US Army Corps
of Engineers
Construction Engineering
Research Laboratories

USACERL Technical Report FE-95/08
January 1995

Central Heating Plant Economic Evaluation Program, Volume 1: Technical Reference

by
Mike C.J. Lin
Ralph Moshage
Gary Schanche
Christopher Blazek
Richard Biederman
John Kinast
Janet Gutraj
Dale Conley
Charles Schmidt

Public Law has directed the Department of Defense (DOD) to rehabilitate and convert its existing domestic power plants to burn more coal. Other Federal legislation requires DOD to use the most economic fuel for any new heating system.

This five-volume report discusses the Central Heating Plant Economic Evaluation Program (CHPECON), a computer program for screening potential new and retrofit steam/power generation facilities.

Volume 1 is the Technical Reference.
Volume 2 is the User's Manual.
Volume 3 is the Military Base Weather Information Data Management Program.
Volume 4 is the Coalfield Properties Information Data Management Program.
Volume 5 is the Emission Regulations Data Managemen Program.

CHPECON provides screening criteria to evaluate competing combustion technologies using coal, gas, or oil; detailed conceptual facility design information; budgetary facility costs; and economic measures of project acceptability including total life cycle costs and levelized cost of service.

The program provides sufficient flexibility to vary critical design and operating parameters to determine project sensitivity and parametric evaluation.

USER EVALUATION OF REPORT

REFERENCE: USACERL Technical Report FE-95/08, *Central Heating Plant Economic Evaluation Program, Volume 1: Technical Reference*

Please take a few minutes to answer the questions below, tear out this sheet, and return it to USACERL. As user of this report, your customer comments will provide USACERL with information essential for improving future reports.

1. Does this report satisfy a need? (Comment on purpose, related project, or other area of interest for which report will be used.)

____

____

____

2. How, specifically, is the report being used? (Information source, design data or procedure, management procedure, source of ideas, etc.)

____

____

3. Has the information in this report led to any quantitative savings as far as manhours/contract dollars saved, operating costs avoided, efficiencies achieved, etc.? If so, please elaborate.

____

____

4. What is your evaluation of this report in the following areas?

   a. Presentation: ______________________

   b. Completeness: ______________________

   c. Easy to Understand: ______________________

   d. Easy to Implement: ______________________

   e. Adequate Reference Material: ______________________

   f. Relates to Area of Interest: ______________________

   g. Did the report meet your expectations? ______________________

   h. Does the report raise unanswered questions? ______________________

i. General Comments. (Indicate what you think should be changed to make this report and future reports of this type more responsive to your needs, more usable, improve readability, etc.)

____

____

____

____

____

____

5. If you would like to be contacted by the personnel who prepared this report to raise specific questions or discuss the topic, please fill in the following information.

Name: ______________________________

Telephone Number: ______________________________

Organization Address: ______________________________

____

____

6. Please mail the completed form to:

Department of the Army
CONSTRUCTION ENGINEERING RESEARCH LABORATORIES
ATTN: CECER-IMT
P.O. Box 9005
Champaign, IL 61826-9005

REPORT DOCUMENTATION PAGE

Form Approved
OMB No. 0704-0188

1. AGENCY USE ONLY *(Leave Blank)*

2. REPORT DATE
January 1995

3. REPORT TYPE AND DATES COVERED
Final

4. TITLE AND SUBTITLE
Central Heating Plant Economic Evaluation Program, Volume 1: Technical Reference

5. FUNDING NUMBERS
MIPR
W56HZV-89-AC-01,
dated 20 November 1989

6. AUTHOR(S)
Mike C.J. Lin, Ralph Moshage, Gary Schanche, Christopher Blazek, Richard Biederman, John Kinast, Janet Gutraj, Dale Conley, and Charles Schmidt

7. PERFORMING ORGANIZATION NAME(S) AND ADDRESS(ES)
U.S. Army Construction Engineering Research Laboratories (USACERL)
P.O. Box 9005
Champaign, IL 61826-9005

8. PERFORMING ORGANIZATION REPORT NUMBER
FE-95/08

9. SPONSORING / MONITORING AGENCY NAME(S) AND ADDRESS(ES)

Office of the Assistant Secretary of Defense,
Production & Logistics, Energy Policy
ATTN: OASD(P&L/EP)
400 Army/Navy Drive, Suite 206
Arlington, VA 22202

Assistant Chief of Staff for Installation Management
ATTN: DAIM-FDF-U
7701 Telegraph Road
Alexandria, VA 22310-3862

10. SPONSORING / MONITORING AGENCY REPORT NUMBER

11. SUPPLEMENTARY NOTES
Copies are available from the National Technical Information Service, 5285 Port Royal Road, Springfield, VA 22161.

12a. DISTRIBUTION / AVAILABILITY STATEMENT
Approved for public release; distribution is unlimited.

12b. DISTRIBUTION CODE

13. ABSTRACT (Maximum 200 words)

Public Law has directed the Department of Defense (DOD) to rehabilitate and convert its existing domestic power plants to burn more coal. Other Federal legislation requires DOD to use the most economic fuel for any new heating system.

This five-volume report discusses the Central Heating Plant Economic Evaluation Program (CHPECON), a computer program for screening potential new and retrofit steam/power generation facilities.

Volume 1 is the Technical Reference.

Volume 2 is the User's Manual.

Volume 3 is the Military Base Weather Information Data Management Program.

Volume 4 is the Coalfield Properties Information Data Management Program.

Volume 5 is the Emission Regulations Data Management Program.

CHPECON provides screening criteria to evaluate competing combustion technologies using coal, gas, or oil; detailed conceptual facility design information; budgetary facility costs; and economic measures of project acceptability including total life cycle costs and levelized cost of service.

The program provides sufficient flexibility to vary critical design and operating parameters to determine project sensitivity and parametric evaluation.

14. SUBJECT TERMS
Central Heating Plant Economic Evaluation (CHPECON)
central heating plants
coal-fired technologies
economic analysis

15. NUMBER OF PAGES
234

16. PRICE CODE

17. SECURITY CLASSIFICATION OF REPORT	18. SECURITY CLASSIFICATION OF THIS PAGE	19. SECURITY CLASSIFICATION OF ABSTRACT	20. LIMITATION OF ABSTRACT
Unclassified	Unclassified	Unclassified	SAR

Foreword

This study was conducted for the Assistant Chief of Staff for Installation Management (ACS(IM)), Directorate of Facilities and Housing under the Coal Conversion Studies Program, which is administered by the Energy Policy Directorate of the Office of the Assistant Secretary of Defense, Production & Logistics, Energy Policy (OASD P&L/EP). Millard Carr is the Program Manager. Funding was provided under Military Interdepartmental Purchase Request (MIPR) No. W56HZV89-AC-01; Work Units "Coal Conversion Strategies for DOD" and "Enhancement of Existing Models," dated 20 November 1989. The technical monitor was Qaiser Toor, DAIM-FDF-U.

The work was performed by the Fuels and Power Systems Team (FEP), Energy and Utility Systems Division (FE) of the Infrastructure Laboratory (FL), U.S. Army Construction Engineering Research Laboratories (USACERL). Special acknowledgement is given to Lee Thurber, Rama Katz, and Mei-Yi Feng, CECER-FE for their efforts in organizing technical materials. Dr. David M. Joncich is Chief, CECER-FE, and Alan Moore is Acting Chief, CECER-FL. The USACERL technical editor was Gloria J. Wienke, Information Management Office.

LTC David J. Rehbein is Commander and Acting Director, USACERL. Dr. Michael J. O'Connor is Technical Director.

Contents

SF 298 1

Foreword 2

List of Tables and Figures 5

1 **Introduction** 7
Background 7
Objective 7
Approach 7
Report Organization 9
System Requirements 9
Scope 9
Mode of Technology Transfer 10

2 **Technology Discussions** 11
Oil- and Gas-Fired Boiler Technology Review 11
Stoker Boilers 30
Atmospheric Fluidized Bed Combustion Boilers 34
Status of Coal Slurry Fuels 39
Micronized Coal Combustion Technology 44
Slagging Coal Combustors 46
Coal Gasification for Producing Low-Btu Gas for Industrial Boilers 48
Cogeneration Technology and Financing 50
Consolidation of Steam Distribution System 53

3 **Screening Models** 55
New Heating Plant Screening Model 55
Cogeneration Screening Model 66
Third Party Cogeneration Screening Model 71
Consolidation Screening Model 73
Retrofit Screening Model 74

4 **Equipment Sizing** 81
New Heating Facility 81
New Cogeneration Facility 134

5 **Capital Costs** 141
New Facility Capital Construction Cost 141
Retrofit Capital Costs 187

6 **Facility Operations and Maintenance Cost** 205
Operational Cost Components 205
Major Maintenance 218

7 **Life Cycle Cost Economic Analysis** 222
Assumptions 222
LCC Program Inputs 223
Program Applications 225
LCC Program Output 225

8 **Summary and Recommendations** 227

Metric Conversion Table 228

Acronyms 229

DISTRIBUTION

List of Tables and Figures

Tables

1	Major facility equipment	15
2	Currently available size ranges for stoker-fired boilers	33
3	Sulfur capture capabilities of AFBC boilers	38
4	Coal water fuel specifications	40
5	Coal gasification reactions	49
6	Plant area requirement	62
7	Pollutant factors	66
8	Pollution control equipment factors	67
9a	Micronized boiler coal specifications	77
9b	Slagging boiler coal specifications	77
9c	Fixed-bed two-stage gasifier coal specifications	78
10	Major facility equipment - stoker boilers	82
11	Major facility equipment - CFBCs and BFBCs	85
12	Major facility equipment - COS and CWS	88
13	Width and length of boiler houses	151
14	Productivity factors by state	182
15	Labor hours and bulk material cost factors	183
16	Default labor categories and wages	206

Figures

1	Process flow diagram of a typical steam generating facility	16
2	Process flow diagram of a typical cogeneration facility	16
3	Plant layout of a boiler house	19
4	Plant layout of a steam generating facility	20
5	Plant layout of a cogeneration facility	20
6	Retrofit with extended furnace area in oil/gas furnace	37
7	Comparison of particle size distribution of micronized and pulverized coal	44
8	Representative plot of steam demand vs. month for cogeneration plant	68
9	Rail car thawing shed	91
10	Typical limestone handling and storage system for CFBC and BFBC facilities	109
11	Typical 4-boiler small cogeneration facility layout	135
12	Typical 4-boiler large cogeneration facility layout	136
13	Steam distribution system design: tunnel contruction	176
14	Steam distribution system design: direct burial Ricwil casing	177
15	Steam distribution system design: shallow trench/walkway construction	178
16	Steam distribution system design: above ground single stanchion construction	179

1 Introduction

Background

The fiscal year (FY) 1986 Defense Appropriation Act (Public Law [PL]-99-190 Section 8110) directed the Department of Defense (DOD) to implement the rehabilitation and conversion of central heating plants to coal firing. The target set by this act was 1.6 million short tons* of coal per year above the 1985 consumption level by 1994. The language further stated that 300,000 tons of this amount should be anthracite coal. The purpose of this Section was to offset decreasing anthracite coal use in Germany resulting from U.S. Army, Europe (USAREUR) installations connecting to district heating systems. The FY 1987 Defense Authorization Act (PL-99-661, Section 1205) also directed that the primary fuel source in any new heating system be the most life cycle cost effective. To assist in complying with these acts, the U.S. Army Center for Public Works (USACPW) requested that the U.S. Army Construction Engineering Research Laboratories (USACERL) provide technical studies and support for the Army's Coal Conversion Program.

Objective

The objective of this project is to develop a series of screening and life cycle cost estimating computer models to determine when and where specific coal combustion technologies can be economically implemented at Army central heating plants.

Approach

The approach for providing Coal Conversion Program support has been to develop tools useful for long range utility planning and for evaluating both the technical and economic feasibility of conversion. Cost estimating methods have been developed for building new coal, gas, or oil plants, and for retrofitting existing plants to coal firing capability. Supporting data bases have been developed covering installation-specific data (heating plant inventory, building inventory, weather data, energy usage),

---

* A metric conversion table is on page 228.

environmental regulations, coal supply information, and combustion equipment performance. The plant sizes examined in the model range from 50,000 to 600,000 pounds per hour (lb/hr) with individual boiler sizes from 20,000 to 200,000 lb/hr of steam or high temperature hot water (HTHW). The program is divided into two parts: the preliminary screening model and the detailed cost model. The screening model is used to initially evaluate each plant site and boiler technology option to produce a list of the promising locations and technology options. The screening model contains five distinct sections for evaluating new heating plants, retrofit heating plants, cogeneration facilities (in base-managed and third-party-managed forms), and consolidation of existing multiple boiler plants.

The new heating plant screening model is used to determine if a new coal-fired heating plant can be built to replace an existing steam plant (150 pounds per square inch gauge [psig] saturated steam or equivalent hot water or 250 psig saturated steam). The boiler technology options include: stoker, bubbling fluidized bed, circulating fluidized bed, coal/water slurry, coal/oil slurry, natural gas, and #2 and #6 fuel oils.

The retrofit screening model is used to determine if the existing boilers can be retrofitted to fire coal or low-British thermal unit (Btu) gas supplied from a gasifier. The boiler options include: coal-water slurry, coal-oil slurry, micronized coal, slagging coal, bubbling fluidized bed, and stoker, as well as gasification.

The cogeneration screening model is used to determine if a new cogeneration steam plant is a feasible alternative for a military base heating plant. Medium pressure (600 psig, 750 °F) or high pressure (1300 psig, 1000 °F) plants can be analyzed. The boiler types considered are stoker, coal-oil slurry, coal-water slurry, bubbling fluidized bed, and circulating fluidized bed.

The consolidation screening model is used to determine if the military base should consolidate several individual heating plants into one main heating plant. This section assesses whether the steam distribution density is sufficient to consider consolidation as a practical option.

After the screening model has been executed, the user has the option to quit or to restart another screening model (for another option) or to continue to obtain a cost estimate for the selected facility. The costing model contains sections for a new heating plant, retrofit heating plant, cogeneration facility (base and third party), and consolidated facility.

The costing model provides conceptual facility design, capital installed costs of the conceptual facility, operational and maintenance costs over the life of the conceptual facility, and life cycle costs.

Report Organization

This report discusses the Central Heating Plant Economic Evaluation Program (CHPECON) and is divided into the following five volumes:

Central Heating Plant Economic Evaluation Program, Volume 1: Technical Reference.

Central Heating Plant Economic Evaluation Program, Volume 2: User's Manual.

Central Heating Plant Economic Evaluation Program, Volume 3: Military Base Weather Information Data Management Program.

Central Heating Plant Economic Evaluation Program, Volume 4: Coalfield Properties Information Data Management Program.

Central Heating Plant Economic Evaluation Program, Volume 5: Emission Regulations Data Management Program.

System Requirements

CHPECON was developed using an 80286 personal computer with 640K memory, and was run using MS-DOS 3.3. The models should operate satisfactorily on 8088/80286/80386 processors with MS-DOS 2.0 and above. The program is written in dBase III Plus* compatible language with some extensions. To provide the necessary speed and compactness, the program is distributed in compiled form using Nantucket's Clipper** and allows stand-alone operation without requiring additional utilities.

Scope

The purpose of this work is to investigate the feasibility of converting Army central heating plants to coal firing. The models developed are generally applicable to industrial or large commercial facilities. The economic evaluation program for screening and life cycle costs will serve as a tool to select and rank potential Army sites for coal conversion.

---

* dBase III Plus is a registered trademark of Ashton-Tate.

** Clipper is a registered trademark of Nantucket Software.

Mode of Technology Transfer

The CHPECON program may be obtained by contacting the USACERL Fuels and Power Systems Team at 1-800-872-2375, extension 5551. The program will be transferred to Major Army Command Headquarters for further distribution. It is recommended that availability of this program and the information presented in this report be disseminated in a Public Works Technical Bulletin.

2 Technology Discussions

This section presents a brief overview on each of the boiler technologies evaluated in the screening model. In addition to a review of each of the combustion technologies, discussions on cogeneration and consolidation of multiple boiler facilities are also presented. Boiler technologies considered in this section are:

- oil- and gas-fired boilers
- stoker boilers
- industrial fluidized bed combustion
- coal slurry boilers
- micronized coal boilers
- slagging combustion boilers
- coal gasification
- cogeneration
- consolidation (adding a distribution system).

Subjective assessments are included for each technology discussed and are ranked on a scale from 0 to 10, with 0 representing a theoretical concept that has not been tested, and 10 representing a long-term, commercially proven technology that can be purchased with a process and equipment guarantee. The assessments provide a brief review of the critical variables concerning the status of each technology.

Oil- and Gas-Fired Boiler Technology Review

This section presents a brief overview on the oil- and gas-fired boiler technology, performance, and operation.

Basic Technology

The technology of oil- and gas-fired boilers is fully commercialized and has been available for many years. Steam generating capacities up to 3,850,000 lb/hr have been installed. Boiler operating pressures from 150 psig to 2500 psi and steam temperatures from saturation to about 1050 °F are common in the industry. These boilers have exhibited overall efficiencies as high as 90 percent. Many companies

currently market standard oil-/gas-fired boiler designs. Oil/gas firing is currently used for packaged fire-tube boilers, packaged water-tube boilers, and field erected water-tube units. For single units up to about 200,000 lb/hr of steam generating capacity, packaged boilers are preferred.

Oil/gas firing refers to burning these fuels to generate steam. Natural gas is the simplest fuel to burn; it requires little or no preparation and readily mixes with the combustion air supply. Industrial boilers generally use low-pressure burners operating at a pressure of 1/8 to 4 pounds per square inch (psi). Gas is usually introduced at the burner through several orifices that create jets to produce rapid mixing with the incoming combustion air supply. The designs in use differ primarily in the orientation of the burner orifices and their locations in the burner housing. Usually, most of the combustion air is introduced with injection of gas or oil. In the case where #6 fuel oil is used, it is necessary to preheat the oil to 200 to 220 °F to reduce its viscosity and improve its flow characteristics. To improve the combustion efficiency of the unit, it is also desirable to atomize the oil before vaporization and mixing with the combustion air supply. Atomizing can be accomplished through the use of air, steam, or mechanical atomizers. Oil is introduced into the furnace through a gun fitted with a tip that distributes the oil in a fine spray, allowing mixing between the oil droplets and the combustion air supply. Oil cups that spin the oil into a fine mist are also used on small units. An oil burner may be equipped with diffusers that act as flame holders by inducing strong recirculation patterns near the burner. In some burners, primary air nozzles are used. Burning oil or gas in the presence of air generates heat and hot combustion products. The heat is absorbed by the tubes forming the combustion chamber and heat transfer areas. The boiler shell is protected from high temperatures and corrosion attack by a refractory lining. The water inside the tubes absorbs the heat and becomes steam. The flue gases, which are the products of combustion, leave after most of the heat of combustion is absorbed in the boiler and economizer sections. The flue gases leave through the stack, which is usually about 50 to 60 feet (ft) tall. The different components of oil/gas boilers will be described in more detail later.

As noted earlier, packaged units are the most cost effective for steam generation capacities up to 200,000 lb/hr/boiler. Packaged boilers are designed, fabricated, and assembled at the manufacturing plant. The assembled units are then shipped via rail, road, or barge. Packaged boilers allow maximum use of building space. Some of the main advantages of the packaged units are:

- Minimal capital investment,
- Minimal space requirements,
- Minimal operator attention requirements,

- Fully automatic controls,
- Operating flexibility through multiple units,
- Minimal delivery time,
- Indoor or outdoor installation,
- Minimal foundation requirement,
- Arrangement versatility,
- Minimal number of burners, and
- Proven reliability.

Operational Problems and Risks

Even though the technology used in oil- and gas-fired boilers is proven and well understood, problems can occur if improperly heated oil is used or if the boiler is not operated carefully. A properly designed and maintained boiler burning a fuel within the design specifications should result in equipment availability above 90 percent.

Packaged boilers are not designed with overload capacities and must be operated strictly within their design capacity. Any request for deviation from the standard designs can result in price and delivery penalties. Requests for units with specially designed controls are also risky because there is no guarantee that the manufacturer will still be in the business at the time repair parts are needed. Specially-designed burners and controls may result in servicing complications as well.

The need for operating experience, particularly if casual (unplanned) maintenance is involved, is not always anticipated. Use of automatic controls can lull the owner into believing that the equipment does not require attention such as cleaning the fireside surfaces, oiling motors, and adjusting the burner.

Another problem can arise due to the compactness of the packaged unit; servicing can be difficult.

A Technology Assessment

Oil/gas-fired boilers of various sizes are available. Units can be either field-erected or packaged. However, very few packaged units are installed in sizes larger than about 200,000 lb/hr due to the 14 ft size limitation for shipping by rail and road. Field-erected boilers have been designed for capacities over 1,000,000 lb/hr of steam generation.

Advantages of oil/gas boilers include:

- Firm equipment and process guarantees are available,
- The technology is proven and is commercially available,
- There are many national and international suppliers,
- A technology data base of at least 50 years is available,
- The present boiler size range is approximately 10,000 to 200,000 lb/hr of steam for packaged units, and
- The technology is currently used by industry and heating facilities.

Because of these advantages, oil/gas boiler technology is given an assessment rating of 10 in terms of technology readiness and state of maturity.

Equipment Sizing

The specific components required for a particular central heating plant are determined by the cost model and are based on the user selections made during the screening model analysis, and on additional information requested during program operation. The basic methods on selecting and sizing of equipment are discussed in this section. The requirements for a new heating facility are discussed first, followed by discussions of cogeneration, third-party cogeneration, and consolidation options, because all options are built upon the basic configuration that forms the new heating plant specification.

New Heating Plant. This section describes a steam generating facility and the design methods and equations used to calculate the plant cost, area, and equipment sizes.

This research considers central heating and/or cogeneration facilities having a minimum steam generation capacity of 50,000 lb/hr and a maximum steam generation capacity of 600,000 lb/hr of saturated or superheated steam. The fuel can be natural gas, #6 fuel oil, or #2 fuel oil with less than 0.5 percent sulfur. Currently, #2 fuel oil is more commonly used, especially for smaller size boilers. Also, #2 fuel oil is easier to handle, burns in a way that is more environmentally acceptable, and makes boiler operation easier. A further constraint used to determine the number of boilers in a heating or cogeneration facility is that, as a minimum, the facility should be able to provide 60 percent of its plant maximum continuous rating (PMCR) when one boiler is receiving repair or maintenance.

Equipment Lists. The major equipment that can be included in a boiler design is listed in Table 1. The equipment included in a particular conceptual design depends on selection of the type of facility.

Table 1. Major facility equipment.

Component	Parts
Boiler	Boiler pressure parts and drum Support steel Soot blower (for #6 oil only) Burners Forced draft fans Instruments and controls Feedwater deaerator Mud drum Shop assembly Metal stack
Oil Handling and Storage System	Rail car mover Oil unloading pumps Long-term oil storage tanks Oil transfer pumps Day fuel storage tank Boiler fuel pump Boiler fuel heater Fuel piping
Boiler Feedwater System	Sodium zeolite softening with brine tank Brine wastewater tank Neutralization tank Acid and caustic tank Demineralizer with degasification and mixed bed demineralization Dealkalizer Condensate storage Deaerator Boiler feedwater motor-driven pumps Condensate pumps
Auxiliary Equipment	Air compressors Continuous and intermittent blowdown tanks Electric substation
Cogeneration Equipment	Turbine generator Condenser Cooling tower Circulating water pumps Feedwater heaters
Other Items	Piping and electrical Boiler water laboratory Mobile equipment: forklift, pickup truck, and power sweeper Hand tools and storage Spare parts Consumables with a complete initial facility inventory

Facility Description and Layout. Figure 1 shows a simplified process diagram of a generic steam generating facility. Figure 2 shows the simplified process flow diagram for a generic cogeneration facility. Steam generating facilities typically consist of two or more boilers, a fuel handling and storage system, a feedwater system, the steam distribution and heating system, and a condensate handling system. Cogeneration facilities additionally have turbines and associated equipment to convert the steam energy into electricity.

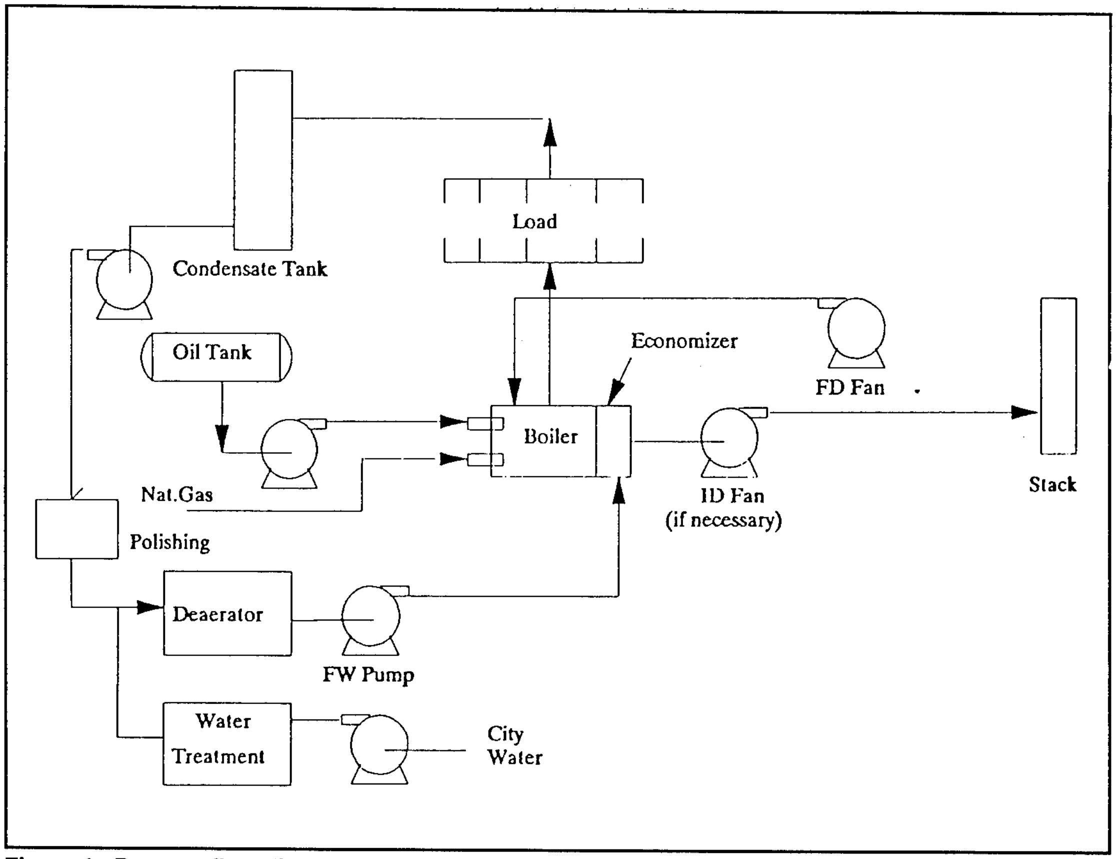

Figure 1. Process flow diagram of a typical steam generating facility.

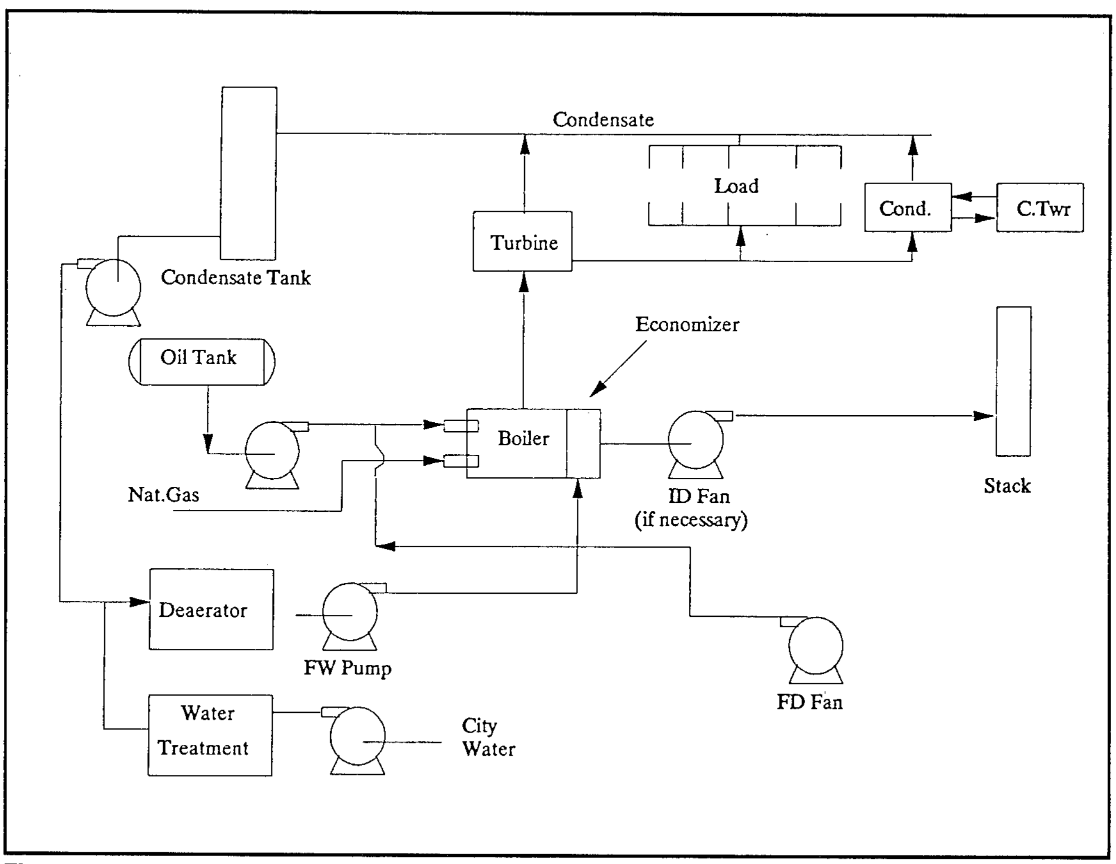

Figure 2. Process flow diagram of a typical cogeneration facility.

The fuel handling system consists of equipment used to handle the oil and/or natural gas fuel. If the plant's steam generating capacity is large, the oil is brought to the plant by rail, the preferred method for high volume requirements. For smaller fuel requirements, truck deliveries are common. The oil is pumped from the trucks or rail cars into long-term oil storage tanks using medium-capacity pumps (200 to 500 gallons per minute [gpm]). Long-term oil storage tanks typically have storing capacities of 15 to 90 days, depending upon the plant. A 30-day storage capacity (or less) is a very common industrial size, and was selected for the equipment sizing requirements in the program. It is sometimes necessary to circulate steam through the oil tank cars, to heat the oil to improve its pumping characteristics.

From the long-term storage tank, the oil is pumped to a day storage fuel tank, usually having 4 to 8 hours of storage capacity. The oil from the day tank is preheated (for better flow characteristics) and pumped to the burner where it is atomized before combustion. Oil atomization is necessary in order to burn fuel oil completely at high rates of consumption. The oil is dispersed as a fine mist, maximizing the oil particles' surface area for contact with combustion air to assure prompt ignition and rapid combustion. For proper atomization, #6 oil must be heated to 200 to 220 °F to reduce its viscosity to 135 to 150 SSU (Saybolt Seconds Universal). Fuel atomization is achieved through mechanical means or by using air or steam.

In many respects natural gas is an ideal fuel since it requires no preparation for rapid and intimate mixing with the combustion air flowing through the burner throat. However, one disadvantage is that sufficient quantities for extended operation cannot be stored on site.

Each boiler plant consists of two or more boiler drums connected by water tubes. The required volume of the combustion chamber is determined by the design combustion intensity and total capacity. Heat release rates of 60,000 to 90,000 Btu/cu ft are common.

A forced draft fan provides the necessary oxygen for fuel combustion by forcing the air through the combustion chamber. The combustion products consist mostly of carbon dioxide (CO_2), water (H_2O), carbon monoxide (CO), and unburned hydrocarbons. Trace materials, such as sulfur from the fuel oil, are also found in the combustion products, along with nitrogen oxide (NO_x), a byproduct of the combustion occurring in the presence of nitrogen. After transferring the heat through the tube walls to the water, and if no special heat recovery equipment is provided, the flue gases leaving through the stack are within the temperature range of 400 to 600 °F. It is common practice to provide an economizer to recover some of the sensible heat of the flue gases by preheating the feedwater. Additional heat can be recovered by preheating the

combustion air with the flue gas in an air preheater. The flue gases then pass through the metal stacks and enter the atmosphere. It is necessary to have soot blowers in the boiler when #6 oil is used. Soot blowers minimize the ash and soot (carbon) deposition on the tube walls.

