18.1.2 Prevention of Significant Deterioration Limits. Originally under the Clean Air Act (CAA), new air pollution sources could be added until the ambient air quality became as bad as the NAAQS. Now the CAA includes limits to the amount of new pollution in clean air areas. These increment limits currently exist for only SO_2, NOx, and particulate matter. The maximum permitted increases are as follows:

Pollutant	Maximum Allowable Increase Class I micrograms/m^3	Class II micrograms/m^3	Class III micrograms/m^3
Particulate Matter (TSP)			
Annual geometric mean	5	19	37
24-hour maximum	10	37	75
Sulfur Dioxide			
Annual arithmetic mean	2	20	40
24-hour maximum	5	91	182
3-hour maximum	25	512	700
Nitrogen Dioxide			
Annual arithmetic mean	2.5	25	50

The maximum allowable concentration resulting from an applicable increment will not be allowed to exceed a national primary or secondary ambient air quality standard.

The three classes have been established to allow flexibility in new source permitting. Most of the United States is classified as Class II. There are no Class III areas in the country. A Class III area would allow the largest amount of new pollution. The most stringent classification is Class I. These areas are principally international parks and large national wilderness areas, large national parks, and large national memorial parks. If the facility is located within a Class II area, the Class I increments must still be met at the boundaries of any nearby Class I area.

All new sources since an established "baseline date" will use up available increment. Old sources which shut down will make more increment available. The amount of increment available to a proposed new source must be calculated as part of the permitting process. Again modeling is used for the calculations. Just as in the NAAQS, the amount of increment available to a new source may affect the amount of stack emissions which can be permitted.

18.1.3 New Source Performance Standards. Both the EPA and the states have new source performance standards (NSPS). These standards are direct limits on the pollutant concentrations in the flue gas emissions. They vary depending on the fuel to be burned. The Federal NSPS have been established for three categories of fossil fuel steam power plants as follows:

a) 40 CFR Part 60, Subpart D, Standards of Performance for Fossil Fuel Fired Steam Generators for Which Construction is Commenced After August 17, 1971.

b) 40 CFR Part 60, Subpart Da, Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978.

c) 40 CFR Part 60, Subpart Db, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Unit.

The most stringent of these regulations (Subpart Da) applies to new electric utility steam generating units and should not be applicable to a military power plant.

The Subpart Db NSPS apply to industrial-commercial-institutional steam generating units larger than 100 million Btu per hour heat input rate. SO_2, NOx and particulate matter are currently regulated under these regulations. A military power plant would qualify as an industrial-commercial-institutional steam generating unit. The Federal NSPS for such units are presented in Table 31.

Table 31
New Source Performance Standards for Industrial-Commercial-Institutional Steam Generating Units Larger Than 100 MBTU/HR Input Rate

Pollutant	Fuel	Special Conditions	Maximum Emission Rate lb/MBtu
Particulate Matter	Coal	Up to 10% annual capacity factor of other fuels	0.05
	Oil	---	0.10
	Coal & other fuels	Other fuels greater than 10% annual capacity factor	0.10
	Wood & other fuels except coal	Annual capacity factor greater than 30% for wood	0.10
	Wood & other fuels except coal	Annual capacity factor greater than 10% but less than 30% for wood and unit less than 250 MBtu/hr	0.20
	Municipal type solid waste	Up to 10% annual capacity factor of other fuels	0.10

Table 31 (Cont.)
New Source Performance Standards for Industrial-Commercial-Institutional Steam Generating Units Larger Than 100 MBTU/HR Input Rate

Pollutant	Fuel	Special Conditions	Maximum Emission Rate lb/MBtu
Nitrogen Dioxide	Natural gas or distillate oil	Low heat release rate	0.10[2]
	Natural gas or distillate oil	High heat release rate	0.20
	Residual oil	Low heat release rate	0.30[3]
	Residual oil	High heat release rate	0.40
	Coal	Mass-feed stoker	0.50
	Coal	Spreader stoker or fluidized bed combustion	0.60
	Coal	Pulverized coal	0.70
	Lignite	ND, SD, or MT Lignite combusted in a slag tap furnace	0.80
	Lignite	All other lignite	0.60
	Coal-derived synthetic fuels	---	0.50
	Sulfur Dioxide		
	Coal		90% reduction[4] plus 1.2 lb/MBtu
	Oil		90% reduction[4] plus 0.80 lb/MBtu or 0.30 lb/Mbtu

[1] An opacity limit also exists. Opacity must not exceed 20 percent, except for one six-minute period per hour of not more than 27 percent opacity.

[2] For natural gas or distillate oil in a duct burner used in a combined cycle plant, the limit is 0.20 lb/MBtu.

[3] For residual oil in a duct burner used in a combined cycle plant, the limit is 0.40 lb/MBtu.

[4] The percent reduction requirement is waived for facilities that have a permit limiting annual capacity factor on oil and coal to 30 percent or less.

Subpart D would still apply to any new, fossil-fuel fired steam generating units larger than 250 MBtu/hr heat input rate which is not covered by Subpart Db or Subpart Da. The emission limits under Subpart D are presented in Table 32.

Table 32
New Source Performance Standards for Fossil-Fuel Fired
Steam Generating Units Larger Than 250 MBTU/HR Heat Input Rate

Pollutant	Maximum One Hour Average Emission Rate lb/MBtu
Sulfur Dioxide[1]	
Liquid Fuel	0.80
Solid Fuel	1.2
Particulate Matter[2]	
Any Fuel	0.10
Nitrogen Dioxide[1]	
Gaseous Fuel	0.20
Liquid Fuel	0.30
Solid Fuel (except lignite)	0.70
Lignite	0.60 or 0.80

[1]When combinations of fuel are burned simultaneously, the applicable standard shall be determined by proration.

Sulfur Oxides $y\ (0.80) + z\ (1.2)\ /\ (x + y + z)$

Nitrogen Oxides $x\ (0.20) + y\ (0.30) + z\ (0.70)\ /\ (x + y + z)$

Where x is the percent of total heat input derived from gaseous fuel, y from liquid fuel, and z from solid fuel.

2 An opacity limit also exists. Opacity must not exceed 20 percent except for one six-minute period per hour of not more than 27 percent opacity.

Each furnace or boiler is considered a separate unit. The Federal NSPS does not apply to any units less than 100 million Btu/hr. This is the case even if several units side by side add up to more than 100 million Btu/hr. Only the state (or local) emission limits apply to small units.

State or local emission limits will also apply the units covered by the Federal NSPS. The facility must be designed to meet the most stringent of the federal or state emission limits. Usually the states have adopted the Federal NSPS but some states do have more restrictive limits for some pollutants, notably SO_2.

18.2 Water Quality Regulations. Wastewater from a power plant is regulated in two separate ways much as air pollutants are regulated. The first method is by water quality standards that are established for water bodies. Discharges to a water body must be analyzed to determine its impact on water quality. The second method is effluent standards for each specified waste stream from the power plant. However, the EPA's regulation of effluents from power plants is limited to generating units at an establishment primarily engaged in the generation of electricity for distribution and sale which results primarily from a process utilizing fossil-type fuel or nuclear fuel in conjunction with a thermal cycle employing the steam water system as the thermohydraulic medium. Therefore, military installation would not ordinarily be subject to the EPA's effluent guidelines and standards for steam electric power plants. The regulations of the applicable state must be examined for separate effluent regulations. Only water quality standards will be addressed in this section.

The major Federal statute regulating water quality and wastewater discharges is the Clean Water Act (CWA). The objective of the CWA is to restore and maintain the chemical, physical, and biological integrity of the Nation's waters. The Environmental Protection Agency (EPA) is responsible for administering the CWA. The CWA includes provisions to recognize, preserve, and protect the primary responsibilities and rights of states and for the states to implement permit programs to prevent, reduce, and/or eliminate pollution. The EPA and the States, acting in coordination, are to develop and publish regulations specifying minimum guidelines for public participation in such processes.

18.2.1 Water Quality Standards. The purpose of water quality standards is to define the water quality goals of a water body, or portion thereof, by designating the use or uses to be made of the water and by setting criteria necessary to protect the uses. Water quality standards, should, wherever attainable, provide water quality for the protection and propagation of fish, shellfish, and wildlife and for recreation in and on the water and taken into consideration their use and value for public water supplies, agricultural, industrial, and other purposes including navigation. States are to adopt water quality standards to protect public health or welfare, enhance the quality of water, and serve the purposes of the CWA.

States are responsible for reviewing, establishing, and revising water quality standards. The state adopted standards may be more stringent than required by Federal regulation. Under provision of the CWA, EPA is to review and approve, or disapprove the state-adopted water quality standards.

There are three main factors to be considered in establishing water quality standards. These factors are designation of uses, criteria, and antidegradation policy.

18.2.1.1 Designation of Uses. Each state must specify appropriate water uses to be achieved and protected. In designating uses of a water body and the appropriate criteria for those uses, the state must take into consideration the water quality standards of downstream waters and ensure that its water quality standards provide for the attainment and maintenance of the water quality standards of down stream waters. States may adopt subcategories of a use and set appropriate criteria to reflect varying needs of such subcategories of uses. At a minimum, uses are deemed attainable if they can be achieved by the imposition of effluent limits required under Sections 301(b) and 306 of the CWA and cost-effective and reasonable best management practices for nonpoint source control. The state shall provide notice and an opportunity for a public hearing prior to adding or removing any use or establishing subcategories of a use.

Seasonal uses may be adopted as an alternative to reclassifying a water body to uses requiring less stringent water quality criteria.

States may remove a designated use, which is not an existing use, or establish subcategories of a use if the state can demonstrate that attaining the designated use is not feasible because of naturally occurring pollutants concentrations, or natural, ephemeral, intermittent, or low flow conditions or water levels.

The state is required to conduct a use attainability analysis unless otherwise exempted in the CWA.

18.2.1.2 Criteria. States are required to adopt water quality criteria that protect the designated use of the most sensitive use. Such criteria must be based on sound scientific rationale and must contain sufficient parameters or constituents to protect the designated use. States must identify specific water bodies where toxic pollutants may be adversely affecting water quality, attainment of a designated water use, or are at a level to warrant concern. Where a state adopts narrative criteria for toxic pollutants, it must provide information identifying the method by which the state intends to regulate point source discharges of toxic pollutants. Toxic pollutants are those listed by the EPA under Section 307(a) of the CWA.

18.2.1.3 Antidegradation Policy. The state is to develop and adopt a statewide antidegradation policy and identify the methods for implementing the policy. Where the quality of the waters exceeds the level necessary for the designated use, that quality will be maintained and protected unless after the full satisfaction of the intergovernmental coordination and the public participation provisions the state finds that allowing lower water quality is necessary to accommodate important economic or social development in the area where the waters are located.

Where high quality waters constitute an outstanding national resource, such as waters of national and state parks and wildlife refuges and waters of exceptional recreational or ecological significance, that water quality shall be maintained and protected.

Where a potential water quality impairment associated with a thermal discharge is involved, the antidegradation policy and implementation method must be consistent with Section 316 of the CWA.

18.2.1.4 Public Hearings and EPA Notification. The state must, at least once every three years, hold public hearings for the purpose of reviewing applicable water quality standards and modifying them as appropriate. The state is to submit the results of the review and any supporting analysis for the use attainability analyses to EPA. The methodologies used for site-specific criteria development, any general policies, and revisions to the water quality standards are also to be submitted to EPA for review and approval.

After the state submits the officially adopted revisions, EPA notifies the state within 60 days of approval or within 90 days of disapproval. A state water quality standard remains in effect, even though disapproved by EPA, until the state revises its standard or EPA promulgates a rule that supersedes the state standard.

If the state does not adopt changes specified by EPA within 90 days after notification of disapproval, EPA will promptly propose and promulgate such a standard. In promulgating water quality standards, EPA is subject to the same policies, procedures, and public participation requirements as established for states.

18.2.2 Pretreatment Standards. EPA has also established pretreatment regulations applicable to any industrial wastewater discharges to publicly-owned sewage treatment works (POTW). The pretreatment regulations prohibit the discharge from causing inhibition or disruption of the receiving POTW's sewer system, treatment processes, or operations which contribute to a violation of the NPDES permit of the POTW. The pretreatment regulations contain the following specific prohibitions.

a) Discharges cannot contain pollutants which create a fire or explosion hazard.

b) Discharges cannot cause corrosive structural damage to the POTW. In no event can the discharge have a pH less than 5.0, unless the POTW is specifically designed for such discharges.

c) Discharges cannot contain solid or viscous pollutants in amounts which will cause obstruction to the flow in sewers or other interference with the operation of the POTW.

d) Discharges cannot be of such volume or pollutant strength as to interfere with the operation of the POTW.

e) Discharges may not contain heat in amounts which will inhibit biological activity in the POTW resulting in interference with the proper operation of the POTW. In no event can the discharge exceed 40 C (104 F), unless specifically approved by the POTW.

If the power plant will be discharging to a POTW, then coordination with the POTW will be required to ensure that the facility has the capacity to accept the discharge and to determine the industrial wastewater treatment charges.

18.2.3 Oil Spill Regulations. Discharges of oil into any stream, river, or lake are prohibited by the Clean Water Act if the discharge is considered harmful. Oil discharges are considered harmful to the public health or welfare if they meet either of the following criteria.

a) Cause a violation of applicable water quality standards.

b) Cause a film, sheen upon, or discoloration of the surface of the water or adjoining shorelines, or cause a sludge or emulsion to be deposited beneath the surface of the water or upon adjoining shorelines.

To minimize the environmental effects of oil spills, a Spill Prevention, Control, and Countermeasure (SPCC) Plan is required if the project would have an aggregate above ground storage capacity of oil which exceeds 1,320 gallons, a single above ground container larger than 660 gallons, or an aggregate underground storage of oil which exceeds 42,000 gallons and which has discharged, or could reasonably be expected to discharge oil in harmful quantities into nearby lakes or streams.

Appropriate containment and diversionary structures or equipment to prevent discharged oil from reaching a navigable watercourse should be provided. One of the following systems or its equivalent should be used as a minimum.

a) Dikes, berms, or retaining walls sufficiently impervious to contain spilled oil.

b) Curbing.

c) Culverting, gutters, or other drainage systems.

d) Weirs, booms, or other barriers.

e) Spill diversion ponds.

f) Retention ponds.

g) Sorbent materials.

The SPCC Plan, in addition to a discussion of the method used as the minimal prevention standard, should include a complete discussion of conformance to the following listed guidelines, or if more strict, local regulations.

a) Facility Drainage. Drainage from the diked areas should be restrained by valves to prevent spill or leakage from entering into the drainage system unless it is designed to handle such leakage. Valves used for drainage should open and close only by manual operation.

b) Bulk Storage Tanks. All bulk storage tank installations should be constructed so that a secondary means of containment is provided for the entire contents of tank plus precipitation.

c) Inspection. A procedure for inspection should be incorporated in the plan. A record of the inspection, signed by the appropriate supervisor or inspector, should be made a part of the plan and maintained for a period of 3 years.

d) Security. All plants which handle, process, and store oil should be fully fenced, and entrance gates should be locked and guarded when the plant is not in production or is unattended. The master flow and drain valves, and any other valves permitting outward flow from the tanks, should be securely locked in the closed position. Facility lighting should be commensurate with the type and location of the facility, and consideration should be given to discovery of spills during darkness and prevention of vandalism.

e) Personnel Training. Each applicable facility should have a designated person who is accountable for oil spill prevention and who reports to line management.

18.3 Solid Waste Disposal. The Resource Conservation and Recovery Act of 1976 (RCRA) replaced the Solid Waste Disposal Act. RCRA significantly expanded the scope of the regulatory authority of EPA in the area of hazardous wastes and solid waste disposal practices. The stated objectives of RCRA are to promote the protection of health and the environment, and to conserve valuable material and energy resources. These objectives are to be accomplished by certain steps including the following.

18.3.1 Dumping. Prohibiting future open dumping on the land and requiring the conversion of existing open dumps to facilities which do not pose a danger to the environment or to health.

18.3.2 Treatment, Storage, and Disposal. Regulating the treatment, storage, transportation, and disposal of hazardous wastes which have adverse effects on health and the environment.

18.3.3 Guidelines. Providing for the promulgation of guidelines for solid waste collection, transport, separation, recovery, and disposal practices and systems.

The primary effort to implement RCRA is the task of the individual states.

Under RCRA, all solid wastes are divided into two categories; hazardous and nonhazardous. Some wastes are designated specifically as being hazardous while others, including fly ash, bottom ash, and scrubber sludge, are classified as nonhazardous. This exception for coal combustion wastes has been interpreted by EPA to cover other power plant wastes which are treated or disposed of in conjunction with the ash or scrubber sludge wastes. Consequently, the regulatory requirements for disposal of wastes which otherwise could be classified as hazardous can currently be simplified by mixing them with coal combustion wastes.

18.3.3.1 Hazardous Waste. Under RCRA the EPA was required to develop and issue criteria for identifying the characteristics of hazardous waste, and for listing the hazardous wastes which would be regulated. All wastes at a power plant not included within the coal combustion waste exemption must be tested or compared to each of the following generic characteristics of hazardous wastes. If the waste exhibits any of these characteristics, it must be handled as a hazardous waste, unless otherwise exempted.

a) Ignitability.

b) Corrosiveness.

c) Reactivity.

d) Extraction Process Toxicity.

At a power plant, the regeneration wastes from water treatment systems and the metal cleaning wastes can sometimes meet the corrosiveness test with a pH below 2.

