# An Introduction to Central Heating Plant Planning

Course No: D02-002

Credit: 2 PDH

J. Paul Guyer, P.E., R.A., Fellow ASCE, Fellow AEI

Continuing Education and Development, Inc.
22 Stonewall Court
Woodcliff Lake, NJ 07677

P: (877) 322-5800
info@cedengineering.com

# An Introduction to Central Heating Plant Planning

J. Paul Guyer, P.E., R.A.

Paul Guyer is a registered civil engineer, mechanical engineer, fire protection engineer and architect with 35 years of experience designing buildings and related infrastructure. For an additional 9 years he was a principal staff advisor to the California Legislature on capital outlay and infrastructure issues. He is a graduate of Stanford University and has held numerous national, state and local offices with the American Society of Civil Engineers, Architectural Engineering Institute and National Society of Professional Engineers.

## CONTENTS

# 1. INTRODUCTION

**1.1 SCOPE.** This publication contains data and information as criteria to guide the planning of steam and high temperature water (HTW) central and individual heating plants. Engineering and economic considerations are identified to guide siting decisions, fuel selection, and the choice of either high temperature water or steam distribution media. The primary purpose of these plants is to generate steam and high temperature water for space heat and process steam in the most economical, operationally efficient, and environmentally acceptable manner possible for distribution to groups of buildings.

## 2. POLICY

**2.1 ECONOMY.** New heating plants shall be designed to meet application requirements for the lowest overall ownership, operation and energy consumption costs during their life span. The application of any facility must be justified by an economic analysis to ensure the most appropriate facility at the lowest overall cost to the owner. The economic analysis for new or modified plant construction projects shall consider all suitable alternatives to determine the most cost effective method of accomplishment. Figure 1 provides a list of cost considerations for comparing alternative plants.

### 2.2 PLANT ALTERNATIVES

**2.2.1 CENTRAL HEATING PLANTS.** These plants are for groups of buildings which are existing or anticipated within a five year program. Central heating plants are justified when the distribution system will have a lower life cycle cost than other alternatives.

**2.2.2 COGENERATION**. Plants which generate electric power and heat can be utilized when an economic analysis determines lower life cycle costs than other alternatives.

**2.2.3 INDIVIDUAL HEATING PLANTS.** Individual plants are typically inside or adjoin the building they serve. Individual plants are considered when economically justified and for the following reasons:

a) When installation and maintenance of an extension of the distribution system from a central plant to an isolated building is not economically justified.

b) When dispersal of facilities and continuity of services are so essential that disruption of service by any damage to the central heating plant and connecting distribution system cannot be tolerated.

c) When fuel costs are paid by occupants of residences.

**2.2.4 EXPANSION OF EXISTING PLANTS.** Additional steam capacity, including reserve capacity for loads expected within five years, may be added to an existing central heating plant. An economic study must show that modifications and additions to an existing plant and distribution system will be more cost effective than other alternatives.

| **Items** | **Central Steam Plant** | **Central HTW Plant** | **Individual Plant** |
|---|---|---|---|
| | | | |
| Boilers | | | |
| Burners | | | |
| Stokers | | | |
| Economizer or air heater | | | |
| Forced and induced draft fans and drives | | | |
| Fuel storage and handling | | | |
| Fire protection systems | | | |
| Ash handling | | | |
| Metering, scales, etc. | | | |
| Deaerating heaters | | | |
| Condensate receiver and pumps | | | |
| Boiler feed pumps and drives | | | |
| Feedwater treatment system | | | |
| Combustion and feedwater controls | | | |
| Burner management system | | | |
| Piping systems with valves and fittings | | | |
| Steam or HTW return | | | |
| Condensate or HTW return | | | |
| Feedwater and air | | | |
| Stacks, breeching, dampers and accessories | | | |
| Air pollution control equipment | | | |
| Compressed air system | | | |
| Blowdown systems | | | |
| Plant building | | | |
| Equipment foundations | | | |
| Electric work | | | |
| Emergency generator | | | |
| Sanitary work | | | |
| Space heating and ventilating | | | |
| Contingency, overhead and profit | | | |
| Total investment cost | | | |
| Annual owning cost | | | |
| Annual fuel cost | | | |
| Annual distribution losses | | | |
| Annual Distribution system maintenance | | | |
| Annual disposal costs | | | |
| Annual operation and maintenance materials | | | |
| Annual operation and maintenance labor | | | |
| Note: Make similar comparison for each fuel under consideration. | | | |