The feedwater system consists of the equipment necessary to process the feedwater, making it suitable for steam generation. In a typical system the water is filtered and passed through an ion exchange/zeolite softening system to reduce its hardness. Hardness in water, caused by calcium (Ca) and magnesium (Mg) ions results in scale formation in boiler drums and tubes, which will eventually plug the tubes. In addition, scale formation inhibits efficient heat transfer between the tubes and the water flowing through them. For a cogeneration facility, a demineralization process may be better suited for achieving good water quality. Better water treatment processes are necessary when the steam generation temperature and pressure is increased. The softened or demineralized water is then passed through the economizer to recover some heat from the flue gases. Next it is passed through a deaerator where it is scrubbed with steam. The objective of the deaerator is to remove any trace of oxygen from the feedwater. The presence of oxygen in the feedwater would otherwise promote corrosion. The water is then fed to the boiler drums where it is converted to steam. The steam drums have internal baffles designed to ensure that most of the steam leaving is dry and that very little liquid water (in the form of droplets or mist), if any, is carried out. The steam passes through a flow measuring device on its way to the steam distribution system. In the case of a cogeneration facility, the steam is superheated to 700 to 750 °F. Before the steam goes to the distribution system, all or some of it is passed through the steam turbines. The turbines convert the steam energy into electricity. A portion of the steam is condensed in the turbine; the remainder of the steam is either condensed in the condenser or fed to the distribution system. In the condenser, an intermediate water loop is used to remove the latent heat of the steam. This heated water is cooled in the cooling towers and recycled. The steam condensate from the turbines and from the steam heating facility is also recycled. The condensate storage tank holds the condensate until it is ready to be recycled.

In a conventional facility design the equipment is laid out horizontally. Figure 3 presents a typical layout drawing of a boiler house. It shows two 100,000 lb/hr boilers equipped with economizers, a feedwater softening system, a deaerator, and feedwater pumps. Areas for the office, storage, lab, and locker room are also shown. For a cogeneration facility the boiler house would be about 40 ft longer than a similar non-cogeneration facility. The additional area would house the steam turbines, condensers, steam piping, and feedwater heaters. Figure 4 shows an overall layout for a steam generating facility. Figure 5 shows an overall layout for a cogeneration facility.

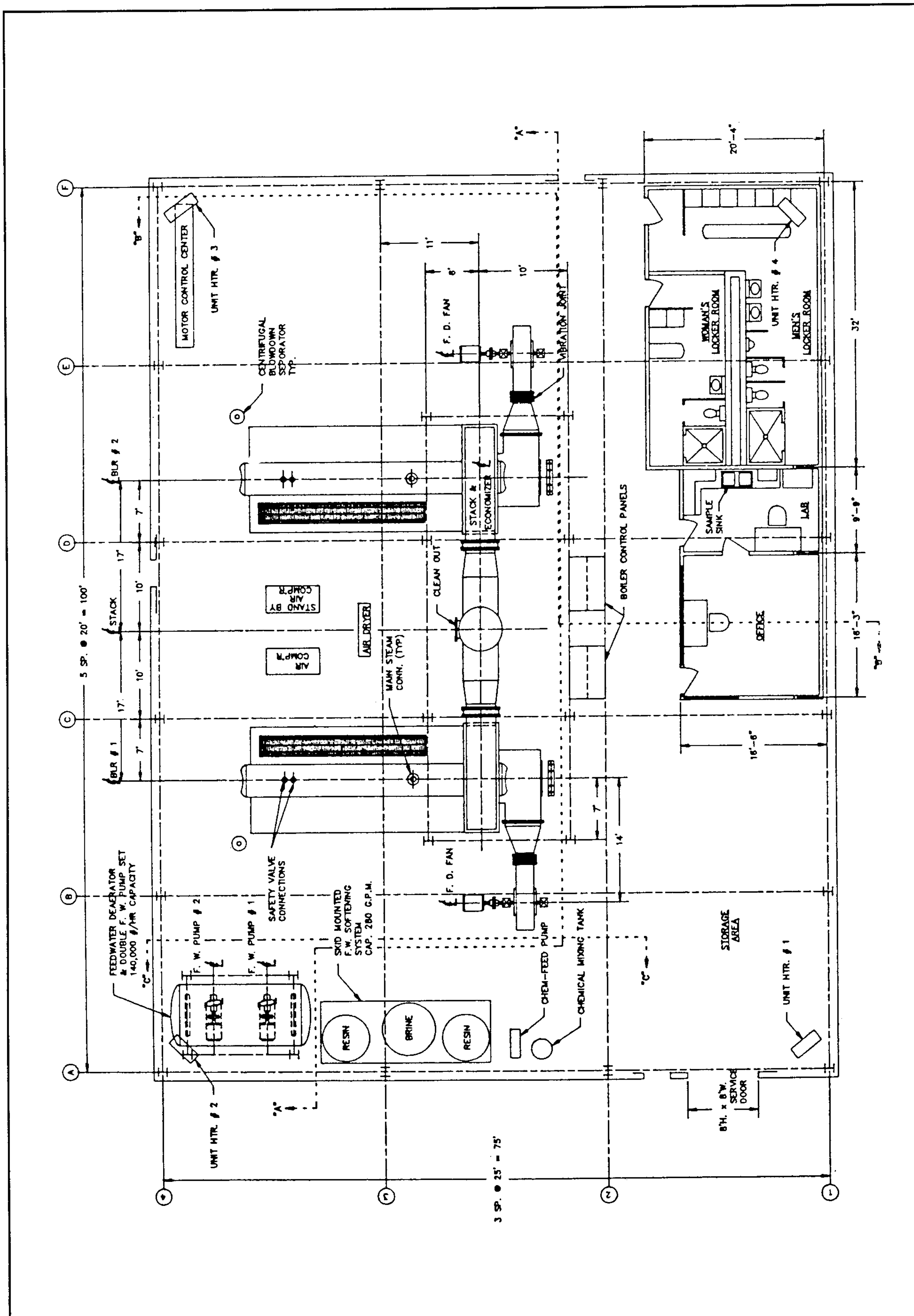

Figure 3. Plant layout of a boiler house.

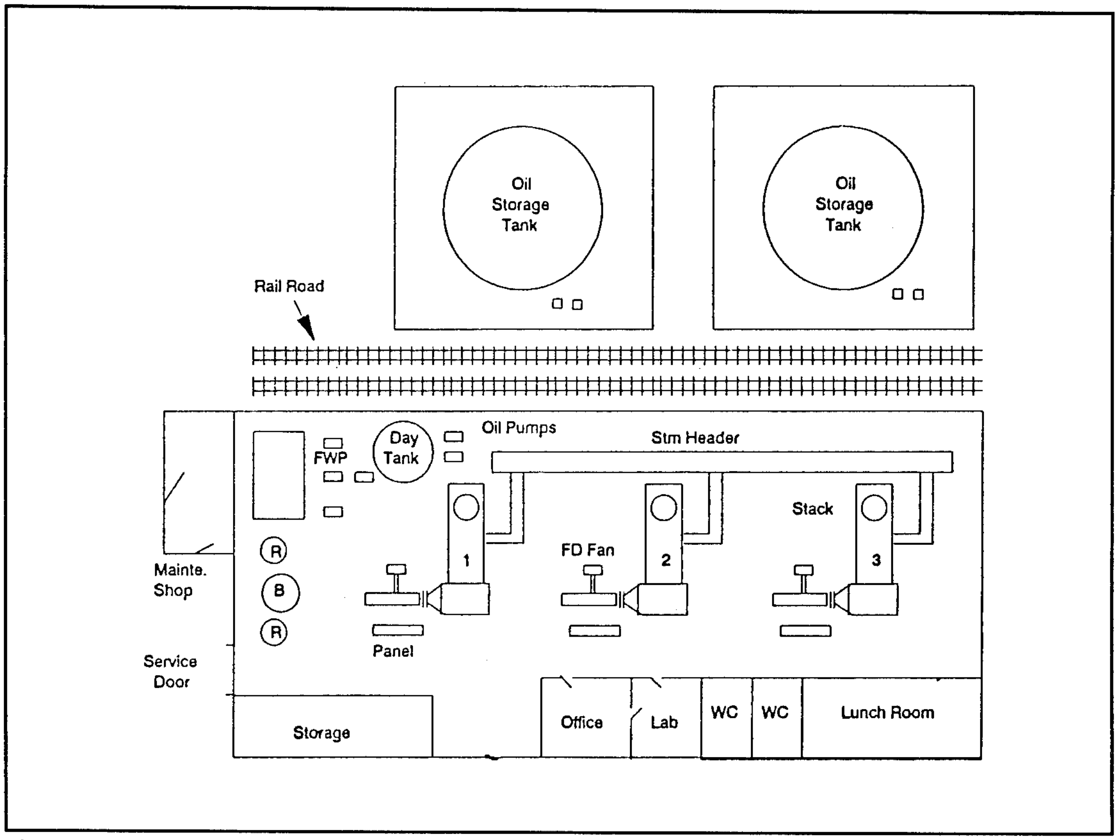

Figure 4. Plant layout of a steam generating facility.

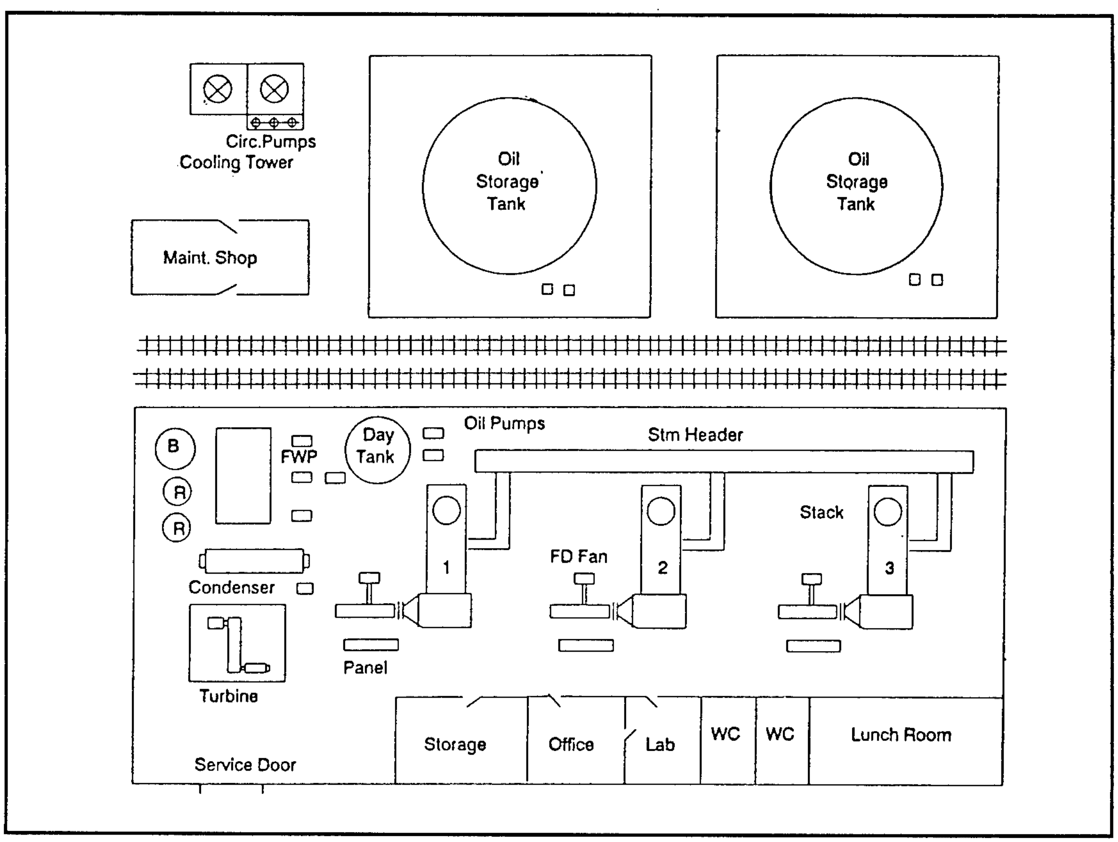

Figure 5. Plant layout of a cogeneration facility.

Boiler Components. The steam drums are made of carbon steel for steam generation up to an operating temperature of 750 °F. All drums are made of welded construction in strict conformance with the American Society of Mechanical Engineers (ASME) Power Boiler Code. All drums are stress relieved, their welded seams are radiographed, and the unit is hydrostatically tested in the shop at 1.5 times the design pressure. The top drum is completely supported by the connecting tubes; no extra supporting steel is required. The drum is fitted with an internal feed pipe, a chemical feed pipe, and blowdown piping. A control mechanism for maintaining an adequate water level is also provided. A steam separator or dryer is included to ensure good steam quality. The water tubes are directly connected to the drums and are designed with an adequate pitch to ensure adequate drainage and proper circulation. The lower drum has a blowdown provision so it can blow off the drum without affecting the water circulation in the unit.

The unit is enclosed within a double panel casing. The portion of the casing that may be exposed to combustion products is seal welded. The casing is supported from the structural steel frame and is not generally welded to it so that parts under pressure within the casing are allowed free expansion.

Oil Handling and Storage Equipment. This section describes the major fuel oil handling equipment and sizing equations required to estimate the cost of the equipment. Most of the components are required whether truck or rail transport is used. The rails and rail car mover are not needed if the system is exclusively fed by truck.

Rail Car Mover. The car mover system is a complete, reversible, endless rope type. The system includes: a double drum with a running rope pull at the drums of 18,000 lb, and a starting pull of 36,000 lb; a 20-horsepower (hp) motor with drive gear; 600 ft of 1-in. diameter wire rope with two hitch rope assemblies; a take-up assembly; stationary bend sheave assemblies; travel limits; guards; track guides; and controls.

Fuel Receiving Piping. The fuel collection and distribution piping system is necessary to connect the fuel tank cars to the fuel receiving pumps and to deliver the fuel to the long-term storage tanks or the day fuel storage tank. The positive displacement fuel receiving meter is rated at 750 gpm and is used to measure the amount of fuel received from the tank cars.

Oil Unloading Pumps. These positive displacement pumps are designed for pumping #6 fuel oil. Each pump is sized for 200 gpm at 75 psi discharge pressure and comes with valves, a strainer, and a 20 hp motor.

Long-Term Oil Storage Tanks. The long-term oil storage tanks are constructed of steel and have a domed roof. They are atmospheric tanks, sized to accommodate a 30-day

fuel supply. Tank sizes will vary from 7,500 barrels to 70,000 barrels depending on the plant size. The storage tank diameter varies from 50 to 120 ft and the height varies from 24 to 40 ft. The long term storage tanks have dike areas around them to contain any spills that may occur.

Oil Transfer Pumps. The transfer pumps move the fuel from the long-term storage tanks to the day fuel storage tank. The positive displacement pumps are designed to pump #6 fuel oil. Each pump has the same capacity as the oil feed pump (described below) and comes complete with valves, a strainer, and a motor.

Day Fuel Storage Tank. The day fuel storage tank stores a 4 to 8 hour supply of fuel for the facility. The atmospheric tank has a steel domed roof and heating coils.

Boiler Fuel Pumps. The boiler fuel pumps move the fuel from the day fuel tank, through the boiler fuel heater, to the boiler fuel distribution/recirculation system. They are positive displacement pumps. Typical systems contain three pumps; each is sized to meet about 50 percent of the plants fuel needs.

Boiler Fuel Heaters. These heaters use steam to heat the boiler fuel to the fuel firing temperature.

Boiler Fuel Piping. The boiler fuel piping is the distribution/recirculation system that conveys the fuel from the day tank to the boilers. The recirculation line returns unused fuel to the day tank.

Sizing of Fuel Handling Equipment. The following fuel handling and storage equipment is suggested for oil-fired boiler plants:

Fuel receiving pumps	Fuel receiving piping
Long-term storage tanks	Day tank transfer pumps
Day fuel storage tank	Boiler fuel pumps
Boiler fuel heaters	Boiler fuel piping

As noted earlier, to receive oil shipments by rail, rail car mover equipment must also be included.

The fuel handling equipment is sized based on the amount of fuel required to maintain the facility at PMCR operating conditions. Conceptual sizing is based on the ability to unload 3 days of the fuel supply within 6 to 8 hours for rail receiving, while operating at PMCR. This equates to three deliveries per week. The maximum receiving rate assumes the unloading of three rail cars simultaneously. If the facility

requires more fuel than the pump capacity, the receiving system will operate more frequently or increase the unloading time.

Truck deliveries are handled in a manner similar to rail deliveries. A truck would supply approximately 6,000 gal of oil, which can be unloaded in 30 to 45 minutes.

The number of long-term fuel storage tanks is determined by the following equation:

Long-term fuel storage capacity (gal) = (Days long-term storage)(Fuel @ PMCR [gal/hr]) (24 hrs/day)

The "days of long-term fuel storage" is usually taken to be 30 days.

The number of long-term storage tanks required depends on the fuel consumption. It can be generally stated that smaller plants would require one tank and larger plants (greater than 225,000 lb/hr steam) would require two tanks to provide the specified total capacity. Some of the typical tank sizes are as follows:

Plant Capacity (lb/hr)	No. of Tanks	Tank Size (diameter x height, in ft)
50,000 (w/o cogen)	1	50 x 24
100,000 (w/o cogen)	1	60 x 30
150,000 (w/o cogen)	1	80 x 24
300,000 (w/o cogen)	2	80 x 24
450,000 (w/o cogen)	2	90 x 30
600,000 (w/o cogen)	2	90 x 40
150,000 (w/ cogen)	1	80 x 30
300,000 (w/ cogen)	2	80 x 30
450,000 (w/ cogen)	2	90 x 33
600,000 (w/ cogen)	2	100 x36

The day fuel storage tank is sized by:

Tank capacity (gal) = (Fuel @ PMCR [gal/hr]) (4 hours storage)

Fuel Oil Transfer Pumps are sized as follows:

For a heating-only system -

Pump capacity, (gal/min) = 1.5 X PMCR/10000

Pump discharge pressure = 100 psi
Pump power, hp = (PMCR-150000) X 4/150000 + 7.5

For a cogeneration system -
Pump capacity, (gal/min) = PMCR/6000
Pump discharge pressure = 100 psi
Pump power, hp (@PMCR <= 200,000) = PMCR/30000
Pump power, hp (@PMCR > 200,000) = PMCR/30000 + 2.5

Boiler Fuel Pumps are sized as follows:

For a non-cogeneration system -
Pump capacity, gal/min = PMCR/10000 X 1.5
Pump discharge pressure = 250 psi
Pump power, hp (@PMCR <= 100,000) = 5
Pump power, hp (@PMCR > 100,000) = PMCR/1000 X 0.05

For a cogeneration system -
Pump capacity, gal/min = PMCR/6000
Pump discharge pressure = 250 psi
Pump power, hp (@PMCR <= 100,000) = 5
Pump power, hp (@PMCR > 100,000) = PMCR/1000 X 0.05

Boiler Feedwater System. This section describes water treating processes commonly used to produce boiler feedwater. Boiler water treatment is a standard practice used to eliminate or minimize problems caused by impurities in the water and steam. The problems caused by poor quality water include corrosion, scale, carry-over, and caustic embrittlement.

Corrosion can deteriorate feedwater heaters, boilers, economizers, condensers, and piping, eventually resulting in leakage. Scale reduces heat transfer rates and causes overheating of the boiler tube metal. Foaming and priming cause boiler water carry-over with the steam, which can result in mechanical trouble and piping deposits. Caustic embrittlement or intercrystalline cracking of metal occurs when the boiler water has embrittling characteristics and is capable of attacking boiler metal, eventually leading to failure of the material.

The choice of a boiler water treatment system design depends on the boiler's specified inlet water quality, the steam or hot water outlet pressure, the steam outlet use, and the amount of water needed to be added into the system. This information is used as a design guideline since it is virtually impossible to provide a complete general design

that would cover every aspect of water treatment economically. If a facility design proceeded to the detailed design phase, the preliminary design should be updated with information on actual raw water quality, boiler type and pressure, steam usage, operating procedure, blowdown limits, etc.

For screening, the following categories are identified:

1. Steam or hot water heating only; less than 625 psig.
2. Steam generation with cogeneration; less than 625 psig and 750 °F.

Each condition requires a different boiler feedwater quality and therefore a different water treatment system. The following water treatment systems are suggested:

Sodium Zeolite Softening. This system is used for heating-only steam or hot water boiler systems.

Demineralization With Degasification. This system consists of a strong cation vessel, a packed degasifier, and a strong anion vessel. It is used for cogeneration boiler systems.

Mixed Bed Demineralization. This system can follow one of the previous selections for further treatment, or it can be used to clean or polish the steam system's returned condensate.

Dealkalizer. This system can follow the sodium zeolite-based equipment to reduce the alkalinity of the softened effluent.

For the cost model (and the conceptual design it requires), the sodium zeolite softening system will be used with the heating-only boilers, and the system providing demineralization with degasification will be used with cogeneration boilers. As a user option, a dealkalizer and/or another mixed bed may be added to each of the systems.

These water treatment designs produce a boiler feedwater quality of:

1. Zeolite: 0 to 5 ppm hardness as $CaCO_3$ with 200 to 300 parts per million (ppm) of total dissolved solids (TDS).

2. Demineralization With Degasification: 0 to 1 ppm hardness as $CaCO_3$ with 0 to 10 ppm TDS.

3. Demineralization with Degasification followed by a Mixed Bed polisher: 0 to 1 ppm hardness as $CaCO_3$ with 0 to 2 ppm TDS.

The water treatment equipment assumes that a good source of fairly high quality water (city water) exists. If the facility under consideration cannot obtain water from a good water source system, additional equipment is required. Such additional equipment is listed below for different sources of water. This equipment is not an option in the program and is not costed out in the program.

River water	Raw water pumps Fire water storage and pumps Chlorinator River water clarifier system Lime injection system Chemical tanks and injection pumps Acid injection system Filter press and pumps Clear well and pumps Anthracite filters
Well water	Well water pumps Fire water storage and pumps Potable water filter, tank, and pumps
City water	Break tank Fire water storage and pumps City water pumps.

Capital Costs

New Facility Capital Construction Cost. This section of the program includes the cost equations (in 1988 dollars) used to determine the capital cost for new oil- or gas-fired steam production and cogeneration power plants. After the equipment costs are determined, they are added to the other direct costs of freight costs and installation costs. Finally, the indirect costs are added to complete the boiler plant cost estimate.

Major facility equipment considered includes:

Boiler
Oil Storage and Handling System
Boiler Feed Water System
Auxiliary Equipment
Piping
Instrumentation
Electrical

Building and Services
Site Development
Spare parts, tools, mobile equipment.

Cost Equations for cogeneration equipment include:

Condenser
Cooling Tower
Water Recirculation Pumps
Feed Water Heater
Turbine Generator.

Boilers. The boiler equations include cost estimates for the boiler, economizer, forced draft fan, stack, and associated instrumentation and controls. The boiler budget cost represents a typical packaged boiler subcontract. The items include:

Boiler pressure parts and drums
Boiler trim and soot blowers
Boiler refractory, insulation, and lagging
Forced draft (F.D.) fans
Combustion air ductwork and distribution system
Boiler convective sections
Economizer
Main steam non-return and block valve
Boiler steel
Boiler instruments
Operation manuals.

Excluded from the boiler costs are items such as foundations, tie-ins for electricity, and controls and piping to and from the boilers. These items are part of the instrumentation, piping, and electrical costs. The boiler cost equations are all linear and are shown as a function of the maximum continuous rating (MCR) of the boiler. The costs are estimated by:

1. Heating only oil-/gas-fired boilers — 250 psig steam:

For PMCR <= 250,000 lb/hr, # of boilers = 2
MCR per boiler = 0.6 X PMCR
Cost/boiler = 4.227 X (MCR) + 178,700

For PMCR > 250,000 lb/hr, # of boilers = 3
MCR per boiler = PMCR/3
Cost/boiler = 4.227 X (MCR) + 178,700

2. Cogeneration oil-/gas-fired boilers — 600 psig and 750 °F steam:

For PMCR <= 250,000 lb/hr, # of boilers = 2
MCR per boiler = 0.6 X PMCR
Cost/boiler = 5.833 X (MCR) + 225,000

For PMCR > 250,000 lb/hr, # of boilers = 3
MCR per boiler = PMCR/3
Cost/boiler (@ MCR <= 150,000 lb/hr) = 5.833 X (MCR) + 225,000
Cost/boiler (@ MCR > 150,000 lb/hr) = 4 X (MCR) + 500,000

Stack. The packaged boilers are equipped with stub stacks, which require separate stacks. The facility stack(s) are freestanding structures that enclose steel flues. Although some designs have used a stack for more than one boiler, the conceptual design uses one stack for each boiler to standardize and replicate the most common configuration. The steel flues are insulated, have stack sampling ports, and are independently bottom supported. The freestanding stacks are designed for a wind load of 100 miles per hour (mph), and include lighting. The stack height is about 60 ft. The cost of the stack is:

Cost/boiler = (height, about 60 ft) X 175 $/ft

Oil Handling System. The oil handling system is used in oil-fired boiler plants and consists of the long-term storage tanks, unloading and transfer pumps, the day tank, a heater, and a pump to deliver oil to the combustion chamber.

Fuel Receiving. If the plant PMCR is 150,000 lb/hr or less, the oil could be brought in by trucks. For a larger PMCR, however, the number of truck deliveries per day would exceed an acceptable level of 6 to 7 per day. In these situations it is necessary that oil be brought in by rail cars. When the oil is delivered by trucks, no special provisions need to be made. For rail car receiving, tracks and a car puller must be provided. These costs are as follows:

Car puller and accessories = $20,000

Rail track length (L) is 250 ft if there is only one long-term oil storage tank.

The length is 500 ft if there are two long-term oil storage tanks.

The railroad track cost is $85 per linear foot of track.

Oil Storage Tanks. The size and number of long-term storage tanks is determined in the equipment sizing section. The cost is:

Long-term storage tank cost = 6.295 X (storage capacity in barrels) + 54,485.

The cost of the remaining items associated with the oil storage tanks, such as foundation rings, dike work, and suction heaters, is estimated by:

Long-term storage auxiliaries cost = 0.946 X (storage capacity in barrels) + 20,280.

The total cost of the oil storage system is the sum of the two costs.

Oil Unloading and Transfer Pumps. Capital costs include three oil unloading pumps, each with a capacity of 200 gpm and a discharge pressure of 75 psi. The cost per pump, including a basket strainer with stainless steel mesh basket, is $4,400.

Three oil transfer pumps are needed to transfer oil from the long-term storage tanks to the day tank or, if preferred, directly to the burners. The cost per pump is:

Oil transfer pump cost = 4.04 X PMCR/1,000 + 1,200

with the total being:

Total oil transfer pump cost = oil transfer pump cost X number of oil transfer pumps

The day fuel storage tank cost is:

Cost = 1.417 X (number of gallons) + 9,700.

The cost of the pump and heater set to transfer oil from the day tank to the burner, for heating only operation, is:

Day tank pump cost (heating only) = 27.808 X (pump capacity in GPM) + 1253.
Day tank heater set cost = 150 X (pump capacity in GPM) + 2400.

For the cogeneration case, the unit costs are as follows:

Day tank pump cost (heating only) = 30.4 X (pump capacity in GPM) + 1200.
Day tank heater set cost = 150 X (pump capacity in GPM) + 2400.

The overall cost of the pump and heater set is:

Total cost = 3 X day tank pump cost + day tank heater set cost.

Stoker Boilers

Stoker firing is one of the oldest coal combustion technologies and is fully commercialized. Stoker firing refers to coal combustion methods that involve burning a mass or a layer of coal on some sort of supporting grate. Usually, the majority of the combustion air is introduced from below so the air flows upward through the grate and the coal layer. The discussion in the following section focuses on popular types of stoker boilers.

Standard Stoker Boiler Designs

Chain, Traveling, and Vibrating Grate Stokers. Chain and traveling grate stoker firing involves a moving grate mechanism; a type of continuous belt that moves slowly through the length of the furnace box. A layer of coal deposited at one end of a chain, traveling, or vibrating grate begins to burn when exposed to heat in the furnace box. The layer is then carried by the grate to the opposite end where ash is dumped into a pit. A typical boiler is designed for relatively constant steam loads up to about 150,000 lb/hr. The chain grate stoker is less efficient than the traveling grate stoker for firing anthracite coal. On a chain grate, the finely-sized anthracite can fall between the links of the grate, sending unburned carbon to the ash pit and consequently decreasing boiler efficiency.

Spreader Stokers. A spreader stoker uses a coal distribution (feeder) system that throws the coal onto the stoker grate. This method permits suspension burning of fine coal while allowing the larger and heavier lumps to fall onto the grate for combustion on a thin, fast-burning bed. The spreader stoker is particularly suitable for applications where rapid load changes can occur. The suspension burning of fines results in almost immediate ignition and the thin fuel bed can be quickly burned down should the load be shed.

The spreader stoker may use a traveling, dump, agitating, vibrating, oscillating, or reciprocating grate. Traveling grate spreader stokers are extremely popular in industry today, primarily because they are capable of burning a wide range of coals,

from high-rank Eastern bituminous to lignite or brown coal, and because they offer a fast response to load swings (25 to 50 percent of the coal is burned in suspension, and the remainder on the grate). Turndown ratios of 5:1 or greater are possible, but optimum combustion conditions generally deteriorate at ratios above 3:1. The thick ash bed keeps metal parts at allowable operating temperatures. The grate is designed to act as an orifice to allow even air distribution.

Spreader stokers with a dump grate are cleaned manually. Dump grates operate using several grate segments, with each section having its own spreader stoker and underfire air damper. When the ash builds up to about 4 in. deep on a particular section of the grate, the fuel supply is temporarily discontinued to that section, the underfire air is shut off and the ash is dumped into the pit beneath the grate. The grate is then returned to its operating position, and the air and fuel are restored. Ignition is accomplished by heat from the other sections of the grate that still have coal and by the reflective surfaces. This method of cleaning is very disruptive to the combustion process because the bed has to be completely reformed, causing large fluctuations in the required primary air.

Spreader Stokers with Continuous Ash Discharge — Agitating Grate. This group of spreader stokers consists of vibrating, reciprocating, and oscillating grate ash discharge systems. The vibrating grate spreader stoker moves the fuel forward through the furnace by the vibration of the grate. The ash is discharged from the front of the furnace into the ash hopper below. A reciprocating grate functions in the same manner except that it moves the fuel bed forward by a set of lateral rows of overlapping grates. An oscillating grate, on the other hand, is inclined towards the discharge end of the unit and moves the fuel through the furnace to a set of free-moving, cross-tee grid assemblies.

The most important parameter for these units is their size and the size distribution of the coal to the stoker hoppers. Again, the ash fusion temperature is also important for proper air distribution under the grate.

Spreader Stokers with Continuous Ash Discharge — Traveling Grate. Traveling grates are composed of grates that move toward the front of the boiler. They can be designed to handle a wide variety of coals, from lignite to bituminous coals. As with the other type of stokers, proper coal sizing and size distribution is important.

Underfeed Retort Stokers. In underfeed single retort stokers, coal is introduced into the furnace beneath the burning fuel bed through a feed trough or retort where it spills onto the grate at either side of the retort. Air is introduced on both sides of the trough through tuyeres.

Underfeed single retort stokers have a maximum capacity of approximately 25,000 lb/hr of steam. They are designed to burn mildly caking bituminous coals and certain free-burning bituminous coals. The primary consideration for the proper combustion of coal on single retort stokers is proper coal sizing. Proper coal sizing is critical in achieving an even fuel distribution across the length of the retort.

Multi-retort stokers consist of a series of inclined feeding retorts extending from the front to the rear of the boiler. They have the same considerations as single retorts with respect to coal specifications. A multi-retort stoker can be designed for steam capacities up to 60,000 lb/hr steam. Although units of up to 450,000 lb/hr have been built, spreader stokers have replaced this technology in today's commercial market.

Performance of Stoker Systems

Stoker systems burn coals that are double screened; the small and large pieces are removed. The oversize pieces can be broken and used, but the fines are unusable. Stoker grade coals cost more than run-of-mine coal due to the sizing requirement. The efficiency of stoker boilers depends on the type of firing system, amount of excess air, coal properties, and the heat recovery equipment to be used. Combustion efficiency will range from 94 to 98 percent with properly designed and maintained equipment. Average boiler efficiency can vary from about 70 to 85 percent.

Stack emissions are a drawback of stoker firing. Generally, a stoker boiler does not control NO_x emissions well and must rely on flue gas desulfurization (FGD) scrubbing technology. Stoker boilers generally use a baghouse or electrostatic precipitator to control particulate emissions.

Stoker grades of coal are also somewhat more expensive than coals used for other types of combustion systems, primarily due to the requirement that fines be removed. The requirements for coal caking properties, swelling indexes, moisture and ash content, and ash softening temperature also limit the choice of the coals. Stokers generally are designed for a relatively narrow range of coal properties and are sensitive to the caking and ash softening properties of coal.

Operational Problems and Risks

Although stoker boiler technology is proven, problems can occur when improper coal is used or when the boiler is not carefully operated. A properly designed and maintained boiler, burning a fuel within the design specifications, should result in equipment availability exceeding 90 percent.

It is important that the coal be distributed properly on the grate and that the amount of excess air be controlled. Lack of control over the coal distribution and air can lead to grate overheating and subsequent damage, in addition to incomplete combustion. Use of the correct coal coupled with the proper operation and maintenance of the boiler aids in avoiding these problems.

Coal and ash handling can be troublesome. Wet coal and ash may be particularly difficult to handle. This again emphasizes the importance of having a properly designed, maintained, and operated solids handling system.

Assessment of Stoker Boiler Technology

The key features of stoker technology are:

- Firm equipment and process guarantees are available,
- The technology is well proven and is commercially available,
- Boiler sizes range from approximately 15,000 to 250,000 pounds of steam per hour, and
- Stokers are currently used by industry and heating facilities.