18.3.3.2 Totally Enclosed Facilities. A Hazardous Waste Management Facility (HWMF) permit is not required for any "totally enclosed" facilities used to treat hazardous wastes. A facility is considered "totally enclosed" if the facility is constructed and operated in a manner which prevents the release of any hazardous waste constituent into the environment. A covered neutralization tank is an example of a totally enclosed treatment facility.

To qualify for the exception, the neutralization tank must meet the following requirements.

a) The neutralization tank must be in a secure area. A fence with controlled access around the entire generating facility would suffice.

b) The neutralization tank must be inspected for equipment malfunctions or deterioration, operator errors, and discharges of the waste. A written inspection plan and log must be kept.

c) The treatment process must not generate extreme heat or pressure, produce uncontrolled toxic vapors, or pose a risk of fire or explosion. The process must be conducted so as not to damage the structural integrity of the tank.

d) The tank must be constructed of sturdy, leakproof material and must be designed, constructed, and operated so as to prevent hazardous wastes from being spilled or leaked.

e) Any significant spills or leaks of hazardous waste must be reported to the EPA Regional Administrator.

18.3.3.3 Nonhazardous Waste. RCRA classifies all nonhazardous waste disposal facilities as either sanitary landfills or open dumps. Open dumps are facilities that do not provide adequate protection for health and the environment. They are unacceptable under RCRA and they were all to be up graded to a sanitary landfill or phased out within 5 years. Sanitary landfills are disposal facilities that do provide adequate safeguards for health and the environment. All nonhazardous waste disposal facilities, then, must either meet the requirements of a sanitary landfill or must have been closed. EPA has promulgated regulations that define more specifically the difference between sanitary land fills and open dumps. The portions of these regulations that would be applicable to fly ash, bottom ash, or scrubber sludge disposal are as follows.

a) Facilities or disposal practices in a flood plain cannot restrict the flow of a 100-year flood, reduce the temporary water storage capacity of the flood plain, or result in washout of solid waste.

b) Facilities or disposal practices cannot cause or contribute to the taking of any endangered species or result in the destruction or adverse modification of the critical habitat of such species.

c) Facilities of disposal practices cannot cause a pollutant discharge in violation of the NPDES program or a discharge of dredge/fill material in violation of Section 404 or the CWA and the Dredge and Fill Program. Furthermore, facilities or disposal facilities cannot cause nonpoint source pollution that violates an approved area wide or statewide water quality management plan.

d) Facilities or disposal practices cannot contaminate an underground drinking water source beyond the outermost perimeter of the disposed solid waste as it would exist at the completion of all disposal activity.

e) Facilities cannot dispose of wastes containing cadmium within 3 feet of the surface of land used for the production of food-chain crops unless the application of such wastes complies with the complex requirements of 40 CFR Section 257.3-5, Criteria for Classification of solid waste disposal facilities and Practices.

f) Facilities or disposal practices must minimize the population of disease vectors through periodic application of cover material or other techniques as appropriate so as to protect public health.

g) Facilities or disposal practices cannot engage in open burning.

h) The concentration of explosive gases cannot exceed 25 percent of the lower explosive limit for such gases in facility structures and cannot exceed the lower explosive limit at the site boundaries.

i) Facilities or disposal practices cannot pose a hazard to the safety of persons or property from fires.

j) Facilities located within 10,000 feet of any airport runway used by turbojet aircraft or within 5,000 feet of any airport runway used only by piston-type aircraft cannot pose a bird hazard to aircraft.

k) Facilities or disposal practices cannot allow uncontrolled public access to the facility.

In addition to the solid waste regulations already described, EPA has drafted solid waste guidelines to describe recommended considerations and practices for the location, design, construction, operation, and maintenance of solid waste landfill disposal facilities. EPA has issued a proposed set of guidelines for burial of solid waste, (Federal Register Volume 44, page 18138, March 26, 1979) but has not yet issued guidelines for surface impoundments (e.g., ash ponds) or landspreading operations for solid waste disposal. Recommendations are made in the proposed guidelines for landfill disposal of solid waste, in the following areas.

a) Site Selection.

b) Design.

c) Leachate Control.

d) Runoff Control.

e) Operation.

f) Monitoring.

Each area is covered in detail. The current set of guidelines shall be referred to when a solid waste disposal landfill facility is needed.

18.4 Dredge and Fill Regulations. The Rivers and Harbors Act of 1899 (RHA) grants authority for the control of structures in navigable waters to the Secretary of the Army and, through delegation, to the Corps of Engineers. Under the command of the Chief of Engineers, the Corps of Engineers administers the civil functions of the Department of the Army. The administrative organization of the Corps of Engineers for the United States and its possessions consists of 11 "divisions" and 36 "districts" based on watershed boundaries of principal rivers or other hydrologic boundary limits. Each Division, headed by a Division Engineer, is subdivided into Districts headed by District Engineers. District Engineers are responsible for all Federal civil works functions within the boundaries of their respective Districts and report to the appropriate Division Engineer. Division Engineers are similarly responsible for civil works functions within their Divisions and report to the Chief of Engineers in Washington, DC.

The two major types of activities which are regulated by the Corps are construction work or structure in navigable waters and discharges of dredge or fill material into waters of the United States.

18.4.1 Obstruction or Alteration. Section 10 of the RHA prohibits the unauthorized obstruction or alteration of any navigable water of the United States. The construction of any structure in or over any navigable water of the United States, the excavation from or depositing of material in such waters, or the accomplishment of any other work affecting the course, location, condition, or capacity of such waters are unlawful unless the work has been recommended by the Chief of Engineers and authorized by the Secretary of the Army.

18.4.2 Harbor lines. Section 11 of RHA authorizes the Secretary of the Army to establish harbor lines channel-ward of which no pier, wharves, bulk heads, or other works may be extended or deposits made without approval of the Secretary of the Army.

18.4.3 Discharge of Refuse. Section 13 of the RHA provides that the Secretary of the Army, whenever the Chief of Engineers determines that anchorage and navigation will not be injured, may permit the discharge of refuse into navigable waters. In the absence of a permit, the discharge of refuse is prohibited. While the statutory prohibition of this section is still in effect, the Secretary of the Army has waived its Section 13 permit authority in view of the permit authority provided the EPA Administrator under Sections 402 and 404 of the CWA.

18.4.4 Regulatory Program. The Corps has consolidated its civil regulatory functions into one regulatory program so that one permit will constitute the authorization required by all the various statutes administered by the Corps.

General categories of activities that are covered by the Corps' Regulatory Program are as follows.

a) Dams or dikes in navigable waters of the United States.

b) Other structures of work including excavation, dredging, and/ or disposal activities.

c) Activities that alter or modify the course, condition, location, or capacity of a navigable water.

d) Construction of artificial islands, installations, and other devices on the outer continental shelf.

e) Discharges of dredged or fill material into waters of the United States.

f) Activities involving the transportation of dredged material for the purpose of disposal in ocean waters.

The authorization required for activities subject to the Corps' regulatory program can be either a general or individual permit. The Corps of Engineers is authorized to issue general permits on a state, regional, or nationwide basis for a category of activities which are essentially similar in nature, and will cause only minimal adverse environmental effects when performed separately, and will have only minimal cumulative adverse effects on the environment. General permits can be issued on either a nationwide or regional basis. Since a general permit is "automatically" issued upon compliance with certain conditions, a permit application is not necessary to obtain a general permit. However, Division Engineers can override general permits and require the activity to be authorized by an individual permit. Individual permits are issued following a case-by-case review of the project and a determination that the proposed activity is in the public interest.

18.4.5 State Permit Program. The individual states may request to administer the dredge and fill permit program within their jurisdiction, but only for ultra state waters. To request this delegation, the Governor of the state must submit a request to the EPA Administrator which includes a full and complete description of the program the state proposes to administer. EPA will review the application and statutory authority of the state, and will notify the Corps of Engineers when the program has been approved. The Corps of Engineers will transfer to the state pending applications for the state to issue the appropriate permits.

The state may also elect to administer and enforce the issuance and enforcement of the general permits issued by the Corps of Engineers. This enforcement will be effective when the state receives approval of its program from EPA and gives notification to the Corps of Engineers. Upon receipt of the notice, the Corps of Engineers will suspend the administration and enforcement of the general permit activities within the state.

Paragraph 18.5 describes each of the three types of permits - nationwide permits, regional permits and individual permits and the considerations required of each type of permit.

18.4.6 EPA guidelines. The EPA dredge and fill guidelines must be used by the Corps of Engineers to evaluate the effects of the proposed discharge of dredge and fill material. The fundamental precept of this review is that the discharge should not be approved unless it can be demonstrated that such a discharge will not have an unacceptable adverse impact.

Under these guidelines, the Corps of Engineers cannot issue a permit for the discharge under the following circumstances.

a) No discharge of dredge or fill material can be permitted if there is a practicable alternative to the proposed discharge which would have less adverse impact on the aquatic ecosystem, so long as the alternative does not have other significant adverse environmental consequences.

b) No discharge of dredge or fill material can be permitted if it would cause or contribute to a violation of any water quality standard, toxic effluent standard, or any requirement imposed by the US Department of Commerce to protect any marine sanctuary.

c) No discharge of dredge or fill material can be permitted if it jeopardizes the continued existence of any listed endangered or threatened species, or results in the likelihood of the destruction or adverse modification of a critical habitat. If an exemption for the project is obtained from the Endangered Species Committee, then the permit can be issued but must contain the conditions of the exemption.

d) No discharge of dredge or fill material can be permitted which would cause or contribute to significant degradation of any waters of the United States. The guidelines specify that significantly adverse effects upon the following items must be considered.

(1) Human health and welfare.

(2) Life stages of aquatic life and other wildlife dependent on aquatic ecosystems.

(3) Aquatic ecosystem diversity, productivity, and stability.

(4) Recreational, esthetic, and economic values.

e) No discharge of dredge or fill material can be permitted unless appropriate and practicable steps have been taken which will minimize potential adverse effects on the ecosystem.

18.5 Permits

18.5. Environmental Impact Statements

18.5.1.1 NEPA. The National Environmental Policy Act (NEPA) requires that all major Federal actions which significantly affect the quality of the human environment must be accompanied by an Environmental Impact Statement (EIS) which evaluates the following.

a) The environmental impact of the proposed action.

b) Any adverse environmental effects which cannot be avoided should the proposal be implemented.

c) Alternatives to the proposed actions.

d) The relationship between local short-term uses of man's environment and the maintenance and enhancement of long-term productivity.

e) Any irreversible and irretrievable commitment of resources which would be involved in the proposed action should it be implemented.

18.5.1.2 CEQ. Federal regulations implementing NEPA have been promulgated by the Council on Environmental Quality (CEQ). A new fossil-fueled steam power plant on a military facility would be a "major Federal action." A determination must be made whether the Federal action "significantly affects" the quality of the human environment. This determination of the significance of the project's impacts requires consideration of the context and intensity of the effects of the entire project on the environment. This decision is usually made as a case-by-case basis. The Navy can prepare an Environmental Assessment (EA) to assist it in making the impact significance determination. An EA should include a brief discussion of the need for the proposed project, project alternatives, the environmental impacts of the proposed projects and its alternatives, and a listing of agencies and persons consulted during preparation of the EA.

18.5.1.3 Environmental Impact Statements. If the EA's conclusion is that the proposed project would not significantly affect the human environment, the agency will issue a Finding of No Significant Impact (FONSI) and no EIS is necessary. If the EA concludes that the proposed project will significantly affect the human environment, the agency will proceed to prepare an EIS.

18.5.1.4 Federal Register. If the Navy commits itself to prepare an EIS, it must publish a notice of such intent in the Federal Register describing the proposed action, possible alternatives, and the scoping process. The notice should include whether, when, and where any scoping meeting will be held, and state the name and address of a person within the agency who can answer any questions concerning the action.

18.5.1.5 Format. The CEQ regulations specify the following format and general information categories to be contained in an EIS.

a) Cover Sheet - This single page must include a list of all Federal agencies involved in the EIS preparation; the title of the proposed action; the name, address, and telephone number of the person to con tact for more information; a designator of whether the EIS is a draft, final, or draft/final supplement; a one paragraph abstract; and the date by which comments must be received.

b) Summary - This section must accurately and adequately summarize the EIS and must stress the major conclusions and any remaining issues to be resolved.

c) Purpose and Need - This section must briefly specify the underlying purpose and need for the project.

d) Alternatives - This section should compare the environmental impacts of the proposal and the alternatives. All reasonable alternatives must be rigorously explored and objectively evaluated. The reasons behind the elimination of any alternative must be disclosed. These alternatives must include the alternative of no action and all reasonable alternatives not within the jurisdiction of the Navy. Each remaining alternative must be considered and discussed in depth. The preferred alternative must be identified. Appropriate mitigation measures must be included.

e) Affected Environment - This section must sufficiently describe the environment of the area(s) to be affected or created by the alternatives under consideration.

f) Environmental Consequences - This section must include a discussion of the environmental impacts of the proposal and its alternatives, any adverse environmental effects which cannot be avoided, the relationship between the short-term uses of man's environment and the maintenance and enhancement of long-term productivity, and any irreversible or irretrievable commitment of resources. The discussion should include direct and indirect effects and their significance, possible conflicts between the proposal and the objectives of any affected governmental unit, environmental effects, energy and natural or depletable resource requirements and conservation potentials. Also include urban quality, historic, and cultural resources and the design of the built environment, including the reuse and conservation potentials, mitigation measures.

g) List of preparers

h) Index.

i) Appendices - This section consists of material which is prepared for, substantiates, or is incorporated by reference in the EIS.

18.5.1.6 Draft EIS. When the draft EIS is completed, it is filed with EPA. The EPA then files a copy with the Council and publishes a notice in the Federal Register of the filing.

18.5.1.7 Coordination. The draft EIS is circulated to any other Federal agency which has jurisdiction by law or special expertise with respect to any environmental impact involved; to any Federal, state, or local agency authorized to develop and enforce environmental standards; and to anyone requesting the EIS. The minimum comment period is 45 days.

18.5.1.8 Resolution. The Navy must respond in the final EIS to all comments upon the draft EIS. Possible responses are modifications to the alternatives including the proposal; development and evaluation of new alternatives; supplements, improvements, or modifications to its analyses; factual corrections; and explanations why the comment(s) did not warrant further Navy response.

18.5.1.9 Final Comment. The final EIS must also be circulated for comments to all those who received copies of the draft as well as to those who made substantive comments upon the draft EIS. The final EIS is filed with EPA. The EPA then files a copy with the Council and publishes a notice in the Federal Register of the filing.

18.5.1.10 Time Period. The Navy must consider its decision for at least 90 days after the Federal Register notice of the filing of the draft EIS or 30 days after the Federal Register notice of the filing of the final EIS, which is later. These periods may run concurrently.

18.5.2 Air Permits

18.5.2.1 New Source Permits. A permit under the Federal Clean Air Act may be required. This permit is called a "new source review" although it is also frequently called a "PSD permit" for prevention of significant deterioration. Actually a new source review can involve both a PSD permit and a nonattainment review. The permit is required before construction begins on the power plant.

The new source review is a rather complex process. A number of steps must be accomplished for each pollutant to be emitted. Figure 47 presents the principal steps in the new source review process. Different pollutants may take different paths through the process even though they may be from the same source. For instance, if the area where the source is located is attainment for sulfur dioxide but nonattainment for particulate matter, then SO_2 will follow PSD requirements while particulate matter will follow the nonattainment path of offsets and Lowest Achievable Emission Rate (LAER).

The PSD program is triggered in clean air areas where the proposed unit is larger than 250 million Btu per hour heat input rate and has a potential to emit 100 tons per year or more of SO_2, NOx, or particulate matter. If the unit is less than 250 million Btu per hour heat input rate, it will not be regulated under the PSD program unless it has the potential to emit 250 tons per year or more of any of the pollutants. However in this case the emission from separate new units or modifications on the same site will be added together. Even if a unit is not subject to the Federal NSPS, it may need a PSD permit. Conversely, a unit may be subject to the NSPS but not need a PSD permit.

18.5.2.2 Purpose. The purpose of the PSD Program is to ensure that new major sources of air pollution do not significantly degrade existing ambient air quality. In order to achieve this goal, construction of new major source cannot commence until after receiving approval from EPA or a state which has been delegated PSD authority by EPA. The following requirements must be fulfilled before a PSD permit can be issued.

a) Appropriate emission limitations have been established.

b) The proposed permit has been duly reviewed and a public hearing is held with opportunity for interested persons to appear and submit written or oral presentations on the air quality impact of the source, alternatives, control technology requirements, and other appropriate considerations.