* *

Figure 1

Format for Comparing Plant Costs

**2.2.5 REHABILITATION VERSUS REPLACEMENT.** If an existing plant has deteriorated to the point of producing numerous outages, is becoming a safety hazard, or is not in compliance with air pollution regulations, its rehabilitation or replacement will be determined by a life cycle economic analysis. If replacement is determined to be the most cost effective, then the capacity of the modern plant is required to handle any additional projected load. Necessary equipment and systems for air pollution regulation compliance and other operating, safety or maintenance deficiencies must be included for either the rehabilitated plant or replacement plant.

**2.3 STANDBY FACILITIES.** A standby facility is a facility which is redundant to the primary facility and maintained to operate in the event the primary facility becomes inoperable. A standby facility will be considered only when:

a) A crucial need exists and redundant equipment and systems in the primary facility will not provide required or necessary reliability of continuous operation.

b) An outage could endanger life or property, or seriously interfere with the mission of an activity.

c) The financial loss to the owner from a reasonable outage schedule will be greater than the costs of standby equipment.

d) The consumer load is sufficiently critical. When a replaced plant is considered for a standby facility it shall be made suitable for operation in conformance with safety and clean air regulations.

**2.4 STEAM VERSUS HIGH TEMPERATURE WATER (HTW) HEATING PLANTS**. Central steam heating plants shall be utilized unless a thorough analysis dictates that a HTW plant is preferable. The following factors will be among those considered in the analysis:

a) Economic advantages of thermal storage of the HTW system in sizing of equipment such as boilers, pumps and piping.

b) Operating and maintenance costs of HTW distribution system versus steam distribution system.

c) Pressure and temperature requirements provided economically by steam or HTW.

d) Cost of replacement or renovation of an existing plant and distribution system compared with the construction of a new plant and/or distribution system. A comparison will be on a life cycle basis. The analysis must indicate if a system change is economical before the change is made.

e) Prevalence of skilled plant operators in the area. This is critical in remote locations. HTW system operators require more skill to make the system operate efficiently.

f) Complexity of controls and ability of the system to maintain fluctuating or constant temperature conditions through the assigned or existing heat transfer equipment.

## 2.5 FUEL SELECTION

**2.5.1 SELECTION.** Select fuels which are within the national guide lines and which produce the required performance at lowest life cycle costs. The fuel policy has been to use a solid domestically produced fuel as a primary fuel for heating 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. New or replacement boilers in plants with design input over the threshold minimum established by owner policy, are required to burn solid fuel. Another fuel may be used when the primary fuel is not available or where it is critical to keep the steam plant in operation on an emergency basis.

**2.5.2 CHARACTERISTICS**. When oil is used the boiler should be capable of conversion to grades No. 2 through No. 6 oil.

**2.6 CODES AND REGULATIONS**

**2.6.1 CONFORMANCE.** It is mandatory to conform to Federal, State, and local air and water pollution abatement codes.

**2.6.2 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 (NBBI), 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) American Institute of Mining, Metallurgical, and Petroleum Engineers (AIME).

## 3. PLANT DESIGN

**3.1 PLANT STUDY**. A plant study shall be conducted before authorization to develop definitive designs is provided. The study will evaluate plant operating parameters with a primary emphasis on economic factors. Major emphasis will also be given to energy conservation and environmental concerns. The documented study shall determine:

a) Plant load and operating characteristics;

b) Fuels to be burned;

c) Required dependability of service;

d) Predicted lifespan of the plant;

e) Estimated cost (Capital and operating); and

f) Required pollution abatement equipment.

Figure 1 provides the predominant costs which affect the plant. It may be used as a basis for comparing plant alternatives. Table 1 provides a list of predominant design considerations for the design of thermal plants.