Stoker-fired boilers of various types are widely available in sizes up to 400,000 lb/hr. Very few, however, are installed in sizes larger than about 200,000 lb/hr due to the greater efficiencies enjoyed by other coal-fired boiler technologies. The technology should be appropriately matched with the boiler size requirements for a facility under consideration. Table 2 presents the currently available size ranges for the most common stoker-fired boilers.

Table 2. Currently available size ranges for stoker-fired boilers.

Technology	Available Size (lb/hr)
Traveling grate stoker	20,000 - 150,000
Chain grate stoker	20,000 - 150,000
Dump grate spreader stoker without fly ash reinjection	20,000 - 200,000
Spreader stokers with vibrating grate, without fly ash reinjection	20,000 - 125,000
Spreader stokers with reciprocating grate, without fly ash reinjection	20,000 - 125,000
Spreader stokers with traveling grate, without fly ash reinjection	75,000 - 400,000
Dump grate spreader stokers, with fly ash reinjection	20,000 - 200,000
Spreader stokers with vibrating grate, with fly ash reinjection	20,000 - 125,000
Spreader stokers with reciprocating grate, with fly ash reinjection	20,000 - 125,000
Spreader stokers with traveling grate, with fly ash reinjection	75,000 - 400,000

Atmospheric Fluidized Bed Combustion Boilers

Atmospheric fluidized bed boilers have been on the U.S. market for less than 10 years. Although relatively new, atmospheric fluidized bed combustion (AFBC) has recently started to dominate the industrial coal-fired boiler market for new installations. Units are commercially available with capacities ranging from 2,000 to over 1.5 million lb/hr of steam.

The recent market growth in fluidized bed boilers has been influenced by many factors. The price increase of oil and gas (AFBC has the ability to burn whatever fuel happens to be the cheapest on the market at the time), legislation (the Public Utilities Regulatory Policy Act [PURPA] for example), environmental regulations, and increasingly modular approaches to utility plant construction have all contributed to the growth of fluidized bed technology. Recent new source performance standards (stipulating that facilities with 100 million Btu input or greater must achieve 90 percent sulfur capture) issued by the U.S. Environmental Protection Agency (USEPA) have also focused attention on fluidized bed technology. If additional, stringent regulations are issued, they will only serve to further promote AFBC technology.

The two most common types of AFBCs are bubbling fluidized bed combustors (BFBCs) and circulating fluidized bed combustors (CFBCs). Units smaller than 100,000 lb/hr are generally BFBCs, while larger units are CFBCs. In both designs, the fuel is combusted in a suspended bed of inert material and sorbent. The sorbent reacts with the sulfur dioxide (SO_2) released during combustion to form a solid sulfate material. Raw sorbent is continually injected into the bed while a gravity drain system withdraws spent material and ash particles. The bed is maintained at a relatively low temperature of about 1400 to 1500 °F to maximize sulfur capture. This low bed temperature also reduces nitrogen oxide emissions (NO_x) while minimizing clinker formation.

Bubbling Bed

Generally, combustion air enters the bottom of the bubbling fluidized bed at velocities in the range of 6 to 16 ft per second. Air flows up through an air distributor plate and passes through the bed containing the fuel, sorbent, and ash particles.

Crushed coal and sorbent are continuously fed to the bed using either overbed, underbed, or in-bed feeders. Overbed feed systems supply fuel to the surface of the fluidized bed by a spreader, a screw conveyor, or through a chute by gravity. Almost any fuel can be used in overbed feed systems. Coal fines do not interfere with the feeding, but these fines can blow away from the bubbling bed, resulting in large

amounts of unburned carbon in the ash. An underbed feed system introduces fuel into the bed by a pneumatic feeder through the bottom of the bed combustion zone. Carbon losses in an underbed system are less than in an overbed feed system due to the retention of fines in the combustion zone for a longer period. In-bed feeding systems enter the side of the combustor, beneath the surface of the bed. This feeder type is also suitable for feeding fines.

Cyclones are generally used after the boiler to capture and recycle the entrained ash and limestone. Captured particles are recycled to improve combustion efficiency and SO_2 capture. The recycle ratio (mass flow of returned solids to the mass flow of fresh fuel) is typically 4:1 or less. A baghouse or electrostatic precipitator is usually used as the final particulate collection system.

Circulating Bed

A CFBC differs from a BFBC in that the solid particles are entrained in the fluidizing gases and the bed does not have a well defined thickness. Most of the entrained particles are captured by a cyclone system and reinjected into the combustor; therefore, ash recycle is inherent to CFBCs. CFBC designs usually require tall combustors with large combustion zone volumes and relatively large cyclone ash collector systems. This makes them relatively unattractive for retrofit applications.

A typical feed system for a CFBC uses a screw feeder, rotary valve, or spreader to meter the fuel and sorbent flow. The feed enters the combustor through one or more in-bed feeders. Because higher fluidizing air velocities are used for CFBC boilers, they tend to be more tolerant of uneven feed distribution and larger feed particles (0.25 to 2.5 in.). Furthermore, due to the recirculation scheme of the CFBC boiler, fines do not decrease combustion efficiency.

Multiple Bed

Multibed combustion (MBC) is a variation of atmospheric fluidized bed combustion. This technique uses multiple shallow fluidized beds to produce staged combustion. Crushed and sized coal is normally fed pneumatically into the lower bed where primary air, which serves as the fluidizing medium, reacts with the coal. Combustion in the lower bed occurs at temperatures of 1650 to 1750 °F. Combustion gases released from the first bed together with secondary air act as the fluidizing medium for the second bed. Small unburned particles from the first bed are combusted in the second bed. Sulfur dioxide emissions are controlled within the second bed. The second bed operates at about 1500 °F, which is the optimum temperature for sulfur retention. Each of the beds is designed with a minimum height, producing a compact design.

There is no need for flyash reinjection. The gases are cleaned by a baghouse or electrostatic precipitator before release to the atmosphere.

Retrofits

Retrofit with an AFBC may be an attractive option for an existing boiler. Boiler types that lend themselves to retrofitting include: pulverized coal, cyclone, stoker, oil, and gas boilers. Some important considerations when retrofitting an existing boiler are:

- size of existing boiler,
- age of existing boiler,
- water/steam circulation design,
- furnace bottom to grade clearance,
- air heater type and arrangement,
- boiler support,
- type of particulate control device,
- fan capacity, and
- available space.

The heat output available from a fluidized bed boiler depends on the bed area and the fluidizing velocity. A retrofit may be made possible by matching the heat release rate of the AFBC to the existing boiler. A typical conversion involving an existing furnace in an oil-/gas-fired boiler is shown in Figure 6. Simple circulation systems, such as those found in low pressure units, are best suited for AFBC retrofits.

Because an AFBC boiler usually weighs more than the existing boiler, additional support may be needed. Available space around the existing boiler is also an important consideration in a retrofit. An AFBC needs space, for example, for the air plenum under the air distribution plate, as well as for the baghouse, the dry pneumatic bottom ash system, and storage for sorbent and coal. The existing flyash system on coal fired units can be reused, but may need some modifications.

Capabilities of AFBC Boilers

AFBC boilers have a significant degree of fuel flexibility, and hence can be designed to burn almost any fuel at reasonable efficiencies. Problems can arise, however, when switching fuels since the heat release does not always correspond to the originally designed heat transfer surfaces. The moisture, volatiles content, and reactivity of fuels play important roles in the distribution of the heat release and the temperature distribution within the boiler.

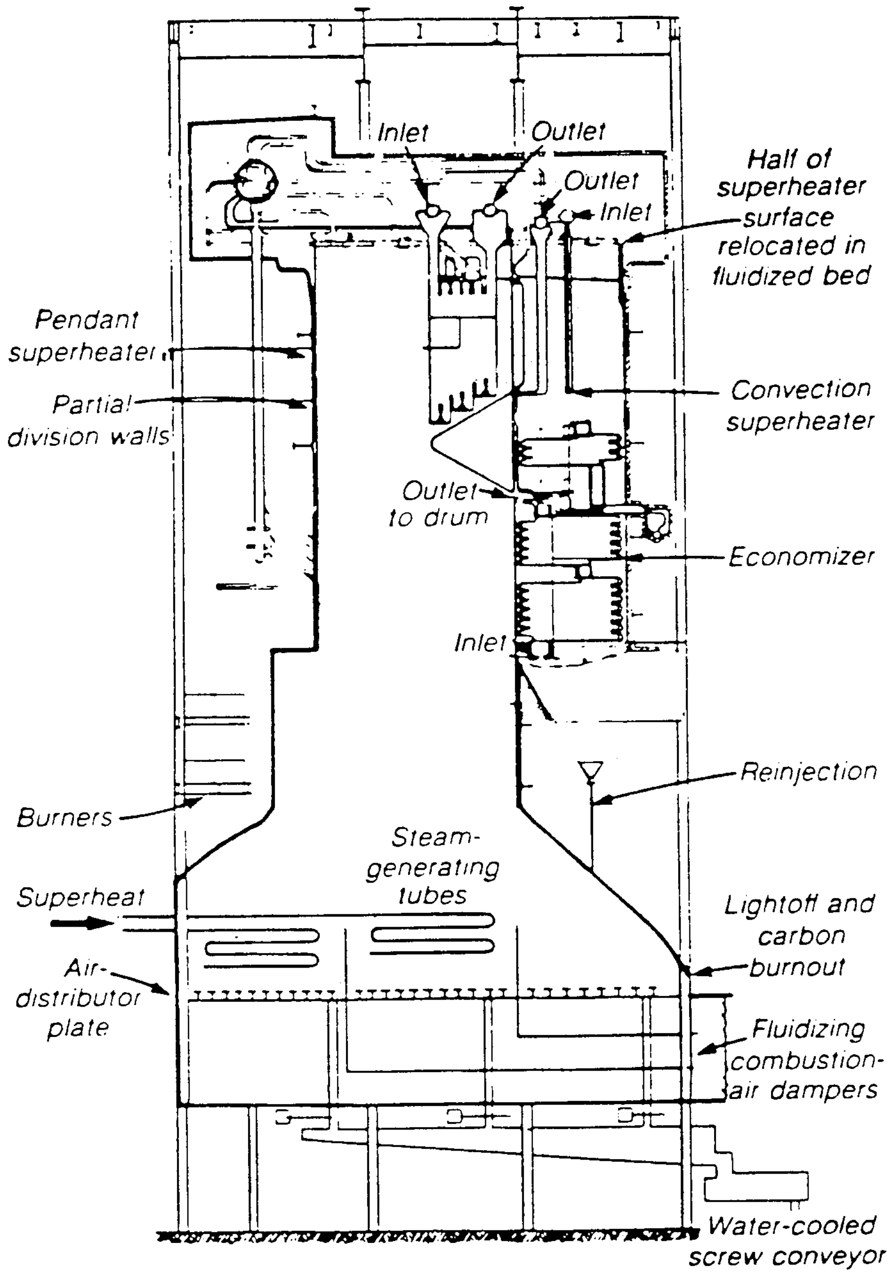

Figure 6. Retrofit with extended furnace area in oil/gas furnace.

BFBCs using overbed feeding and no ash recycle are limited to firing stoker grades of coal, oils, gas, and coal mixed with moderate amounts of waste. Lower grade coals can be used if the top size is limited and the ash removal system has sufficient capacity. Coals with high fines or unreactive coals may be burned more efficiently with ash recycle and underbed feeding. Designs that include controlled staged combustion and/or flue gas recycle in addition to ash recycle, have the greatest fuel flexibility.

CFBCs are the most flexible systems. They can fire a wide range of coals as well as oil, gas, and wastes. Staged combustion, flue gas recycle and external heat exchanger systems enhance fuel flexibility. Often it is not the boiler itself that limits the multifuel capacity, but the fuel handling system.

During combustion of fuels, NO_x can originate from the oxidation of atmospheric nitrogen (thermal oxidation) or from the oxidation of nitrogen in the fuel. NO_x emissions increase with temperature. At the low operating temperatures of fluidized bed combustors, NO_x formation is predominantly by oxidation of the fuel nitrogen, with less than 5 percent of the NO_x produced by thermal oxidation. In most cases, therefore, AFBC systems can burn typical coals and stay well below the NO_x emission limits.

The Federal New Source Performance Sulfur Standards for Industrial/Commercial/Institutional coal-fired steam generating units is 1.2 lb/MMBtu with 90 percent SO_2 capture. As shown in Table 3, certain AFBC boiler configurations are capable of removing 90 percent of the sulfur. One shortcoming of using a sorbent for SO_2 removal, however, is the large amount of sorbent required. Typically, the amount of sorbent used is twice the theoretical requirements.

One of the shortcomings of the AFBC technology is its poor combustion efficiency. Conventional solid fuel boilers have better turndown than BFBC boilers. BFBCs can turndown to between 40 and 65 percent of full load while maintaining SO_2 removal and combustion efficiency. Most CFBCs are capable of turndown to 25 to 35 percent of full load. Efficient SO_2 removal rates, however, may not be achievable at turndown ratios of less than 50 percent.

Table 3. Sulfur capture capabilities of AFBC boilers.

AFBC Boiler Design	% SO_2 Capture	Ca/S
BFBC overbed feeding, no ash recycle	60	3.0
BFBC with low fines	70	1.7-2.5
overbed feeding with high fines	70	2.5-3.0
and ash recycle	90	2.8-5.0
BFBC	70	1.8-2.5
pneumatic underbed feeding, no ash recycle	90	3.0
BFBC	70	1.5-1.8
pneumatic underbed feeding	90	2.0-3.0
and ash recycle	90	1.5-2.0
CFBC	95	3.0

The rate of turndown is generally slower for all BFBCs than for conventional solid fuel boilers, which have turndown rates as high as 7 percent per minute. CFBCs with external heat exchangers may achieve a 15 to 20 percent per minute turndown while a simple CFBC system without external heat exchangers may only achieve a 4 percent per minute turndown.

The erosion and corrosion of construction materials have also been serious problems with AFBC boiler systems.

Assessment of Atmospheric Fluidized Bed Combustion Technology

The following is a summary of the key features of the two most common types of AFBCs (BFBC and CFBC).

- They are commercially available,
- Conditional equipment and process guarantees are available for new units,
- The technology has been demonstrated on large industrial utility boilers,
- The boiler technology has shown some operational and maintenance difficulties (i.e., turndown, erosion, ash removal and cooling, hot cyclone maintenance, etc.),
- The technology has demonstrated advantages in use of multiple and poor quality fuels, low combustion temperatures, and minimization of acid gas emissions,
- Boiler efficiencies can be equal or close to pulverized coal boiler efficiencies, and
- The present boiler size ranges from approximately 45,000 to 200,000 pounds of steam per hour.

Status of Coal Slurry Fuels

Current Activity

Coal-water slurries (CWS) and coal-oil mixtures (COM, an alternate name for coal-oil slurries) emerged in the mid-1970s when a market demand developed for an economical fuel oil replacement product. The technical feasibility of COM use has been demonstrated, but the savings in using COM have not been sufficient to justify the capital expense of conversion since more than 60 percent of the energy content of COM is still derived from oil. Currently, with declining oil prices, most of these potential replacement products prove uneconomical. An exception to this is coal-water fuels.

Market studies have shown that CWS economics favor a large utility user, but conversion of oil-fired industrial boilers is expected to be the first CWS market to

develop. The main conversion candidates are boilers originally designed for oil but capable of burning CWS without major derating.

Fuel Preparation

It is envisioned that CWS fuels will be produced at central preparation plants with distribution by road, rail tankers, or pipelines to local storage depots or directly to customers. The location of CWS production facilities plays an important part in determining the economic feasibility of CWS fuels.

Coal water slurry fuels typically contain 68 to 70 percent by weight pulverized coal, 25 to 30 percent water, and 0.1 to 0.5 percent additives for viscosity reduction and stability enhancement. Table 4 shows a recommended CWS specification for a boiler that previously burned fuel oil.

Physical preparation of coal slurry fuels includes crushing and sizing the coal. This initial step improves the coal's handling and transportation properties. For good combustion it is necessary to limit the top (largest) size and achieve a small mass median particle size. In the case of regular slurries, the coal is ground to 99 percent smaller than 30 mesh with 80 percent smaller than 200 mesh, and mass median particle diameter in the range of 20 to 30 microns. In fine slurries, the coal is ground to pass through a 200 mesh screen and has a mass median particle diameter of 10 microns or less.

Table 4. Coal water fuel specifications.

Slurry		
	Coal	68 - 71 percent
	Water	25 - 30 percent
	Additives	0.1 - 0.5 percent
	Specific Gravity	1.19 - 1.25
	HHV	>95,000 Btu/gal
	Viscosity	7 - 116 cP
Coal		
	Size	75 percent through 200mesh, <2 percent greater than 50 mesh, mass mean particle size: 44 - 54 microns
	Volatiles	>31 percent
	HHV	>14,000 Btu/lb
	Ash	<7 percent
	Initial Ash	>2450 °F deformation temp.
	Slagging Index	<0.6
	Fouling Index	<0.2
	Fe_2O_3 in ash	<9 percent
	Chlorine in coal	<0.25 percent
	Initial Hardgrove Index	>55

Coal cleaning, also called benefication, is used to separate mineral matter from the coal and reduce the ash content of the coal. Advanced chemical coal cleaning techniques have the potential to be the most cost effective means of significantly reducing sulfur oxide emissions from existing electric utility, industrial, and perhaps even smaller coal-burning facilities. These advantages, coupled with the reduction of postcombustion controls such as flue gas desulfurization, can offset the cost of the advanced benefication technologies.

Equipment Required for a Retrofit CWS Plant

Existing oil storage tanks are appropriate to receive pumped slurry, providing the tanks have been adequately cleaned. The stability of CWS during storage is generally satisfactory. As a precaution however, a low speed impeller could be used in tanks to prevent settling. In contrast to oil, CWS can be pumped at ambient temperatures. Heat tracing is not normally required except when below freezing temperatures are expected for an extended period.

Positive displacement pumps are the most satisfactory for slurry handling. Two pumps with variable speed motors should be specified for boiler conversion, each capable of providing the total flow at maximum conditions.

CWS cannot be burned adequately in conventional oil or coal burners. A T-jet atomizer is one of the most efficient methods for providing the fine droplet spray required for acceptable carbon conversion. The atomizing fluid can be either steam or air. To achieve efficient combustion of CWS, the secondary air is preheated, usually in the range of 250 to 400 °F. A CWS and oil/gas commercial burner has also been developed. This burner has multiple air zones and imparts a high degree of swirl to the combustion air to achieve stable combustion with the flame remaining in the burner throat.

Other necessary equipment for a retrofit CWS plant would include a front-end CWS unloader, transport, and handling system; a bottom-ash transport system; and a back-end flyash emissions collection device. The major hardware additions and modifications for the boiler include any or all of the following: soot blowers, conversion of furnace bottom to accommodate increased bottom ash loading, addition or redesign of the ash hoppers, replacement of economizer, and additional forced draft and induced draft fan capacity.

Performance of Coal-Water Slurry Boilers

Sulfur emissions from CWS retrofits depend on the coal used. In the case of sulfur oxides emissions, virtually all of the sulfur in the coal of CWS is emitted as SO_2. To comply with regulations, the coal must either be a "compliance" coal (meets regulations for SO_2 emissions) or be beneficiated.

Particulate emissions are low for all cases using an electrostatic precipitator (ESP) or a baghouse. A 99.8 percent ESP collector efficiency is representative of state-of-the-art systems.

The level of NO_x emissions from a CWS retrofit is still questionable, although levels below 300 ppm have been reported. The NO_x level in the industrial environment tends to be inconsistent with commercially available CWS fuels. Most NO_x levels reported have been in the range of the parent coal (500 ppm), which means additional controls could be required.

Depending on the coal used, boiler efficiency for CWS is generally about 2 to 3 percent less than the efficiency for #6 oil, 1 to 2 percent higher than natural gas, and nearly equal to conventional pulverized coal firing.

Retrofit engineering primarily depends on the type of boiler and the parent coal in the CWS. These factors contribute to the severity of the derate. Derate is caused by three factors. The first is furnace volume. Gas and oil burn almost instantaneously in a hot furnace, whereas coal requires more time. Thus a furnace designed for gas or oil with a retention time of 0.2 to 0.5 seconds is inadequate for a coal particle, which requires approximately 1.0 second to completely burn. Another adverse condition arising from burning coal is slagging and fouling on the furnace and convection tubes. Slagging and fouling deposits will lower the thermal efficiency of the boiler and lead to tube corrosion and failure. Erosion is also a worry with burning coal in a gas/oil unit. Fly ash in the flue gas erodes the convective tube section. To avoid excessive erosion, flue gas velocities should be maintained at recommended values.

The adverse effects of burning coal in a gas/oil unit can be minimized by the following:

- Reduce required retention time by decreasing the coal particle size, improving atomization, achieving higher turbulence, or reduced firing,
- Avoid slagging and fouling by reducing the firing rate to keep the furnace exit gas temperature well below the initial ash deformation temperature, and

- Minimize erosion by reducing the firing rate to lower the fly ash velocity, and change the composition and particle size so the fly ash particle follows the gas flow around the tubes.

Assessment of Coal Slurry Boiler Technology

The development and application of CWS is a key element in the future of coal use. The feasibility of boiler conversion to CWS fuel should be evaluated on a case-by-case analysis of each boiler. Whether CWS can replace gas or oil as a boiler fuel is fundamentally a question of economics. The costs of various coals and their conversion to CWS are known, and transportation costs are similar to those of conventional fuel oil.

Coal-Water Slurry Technology. The principle advantages of CWS are:

- Predictable price structure and availability of base coals,
- Current technology needs little adaptation for the preparation of CWS (minimal modification of existing oil storage facilities and no radical innovations in burner design are required),
- Compared to conventional coal conversions, CWS offers simplicity of transport, handling, storage, and elimination of dust and associated hazards at transfer and storage points,
- Beneficiated (cleaned) coals used in CWS result in lower SO_x emissions and reduced ash related problems,
- The economic life of suitable existing-oil fired boilers can be extended by converting to CWS, and
- CWS offers advantages over pulverized coal firing where high turndown is required, due to the substitution of water for transport air, which produces a more stable flame at lower loads and eliminates support fuel requirements and the need for higher volatile coals.

Coal-Oil Slurry Technology. COS technology has shown positive results but problems with fuel handling, erosion, and burning still arise. One drawback is that no commercial bulk fuel preparation facility is in operation. (At one time there were funded operational facilities.) This technology has been advocated mostly for coal conversion of oil boilers. (New facilities would probably be pulverized coal [PC] facilities.)

Micronized Coal Combustion Technology

Pulverized Coal Combustion versus Micronized Coal Combustion

Micronized coal is defined as coal with a nominal top size of 325 mesh (44 microns). In contrast, the pulverized coal particle size distribution is such that 70 percent passes through 200 mesh, 28 percent passes through 50 mesh and is retained on 200 mesh, and the remaining 2 percent is larger than 50 mesh. Figure 7 shows the typical size distribution in a pulverized coal and a micronized coal sample.

The relatively small particle size of micronized coal results in a large surface area available for combustion. Analysis of various coal samples ground through different micronizing equipment show that the coal surface area seems to vary between 60,000 to 130,000 sq m/ton of coal, depending on the density and the particle size distribution. Conversely, pulverized coal has about 4 to 10 times less surface area.

Direct combustion of micronized coal is becoming increasingly attractive for many utility and industrial boilers and furnaces, especially for converting an oil-fired unit to coal. Conversion from an oil-fired to a coal-fired unit has a number of options, including:

- Install new coal fired boilers,
- Convert to stoker firing,
- Convert to pulverized coal firing (coal size 70 percent less than 76 microns), or
- Convert to micronized coal firing (coal size 100 percent less than 44 microns).

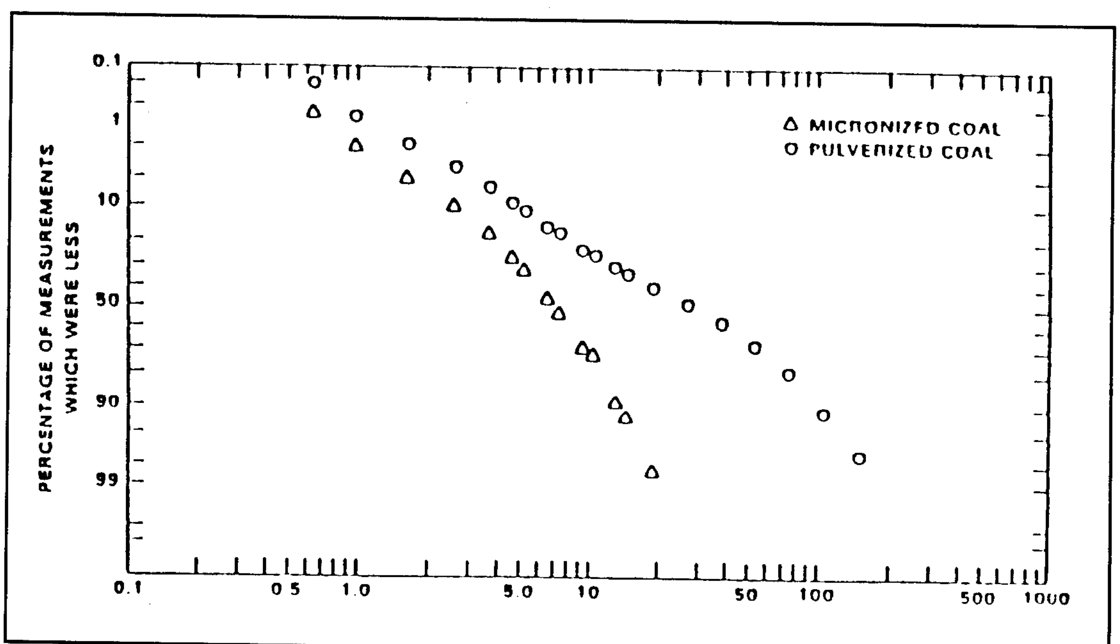

Figure 7. Comparison of particle size distribution of micronized and pulverized coal.

New boilers may be the best long term solution, particularly if the existing boilers are near the end of their life. The capital cost, however, is high and the time scale for implementation is rather long.

Conversion to stoker firing is possible only if the boiler design and the type of coal to be used are suitable for stoker firing. The required coal milling plant can be expensive to purchase and maintain. Conversion to pulverized coal firing as compared to micronized coal firing has many problems associated with it such as tube bank erosion, inadequate furnace residence time, insufficient radiant heat transfer, ash removal problems, and inadequate space.

It may not be possible to convert from oil to coal because of the lack of space. In other cases, the overall cost of conversion may be prohibitive.

A positive conversion scenario would be to significantly derate the boiler to allow for reduced velocities and complete combustion within the smaller furnace volume. Derating would also reduce the slagging and fouling problems.

Micronized coal firing offers the potential to minimize the practical problems, capital cost, maintenance costs, and time scale for converting from oil to coal firing. It also minimizes the derating that may be required when the boiler is converted from oil or gas firing. Some of the advantages of micronized coal combustion are:

- It can replace an oil- or gas-fired boiler with a coal-fired boiler requiring minimal modifications and little or no derating.
- Coal is more cost effective than oil or gas,
- Higher combustion efficiencies can be achieved,
- Sulfur dioxide emission levels can be reduced by adding limestone, and
- It reduces dependency on foreign oil and gas.

Mechanism of Micronized Coal Combustion

During the early 1980s demonstration tests to prove the micronized coal combustion concept were carried out by the Institute of Gas Technology (IGT), Gulf State Utilities (GSU), and Mississippi Power and Light Company (MP&L).

The main difference between micronized coal and pulverized coal is the mean particle diameter. It takes a long time, 67,500 seconds, for a 1 micron particle to drop to a distance of 10 feet under gravitational force. Conversely a 74 micron particle takes about 12.5 seconds to drop the same distance. If large ash particles are entrained in the flue gas, their inertia causes them to separate from the flue gas stream as it

changes direction to travel around the tube in the convection section. This results in impact deposition on the tube and/or erosion as the particles are swept over the tube surface.

Also, very large ash particles tend to drop out of the flue gas stream before it leaves the furnace; they collect on the bottom. Smaller ash particles go around the tube along with the gas stream. These small ash particles produced by the combustion of micronized coal allow aerodynamic forces to overcome the inertial forces that tend to separate ash particles from the flue gas flow; the ash remains entrained in the gas, passes around the tubes, and is collected in a bag house or an electrostatic precipitator.

The available surface area for combustion increases with the square of the particle diameter. Decreasing the particle size also decreases the amount of surrounding air required for combustion of the particle, thus helping to increase the combustion intensities and decrease the resulting ash particle size. The firing of micronized coal as compared to conventional pulverized coal should therefore result in improved carbon use; shorter, more intense flames; and a subsequent reduction in combustion volume requirements for a given heat input. These factors should make it feasible to burn micronized coal efficiently in the smaller furnaces of oil/gas designed units without the need for major modifications or derating. Boilers designed exclusively for gas would probably require cleaner (less ash) coal and an even finer grind of coal.

Combustion of micronized coal has its penalties too. It results in a significant increase in grinding costs. It also requires coal and ash storage, handling, and collection systems. It is, therefore, important to strike a compromise at the point where grinding costs are not significantly high, but the impact on boiler functioning is minimized. The selection of particle size will help decide the necessary grinding equipment. There are many grinding units available that can provide size distribution with a top nominal size of 325 mesh or 44 microns.

Slagging Coal Combustors

The slagging coal combustor (SCC) operates by firing pulverized coal (70 percent through 200 mesh) into either a water-cooled or an air-cooled combustion chamber. The combustion chamber is operated under sub-stoichiometric conditions; that is, supplying approximately 70 percent of the oxygen required for complete combustion in the first stage. The temperatures in the combustion chamber reach 3000 °F which is hot enough to melt the residual ash material thrown to the sides of the chamber by the vortex that develops. The molten ash, or slag, then flows down the sides of the chamber to a slag tap and in to a water quench pit. The remaining combustion flue

gas is then exposed to secondary air, at the exit of the combustion chamber, to complete the combustion process.

Due to the staged combustion effect of segregating the combustion air, SCC developers are claiming low NO_x emissions on the order to 200 to 250 ppm NO_x, the requirement for USEPA New Source Performance Standards (NSPS). Additionally, through the addition of a sorbent material such as lime, SCC developers have claimed sulfur capture ranging from 25 to 90 percent.

Another advantage of SCCs is that up to 90 percent of the ash is captured in the combustion chamber and thus never reaches the furnace convective section. Because most of the ash particles that do remain are small, the fly ash that goes to the convective section will follow the path of the flue gases and not impact on the furnace tubes. If this actually occurred in a retrofit application, the boiler would not have to be derated and the investment payback would be quicker.

Developmental History

The SCC is the latest variation (using pulverized coal) of a concept originally introduced by Babcock and Wilcox (B&W) as the cyclone furnace in the 1940s. B&W were aware of the inherent advantages SCC had over existing pulverized coal combustion. Existing combustors had several disadvantages, namely:

- A large power consumption required for driving pulverizers,
- High maintenance costs for pulverizers,
- Excessive fly ash discharge from the stack (approximately 80 percent for dry-ash removal furnaces without dust collectors),
- Erosion of boiler pressure parts by fly ash entrained in the flue gases (unless low gas velocities are maintained),
- Erosion of induced-draft fan blades and scrolls, even when the fans are located after dust collectors,
- Lower system availability and increased maintenance because of eroded components, and
- Relatively large furnace volumes required for good combustion.

The cyclone furnace was a great success for B&W with more than 23,000 megawatts (MW) of cyclone design utility boilers installed in the United States. Its downfall was excessive NO_x emissions. Attempts to apply conventional combustion modifications for NO_x control were largely unsuccessful in meeting the USEPA's NSPS.

Slagging Coal Combustor Technology Overview

Staged slagging coal combustors are being promoted as a means of converting oil and gas designed boilers to coal with a minimum of boiler modifications and derating while achieving reduced NO_x and SO_x emissions for coal-fired boilers without the need for post-combustion controls.

Coal is burned in a dry pulverized state in a highly turbulent regime at heat release rates up to 50 times greater than conventional coal-firing methods. This generates temperatures above 2700 °F, high enough to consume up to 99 percent of the carbon and liquify most coal ash. Up to 90 percent of the ash is removed from the combustor as molten slag. The remaining fly ash is extremely small, less than 20 microns. As such, the fine ash will follow the aerodynamic path of the flue gas through the convection section, not impinging on the tube surfaces.

Combustion takes place within the chamber at sub-stoichiometric conditions typically in the range of .7 to .8. Oxides of nitrogen formation (NO_x) are held at low levels under these conditions by avoiding thermal NO_x formation from combustion air. SO_x is controlled by injecting limestone into the combusted flue gas.

Five major companies are currently developing the SCC technology: TRW, TransAlta (formerly Rockwell), Coal Tech/GE, Avco-Everett, and Energy and Environmental Research Corporation (EER).

Performance

The ability to control NO_x, sulfur emissions, particulate emissions, and the capacity of the combustors are the major performance issues involved in the use of SCC technology. One of the popular approaches for NO_x control requires the operation of a cyclone in a fuel-rich environment so as to limit the conversion of fuel-bound nitrogen to NO_x. The use of ash constituents or other dry additives aid in the control of sulfur emissions. Controlling the particulate emissions involves the capture and removal of ash, commonly by using an electrostatic precipitator or a baghouse.