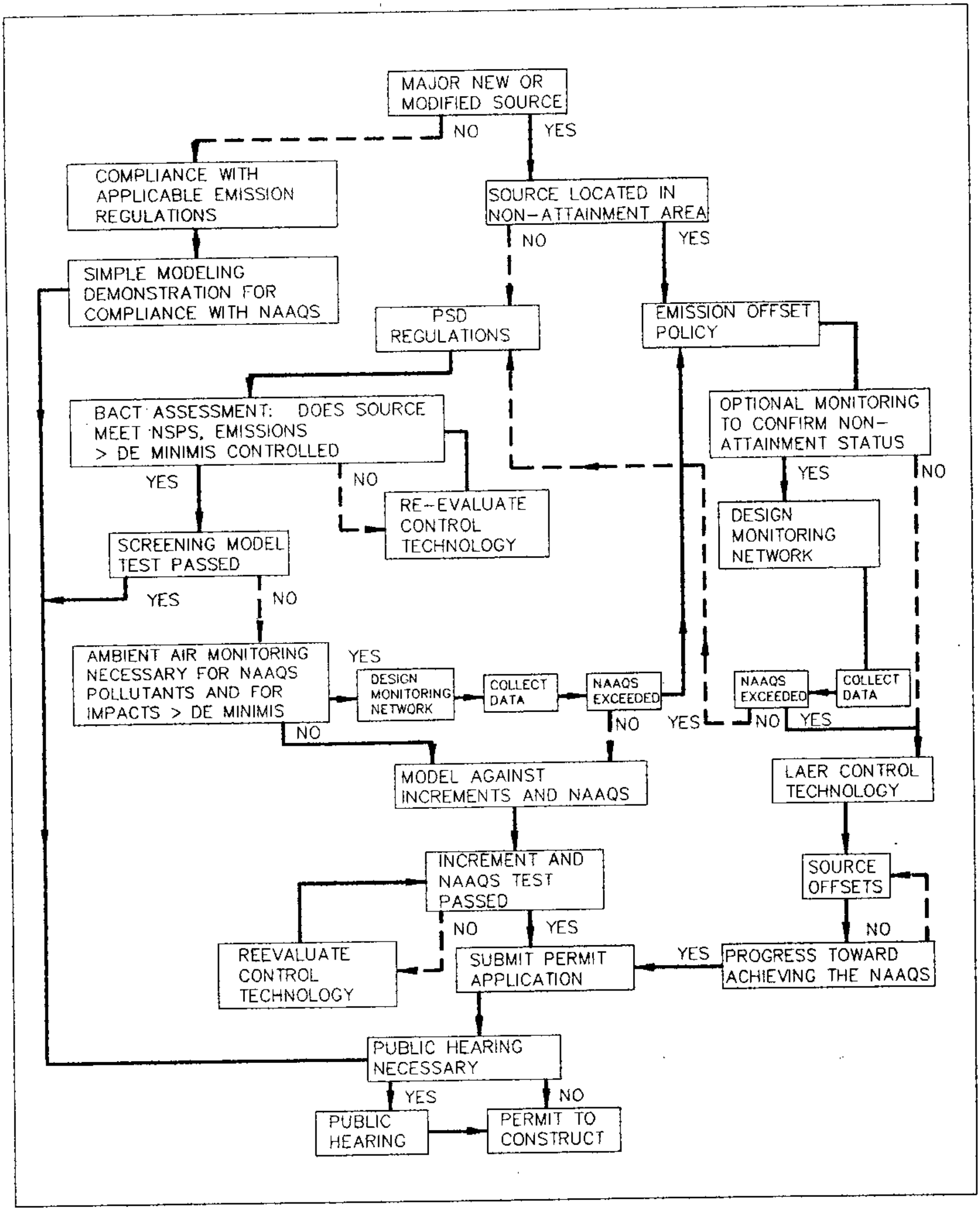

Figure 47
Principal Steps in the New Source Review Process

c) Emissions from construction or operation of the facility must be shown not to cause or contribute to air pollution in excess of the allowable increments or allowable concentration more than once per year, any national ambient air quality standard, or any applicable emission standard or standard of performance.

d) The facility is subject to best available control technology.

e) Class I areas are protected.

f) An analysis of air quality impacts projected for the area as a result of growth associated with the facility is performed.

g) An agreement is reached to conduct necessary ambient air quality monitoring.

18.5.2.3 De Minimis Amounts. Once a unit is determined to require a PSD permit, then the review will extend to all pollutants which exceed the following "de minimis" amounts:

Pollutant	Emission Rate tons per year
Carbon Monoxide	100
Nitrogen Oxides	40
Sulfur Dioxide	40
Particulate Matter	
Total	25
PM-10	15
Ozone (Volatile Organic Compounds)	40
Lead	0.6
Asbestos	0.007
Beryllium	0.0004
Mercury	0.1
Vinyl Chloride	1
Fluorides	3
Sulfuric Acid Mist	7
Hydrogen Sulfide (H_2S)	10
Total Reduced Sulfur (Including H_2S)	10
Reduced Sulfur Compounds (Including H_2S)	10

18.5.2.4 Best Available Control Technology. One of the PSD permit requirements listed earlier was that the facility must be designed in accordance with best available control technology (BACT). BACT requires the imposition of emission controls capable of at least complying with the applicable new source performance standards and with all applicable state emission limitations. Frequently, the BACT review will result in a permitted emission limitless than the new source performance standards. The BACT requirement will be applied on a pollutant-by-pollutant basis. BACT is required for each pollutant emitted by a major source if the allowable emissions are in excess of de minimis amounts specified above.

18.5.2.5 Class I Areas. A PSD permit will not be issued if the proposed source will have an adverse impact on visibility within any protected Class I area or integral vista. An adverse impact on visibility is defined as visibility impairment which interferes with the management, protection, preservation, or enjoyment of a visitor's experience of a mandatory Class I area.

18.5.2.6 Ambient Air Data. An analysis of ambient air quality at the site must be conducted as part of the PSD review. Consequently, the PSD permit application must contain continuous air quality monitoring data for each pollutant emitted in excess of the de minimis amounts. However, the monitoring requirement is waived for any pollutant if the emissions from the proposed source would have maximum modeled air quality impacts less than certain amounts specified by the EPA. Although a year of monitoring data is usually required, a shorter period of data can be accepted if a complete and adequate analysis can be performed. The EPA regulations specify that at least 4 months of monitoring data are required.

EPA is granted a period of one year from receipt of a complete PSD permit application to make a final determination. EPA will examine the initial PSD permit application and within 30 days will advise the applicant of any deficiency in the application or additional information required. In the event of a deficiency, the date of receipt of the application is the date all information is provided, and not the initial filing date. The general outline for consideration and issuance of the approval is as follows.

a) A preliminary determination is made to approve, approve with conditions, or disapprove the request.

b) Make available all materials provided by applicant, a copy of preliminary determination, and other materials used.

c) Notify public of the application, determination, and amount of increment consumed, and advise of opportunity for hearing.

d) Send a copy to other Federal, state, and local agencies.

e) Provide opportunity for public hearing on air quality impact, alternative to the source, the control technology required, and other appropriate considerations.

f) Consider all comments and issue final determination.

18.5.2.7 Nonattainment Areas. If the project's emissions significantly affect ambient concentrations of a nonattainment pollutant within the nonattainment area, the project will be subject to a nonattainment review for that pollutant. The project's emissions are deemed to significantly affect a nonattainment area if the ambient air quality impact of those emissions exceed the values shown in Table 33.

Table 33
Significance Levels (in micrograms per cubic meter)

Pollutant	Averaging Times				
	Annual	24-hour	8-hour	3-hour	1-hour
SO_2	1.0	5	--	5	--
TSP	1.0	5	--	--	--
NOx	1.0	--	--	--	--
CO	--	--	500	--	2,000

The following demonstrations are required by a nonattainment review.

a) The project will comply with the lowest achievable emission rate (LAER). LAER is defined as the more stringent of 1) the most stringent emissions limitation imposed by any state on a similar source unless proven not to be achievable, or 2) the most stringent emissions limitation achieved in practice by a similar source.

b) The owner or operator of the proposed source must demonstrate that all major stationary sources owned or operated by such person (or by an entity controlling, controlled by, or under common control with such person) in the state are subject to emission limitations and are in compliance, or on a schedule for compliance, with all applicable Federal and state emission limitations and standards.

c) The owner or operator of the proposed source must obtain sufficient emission reductions to offset the impacts within the nonattainment area of the source's emissions of the nonattainment pollutant. Air quality modeling must predict the emission offsets will cause a positive net air quality benefit in that portion of the nonattainment area affected by emissions from the proposed source.

d) The most stringent emissions limitation imposed by any state on a similar source unless proven not be achievable.

e) The most stringent emissions limitation achieved in practice by a similar source.

18.5.2.8 Local Permits. A separate state or local construction and operating permit may be needed for the power plant. Consult the air pollution control agency in the state where the power plant will be built.

18.5.3 Wastewater Discharge Permit. Any point source discharge of a pollutant to the navigable waters not authorized by a National Pollution Discharge Elimination System (NPDES) permit is unlawful. Permits will be issued by EPA only if the applicable effluent limitations are met.

18.5.3.1 State Permit Program. EPA may authorize a state to carry out the provisions of the permit program if the state can show it has enacted legislation and regulations to conform to the guidelines promulgated by EPA. About thirty of the states have been approved for this delegation. In these not approved, both the NPDES permit and a separate state wastewater discharge permit will be required.

18.5.3.2 Federal License or Permit. Applicants for a Federal license or permit to conduct any activity which may result in any discharge into the navigable waters are required to provide the permitting agency a certification, from the state in which the discharge originates, that any such discharge will comply with applicable provisions of the Clean Water Act (CWA). In any case where a state or interstate agency has no authority to give such a certification, the certification should be from the EPA Administrator. No license or permit may be granted until the certification has been obtained or waived by the appropriate agency.

EPA, when issuing a permit, is authorized to prescribe conditions on the permit to assure compliance with applicable effluent limitations including conditions on data and information collection, reporting, and other such requirements as it deems necessary.

EPA is directed to promulgate guidelines for determining the degradation of the waters of the territorial seas, the contiguous zone, and the oceans. No NPDES permit will be issued except in compliance with these guidelines for discharges into water of these seas, contiguous zones, or oceans.

18.5.3.3 New Source. Any person who proposes to discharge pollutants and does not have an effective permit must complete an NPDES application.

EPA has specified that the following construction activities result in a new source.

a) Construction of a source on a site at which no other source is located, or

b) Construction on a site at which another source is located of a building, structure, facility, or installation from which there is or may be a discharge of pollutants, the process or production equipment that causes the discharge of pollutants from the existing source is totally replaced by this construction, or the construction results in a change in the nature or quantity of pollutants discharged.

c) Construction on a site at which an existing source is located results in a modification rather than a new source if the construction does not create a new building, structure, facility, or installation from which there is or may be a discharge of pollutants but otherwise alters, replaces, or adds to existing process or production equipment.

Construction of a new source is considered to have commenced when the owner or operator has begun or caused to begin as part of a continuous on-site construction program:

a) Any placement, assembly, or installation of facilities or equipment.

b) Significant site preparation work which is necessary for the placement, assembly, or installation of new source facilities or equipment.

c) Entering into a binding contractual obligation for the purchase of facilities or equipment which are intended for use in its operation within a reasonable time.

18.5.3.4 Environmental Impact Statement. No on-site construction of a new source, for which an Environmental Impact Statement (EIS) is required, is to commence before all appropriate EIS-related requirements have been incorporated in the project and a final permit is issued, or, before execution of a legally binding written agreement by the applicant requiring compliance with all such requirements, unless EPA determines that such construction will not cause significant or irreversible adverse environmental impact.

No on-site construction of a new source for which an EIS is not required may commence until 30 days after the issuance of a finding of no significant impact unless EPA determines that the construction will not cause significant or irreversible adverse environ mental impact.

18.5.3.5 Violation of Regulations. The permit applicant must notify EPA of any on-site construction which begins before the above specified times. If on-site construction begins in violation of regulations, the owner or operator is proceeding at its own risk and such construction activity constitutes grounds for denial of a permit. EPA may also seek a court order to enjoin construction in violation.

18.5.3.6 Storm Sewers and Conveyances. Separate storm sewers are point sources subject to the NPDES permit program which may be permitted either individually or under a general permit. Separate storm sewer is defined as a conveyance or system of conveyances (including pipes, conduits, ditches, and channels) used primarily for collecting and conveying storm water runoff.

Conveyances which discharge storm water runoff contaminated by contact with wastes, raw materials, or pollutant-contaminated soil, from lands or facilities used for industrial or commercial activities, into waters of the United States or into separate storm sewers are point sources that must obtain NPDES permits.

18.5.3.7 Filing Date. EPA requires an application for a NPDES permit to be filed at least 180 days before the discharge is to begin. However, in view of the environmental review required of new sources, EPA recommends filing much earlier.

18.5.3.8 NPDES Permit. The NPDES permit application consists of two consolidated forms. Form 1 is a general information form about the applicant the proposed facility. The other part of the NPDES permit application for a proposed facility is to adapt Form 2C (for existing facilities) to reflect the fact that there are no discharges from the project yet.

EPA will not issue an NPDES permit under any of the following circumstances.

a) When the conditions of the permit do not provide for compliance with the applicable requirements of the CWA, or regulations promulgated under the CWA.

b) When the applicant is required to obtain a state or other appropriate certification under Section 401 of the CWA and that certification has not been obtained or waived.

c) When the imposition of conditions cannot ensure compliance with the applicable water quality requirements of all affected states.

d) When in the judgment of the Corps of Engineers, anchorage and navigation in or on any of the waters of the United States would be substantially impaired by the discharge.

e) For the discharge of any radiological, chemical, or biological warfare agent or high-level radioactive waste.

f) For any discharge inconsistent with a plan or plan amendment approved under Section 208(b) of the CWA.

g) To a new source of a new discharger, if the discharge from its construction or operation will cause or contribute to the violation of water quality standards. A NPDES permit will be issued for a term not to exceed five years. The conditions of an NPDES permit issued to a source which is subject to a new source performance standard (NPDES) cannot be made more stringent for the shortest of the following intervals.

(1) Ten years from the date that construction is completed.

(2) Ten years from the date the source begins to discharge process or other nonconstruction-related wastewater.

(3) The period of depreciation or amortization of the facility for the purposes of Section 167 or 169 (or both) of the Internal Revenue Code of 1954.

However, the protection from more stringent conditions does not extend to limitations not based upon technological considerations (e.g., conditions based upon compliance with water quality standards or toxic effluent standards) or to toxic/hazardous pollutants not subject to any limitation in the applicable new source performance standard.

18.5.3.9 NPDES Permit Conditions. The following conditions are applicable to all NPDES permits.

a) The permittee must comply with all conditions of the permit. Failure to do so is grounds for enforcement action; for permit termination, revocation and reissuance, or modification; or for denial of a permit renewal application. Violation of any permit condition will not be excused on the grounds that it would have been necessary to halt or reduce the permitted activity in order to remain in compliance.

b) The permittee must take all reasonable steps to minimize or correct any adverse impact on the environment resulting from noncompliance with the permit.

c) The permittee must at all times properly operate and maintain all facilities and systems of treatment and control (and related appurtenances) which are installed or used by the permittee to achieve compliance with the conditions of the permit. Proper operation and maintenance includes effective performance, adequate funding, adequate operator staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures. This condition requires the operation of backup or auxiliary facilities or similar systems only when necessary to achieve compliance with the conditions of the permit.

d) The permit does not grant any property rights or any exclusive privilege.

e) The permittee must allow EPA or its authorized representative, upon the showing of any documents required by law, to conduct the following actions.

(1) To enter upon the permittee's premises.

(2) To have access to and copy any records required by the permit.

(3) To inspect any activities regulated by the permit.

(4) To sample any waste streams regulated by the permit.

f) The permittee must provide EPA with any requested information pertinent to any permit action contemplated by EPA.

g) All samples and measurements taken for the purpose of monitoring must be representative of the monitored activity.

h) All monitoring records must be kept for a minimum of three years. This period can be extended by EPA. Monitoring records include the following data.

(1) The date, exact place, and time of sampling or measurements.

(2) The individual(s) who performed the sampling or measurements.

(3) The date(s) analyses were performed.

(4) The individual(s) who performed the analyses.

(5) The analytical techniques or methods used.

(6) The results of such analyses.

i) The permittee must notify EPA of any planned changes to the facility, any anticipated noncompliance, and any permit transfer. Any noncompliance which may endanger health or the environment must be reported verbally to EPA within 24 hours and a written report must be submitted within five days.

j) All monitoring must be conducted according to test procedures approved by 40 CFR 136, Guidelines establishing test procedures for the analysis of pollutants, unless other procedures are specifically approved by EPA.

j) All monitoring results must be reported on a Discharge Monitoring Report. All averages must be done on an arithmetic basis. All results must be reported.

k) Any unanticipated bypass or upset which exceeds any permit effluent limitation must be reported to the EPA within 24 hours.

Noncompliance caused by a bypass can be an actionable violation, but noncompliance caused by an upset will always be excused. A bypass is an intentional diversion of a waste stream from any portion of a treatment facility when there are no feasible alternatives to bypassing and it is necessary to bypass in order to avoid loss of life, personal injury, or severe property damage. An upset is an exceptional incident in which there is unintentional and temporary noncompliance with technologically-based effluent limitation because of factors beyond the reasonable control of the permittee. An upset does not include noncompliance caused by lack of preventive maintenance; careless or improper operation; or lack of backup equipment for use during normal periods of equipment downtime or preventive maintenance. The permit can also require reporting within 24 hours of violation of a maximum daily discharge limitation for any pollutant of special concern to EPA.

The permit will specify requirements concerning the monitoring equipment (e.g., proper use, maintenance, and installation), monitoring activities (e.g., type, intervals, and frequency), and the reporting of monitoring results. The permit will contain requirements to monitor the mass (or other measurement related to any effluent limitation) for each pollutant regulated by the permit, the volume of effluent discharged from each outfall and any other relevant information.

18.5.4 Oil Spill Plan. A Spill Prevention, Control, and Countermeasure (SPCC) Plan is required if the project would have an aggregate underground-aboveground storage capacity of oil which exceeds 1,320 gallons, a single aboveground container larger than 660 gallons, or an aggregate underground storage of oil which exceeds 42,000 gallons and which has discharged, or could reasonably be expected to discharge oil in harmful quantities into nearby lakes or streams. Almost all power plants have this much oil after transformer oils and lube oils are considered. The SPCC Plan need not be submitted but merely available to the EPA for inspection at the plant.