### 3.2 THERMAL GENERATING EQUIPMENT

**3.2.1 EQUIPMENT CAPACITY.** The combination of number and size of thermal generating equipment in a plant determines the plant capacity. A plant may be installed with a single boiler able to provide the required plant capacity for applications where loss of the boiler will not adversely affect the operation. Most applications cannot tolerate the complete loss of a thermal plant. These applications require that two boilers provide 135 to 150 percent of the plant's maximum steam demand. The continuous capacity of the plant with a boiler not operating shall be greater than the essential plant load. A spare boiler may be needed to provide the necessary backup. The recommended method for selecting the number of boilers in this situation is to use three equal capacity boilers which can each carry 50 percent of the maximum load. A variation of this scheme is to use two equal capacity boilers each capable of providing two thirds of the maximum load and a smaller boiler capable of carrying one third of the maximum load. The maximum steam plant demand shall not require operation of more than three simultaneously fired boilers. A smaller peak and off-season boiler should be included if increased efficiency at low loads economically justifies the installation. Avoid the installation of initial main boilers whose capacities are smaller than those to be added when the plant is expanded. Avoid unnecessary large numbers of small boilers.

| Factor | Effect |
|---|---|
| Load characteristics | Affects number, size, and type of boilers. Boiler performance requirements. (Turn down ratio and response to load swings.) |
| Fuels | Affects type of boiler fuel handling and pollution control equipment required. |
| Availability of water | Affects type of water treatment required |
| Electric service | Affects type of auxiliaries. Will require emergency generator if continuous service is critical. |
| Plant location | Building cost; altitude affects air density and stack height. Local regulations affect type of fuel and required pollution abatement equipment. |

Table 1
Plant Design Considerations

**3.2.2 MINIMUM LOAD.** The plant shall operate efficiently at minimum loads. The following variables can be manipulated to meet minimum load requirements:

a) Type of fuel and method of combustion. This will determine operating ranges of combustion control turn-down which may range from 8:1 to 3:1. The boiler turn-down must include the minimum load. By changing burner tips in oil firing, low minimum loads can be obtained.

b) Number of boilers. More smaller boilers will lower the minimum plant capacity. This option should not be considered if plant would require more than four equal capacity boilers.

c) Minimum load boilers. Where the difference between a minimum plant steam demand and minimum boiler load with main boilers is large, a small, packaged boiler unit with its own boiler feed pumps should be used to provide low plant capacities.

**3.2.3 OPERATING PRESSURE.** Select a plant operating pressure which provides adequate pressure at any user outlet and allows for the pressure drop through piping in the building, distribution system, boiler plant, and the dry piping in the boiler steam drum. Boiler design pressure should be 250 psi (1725 kPa) minimum for all water tube boiler applications. For all other applications, the design pressure should be determined in accordance with the ASME Boiler and Pressure Vessel Code. Modify pressures when it is economical and practicable to distribute steam at pressures below or above those indicated by this publication.

**3.2.3.1 HEATING PLANTS.** Heating plants normally do not require operating steam pressures over 150 psig (1035 kPa). Lower pressures have smaller heat losses from distribution piping. Cast iron valves can be used up to 125 psig (862 kPa) but steel valves are required between 125 psig (862 kPa) and 150 psig (1035 kPa) unless 250 psig (1725 kPa) class cast iron valves are used. For this reason, the recommended operating pressure range is 100 psig (690 kPa) to 125 psig (862 kPa) for maximum economy of distribution piping including valves and fittings. When the maximum plant and distribution loads are large and the most remote terminal requirements cannot be satisfied with sufficient quantities of steam, combinations of higher pressures and related pipe sizes should be analyzed to compare installation and operating costs of various steam pressures up to 250 psig (1725 kPa) (the next higher pressure rating of cast iron valves).

**3.2.3.2 PROCESS LOADS REQUIRING HIGHER PRESSURES THAN 100 PSIG (690 KPA).** When a process load is required in excess of 100 psig (690 kPa) an economic analysis should determine whether steam should be generated and distributed at the pressure required at the process, distributed at two pressure levels, or generated at the higher pressure locally by a separate heating plant as needed.