Coal Gasification for Producing Low-Btu Gas for Industrial Boilers

Coal Gasification Process Review

Coal gasification has been in use for more than 100 years; many types of coal gasifiers have been developed. Before the 1940s, thousands of gasifiers supplied fuel gas for

boilers and process furnaces. These units were usually abandoned when less expensive natural gas become available in the 1940s and 1950s. In the 1970s, the rise in the cost of natural gas and concerns about future availability prompted a second look at the development of more efficient coal gasification technology. These efforts subsided with the stabilization of the natural gas supply in the early 1980s.

Coal gasifier designs are available in a wide variety of capacities and product gas compositions. Three major types of gasifiers are fixed bed, fluidized bed, and entrained bed, which differ in the contacting method between the coal and the reactant gases inside the gasifier vessel. Each bed type has unique characteristics that determine its suitability for any specific application.

Coal gasification is the conversion of coal matter to combustible gases. Gases manufactured from coal are usually classified by their heating value. High-Btu gas consists essentially of methane and has a heating value of approximately 1000 Btu per standard cubic ft (SCF). Medium-Btu gas consists primarily of carbon monoxide, hydrogen, and small amounts of carbon dioxide with heating values in the range of 250 to 600 Btu per SCF. Low-Btu gas has a heating value between 100 and 200 Btu per SCF. Some of the important reactions encountered in coal gasification are shown in Table 5.

Raw coal fed into the gasifier comes in contact with hot, raw gases, driving off the moisture in the coal. As the coal heats up, occluded carbon dioxide and methane are driven off at temperatures less than 400 °F. Organic sulfur in the coal decomposes and converts to hydrogen sulfide in the 400 to 900 °F temperature range. Nitrogen compounds in the coal decompose to release nitrogen and ammonia. Above 550 °F, oils and tars are distilled from the coal. The devolatilized coal, or char, reacts with the steam feed and combustion products such as carbon dioxide to form carbon monoxide and hydrogen. The heat required for the endothermic steam-carbon and carbon dioxide-carbon reactions is provided by the exothermic combustion reaction of the remaining carbon in the char with the oxygen feed.

Table 5. Coal gasification reactions.

Name	Process	
Combustion	$C + O_2$ ---->	CO_2 + 169,300 Btu
Steam Decomposition	$C + H_2O$ ---->	$H_2 + CO$ - 56,500 Btu
Methane Formation	$C + 2H_2$ ---->	CH_4 + 32,200 Btu
Carbon Dioxide Decomposition	$C + CO_2$ ---->	$2CO$ - 74,200 Btu
Water-Gas Shift	$CO + H_2O$ ---->	$CO_2 + H_2$ + 17,700 Btu
Methanation	$CO + 3H_2$ ---->	$CH_4 + H_2O$ + 88,700 Btu

All coal gasification processes are essentially controlled by balancing the heat effects of the exothermic and endothermic reactions. This can be accomplished by oxidation with air or oxygen or from an indirect heat source.

The direct use of air for oxidation of carbon as a heat input results in the production of low-Btu gas because the product gas is diluted with nitrogen. Higher-Btu gases generally require air separation plants to provide pure oxygen as the reactant gas.

Modifications Required for Retrofitting Existing Industrial Boilers

Industrial boilers, both fire-tube and water-tube types, require minimum modifications for retrofit to a coal gasification boiler producing low-Btu gases (150 to 170 Btu per SCF), and sustain minimum derating if any. The exact modification and reduction in output primarily depend on the design of the boilers and burners. No changes are required for the combustion air supply system. To maintain the same heat input, the volumetric flow rate of low-Btu gas is about 6 times that for natural gas.

The fuel gas supply system, therefore, requires the most changes. For example, a larger fuel gas pipeline or a higher supply pressure is necessary to compensate for the increased volume and pressure drop. Generally, no flame stability problems are expected for low-Btu gas. However, the fuel gas nozzle/injector of certain types of burners may need to be enlarged to improve flame stabilities. The lower flame temperatures of low-Btu gas result in lower radiant heat-transfer and lower thermal efficiency. This is offset to some extent by the higher convective heat transfer resulting from the increased volume of air and fuel gas. The overall reduction in thermal efficiency is not expected to be significant. The increased volume (about 30 percent) of combustion products can be compensated for by increasing the load on the induced or forced draft fans, and/or by removing some tubes in the waste-heat recovery unit downstream of the combustion zone.

Cogeneration Technology and Financing

Cogeneration can be defined as the production of both electricity and thermal energy from a common fuel source. Third party financing involves a developer or group of developers who build, operate, and finance the heat supply plant. From the plant, thermal energy is sold under contract to a buyer, and electricity is sold to the utility. In some cases, it is sold to the thermal energy user as well.

The issues involved in the operation and financing of cogeneration projects have been the subject of much debate since the introduction of full form PURPA in 1978.

Cogeneration projects, including the third party projects, can be organized a number of ways, depending on the desired cash flow characteristics and form of ownership. The regulatory structures facing the cogenerator will play a large role in the success of the project.

Overview of Cogeneration Development

The National Energy Act and its offspring, PURPA, were enacted in 1978 to reduce the nation's dependence on imported fuel supplies. Cogeneration was targeted by Congress as a preferred source of future electric generation due to its inherent efficiency of simultaneous coproduction of electricity with an existing thermal load. The higher heat and energy requirements of electric generation could be used as byproducts to fulfill process thermal requirements such as building heat or commercial steam demand, thus essentially using energy for two purposes rather than just one.

PURPA further directed that the states carry out these intentions of the law. This resulted in a nonuniform enforcement approach of PURPA rules by different states. Some states have been content with fulfilling the minimum requirements by allowing utilities to control buyback rates and contract terms. Others have adopted supplemental state regulations, aggressively issuing strict guidelines on the avoided cost rates and the acceptable contract provisions. The attitude of state regulators toward increased energy competition and independent energy producers generally reflects the prevailing costs for electric generating capacity in that state. A lack of generating capacity, the desire for more efficient energy production, or a need for resource diversification will provide encouragement for cogeneration development.

Third party cogenerators are compensated in two ways:

1. The income via an agreement to provide a customer with thermal energy and in some cases electricity, and

2. The payment from the electric utility for buybacks of cogenerated electricity.

The first form of compensation is a fairly straightforward contractual matter between the cogenerator and the thermal energy user. The cogenerator assumes responsibility for all aspects of the operation and construction of the facility and agrees to provide thermal energy to the user for a specified rate that is typically below the user's cost of thermal energy production. This is possible because the cogenerator is coproducing electricity and can afford to subsidize thermal output, which is sold at a discount to the user. This discount represents the user's compensation from third party cogeneration.

The user may also wish to purchase electricity from the cogenerator instead of from the local utility grid, possibly receiving a discounted price on these sales as well.

Since electricity is most efficiently cogenerated in conjunction with high thermal loads, the nature of the load required by the thermal energy user will have an impact on the value of cogenerated electricity produced. For example, the use of thermal energy for building heating may require a significant thermal load only during business hours, while a user with a process thermal load may require a steady load all day and night. The cogenerator has a great incentive to produce electricity, and thus thermal energy, during electric utility peak load times.

Electric buy-backs from the utility, the second form of cogenerator compensation, is a complex issue that determines the profitability of the project.

Trends in the Cogeneration Industry

A number of changes that have occurred in the cogeneration industry seem to indicate the future direction of the industry. A spate of mergers and consolidations have produced an industry dominated by larger firms. Changes in tax laws seem to have dampened the presence of limited partnerships but have spurred the corporations and joint ventures, particularly the larger construction and energy consumption institutions. In addition, a number of utilities and utility holding companies have formed subsidiaries that make investments in cogeneration projects. Utilities, however, are limited by law to a 50 percent equity stake in cogeneration projects. A trend also exists toward competitive bidding solicitation by utilities for cogenerated or independently produced power. The overall movement in the direction of increased competition in energy production is likely to intensify, pitting cogenerators against other cogenerators as well as utilities in competition for cheapest power production. Competition will become more fierce as wheeling charges are reduced by regulators in an attempt to foster lower prices through competition. This trend has been greatly encouraged by consumers in areas that experience high retail electric rates.

Conclusion

Cogeneration has emerged as a practical method of electric generation and an important option in national energy planning. Third party financing of cogeneration is extremely important because it allows organizations lacking the necessary managerial or financial resources to take advantage of profitable opportunities through an agreement with another party capable of carrying out cogeneration projects. Although recently the attractiveness of cogeneration may have diminished

somewhat, numerous methods exist for third parties to identify profitable cogeneration opportunities and reduce the risks of those projects.

Cogeneration is presently at the forefront of an emerging trend toward increased free market competition in electric generation. Third party financing is crucial to the full development of this potential market. Because cogeneration is valuable to thermal energy users and electric consumers alike, it will prove to be a popular alternative in future energy planning.

Some generalizations can be drawn about the third party cogeneration's future prospects.

1. Third party cogeneration is most attractive in areas that have high electric rates because it offers favorable avoided cost payments for cogenerated electricity (> $.06/kWh),

2. Facilities that use or could use natural gas as a fuel are the best suited to cogeneration technology,

3. Facilities that have large thermal loads (> 25 MMBtu) are good candidates for installation of cogeneration facilities, particularly those requiring expansion or replacement of existing central heat plant facilities, and

4. Bituminous coal is feasible in very large plants (> 500 MMBtu).

Consolidation of Steam Distribution System

The objective of the consolidation model is to determine the feasibility of building a central heating plant that would replace several smaller heat generators. Because the decision to consolidate is very site-specific, the screening model analyzes the steam distribution system by questioning the user about the specific criteria that should be considered when making the decision to build a central heating plant. To further analyze the feasibility, the costing model should be used to determine the cost of the distribution system. At this point, if it is determined that the central heating plant is feasible, the program then allows the user to evaluate the heating plant or cogeneration plant screening and costing models. Upon determining the total costs, a comparison of the cost of the consolidated plant with the sum of the total other exiting loads indicates the feasibility of placing the consolidation technology in the existing scenario.

The steam distribution system's conceptual design depends on the type of system and the distance the system must extend. The model allows the user to select from four types of conceptual steam system designs: tunnel construction, direct burial Ricwil casing, shallow trench/walkway construction, or above ground single stanchion construction.

After selecting the system or systems to be used, the user must also input the length of each system and the number of branch lines or connections. The program uses this information to provide a conceptual budget for an estimated installed constructed cost of the steam distribution system.

3 Screening Models

A computer-based screening model has been developed to aid Army planners in the preliminary evaluation of potential sites for coal-fired central heat plants. The screening model consists of five sections; New Heating Plant Screening Model, Cogeneration Screening Model, Third Party Cogeneration Model, Consolidation Screening Model, and Retrofit Screening Model. The models are menu driven, prompting the user to supply information describing the facility's characteristics and energy needs. The screening model has three basic units: the program interactive query section, internal data bases, and engineering calculations. Based on the information supplied, the program lists the relevant plant parameters. In addition to calculated outputs, such as peak boiler house loads, a subjective weighted analysis output is provided. The output provides information for comparing the potential sites with available technologies and other locations.

New Heating Plant Screening Model

The New Heating Plant Screening Model can be used to determine the feasibility of constructing a new coal-fired heating plant (150 psig saturated steam or equivalent hot water) at an existing installation. The program prompts the user to supply information describing the requirements and resources available for the new heating plant. The boiler plant options include stoker, bubbling fluidized bed, circulating fluidized bed, coal-water slurry, coal-oil slurry, pulverized coal, gas and oil fired boilers. Based on the information supplied and internal program information, the output provides conceptual area requirements, steam heating load predictions, plant performance estimates, fuel storage area requirements, location site information, boiler coal specifications, coal analysis, boiler sizes, allowed emissions, calculated emissions, and water requirements. In addition, a weighted analysis is provided for subjective factors considered when deciding to build a new heating plant.

The New Heating Plant Screening Model is divided into sections; each focuses on a specific aspect of building a new heating plant. For each section, user inputs are required to evaluate the relevant criteria. The following paragraphs discuss each section, including the inputs required and the computer logic and actions. The algorithms, where relevant, are also provided.

Plant Site Information

This section requires the user to enter the state in which the new heating plant will be located. After entering the state, the program automatically lists military bases in the state. The user then selects one of the bases listed. If the state is divided into a number of regions for emission regulations, the user will be asked to identify the region of the base.

Heating Plant Monthly Loads

The heating plant load demand calculation requires the following information: the type of boiler plant to be built (steam or high temperature hot water), the average hourly steam demand for each month in pounds per hour (or MBtu/hr for hot water), and the process steam demand for each month in pounds per hour (only for steam). The program asks the user to input these values and confirm that they are correct before continuing.

Heating Plant Maximum Continuous Rating Calculations

The steam load prediction formulas calculate the plant maximum continuous rating (PMCR steam flow) in pounds per hour. If the PMCR is outside of the plant limit size of the model (50,000 lb/hr to 600,000 lb/hr or approximately 50 million Btu/hr to 600 million Btu/hr), the program will alert the user. The following equations are used for a specific location with known long-term average monthly degree days, long-term mean monthly ambient air temperatures, and monthly average steam flows in pounds per hour.

Average monthly steam flow (lb/hr) =

$$(PMCR)\,(A \times B \times C + A \times C \times D + 0.125)\,(LF) \qquad \text{(Eq 1)}$$

where: A = Ta/Tm

B = DDM/DDCM, where DDM>1.0 & DDCM>1.0

C = (Tta)/(TdTo), where T-Ta> +1.0

D = [0.5][(PDDM + DDPM) - DDCM]

[PMCR] A B C > + 500

[PMCR] A C D > + 500

PMCR = Plant Maximum Continuous Rating, which is the total plant maximum continuously required steam flow in pounds per hour.

DDM = Degree Days of the specific month being predicted. This is a long-term average of at least the previous 10 years.

DDCM	=	Degree Days of the Coldest Month of the year. This is the month with the most degree days. The value is a long-term average of at least the previous 10 years.
PDDM	=	Predicted Degree Days of the specific month being predicted. This can be equal to the DDM value or some other value depending on the user's prediction of the month's degree days. (Default should be the DDM value).
DDPM	=	Degree Days of the Previous Month being predicted. This is equal to the previous month's degree days. This value can be either an actual value or a long-term value depending on the user. (Default should be the 10-year average degree days value of the month previous to the specific month.)
T	=	Average indoor building temperature (°F) for the month. Default should be 70 °F.
Ta	=	Average ambient outdoor temperature (°F) of the specific month.
Td	=	Indoor design temperature. Default should be 70 °F.
Tm	=	Outdoor yearly mean temperature (°F). This value is a long-term, minimum of 10 years, average of the mean temperature.
To	=	Outdoor winter design temperature (°F). This value should be based on the once-in-13 or once-in-20 years frequency of recurrence temperature.
LF	=	Load factor for each month determined from actual long-term data for a specific installation. For a new plant or a plant without actual data, the following is:

- Months of December, March, and April: LF = 0.836.
- First month of the heating season: LF = 1.333. The first month in the north is September and in the south is October.
- Months of June and July: LF = 1.08
- All other months: LF = 1.0

Distribution System Minimum Monthly Steam Flow (lb/hr) = (PMCR)(0.09)

Plant Minimum Total Steam Flow (lb/hr) = (PMCR) (0.08)

Plant Average Low Monthly Steam Flow (lb/hr) =

(Average Monthly Steam Flow) - (LLF)(PMCR)(LDDCM)/(BDD)

where: LLF = Low Load Factor for the specific month in question and are:

Jan	=	0.16	Jul	=	0.02
Feb	=	0.16	Aug	=	0.02
Mar	=	0.14	Sept	=	0.06
Apr	=	0.12	Oct	=	0.085
May	=	0.08	Nov	=	0.11
June	=	0.035	Dec	=	0.14

(LLF)(LDDCM)/(BDD) > 0.02

LDDCM	=	The specific Location Degree Days of the Coldest Month in question.
BDD	=	Base Degree Days = 1250.

Plant Maximum Monthly Steam Flow (lb/hr) =
(Average Monthly Steam Flow) + (PLF)(PMCR)(LDDCM)/(BDD)
where: (PLF)(LDDCM)/(BDD) = 0.07

PLF = Peak Load Factor for the specific month in question:

Jan	= 0.40		Jul	= 0.07
Feb	= 0.40		Aug	= 0.07
Mar	= 0.40		Sept	= 0.22
Apr	= 0.38		Oct	= 0.25
May	= 0.25		Nov	= 0.33
June	= 0.15		Dec	= 0.40

Predictions are only for heating facilities without any type of cogeneration or air conditioning (cooling) loads in the summer.

Boiler Technology

In this section of the screening model the type of boiler plant to be analyzed is selected. The choices are:

1. Spreader stoker with traveling grates
   a. With fly ash reinjection
   b. Without fly ash reinjection
2. Dump grate spreader stoker
   a. With fly ash reinjection
   b. Without fly ash reinjection
3. Spreader stoker with vibrating grate
   a. With fly ash reinjection
   b. Without fly ash reinjection
4. Spreader stoker with reciprocating grate
   a. With fly ash reinjection
   b. Without fly ash reinjection
5. Chain grate stoker
6. Traveling grate stoker
7. Bubbling Fluidized Bed Combustor (BFBC)
8. Circulating Fluidized Bed Combustor (CFBC)
9. Coal-Water Slurry (CWS) Boiler

10. Coal-Oil Slurry (COS) Boiler
11. Pulverized Coal Boiler
12. Gas/Oil-Fired Boiler

Conceptual Boiler Sizing

This program section allows the user to select a conceptual plant with three, four, or five boilers. The equations require the number of boilers and the plant design PMCR (as derived from the plant monthly loads) to be entered as input. The input is then used to determine the correct size for each of the plant's boilers in pounds per hour outlet flow. If the boiler sizes are outside the feasible size range for the chosen technology or for the program limits of 20,000 to 200,000 lb/hr (20 to 200 MMBtu/hr), the program will alert the user to the problem and allow the user to quit, change the number of boilers, or change the plant demand.

The three-boiler sizing method allows the plant to generate 68 percent of the PMCR with one large boiler out of service. The four-boiler plant will be able to generate 100 percent of the PMCR with one large boiler out of service. The five-boiler plant will be able to generate 100.5 percent of the PMCR with one large boiler out of service.

The four-boiler plant is the default method for coal-fired unit while the three-boiler plant is used for gas/oil-fired unit. With this sizing configuration, the plant will be able to meet the minimum heating loads of summer and the possible over-demands of winter. The sizing also provides for a small future capacity increase and a redundant boiler. The redundant boiler can cover forced boiler outages. The plant will be able to use the four boilers in a pattern typical of coal-fired boiler heating facilities.

In the summer (minimum heating season) the plant will have the small boiler on-line. During the fall (steam demand will be increasing), the plant will bring a large boiler on-line with the small boiler. Sometime during the fall, depending on the specific seasonal conditions and steam system requirements, the small boiler will be taken off-line and replaced with another large boiler. In late fall or early winter, the third large boiler will be brought on-line, thus enabling the plant to meet the highest requirements at the most demanding time of the year. Sometime at the end of the winter season or beginning of the spring season, the plant will take -one large boiler off-line and bring the small boiler on-line again. During the spring season, the plant will take the large boilers off-line (one at a time) until only the small boiler is on-line for the summer load.

Reasons for using the three large boilers during the winter season include: the plant will have to use frozen and/or wet coal, the ambient air and water temperatures will

be at the lowest values, and the plant will have to supply the highest in-plant steam/heat use and the largest system load.

The four-boiler default sizing formula also includes an understanding of scheduled boiler maintenance. Each boiler will be off-line for scheduled maintenance approximately 1 month per year; either one continuous month or two 2-week periods. Approximately every 5 years, each boiler will also be scheduled for a major overhaul. Each overhaul will be performed over a period of approximately 30 to 60 continuous days. Experience has shown that the plant will schedule yearly boiler outages depending on the season. The large boilers will have scheduled maintenance performed sometime during the spring, summer, and fall seasons; one boiler is scheduled for maintenance at a time. The small boiler will have a scheduled maintenance sometime during late fall, early winter, or during late winter. This will keep the small boiler available during the coldest part of the winter for backup to the largest boilers, in case of forced or unscheduled boiler outages that may occur when the boilers are operated near maximum conditions.

The program's default sizing optimizes the design of the facility's major components to assure availability and reliability by considering all significant factors likely to influence facility operation.

Fuel Search

The fuel search requires the user to enter the radius in miles from the base for the fuel search. For the stoker and FBC boilers, the program searches the COALFIELD data base for coal deposits within the specified radius, and compares the required coal specifications of the chosen boiler type with each coal deposit to determine which coal sources can be used.

If a coal-oil slurry or coal-water slurry boiler is selected, the program asks the user if a coal slurry production plant is located in the area. The user should be aware that only one coal slurry production site is presently in operation, and that future sites most likely will be located near areas of the country having large electric utility loads.

Water Requirements

When considering a new boiler plant, the amount of water required must be estimated. Estimates for boiler leakage, condensate return, and blowdown as percentages of PMCR must be entered.

Plant/Boiler Performance Estimates

This section calculates the heat and mass balance for the total boiler plant when operating at the PMCR. This calculation assumes that the boilers are essentially the same and will operate with the same efficiency regardless of size differences. This assumption is valid for the conceptual design stage and with the boiler sizing methods used in this study.

The program begins with the key boiler data inputs. The boiler sections calculate the boiler efficiency (according to the American Society of Mechanical Engineers [ASME]), the air requirements and flow, the products of combustion and flow, and the flue gas specific heats.

The screening model program includes three versions: one for a stoker plant, one for a FBC boiler plant, and one for a coal slurry plant.

Stoker Plant Program With a Dry Scrubber and Baghouse. This program section includes calculation of a dry scrubber mass and energy balance, which then generates the dry scrubber lime and water requirements, flue gas flows, and several flue gas specific heats. These values are calculated from the inlet of the scrubber through the baghouse and into the stack. The boiler portion includes the boiler superheater, economizer and/or air heater, and all associated fans, pipes, and controls needed to introduce air and fuel into the system. The scrubber and baghouse portion includes the necessary equipment required to introduce air, water, and lime into the system.

FBC Boiler Plant Equipped With a Baghouse. This program section evaluates information required for sizing a FBC boiler plant equipped with a baghouse. The boiler portion includes the furnace, boiler, superheater, economizer and/or air heater, and all associated fans, pipes, and controls needed to introduce air, fuel, and limestone into the system.

Slurry Boiler Plant Equipped With a Baghouse. This program section calculates and displays boiler information required for sizing a boiler plant with a baghouse. It includes the boiler superheater, economizer and/or air heater, and all associated fans, pipes, and controls needed to introduce air and fuel into the system.

Plant Area Requirements

To determine whether sufficient area is available to build a new boiler plant, the program calculates the plant area, coal storage rain runoff pond area, and coal storage areas. The sum of these areas is the total area required to build a new plant. The

program also calculates the required rail track length, the plant height, the stack height, and the building size.

Table 6 shows the equations used to calculate the area required for a new, horizontally designed three-, four-, or five-boiler plant. These equations apply to HTHW facilities to 250 psig and steam facilities to 600 psig and 750 °F. The equivalent plant maximum continuous rating (EPMCR) for HTHW steam facilities is determined by plant heat output in millions of Btu per hour divided by the enthalpy of evaporation. This can be approximated by dividing the millions of Btu by 1000.

The plant acreage is the area required by the boiler plant and includes the boiler plant building, fuel and lime storage, air pollution control devices (baghouses), induced draft (I.D.) fans, stacks, coal handling, limestone handling, ash handling, roads, and parking.

Coal Storage Area - Stoker, CFBC, BFBC

The long-term coal storage area includes the long-term coal storage pile, short-term dead storage pile, live or stockout pile, coal reclaim equipment, and a circulation allowance for coal yard vehicles. This total area is to be constructed such that storm water will be collected and directed to the coal storage rain runoff pond. The conceptual area allowance calculations conform to Department of the Army Technical Manual TM 5-848-3; *Ground Storage of Coal*, dated March 1984.

Table 6. Plant area requirement.

Plant Type	Acres
Stoker plant	
3-boiler	[(0.003457)(PMCR/1000)] + 0.80
4-boiler	[(0.004762)(PMCR/1000)] + 0.83
5-boiler	[(0.004348)(PMCR/1000)] + 1.00
CFBC plant	
3-boiler	[(0.003457)(PMCR/1000)] + 0.80
4-boiler	[(0.004762)(PMCR/1000)] + 0.83
5-boiler	[(0.004348)(PMCR/1000)] + 1.00
BFBC plant	
3-boiler	[(0.0027)(PMCR/1000)] + 0.79
4-boiler	[(0.00326)(PMCR/1000)] + 0.81
5-boiler	[(0.0036)(PMCR/1000)] + 0.90
COS plant	
3-boiler	[(0.002)(PMCR/1000)] + 1.16
4-boiler	[(0.00219)(PMCR/1000)] + 1.27
5-boiler	[(0.0025)(PMCR/1000)] + 1.36
CWS plant	
3-boiler	[(0.001)(PMCR/1000)] + 1.4
4-boiler	[(0.00273)(PMCR/1000)] + 1.32
5-boiler	[(0.011)(PMCR/1000)] + 1.71

In this subsection of the program, the user has the option of selecting either multiple coal piles or a single pile as the method of long-term coal storage. The user also has the option of selecting the number of days of long-term and short-term storage. Both sets of equations base the coal storage on the amount of coal the plant requires while operating at the PMCR.

To calculate the long-term storage area, the user must enter the following:

1. number of days long-term coal storage
   range: 60 to 100 days
   default: 90 days
2. long-term coal storage capacity (lb)
   = (days long-term storage)(coal @ PMCR-lb/hr)(24 hr/day)

   coal storage area calculations:
3. long-term single pile area (acres)
   = [(days long-term storage)(coal @ PMCR-lb/hr)(24 hr/day) /(70 lb/CF)(15 ft high)] + 2700 sq ft + (104)[SQRT](days long-term storage)(coal @ PMCR)(24 hour/day) /(70)(15) / (43,560 sq ft/acre)
4. long-term multi pile area (acres)
   = ([(days long-term storage)(coal @ PMCR)(24 hr/day)/350 lb/sq ft] / (43,560 sq ft/acre)

To calculate the area required for the short-term pile area, the user must input (1) the number of days short-term coal storage (range: 1 - 3 days, default: 1 day) and (2) the short-term pile capacity (tons) = (days short-term storage)(coal @ PMCR) (24 hr/day)

If the capacity is 200 tons or less, the pile area is 45 ft in diameter and the area requirement is 0.1 acre. If the capacity is larger than 200 tons, the program first calculates a pile length for the area determination.

pile length (ft) = [(days short-term storage)(coal @ PMCR) (24 hrs/day)/ 9] - 22

pile area (acres) = [(days short-term storage)(coal @ PMCR) (24 hr/day)/9 + 38] (75 ft)/43560 sq ft/acre

circulation area = 0.5 acre

reclaim area = 0.5 acre

long-term coal storage area (acres) = (long-term pile area) + (short-term pile area) + (circulation area) + (reclaim area).

Fuel Storage Area - COS, CWS

The long-term fuel storage area includes the long-term fuel storage tanks with individual diked areas and a circulation allowance for tank truck deliveries. The screening model area calculations are based on storing 90 days of fuel.

In this subsection, the user has the option of selecting the number of days of long-term fuel supply to be stored. The equations are based on the amount of fuel required by the plant while operating at the PMCR.

Coal Storage Rain Runoff Pond - Stoker, CFBC, BFBC

TM 5-848-3 requires a runoff pond for the long-term coal storage area. The pond must be sized to contain the runoff from a 10-year, 24-hour storm with 2 ft of freeboard. The conceptual sizing method uses an average pond water depth of 4 ft and sizes the pond for 4 in. of rain in 24 hours, with no absorption. For conceptual design this is reasonable since the pond can be dug deeper for higher rainfalls without affecting the plan area. The design goal of the pond is to conform to the requirements of TM 5-848-3.

Railroad Track Spur Length

The railroad track spur length is the linear feet of single railroad track required to store empty and full rail cars. The length does not include space for track switches. This parameter is encountered in the program when a user selects the option of receiving coal by rail.

Stoker, CFBC, BFBC. The length of single track is based on railroad clearances published in Stephens-Adamson Manufacturing Company's General Catalog Number 66 for 70-ton railroad hopper cars. The track length is calculated based on receiving enough coal three times per week to operate the plant at the PMCR.

COS, CWS. The length of single track is based on railroad tank car clearances of 40 ft per car. The track length is calculated based on receiving enough fuel three times per week to operate the plant at the PMCR.

Weighted Factors

To include nonquantitative factors in evaluating the feasibility of building a new coal-fired heating plant, weighted factors have been included in the program to scale several subjective factors. The subjective factors are evaluated by the response to questions. The allowable responses are listed, and for each response, the program explains the consequences of the reply. A weighted numerical analysis is provided in the output. The model adds these factors at the end of the program. A higher sum is more desirable than a lower one. The weighted factor questions are listed below.

1. Is rail transportation available for coal/limestone? Y/M/N
2. Is highway transportation available for coal/limestone? Y/M/N
3. Ash disposal requirements are estimated to be ____ ton/day @ PMCR. Are there available sites for ash disposal?
   a) No landfill is on or near base.
   b) Landfill is near base.
   c) Landfill on base not adjacent to plant site.
   d) Landfill is on base and adjacent to plant site.
4. Effluent discharge at PMCR has been estimated to be ____ gpm. Is local sewage disposal available for boiler water discharge?
5. Is transportation of coal and/or ash through the community and/or base feasible? Y/M/N
6. Would the local community impose resistance to building a new boiler plant? Y/M/N
7. Is sufficient city water available for central steam plant makeup water requirements ? Y/M/N
8. Will a new electrical substation be required for the new central heat plant load? Y/M/N
9. Limestone requirements at PMCR have been estimated to be ____ tons/day. Is limestone available for the FBC boiler technology selected ? Y/M/N
10. Lime requirements have been estimated to be ____ tons/day. Is lime available for stoker boiler stack gas sulfur removal equipment? Y/M/N
11. How accessible is the existing steam distribution system?
    a) Routing is very long and/or difficult.
    b) Routing is fairly accessible and medium length.
    c) Routing is short and accessible.
12. What is the present condition of the existing steam or high temperature hot water distribution system?
    a) Poor Condition
    b) Fair
    c) Good.

Plant Emissions

To determine if the proposed plant will meet emission standards, the plant emissions section calculates the emissions and compares the results to the EMISSION data base. To do this however, the user must choose a region of a state if requested to do so while running the program. To calculate the particulate, SO_x, and NO_x (lb/ton of coal burned) emissions, factors were determined for each boiler type and coal type. Table 7 lists these factors. Table 8 lists the pollution control equipment factors used to determine the pollutants exiting the gas cleanup equipment.

Cogeneration Screening Model

The cogeneration plant screening model follows the same pattern as the new heating plant screening model. The following discussion reviews each section, including the inputs required as well as the logic and actions represented in the computer model.

Table 7. Pollutant factors.

Boiler Types*	Coal Type**	Particulates†	SO_x††	NO_x
Dump grate spreader stoker;				
Vibrating grate;	B, S	20	38	15
Traveling grate				
w/ fly ash reinjection	B, S	13	38	15
w/o fly ash reinjection	L	7	30	6
Traveling grate stoker; Chain grate	A	1	38	10
	B, S	5	38	15
	L	3	30	6
Coal-oil slurry		25	38	18
Coal-water slurry		25	38	18
Bubbling fluidized bed combustion (BFBC)	A, B, S	24	8	15
	L	8	8	6
Circulating fluidized bed combustion (CFBC)	A, B, S	20	5	15
	L	7	5	6

*In lb/ton of coal burned.
**A - anthracite; B - bituminous; L - lignite; S - subbituminous.
† value in weight percent of ash in coal.
†† value in weight percent of sulfur in coal.

Table 8. Pollution control equipment factors.*

Boiler Type	Setting Chamber	Mechanical Collector	Dry Scrubber	Baghouse
Spreader stoker	0.8	0.15	0.15	0.005
Traveling grate stoker	0.9	0.7	0.15	0.005
Chain grate stoker	0.9	0.20	0.15	0.005
Coal-oil slurry	0.99	0.7	-	0.005
Coal-water slurry	0.99	0.7	-	0.005
Bubbling FBC	0.9	0.20	-	0.005
Circulating FBC	0.99	0.25	-	0.005

*Fraction out/in.

Plant Site Information

See the New Heating Plant Screening Model page 55.

Cogeneration Plant Monthly Loads

The cogeneration plant load demand calculation requires the same information as the new heating plant screening model: the type of boiler plant to be built (steam only), the average hourly steam demand for each month in pounds per hour or in MBtu/hr for hot water, and the process steam demand for each month in pounds per hour (only for steam). The model also requires information about the average and peak electrical loads. The user must input these values and confirm that they are correct before continuing.