The SPCC must be prepared within 6 months after the plant begins operation and must be implemented not later than one year after the plant begins operations. If the plan is not completed on time, a request can be made to the EPA Regional Administrator for an extension. The plan must be reviewed by a registered Professional Engineer (PE), and he must attest that the SPCC Plan has been prepared in accordance with good engineering practices. EPA has proposed revisions to the SPCC Plan regulations. The changes would require the SPCC Plan to be fully implemented when the plant begins commercial operation. The PE certification would also include a statement that the SPCC Plan conforms to the requirements of EPA's regulations.

Where experience indicates a reasonable potential for equipment failure (such as tank rupture, overflow, or leakage), the plan should include a prediction of the direction, rate of flow, and total quantity of oil which could be discharged from the facility as a result of each major type of failure.

18.5.5 Solid Waste Disposal Permit. If any hazardous wastes are stored, treated, or disposed of by methods other than those described above, a Hazardous Waste Management Facility (HWMF) permit must be obtained from EPA. Compliance with the following requirements is a prerequisite for obtaining the permit.

a) The HWMF must be in a secure area.

b) The HWMF must be inspected for equipment malfunctions or deterioration, operator errors, and discharges. A written inspection plan and log must be kept.

c) Unless EPA agrees that such equipment is not necessary, the HWMF must have an alarm system to warn personnel of emergencies, a method of summoning emergency assistance, and access to emergency equipment.

d) A contingency plan must be prepared. The contingency plan must be designed to minimize hazards of human health and the environment from fires, explosions, or any unplanned release of hazardous waste.

e) A written operating record is required, and a biannual report must be filed with EPA.

f) All personnel must be trained to handle the hazardous waste safely and in compliance with all permit requirements and conditions.

g) All hazardous waste management activities must be conducted at least 200 feet from any fault which has had displacement in the Holocene time. Facilities in jurisdictions other than those listed in Appendix VI of 40 CFR 264 are assumed to comply with this requirement.

h) All hazardous waste management facilities located in a 100-year flood plain must be designed, constructed, operated, and maintained to prevent washout of any hazardous waste by a 100-year flood, unless washout of the waste would have no adverse effects on human health or the environment, or unless the waste can be safely moved to an upland site before flood waters can reach the facility.

i) A ground water monitoring program meeting the requirements of 40 CFR 264.98 is required for any surface impoundment, waste pile, land treatment facility, or landfill which handles hazardous waste unless EPA determines that there is no potential for migration of leachate from the hazardous waste facility to the uppermost aquifer, or unless the facility is exempted from ground water monitoring because of its design (e.g., landfills are exempted from ground water monitoring if they have a double liner system located entirely above the seasonal high water table, a leak detection system located between the liners, and a leachate collection and removal system located on top of the uppermost liner).

j) A written closure plan must be prepared. The closure plan should minimize the need for further maintenance and the post closure escape of hazardous waste constituents.

k) A written estimate of the cost of implementing the closure plan and of post-closure monitoring and maintenance must be prepared. Financial assurance for closure of the HWMF must be provided through a trust fund, surety bond, letter of credit, insurance, a combination thereof, or self-insurance.

l) The HWMF must be covered by liability coverage in the amount of at least $1 million (exclusive of legal defense costs) for claims arising from sudden and accidental occurrences that cause injury to persons or property. The HWMF must also have liability coverage in the amount of at least $3 million per occurrence with an annual aggregate of at least $6 million (exclusive of legal costs) for claims arising from nonsudden accidental occurrences that cause bodily injury or property damage. This liability coverage can be provided by liability insurance and/or self-insurance.

m) Landfills and surface impoundments used to store, treat, or dispose of hazardous waste must have a ground water protection plan unless the facility has a double liner equipped with a leak detection system or the EPA deter mines that there is no potential for migration of liquid from the facility to the uppermost aquifer. The ground water protection plan must consist of the following three phases.

(1) A ground water sampling program to detect the presence of leachate containing hazardous constituents at the compliance point.

(2) If leachate is detected, a compliance ground water monitoring program must be initiated.

(3) Whenever a ground water protection standard is exceeded, a corrective action program must be initiated.

The EPA has also issued the following regulations governing waste handling practices or equipment at new HWMFs.

a) Containers--40 CFR 264.170 to 264.178.

b) Tanks--40 CFR 264.190 to 264.199.

c) Surface Impoundments--40 CFR 264.220 to 264.230.

d) Waste Piles--40 CFR 264.250 to 264.258.

e) Land Treatment--40 CFR 264.270 to 264.282.

f) Landfills--40 CFR 264.300 to 264.316.

g) Incinerators-- 40 CFR 264.340 to 264.351.

An estimate of the scope of the future regulations for other specific waste handling practices can be made upon examination of the following regulations for existing HWMFs.

a) Thermal Treatment--40 CFR 265.373 to 264.382.

b) Chemical, Physical, and Biological Treatment--40 CFR 265.405.

c) Underground Injection--40 CFR 265.430.

Nonhazardous solid waste disposal permits will be issued by the State where the facility is located. The states standards and permit requirements will need to be examined for specific details applicable to any proposed facility.

18.5.6 Dredge and Fill Permit. Dredge and fill permits for the Corps of Engineers may be of three types: Nationwide permits, regional permits, and individual permits. The first two types authorize dredge and fill without having to obtain specific approval provided all appropriate conditions and notifications are met. The third type, the individual permit, must be applied for when neither of the other two are available.

In assessing the applicability of the Corps' regulatory program to a proposed project activity, the following definitions should be utilized.

a) Waters of the United States--This term includes the following waters.

(1) All waters which are currently used, or were used in the past, or may be susceptible to use in interstate or foreign commerce, including all waters which are subject to the ebb and flow of the tide.

(2) All interstate waters including interstate wet lands.

(3) All other waters such as intrastate lakes, rivers, streams (including intermittent streams), mudflats, sandflats, wetlands, sloughs, prairie potholes, wet meadows, playa lakes, or natural ponds, the use, degradation or destruction of which could affect interstate or foreign commerce, including any such waters which are or could be used by interstate or foreign travels for recreational or other purposes, or from which fish or

shellfish are or could be taken and sold in interstate or foreign commerce, or which are or could be used for industrial purposes by industries in interstate commerce.

(4) All impoundments of waters otherwise defined as waters of the United States.

(5) Tributaries of any of the above waters.

(6) The territorial sea.

(7) Wetlands adjacent to any of the above waters.

Note: Waste treatment systems, including treatment ponds or lagoons designed to meet the requirements of CWA, are not waters of the United States. Cooling ponds, as defined by 40 CFR 123.11(m), which also meet the criteria of this definition may be waters of the United States.

b) Navigable Waters--This term means those waters that are subject to the ebb and flow of the tide and/or are presently used, or have been used in the past, or may be susceptible for use to transport interstate or foreign commerce (see 33 CFR 329 for a more complete definition).

c) Wetlands--This term means areas that are inundated or saturated by surface or ground water at a frequency and duration sufficient to support, and that under normal circumstances, do support, a prevalence of vegetation typically adapted for life in saturated soil conditions. Wetlands generally include swamps, marshes, bogs, and similar areas.

d) Adjacent--This term means bordering, contiguous, or neighboring. Wetlands separated from other waters of the United States by manmade dikes or barriers, natural river berms, beach dunes, and the like are "adjacent wetlands."

e) Lakes--This term means a standing body of water that occurs in a natural depression fed by one or more streams from which a stream may flow, that occurs due to the widening or natural blockage or cutoff of a river or stream, or that occurs in an isolated natural depression that is not a part of a surface river or stream, or tidal area. (Artificial lakes created by excavating or diking dryland to collect and retain water for stock watering, irrigation, settling basins, cooling, or rice growing are not included.)

f) Ordinary High Water Mark--This term means the line on the shore established by the fluctuations of water and indicated by physical characteristics such as a clear, natural line impressed on the bank; shelving; changes in the character of the soil; destruction of terrestrial vegetation; the presence of litter and debris; or other appropriate means that consider the characteristics of the surrounding areas.

g) High Tide Line--This term means the line or mark left upon tide flats, beaches, or along shore objects that indicate the intersection of the land with the water's surface at the maximum height reached by a rising tide. The term includes spring high tides and other high tides that occur with periodic frequency, but does not include storm surges.

h) Headwaters--This term means the point on a national stream above which the average annual flow is less than 5 cubic feet per second. For intermittent streams, the criterion may be the median flow. That is, the point at which a flow of 5 cubic foot per second is equaled or exceeded 50 percent of the time.

i) Structure--This term means, without limitation, any pier, wharf, dolphin, weir, boom, breakwater, bulkhead, revetment, riprap, jetty, permanent mooring structure, power transmission line, permanently moored floating vessel, piling, aid to navigation, or any other obstacle or obstruction.

j) Dams and Dikes--Either term means an impoundment structure, except a weir, that completely spans a navigable water of the United States and that may obstruct inter state waterborne commerce.

k) Work--This term means any dredging or disposal of dredged material, excavation, filling, or other modification of a navigable water of the United States.

l) Dredged Material--This term means any material dredged or excavated from waters of the United States.

m) Discharge of Dredged Material--This term includes the addition of dredged material to a specified discharge site located in waters of the United States, and runoff from or overflow from a contained land or water disposal area.

n) Fill Material--This term includes any material used for the primary purpose of replacing an aquatic area with dryland or of changing the bottom elevation of any body of water. (The discharge of wastewater is not considered fill material and is regulated by the NPDES Permit Program.)

o) Discharge of Fill Material--This term means the addition of any fill material to waters of the United States. Generally, any fill material required in connection with construction of facilities in waters of the United States is considered a discharge of fill material.

18.5.6.1 Nationwide Permits. Discharges of dredge and fill material into the following waters are authorized by a nationwide permit: 1) Non-tidal rivers, streams, and their lakes and impoundments, including any adjacent wetlands, that are located above the headwaters, and 2) Other non-tidal waters that are not part of a surface tributary system to interstate or navigable waters.

However, a state can revoke a nationwide permit by refusing to grant the water quality certification required by Section 401 of the CWA.

This type of nationwide permit requires compliance with the following conditions.

a) The discharge of dredge and fill material must not destroy a threatened or endangered species as identified under the Endangered Species Act or endanger the critical habitat of such species.

b) The discharge of dredge or fill materials must consist of suitable material free from toxic pollutants in other than trace quantities.

c) The fill created by the discharge of dredge or fill materials must be properly maintained to prevent erosion and other nonpoint sources of pollution.

d) The discharge of dredge or fill materials must not occur in a component of the National Wild and Scenic Rivers System or in a component of a state wild and scenic river system.

e) The best management practices listed later in this section should be followed to the maximum extent practicable.

18.5.6.2 <u>Activities Authorized by a Nationwide Permit</u>

a) The placement of aids to navigation and regulatory markers which are approved by and installed in accordance with the requirements of the US Coast Guard.

b) The repair, rehabilitation, or replacement of a previously authorized facility. The facility must be currently serviceable, the work must not result in significant deviations from the original plans, and the uses of the facility must not have been changed. Maintenance dredging is not authorized by this nationwide permit.

c) Staff gages, tide gages, water recording devices, water quality testing and improvement devices, and similar scientific structures.

d) Survey activities including core sampling, seismic exploratory operations, and plugging of seismic shot holes and other exploratory-type bore holes.

e) Outfall structures and associated intake structures where the effluent from that outfall has been permitted under the NPDES program providing that the individual and cumulative adverse environmental effects of the structure itself are minimal. (Intake structures by themselves are not included--only those directly associated with an outfall structure are covered by this nationwide permit.)

f) The discharges of material for backfill and bedding for utility lines and outfall and intake structures if no change in preconstruction bottom contours occur and excess material is removed to an upland site. ("Utility line" includes pipelines, communications cables, and electrical transmission lines. This nationwide permit does not include Section 10 authorization, and an individual Section 10 permit will be required if in navigable waters of the United States.)

g) Bank stabilization activities for erosion control if less than 500 feet long and involving less than 1 cubic yard per running foot of bank. Furthermore, no material can be placed in a wetland, water flows into and out of wetlands cannot be impaired, the material must be "clean fill," and the activity must be a single and complete project.

h) Temporary and permanent minor road crossing fills of a non-tidal body of water if designed so that the crossing can withstand expected high flows of surface water and will not restrict such flows. Discharge of material must total less than 200 cubic yards below ordinary high water mark and extend into adjacent wetlands no more than 100 feet from the ordinary high water mark on either side. (If located in a navigable water of the United States, the crossing will require a permit from the US Coast Guard.)

i) The placement of fill incidental to the construction of bridges across navigable waters of the United States if the fill has been authorized by the US Coast Guard as part of the bridge permit. Causeways and approach fills are not included and will require individual or regional permits.

j) Return water from a contained dredged material disposal area if the state has issued a Section 401 water quality certification. (The dredging itself requires an individual permit if it occurs in navigable waters of the United States.)

k) Fill material for small hydroelectric projects of not more than 1,500 kW which are licensed by the Department of Energy (DOE) under the Federal Power Act. The project must qualify for the short-form Federal Energy Regulatory Commission (FERC) licensing procedures of DOE and the adverse environmental effects must be minimal.

l) Discharges of dredged or fill material of 10 cubic yards or less into waters of the United States if no material is placed in a wetland.

m) Dredging of 10 cubic yards or less from navigable waters of the United States as part of a single and complete project.

n) Structures, work, and discharges authorized by the Department of the Interior, Office of Surface Mining for surface coal mining if the District Engineer has had the opportunity to review the application and other pertinent documentation, and he determines that the individual and cumulative adverse effects are minimal.

o) Activities, work, and discharges included under categorical exclusions from environmental documentation by other federal agencies if the Office of the Chief of Engineers has been notified of the exclusion and agrees with it.

p) Any activity authorized by a state administered dredge and fill permit program approved by the Corps of Engineers.

q) The discharge of concrete into tightly sealed forms or cells where the concrete is used as a structural member which would otherwise not be subject to the jurisdiction of the CWA.

18.5.6.3 Activity-Specific Conditions. In addition to complying with any activity-specific conditions discussed above, compliance with the following special conditions is required for any of the above nationwide permits for specific activities to be valid.

a) The discharge of dredge or fill material will not be located in the proximity of a public water supply intake.

b) The discharge of dredge or fill material will not occur in areas of concentrated shellfish production.

c) The activity will not destroy a threatened or endangered species as identified under the Endangered Species Act, or endanger the critical habitat of such species.

d) The activity will not disrupt the movement of those species of aquatic life indigenous to the body of water.

e) The discharge of dredge or fill material will consist of suitable material free from toxic pollutants in other than trace quantities.

f) The fill or structure will be properly maintained to prevent erosion and other nonpoint source of pollution.

g) The activity will not occur in a component of the National Wild and Scenic River System or in a component of a state wild and scenic river system.

h) The activity will not cause an unacceptable interference with navigation.

i) The best management practices listed below should be followed to the maximum extent practicable.

18.5.6.4 Management Practices. The best management practices for nationwide permit must be followed to the maximum extent practicable for both the nation wide permits in certain waters and nationwide permits for specific activities.

a) Discharges of dredge or fill material into waters of the States should be avoided or minimized through the use of other practical alternatives.

b) Discharges of dredge or fill material in spawning areas during spawning seasons should be avoided.

c) Discharges of dredge or fill material should not restrict or impede the movement of indigenous aquatic species or the passage of normal or expected high flows, or cause the relocation of water (unless that is the primary purpose of the activity).

d) If the activity creates an impoundment, adverse impacts on the aquatic system caused by the accelerated passage of water and/or the restriction of its flow should be minimized.

e) Discharges of dredge or fill material in wetlands area should be avoided.

f) Heavy equipment working in wetlands should be placed on mats.

g) Discharges of dredge or fill material into breeding areas for migratory waterfowl should be avoided.

h) All temporary fills should be removed in their entirety.

18.5.6.5 Regional Permits. Each Division Engineer is authorized to issue general permits for activities within his jurisdiction (i.e., regional permits) which meet the general criteria for a nationwide permit category (e.g., minimal cumulative environmental impact), but which cannot qualify for any promulgated nationwide permit category. The Division Engineer is also authorized to issue regional permits modifying any nationwide permit category by adding conditions applicable to certain activities or specific geographic areas within his division. As with nationwide permits, the Division Engineer can revoke a regional permit and require an individual permit for any activity.

18.5.6.6 Individual Permits. Individual permits are required for activities not authorized by either a nationwide or regional general permit or not exempted from the Corps' regulatory program.

Applications for individual permits must be prepared using the prescribed application form, ENG Form 4345, OMB Approval OMB 49-R0420. The completed application should be submitted to the District Engineer in charge of the Corps of Engineers District where the proposed activity will occur. Local variations of the application form to facilitate coordination with state and local agencies may be encountered. Items taken into consideration when reviewing an individual permit are as follows.

a) The Corps' general approach in evaluating applications for individual permit authorizations required by its regulatory program can be described as a public interest balancing process which reflects national concerns for both the protection and utilization of important resources. This public interest review is based upon an evaluation of the probable impact, including cumulative effects, of the proposed activity and its intended use on the public interest. As part of this evaluation, the benefits which reasonably may be expected to accrue from the proposal will be balanced against its reasonably foreseeable detriments. The following general criteria will be considered during the balancing process.

(1) Public and private need for the proposed structure or work.

(2) Availability of reasonable alternatives.

(3) Extent and duration of beneficial and/or detrimental effects.

b) The Corps strongly discourages activities which adversely affect any wetlands considered to perform any of the following important functions.

(1) Wetlands which serve significant natural biological functions, e.g., wetlands habitat for aquatic or terrestrial species.

(2) Wetlands which have been set aside as study areas, refuges, or sanctuaries.

(3) Wetlands which have significant hydrological characteristics.

(4) Wetlands which shelter other areas from wave action, erosion, or storm damage.