**3.3 EQUIPMENT TYPES AND CLASSIFICATIONS.** Watertube and firetube boilers are the two general types of boilers available. The boilers are also classified as either high pressure or low pressure and whether they produce hot water or steam. A high pressure boiler is a boiler which operates at pressures above 15 psig (103 kPa). The advantage of the high pressure boiler is reduced boiler size and distribution piping required to equal the capacity of a low pressure boiler. Most large capacity boilers are high pressure boilers. A hot water boiler is a misnomer since the water does not boil. A high temperature water (HTW) boiler is a hot water boiler which produces water at temperatures higher than 250 degrees F (121 degrees C). Other classifications for boilers are the type of fuel and method of firing. Burners and stokers are the two general methods of firing with further categories of these types of firing schemes.

**3.4 BOILER TYPE SELECTION.** Once the operating parameters (load, fuel, etc.) have been determined, the type of boilers which will provide the best operating characteristics shall be selected. Table 2 lists the advantages and disadvantages of high temperature hot water boilers versus steam boilers. Table 3 lists acceptable boiler types and criteria to consider when selecting the type and possible pollutants to control. Pollution control equipment will be a major cost factor when evaluating the most cost effective alternative.

| High temperature water advantages | Steam advantages |
|---|---|
| 1. Minimal system water loss; therefore makeup primarily required for losses from pump glands, valve packing, expansion tank overflow. | 1. Steam system operation more familiar to most operators. |
| 2. Supply and return water thermal energy is retained in system and not lost through leaking other than traps, condensate losses, PRV stations and flashing. | 2. Less pumping horsepower required. |
| 3. If desirable or necessary, heat storage in system will allow continued operation for a period of time after heat input has been cut off. | 3. Provides energy for uses other than heating; i.e., turbine driven equipment. |
| 4. Temperatures of the HTW and space conditions can be closely controlled. | 4. Fewer and less complicated controls. |
| 5. Systems will respond to quick load swings. | 5. Usually considered safer due to possibility of highly dangerous rupture with HTW. |
| 6. Heat storage (fly wheel) effect can reduce size of HTW generators. | |
| 7. Water treatment requirements are minimal in closed circulation loop systems. | |
| 8. No deaeration required. | |
| 9. No steam traps or pressure reducing stations required. | |
| 10. Distribution system can more nearly follow natural topography. | |
| 11. Boiler blowdown not required for HTW generators. | |

Table 2 (continued below)
Advantages and disadvantages of HTW plants and steam plants

| High Temperature Water Disadvantages | Steam Disadvantages |
|---|---|
| 1. Primary and secondary pumping required to assure proper heat distribution. | 1. Condensate losses in distribution range from 12 to 25 percent minimum. |
| 2. Proper operation of system depends on artificial pressurization. Loss of pressurization causes shutdown. | 2. Oxygen and bicarbonates in the feedwater can result in corrosion in the condensate pipe. Adequate water treatment is required to prevent premature failure of the condensate system. |
| 3. Steam driven auxiliaries not practicable. | 3. Steam boiler requires expensive steam drum, extensive feedwater system. |
| 4. Strainer or sediment trap required at inlet to generator to prevent solid impurities from entering the generator. | 4. Inadequate pressure at end of steam main will cause insufficient quantity of steam for user. |
| 5. Flashing of water on reduction of pressure in piping system can cause cavitation and water hammer. | 5. Generally requires more excavation for underground systems due to required pitch of lines. |
| 6. Water flashing to steam on rupture can result in an extremely violent and dangerously explosive action throughout the system. | 6. Valves, traps, and strainers are sources of steam loads. |
| 7. Under constant flow conditions, high return-water temperatures can result at low load conditions, thus causing additional thermal losses. | |
| 8. Heat exchangers are usually required at end usages of HTW. | |

Table 2 (continued)