Cogeneration Plant Maximum Continuous Rating Calculation

The cogeneration plant load demand calculations are based on the PMCR required for heating. The values entered for peak and average electrical demand determine the operating mode for the plant to meet heating demand or electrical demand. The values have no effect, however, on the PMCR, which is derived only from heating and process loads. For the model, power is generated from turbines operating at steam inlet pressures of 600 or 1300 psig and an outlet pressure of 150 psig. Additional power can be generated in the summer by the steam not used for heating.

Figure 8 is an example plot of heating steam demand versus month of year. The figure shows the plant's low, average, and maximum (peak) monthly steam flows and the minimum turbine condensing steam flow required for electrical generation. A minimum amount of steam equal to 20 percent of PMCR is required to operate the

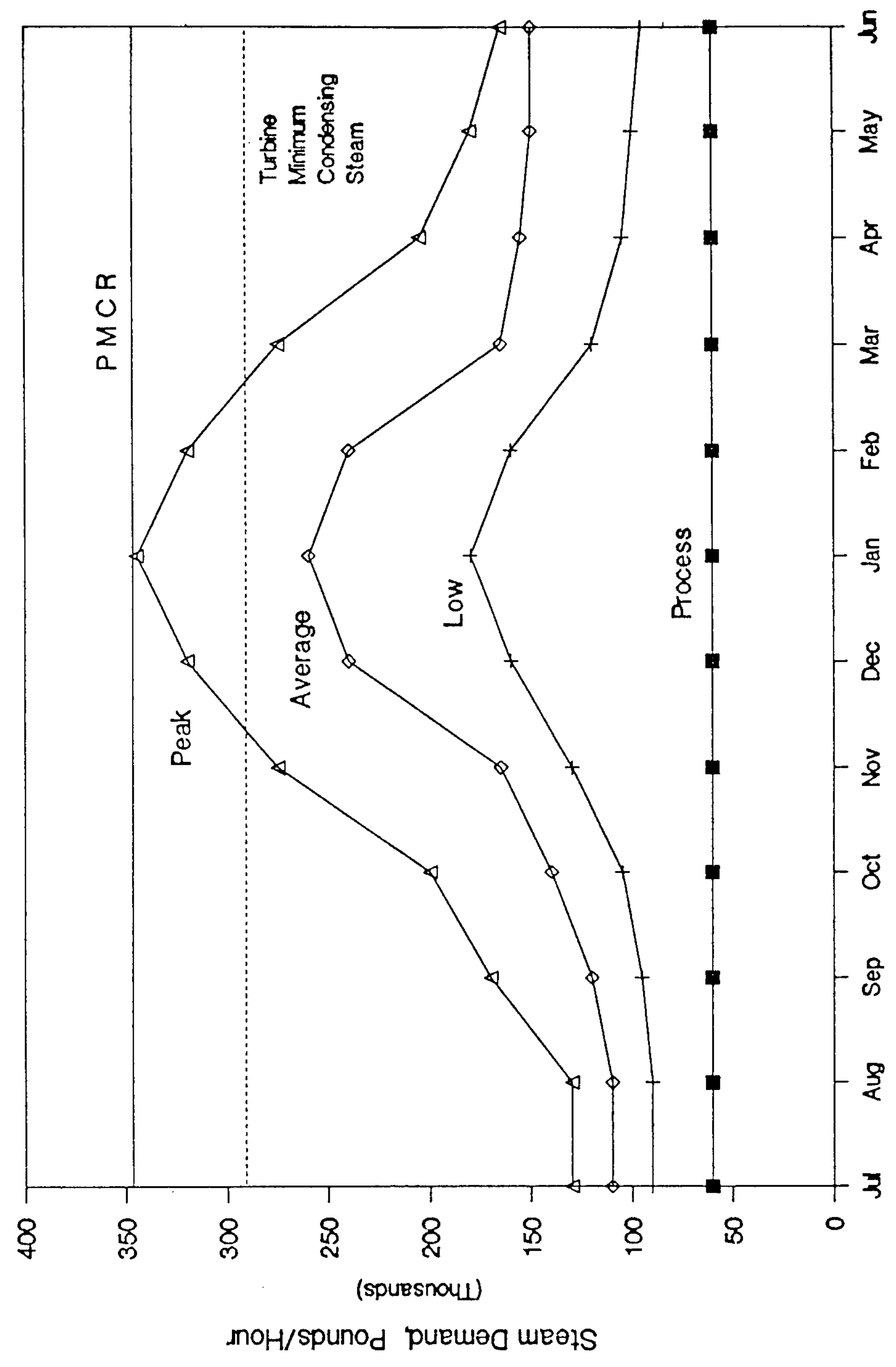

Figure 8. Representative plot of steam demand vs. month for cogeneration plant.

turbine. If this minimum amount does not exist, the turbine cannot operate nor generate electricity.

Boiler Technology

See the New Heating Plant Screening Model, page 58.

Conceptual Boiler Sizing

See the New Heating Plant Screening Model, page 59.

Fuel Search

See the New Heating Plant Screening Model, page 60.

Water Requirements

See the New Heating Plant Screening Model, page 60.

Plant/Boiler Performance Estimates

Except for the higher steam pressure input value, the plant/boiler performance estimates are similar to calculations in the New Heating Plant Screening Model. See page 61.

Plant Area Requirements

To determine whether sufficient area is available to build a new cogeneration plant, the program calculates the plant area, coal storage rain runoff pond area, and coal storage areas. The sum of these is the total area required to build a new cogeneration plant. The program also calculates the required rail track length and the plant height, stack height, and building size.

The plant acreage is the area required by the boiler plant. This area includes the boiler plant building, fuel and lime storage, air pollution control devices (baghouses), I.D. fans, stacks, coal handling, limestone handling, ash handling, roads, and parking. The total area is calculated using the equations in Table 6.

Coal Storage Area - Stoker, CFBC, BFBC

See the New Heating Plant Screening Model, page 62.

Coal Storage Rain Runoff Pond - Stoker, CFBC, BFBC

See the New Heating Plant Screening Model, page 64.

Railroad Track Spur Length

See the New Heating Plant Screening Model, page 64.

Weighted Factors

To include nonquantitative factors in evaluating the feasibility of building a new coal-fired cogeneration plant, weighted factors have been included in the program to scale several subjective factors. The subjective factors are evaluated by the responses to questions. The allowable responses are listed, and for each response, the model explains the consequences of the reply. A weighted numerical analysis is provided in the output. The program adds these factors at the end of the program. A higher sum is more desirable than a lower one. The weighted questions (12 through 24) are listed below. For questions 1 through 11 see the New Heating Plant Screening Model page 65.

12. How many hours per year will the plant be operated?
    a. Less than 4000 hrs
    b. 4000- 6000 hrs
    c. Greater than 6000 hrs
13. Is the existing electric distribution system conducive to a single point electric supply and metering such that the cogenerated electricity can displace the purchased power? Y/M/N
14. Is it likely that the energy demand will be curtailed in the foreseeable future? Y/M/N
15. Will the utility supply service to maintain and repair interconnection facilities? Y/M/N
16. Will the local electric utility be cooperative in setting the electrical interconnections and stand-by power costs?
17. Does a local electric utility use coal as their primary fuel? Y/M/N

18. What is the facility's power load factor? Where: The load factor is determined by dividing the average annual hourly load by the annual peak hourly load.
    a. Less than 30%
    b. 30 - 40%
    c. Over 40%
19. What is the facility's annual power to annual steam ratio? Where: ratio = Pe/H = annual electric (kWh/yr)/annual steam (MMBtu/yr)
    a. Less than 35 kWh/MMBtu
    b. 35 - 75 kWh/MMBtu
    c. Greater than 75 kWh/MMBtu
20. What is the facility's average ratio of the hourly power to hourly steam for a typical day? Where: ratio = hourly electric (kWh/hr)/hourly steam (MMBtu/hr)
    a. Less than 35 kWh/MMBtu
    b. 35 - 75 kWh/MMBtu
    c. Greater than 75 kWh/MMBtu
21. What is the facility's electric load?
    a. Below 25 MW
    b. 25 - 50 MW
    c. Greater than 50 MW
22 A. What is the cost of fuel? $/MMBtu
   B. What is your present electric rate? $/kWh

The program will compare the cost of the fuel ($/MMBtu) to half the cost of utility-furnished electricity (cents/kWh).

23. The facility's steam or hot water load factor will be calculated and listed.
24. The facility's total PMCR will also be compared to the "feasible" cogeneration plant size (400 MMBtu/hr). The program will alert the user if the plant is too small.

Third Party Cogeneration Screening Model

The third party cogeneration screening model is essentially the same as the standard cogeneration screening model. The main difference is that the third party cogeneration plant is run at full capacity to generate electricity for use on the base and for sale to the outside.

Plant Maximum Continuous Rating Calculation

Determining the PMCR for the third party cogeneration site remains the same. The value, however, is treated differently when running the facility. Because the third party has the option of selling electricity to an outside consumer, the plant is modeled as running continuously at PMCR. The effect of these changes is shown in the cost analysis.

Third Party Cogeneration Questions

The following questions are asked in addition to those for the standard cogeneration analysis.

1. What is the current cost or expected future cost ($/MMBtu) of thermal energy provided by the user?
2. What is the expected future cost ($/MMBtu) of thermal energy provided to the user by the cogenerator?
3. What is the current demand or expected future demand (MMBtu/h) for thermal energy output by the user?
4. What is the current or expected future average utilization load factor of the thermal energy facility? (Calculate load factor by dividing the average annual hourly load factor by the annual peak hourly load.)
5. How many hours per year is the thermal energy plant currently operated, or expected to be operated in the future?
6. What are the characteristics of thermal energy demand by the user? Will significant electric generation capacity be consistently available between 8:00 AM and 6:00 PM? Y/M/N
7. What are the characteristics of thermal energy demand by the user? Will significant electric generation capacity be consistently available from July 1st to September 15th? Y/N/M
8. What is the expected cost of electricity ($/kWh) that will be produced by the cogeneration facility, given today's fuel prices?
9. What electric buyback rates ($/kWh) are currently available from the local utility? This should include both avoided energy cost payments (kWh) as well as avoided capacity cost payments (kW), if available.
10. If the cogeneration facility will supply the user with electricity as well as thermal energy, what is the current rate or expected future rate ($/kWh) for electricity experienced by the user?

11. If the cogeneration facility will supply the user with electricity as well as thermal energy, what is the most likely rate ($/kWh) that the cogenerator will offer to the user?
12. What is the potential electrical output (MW) of the cogeneration facility, given the expected thermal energy demand of the user?
13. Is the local utility capacity-constrained? (Does there appear to be a shortfall of electric generation supply in the foreseeable future?)
14. Is wheeling of cogenerated electricity to other demand centers a realistic alternative to local utility buybacks? Y/M/N
15. Does the existing heat plant require retrofit, repair, or expansion? Y/M/N
16. Will the thermal output of the facility be no less than 5 percent of total energy output? Y/N
17. Will electric power output plus one-half the useful thermal energy output be no less than 42.5 percent of the fuel heat input if the useful thermal energy is at least 15 percent of the total, and not less than 45 percent otherwise? Y/N

Consolidation Screening Model

The consolidation screening model determines the feasibility of building a central heating plant to replace several smaller heat generators. It analyzes the steam distribution system by questioning the user about various aspects of the proposed plant. If analysis indicates that the plant is a practical option, the user can then evaluate the heating plant screening and costing models. After determining the total cost for the consolidated plant, comparison of the total costs with the sum of the costs for the existing heat generators will estimate the economic viability of the central heating plant.

General Information

The consolidation screening model is the same as the new plant screening model except for the addition of connecting lines for tying together the previously isolated individual lines. The format of information required, as well as the questions for this screening model, are identical to the new plant screening model general questions.

Consolidation Questions

In addition to general questions (see the New Heating Plant Screening Model page 65), the following questions are asked to determine the feasibility of building a centralized heating plant.

1. Does the base have a relatively flat load profile during the typical day? Y/M/N

2. Please enter the area to be served by the proposed distribution system: (in acres)

This request is used to evaluate the load density for the proposed plant. The program then calculates the load density using the PMCR calculated from the heating/process loads. (If the load density is less than 0.3 million Btu/hr/acre, the site is a poor choice for consolidation because it does not have a high heat load density. If the load density is greater than 0.3 million Btu/hr/acre, the site is a good candidate for consolidation because it has a high heat load density.)

3. Can you convince officials and operators of existing buildings of the advantages of a centralized heat plant? Y/M/N
4. Is the distribution system going to be hot water or steam?
   a. Hot Water
   b. Steam
5. Do the existing buildings use steam or hot water for heating? Y/M/N
6. Does the base have a process steam load that will be included in this consolidation and requires steam at greater than 200 psi? Y/N

Retrofit Screening Model

The Retrofit Screening Model can be used to determine the feasibility of retrofitting existing boilers to coal-fired boilers producing 150 psig saturated steam or equivalent hot water. The retrofit boiler options include:

- A heavy oil stoker to a coal stoker,
- A coal stoker to slagging combustion,
- A heavy oil package boiler to slagging combustion,
- A heavy oil package boiler to coal-oil slurry,
- A heavy oil package boiler to coal-water slurry,
- A heavy oil package boiler to micronized coal, and
- A heavy oil package boiler to fluidized bed combustion.

The program prompts the user to supply necessary information describing the requirements and resources available. Based on the information supplied and internal program information, the output gives conceptual area requirements, boiler derate estimates, boiler performance estimates, fuel storage area requirements, location site information, boiler coal specifications, coal analysis, allowed emissions, calculated emissions, and water requirements. Additionally, a weighted analysis is provided for the subjective factors involved when deciding to retrofit a boiler.

The retrofit screening model is divided into nine sections. Each section focuses on a specific aspect of retrofitting a boiler. For each of these sections, user inputs are required to evaluate relevant criteria. The following discussion reviews each section.

Plant Site Information

See the New Heating Plant Screening Model, page 56.

Heating Plant Monthly Loads

See the New Heating Plant Screening Model, page 56.

Heating Plant Maximum Continuous Rating Calculations

This section uses the same PMCR calculations as the New Heating Plant Screening Model (pages 56 through 58). It is checked, however, against the boiler sizes adjusted by derating factors that indicate the expected reduction in capacity that will occur for the retrofit.

Boiler Technology

This section of the screening model analyzes the type of boiler selected. The original boilers must all be of the same type, and must be retrofitted to the same new type. The choices are:

1. Heavy oil stoker to coal stoker
   a. Spreader stoker with traveling grates
      i. With fly ash reinjection
      ii. Without fly ash reinjection
   b. Dump grate spreader stoker
      i. With fly ash reinjection
      ii. Without fly ash reinjection
   c. Spreader stoker with vibrating grate
      i. With fly ash reinjection
      ii. Without fly ash reinjection
   d. Spreader stoker with reciprocating grate
      i. With fly ash reinjection
      ii. Without fly ash reinjection
   e. Chain grate stoker
   f. Traveling grate stoker

2. Coal stoker to slagging combustion
3. Heavy oil package boiler to slagging combustion
4. Heavy oil package boiler to coal-oil slurry
5. Heavy oil package boiler to coal-water slurry
6. Heavy oil package boiler to micronized coal
7. Heavy oil package boiler to fluid bed combustion

Conceptual Boiler Sizing

The retrofit of boilers requires that they have an identified capacity. Each retrofit results in some reduction of capacity for the boilers based on the type of retrofit. For this program routine, the user is asked for the current capacity of the boilers, the number of boilers to be retrofitted, and the maximum continuous rating of each boiler. Using these values, the program calculates the new, derated capacity. This is compared to the heating/process load PMCR to determine if the plant can meet the expected PMCR.

The program will calculate the approximate retrofitted maximum continuous rating and allow the user to continue with the program depending on whether the derate is acceptable. The derate factors for each technology are:

0	percent	Heavy oil stoker to coal stoker
7.5	percent	Coal stoker to slagging combustion
37.5	percent	Heavy oil package boiler to slagging combustion
25	percent	Heavy oil package boiler to coal-oil slurry
30	percent	Heavy oil package boiler to coal-water slurry
27.5	percent	Heavy oil package boiler to micronized coal
35	percent	Heavy oil package boiler to fluid bed combustion

The size range of each retrofit technology is listed below. If the derated boiler size does not fit within the range, the program will alert the user.

20,000 - 200,000 lb/hr	Dump grate spreader stoker
20,000 - 125,000 lb/hr	Spreader stoker with vibrating grate
20,000 - 125,000 lb/hr	Spreader stoker with reciprocating grate
75,000 - 200,000 lb/hr	Spreader stoker with traveling grate
20,000 - 150,000 lb/hr	Traveling grate stoker
20,000 - 150,000 lb/hr	Chain grate stoker
50,000 - 200,000 lb/hr	CFBC boiler
20,000 - 100,000 lb/hr	BFBC boiler
20,000 - 200,000 lb/hr	COS boiler

20,000 - 200,000 lb/hr	CWS boiler
20,000 - 200,000 lb/hr	Micronized coal boiler
40,000 - 200,000 lb/hr	Slagging coal boiler

Fuel Search

The fuel search requires the user to enter the radius in miles from the base for the fuel search. For the stoker, slagging, micronized, FBC, and low-Btu boilers, the program searches the COALFIELD data base for coal deposits within the specified radius and compares the required coal specifications of the chosen boiler type to determine which coal deposits can be used. Table 9a, 9b, and 9c show the coal specifications for the micronized, slagging and low-Btu boiler technologies, respectively. The deposits are sorted according to coal type (lignites, bituminous, anthracite) and arranged according to heating value. For the chosen coal deposit, the coal type, heating value, and proximate analysis are displayed. At this point, the user has the option of choosing the fuel for analysis, changing the radius of the fuel search, or further eliminating coal mines by specifying a maximum percent sulfur limit.

Table 9a. Micronized boiler coal specifications.

Parameter	Anthracite	Bituminous	Subbituminous	Lignite
Moisture*	2-5%	15-20%	15-20%	25-45%
Volatile Matter*	6-11%	30-40%	30-40%	30-45%
Fixed Carbon*	65-85%	40-50%	40-50%	40-55%
Ash*	10-20%	5-20%	5-20%	5-20%
Heating Value (Btu/lb)	11,500-13,000	8,300-11,500	8,300-11,500	6,300-8,300
Grindability Index	50-110	50-105	35-50	35-45

*Proximate analysis.
Notes: Hemispherical ash softening temperature (H=1/2W reducing) 2500 °F minimum.
Free swelling index: 9 maximum

Table 9b. Slagging boiler coal specifications.

Parameter	Bituminous	Subbituminous
Moisture*	0-15%	10-30%
Volatile Matter*	30-40%	20-40%
Fixed Carbon*	40-50%	30-50%
Ash*	5-15%	5-15%
Heating Value(Btu/lb)	10,500-14,000	8,300-11,500

*Proximate analysis.
Notes: Hemispherical ash softening temperature (H=1/2W reducing) 2200 °F minimum.
Free swelling index: 9 maximum

Table 9c. Fixed-bed two-stage gasifier coal specifications.

Parameter	Bituminous	Subbituminous	Lignite
Moisture*	0-35%	0-35%	0-35%
Volatile Matter*	20-40%	20-40%	20-40%
Fixed Carbon*	42-62%	42-62%	42-62%
Ash*	5-20%	5-20%	5-20%
Heating Value (Btu/lb)	12,000-14,000	9,000-11,00	7,000-11,400

*Proximate analysis
Notes: Grindability index: 40-70
Hemispherical ash softening temperature (H=1/2W reducing) 2200°F minimum
Free swelling index: 3 maximum

Water Requirements

See the New Heating Plant Screening Model, page 60.

Plant/Boiler Performance Estimates

This section calculates the heat and mass balance for the total boiler plant at PMCR. The basic assumption is that the boilers are equivalent in efficiency.

The program begins with key boiler data inputs. The boiler sections calculate the ASME boiler efficiency, air requirements and flow, products of combustion and flow, and the flue gas specific heats.

There are three versions of the program: one for a coal-fired plant with a dry scrubber and baghouse used for gas cleanup; one for limestone injection into the boiler; and one for coal slurry plants and micronized coal-fired plants.

Stoker Boiler Plant With a Dry Scrubber and Baghouse. This program is used for stoker and micronized coal technology. In addition to the boiler calculations, this program includes a dry scrubber material and energy balance that calculates the dry scrubber lime and water requirements, flue gas flows, and several flue gas specific heats. These are calculated from the inlet of the scrubber through the baghouse and into the stack. The boiler section includes the boiler superheater, economizer and/or air heater, and all associated fans, pipes, and controls needed to introduce air and fuel into the system. The scrubber and baghouse section includes the necessary equipment required to introduce air, water, and lime into the system.

AFBC Boiler Plant Equipped With a Baghouse. This program is used for BFBC, CFBC, and slagging boilers. It calculates and displays boiler information required for

sizing a retrofit FBC boiler plant equipped with a baghouse. The boiler section includes the furnace, boiler, superheater, economizer and/or air heater, and all associated fans, pipes and controls needed to introduce air, fuel, and limestone into the system.

Plant Area Requirements

To determine whether sufficient area is available to build a coal-fired boiler, the program calculates coal storage rain runoff pond area, coal storage area, and rail track length.

Coal Storage Area - Stoker, CFBC, BFBC

See the New Heating Plant Screening Model, page 62.

Coal Storage Rain Runoff Pond - Stoker, CFBC, BFBC

See the New Heating Plant Screening Model, page 64.

Railroad Track Spur Length

See the New Heating Plant Screening Model, page 64.

Weighted Factors

To include nonquantitative factors in evaluating the feasibility of building a retrofit coal-fired heating plant, weighted factors have been included in the program to scale several subjective factors. The subjective factors are evaluated by responses to questions. The allowable responses are listed, and for each of these responses, the program explains the consequences of the reply. A weighted numerical analysis is provided in the output. The model adds these factors at the end of the program. A higher sum is more desirable than a lower one. The weighted questions are listed below (for questions 1 through 5 and questions 7 through 11, see the New Plant Screening Model, page 65).

6. Would the local community offer resistance to building a new boiler plant? Y/N/M
12. Is there enough room to install an ash handling system? Y/M/N
13. Is there enough room to install air pollution control equipment? Y/M/N
14. Is there enough room to install a new combustion control system? Y/M/N

15. Is there enough room to install fuel burning equipment? Y/M/N
16. Can the boiler be retrofitted without major boiler/equipment modifications? Y/M/N
17. Does the boiler house allow the boiler(s) to be retrofitted without major structure changes or modifications? Y/M/N
18. Is the facility's stack suitable for use? Y/M/N
19. Are the feedwater pumps, deaerator, condensate system, and raw water treatment adequate and in a good state of repair? Y/M/N
20. Is the auxiliary fuel system adequate to support the retrofit technology? Y/N
21. Is the facility/boiler in a condition that requires major nonretrofit repair or replacement? Y/M/N
22. Is existing coal handling equipment available? If so, what is the condition of the equipment?
    a. The equipment does not exist or is beyond repair.
    b. Equipment requires major overhaul.
    c. Equipment requires minor overhaul.
23. Is existing ash handling equipment available? If so, what is the condition of the equipment?
    a. The equipment does not exist or is beyond repair.
    b. Equipment requires major overhaul.
    c. Equipment requires minor overhaul.
24. Does the boiler house have a basement? Y/M/N
25. Is the soot-blowing system in proper working order? Y/M/N

Plant Emissions

To determine if the proposed plant will meet emission standards, this section calculates the plant emissions and compares it to the EMISSION data base. To compare the calculated emissions with the EMISSION data base, the user must choose a region of a state if requested to do so while running the program.

To calculate the particulate, SO_x and NO_x (lb/ton of coal burned) emissions, standard factors are determined for each boiler and coal type.

4 Equipment Sizing

New Heating Facility

This section describes the equations and designs used to calculate coal-fired plant area requirements and plant cost equations for a new heating facility. The following list includes the general topics in this section.

Equipment Lists
Coal Handling and Storage Equipment Sizing
Fuel Handling and Storage Equipment Sizing
Ash Handling and Storage Equipment Sizing
Dry Scrubber for Sulfur Control
Baghouse Sizing
Lime/Limestone Handling and Storage
Boiler Water Treatment
Facility Tank Sizing
Major Facility Fans
Major Facility Pumps
Facility Auxiliary Equipment

Equipment Lists

The major equipment that can be included in a boiler technology design is listed in Tables 10 through 12. The equipment included in a particular conceptual design depends on inputs and selections made in the costing models.

Table 10. Major facility equipment - stoker boilers.

System	Equipment
Coal handling	rail car mover
	rail car thawing shed with thawing pit
	double track hopper
	car shaker
	coal receiving feeder
	double roll crusher
	take away belt conveyor
	truck hopper
	bucket elevator
	coal silo belt feeder
	magnetic separator
	reversing belt conveyor
	coal silo
	stock conveyor with telescoping chute
	reclaim hopper
	reclaim feeder belt conveyor
	reclaim belt conveyor
	transfer house bucket elevator
	bunker tripper conveyor
	coal bunker
	barge receiving with barge unloader and belt conveyor
Ash handling	bottom ash conveying piping system
	mechanical collector conveyor piping system
	dry scrubber collector conveyor piping system
	baghouse collector conveyor piping system
	ash receiver
	bag filter
	ash silos
	air blowers (to vacuum convey ash)
	ash conditioner (one per silo)
Dry scrubbers	rotary atomizer type
	one scrubber per boiler
Baghouse	reverse air or pulse jet type
	one baghouse per boiler
Lime handling	storage silo
	mechanical conveyor
	day storage bin
	mechanical conveyors
	lime feeders
	lime slakers
	grit screen and grit drop box
	lime dilution tank
	lime slurry pumps

System	Equipment
Boiler water treatment	sodium zeolite softening with brine tank brine wastewater tank demineralizer with degasification neutralization tank acid and caustic tank demineralizer with degasification and mixed bed demineralizer mixed bed demineralizer dealkalizer
Water tanks	condensate storage treated water storage deaerator deaerator water storage facility fuel oil storage
Fans	forced draft (F.D.) fans induced draft (I.D.) fans overfire air fans
Pumps	boiler feedwater motor driven boiler feedwater turbine driven treated water pumps condensate pumps track hopper sump truck hopper sump reclaim hopper sump neutralization brine wastewater pond neutralizer
Air compressors	plant
Stacks	concrete chimney with steel flues
Blowdown tanks	continuous intermittent
Chemical injection skid	
Fire protection system	
HVAC system	
Elevator	
Facility controls	boilers yard
Electrical substation	
Continuous emission monitoring system	SO_2, NO_x and opacity
Boiler water laboratory	

System	Equipment
Mobile equipment	front-end loaders forklift drop boxes pickup truck power sweeper dump truck
Furniture	
Plant communications	
Tools	hand tool room
Diesel generator	
Spare parts	
Piping	
Initial facility inventory of consumables	

Table 11. Major facility equipment - CFBCs and BFBCs.

System	Equipment
Coal handling	rail car mover
	rail car thawing shed with thawing pit
	double track hopper
	car shaker
	coal receiving feeder
	vibrating grizzly feeder
	double roll crusher
	take away belt conveyor
	truck hopper
	bucket elevator
	coal silo belt feeder
	magnetic separator
	reversing belt conveyor
	coal silo
	stock conveyor with telescoping chute
	reclaim hopper
	reclaim feeder belt conveyor
	reclaim belt conveyor
	transfer house bucket elevator
	bunker tripper conveyor
	coal bunker
	barge receiving with barge unloader and belt conveyor
Ash handling	bottom ash conveying piping system
	mechanical collector conveyor piping system
	dry scrubber collector conveyor piping system
	baghouse collector conveyor piping system
	ash receiver
	bag filter
	ash silos
	air blowers (to vacuum convey ash)
	ash conditioner (one per silo)
Baghouse	reverse air or pulse jet type
	one baghouse per boiler
Limestone handling	storage silos
	silo belt feeders
	bucket conveyor
	bunker tripper conveyor
	day storage bin or silo

System	Equipment
Boiler water treatment	sodium zeolite softening with brine tank brine wastewater tank demineralizer with degasification neutralization tank acid and caustic tank demineralizer with degasification and mixed bed demineralizer mixed bed demineralizer dealkalizer
Water tanks	condensate storage treated water storage deaerator deaerator water storage facility fuel oil storage
Fans	forced draft (F.D.) fans induced draft (I.D.) fans overfire air fans
Pumps	boiler feedwater motor driven boiler feedwater turbine driven treated water pumps condensate pumps track hopper sump truck hopper sump reclaim hopper sump neutralization brine wastewater pond neutralizer
Air compressors	plant
Stacks	concrete chimney with steel flues
Blowdown tanks	continuous intermittent
Chemical injection skid	
Fire protection system	
HVAC system	
Elevator	
Facility controls	boilers yard
Electrical substation	
Continuous emission monitoring system	SO_2, NO_x and opacity
Boiler water laboratory	

System	Equipment
Mobile equipment	front-end loaders forklift drop boxes pickup truck power sweeper dump truck
Furniture	
Plant communications	
Tools	hand tool room
Diesel generator	
Spare parts	
Piping	
Initial facility inventory of consumables	

Table 12. Major facility equipment - COS and CWS.

System	Equipment
Coal handling	rail car mover
	rail car heating shed
	tank car unloader house
	fuel receiving pumps
	fuel receiving meters
	fuel receiving piping
	long-term fuel storage tanks
	day tank transfer pumps
	day fuel storage tank
	boiler fuel pumps
	boiler fuel heaters
	boiler fuel piping
Ash handling	mechanical collector conveyor piping system
	baghouse collector conveyor piping system
	ash receiver
	bag filter
	ash silo
	air blowers (to vacuum convey ash)
	ash conditioner
Baghouse	reverse air or pulse jet type
	one baghouse per boiler
Boiler water treatment	sodium zeolite softening with brine tank
	brine wastewater tank
	demineralizer with degasification
	neutralization tank
	acid and caustic tank
	demineralizer with degasification and mixed bed demineralizer
	mixed bed demineralizer
	dealkalizer
Water tanks	condensate storage
	treated water storage
	deaerator
	deaerator water storage
	facility fuel oil storage
Fans	forced draft (F.D.) fans
	induced draft (I.D.) fans
	overfire air fans
Pumps	boiler feedwater motor driven
	boiler feedwater turbine driven
	treated water pumps
	condensate pumps
	track receiving sump
	neutralization
	brine wastewater

System	Equipment
Air compressors	plant
Stacks	concrete chimney with steel flues
Blowdown tanks	continuous intermittent
Chemical injection skid	
Fire protection system	
HVAC system	
Elevator	
Facility controls	boilers yard
Electrical substation	
Continuous emission monitoring system	SO_2, NO_x and opacity
Boiler water laboratory	
Mobile equipment	front-end loader forklift drop boxes pickup truck power sweeper dump truck
Furniture	
Plant communications	
Tools	hand tool room
Diesel generator	
Spare parts	
Piping	
Initial facility inventory of consumables	

Coal Handling and Storage Equipment Sizing - Stoker, CFBC, BFBC

This subsection describes the coal handling equipment and the sizing equations required to estimate the cost of the equipment. The design configuration depends on whether truck or rail is used, if a stock/reclaim is used, if car heating is required, and if a coal silo is required.

Rail Car Mover. A completely reversible, endless rope car mover system is used in the coal handling design. The items included are: a double drum with a running rope pull at the drums of 18,000 lb and a starting pull of 36,000 lb; a 20-horsepower (hp) motor with drive gear; and 1400 ft of a 1-in. diameter wire rope with two hitch rope assemblies, a take-up assembly, stationary bend sheave assemblies, travel limits, guards, track guides, and controls.

Rail Car Thawing Shed. The shed is to be included in the conceptual design if the facility is located in a region that experiences freezing conditions for at least 2 months each year or if the coal is purchased from such a region. The facility's auxiliary fuel tank is increased in size to accommodate shed thawing oil requirements. The designed shed is 18 ft wide by 16 ft high by 80 ft long; space enough for two rail cars. The building (shown in Figure 9) is a steel building manufactured by Butler and includes four (two per car) light oil-fired thawing pits, reflector shields, controls, etc. Each thawing pit is rated at 1 million Btu/hr heat input and has the following equipment: two burners, a steel outer shell, end plates with cast refractory, heat shield set, refractory set, encased tiles (one with an opening for the oil pilot), oil pilot assemblies (one per pit) with needle valve and strainer, burner enclosure (two per pit), cover hinged pit with fenders, and interconnecting piping and valves. The oil distribution piping, regulators, combustion air system, and burner controls are also included with the shed.

Double Track Hopper. The conceptual design encloses the rail hoppers in a building 18 ft wide by 45 ft long by 18 ft high. Each hopper is steel construction, 13 ft by 28 ft, and has a 40-ton capacity. The hoppers have a top grating of 6-in. square mesh steel bars and a concrete perimeter. The hoppers include track girders that will support a 100-ton rail car. The bottom of the hoppers have a slide gate shut off.

The hoppers are located in a pit approximately 25 ft wide by 45 ft long by 35 ft deep. The coal receiving feeders, vibrating grizzly feeder, double roll crusher, receiving end of the take-away belt conveyor and a sump pump are also located in the pit.