(5) Wetlands which provide valuable storage area for storm and floodwaters.

(6) Wetlands which are prime natural recharge areas for ground water.

(7) Wetlands which provide natural filtration and purification of water.

c) Evaluation of any wetlands alterations must show that the benefits of the proposed alteration outweigh unavoidable damage to the wetlands. When performing this evaluation, the District Engineer must consider whether the proposed activity is dependent on being located in, or in proximity to, the wetlands and whether practicable alternative sites are available. The District Engineer's decisions will be weighted by Congressional policy expressed in the Estuary Protection Act and state wetlands program.

d) The Division Engineer will consult with and give great weight to the views of the US Fish and Wildlife Service, National Marine Fisheries Service, and their state counterparts concerning minimizing direct and indirect losses and damages to wildlife resources caused by the proposed activity.

e) The Corps will review the permit application to evaluate whether the proposed activity will comply with water quality standards and any applicable effluent limitations. The water quality certification required by Section 401 of the CWA is considered conclusive with respect to water quality considerations unless the EPA mandates that other water quality issues be evaluated.

f) The Corps will strive to ensure that the proposed activity is, insofar as possible, consistent with and avoids significant adverse effects on areas which possess recognized historic, cultural, scenic, conservation, recreational, or similar value.

g) If the proposed activity would affect the coastline or baseline of the territorial seas, the Corps must consult with the Attorney General and Solicitor of the Department of Interior.

h) Permit applications will be evaluated as to the potential for proposed actions to adversely affect others, interfere with a riparian owner's access to navigable water of the United States, affect or be affected by a federal water resource project, or be incompatible with federal projects under construction.

i) Applications will be reviewed for consistency and compatibility with approved Coastal Zone Management Plans.

j) If a proposed action affects a marine sanctuary, the Secretary of Commerce must certify that the action can be accomplished within the regulations pertinent to such areas.

k) Processing of Corps permit applications may involve concurrent processing of required other Federal, state, or local approvals. A Corps' permit may be approved prior to final approval of other certifications or required approvals. However, if other Federal, state, or local certifications are denied prior to final action on a Corps' permit application, the Corps' permit will be approved prior to final approval of other certifications or required approvals. However, if other Federal, state, or local certifications are denied prior to final action on a Corps' permit application, the Corps' permit will be denied, but the applicant has the right to request reinstatement of processing if the other certifications are later approved.

l) Specific land use plans of other Federal, state, local, and Indian tribal agencies must be considered in addition to national interest factors.

m) In the interest of safety, applicants may be required to show that all impoundment structures comply with state dam safety standards or have been designed or reviewed by qualified persons.

n) Whenever practicable alternatives exist outside a flood plain, the District Engineer will avoid, to the extent practicable, authorizing flood plain developments or activities which have long-term or short-term significant adverse impacts upon a flood plain. For those activities in the public interest which must occur in or impact upon flood plains, the District Engineer must assure, to the maximum extent practicable, that the impacts of potential flooding on human health, safety, and welfare and the risks of flood losses are minimized. In such cases, the District Engineer will also strive to restore and preserve the natural and beneficial values served by flood plains.

o) Although the Corps will not impinge upon the states' authority to allocate water, the District Engineer will give full consideration to the public interest review to water conservation and the opportunities to reduce demand and improve efficiency in order to minimize new water supply requirements.

p) Since energy conservation and development is a national objective, the District Engineer will give great weight to energy needs and will give high priority to permit actions involving energy projects.

q) Navigation in all navigable waters is a primary concern of the federal government. The District Engineer will protect navigational and anchorage interests by recommending denial of a permit unless appropriate conditions are included to avoid any substantial impairment to navigation and anchorage.

r) Section 11 of RHA authorized establishment of harbor lines shoreward of which no individual permits were required. Because harbor lines were established on the basis of navigation impacts only, the Corps of Engineers published a regulation on May 27, 1970 (33 CFR 209.150) which declares that permits thereafter would be required for activities shoreward of the harbor lines. Review of applications is based on full public interest evaluation and harbor lines serve as guidance for assessing navigation impacts.

s) The Corps must authorize any power transmission line crossing a navigable water of the United States unless the lines are part of a water power project subject to the control of the Federal Energy Regulatory Commission. Transmission lines crossing navigable waters are required to have a minimum clearance over the navigable channel provided by existing fixed bridges, or the clearances which would be required by the US Coast Guard for new fixed bridges in the vicinity of the proposed power line crossing. The minimum additional clearance above clearance required for bridges for the low point of the line under conditions which produce the lowest sag is given below for various system voltages as outlined in the National Electrical Safety Code.

Nominal System Voltage kV	Minimum Additional Clearance Above Clearance Required for Bridges ft
115 and below	20
138	22
161	24
230	26
350	30
500	35
700	42
750 to 765	45

s) All applications for Department of the Army permits should include a complete description of the proposed activity including the following.

(1) Necessary drawings, sketches, or plans sufficient for public notice. (This does not mean detailed engineering plans or specifications.)

(2) The location, purpose, and intended use of the proposed activity.

(3) Scheduling of the activity.

(4) The names and addresses of adjoining property owners.

(5) The location and dimensions of adjacent structures.

(6) A list of authorizations required by other federal, interstate, state, or local agencies for the work, including all approvals received or denials already made.

(7) Information required for public notices.

u) Permit applications should also be prepared in accordance with the following requirements.

(1) All activities related to a single project which require Department of the Army permits should be described within the same application.

(2) If dredging is involved, the application must include a description of the type, composition, and quantity of the material to be dredged, and the method of dredging, and the site and plans for disposal of the dredged material.

(3) If the activity would include the discharge of dredged or fill material in the waters of the United States, the application must also contain a complete description of the activity including the source, type, purpose of discharge, composition, quantity, method of transportation and disposal, and location of disposal site.

(4) If the activity would include a filled area, or pile or float-supported platform, the project description must indicate the uses of and specific structures to be erected on the fill or platform.

(5) If an impoundment is included, the application must show that the structure complies with state dam safety criteria or has been designed, reviewed, or modified by qualified persons.

(6) The application must be signed by the person who proposes to undertake the proposed activity or his duly authorized agent. More than one owner or proposer may be represented by a single agent.

v) The District Engineer may request further additional information if essential to assist in the evaluation of the application.

w) Fees are required for permits issued under the Corps' regulatory program.

x) A fee of $100 will be charged for permits for commercial activities and $10 for noncommercial activities. The determination as to the commercial or noncommercial nature of proposed activities will be made by the District Engineer. Fees are not charged for applications withdrawn or denied. Only when an affirmative decision has been reached will the applicant be advised of the appropriate fee.

y) The Corps strives to process applications for individual permits not requiring an Environmental Impact Statement according to the following procedure and time deadlines.

(1) Upon receipt of the application, the District Engineer will assign it an identification number and acknowledge receipt of the application. The acknowledgement will advise the applicant of the identification number assigned to its application.

(2) Within 15 days of receipt of the application, the District Engineer must request from the applicant any additional information necessary for further processing.

(3) Within 15 days of receipt of all necessary information, the District Engineer will issue a public notice of the proposed activity and a draft permit.

(4) The public notice period will usually last 30 days but can be extended to 60 days.

(5) The District Engineer must consider all comments received. The applicant will be given a chance to rebut or resolve adverse comments.

(6) Within 60 days of the receipt of the application (90 days, if the public comment period is extended to 60 days), the District Engineer will make a final decision on the application. However, the final decision may be delayed in order to complete other procedural requirements (e.g., the NEPA environmental impact review process, endangered species consultation, or historical/ cultural preservation process).

z) If the proposed activity only needs an individual authorization under Section 10 of the River and Harbor of 1899, (For instance, the nation-wide permit for utility line crossings does not constitute authorization under Section 10 if a navigable water is to be crossed. A letter of permission could be used in such situations in lieu of the complex permit process) the District Engineer can omit publishing a public notice and authorize the activity by a letter of permission if the work meets the following conditions.

(1) The proposed work is minor.

(2) The proposed activity would not have significant individual or cumulative impact on environmental values.

(3) The proposed work would encounter no appreciable opposition.

18.5.7 FAA Permit. The Federal Aviation Administration (FAA) must be notified before there is any construction or alteration of more than 200 feet in height above ground level of a site, and any construction or alteration of greater height than an imaginary surface extending outward and upward at one of the following slopes.

a) One hundred to one for a horizontal distance of 20,000 feet from the nearest point of the nearest runway of each airport which has at least one runway more than 3,200 feet in actual length excluding heliports.

b) Fifty to one for a horizontal distance of 10,000 feet from the nearest point of the nearest runway of each airport which has at least one runway more than 3,200 feet in actual length excluding heliports.

c) Twenty-five to one for a horizontal distance of 5,000 feet from the nearest point of the nearest landing and takeoff area of each heliport.

18.5.7.1 Forms. The FAA is notified by filing four copies of FAA Form 7460-1, "Notice of Proposed Construction or Alteration." This notice should be forwarded to the appropriate FAA Regional Office. The notification form must be submitted not later than 30 days prior to the date the proposed construction is to begin.

The FAA will acknowledge in writing the receipt of each notice. If the construction or alteration proposed is one for which marking standards are prescribed in the FAA Advisory Circular AC 70/7460-1, the acknowledgment will contain a statement that the structure must be marked and lighted in accordance with the circular. The acknowledgment will also state that an aeronautical study has reached one of the following conclusions concerning the construction or alteration.

a) It would not exceed an obstruction standard and would not be a hazard to air navigation.

b) It would exceed an obstruction standard but would not be a hazard to air navigation.

c) It would exceed an obstruction standard and further aeronautical study is necessary to determine whether it would be a hazard to air navigation. In such cases, the sponsor must request within 30 days that the FAA complete its studies. Pending completion of these studies, it is presumed the construction or alteration would be a hazard.

An existing or future structure is considered to be an obstruction to air navigation if it is of greater height than 500 feet above ground level at the site of the object, or greater than certain lesser heights within 6 nautical miles of an airport.

18.5.7.2 Supplemental Notice. A supplemental notice filed on FAA Form 117-1, "Notice of Progress of Construction or Alteration," must be filed with the Chief of the Air Traffic Division having jurisdiction over the FAA Region 5 days after the construction reaches its greatest height in the following instances.

a) The construction or alteration is more than 200 feet above the surface level of the site.

b) An FAA regional office advises that submission of the form is required.

Section 19. TESTING

19.1 Equipment Testing

19.1.1 Turbine Generators. Turbine generators shall be tested in accordance with ASME Performance Test Code, PTC 6.1 Interim Test Code for An Alternative Procedure for Testing Steam Turbines.

a) The following are the major measurements which must be made for a condensing turbine in a reheat regenerative cycle using superheated inlet steam. Measurements for a non-reheat, back pressure, or automatic extraction turbine are similar in principle.

1) HP turbine throttle temperature.

2) HP turbine throttle pressure.

3) HP turbine exhaust pressure.

4) HP turbine first stage pressure.

5) Cold reheat temperature.

6) IP Turbine throttle temperature.

7) IP Turbine throttle pressure.

8) LP Turbine throttle temperature.

9) LP Turbine throttle pressure.

10) LP Turbine exhaust pressure.

11) Generator output.

12) Generator hydrogen pressure.

13) Generator power factor.

14) Boiler feed pump discharge temperature.

15) Boiler feed pump discharge pressure.

16) Superheater spray flow.

17) Reheater spray flow.

18) Highest pressure feedwater heater feedwater inlet temperature.

19) Highest pressure feedwater heater feedwater outlet temperature.

20) Highest pressure feedwater heater drain outlet temperature.

21) Highest pressure feedwater heater extraction temperature.

22) Highest pressure feedwater heater extraction pressure.

23) Feedwater flow to boiler.

24) Feedwater pressure at boiler inlet.

25) HP Turbine gland leakage flow.

26) HP Turbine gland leakage temperature.

27) HP Turbine gland leakage pressure.

28) Main steam flow to steam seal receiver.

b) As a result of calculations based on PTC 6S methods, the following performance parameters can be quantified.

1) Maximum capability.

2) Heat rate.

3) Enthalpy-drop efficiency.

19.1.2 Steam Generators. Steam generators shall be tested in accordance with ASME Performance Test Code, PTC 4.1, Steam Generating Units, which is currently being revised. The changes which have been incorporated into the latest draft code, such as the use of continuous analyzers instead of Orsat analyzers, are recommended for use. For additional testing requirements see MIL-HDBK-1003/6.

19.1.2.1 Input/Output Method

a) The following are the major measurements which must be made for input/output method.

1) Coal flow.

2) Higher heating value.

3) Combustion air temperature.

4) Feedwater flow.

5) Feedwater temperature.

6) Feedwater pressure.

7) Superheat desuperheat spray flow.

8) Superheat desuperheat spray temperature.

9) Superheat desuperheat spray pressure.

10) Blowdown flow.

11) Auxiliary steam flow.

12) Auxiliary steam temperature.

13) Auxiliary steam pressure.

14) Sootblowing steam flow.

15) Main steam temperature.

16) Main steam pressure.

17) Cold reheat steam pressure.

18) Cold reheat steam temperature.

19) Hot reheat steam pressure.

20) Hot reheat steam temperature.

In addition to these measured parameters, cold reheat flow is required. This can be determined under the turbine generator test.

b) As a result of calculations based on PTC 4.1 methods, the following performance parameters can be quantified.

1) Steam generator efficiency.

2) Input.

3) Output.

4) Steam temperature and control range.

5) Capacity.

6) Water and steam side pressure drop.

19.1.2.2 Heat Loss Method

a) The following are the major measurements which must be made for heat loss method.

1) Auxiliary steam flow from steam generator.

2) Auxiliary steam temperature.

3) Auxiliary steam pressure.

4) Blowdown flow.

5) Carbon monoxide at economizer outlet.

6) Coal flow.

7) Cold reheat pressure.

8) Cold reheat temperature.

9) Cold reheat flow (calculated by PTC 6 methods).

10) Drum pressure.

11) Feedwater flow at economizer inlet.

12) Feedwater pressure at economizer inlet.

13) Feedwater temperature at economizer inlet

14) Flue gas temperature at air heater outlet.

15) Hot reheat pressure.

16) Hot reheat temperature.

17) Main steam pressure.

18) Main steam temperature.

19) Motor power.

20) Flue gas oxygen at economizer outlet.

21) Pulverizer reject flow.

22) Reheat desuperheating spray flow.

23) Reheat desuperheating spray pressure.

24) Reheat desuperheating spray temperature.

25) Sootblowing steam flow.

26) Sootblowing steam temperature.

27) Sootblowing steam pressure.

29) Superheat desuperheating spray flow.

30) Superheat desuperheating spray temperature.

31) Superheat desuperheating spray pressure.

In addition to these measured parameters, a fuel ultimate analysis, fuel heating value, and ash (if any) heating values are required.

b) As a result of calculations based on PTC 4.1 methods, the following performance parameters can be quantified.

1) Steam generator efficiency.

2) Steam generator steam flow.

3) Steam temperature and control range.

4) Exit flue gas temperature.

5) Water and steam side pressure drop.

6) Steam generator maximum capability.

19.1.2.3 Condensers. Condensers shall be tested in accordance with ASME Performance Test Code, PTC 12.2 Steam Condensing Apparatus.

a) The following are the major measurements which must be made.

1) Circulating water flow.

2) Condenser pressure.

3) Condenser inlet cooling water pressure.

4) Condenser inlet cooling water temperature.

5) Condenser outlet cooling water pressure.

6) Condenser outlet cooling water temperature.

7) Condenser absolute pressure.

b) As a result of calculations based on PTC 12.2 methods, the following performance parameters can be quantified.

1) Condenser tube cleanliness factor.

2) Condenser tube fouling factor.

3) Condenser waterside pressure drop.

4) Condenser heat load.

19.1.2.4 Cooling Towers. Cooling towers shall be tested in accordance with The Cooling Tower Institute's (CTI), ATC 105, Acceptance Test Code For Water Cooling Towers (Part 1, Test Procedure; Part 2, Evaluation of Results).

ATC 105 recognizes two methods for evaluating the performance of a cooling tower: the characteristic curve method and the performance curve method. Both methods require the same measured data and calculate the same performance parameter.

The following are the major measurements which must be made.

a) Wet bulb temperature at tower inlet.

b) Dry bulb temperature.

c) Cold water temperature.

d) Hot water temperature.

e) Cooling water flow.

f) Fan power.

g) Makeup water temperature.

h) Makeup water flow.

i) Blowdown temperature.

j) Blowdown flow.

As a result of calculations, the cooling tower capability can be quantified as a percent of design.

19.1.2.5 Evaporators. Evaporators shall be tested in accordance with ASME Performance Test Code, PTC 14, Evaporating Apparatus.

a) The following are the major measurements which must be made.

1) Evaporator feedwater flow.

2) Evaporator feedwater temperature.

3) Evaporator vapor sample.

4) Evaporator vapor pressure.

5) Evaporator vapor temperature.

6) Steam supply pressure.

7) Steam supply temperature.

b) As a result of tests and determinations based on PTC 14 methods, the following performance parameters can be quantified.

1) Maximum capacity.

2) Total solids in vapor.

19.1.2.6 Deaerators. Deaerators shall be tested in accordance with Performance Test Code, PTC 12.3, Deaerators. ASME PTC 12.3 Part II describes several methods of determining the dissolved oxygen content in deaerated water. These methods include the titration method and the colorimetric method. Continuous oxygen analyzers are also commercially available.

19.1.2.7 Pumps. Centrifugal pumps shall be tested in accordance with ASME Performance Test Code, PTC 8.2, Centrifugal Pumps.

a) The following are the major measurements which must be made for each pump.