Advantages and disadvantages of HTW plants and steam plants

| Boiler Type | Fuel | Typical Capacity Range | Possible Emissions to Control | Characteristics |
|---|---|---|---|---|
| Fire tube (packaged) | Oil | 350 - 35,000 lb/hr | NOx, SOx, toxics | Low Cost; typically fully automatic; low pressure (300 psig max); has salvage value; small space requirements; easily transported. |
| | Gas | 350 - 35,000 lb/hr | NOx | |
| | Unfired | 350 - 35,000 lb/hr | Dependent on process fuel | Requires reliable heat source greater than 600 degrees F. |
| Watertube (shop assembled) | Oil | 100 - 150,000 lb/hr | NOx, SOx, toxics | Low Cost; can be high pressure; movable; smaller space requirements then field erected. |
| | Gas | 100 - 150,000 lb/hr | NOx | |
| | Unfired | 100 - 35,000 lb/hr | Dependent on process fuel | |
| Watertube (field erected) | Gas | 20,000 - No Limit | NOx | |
| | Oil | 20,000 - No Limit | NOx, SOx, Toxics | |
| Stokers | Coal | 20,000 - No Limit | NOx, SOx, toxics, particulate | Are typically more economical for boiler loads below 100,000 lb/hr; not responsive to load swings. |
| | Wood | 20,000 - No Limit | NOx, toxics, particulate | |

Table 3 (continued below)
Boiler selection criteria

| Boiler Type | Fuel | Typical Capacity Range | Possible Emissions to Control | Characteristics |
|---|---|---|---|---|
| | RDF | 2,000 - No Limit | NOx, toxics, particulate | |
| Pulverized Coal | Coal | 50,000 - No Limit | NOx, SOx, toxics, particulate | High energy and maintenance requirements; economical for capacities over 100,000 lb/hr. |
| Fluidized Bed | Coal | 50,000 - No limit | Toxics, particulate | High capital and and maintenance cost |
| | Wood | 20,000 - No Limit | Toxics, particulate | |
| | RDF | 20,000 - | Toxics, particulate | |
| High Voltage | Electric | No limit - 150,000 lb/hr | None | Convenient; low capital cost; small space requirements |
| | Electric | No Limit - 50,000 lb/hr | None | |

Table 3 (continued)
Boiler selection criteria

**3.5 BOILER DESIGN.** Boiler design is primarily dependent on the fuel and type of firing. Both furnace heat release rate and EPRS are factors which determine distribution of heat within the furnace. Proper values must be maintained to keep local absorption to a minimum and avoid "hot spots." The primary criteria for design are based on the following:

a) Furnace heat release rate -- the volumetric heat release rate is the Btu input rate per cubic foot of furnace volume

b) Effective Projected Radiant Surface (EPRS) -- the portion of the furnace in square feet which is exposed to radiant heat of the flame,

c) Grate heat release rate (for stoker boilers)

d) Flue gas velocities through tube banks

e) Tube spacing

**3.5.1 HEATING SURFACE.** Computations of effective radiant heating surface for water tube boilers are 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.

b) Extended surfaces (metal and metallic surfaces extending from the tubes or headers): sixty percent of the flat projected area, except that metal blocks are not integral with tubes or headers, extended surfaces less than 1/4 inch (6 mm) thick or more than 1-1/4 inch (31 mm) in length, and the part of the extended surface which is more than one tube or header radius from the tube or 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.

d) Grate heat release rate -- This burning rate is the higher heating value in the coal used per hour at the rated boiler capacity divided by the total active burning area of the stoker grate. These values 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. A high grate heat release rate will cause high carbon loss and increased particulate emissions.

e) Flue gas velocities through tube banks -- Gas and light oil flue gas velocities are typically determined by the need to limit draft losses. Coal, wood or solid waste boilers need to limit flue gas velocities to prevent undue erosion of boiler convection tubes. The gas velocities through the convection section of these boilers shall not exceed velocities shown in Table 4.

f) Tube Spacing -- Tube spacing is governed by the amount of deposits which will accumulate. Spacing is not critical for boilers firing gas or distillate oil. Boilers firing solid fuels or residual oil need proper spacing and proper soot blowing arrangement to limit deposit buildup on tubes, poor heat distribution, poor efficiencies and premature tube failures.

| | Single Pass Water Tube | | | Multi-Pass Water Tube |
|---|---|---|---|---|
| | Coal | Wood | Solid Waste | Coal |
| Pulverized coal | 50 | | | 60 |
| Underfeed stoker | 75 | | | 60 |
| Spreader stoker traveling grate | 60 | 50 (1) | | 50 |
| Spreader stoker traveling grate | 60 | 50 | | 50 |
| Traveling grate (front gravity feed) | 75 | | | 60 |
| Solid waste | | | 30 | |

(1) If wood has sand, use 35 fps.