Car Shaker. The car shaker is in the track hopper building described with the double track hopper. The shaker is a stationary installation and includes all equipment for

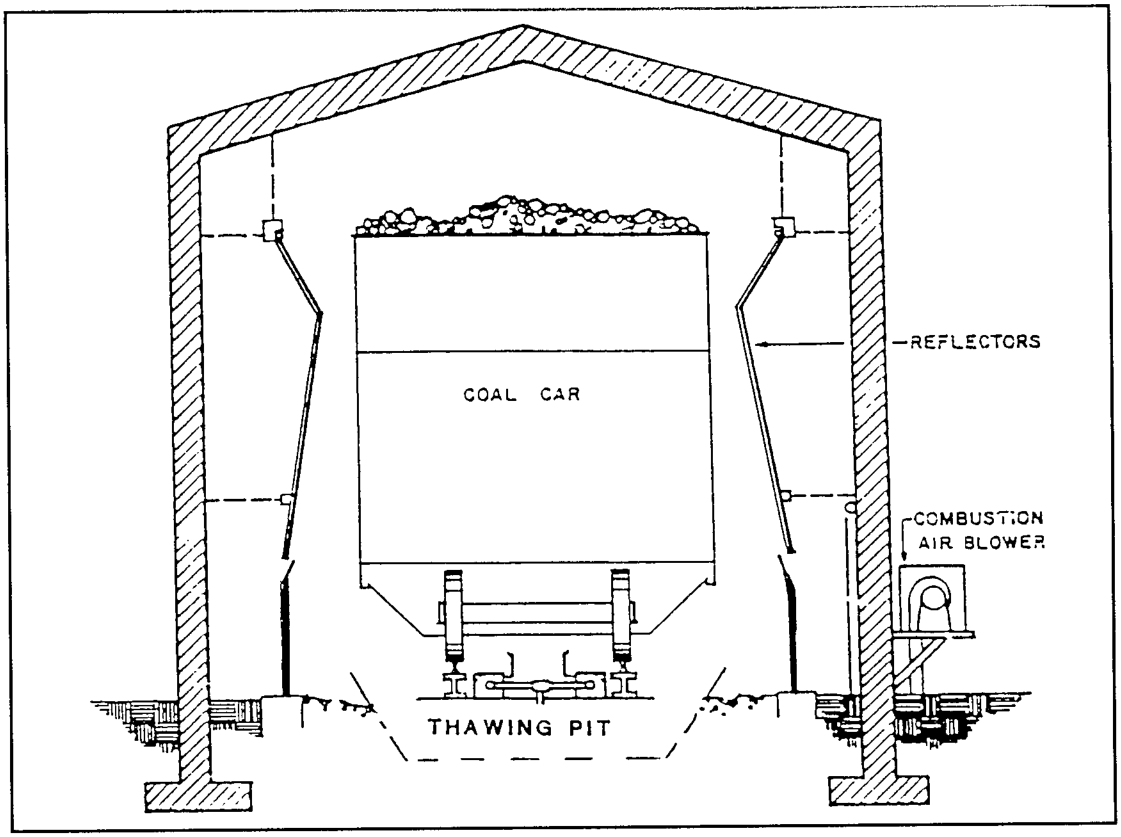

Figure 9. Rail car thawing shed.

a complete installation (i.e., base plate, boom, shaker assembly, power unit, hydraulic system, etc.). The shaker requires a 25-horsepower hp motor to drive the hydraulic unit that shakes the rail car.

The shaker is supported by a boom assembly mounted on base plates. The purpose of the boom assembly is to retract the shaker outside the rail car clearance line. The boom also extends the shaker until the top shoe is over the side of the car. The shaker is then lowered into place and hangs on the side of the car. The lower hook is then positioned under the car and locked into place and the support cables are slackened. At this point the shaker becomes a part of the car. The valve for the shaker motor is closed and the shaker begins to operate. After the car is unloaded, the shaker is stopped, disconnected, and retracted.

Coal Receiving Feeder. The feeder is a conveyor belt and the related equipment (i.e., motor, stop/start controls, drive system, idlers, belts, skirts, discharge hopper and hood, belt wiper, platform, etc.).

Vibrating Grizzly Feeder. The grizzly feeder is located at the discharge end of the coal receiving feeder. It will screen the coal for size, allowing undersize coal to bypass the

crusher. The larger pieces of coal will be fed into the crusher for sizing. The grizzly includes a bar screen, 3-hp motor, skirts and discharge hopper, controls, etc.

Crusher. The crusher is an adjustable, double-roll crusher for coal sizing. The crusher includes a 10-hp motor, discharge hopper, controls, and other necessary components.

Take Away Belt Conveyor. This conveyor transports below grade the received coal from the grizzly/crusher to the bucket elevator. The head end of the conveyor is about 30 ft underground and the tail or discharge end about 10 ft underground. The conveyor tunnel is 10 ft wide by 10 ft high and ends in the bucket elevator shaft pit. The belt is 24 in. wide. Its major components include head shaft, tail shaft and take-up, drive and motor, idlers, frame, support, skirts, discharge hopper and hood, belt wiper, and controls.

Truck Hopper. The conceptual design encloses the truck hoppers in a three-sided Butler building 15 ft wide by 30 ft long by 20 ft high in the front, tapering to 10 ft high in the back. Each hopper is steel, 12 ft by 24 ft, and has a 30 ton capacity. The hoppers have a top grating of 6-in. square mesh steel bars and a concrete perimeter, and a slide gate shut off in the bottom. The hopper can support a 35-ton truck.

The hopper is located in a pit approximately 15 ft wide by 25 ft long by 25 ft deep. The only other piece of equipment in the pit is the receiving end of the bucket elevator. The hopper is located next to the coal storage silo if one was selected; otherwise it is next to the transfer house.

Bucket Elevator. The bucket elevator receives coal from the take away belt conveyor and/or the coal silo belt feeder, whichever is applicable, or the truck hopper, and lifts the coal to approximately 12 ft above the reversing belt conveyor. The reversing conveyor is about 3 ft above the top of the coal silo or about 6 ft above the coal bunker tripper belt conveyor.

The bucket elevator is steel with "V" type bucket carriers moved by a continuous chain. The elevator is about 3 ft wide and comes complete with "boot" section, drive and motor, controls, bucket and chains, casing, platforms, hoist, and discharge "pantleg" chute.

Coal Silo Belt Feeders. These belt conveyors, one per coal silo, remove coal from the bottom of the silo and discharge the coal into the receiving chute of the bucket elevator. The conveyors are 18 inches wide. Components include a head shaft, tail shaft and take-up, drive and motor, idlers, frame, supports, skirts, discharge hopper and hood, belt wiper, and controls. The conveyor is included only with the coal silo option.

Magnetic Separator. The magnetic separator is a permanent rectangular belt magnet with suspension mounting hardware. A 1-ton capacity trolley hoist, a tramp iron chute, and a box at grade are included. The separator is at the end of the bucket conveyor and separates iron products from the coal.

Reversing Belt Conveyor. The reversing conveyor receives coal from the bucket elevator and sends it to the coal stock conveyor or a local stock-out pile, or to the coal bunker tripper conveyor depending on the direction of the conveyor and the coal system. The conveyor includes a head shaft, tail shaft, reversing gear, drive and motor, controls, frame supports, and skirts.

Coal Silos. The coal silos are an option the user can select. The silos are of steel or concrete stave construction with a flat bottom. Components include an inlet chute, dust collection, outlet neck, and slider gate. The silos are sized for 1 to 7 days (specified by the user) of coal storage based on the PMCR.

Stock Conveyor. The stock conveyor belt is about 24 in. wide and includes a head shaft, tail shaft and take-up, drive motor, idlers, frame, supports, skirts, discharge hopper and hood, belt wiper, and controls. The conveyor is at the same elevation as the coal silo or the bunker tripper belt conveyor (discussed later). The receiving end is located at the transfer house. The conveyor inclines downward to an elevation of approximately 35 ft above ground and discharges into a telescoping discharge chute above the coal stockout area.

Reclaim Hopper. The hopper is 15 ft square in plan with a top grating of 6-in. square mesh steel bars. The top of the hopper and grating is formed by concrete that extends 8 ft from each side. The grating is designed to support 50 tons. The hopper is steel and is located in a pit approximately 25 ft square by 25 ft deep. The pit encloses a feeder belt conveyor and the intake end of the reclaim conveyor.

Reclaim Feeder Belt Conveyor. Th reclaim feeder belt conveyor is the same as the coal receiving feeder (see page 91).

Reclaim Belt Conveyor. This 150-ft conveyor receives coal from the reclaim feeder belt conveyor and transports it up to the transfer house bucket elevator. The conveyor ends in the transfer house and includes: a head shaft, tail shaft and take-up, drive, motor, idlers, frame, supports, skirts, discharge hopper and hood, belt wiper, and controls.

Transfer House Bucket Elevator. This conveyor is constructed in the same manner as the bucket elevator. It is located in the transfer house and is included only if the

user selects coal silo storage. It elevates the coal about 40 ft to the reversing belt conveyor and includes the components described with the bucket elevator (see page 92).

Bunker Tripper Conveyor. The tripper belt conveyor receives coal from the reversing belt conveyor and discharges the coal into the coal bunkers above and adjacent to the boilers. Conveyor components include a tripper assembly, head shaft, tail shaft, drive, and motor, idlers, frame, supports, skirts, and discharge hood.

Coal Bunker. The coal bunkers, located inside the boiler house, are sized for 1 day of coal storage per boiler. Each boiler has its own bunker. The bunkers are of steel construction and can, if large enough, have common walls. The bunkers receive coal via the tripper belt conveyor.

Coal Storage Systems. The following coal handling and storage equipment is suggested for a facility that has an adjacent long-term coal storage area.

Truck receiving, 100 tons per hour (TPH) or less

- truck hopper with hopper pit and building
- bucket elevator with bifurcated chute
- transfer house
- magnetic separator
- bunker tripper conveyor
- coal bunker, 1 day.

Truck receiving, 125 to 150 TPH

- truck hopper with hopper pit and building
- bucket elevator with bifurcated chute
- transfer house
- magnetic separator
- reversing belt conveyor
- bunker tripper belt
- stock conveyor
- reclaim hopper with hopper pit
- reclaim belt conveyor
- transfer house bucket elevator
- coal bunker.

Rail receiving up to 150 TPH

- rail track
- rail car mover

- rail car thawing shed with thawing pits
- double track hopper with hopper pit and building
- car shaker
- coal receiving feeder
- vibrating grizzly feeder
- crusher
- take away belt conveyor and underground tunnel
- bucket elevator with elevator pit
- transfer house
- magnetic separator
- reversing belt conveyor
- bunker tripper conveyor
- coal bunker, 1 day.

Rail receiving up to 250 TPH

- rail track
- rail car mover
- rail car thawing shed with thawing pits
- double track hopper with hopper pit and building
- car shaker
- coal receiving feeder
- vibrating grizzly feeder
- crusher
- take away belt conveyor and underground tunnel
- bucket elevator with elevator pit
- transfer house
- magnetic separator
- reversing belt conveyor
- stock conveyor
- reclaim hopper
- reclaim feeder belt conveyor
- reclaim belt conveyor
- transfer house bucket elevator
- bunker tripper conveyor
- coal bunker, 1 day.

The following coal handling and storage equipment is reccommended for a facility lacking an adjacent long-term coal handling storage area.

Truck receiving, 100 TPH or less

- truck hopper with hopper pit and building

- bucket elevator with bifurcated chute
- transfer house
- magnetic separator
- single coal silo, 3 days
- coal silo belt feeder
- bunker tripper conveyor
- coal bunker, 1 day.

Rail receiving, 125 to 150 TPH

- rail track
- rail car mover
- rail car thawing shed with thawing pits
- double track hopper with hopper pit and building
- car shaker
- coal receiving feeder
- vibrating grizzly feeder
- crusher
- take away belt conveyor and underground tunnel
- bucket elevator with elevator pit
- magnetic separator
- single coal silo, 3 days
- coal silo belt feeder
- reversing belt conveyor
- bunker tripper conveyor
- coal bunker, 1 day.

Coal Handling Equipment Sizing. Most of the coal handling equipment is sized by capacity, on the tonnage of coal required to maintain the facility at the PMCR operating conditions. The conceptual sizing is based on the ability to unload 3 days of PMCR coal supply within 8 hours. For rail receiving, this equates to 3 deliveries per week, unloading each delivery within 6 hours, up to a maximum of about 650 tons per day, 7 days per week, facility coal use rate. This provides a coal handling system maximum receiving rate capacity of 250 TPH. The maximum receiving rate is based on the physical limits of unloading two and one-half, 100-ton bottom dump rail cars per hour, or three other (60 or 70 ton) rail cars per hour. If the facility requires more coal than 650 tons per day, the receiving system will operate with increased unloading times. The coal handling equipment is sized by capacity using the following equation and set of parameters.

Capacity (TPH) = [(coal @ PMCR)(24 hrs/day)(7 days/wk)] / (3 deliveries/wk)
(6 hrs unload/delivery)

Parameters:

a. For coal at PMCR, see the facility performance estimate subprogram.
b. Capacity below 50 TPH is 50 TPH (minimum capacity).
c. Capacity is to be rounded up to the nearest 25 TPH from 50 to 150 TPH.
d. Capacity above 150 TPH is to be rounded up to the nearest 50 TPH.
e. Capacity greater than 250 TPH is 250 TPH (maximum capacity).

The coal reclaim system is sized at 100 TPH. This almost doubles the amount of coal required by the largest, "worst case", coal facility. To supply this facility, therefore, the system would need to be operated approximately 12 hours per day, 7 days per week or 16 hours per day, 5 days per week.

The coal silos are user selectable. Each is sized according to the following equation and parameters.

Capacity (tons) = (coal @ PMCR)(24 hrs/day)(no. of days storage)/(2000 lb/ton)

Parameters:

a. For coal at PMCR see facility performance estimate subprogram.
b. No. of days storage is a user input value from 1 to 7 days. The default value is 3 days.

The brake horsepower (BHP) of the conceptual coal handling systems are estimated according to the following:

a. If the coal handling range is 50 to 100 TPH, the system BHP = (1.2)(TPH) + 100.
b. If the coal handling range is 110 to 500 TPH, the system BHP = (0.34)(TPH) + 100.

Fuel Handling and Storage Equipment Sizing - COS, CWS

This section describes the fuel handling equipment and sizing equations required to estimate the cost of the fuel handling and storage equipment. The design configuration depends on whether truck or rail is used and if car heating is required. The following discussion further explains the fuel handling equipment.

Rail Car Mover. The car mover system is the same as that used for a stoker unit.

Rail Car Thawing Shed. The shed is the same as that used for a stoker unit.

Tank Car Unloader House. The building included in the conceptual design houses the fuel receiving pumps and meters. It is a steel building approximately 10 ft wide by 15 ft long by 10 ft high.

Fuel Receiving Pumps. These positive displacement pumps are designed for pumping coal-slurry fuel. Each pump is sized at 500 gallons per minute (GPM) and includes valves, strainer, and a 150-hp motor.

Fuel Receiving Meters. These positive replacement meters are rated at 750 GPM. They are used to measure the amount of fuel received from the rail tank cars.

Fuel Receiving Piping. This fuel collection and distribution piping system connects the rail tank cars to the fuel receiving pumps and delivers the fuel to the long-term storage tanks or the day fuel storage tank.

Long-Term Fuel Storage Tanks. These fuel storage tanks are of steel construction, have a domed roof, and are atmospheric tanks sized at 500,000 gallons each. Each tank includes heating coils.

Day Fuel Tank Transfer Pumps. These pumps transfer fuel from the long-term storage tanks to the day fuel storage tank. They are positive displacement pumps designed for pumping coal-slurry fuel. Each is sized for 150 GPM and comes with valves, strainer and a 30-hp motor.

Day Fuel Storage Tank. This tank stores a 1-day supply of fuel for the facility. It is an atmospheric tank of steel construction and has a domed roof and heating coils.

Boiler Fuel Pumps. These units pump fuel from the day fuel tank, through the boiler fuel heater, and to the boiler fuel distribution/recirculation system. They are positive displacement pumps sized at 50 GPM and come with a 10-hp motor.

Boiler Fuel Heaters. These heaters use steam to heat the boiler fuel to the fuel firing temperature.

Boiler Fuel Piping. This is the distribution/recirculation piping that conveys the fuel from the day tank to the boilers. The recirculation line returns fuel to the day tank.

Fuel Handling Equipment Sizing. The following fuel handling and storage equipment is suggested for coal slurries.

Truck only receiving

- long-term storage tanks
- day tank transfer pumps
- day fuel storage tank
- boiler fuel pumps
- boiler fuel heaters
- boiler fuel piping.

Rail receiving

- rail car mover
- rail car heating shed
- tank car unloader house
- fuel receiving pumps
- fuel receiving meters
- fuel receiving piping
- long-term storage tanks
- day tank transfer pumps
- day fuel storage tank
- boiler fuel pumps
- boiler fuel heaters
- boiler fuel piping.

The fuel handling equipment is sized by capacity according to the amount of fuel required to maintain the facility at PMCR operating conditions. The conceptual sizing is based on the ability to unload 3 days of PMCR fuel supply within 6 hours for rail receiving. This equates to 3 deliveries per week, unloading each delivery within 6 hours. The maximum receiving rate is based on the physical limits of unloading three 10,000-gallon tank rail cars per hour. If the facility requires more fuel, the receiving system will operate for a longer unloading time. Truck deliveries will be pumped by the truck directly into either the long-term or day storage tanks. A truck can unload approximately 8000 gallons of fuel per hour.

The number of long-term fuel storage tanks is determined by the following. (Note that the resultant number is rounded to the nearest whole number.)

No. of long-term storage tanks = storage capacity in gallons/500,000

Storage capacity (gallons) = (long-term fuel storage capacity in lb)/(8.33)(.96)

Long-term fuel storage capacity (lb) = (days long-term storage)(fuel @ PMCR) (24 hrs/day)

The user must input the number of days long-term fuel storage; the selections are 20,30,45, 60, or 90 days, and the default is 90 days.

The day fuel storage tank is sized according to the following equation:

Tank capacity (gallons) = (fuel @ PMCR)(24 hrs/day) / (8.33)(.96)

Ash Handling and Storage Equipment Sizing

This subsection describes all of the major ash handling and storage equipment. Included in the conceptual design are pneumatic ash conveying (piping) systems, air operated ash intake valves, a high efficiency ash receiver (separator), an ash bag filter, three 100 percent mechanical exhausters, an automatic control system, ash storage silos sized for 4 days of ash, and ash conditioners for truck load up. Pickup points for the boiler house vacuum conveying system are: each bottom ash boiler outlet or each boiler mechanical collector hopper, each air heater or economizer settling chamber hopper, and each air pollution control device. The ash silos are equipped with a high efficiency ash receiver with a bag filter for removing ash from the conveying air. The silos are also equipped with a bag vent filter for filtering the air released from the silos during ash filling. One conveying system can serve multiple boilers and one ash storage silo can have multiple conveying systems feeding into it. Each conveying system has its own fan, cyclones, and baghouse.

The model's conceptual ash system design, for sizing purposes, is based on a 4-boiler facility. The stoker facility ash system will have to take care of the ash and scrubber residue. The CFBC and BFBC ash systems will have to handle the ash and limestone residue. The COS and CWS ash systems will only have to handle the ash.

Fly Ash Calculations. For each of the boiler technologies, the fly ash per boiler is calculated as follows:

Fly ash/boiler in lb/hr = (total fly ash)/(no. of boilers - 1)

Stoker. The total fly ash out of a stoker boiler is 40 percent by weight of the total ash input with the fuel, plus an amount of carbon equal to 50 percent by weight of the fly ash. This is calculated by:

Total fly ash (lb/hr) = (0.40)(ash input in wt%)(total fuel input in lb/hr)(1.5)

CFBC. The total fly ash out of a CFBC is 60 percent by weight of the total ash input with the fuel, plus an amount of carbon equal to 10 percent by weight of the fly ash, plus 25 percent by weight of the limestone added. This is calculated by:

Total fly ash (lb/hr) = [0.66 ([ash input in wt%] + [.25][limestone in lb/lb fuel])] (total fuel input in lb/hr)

BFBC. The total fly ash out of a BFBC is 40 percent by weight of the total ash input with the fuel, plus an amount of carbon equal to 10 percent by weight of the fly ash, plus 15 percent by weight of the limestone added. This is calculated by:

Total fly ash (lb/hr) = [0.44 ([ash input in wt%] + [.15][limestone in lb/lb fuel])] (total fuel input in lb/hr)

COS and CWS. The total fly ash out of the coal slurry boilers is 100 percent by weight of the total ash input with the fuel, plus an amount of carbon equal to 10 percent by weight of the fly ash. This is calculated by:

Total fly ash (lb/hr) = (ash input in wt%)(total fuel input in lb/hr)(1.1)

Bottom Ash Calculations.

Stoker. The total bottom ash out of the stoker boiler is 70 percent by weight of the total ash input with the fuel, plus an amount of carbon equal to 10 percent by weight of the bottom ash. This is calculated by:

Total bottom ash in lb/hr = (0.70)(ash input in wt%)(total fuel input in lb/hr)(1.1)

CFBC. The total bottom ash out of the CFBC is 80 percent by weight of the total ash input with the fuel, plus an amount of carbon equal to 10 percent by weight of the bottom ash, plus 40 percent of the limestone added. This is calculated by:

Total bottom ash in lb/hr = [(0.88)(ash input in wt%) + (0.40)(limestone input in lb/lb fuel)] (total fuel input in lb/hr)

BFBC. The total bottom ash out of the BFBC is 80 percent by weight of the total ash input with the fuel, plus an amount of carbon equal to 10 percent by weight of the bottom ash, plus 50 percent of the limestone added. This is calculated by:

Total bottom ash in lb/hr = [(0.88)(ash input in wt%) + (0.50)(limestone input in lb/lb fuel)] (total fuel input in lb/hr)

COS and CWS. All of the ash exits the boiler as fly ash. There is no bottom ash.

Ash Conveying Systems. The ash conveying systems, boiler, and air pollution control are sized for the facility operating at the PMCR. The ash conveying systems are sized to convey 3 hours of ash or residue in 1hour. The maximum size of any single ash conveying system is 75 TPH; if a system is larger than 75 TPH, then it is split into 2 conveying systems. The minimum size of any single conveying system is 2 TPH. The scrubber residue conveying system conveys the residue collected in each baghouse. Each baghouse has multiple hoppers and a residue conveying system for the collected residue.

All the ash hoppers are sized to hold 12 hours of ash. The hoppers are arranged so that, in an emergency, ash can be spilled onto the floor and removed by hand later, allowing the facility to remain in operation. The ash system vacuum pumps are sized for conveying the required largest ash amount in tons per hour.

The ash conveying system sizing is calculated by the following equations for each type of boiler. For each system, if the calculated TPH is 2 TPH or less, the system is 2 TPH; if the calculated TPH is grater than 75 TPH, divide the ash system into 2 systems; and, finally, the calculated system TPH should be rounded up to the nearest TPH conveyor size.

Stoker. The sizing equations are:

Boiler ash conveying (TPH) = (total bottom ash)(3)/(2000 lb/ton)

Mechanical collector and settling chamber ash conveying (TPH) = [(total mechan. collector ash) + (total settling chamber ash)](3)/2000lb/ton

Scrubber ash conveying (TPH) = (total scrubber residue) (3)/ (2000lb/ton)

Baghouse ash conveying (TPH) = (total baghouse residue) (3)/ (2000lb/ton)

CFBC, BFBC. The sizing equations are:

Boiler ash conveying (TPH) = (total bottom ash)(3)/(2000 lb/ton)

Mechanical collector and settling chamber ash conveying (TPH) = [(total mechan. collector ash) + (total settling chamber ash)](3)/2000lb/ton

Baghouse ash conveying (TPH) = (total baghouse residue) (3)/2000lb/ton)

COS, CWS. The sizing equations are:

Mechanical collector and settling chamber ash conveying (TPH) = [(total mechan. collector ash) + (total settling chamber ash)](3)/2000lb/ton

Baghouse ash conveying (TPH) = (total baghouse residue) (3)/ (2000lb/ton)

Mechanical Collector. All of the fly ash enters the high efficiency mechanical collector, which will, for ash system sizing purposes, collect 80 percent of the fly ash. Ash collected is calculated by:

Total mechanical collector ash (lb/hr) = (total fly ash)(0.80)

Mechanical collector ash/boiler (lb/hr) = (fly ash/boiler)(0.80)

Settling Chambers. For sizing purposes, settling chambers ash systems are sized the same as mechanical collector ash systems.

Dry Scrubber - Stoker. Fly ash into the dry scrubber is, for ash system sizing purposes, 80 percent of the fly ash out of the boiler. This is calculated by:

Total fly ash into scrubbers (lb/hr) = (0.80)(total fly ash)

Fly ash into each scrubber (lb/hr) = (0.80)(fly ash/boiler)

The dry scrubber residue (ash) system is sized for 50 percent of the total weight of solids into the scrubber. This residue out of the scrubber consists of fly ash, calcium oxide, lime inerts, and calcium sulfate. The residue collected by the scrubber, for sizing purposes, is calculated by:

Total scrubber residue (lb/hr) = (0.5)[(total fly ash into scrubber in lb/hr)+(total lime in lb/hr)]

Each scrubber residue (lb/hr) = (total scrubber residue in lb/hr)/(no. boiler - 1)

Baghouse. The baghouse, for residue collection sizing purposes, will collect 99.5 percent of the total residue into the baghouse.

Stoker. The equations are:

Total baghouse residue (lb/hr) = (0.995)(total scrubber residue in lb/hr)

Each baghouse residue (lb/hr) = (0.995)(each scrubber residue in lb/hr)

CFBC, BFBC, COS, CWS. The equations are:

Total baghouse residue (lb/hr) = (0.995)(total fly ash in lb/hr)

Each baghouse residue (lb/hr) = (0.995)(fly ash/boiler in lb/hr)

Ash Silo. The ash silo(s) have a flat bottom, and are sized to store 4 days of ash and residue at the facility PMCR. Facilities producing up to 175 TPD of ash and residue will have a single storage silo. Facilities producing more than 175 TPD will have two ash silos. Each silo will have a high efficiency ash receiver with a bag filter and bag vent filter. The silo(s) size is calculated by:

Total residue collected (TPD) = [(ash input in wt%) (total fuel input in lb/hr) + (0.56)(total lime in lb/hr)] (24hr/day)(1.1)(1.05)

The 1.05 factor is an estimate of the amount of carbon in the ash. This equation, for conservation in design, uses 100 percent of the fuel ash captured.

If total residue collected is equal to or less than 175 TPD, the above value should be used to determine the ash silo sizing. If the value is greater than 175 TPD, the facility should have 2 silos of equal size, each calculated by using half the above calculated total residue collected. The minimum silo capacity (assuming an ash density of 45 lb/cu ft) is determined by:

Min. silo capacity (cu ft) = (total residue collected in tons/day) (4 days storage)(2000 lb/ton)/ (45 lb/cu ft ash)

The silo height is selected so it is minimized while still containing at least the minimum silo capacity. This is accomplished with the following equation.

Actual silo capacity = (height)(3.14)(diameter^2/4)/1.1

The allowable silo diameters are 12, 14, 16, 20, 30, or 40 ft. The silo height is 60 ft or less and at least 1.5 diameters, but less than 3.5 diameters.

Each ash silo will have an individual residue conditioner - unloader. The conditioner wets the residue with water to prevent dust problems and loads it into a truck. The type of conditioner supplied with the conceptual design is determined by the quantity of ash produced by the facility. If the facility generates 100 TPD of ash or less, the conditioner is a 40 TPH unit that uses 60 GPM of water and has a 5 hp motor. If the facility generates in excess of 100 TPH of residue, each conditioner is a 60 TPH unit that uses 75 GPM of water and has a 10 hp motor.

Dry Scrubber for Sulfur Control - Stoker

The stoker boiler facility design uses dry scrubbers for sulfur removal. Dry scrubbing systems can achieve at least 90 percent sulfur removal and 70 to 80 percent acid gas removal. Each boiler uses a dry scrubber and a baghouse. Each scrubber has the necessary processing equipment to mix the boiler flue gases with a reagent to reduce acid gases and includes a rotary atomizer, maintenance hoist, maintenance penthouse above the scrubber vessel, stairs, and platform. Lime is delivered into the reactor in the form of slaked lime and atomized by the rotary atomizer into fine droplets (the lime delivery and storage system is described under the lime system). Acid gases are removed by the reaction of lime (calcium oxide) with the acid gas (SO_2) to form calcium sulfate, gypsum, and/or calcium sulfite, which is then dried in the vessel.

The dry scrubbers are sized by the following equations.

Scrubber gas flow inlet (lb/hr) = (value calculated)/(no. of boiler -1)

Scrubber diameter (ft:rounded up to the nearest ft) = [(7.2 x 10^{-5})(scrubber gas flow inlet) + 10]

Scrubber height (ft:rounded up to the nearest 5 ft increment) = [(2.0 x 10^{-4})(scrubber gas flow inlet) + 10]

Parameters:

a. Minimum vessel height is 50 ft.
b. Maximum vessel height is 115 ft.

Scrubber gas flow inlet (in "actual cubic feet per minute" or ACFM) = (value calculated in the facility performance subprogram)/(no. of boilers - 1)

The total dry scrubber system BHP is estimated as follows.

BHP = (no. of boilers)(150 BHP)

Baghouse Sizing

The baghouses are reverse air type and have a cloth-to-air ratio of 2:1 with a particulate collection efficiency of 99.5 percent. Typically, each boiler is supplied with a baghouse. Each baghouse is compartmentalized and includes inlet and outlet gas flow manifolds, isolation dampers, penthouse, stairs, ladders, platforms, doors, residue hoppers, hopper heating, etc. The baghouses are sized by the following equations.

Baghouse gas flow inlet (lb/hr) = (value calculated in the facility performance subprogram)/(no. of boilers - 1)

Baghouse width (ft) = [(baghouse gas flow inlet)(3.337 x 10^{-3}) + 128]/30

Parameters:

a. Depth of the baghouse is 30 ft.
b. Width is rounded up to the nearest whole number 10 (i.e., 10, 20, 30 40).

Baghouse (sq ft) = (baghouse width)(30).

For all cases, the baghouse is 60 ft in height. This allows room for a penthouse, ash hoppers, and the ash conveying lines.

Lime Handling and Storage - Stoker

The lime handling and storage system receives, stores, and slakes 3/4 in. pebble lime and supplies the slaked lime to the dry scrubbers. The system consists of:

- A single, 14-day lime storage silo that includes a pneumatic lime fill pipe for receiving lime from a self-powered unloading truck, an air fluidization or bin activation system, and a lime dust vent collection system installed on top of the silo for collecting lime dust during silo filling. A storage silo has a minimum capacity of 60 tons and a maximum capacity of 3600 tons.

- A mechanical lime conveyor to transport lime from the silo to the lime storage day bin.

- All controls, valves, piping, and other components necessary for a complete system.
- An air pollution control (APC) building that contains most of the previously described equipment. The building is of steel construction, made by Butler.

The equipment is sized by the following equations.

Storage silo capacity (tons) = [(total lime in lb/hr@PMCR)(24 hrs/day)(14 days)(1.1)]/(2000 lb/ton)

Lime conveyor(TPH) = [(storage silo capacity in tons)/(14)(24)](4)
Note that the conveyor capacity is based on filling the day bin in 4 hours.

Day bin (tons) = (storage silo capacity in tons)/14

Feeder Capacity (TPH) = (1.5)(Lime Conveyor in TPH)
(This is also the slaker's lime capacity.)

Dilution Tank Size (cu ft) = (Total Water to Scrubber in GPM)(60 min/hr)(12 hrs)/(7.48 gal/cu ft)

The tank size is based on 12 hours of capacity.

Dilution Tank Height (ft) = [(Dilution Tank Size)(4)/(3.14)$(D)^2$] + 2

Parameters:

a. The diameter is either 4, 6, 8, or 10.
b. If diameter-to-height ratio is less than 1:1 or greater than 2.5:1, the user must reselect the diameter.

The total lime system BHP is estimated as a function of lime flow to the dry scrubber and is provided by:

BHP = (Total Lime in lb/hr@PMCR)(0.015) + 60

Limestone Handling and Storage - CFBC, BFBC

The limestone handling and storage system receives, stores, and supplies the limestone to the CFBC and BFBC boilers. The system (Figure 10) consists of the following.

- Two 10-day limestone storage silos. Each silo includes a pneumatic lime fill pipe for receiving limestone from a self-powered unloading truck, an air fluidization or bin activation system, and a lime dust vent collection system installed on top of each silo to collect dust during silo filling. A limestone storage silo has a minimum capacity of 60 tons and a maximum capacity of 1800 tons.
- Limestone belt feeders (one per silo) that remove the limestone from the storage silo and convey it to the limestone bucket elevator.
- A limestone bucket elevator that receives the limestone from the belt feeders and conveys it to the tripper conveyor.
- A limestone tripper belt conveyor to transport limestone from the bucket elevator to each boiler limestone storage bin or silo.
- A limestone day bin or storage silo, one per boiler, which includes a lime dust vent collection system for collecting dust during filling.
- All controls, valves, piping, and other components necessary for a complete system.

The conceptual equipment is sized by the following equations.

Total Storage Silo Capacity(tons) = (Total Limestone in lb/hr@PMCR)(24 hrs/day)(20 days)(1.1)/(2000 lb/ton)

Limestone Conveying System (TPH) = [(Total Storage Silo Capacity in tons)/(20)(24)] (4)

Parameter: The conveyor capacity is based on filling the day bin in 4 hours.