1) Inlet flow.

2) Inlet temperature.

3) Inlet pressure.

4) Discharge flow.

5) Discharge temperature.

6) Discharge pressure.

7) Bleedoff flow.

8) Bleedoff temperature.

9) Bleedoff pressure.

10)Pump input power.

11) Pump speed.

b) As a result of calculations based on PTC 8.2 methods, the following performance parameters can be quantified.

1) Capacity.

2) Pump total head.

3) Pump power.

4) Pump efficiency.

5) Suction requirements.

6) Available net positive suction head.

7) Specific speed.

19.1.2.8 Fans. Forced draft and induced draft fans shall be tested in accordance with ASME Performance Test Code, PTC 11, Fans. For additional test requirements see MIL-HDBK-1003/6.

a) Test Code PTC 11 recognizes two methods for expressing fan performance.

1) Mass flow/specified energy.

2) Volume flow/pressure.

The mass flow/specific energy method requires velocity and static pressure measurements at the fan inlet and outlet. Experience has shown that accurate velocity pressure measurements at the fan outlet are at best very difficult. Therefore, the volume flow/pressure method which does not require fan outlet velocity pressure is recommended.

b) The following are the major measurements required for the volume flow/pressure method.

1) Fan inlet static pressure.

2) Fan inlet velocity pressure.

3) Fan outlet static pressure.

4) Air or gas inlet temperature.

5) Fan speed.

6) Fan input power.

In addition to these measured parameters, the air or gas composition is required.

c) As a result of calculations based on PTC 11 methods, the following performance parameters can be quantified.

1) Fan static pressure.

2) Volumetric flow.

3) Mass flow.

4) Fan static efficiency.

19.1.2.9 <u>Compressors</u>. Air compressors shall be tested in accordance with ASME Performance Test Code, PTC 9 Displacement Compressors, Vacuum Pumps and Blowers.

a) The following are the major measurements which must be made.

1) Capacity.

2) Inlet static pressure.

3) Discharge static pressure.

4) Stage inlet static pressure (for multistage machines).

5) Stage outlet static pressure (for multistage machines).

6) Inlet air or gas temperature.

7) Intercooler inlet and outlet gas temperatures (for multistage machines).

8) Discharge air or gas temperature.

9) Cooling water flows to individual cylinders and coolers.

10) Cooling water inlet temperatures to individual cylinders and coolers.

11) Cooling water outlet temperatures to individual cylinders and coolers.

12) Compressor speed.

13) Input power.

14) Indicated power.

In addition to these measured parameters, the gas composition is required.

b) As a result of calculations based on PTC 9 methods, the following performance parameters can be quantified.

1) Compression ratio.

2) Isentropic power.

3) Volumetric efficiency.

4) Stage compression efficiency.

5) Mechanical efficiency.

6) Compressor efficiency.

7) Power economy (units of power per unit of capacity).

19.1.2.10 <u>Heat Exchangers</u>. Feedwater heaters and auxiliary cooling water heat exchangers shall be tested in accordance with ASME Performance Test Code, PTC 12.1 Closed Feedwater Heaters.

a) Feedwater Heaters. The following are the major measurements which will be required for each closed feedwater heater.

1) Feedwater flow.

2) Feedwater inlet temperature.

3) Feedwater outlet temperature.

4) Feedwater inlet pressure.

5) Feedwater outlet pressure.

6) Drain inlet flow (where applicable).

7) Drain inlet pressure (where applicable).

8) Drain inlet temperature (where applicable).

9) Drain outlet flow.

10) Drain outlet temperature.

11) Drain outlet pressure.

12) Extraction steam flow (can be calculated).

13) Extraction steam temperature.

14) Extraction steam pressure.

15) Heater pressure.

In addition to these measured parameters, the heater manufacturer's design data is also required.

b) As a result of calculations based on PTC 12.1 methods, the following performance parameters can be quantified.

1) Terminal temperature difference.

2) Feedwater temperature rise.

3) Drain cooler approach (where applicable).

4) Feedwater pressure drop.

5) Pressure drop through drain cooler (where applicable).

c) Auxiliary Cooling Water Heat Exchangers. Using PTC 12.1, the cooling water heat exchanger will be treated as an external drain cooler.

The following are the major measurements which must be made.

1) Tube side water inlet temperature.

2) Tube side water inlet pressure.

3) Tube side water outlet temperature.

4) Tube side water outlet pressure.

5) Shell side inlet temperature.

6) Shell side inlet pressure.

7) Shell side outlet temperature.

8) Shell side outlet pressure.

9) Tube side flow.

10) Shell side flow.

d) As a result of calculations based upon PTC 12.1 methods, the following performance parameters can be quantified.

1) Tube side pressure drop.

2) Shell side pressure drop.

3) Approach temperature.

19.1.2.11 Air Heaters. Boiler tubular and regenerative air heaters shall be tested in accordance with ASME Performance Test Code, PTC 4.3 Air Heaters, which is currently being revised as PTC 41. The changes which have been incorporated in developing PTC 41 are recommended for use.

a) The following are the major measurements which must be made for each air heater.

1) Flue gas inlet temperature.

2) Flue gas outlet temperature.

3) Air inlet temperature.

4) Air outlet temperature.

5) Air inlet flow.

6) Air outlet flow.

7) Flue gas inlet flow

8) Flue gas outlet flow.

9) Flue gas side inlet and outlet static pressure.

10) Flue gas side inlet and outlet velocity pressure.

11) Air side inlet and outlet static pressure.

12) Air side inlet and outlet velocity pressure.

13) Inlet flue gas analysis (CO_2, CO, O_2).

14) Outlet flue gas analysis (CO_2, CO, O_2).

15) Fuel flow (measured or calculated by steam generator output and efficiency).

b) In addition to these measured parameters, a fuel ultimate analysis is required.

As a result of calculations based on PTC 41 methods, the following performance parameters can be quantified.

1) Flue gas side efficiency.

2) Air leakage.

3) Heat capacity ratio (X-Ratio).

4) No leakage exit flue gas temperature.

5) Flue gas side pressure drop.

6) Air side pressure drop.

19.1.2.12 Dust Collectors. Mechanical dust collectors shall be tested in accordance with ASME Performance Test Code, PTC 21 Dust Separating Apparatus except Environmental Protection Agency Method 5 (40 CFR Part 60 Appendix A, Reference Methods), sampling (isokinetic sampler with heated filter) should be used. Measurements taken include particulate concentration and mass flow rate at both the inlet and outlet of the dust collector. Flue gas flow rate, composition, and temperature are also measured. Measurements at the inlet and outlet allow determination of dust collector overall efficiency. For other testing requirements see MIL-HDBK-1003/6.

19.1.2.13 Precipitators. Electrostatic precipitators shall be tested for performance and compliance (if required by Federal, state, or local regulations). Testing will be the same as described above under Dust Collectors.

19.1.2.14 Flue Gas Scrubbers. Flue gas scrubbers shall be tested for performance and compliance (if required by Federal, state, or local regulations). An ASME performance test code is in the process of preparation, however, no interim PTC for scrubbers is yet available. Testing should be done in accordance with 40 CFR Part 60 Appendix A, EPA Method 5 or 17 for particulate matter and Methods 6 and 8 for SO_2, SO_3, and NOx. See also MIL-HDBK-1003/6, for information relative to sampling ports.

19.2 Preparations for Tests. Preparations for testing includes the following.

a) Determine applicable test code.

b) Read and observe applicable parts of ASME PTC 1, General Instructions and ASME PTC 2, Definitions and Values.

c) Determine test data and readings required.

d) Prepare necessary forms for recording of test data.

e) Determine instrumentation to be used for tests and provide temporary supplemental instruments as necessary.

f) Calibrate or verify calibration of instruments.

g) Determine the necessary parties to the test.

19.3 Test Equipment and Materials. The test equipment shall consist of instruments and apparatus as necessary to provide indication or record of test properties and variables. Materials shall consist of miscellaneous chemicals for charging instruments and supplies. Each individual test code for specific equipment contains information covering permissible choices of instrumentation, methods of calibration, and precautions to be observed. Whether cited or not in the test code, Supplements to ASME Performance Test Code, PTC 19 Instruments and Apparatus should be consulted as necessary. These supplements are as follows:

a) PTC 19.2 Pressure Measurement.

b) PTC 19.3 Temperature Measurement.

c) PTC 19.5 Application, Part II of Fluid Meters: Interim Supplement on Instruments and Apparatus.

d) PTC 19.5.1 Weighing Scales.

e) PTC 19.6 Electrical Measurements in Power Circuits.

f) PTC 19.7 Measurement of Shaft Power.

g) PTC 19.8 Measurement of Indicated Horsepower.

h) PTC 19.10 Flue and Exhaust Gas Analyses - Instruments & Apparatus - V Part 10.

i) PTC 19.12 Measurement of Time.

j) PTC 19.13 Measurement of Rotary Speed.

k) PTC 19.14 Linear Measurements.

l) PTC 19.16 Density Determinations of Solids and Liquids.

m) PTC 19.17 Determination of the Viscosity of Liquids.

Section 20. LOAD SHEDDING

20.1 Objectives of Load Shedding Program. When a power plant or an individual power generating unit experiences a gradual increase in load, or a sudden but mild overload, the unit governors will sense the resulting speed change and increase the power input to the generator. The additional load is handled by using the spinning reserve; that is, the unused capacity of the generator. However, if all generators are operating at maximum capacity, the spinning reserve is zero and the governors may not be able to relieve the overload.

When severe overloads occur, or when large sudden load increases are experienced, the first effect is a slowing down of the generator. If the overload is large enough or if the governor cannot accommodate the sudden load increase, then speed and frequency will continue to drop until the plant or generating unit is tripped to prevent equipment damage, and the load is lost.

20.1.1 Definition. Load shedding is the deliberate and selective dropping of electrical load in accordance with a preplanned program.

20.1.2 Purpose. The purpose of load shedding is to reduce plant loads so that the plant will not trip on overload and so that certain preselected loads can be saved, even though other loads are lost.

20.2 Requirements for Load Reduction. A typical scenario in which load shedding would be advantageous would be the case of a power plant operating in parallel with a utility, with a total system load exceeding the capability of the plant alone. Should the interconnection trip, the plant would experience a sudden overload from which it might not be able to recover.

Another scenario could involve an isolated plant (not interconnected with a utility), with several generating units loaded at or near their combined capability. Should one unit trip, the remaining units would experience a sudden load increase, possibly leading to loss of the plant.

20.2.1 Stable Operation and Overload Capability. Generating plants are highly sensitive to frequency drop. There are two major problem areas.

20.2.1.1 Motor speed. Motor-driven auxiliaries, particularly boiler feedwater pumps, will slow down, reducing generator output. Safety margins in generator-cooling and bearing lubricating systems will be reduced. The lowest safe plant operating speed will depend on the safety margins included in the plant design. However, operation below the 56.6 to 57.5 Hz range is generally not advisable.

20.2.1.2 Turbine Blade Fatigue. The last rows of long, low-pressure blades in steam turbines are tuned to operate free of resonance in a narrow band of frequencies around 60 Hz. When running under heavy load at about 58.5 Hz or below, the steam excitation frequency approaches blade resonance. Under this condition, the blades may vibrate severely, producing fatigue stress. On the average, blades should not be subjected to more than ten minutes of severe vibration totaled over their lifespan; fatigue is cumulative. Operation below about 58.0 to 58.5 Hz should be avoided; the generator protective devices may trip the unit in this speed range, regardless of load. Frequency and time limits for turbines should be specified by the turbine manufacturer, and protective system operation by the plant designer.

20.2.2 Generating Unit Sizes. In order to design an effective load shedding scheme, the following information is required for each generating unit in the plant.

a) The lowest safe operating speed (F) in Hz.

b) The rated capacity (MW) of the machine in megawatts.

c) The power factor (p) rating of the machine, dimensionless.

d) The inertial constant (H) of the machine in megawatt seconds per MVA.

20.2.3 Number of Generating Units. The value of plant capability used to design a load shedding program should take into account the possibility that one or more generating units may be out of service when the overload incident occurs. This determination must be based on plant configuration and judgment. However, the following conditions should be considered.

a) All units in operation.

b) All but the largest unit in operation.

c) All but the two largest units in operation.

20.2.4 Reduced Plant Capability. The reduction in plant capability resulting from underspeed operation should be known but will generally be unavailable. As an approximation, assume a capability loss of about four percent capability for each Hz of underfrequency.

20.2.5 Load Reduction Requirements. In order to attain stable plant operation, load must be shed to such a degree that the total load served does not exceed plant capability. As already explained, the determination of plant capability must take into account the possibility that one or more generating units in the plant may be out of service and also that the remaining plant may experience some loss of capability because of underfrequency operation.

20.2.5.1 Rate of Load Reduction. Load must be shed fast enough to attain the required load reduction before plant frequency has deteriorated to an unacceptable level. The rate of frequency change can be estimated from the following formula.

EQUATION: $$R = pL(f_1 - f_0) / H(1 - f_1^2/f_0^2 \qquad (15)$$

where:

- R = Average rate of frequency change, Hz per second
- p = Power factor of machine
- L = Average per unit overload
  = (Load-Power Input)/(Power Input)
- f_o = Initial frequency, Hz
- f_1 = Final frequency, Hz
- H = Inertial constant of machine, MW sec/MVA

For a typical calculation, assume that a 100 MW, 0.85 power factor machine with an inertial constant of H=4 experiences a sudden overload to 120 MW and we wish to find the rate at which frequency drops from the initial frequency of fo = 60 Hz to f1 = 58 Hz. In this case,

EQUATION: $$L = (120\ MW - 100\ MW) / (100\ MW) = 0.20 \qquad (16)$$

and substituting in Equation (15):

$$R = [(0.85)(0.20)(60-58)]/[4(1 - (60^2/58^2))]$$

$$= -1.21\ Hz/second.$$

In this case, the minus sign indicates that the frequency is decreasing at a rate of 1.21 Hz per second.

The total time for the frequency to drop 2 Hz, from f_o = 60 Hz to f_1 = 58 Hz would be

$$Time = 2/1.21 = 1.65\ seconds$$

This indicates that the load shedding plan must accomplish a load reduction of at least 20 MW within 1.65 seconds.

For calculations involving an entire plant, composite values should be used to obtain a rate of frequency drop for the entire plant. The composite inertial constant for the plant, H Plant, is calculated from the following formula.

EQUATION: $$H_{plant} = (H_1MVA_1 + H_2MVA_2 + \ldots + H_NMVA_N)/(MVA_1 + MVA_2 + \ldots + MVA_N) \qquad (17)$$

where the subscripts refer to the individual generating units.

20.2.5.2 Total Load Reduction. The load shedding plan must accomplish a total load reduction sufficient to relieve the plant overload and also to provide a slight underload so that the plant will have reserve capability to reaccelerate to the normal operating frequency. One must also take into account the loss of capability that results from underfrequency operation.

In the previous example (a 100 MW generator with a 120 MW load) assume that the plant frequency dropped to 58 Hz before load shedding was initiated and that the plant capability loss was four percent for each Hz of frequency drop. In this case, the plant capability would be only 92 percent (or 92 MW) at 58 Hz. If 30 MW of load were shed (reducing the total load from 120 MW to 90 MW) then the generator would have a 2 MW margin (92 MW capability less 90 MW load) to reaccelerate back to the normal operating frequency of 60 Hz. The time to reaccelerate may be computed from the same formulas already given.

20.2.5.3 Minimum Power Supply. It is reasonable to design a load shedding plan to drop nearly all or perhaps even all of the plant load. The rationale is that even if all load is dropped but the plant is saved, load restoration would be faster and easier than if the plant were lost also.

20.3 Methods of Load Shedding. There are many methods of load shedding, both automatic and manual. The automatic methods include underfrequency relaying and various transfer-trip arrangements. All of these methods have relative advantages and disadvantages and the choice of the most advantageous method should be based on the specific conditions that prevail. However, load shedding by underfrequency relaying is the most common and generally the preferred method.

20.3.1 Underfrequency Relaying. The principal advantage of under frequency load shedding is that the underfrequency relays respond to the underfrequency condition resulting from generator overload. They do not respond to the overload directly, but to the deleterious conditions resulting from overload. Therefore, they respond only if the generators are suffering the adverse consequences of overload.

20.3.1.1 Automatic Operation. Load shedding with under-frequency relays is generally performed automatically; when frequency drops to a preset level, certain predetermined loads or blocks of load are tripped automatically.

Automatic operation is generally advantageous because, with severe overloads, system frequency may drop faster than the plant operator can respond.

20.3.1.2 Critical Frequencies. In general, underfrequency relays are applied to shed load in two to five steps, with three-step load shedding being the most common. Each underfrequency relay is set to trip a block of load at progressively lower frequencies; for instance, at 59.5 Hz, 59.0 Hz, and 58.5 Hz. These critical frequencies should be computed as described previously.

20.3.1.3 Incremental Load Reduction. The amount of load to be shed at each critical frequency should be related to the expected percentage overload. In general, this determination can only be made in an approximate manner, because system loads vary and cannot be determined accurately in advance.

It is important to note that with a multi-stepped underfrequency load shedding system, quite often the overload will be eliminated and system frequency will start to recover after only one or two critical frequencies are reached. Herein lies another advantage of underfrequency load shedding; with a well designed load-shedding plan, only the minimum amount of load necessary for system recovery is shed.

20.3.2 Transfer Trip Load Shedding. With transfer trip load shedding, protective relays and circuit breakers are interlocked so that the event that causes a loss of power supply also causes certain loads to be dropped, thereby preserving a balance between load and generation. For instance, with an interconnected plant, auxiliary contacts on the interconnection circuit breaker could be used to trip certain loads whenever the interconnection failed. Similarly, for an isolated plant, the loss of one generating unit could be sensed and used to initiate the tripping of a block of load equal to the generating capacity lost.