Table 4

Maximum flue gas velocities (feet per second) in convection sections for coal, wood or solid waste boilers

**3.6 PLANT LAYOUT.** The plant layout should be designed to reduce maintenance time, and allow for easy operation of equipment. Future situations to consider include:

a) Tube cleaning

b) Tube replacement

c) Future expansion

d) Conversion fuels

Tube replacement for firetube boilers typically requires a space in front of the boiler which is equal to the boiler's longest length. If there is a possibility of future conversion of firing equipment to another fuel, provide space for the installation and operation of such equipment and for local storage and handling of the new fuel. Enough room shall be provided to accommodate all auxiliaries such as feed pumps, fuel pumps, condensate tank water heaters, deairators, condensate receivers and other equipment normally located in the boiler room. When steam-driven auxiliaries are used, provide emergency electrical power generation to start up the plant and operate the following essential services until steam pressure is reestablished: Coal and ash handling, coal firing, emergency lighting, instrument compressors, combustion management controls, flame safeguard controls, control valves, control room ventilation and other essential operation requirements including the auxiliaries for one boiler.

**3.8 FEEDWATER PUMPING SYSTEM.** The ASME Boiler and Pressure Vessel Code (Section 1, Paragraph PG-61) requires that boilers having more than 500 square feet of water heating surface and firing a solid fuel not in suspension be provided with two means of feeding water. It is recommended that all coalstoker fired boilers with a capacity above 100,000 lbs per hour (12.6 kg/s) should have dual feedwater systems containing separate headers, check valves, isolating valves, and regulating valves for operation flexibility and emergency. All coal-stoker fired coal boilers 20,000 lbs per hour (2.52 kg/s) and above shall have a steam turbine-driven boiler feed pump and a motor driven boiler feed pump per boiler. Provide the steam turbine driven boiler feed pump (plant size) with emergency treated water connection for coal-stoker fired plants.

**3.9 STEAM USAGE CONSIDERATIONS.** Consider uses for secondary steam to determine ways to operate a plant more effectively. Several possible ways of using steam for more economical operation are:

a) Fuel oil tank heating coil

b) Water heaters

c) Absorption type of refrigeration machines

d) Space heating

**3.9.1 REFRIGERATION UNITS.** Addition of refrigeration units to a plant design should be considered where heating plant steam can be used during summer to serve refrigeration machines. Chilled water produced by steam absorption or steam turbine driven refrigeration compressors can be distributed economically to buildings for space cooling. A combined plant saves considerable building cost. The addition of refrigeration units increases annual plant load and may reduce owning and operating costs. Turbine driven equipment can be economical if there is use for low pressure exhaust steam. Absorption refrigeration equipment does not work efficiently at low loads. If absorption equipment is not a significant load, it is advisable to utilize electric driven centrifugal equipment. This eliminates the need for low pressure summer steam and saves distribution costs, line losses, fuel and manpower.

**3.9.2 STEAM-DRIVEN AUXILIARIES.** A comparison, similar to that outlined in Figure 1, shall be made for owning and operating steam turbine driven versus electric motor driven rotating equipment. Consider amounts of condensate returned, possible waste of exhaust steam to the atmosphere, and a number of operating hours using steam driven instead of motor driven equipment. Reliability and continuity of service during power outages should also be factors when determining the most cost effective alternative. Steam driven auxiliaries may be provided in lieu of, or in conjunction with, electric motor driven units. Possible auxiliaries which can utilize steam drives include feed pumps, condensate pumps, induced draft fans, forced draft fans, air compressors, overfire air fans, and fuel oil pumps. In all cases, sufficient electric motor driven units must be provided to permit cold startup of the boiler plant.