Day Bin (tons) = (Total Storage Silo Capacity in tons)/20

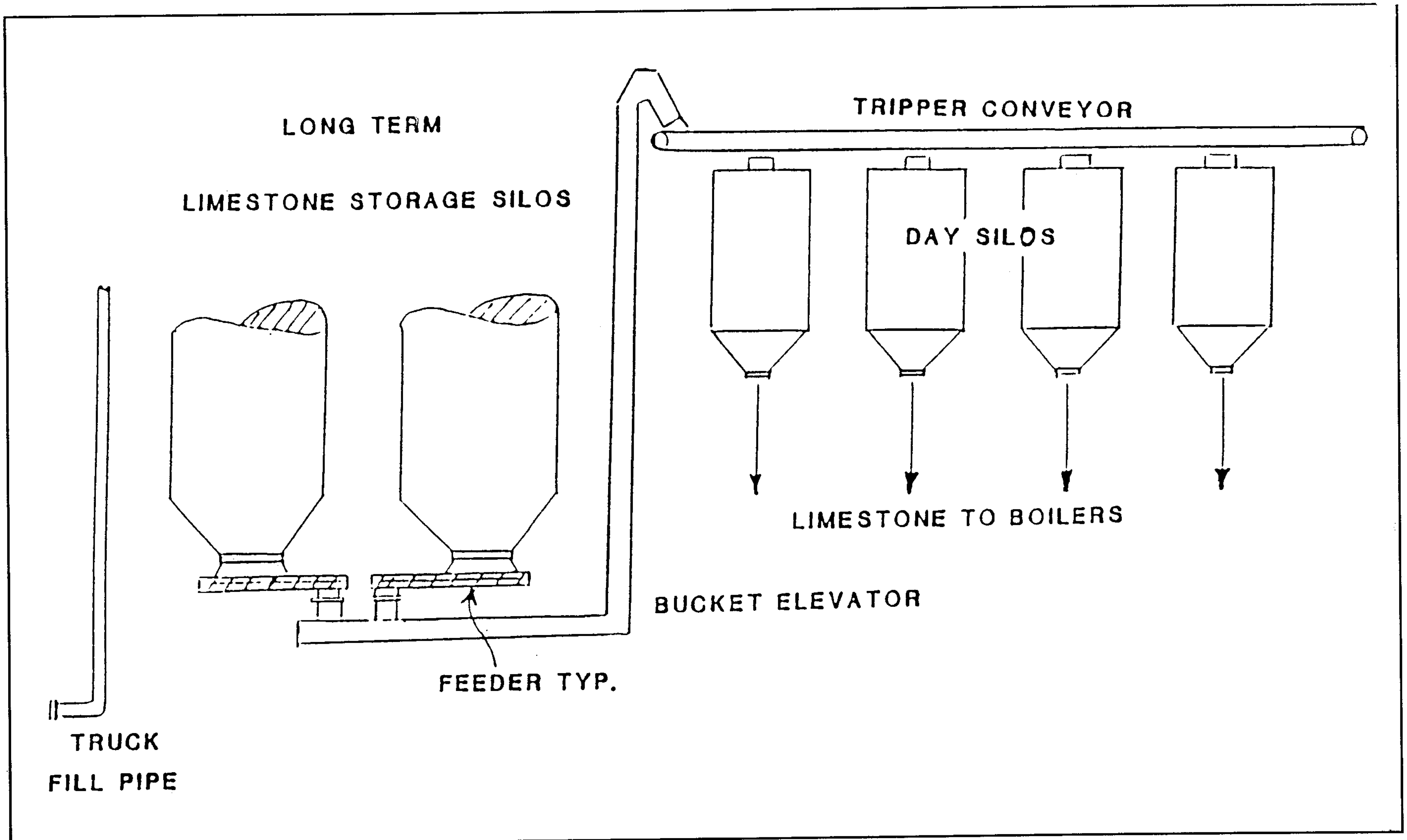

Figure 10. Typical limestone handling and storage system for CFBC and BFBC facilities.

Facilities requiring 100 TPD of limestone or less will have a single storage silo. Those requiring more than 100 TPD will have two storage silos. The total plant limestone storage for this design is 20 days.

Single Silo Size (tons) = (Day Bin in tons)

Silo Size: two (tons) = (Day Bin in tons) / 2

Silo Capacity (cu ft) = (Silo Size in tons)(2000 lb/ton)/50

Note that the limestone density is 50 lb/cu ft.

The maximum diameter producing the minimum height for the silo is selected for the silo capacity within the following constraints:

Silo Height (ft) = [(Silo Capacity in cu ft)(4)/3.14 D^2][1.1]

Parameters:

a. D = silo diameter of 12, 14, 16, 20, 30 or 40 ft.
b. If the silo height-to-diameter ratio is less than 1.5:1, reselect the diameter.
c. If the silo height-to-diameter ratio exceeds 3.5:1, reselect the diameter.
d. If the silo height exceeds 60 ft, reselect the diameter.

The total limestone system BHP versus the tons per hour capacity is estimated as:

(Limestone Handling System at the BHP)(10 - 125 TPH)=(2.36)(TPH) + 22.5

Boiler Water Treatment

This section describes the water treatment process commonly used to produce boiler feedwater. The objective of boiler water treatment is to eliminate or minimize problems caused by impurities in the water and steam. Problems include corrosion, scale, carry-over, and caustic embrittlement.

The choice of a water treatment system design depends on inlet water quality, steam or hot water outlet pressure, steam outlet use, and amount of water added to the system. It is virtually impossible to provide a complete general design that covers every aspect of water treatment. When a facility is further evaluated, the preliminary design would be contingent on actual raw water quality, boiler type and pressure, steam usage, operating procedure, blowdown limits, and other relevant parameters.

The water treatment equipment described assumes that a good water source (city water system) exists. If the facility under consideration cannot obtain raw water from a good water source system, additional equipment will be required. Such additional equipment is listed below for various water sources.

River water
- Raw water pumps
- Fire water storage and pumps
- Chlorinator
- River water clarifier system
- Lime injection system
- Chemical tanks and injection pumps
- Acid injection system
- Filter press and pumps
- Clear well and pumps
- Anthracite filters.

Well water
- Well water pumps
- Fire water storage and pumps
- Potable water filter, tank, and pumps.

City water
- Break tank
- Fire water storage and pumps
- City water pumps

Sodium Zeolite Softening. The primary purpose of sodium zeolite softening is to remove scale-forming salts of calcium and magnesium by replacing them with an equivalent amount of sodium (nonscale forming). Sodium zeolite softening is a cation exchange process that will produce boiler feedwater with a hardness of 0 to 5 parts per million (ppm) as $CaCO_3$.

Synthetic polystyrene resins are commonly used for sodium zeolite softening. The fundamental reaction with calcium in the sodium zeolite softening process is:

Ca^{++}	+	Na_2Z ------->	CaZ	+	$2Na^+$
(Calcium Ion)		(Sodium Zeolite)	(Calcium Zeolite		(Sodium Ion)

When the zeolite resin is exhausted and will not release anymore sodium in exchange for calcium or magnesium, the bed must be regenerated. It is regenerated by treating

with a 10% sodium chloride solution. The regeneration reaction for calcium may be written as follows:

CaZ	+	NaC	------->	Na_2Z	+	$CaCl_2$
(Calcium Zeolite)		(Sodium Chloride)		(Sodium Zeolite)		(Calcium Chloride)

Equipment. The softener consists of a cylindrical steel pressure vessel with an underdrain resin retention system containing the zeolite (bed) material. The size of the zeolite bed will depend on the exchange capacity of the zeolite, the hardness of the water being treated, and the amount of water softened between regenerations. The bed must be deep enough to allow proper contact time between the water and zeolite. The flow rate is usually limited to 2 to 15 GPM/cu ft.

Applications. Sodium zeolite softening is required for boiler makeup water except where demineralized water or condensate is the source of all feedwater.

Limitations. Turbid waters should not be passed through a zeolite softener because accumulated deposits will plug the zeolite bed and reduce its efficiency. Surface waters tend to be turbid and in most cases must be clarified and filtered before zeolite softening. Chlorine (residual) concentration in the water should not exceed 0.3 ppm to prevent oxidation of the resin. If the concentration of chlorine is higher than 0.3 ppm, either a sodium sulfite feeder or activated carbon filter is required.

Note that a reduction in alkalinity or total solids does not occur during sodium zeolite softening. Calcium and magnesium ions are removed, but are replaced by sodium ions.

Demineralization. Demineralization is the process of removing dissolved matter from water by ion exchange. Demineralization involves two types of ion exchange resins. Cations such as calcium, magnesium, and sodium are removed by hydrogen-form cation resins. Anions such as sulfate and chloride are removed by hydroxide-form anion resins.

When the bicarbonate and carbonate alkalinity of the raw water is greater than 50 ppm, a decarbonator is provided in demineralization systems after the cation exchanger to remove carbon dioxide. Carbon dioxide can be removed in a decarbonator at much lower chemical cost than it can be removed in the anion exchanger. However, the treated decarbonator effluent still contains 5 to 10 ppm of free carbon dioxide.

In place of the decarbonator, a vacuum degasifier may be used to remove noncondensible gases including oxygen and carbon dioxide. A vacuum degasifier may be

justified for a demineralization plant in order to eliminate rubber-lined piping for extensive distribution of demineralized water.

Two separate dilution systems for regenerant acid and caustic chemicals are provided to ensure reliability. In addition, neutralization facilities must be provided for the waste regenerant water. Neutralization by batch treatment to a pH of 6 is also required. Hot brine (120 °F) should be provided for periodic treatment of anion resin when organics in the raw water exceed 3 ppm as O_2.

Mixed Bed. Mixed bed processes are the same as in demineralization. However, the resins, cation, and anion are together in the same vessel, which explains the term "mixed bed". The same type of vessels, pipe, etc., are required.

Dealkalizer. A dealkalizer is usually used after and in conjunction with a sodium zeolite softening system to reduce the alkalinity of the effluent. The buffering of effluent is accomplished by adding acid, which is mixed with the effluent in the dealkalizer.

Water Treatment Equipment Sizing. The equipment sizing is based on the amount of continuous treated water flow requirements determined by the amount of treated water makeup required at the PMCR. The makeup depends on the amount of condensate returned to the boiler system, water leakage within the boiler system (i.e., packing/steam leaks, deaerator vent steam, etc.), and the boiler blowdown lost. The amount of treated water is:

Total Treated Water (GPM) = (PMCR) [1+ (percent Blowdown/100) + (percent Leakage/100) - (percent Condensate Return/100)] / (8.33 lb/gal) (60 min/hr)

Parameters:

a. Percent blowdown is a user input.
b. Percent condensate return is a user input value with a range of 0 to 100 percent.
c. The default value is 50 percent.
d. Percent leakage is a user input value of 0 to 5 percent with a default of 1 percent.

The number of water treatment trains is based on the principle that for 0 to 600 GPM total treated water, the system consists of two, 100 percent trains; and for 600 to 1200 GPM total treated water, the system consists of three, 60 percent trains.

Treated Water Flow/Train (GPM) = (x) (Total Treated Water)

Parameters:

a. For a flow rate of 0 to 600 GPM, x = 1.0.
b. For a flow rate of 600 to 1200 GPM, x = 0.6.

The amount of water treatment resin is determined with the restriction of 15 GPM/sq ft of resin vessel area. Approximate vessel sizes are determined by:

Resin Vessel Area (ft^2) = (Total Treated Water in GPM)/15

Resin Vessel Diameter(ft) = SQRT [4 (Resin Vessel Area)/3.1415]
Note that the minimum diameter is 2 ft.

Resin Vessel Height (ft) = (1.3)(Resin Vessel Diameter) + 2.4

Resin Depth (ft) = (Resin Vessel Height)/2.215

The total cubic feet of resin required for the zeolite or demineralizer (not including mixed bed) conceptual design is:

Zeolite or Demineralizer (cu ft) Resin = (Resin Depth) (Treated Water Flow/Train) (No. of Trains) (No. of Resin Vessels/Train)

Parameters:

a. The number of trains is determined by flow rate.
b. Zeolite systems have one resin vessel per train while demineralizer systems have two per train.

Mixed bed unit sizing is provided by the following equations. The conceptual design uses a constant 4 ft of resin depth (2 ft cation and 2 ft anion). The user can input the number of mixed bed units per train.

Mixed Bed Treated Water Flow (GPM) = Treated Water Flow/Train

Resin Vessel Area (sq ft) = Treated Water Flow/Train/15 Vessel Height (ft) = 10 ft

Mixed Bed (cu ft) Resin = (4) (Resin Vessel Area) (No. of Trains) (No. of Mixed Beds/Train)

The number of mixed beds per train is input by the user (note that one train should be used for cogeneration 625 to 1200 psig).

Dealkalizer conceptual sizing is based on the maximum water velocity through the vessel of 8 GPM/sq ft. There is one dealkalizer per train.

Vessel Area (sq ft) = (Total Treated Water)/8 GPM/ft^2

Vessel Diameter (ft) = SQRT [(4)(Vessel Area)/3.14]
Note that the minimum diameter = 3 ft.

Vessel Height (ft) = [1.3 (Vessel Diameter) + 3.4]

Dealkalizer Size (cu ft) = (Vessel Area) (Vessel Height)

The brine tank sizing is as follows:

Tank Diameter (ft) = (0.0083) (Treated Water Flow/Train) + 1.45
Note that the minimum diameter is 2 ft.

Tank Height = 5 ft.

The condensate polisher is sized according to the mixed bed equations. The brine rinse surge tank is used to control release of the rinse water.

During regeneration of the sodium zeolite softening system, wastewater is approximately 15 percent of the amount of water treated. The amount of water treated is approximated by determining the exchange capacity of the resin using either of the following equations:

For total treated water of 10 to 160 GPM, exchange capacity (Gr) = (1765)(total treated water) + 13,500

For total treated water greater than 160 GPM, exchange capacity (Gr) = (5400)(total treated water) - 343,400.

Wastewater per regeneration is then approximated by using the exchange capacity of the resin determined above.

Wastewater/regeneration(gal) = [(exchange capacity in Gr)/15] [0.15]

Brine Tank Size (cu ft) = [(2)(wastewater/regeneration)/(7.48gal/cu ft)][1.15]
Note that the tank is used for two regenerations plus 15 percent extra capacity and that for a round tank, the diameter selections are 8, 10, 12, 16, or 20 ft.

Tank height or length (ft) = (Tank Size in cu ft)(4)/(3.14)(D squared)
Note that the maximum tank height is 30 ft; if height is greater than 30 ft, reselect the diameter.

Parameters:

1. If tank height-to-diameter ratio exceeds 3.5:1, reselect the diameter.
2. If tank height-to-diameter ratio is less than 1:1, reselect the diameter.

The neutralization tank accepts the waste regeneration chemicals, acid and caustic, and the rinse water to ensure a neutralized water discharge. The tank size is estimated and sized using the following equations.

CATION VESSEL
Cation Treated Water (gal) = (Treated Water Flow/Train) (1440)

Acid Required per Regeneration (lb) = (0.00001)(Cation Treated Water in gal)(15)(17.1)

Acid per Regeneration (gal) = (6) (Acid Required per Regeneration in lb)

Backwash Water (gal) = (100) (Resin Vessel Area)

Rinse Water (gal) = (75) (Resin Vessel Area) (Resin Depth in ft)

ANION VESSEL
Caustic Required per Regeneration (lb) = (4) (Resin Vessel Area)(Resin Depth in ft)

Caustic per Regeneration (gal) = (3) (Caustic Required per Regeneration)

Backwash Water (gal) = (75) (Resin Vessel Area)

Rinse Water (gal) = (125) (Resin Vessel Area) (Resin Depth in ft)

MIXED BED VESSEL
Acid Required per Regeneration (lb) = (0.00001)(Cation Treated Water)(3)(17.1)(1.02)

Caustic Required per Regeneration (lb) = (4)(Resin Vessel Area)(2)(1.25)

Caustic per Regeneration (gal) = (3)(Caustic Required per Regeneration)

Backwash Water (gal) = (75) (Resin Vessel Area)

Rinse Water (gal) = (75) (Resin Vessel Area)

The total Volume of Wastewater Per Regeneration is as follows:

> Wastewater (gallons) = (Cation Acid per Regeneration) + (Cation Backwash Water) + (Cation Rinse Water) + (Anion Caustic per Regeneration) + (Anion Backwash Water) + (Anion Rinse Water) + (Mixed Bed Acid per Regeneration) + (Mixed Bed Caustic per Regeneration) + (Mixed Bed Backwash Water) + (Mixed Bed Rinse Water)
>
> Tank Size (gal) = (2.15)(Wastewater in gal)
> Note that the tank is sized for two regenerations plus 15 percent.
>
> Tank Size (cu ft) = (Tank Size in gal)/7.48
>
> Tank Height or Length (ft) = (Tank Size in cu ft)(4)/(3.14)(D squared)

Parameters:

a. D = 10, 12, 16, 20, 24, or 30 ft.
b, If the height is greater than 50 ft, reselect the diameter.
c. If the tank height to diameter ratio exceeds 3:1, reselect the diameter.
d. If the tank height-to-diameter ratio is less than 1:1, reselect the diameter.

Facility Tank Sizing

The facility tanks evaluated in this section are the condensate storage tank, treated water storage tank, facility acid and caustic tank, Deaerator and Storage Tank, Condensate Return Tank, and facility Fuel Oil Tank.

Condensate Storage Tank. The condensate tank is provided as a surge tank that receives condensate from the heating system return lines. The tank can be sized for a user input of 1 to 4 hours of storage capacity with a default of 1 hour. The tank is a carbon steel, atmospheric tank.

The following equations size the tank.

Tank Size(gal) = (hr storage)(percent condensate Return)(PMCR)/(8.33 lb/gal)

Parameters:

a. Hours of storage are a user input value of 1 to 4 hours with default of 1 hour.
b. Percent condensate return is a user input.

Tank Size (cu ft) = [(Tank Size in gal)/7.48 gal/cu ft] (1.15)

Tank Height or Length (ft) = (Tank Size in cu ft) (4)/(3.14)(D squared)

Parameters:

a. D = 6, 8, 10, 12, 16, 20, or 24 ft.
b. If tank length exceeds 50 ft, reselect the diameter.
c. If tank diameter equals 20 ft and length exceeds 30 ft, reselect hours of storage (storage capacity).
d. If tank length-to-diameter ratio exceeds 3.0:1, reselect diameter.
e. If tank length-to-diameter ratio is less than 1.0:1, reselect diameter.

Treated Water Storage Tank. The treated water storage tank is provided as a boiler water system surge tank and as a water supply reserve. It is sized for 8 hours of storage. The tank is a closed atmospheric tank and is constructed of 316 stainless steel. The following equations size the tank.

Tank Size (gal) = (8)(PMCR) [1+(% Blowdown/100)]/(8.33 lb/gal)
Note that PMCR and percent blowdown are user input values.

Tank Size (cu ft) = [(Tank Size in gal)/(7.48 gal/cu ft)] (1.15)

Tank Height or Length (ft) = (Tank Size in cu ft) (4)/(3.14)(D squared)

Parameters:

a. D = 6, 8, 10, 12, 16, 20, 24 or 30 ft.
b. If tank length exceeds 50 ft, reselect diameter.
c. If tank diameter equals 20 ft and length exceeds 30 ft, reselect hours of storage.
d. If tank length-to-diameter ratio exceeds 3.0:1, reselect diameter.
e. If tank length-to-diameter ratio is less than 1.0:1, reselect diameter.

Acid and Caustic Storage Tanks. These tanks are for the boiler feedwater demineralizer and/or mixed bed treatment system. If the facility has a sodium zeolite system, these tanks are not included in the conceptual design. The tanks are sized to hold approximately one and one-half truck loads.

The acid tank is carbon steel and stores 66° Baume strength acid. The tank for the conceptual design is 12 ft in diameter by 16 ft in length.

The caustic tank is carbon steel and stores a 50 percent solution, 1.8 specific gravity of caustic (sodium hydroxide). The tank for the conceptual design is 12 ft in diameter by 16 ft in length.

Deaerator and Storage Tank. Deaeration is the removal of dissolved gases such as oxygen, carbon dioxide, and ammonia from the treated water before it is introduced into the boiler. These gases are undesirable due to their corrosive effect on metal surfaces.

The deaerator is composed of two sections, a deaerating heater and a boiler feedwater storage section. Within the deaerating heater, treated water is deaerated by heating the water to its saturation temperature and scrubbing it with steam to carry away the dissolved gases. It is then transferred to the storage section by gravity flow. The storage section provides holdup capacity to cover system load swings and emergency situations.

The deaerators are carbon steel, spray-tray types. The storage tanks, depending on user input, have 5 to 30 minutes of water storage. The default value is 10 minutes of storage.

A 3-boiler facility has a single deaerator sized for 3-boiler feedwater flow. The 4- and 5-boiler facilities have two identically sized deaerators, each 50 percent of the total plant feedwater flow. Sizing is as follows.

3-BOILER FACILITY DEAERATOR AND STORAGE TANK

Deaerator Size (lb/hr) = (PMCR) [1 + (% Blowdown/100)]

Note that PMCR and percent Blowdown are user inputs.

Deaerator Storage Tank Size (gal) = [(Deaerator Size in lb/hr) (Minutes of Storage) / (60 min/hr) (8.33 lb/gal)] (1.07)

The number of minutes of storage are the user input of 5 to 30 minutes with a default of 10 minutes.

Deaerator Storage Tank Size (cu ft) = [(Deaerator Storage Tank Size)/(7.48 gal/cu ft)] (1.15)

Storage Tank Length (ft) = (Deaerator Storage Tank Size in cu ft)(4)/(3.14)(D squared)

Parameters:

a. D = 6, 8, 10, 12, 16, or 20 ft.
b. If tank length exceeds 30 ft, reselect diameter.
c. If tank diameter equals 20 ft and length exceeds 30 ft, reselect hours of storage.
d. If tank length-to-diameter ratio exceeds 3.5:1, reselect diameter.
e. If tank length-to-diameter ratio is less than 1.0:1, reselect diameter.

4- and 5-BOILER FACILITY DEAERATOR AND STORAGE TANK
Deaerator Size (lb/hr) = (PMCR)[1 + (% Blowdown/100)]/2

Deaerator Storage Tank Size (gal) = [(Deaerator Size)(Minutes of Storage)/(60)(8.33)] (1.07)

The number of minutes of storage are the user input of 5 to 30 minutes with a default of 10 minutes.

Deaerator Storage Tank Size (cu ft) = [(Deaerator Storage Tank Size)/(7.48)] (1.15)

Storage Tank Length (ft) = (Deaerator Storage Tank Size in cu ft)(4)/(3.14)(D Squared)

Parameters:

a. D = 6, 8, 10, 12, 16, or 20 ft.
b. If tank length exceeds 30 ft, reselect diameter.
c. If tank diameter equals 20 ft and length exceeds 30 ft, reselect hours of storage.
d. If tank length-to-diameter ratio exceeds 3.5:1, reselect diameter.
e. If tank length-to-diameter ratio is less than 1.0:1, reselect diameter.

Condensate Return Tank. This tank is used as a surge tank for condensate returned from the steam or HTHW distribution system. It is used before the condensate "polisher" or mixed-bed to clean the return before it enters the boiler system. The tank is sized for 1 hour of storage.

Tank Size(gal) = (hrs. storage)(% condensate return)(PMCR)/ (8.33 lb/gal)

Parameters:

a. The number of hours of storage is a user input value of 1 to 4 hours with a default of 1 hour.
b. Percent Condensate Return is a user input.

Tank Size (cu ft) = [(Tank Size in gal)/7.48 gal/cu ft] (1.15)

Tank Height or Length (ft) = (Tank Size in cu ft)(4) / (3.14)(D Squared)

Parameters:

a. D = 6, 8, 10, 12, 16, 20, or 24 ft.
b. If tank length exceeds 50 ft, reselect diameter.
c. If tank diameter equals 20 ft and length exceeds 30 ft, reselect hours of storage (storage capacity).
d. If tank length-to-diameter ratio exceeds 3.0:1, reselect diameter.
e. If tank length-to-diameter ratio is less than 1.0:1, reselect diameter.

HTHW Expansion Tank. The expansion tank allows the system to treat the water in a way similar to the deaerator. The tank is sized by the same method as the deaerator storage tank.

Facility Fuel Oil Tank. The facility fuel oil tank is sized for 12,000 gallons of No.2 fuel oil plus 15,000 gallons. This is 1 month's use of oil for the railroad car thawing pits, if the facility is so equipped, plus boiler startup auxiliary fuel. Therefore, the facility will have a 12,000- or 27,000- gallon oil tank.

The fuel oil is used for boiler startup, shutdown, and stabilization, as well as for the diesel-driven fire water pumps, diesel-driven auxiliary generators, plant vehicles (front-end loaders, trucks, etc.), and the thawing shed if so equipped.

Major Facility Fans

The major facility fans consist of the forced draft (F.D.) fan, overfire air (O.A.) fan, and induced draft (I.D.) fan. Each fan has a single speed motor. The F.D. and I.D. fans are used with each of the boiler technologies. The O.A. fan is used with stoker boilers only and supplies air above the fuel bed. The F.D. fan will supply air to the grate windboxes. The I.D. fans, located after the baghouse and before the stack, draw the flue gases from the boiler through the downstream equipment.

F.D. Fan Sizing.

Stoker. The F.D. fan is sized for 90 percent of the boiler's total design airflow when operating at maximum continuous rating. The fan is designed for a static pressure of 3 in. of water column and has an efficiency of 70 percent.

Fan Flow (ACFM) = (0.90)(ACFM)

Parameters:

ACFM = (Wet Airflow, ACFM)/(No. of Boilers - 1), or use the boiler program for one boiler to determine wet air ACFM flow.

BHP = [(144)(Fan Flow in ACFM)(3)]/[(33,000)(27.67)(0.7)]

Fan Motor Size (kW) = (BHP)(1.15)(0.746)

CFBC. The F.D. fan is sized for 110 percent of the boiler's total design air flow when operating at maximum continuous rating. The fan is designed for a static pressure of 80 in. of water column and has an efficiency of 65 percent.

Fan Flow (ACFM) = (1.1)(ACFM)

Parameters:

ACFM = (Wet Airflow, ACFM)/(No. of Boilers - 1), or use the boiler program for one boiler to determine wet air ACFM flow.

BHP = [(144)(Fan Flow in ACFM)(80)]/[(33,000)(27.67)(0.65)]

Fan Motor Size (kW) = (BHP)(1.15)(0.746)

BFBC. The F.D. fan is sized for 110 percent of the boiler's total design airflow when operating at maximum continuous rating. The fan is sized for a static pressure of 60 in. of water column and has an efficiency of 65 percent.

Fan Flow (ACFM) = (1.1)(ACFM)

Parameters:

ACFM = (Wet Airflow, ACFM)/(No. of Boilers - 1) or use the boiler program for one boiler to determine wet air ACFM flow.

BHP = [(144)(Fan Flow in ACFM)(80)]/[(33,000)(27.67)(0.65)]

Fan Motor Size (kW) = (BHP)(1.15)(0.746)

COS, CWS. The F.D. fan is sized for 110 percent of the boiler's total design airflow when operating at maximum continuous rating. The fan is sized for a static pressure of 15 in. of water column and has a fan efficiency of 70 percent.

Fan Flow (ACFM) = (1.1)(ACFM)

Parameters:

ACFM = (Wet Airflow, ACFM)/(No. of Boilers - 1) or use the boiler program for one boiler to determine wet air ACFM flow.

BHP = [(144)(Fan Flow in ACFM)(80)]/[(33,000)(27.67)(0.65)]

Fan Motor Size (kW) = (BHP)(1.15)(0.746)

I.D. Fan Sizing.

Stoker, CFBC, BFBC, COS, CWS. The I.D. fans (one per boiler) draw the boiler flue gases out of the boiler, through such items as the mechanical collector, dry scrubber, and baghouse, and exhaust them into the boiler stack flue. The fan is sized for the combustion gases plus air leakage into the boiler, dry scrubber, and baghouse system. For this design, each fan is sized for 100 percent of the flue gas flows plus 15 percent leakage, a static pressure of 20 in. of water column and an efficiency of 70 percent.

Boiler Flue Gas Flow (ACFM) = (ACFM)/(No. of Boilers - 1)

I.D. Fan Gas Flow (ACFM) = (Boiler Flue Gas Flow) (1.15)

I.D. Fan BHP = (144) (I.D. Fan Gas Flow in ACFM)(20)/(33,000)(27.67)(0.7)

I.D. Fan Motor Size (kW) = (I.D. Fan BHP) (1.15) (0.746)

O.A. Fan Sizing: Stoker. The O.A. fan supplies air above the fuel bed of the stoker boilers. It is sized at 20 percent of the boiler's total design air flow when operating at maximum continuous rating. For the design, the fan is designed for a static pressure of 35 in. of water column and has an efficiency of 80 percent.

Fan Flow = (0.20)(ACFM)

Fan BHP = [(144)(Fan Flow)(35)]/[(33,000)(27.67)(0.8)]

Fan Motor Size (kW) = (Fan BHP)(1.15)(0.746)

Major Facility Pumps

There are three categories of pumps. One is the boiler feedwater pumps (BFWP). The second is the plant centrifugal pumps, which include the condensate pumps and the makeup or treated water pumps. The third is the Miscellaneous Centrifugal Sump Pumps, which include the rail-track hopper pumps, truck hopper pump, reclaim hopper pumps, neutralization tank pumps, brine wastewater sump pump, and the coal pile runoff pond neutralization pumps. Each category is generally described and sized for the design. (The firewater pumps are included in the fire protection subsection. The chemical feed pumps are included in the chemical feed skid subsection.)

Boiler Feedwater Pumps. The boiler facility includes two classes of BFW pumps. One is a motor driven, multi-stage, centrifugal pump; the second is a steam turbine driven, multi-stage, centrifugal pump.

The BFW pumps are sized so one boiler is used up to an individual boiler maximum continuous rating of 150,000 pounds of steam per hour (pph), while two pumps per boiler are used above the 150,000 pounds per hour rating. The pumps are volumetrically sized at plus 10 percent. The BFWP outlet pressures for both classes of pumps are as shown below.

Boiler Outlet Pressure (in psig)	BFWP Outlet Pressure (in psig)
250 PSIG	300 PSIG
625 PSIG	800 PSIG
1325 PSIG	1500 PSIG

The BFWP outlet pressure is appreciably greater than the boiler pressure because of the pressure losses in the piping and the boiler. The BFWPs include the pump, pump

driver (motor or turbine), base plate, coupling, and guards. The pumps are sized by the following equations.

Motor driven, for a boiler up to 150,000 pph MCR

Pump Size(GPM) = [(1.1)(Boiler MCR in lb/hr)(1 + % Blowdown)]/[(8.33 lb/gal)(60 min/hr)(1.2)]

Parameters:

a. Boiler MCR is from the screening model: boiler sizing.
b. Percent blowdown is a user input.
c. The equation is used for each boiler.

Motor driven, for a boiler greater than 150,000 pph MCR

Pump Size(GPM) = [(1.1)(Boiler MCR in lb/hr)(1 + % Blowdown)/(8.33 lb/gal)(60 min/hr)(1.2)]/2

Turbine driven BFWP, Pump Size (GPM) = (1.1)(Boiler MCR in lb/hr)(1 + % Blowdown)/(8.33 lb/gal)(60 min/hr)(1.2)

Use the following equation to estimate the BHP of each pump.

Pump BHP = (2.13)(Pump Size in GPM)(Pump Outlet Pressure)/(3960)(0.7)

Parameters:

a. Pump Size (GPM) is calculated from the appropriate preceding equations.
b. Pump Outlet Pressure is as shown in the general pump description.

Motor Size (kW) = (Pump BHP)(0.746)(1.15)

Turbine Drive BHP = (Pump BHP)/(0.85)

Plant Centrifugal Pumps. The centrifugal pumps pump water from various areas of the plant. The treated water pumps remove the treated water from the storage tank and deliver the water to the deaerator. The condensate pumps remove condensate from the storage tank and also deliver the water to the deaerator. These pumps are of one- or two-stage design; the head which they must operate against is largely a matter of piping loss and static-elevation pressure. These pumps are horizontal, end

section centrifugal pumps with constant speed motors, and include the pump, motor, coupling, base plates, and guards. There are three treated water pumps and three condensate pumps per facility. The pumps are sized using the following equations.

Pump Size (GPM) = (0.60) [(1.1)(PMCR)(1 + % Blowdown)/(8.33 lb/gal)(60 min/hr)]

Parameters:

a. PMCR and percent blowdown are user inputs from the boiler program.
b. Each pump is sized at 60 percent of the flow rate required to keep the plant operating at the PMCR.

Pump BHP = (2.31)(Pump Size in GPM)(50)/(3960)(.65)
The pump has an outlet pressure of 50 psi and an efficiency of 65 percent.

Motor Size (kW) = (Pump BHP)(1.15)(0.746)

Centrifugal Sump Pumps. The centrifugal sump pumps remove water from various plant areas. The pumps are sized as follows for stoker, CFBC, and BFBC.