Although transfer trip load shedding has the advantage of simplicity, the use of this method will almost always result in greater loss of load than with underfrequency load shedding. For this reason, the transfer trip method is generally not recommended.

20.3.3 Manual Load Shedding. In general, manual load shedding cannot be used to resolve problems of severe plant overloads. With severe overloads, the system frequency drops too rapidly for an operator to respond and the plant can be lost within seconds.

Manual load shedding is appropriate to relieve mild overloads; that is, overloads that are small enough to be accommodated by governor action (thereby preventing underspeed operation), but that are still large enough to cause excessive equipment stress (overheating, accelerated wear, etc.) if uncorrected.

It is appropriate to combine manual load shedding (to relieve mild overloads) with underfrequency load shedding (to relieve severe overloads).

20.3.3.1 Load Shedding Plan. With manual load shedding, it is appropriate to have a load shedding plan. This plan can be quite simple; it need consist of no more than a list of what loads (or feeders) should be tripped and how.

It is important that the plan be prearranged so that the plant operator can implement it quickly under emergency conditions.

20.3.3.2 Incremental Load Reduction. In designing a manual load shedding plan, the total amount of load to be shed manually should be sufficient to relieve the anticipated plant overload.

Manual load shedding can be performed in one or several steps to take account of varying system conditions, such as the difference between summer and winter peaks or seasonal changes in plant capability because of scheduled maintenance.

20.3.4 Point of Application. In order to determine the point of application, local or remote, the designer must take into account the location of the specific loads to be shed and the electric distribution system configuration. This determination will also be influenced by the load shedding method; underfrequency, transfer trip, or manual.

20.3.4.1 Local Application. When load shedding is initiated locally, that is, at the power plant, individual outgoing feeders are tripped. Generally, each feeder will be tripped sequentially in a predetermined order of preference until the overload has been corrected.

Local load shedding is the system that is the most common and easiest to implement and can be utilized with underfrequency, transfer trip, or manual systems.

A disadvantage is that, if a feeder is tripped, then all loads served from that feeder are dropped, regardless of their criticality. In some systems, all non-essential loads can be grouped on a single feeder, and this feeder is tripped first. In other systems, this approach may not be practical.

20.3.4.2 Remote Application. With remote application, individual loads are tripped rather than entire feeders. With this approach, each load can be given a priority and tripped sequentially in accordance with that priority.

Remote tripping can be readily implemented with underfrequency relays installed at the remote circuit breaker. With manual or transfer trip load shedding, the trip signal must be transmitted to the remote circuit breaker.

20.4 Electrical Usage and Critcality. In general, the least critical loads should be tripped first, and the load shedding should proceed in stages with progressively more critical loads being shed at each stage. The following provides guidelines for the determination of the relative criticality of loads.

20.4.1 Critical Loads. To develop a load shedding plan, the critical loads shall be identified first, along with an estimate of the magnitude of each.

The load shedding plan shall be designed so that critical loads are shed last. However, in some cases, it may be necessary to divide the critical loads into two or more categories and assign relative priorities to each category.

20.4.1.1 Mission Critical Loads. Mission critical loads are the loads that are essential for the operation of the facility and, if shed, would adversely impact the facility mission. Mission critical loads may also include base security.

20.4.1.2 Life Support Loads. Life support loads include hospitals and similar facilities where loss of power may endanger life.

20.4.1.3 Cost of Power Outage. In some cases, a power outage, while not endangering the mission or life support, may result in excessive costs. For instance, the power supply to a food storage facility may be considered critical because a power outage may result in food spoilage with inherent loss of money and morale.

20.4.1.4 Political Implications. In some cases, the selection of critical loads must be made on a purely subjective basis, taking into account the effect on the community of providing power, or of not providing power, to a specific load during a widespread power failure.

20.4.2 Time-Critical Loads. In many cases, load criticality will vary with time. These variations should be taken into account, if possible, when designing the load shedding plan.

20.4.2.1 Seasonal Variations. In a severely cold climate, a load related to providing heat could be considered critical during the winter and noncritical during the summer. Under the same conditions, the power supply to a frozen food storage facility could be considered critical during the summer and non-critical during the winter.

20.4.2.2 Diurnal Variations. The criticality of some loads may vary from day to night or from weekday to weekend because of changing usage. Examples may include auditoriums, theaters, and offices.

20.4.2.3 Interruptible Loads. Some loads can withstand short interruptions but not lengthy interruptions. Examples may include community facilities with emergency (battery powered) lighting. These loads can be classified non-critical for load shedding, but could also be given a high priority for load restitution.

20.4.3 Standby Power. In many cases, highly critical loads such as those identified as mission critical or life support will be provided with standby emergency power supplies (uninterruptable power supply, diesel generator, etc). In these cases, the load under consideration can be downgraded from critical to interruptible or even non-critical depending on the capability of the standby power supply.

20.4.4 Non-Critical Loads. Having identified all critical loads, those that remain can be classified as non-critical and identified for first-step load shedding.

Section 21. POWER PLANT COGENERATION

21.1 Definition. Cogeneration is the simultaneous generation of electricity (or mechanical energy) and steam (or other thermal energy such as hot air or hot water) from the same fuel (or energy) source.

21.2 Cycles. Cogeneration cycles consist of energy conversion equipment such as boilers, turbines, and electric generators arranged to produce both electricity and steam or other thermal energy.

21.2.1 Basic Cycle. The basic conventional cycle consists of a steam boiler and turbine, which drives either an electrical generator or other mechanical equipment, and from which steam is extracted or exhausted to environmental heating or processes.

21.2.2 Combined Cycle. See Figures 13, 19, and 48 for typical cogeneration cycles. The combined cycle consists of a gas turbine which exhausts to a heat recovery steam generator (HRSG). The HRSG in turn produces steam to drive a steam turbine. Both turbines can drive a single or separate electrical generator. Low pressure turbine exhaust steam can be used directly for process or heating purposes or the steam can be otherwise condensed and returned to the HRSG.

21.3 Efficiency. The overall efficiency of a cogeneration cycle is a ratio of all usable energy (electricity, steam, hot water, etc.) obtained from the cycle to the energy (fuel, solar, etc.) input to the cycle.

21.4 Methods of Operation

21.4.1 Parallel Operation. Under parallel operation, the cogeneration plant is electrically interconnected and synchronized with an electric utility distribution or transmission system, with both the cogenerator and electric utility generating electricity simultaneously. Under parallel operation, some electricity will be flowing either to or from the cogeneration system.

21.4.1.1 Reasons for Paralleling

a) Selective use of electrical energy from the electric utility by the cogenerator. The cogenerator purchases electrical energy during periods and in amounts as needed to supplement its cogeneration capabilities.

b) Sale of excess electricity by the cogenerator to the electric utility. The cogenerator has a large heat demand for process use or environmental heating and can cogenerate electricity in excess of facility needs. The excess electricity generated is sold to the electric utility generally at a rate which is less than the generating costs; this is usually not economical.

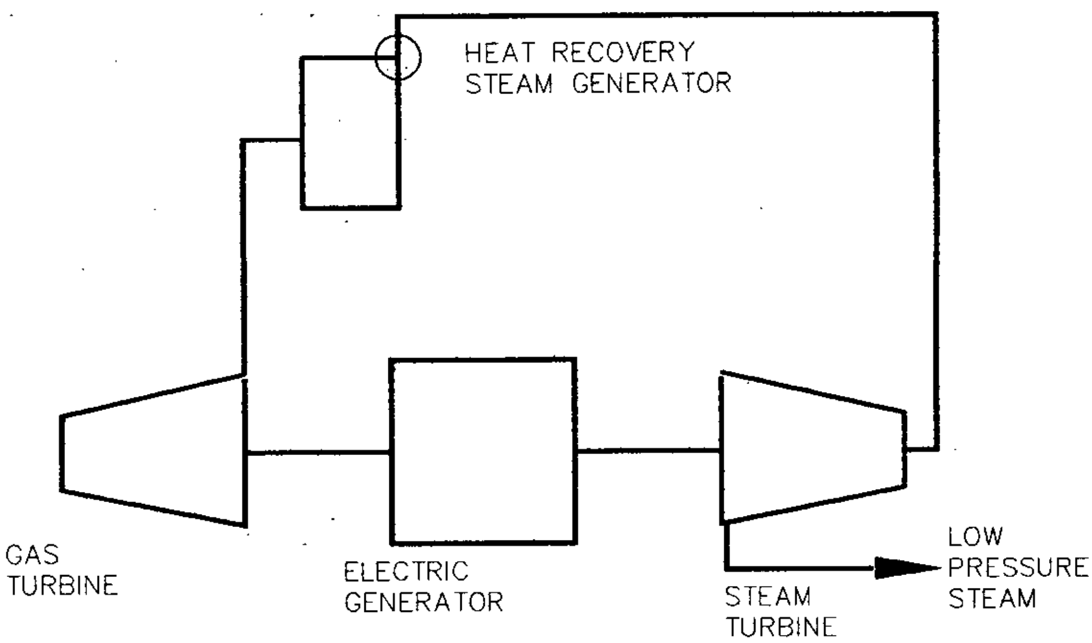

Figure 48
Combined Cycle

c) Peak Shaving. Cogeneration is used to minimize demand charges from the electrical utility.

21.4.2 Isolated Operation. Under isolated operation, the cogeneration plant generates, independently of the electric utility, all electricity and steam needed and used by the facilities that it serves.

21.4.2.1 Reasons for Isolation

a) The facilities and cogeneration plant are in a remote location and electricity is not or cannot feasibly be made available from an electric utility to the facilities.

b) Critical mission requires self-contained system, including onsite standby.

c) Facility heat and electrical needs coincide to permit self-contained (total energy) cogeneration system.

d) Agreement for parallel operation cannot be reached with electric utility.

21.4.2.2 Electric Utility Crosstie. A cogenerator may operate in isolation and may also be interconnected to an electric utility for service during maintenance down times and/or for standby service for use during an emergency outage of the cogeneration plant. If a cogenerator is not crosstied to an electric utility, backstart capability must be provided.

21.4.3 Base Load Thermal. In this mode of operation, the cogeneration equipment is sized and installed to generate electricity at a constant (base) load equal to that afforded by minimum steam demand, as determined from periodic swings in steam load. Supplemental electrical demands above the base load would be supplied by the electric utility through a parallel arrangement. Supplemental steam demands would be supplied by the use of supplementary firing of heat recovery steam generators or separate boilers.

21.4.4 Base Load Electric. In this mode of operation, the cogeneration equipment is sized and installed to generate electricity at a constant (base) load equal to the minimum annual (or some other chosen period) electrical demand. Some of the electricity included in the base load may not be cogenerated but may serve to reduce demand supplied by an electric utility. Because of the duality of steam production and utilization, automatic extraction condensing turbine generators lend themselves to base load electric operation.

21.4.5 Electric Peak Shaving. Peak shaving is accomplished by the use of onsite generation or cogeneration equipment to limit the demand, during peak electrical use periods, of electricity purchased from an electric utility through a parallel arrangement. Peak shaving is usually done on a daily cyclic basis. The objective of peak shaving is to economically reduce electric utility demand charges and overall electrical energy costs. If there is a high demand for steam during peak electric demand periods, cogeneration can be used to supplement purchased power to achieve peak shaving, if it proves to be economical.

21.4.6 Electric and Thermal Tracking

21.4.6.1 Electric Tracking. Electric tracking is defined as the continuous generation of electricity to meet the electrical demands of a facility as they occur throughout the daily load swings. With electric tracking, cogeneration equipment is used to generate as much steam as the electric load will allow with supplemental steam demands generated directly by use of boilers. The use of automatic extraction condensing turbine generators and combined cycles also provides the means for electric tracking.

21.4.6.2 Thermal Tracking. Thermal tracking is defined as the continuous generation of heat or steam to meet the thermal demands of a facility as they occur throughout the daily load swings. With thermal tracking, cogeneration equipment is used to generate as much electricity as the steam load will allow with supplemental electrical demands generated on other equipment such as gas turbine generators, diesel generators, and steam turbine generators. Automatic extraction condensing turbine generators and combined cycles provide the means for simultaneous tracking of both electric and thermal loads.

21.5 Interconnection with Utility

21.5.1 Operation Requirements. Operational requirements of a cogeneration plant interconnected with an electric utility are conditions of either the electric utility rate schedule for parallel generation contract service or separate contract of agreement between the cogenerator and utility. The conditions as set out in the contract may be site specific and cogeneration system specific. Typical examples are as follows:

a) Voltage, frequency, and wave shape of alternating current to be delivered to the utility system shall be maintained within specified limits.

b) The utility may reserve the right to limit the amount of electrical load delivered to the utility system at certain times and as utility electric operating conditions warrant.

c) The utility may reserve the right to inspection, observation of testing, and specification of certain maintenance requirements.

d) The cogenerator may be required to notify the utility prior to initial energizing and startup testing of the cogeneration facility.

e) The cogenerator may be required to notify the company prior to each start of energy delivery and interconnection to the utility system.

f) The utility may require that the cogeneration plant's scheduled outage for maintenance coincide with periods when utility power system demand is low.

g) The utility may require a demonstration of reasonable reliability of the cogeneration plant over the life of the contract.

h) The utility may require a contract specifying technical and operating aspects of parallel generation.

21.5.2 Interconnection Equipment

21.5.2.1 Utility Standby Service. This arrangement requires a manual or automatic throwover switch that will first disconnect the cogeneration electrical source from the facility electrical load before connecting the facility electrical load to the electric utility service entrance line.

21.5.2.2 Parallel Operation. This arrangement requires two manually operated disconnect switches, one to disconnect or connect the cogeneration electrical source to the facility electrical load and the other to disconnect or connect the facility electrical load to the utility service entrance line. In addition to these switches, meters for billing will be required and are usually supplied, owned, and maintained by the electric utility. The manual switch for connect or disconnect of the utility service from the facility electric load and cogeneration system electric source is usually a mandatory contract requirement by the utility. The utility will further require that this switch be under exclusive control of the utility, and that it must have the capability of being locked out by utility personnel to isolate the utility's facilities in the event of an electrical outage on transmission and distribution facilities serving the cogenerator. The other manual switch or isolation device will also usually be required by the utility contract to serve as a means of isolation for the cogeneration equipment during maintenance activities, routine outages, or emergencies.

The interconnection with the utility for parallel operation also requires synchronizing controls for electrically synchronizing the cogeneration system with the electrical utility system.

21.5.3 Line and Equipment Protection. Parallel operation introduces variables in distribution line protection in that fuses and other sectionalizing devices may be affected by generator contributions to fault currents. Line sectionalizing studies should be made to verify correct operation of sectionalizing devices over the range of conditions that could arise. Generators operating in parallel with the utility system need protection against overload. To protect both line and cogeneration equipment in the event of unacceptable fault, one protective relaying system is required to separate the utility system from the cogeneration bus and another protective relaying system is required to separate the cogenerator from the cogeneration bus. The required protective relay functions are usually designated by the electric utility and the final design of the complete protective relaying system must have the approval of the electric utility prior to initial operation of the cogeneration system.

21.5.4 Utility Power Rates. Utility power rates are based on the utility's costs to provide both electrical capacity and energy. This is reflected in the billing as charges for electrical demand and energy.

21.5.4.1 Demand Charge. The electrical demand for billing purposes is usually determined from demand instruments located at the customer facility such as a kW meter and associated printing recorder which periodically records the kW load or demand. In some cases, the demand may be determined by tests made by the utility. Billing demand is usually established on a monthly basis and is taken as the highest demand recorded, usually in any 30-minute interval. Many utilities' rate schedules also contain a ratcheted demand clause which establishes a minimum billing demand based on the highest, or some percentage of the highest, demand occurring in the previous 12 months, or some other chosen period. The effect of the ratchet may result in a billing demand for a month of low demand, for instance a winter month, that is based on a high demand in a previous summer month. Rate schedules take various forms, depending on the utility and state public utility commission practices. Rate schedules for demand will vary according to geographic area and usage.

21.5.4.2 Energy Charge. The energy usage for billing purposes is determined from kWh meters located at the customer's facility. Energy charges are usually tied to billing demand in such a manner that low energy use at a high demand is charged at a high rate whereas a large energy use at a low demand is charged at a lower rate. Therefore any peak shaving scheme which can be used to reduce demand can result in savings which may economically justify the investment costs for peak shaving equipment and its fuel usage, operation, and maintenance. Rate schedules for energy will vary according to geographic area and usage.

21.5.4.3 Total Electric Billing. The electric billing by the electric utility is usually computed and issued on a monthly basis. The total electric bill will usually be the sum of the demand and energy charges plus adjustment for such items as fuel cost, research and development surcharge, and taxes.

21.5.4.4 Other Factors for Sale of Electricity. The rates charged for electrical demand and energy depend on other factors or the type of service. These are typically as follows:

a) Service at secondary voltage.

b) Service at primary voltage (12,000 to 69,000 volts).

c) Standby service.

d) Breakdown service.

e) Supplementary service.

f) Seasonal service.

g) Water heating.

h) Space heating.

21.5.4.5 Purchase of Electricity. For parallel operation with a cogenerator, electric utilities under certain terms and conditions, may purchase excess electricity generated by the cogenerator.

As covered under section 201 of the Public Utility Regulatory Policy Act of 1978 (PURPA), cogeneration facilities that are not owned by an electric utility and that meet certain standards are eligible for special incentive rates to be paid to them by the utility as required under Section 210 of PURPA. These incentive rates that the utility is obligated to pay to qualifying facilities are not required directly by PURPA but are required by rules promulgated by the Federal Energy Regulatory Commission (FERC.)

These rules by FERC provide that electric utilities must purchase electric energy and capacity made available to the electric utilities by qualifying cogenerators at a rate that reflects the costs that the purchasing utility can avoid as a result of obtaining energy and capacity from these sources, rather than generating the energy itself or purchasing the energy or capacity from other suppliers.

The term "avoided costs" has been defined by FERC as the costs to an electric utility of energy, capacity, or both, that but for the purchase from a qualifying facility, the electric utility would generate or construct itself or purchase from another source. "Avoided costs" include the fixed and running costs on a utility system that can be avoided by obtaining energy or capacity from a qualifying facility.

An electric utility's "avoided costs" are primarily fuel cost for production of energy and capital cost of facilities for generation capacity. The amount a utility will pay a cogenerator for purchased electricity produced by the cogenerator is equal to or is a percentage of the utility's "avoided cost" as decided by agreement contract between the utility and cogenerator, or as set out in a rate schedule published by the utility.

21.6 Economics. Cogeneration plants are capital intensive and high maintenance facilities. However, cogeneration can be economically justified if the savings in electrical energy costs, resulting from the use of cogeneration as compared to purchase of electricity from a utility, offset the costs of the cogeneration facility capital investment, added fuel usage, added operation, and added maintenance.

21.6.1 Fuel Savings. Using cogeneration, there is no fuel saving when compared to the use of boilers for the production of steam for process or environmental heating/cooling systems. There is a fuel saving for production of electricity, by use of cogeneration as compared to non-cogeneration systems, if the exhaust heat or steam from the prime mover is used by other process or environmental heating/ cooling systems.

21.6.2 Competitive Systems. The basic cogeneration systems that provide the means to utilize exhaust heat from the prime mover are the back pressure steam turbine, gas turbine, combined cycle, or reciprocating combustion engine. A cogenerator using only condensing turbine generator equipment cannot compete economically with an electric utility using the same type of equipment because of the economics of large scale operations. The utility's large condensing steam turbine generators operating at high initial pressure and temperature are much more efficient than would be a cogenerator's small condensing steam turbine generators operating at lower initial pressures and temperatures. However, condensing steam turbine generators can be economically combined with noncondensing or extraction turbine generators if the noncondensing equipment is utilized to the extent that fuel savings more than offset the increased cost of operation of the condensing equipment. The noncondensing and condensing equipment may be combined into single machines such as automatic extraction condensing turbine generators.

21.6.3 Power to Heat Ratio. A gauge for match of the cogeneration system with the facility heat or steam and electric demands is often expressed as the power to heat ratio. This ratio is defined as the ratio of the power generated to heat available for process or environmental heating/cooling systems. The higher the power to heat ratio, the higher will be the efficiency of cogeneration or economic return on investment capital. Table 34 shows typical power to heat ratios of cogeneration systems.

Table 34
Typical Performance of Cogeneration Systems Power to Heat Ratio

	Backpressure Turb. Gen.	Gas Turbine	[1]Combined Cycle	Diesel Gen.
kWh/million Btu steam	50 to 1	200 to 1	250 to 1	400 to 1
Btu power/Btu steam	0.171	0.683	0.853	1.365

[1]Gas turbine, heat recovery steam generator, and backpressure turbine generator.

21.6.4 Economic Variables. The application of cogeneration to a facility is site specific insofar as economic evaluation is concerned. The evaluation will require complete information for the facility concerning electricity and steam (or heat) usage and load demand on an hourly basis throughout a typical year. The annual costs of fuel and purchased electricity must be determined for each alternate system to be considered, including an alternate without cogeneration. Also, for each alternate system considered, a determination must be made of total capital investment cost, annual operating costs, and annual maintenance labor, parts, and material costs. Depending on the type of evaluation used, periodic replacement costs and salvage value may need to be determined.

21.6.5 Economic Evaluation. The economic evaluation of the various alternate systems is best done on a life cycle cost basis and by a present worth type analysis. For a complete description of life cycle costing, modes of analysis, methods and procedures for analysis, and choice of most economical alternate, refer to NAVFAC P-442 or National Bureau of Standards Handbook 135, Life-Cycle Cost Manual for the Federal Energy Management Programs.

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Considine, Douglas M., Process Instruments and Controls Handbook, Third Edition (1985), available from McGraw-Hill., New York, NY.

REFERENCES

Note: Unless otherwise specified in the text, users of this handbook should use the latest revisions of documents cited herein.

FEDERAL/MILITARY SPECIFICATIONS, STANDARDS, BULLETINS, HANDBOOKS, AND NAVFAC GUIDE SPECIFICATIONS:

The following specifications, standards, bulletins and handbooks form a part of this document to the extent specified herein. Unless otherwise indicated, copies are available from STANDARDIZATION DOCUMENTS ORDER DESK, Building 4D, 700 Robbins Ave, Phila., PA 19111-5094.

SPECIFICATIONS

MILITARY

MIL-B-17095	Boiler, Steam, High Pressure Water Tube, Packaged Type
MIL-B-17452	Boiler, Steam & Hot Water, High & Low Pressure, Firetube Packaged Type
MIL-P-17552	Pump Units, Centrifugal, Water, Horizontal, General Service and Boiler Feed, Electric Motor or Steam Driven
MIL-H-17660	Heater, Fluid, Deaerating (For Water Only) 1,000 to 1,600,000 Pounds Per Hour Capacity
MIL-R-18115	Regulator, Boiler Feed Water, Automatic
MIL-F-18523	Fan, Centrifugal, Draft, Forced and Induced
MIL-T-18246	Steam turbines For Mechanical Drive
MIL-B-18796	Burner, Single, Oil, Gas, and Gas/ Oil Combination
MIL-B-18797	Burners, Oil, Mechanical-Draft, Automatic
MIL-M-38784	Manual, Technical, General Style and Format Requirements

HANDBOOKS

MIL-HDBK-1002/2	Loads
MIL-HDBK-1003/6	Central Heating Plants
MIL-HDBK-1003/8	Exterior Distribution of Utility Steam, HTW, CHW, Gas, and Compressed Air
MIL-HDBK-1003/17	Industrial Ventilation Systems
MIL-HDBK-1004/1	Electrical Engineering Preliminary Design Considerations
MIL-HDBK-1004/10	Cathodic Protection
MIL-HDBK-1005/7	Water Supply Systems
MIL-HDBK-1008	Fire Protection for Facilities Engineering, Design and Construction
MIL-HDBK-1023/1	Airfield Lighting
MIL-HDBK-1025/2	Dockside Utilities For Ship Service
MIL-HDBK-1032/2	Covered Storage
MIL-HDBK-1190	Facility Planning and Design Guide

NAVY MANUAL, P-PUBLICATIONS, AND MAINTENANCE OPERATING MANUALS:

Available from Commanding Officer, Naval Publications and Forms Center, (NPFC), 5801 Tabor Avenue, Philadelphia, PA 19120-5099. To order these documents: Government agencies must use the Military Standard Requisitioning and Issue Procedure (MILSTRIP); the private sector must write to NPFC, ATTENTION: Cash Sales, Code 1051, 5801 Tabor Avenue, Philadelphia, PA 19120-5099.

DM-3.01	Pluming Systems
DM-3.03	Heating, Ventilating, and Air Conditioning and Dehumidifying Systems
DM-3.05	Compressed Air and Vacuum System
DM-5.10	Solid Waste Disposal

DM-5.12	Fencing, Gates, and Guard Towers
DM-22	Petroleum Fuel Facilities
DM-38	Weight-Handling Equipment
MO-213	Solid Waste Management
P-355	Seismic Design For Buildings
P-442	Economic Analysis Handbook
WW-H-171E	Hangers And Support, Pipe

NAVY DEPARTMENTAL INSTRUCTIONS: Available from Commanding Officer, Naval Publications and Forms Center, ATTENTION: Code 3015, 5801 Tabor Avenue, Philadelphia, PA 19120-5099.

SECNAVINST 7000.14	Economic Analysis and Program Evaluation for Navy Resource Management
NAVFACINST 10343.1A	Navy Special, Navy Distillate and Marine Diesel Fuel Oils; On-Shore Use of
NAVFACINST 10340.4C	Coal Requirement and Requisitions
OPNAVINST 4100.6	Energy Financing and Source Selection Criteria for Shore Facilities
OPNAVINST 5100.23	Navy Occupational Safety & Heath Program

NAVAL AIR SYSTEM COMMAND: Available from Commanding Officer, Naval Air Technical Services Facility, 700 Robbins Avenue, Philadelphia, PA 19111-5097.

51-50AAA-2	General Requirements for Shorebased Airfield Marking and Lighting

OTHER GOVERNMENT DOCUMENTS AND PUBLICATIONS:

The following Government documents and publications form a part of this document to the extent specified herein. Unless otherwise specified, the issues of the documents which are DoD adopted are those listed in the Department of Defense Index of Specification & Standards (DODISS).

DEPARTMENT OF THE ARMY

TM 5-811-6	Electric Power Plant Design

TM 5-1815-1/AFR 19-6	Air Pollution Control Systems for Boilers and Incinerators

(Unless otherwise indicated, copies are available from US Army AG Publications Center, 1655 Woodson Road, ST. Louis, Missouri 63114)

DEPARTMENT OF LABOR

29 CFR 1910, Chapter XVII, Occupational Safety and Health Act of 1970

29 CFR 1910, Subpart Z, paragraph 1910.1200, Hazard Communication Standard

(Unless otherwise indicated, copies are available from Occupational Safety and Health Administration, 200 Constitution Avenue NW, Washington DC 20210)

DEPARTMENT OF TRANSPORTATION

AC 70/7460-IF	Obstruction Marking and Lighting
AC 150/5345-43C	Specification for Obstruction Lighting Equipment
14 CFR 77	Object affecting navigable Airspace (available from Superintendent of documents, U.S. Government Printing Office, Washington, D.C. 20402)

(Unless otherwise indicated, copies are available from Federal Aviation Administration Office of Airport Standards (AAS-200), 800 Independence Avenue, S.W. Washington, DC 20591)

ENVIRONMENTAL PROTECTION AGENCY

42 USC & 7401 et seq.	Clean Air Act
40 CFR 60, Subpart D	Standards of Performance for Fossil Fuel Fired Steam Generators
40 CFR 60, Subpart Da	Standards of Performance for Electric Utility Steam Generating Units
40 CFR 60, Subpart Db	Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

40 CFR 60, Appendix A	Reference Methods
40 CFR 136	Guide lines establishing test procedures for the analysis of pollutants
40 CFR 257	Criteria for classification of solid waste disposal facilities and practices.
40 CFR 264	Regulations For Owners and Operators of Permitted Hazardous Waste Facilities
40 CFR 265	Interim Status Standards For Owners and operators of Hazardous Waste Treatment, Storage, and Disposal Facilities

(Unless otherwise indicated, copies are available from Superintendent of Documents, U.S. Government Printing Office, Washington, D.C. 20402)

NON-GOVERNMENT PUBLICATIONS:

The following publications form a part of this document to the extent specified herein. Unless otherwise specified, the issues of the documents which are DoD adopted are those listed in the Department of Defense Index of Specifications & Standards (DODISS):

Combustion Engineering, Inc. (1981), Combustion/Fossil Power Systems, available from Combustion Engineering, 1000 prospect Hill Road, Windsor, CT 06095.

Rodney S. Thurston, Design of Suction Piping: Piping and Deaerator Storage Capacity To Protect Feed Pumps, Journal of Engineering for Power, Volume 83, January 1961, ASME

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Salisbury, Kenneth J. (1974), Steam Turbines and Their Cycles, available from Robert E. Krieger Publishing Co., Inc., Melbourne, FL.

AMERICAN CONFERENCE OF GOVERNMENTAL INDUSTRIAL HYGIENISTS

Industrial Ventilation - A Manual of Recommended Practices

(Unless otherwise indicated, copies are available from American Conference of Governmental Industrial Hygienist, 6500 Glenway, Bldg D-7, Cincinnati, OH 45211.)

AMERICAN NATIONAL STANDARDS INSTITUTE (ANSI)

A12	Floor and Wall Openings, Railings, and Boards, Safety Requirements for
A14.03	Fixed-Ladders, Safety Requirements
B15.01	Mechanical Power Transmission Apparatus, Safety Standard for
B20.01	Conveyors and Related Equipment
B30.02	Overhead And Gantry Cranes (Top Running Bridge, Single or Multiple Girder, Top Running Trolley Hoist)
B30.11	Monorails and Underhung Cranes
B30.16	Overhead Hoists (Underhung)
C2	National Electric Safety Code
C50.10	General Requirements for Synchronous Machines
C50.13	Reg. for Cylindrical Rotor Synchronous Generators

C50.14	Requirements for Combustion Gas Turbine Driven Cylindrical Rotor Synchronous Generators
C84.1	Electric Power Systems and Equipment - Voltage Rating
Z83.3	Gas Utilization Equipment in Large Boilers
Z358.1	Eyewash and Shower Equipment, Emergency
ANSI/ASME B31.1	Power Piping
ANSI/IEEE 100	Dictionary of Electrical & Electronic Terms
ANSI/NFPA 31	Installation of Oil Burner Equipment
ANSI/NFPA 37	Combustion Engines and Gas Turbines
ANSI/NFPA 70	National Electric Code
ANSI/NFPA 85F	Installation and Operation of Pulverized Fuel

(Unless otherwise indicated, copies are available from ANSI Standards, 1430 Broadway, NEW York, NY 10018)

AMERICAN SOCIETY OF HEATING, REFRIGERATING, AND AIR-CONDITIONING ENGINEERS, INC. (ASHRAE)

HE	ASHRAE Equipment Handbook
HF	ASHRAE Fundamentals Handbook
HS	ASHRAE Systems Handbook

(Unless otherwise indicated, copies are available from ASHRAE, 1791 Tullie Circle, N.E., Atlanta, GA 30329)

AMERICAN SOCIETY OF MECHANICAL ENGINEERS (ASME)

Boiler and Pressure Vessel Code

Theoretical Steam Rate Tables
Recommended Practices for the Cleaning, Flushing, and Purification of Steam and Gas Turbine Lubrication Systems

ANSI/ASME B31.1	Power Piping
PTC-1	General Instructions
PTC-2	Definitions and Values
PTC-4.1	Steam Generating Units
PTC-4.3	Air Heaters
PTC-6.1	Interim Test Code for an Alternative Procedure for Testing Steam Turbines
PTC-8.2	Centrifugal Pumps
PTC-9	Displacement Compressors, Vacuum Pumps, and Blowers
PTC-11	Fans.
PTC-12.1	Closed Feedwater Heaters.
PTC-12.2	Steam Condensing Apparatus.
PTC-12.3	Deaerators.
PTC-14	Evaporating Apparatus.
PTC-19	Instruments and Apparatus.
PTC-19.2	Pressure Measurement
PTC-19.3	Temperature Measurement
PTC-19.5	Application, Part II of Fluid Meters: Interim Supplement on Instruments and Apparatus
PTC-19.5.1	Weighing Scales
PTC-19.6	Electrical Measurements in Power Circuits
PTC-19.7	Measurement of Shaft Power
PTC-19.8	Measurement of Indicated Horsepower
PTC-19.10	Flue and Exhaust Gas Analyses - Instruments & Apparatus - V Part 10

PTC-19.12	Measurement of Time
PTC-19.13	Measurement of Rotary Speed
PTC-19.14	Linear Measurements
PTC-19.16	Density Determinations of Solids and Liquids
PTC-19.17	Determination of the Viscosity of Liquids
PTC-21	Dust Separating Apparatus.

(Unless otherwise indicated, copies are available from ASME order Dept., 22 Law Drive, Box 2350, Fairfield, NJ 07007-2350)

AMERICAN SOCIETY FOR TESTING AND MATERIALS (ASTM)

A 283/A283M-84a	Specification for Low and Intermediate Tensile Strength Carbon Steel Plates, Shapes, and Bars.
A 285/A285M-82	Specification for Pressure Vessel Plates, Carbon Steel, Low-and Intermediate-Tensile Strength.
A 516/A516M-84	Specification for Pressure Vessel Plates, Carbon Steel, for Moderate and Lower Temperature Service.
D2013-72(1978)	Method for Preparing Coal Samples for Analysis.
D2234-82	Method for Collection of a Gross Sample of Coal.

(Unless otherwise indicated, copies are available from American Society for Testing and Materials, 1916 Race Street, Philadelphia, PA 19103.)

COOLING TOWER INSTITUTE (CTI)

CTI Bulletin ATC-105	Acceptance Test Code For Water Cooling Towers (Part 1, Test Procedure; Part 2, Evaluation of Results)

(Unless otherwise indicated, copies are available from Cooling Tower Institute, 19627 Tower 45 North, Suite 230, Spring, TX 77388)

HEAT EXCHANGE INSTITUTE (HEI)

Standards for Steam Surface Condensers, Sixth Edition

(Unless otherwise indicated, copies are available from Heat Exchange Institute, 122 East 42nd Street, New York, NY 10017)

NATIONAL ASSOCIATION OF CORROSION ENGINEERS (NACE)

Cooling Water Treatment Manual

Handbook

(Unless otherwise indicated copies are available from NACE, 2400 West Loop South, Houston, Texas 77027)

NATIONAL ELECTRICAL MANUFACTURERS ASSOCIATION (NEMA)

SM 23	Steam Turbines for Mechanical Drive Service
SM 24	Land Based Steam Turbine Generator Sets 0 to 33,000 KW
Standard publication/ No. 250	Enclosures for Electrical Equipment (1000 Volts Maximum)

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