No. of Pumps	Description	GPM	Hp	kW
1	Rail-Track Hopper Sump	150	5	4.3
1	Truck Hopper Sump	300	10	8.6
1	Reclaim Hopper Sump	300	10	8.6
2	Neutralization Tank Pumps	300	10	8.6
2	Brine Wastewater Pumps	150	5	4.3
2	Pond Neutralization Pumps	300	10	8.6

The pumps are sized as follows for COS and CWS.

No. of Pumps	Description	GPM	Hp	Kw
1	Rail Receiving Sump	60	3	2.4
2	Neutralizank Pumps	300	10	8.6
2	Brine Wastewater Pumps	150	5	4.3

Facility Auxiliary Equipment

The equipment presented in this section includes other equipment required for a new facility (i.e., air compressors; stacks; blowdown tanks; boiler chemical injection skid; fire protection system; heating ventilation and air conditioning (HVAC) system; elevator; controls; wastewater treatment; electrical system; continuous emission monitoring system (CEMS); boiler water laboratory equipment; mobile equipment; furniture; tools; and boiler house or building).

Air Compressors. General facility and instrument air compressors are reciprocating or rotary screw type units. Each compressor is water-cooled and includes a compressor, motor (V-belt or direct drive), guards, intake filters, silencers, oil filter, air receiver, aftercooler, and air dryer. The plant has two compressors, each sized for 100 percent of the total load. These compressors are sized by the following equations and produce 125 psig compressed air. (They are not for soot blowing or a bi-fluid dry scrubber. That equipment is included in the boiler or dry scrubber section.)

$$\text{Compressor ACFM} = (0.5)(\text{PMCR}/1000) + 125$$

$$\text{Compressor HP} = (0.11)(\text{PMCR}/1000) + 20$$

$$\text{Compressor kW} = (\text{Compressor in HP})(1.15)(0.746)$$

Stacks. Facility stacks are freestanding concrete chimneys that enclose steel flues (one flue for each boiler). Depending on the number of boilers, the plant has one or two chimneys. The 3-boiler facility has a single concrete chimney houses three individual boiler flues. The 4-boiler facility has two concrete chimneys, each housing two boiler flues. The 5-boiler facility has two concrete chimneys; one chimney housing two boiler flues, and the second housing three boiler flues. The steel flues are insulated, have stack sampling ports and are independently bottom supported.

The concrete chimneys are free designed for a wind load of 100 miles per hour and include testing platforms, a safety ladder to the top, interior and exterior lighting, and FAA lights. Diameters of steel flues are sized by:

$$\text{Flue Diameter (ft)} = (0.0001181)(\text{ACFM})$$

Parameter: ACFM is the total flue gas flow, in ACFM, from a single boiler. This can be approximated by: (plant ACFM)/(no. of boilers - 1)

Concrete chimney diameter can be estimated by the following.
For a two-flue Chimney:

Chimney Diameter (ft) = (0.0001181)(ACFM)(2) + 6

For a three flue Chimney:

Chimney Diameter (ft) = (3.5)(0.0001181)(ACFM)

The height of each concrete chimney is based on a "good engineering practice" of 2.5 times the height of a nearby high structure which, for the design, is the height of the boiler house.

Blowdown Tanks. The facility design has two types of boiler blowdown vessels or tanks. One is the continuous blowdown tank or flash tank and the other is the intermittent blowdown tank.

Each facility design includes 4 blowdown vessels, 2 continuous blowdown tanks, and 2 intermittent blowdown tanks. The continuous blowdown or flash tank receives boiler drum blowdown water and "flashes" the water at a design pressure. The flash steam is used in the deaerator and the water is sent to the drain. This tank is sized by:

Vessel Diameter (ft) = [(0.0367)(0.10)(PMCR)/(2)(1000)] + 0.62

Vessel Height (ft) = (3.5)(Vessel Diameter in ft)

The intermittent blowdown tank receives water intermittently from boiler water headers, "mud" drum, etc. For final design, this tank should be sized in accordance with the American Society of Mechanical Engineers (ASME) Pressure Vessel Code. For the design, the tank is the same physical diameter size and is 3 times the height of the continuous blowdown tank.

Chemical Injection Skid. The facility has a single boiler system chemical injection skid. The skid contains the equipment necessary to inject chemicals into the boiler drum (phosphates, amines or chelants and/or antifoaming agents) and an oxygen scavenging chemical (hydrazene or other) into the deaerator. The skid has three 55-gallon polyurethane mix tanks with agitators, piping and valves. Included with the skid are six positive displacement chemical feed pumps that transfer the chemicals to the boiler drum or the deaerator. The displacement pumps are sized at 0 to 10 gallons per hour and have a discharge pressure of 800 psig. (For higher pressure units, the drum chemicals would be injected into the feedwater system.) The skid is sized at 14 ft by 12 ft and has space for all of the previous equipment plus three 55-gallon drums of full strength chemicals.

Fire Protection System. The facility's fire protection system is basically a wet pipe system for protecting the facility from fire. The electrical room is protected by an inert gas system. The wet system includes a separate firehouse, two 1500-GPM at 125 psig diesel-driven fire water pumps, each with an 8-hour diesel storage tank; a jockey pump; fire monitors and alarms; a plant loop distribution system, sprinkler systems and piping, valves, and other necessary equipment. The inert gas system is a Halon system that suppresses fires by oxygen scavenging. The system consists of an inert gas pressure vessel with a discharge valve.

HVAC System. The HVAC system design is confined to the facility's offices, lunch room, locker rooms, and electrical equipment room. The remainder of the facility is not air conditioned. A 5-ton air conditioner is included for all sizes of facilities. The air conditioner is complete with cooling coils, fans, ductwork, insulation, and controls.

The heating system consists of steam or hot water heating coils for general facility heating. The coils are installed with air makeup units in the plant, radiators in the office, lunch room, locker room, and above doors and below windows.

Elevator. The facility includes one freight/personnel elevator. The elevator is 6 ft by 8 ft internal and will operate from the first floor elevation to the top of the boiler.

Facility Controls. The control systems for the facility are divided into two areas: the boiler/steam block and the yard area. The boiler block includes the controls necessary for the boilers, steam header, and boiler-associated equipment and/or systems. It is a conventional analog or digital control system that links every boiler for total plant control. Each boiler control is configured for single loop integrity and has a single control panel for operations overview with dedicated annunciator windows, and motor control and status indicators. Also included are auto/manual stations for combustion controls, steam outlet controls, and control switches and status indicators for the boiler auxiliaries. Each boiler control is interfaced with the total boiler system control for regulation of feedwater, fuel, airflow, desired boiler output, steam control, and proper combustion. Boiler auxiliary controls include monitoring and control of heat cycle equipment, boiler feed pumps, feedwater system, condensate system, and auxiliary electrical system.

The yard area controls include flue gas cleaning equipment, boiler water treatment system, wastewater pretreatment system, runoff pond neutralization system, ash handling system, lime handling system, and the coal handling system. Each control and monitoring system, although it relays information to other control systems, is independent of the others. This scheme physically distributes the total yard control and monitoring systems to their respective areas of operation so a failure of one

component will not significantly affect other yard area controls. For example, information critical to the boiler operations is linked to the boiler controls so operators know of potential yard area problems, but the failure of one control system does not result in the failure of the other.

The makeup water treatment system uses a programmable controller located on the equipment skid. The primary function of the controller is to sequence valve operation for system regeneration. Critical alarms and process variables are transmitted to the boiler block control system using either analog or discrete signal types. The wastewater pretreatment and pond neutralization systems use programmable controllers for caustic, coagulant, and acid feed rate, as well as pH control. Each system controller also directs the operation of all automatic valves, pumps, mixers, and conveyors associated with the system.

The flue gas cleaning equipment control system for the dry scrubbers, lime receiving, storage, and injection system, and baghouse includes a programmable controller for each system. The control panels for each system are located near the equipment they monitor. The ash handling control system uses a programmable controller that allows the operator to automatically adjust the hopper emptying sequence in response to varying firing conditions. The coal or fuel handling system uses a programmable controller that controls the coal conveying system.

Facility Wastewater Treatment. The facility has four types of wastewater flows that must be properly handled: sanitary waste, process (boiler system) wastewater, storm water, and coal pile runoff pond discharge.

Sanitary waste is the waste collected from water closets, sinks, and potable wastewater such as floor drains in the offices, lunch room, etc. The design does not include equipment for the treatment of such waste. All waste is collected and discharged to an existing sanitary sewer system.

Process wastewater is generated by the boiler systems. This is mainly wastewater from the treated water system, the boiler blowdowns, and equipment cooling water. This water should not contain oil, heavy metals, or other material that would make the wastewater unacceptable for discharge to the sanitary sewer system.

The wastewater from the treated water system is pretreated in the neutralization tank. This tank neutralizes the wastewater to an acceptable pH value before it is gradually discharged to the sanitary sewer system. As an alternate, the water could be discharged to the coal pile runoff pond or could be used for ash conditioning. The blowdown wastewater from the flash tank is sent to the sanitary sewer. Other process

water, from bearing cooling, facility washdown water, etc., is preliminarily cleaned using dirt settling chambers and/or grease-oil traps. This wastewater can then be sent to the sewer, runoff pond, dry scrubber system, or used for ash conditioning.

The facility includes a storm water collection system that channels the collected rainwater to an acceptable drainage area. This system also collects the wash water from the ash and coal areas (not including the long-term coal storage area and truck wash area). The drains located in these areas include appropriate traps or settling basins to collect the ash and coal particles.

Electrical Substation. The double-ended substation for the facility design includes two main stepdown transformers with oil filled breakers and other necessary equipment, hardware, and wire. The incoming voltage is 13.8kV and is stepped down to a 480V bus.

Plant Electrical Equipment. The electrical equipment necessary for the facility, includes breakers for equipment and the facility, motor starters, relays, wiring, lights, cable trays, and conduits.

Import Transmission Line. No equipment (wire or poles) is included for the transmission line. The presumption is that the utility serving the heating facility will provide this equipment.

Continuous Emission Monitoring System (CEMS). The continuous emission monitoring system provided for the plant continuously monitors SO_2, No_x, and opacity of the flue gases. This equipment is located in the stack flues near the manual sampling ports. Monitoring equipment is certified and conforms to applicable Federal, State, and local codes. The system has a remote- mounted control unit that is microprocessor based. It also provides status, alarms, and information on a display and/or hard copy. It has selector buttons to allow the operator to access specific data and change operating/alarm parameters such as set points. The equipment automatically maintains and generates reports as required by local, State, or Federal agencies.

Boiler Water Laboratory Equipment. The water laboratory equipment is required to perform boiler water quality analysis during boiler operations. The system analyzes the boiler water for oxygen, carbon dioxide, hydrogen sulfide, turbidity, oil, water hardness (all Ca and Mg salts), sodium alkalinity (NaHCO, Na_2CO_3 and NaOH), chlorides (Cl^-), sulfates (SO_4^{2-}), iron, manganese, silica (SiO_2), oxygen scavenger additive, pH, and scale inhibitor additives.

The system includes the equipment necessary to extract water and steam samples and pipe them to a central freestanding water laboratory cabinet. The cabinet includes a drain, sink, valves, cabinet areas for storing reagents and necessary apparatus, and a workbench for use during water analysis testing.

Mobile Equipment. The design provides mobile equipment for facility operation. The following equipment is included:

- Two front-end loaders with articulating four-wheel drive, diesel power, foam-filled tires, and a 4-cubic yard (6-ton) bucket,
- One light-duty front-end loader with four-wheel drive, diesel power, foam-filled tires, and a 1-cubic yard bucket,
- One forklift (for general plant maintenance) rated at 5,000 pounds capacity with four- wheel drive, diesel power, and pneumatic tires,
- Two heavy-duty steel construction drop boxes (provided for lime grit from the slaker and general plant maintenance) that have a 40-cubic yard capacity and drip-proof seals, and that can be picked up with a tilt frame (roll-off) truck or other vehicle,
- One pickup truck that meets all local, State and Federal safety and emission controls; and that has a 3/4-ton carrying capacity, diesel power, and 8-ply tires,
- One power sweeper (for general internal and external plant maintenance) with diesel power and a wet/dry cleaning option, and
- One 5-ton capacity dump truck, for general plant use, sized with a 5-yard dump body.

Furniture. The new plant includes the necessary equipment to furnish the plant offices, lunch room, locker rooms, maintenance shop, boiler operating areas, and other areas. Furniture in the design includes decks, swivel chairs, two- and four-drawer file cabinets, bookcases, side chairs, stacking chairs, lunch room tables, benches and cabinets with counter tops, lockers, locker room benches, supervisor floor desks, metal storage bins, and racks.

Plant Communications. The plant will also have a telephone system that includes telephone stations, attendant console, private automatic branch exchange (PABX), amplifiers, battery, battery charger, paging speakers and horns, wiring systems, and

all necessary conduits. Units installed in high noise areas, are provided with acoustic booths and noise limiting devices on the telephone receiver. Other features are direct, station-to-station calls within PABX (without attendant assistance), direct outward dialing for outside and long distance calls, direct access to paging systems, night answering, and call forwarding.

Tools. A new facility has basically two types of tools or machinery that need to be included: hand tools and major tool room equipment. Hand tools will be used to perform maintenance on the equipment. Major tool room equipment includes such items as metal lathes, grinders, welders (gas and electric), drill stand or press, hydraulic press, milling machine, and other necessary machinery.

Building. The only building for the stoker boiler facility is the boiler house. This houses the boilers and associated equipment as well as the plant's office, lunch room, men's and women's locker rooms, plant maintenance, and stores. Other enclosed areas, (ash load up room, scrubber penthouse, maintenance) are included with the equipment. The boiler house size is estimated by equations in the Screening Model Section. The building is metal sided with power roof vents, windows, personnel doors, and roll-up vehicle doors. Included with the building are building steel, siding and roof with insulation, stairs, ladders, floors, grating, and other construction materials.

Diesel Generators. The diesel generator is required for on-site backup or emergency electrical power. The units range from 100 to 1500 kW and are skid mounted, stand-alone units. The diesel generator is sized by adding the major equipment BHP or kW and multiplying by a 0.25 factor up to a maximum of 1500 kW.

Piping. The plant piping system includes high, medium, and low pressure steam; exhaust steam; steam system supply; steam return; condensate (plant and return); city process water; city potable water; treated water; feedwater; boiler blowdown; sanitary drains; roof drains; process water drains; storm water drains; plant heating system; fuel oil piping; chemical piping; and compressed air piping. During the preliminary design for a specific facility, the major piping systems should be addressed and a preliminary design should be completed.

Spare Parts. Spare parts for major equipment and systems are a requirement for a new facility. These parts are usually defined as a capital expense during operation of a facility and need to be included in the cost estimate.

Initial Facility Inventory. A new facility must start with an initial inventory of consumables. These are items normally considered yearly operational needs, but a new facility must have an initial inventory to begin operations. Items included in this

category are packing seals, grease, oil, small parts (bearings, valves, pipe, fittings, etc.), rags, light bulbs, buckets, mops, cleaning agents, towels.

New Cogeneration Facility

This section describes the equations and designs used to calculate the plant area requirements and the plant cost equations for cogeneration. Subsections include discussions of the equipment used for a cogeneration plant, typical layouts for each cogeneration facility, and discuss specific cogeneration equipment.

Equipment List

The major equipment list for a cogeneration plant includes all heating plant equipment with the addition of a turbine-generator, condenser, cooling tower, circulating water pumps, and feedwater heaters.

Facility Conceptual Layout

The conceptual facility design layout is horizontally designed. Figures 11 and 12 show a typical 4-boiler facility, including areas for the boiler, turbine-generator, condenser, plant offices, lunch room, locker/restrooms, electrical equipment room, maintenance area, elevator, and other necessary spaces.

Turbine-Generator

The cogeneration facility uses a single extraction-condensation turbine-generator to generate electricity and provide plant heating system and process steam. The 600 psig and 750 ^{0}F steam turbine has a maximum of two steam extractions. The extractions are 170 psig (which are used for the heating system), possibly a feedwater heater and/or process steam, and a 35 or 50 psi extraction for feedwater heating. Total allowable steam extraction is maximized at 80 percent of full turbine throttle flow steam rate. (PMCR for the conceptual design is full turbine throttle flow.) This allows a minimum of 20 percent flowing to the turbine exhaust stages of the turbine cooler. The turbine is designed for full flow condensing.

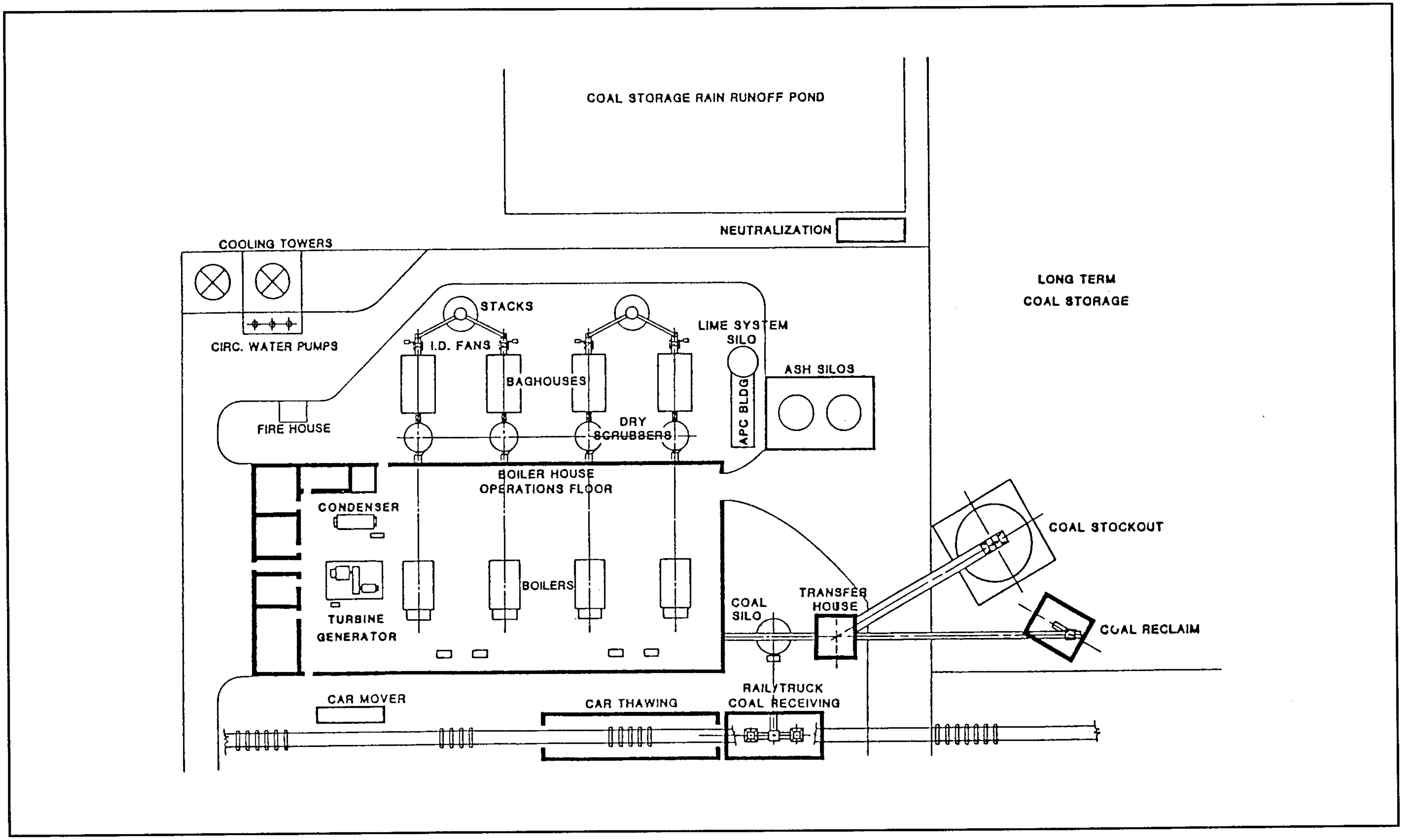

Figure 11. Typical 4-boiler small cogeneration facility layout.

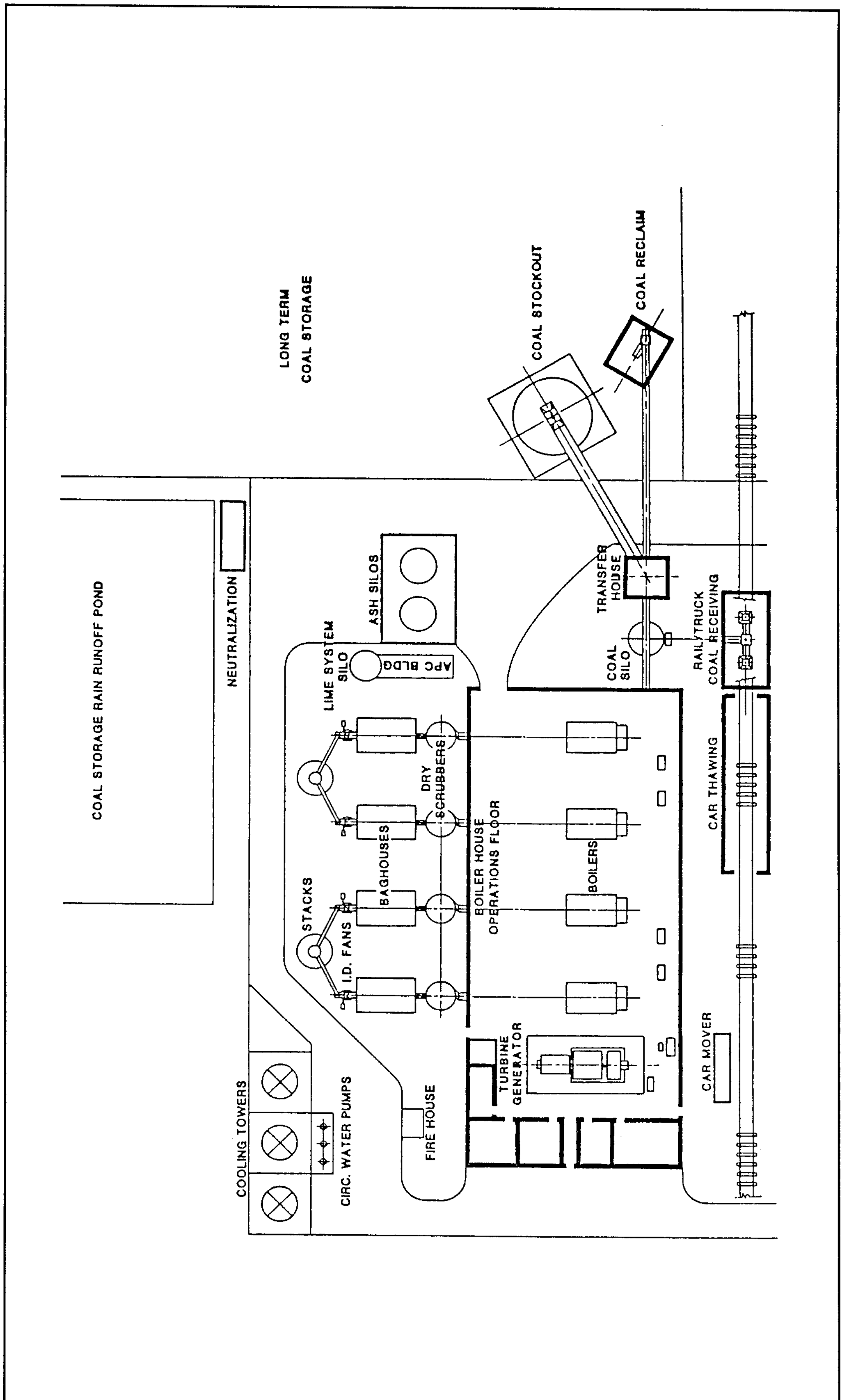

Figure 12. Typical 4-boiler large cogeneration facility layout.

The generator is a 3-phase, 60 cycle, synchronous, air-cooled type with brushless exciters. The generator's voltage is 13.8 KV and rated at 150 MVA with a 0.85 P.F. (power factor). The turbine-generator is sized in megawatts (MW) using full throttle flow condensing.

PMCR @ 600 psig & 750 °F - Condensing MW = (0.1084)(PMCR/1000)

PMCR @ 1300 psig & 1000 °F - Condensing MW = (0.1447)(PMCR/1000)

Condenser

The condenser is a two-pass, shell and tube surface type condensor, sized for full turbine throttle flow condensing at 2.5 or 3 in. mercury, absolute (HgA) depending on the steam turbine system.

The condenser is sized by:

Tube Surface (sq ft) = PMCR/10

Condenser Length (ft) = 0.3(PMCR/10,000)

Condenser Diameter (ft) = [(0.136)(PMCR/10,000) + 9]

Condenser Height (ft) = [(0.136)(PMCR/10,000) + 9] + 1.5

Cooling Tower

The cooling tower is provided to cool the main condenser and plant auxiliary systems. It is designed for a midcontinent location (Tennessee) and for a 1 percent wet bulb condition. It is a multicell, induced draft, counterflow evaporative tower mounted on a concrete basin and foundation.

The cooling tower is sized using the following design factors: the tower heat load equals condenser duty plus 10 percent for auxiliary cooling; cooling water has a 20 °F delta temperature; the cooling tower operates at five cycles; each cooling tower cell is approximately 40 ft high, 45 ft wide, and 50 ft long; and the condensing heat load is that of full turbine throttle flow.

Condenser Cooling Water Flow (gpm) = (PMCR)(1010 Btu/lb)/(20 Btu/lb water) (60 min/hr)(8.33 lb/gal)

Circulating Water Flow (gpm) = (1.1)(PMCR)(1010 Btu/lb)/(20 Btu/lb water) (60 min/hr)(8.33 lb/gal)
Note that the maximum tower cell size is 17,000 gpm circulating water flow.

No. of Cells = (Circulating Water Flow in gpm)/17,000
Note that the number of cells is rounded up to the nearest whole number.

Evaporation (gpm) = (Circulating Water Flow in gpm) (0.014)

Blowdown (gpm) = (Evaporation in gpm)(0.20)

Makeup (gpm) = (Evaporation in gpm)(1.2) + (0.001)(Circulating Water Flow in gpm)

Cooling Tower Length = (No. of Cells) (50)

Cooling Tower Fans (one per cell) are sized by:

Tower Airflow (ACFM) = (Circulating Water Flow in gpm)(18.017)

Tower Fan Flow (ACFM) = (Tower Airflow in ACFM)/(No. of Cells)

Tower Fan BHP = (Tower Fan Flow in ACFM) (0.0004)

Tower Fan Motor Size (kW) = (Tower Fan BHP) (.8579)

Total Tower Fan kW = (Tower Fan Motor Size in kW) (No. of Cells)

Circulating Water Pumps

The circulating water pumps are high capacity, low head pumps. The pumps circulate the cold cooling tower water through the turbine condenser and plant auxiliary coolers and then back to the cooling tower. The facility uses three circulating water pumps. Each pump is sized at 40 percent of the maximum circulating water flow rate and for a 30 psi (70 ft) discharge pressure. The circulating water pumps are sized by:

Total Pump Capacity (lb/hr) = (7.915)(PMCR)

Pump Capacity (gpm) = (7.915)(PMCR)(0.40)/(499.8)

Pump BHP = (2.31)(30)(7.915)(PMCR)(0.40)/(499.8)(3960)(0.70)

Pump Motor Size(kW) = (1.15)(0.746)(2.31)(30)(7.915)(PMCR)(0.40)/(499.8)(3960)(0.70)

Feedwater Heaters

The feedwater heaters are used in the cogeneration regenerative feedwater heating cycle to heat the water before it enters the boilers. The 600 psig and 750 °F cogeneration system does not use a feedwater heater. (The deaerator preheats the feedwater.)

If the throttle flow is from 100,000 to 250,000 pounds of steam per hour, the system has a single low-pressure heater operating at approximately 20 psig. (The deaerator also preheats the feedwater and operates at about 50 psig.)

If the throttle flow is from 250,000 to 600,000 pounds of steam per hour, the system uses a low-pressure heater at about 10 psig and a high-pressure feedwater heater operating at about 120 to 150 psig. (The deaerator also preheats the feedwater and operates at about 20 psig.)

The 1300 psig and 1000 °F cogeneration system uses a high-pressure feedwater heater operating at about 350 psig, a low-pressure heater at about 30 psig, and a second low-pressure heater operating at about 10 psig. (The deaerator also preheats the feedwater and is operating at about 50 psig.) The feedwater heaters are sized by the following for low pressure heaters at less than 50 psig operating pressure:

Surface Area (ft^2) = (Total Treated Water in gpm)(0.00061)
Note that the total treated water is calculated in the boiler feedwater section.

Effective Tube Heating Length (ft) = (2.25×10^{-5})(Total Treated Water in gpm) + 6.5

Shell Diameter (ft) = (0.1167)(Surface Area)/(Effective Tube Heating Length)

Heater Length (ft) = [(Effective Tube Heating Length)/2] + 3

The feedwater heaters are sized by the following for high pressure heaters at less than 175 psig operating pressure:

Surface Area (sq ft) = (Total Treated Water in gpm)(0.00168)

Effective Tube Heating Length (ft) = (7.273 x 10^{-5})(Total Treated Water in gpm) + 4

Shell Diameter (ft) = (0.167)(Surface Area)/(Effective Tube Heating Length)

Heater Length (ft) = [(Effective Tube Heating Length)/2] + 3

The feedwater heaters are sized by the following for high pressure heaters at less than 350 psig operating pressure:

Surface Area (sq ft) = (Total Treated Water in gpm)(0.002)

Effective Tube Heating Length (ft) = (7.273 x 10^{-5})(Total Treated Water in gpm) + 5

Shell Diameter (ft) = (0.167)(Surface Area)/(Effective Tube Heating Length)

Heater Length (ft) = [(Effective Tube Heating Length)/2] + 3.5

5 Capital Costs

New Facility Capital Construction Cost

This section includes the equations used to determine the capital cost for new solid fuel fired steam production and cogeneration power plants. The major equipment costs are divided into subsections that have different costs for each of the boiler technologies. The lists below indicate the subsections required for each of the boiler technologies. Also, additional subsections are indicated for cogeneration and consolidation.

Once the equipment costs are determined, they are added to the freight and installation direct costs. Finally the indirect costs are added to complete the boiler plant cost. These are further explained after the equipment costing subsections.

Stoker - Major Facility Equipment Cost Subsections

Boiler
- Coal Handling
- Ash Handling
- Mechanical Collector
- Dry Scrubber and Lime System
- Baghouse and ID Fan
- Boiler Water Treatment
- Tanks
- Pumps
- Air Compressors
- Wastewater Treatment
- Piping
- Instrumentation
- Electrical
- Building and Services
- Site Development
- Spare parts, tools, mobile equipment

Additional Subsections for Cogeneration
- Condenser
- Cooling Tower
- Feed Water Heater
- Turbine Generator

Additional Subsections for Consolidation
Steam Distribution System
CFBC and BFBC - Major Facility Equipment Cost Subsections
Boiler
- Coal Handling
- Ash Handling
- Mechanical Collector
- Baghouse and I.D. Fan
- Limestone Handling
- Boiler Water Treatment
- Tanks
- Pumps
- Air Compressors
- Waste Water Treatment
- Piping
- Instrumentation
- Electrical
- Building and Services
- Site Development
- Spare parts, tools, mobile equipment

Additional Subsections for Cogeneration
- Condenser
- Cooling Tower
- Feed Water Heater
- Turbine Generator

Additional Subsections for Consolidation
Steam Distribution System
COS & CWS - Major Facility Equipment Cost Subsections
Boiler
- Fuel Handling
- Ash Handling
- Mechanical Collector
- Baghouse and I.D. Fan

Boiler Water Treatment
Tanks
Pumps
Air Compressors
Waste Water Treatment
Piping
Instrumentation
Electrical
Building and Services
Site Development
Spare parts, tools, mobile equipment

Additional Subsections for Cogeneration

Condenser
Cooling Tower
Feed Water Heater
Turbine Generator

Additional Subsections for Consolidation
Steam Distribution System

Boilers

The Boiler Subsection includes cost estimates for the boiler, desuperheater if required, and air heater for COS and CWS. The boiler budget cost represents a typical boiler subcontract. The scope of supply of each boiler type is listed below:

Stokers

Boiler Pressure Parts and Drums
Boiler Trim and Soot Blowers
Boiler Refractory, Insulation and Lagging
Stoker and Grate
F.D. Fan and Overfire Air Fan
Combustion Air Ductwork and Distribution System
Superheater, if applicable, with Attemperator
Boiler Convective Sections
Economizer or Air Heater
Main Steam Non-Return and Block Valve
Coal Feeders

- Coal Distribution Duct
- Coal Scale
- Fly Ash Reinjection System
- Ash Hoppers
- Boiler Steel
- Boiler Instruments
- Freight
- Erection and Erection Supervisor
- Start-up Supervision
- Boilout and Initial Operator Training
- Operation Manuals

Recirculating Fluid-Bed

- Boiler Pressure Parts and Drums
- Combustion Chamber with Membrane Walls
- Boiler Trim and Soot Blowers
- Boiler Non-Return and Block Valves
- Boiler Steel
- Economizer
- Hot Cyclone Separators with Hot Gas Ducts between Cyclones and Combustion Chamber and between Cyclones and Superheater, if applicable
- Ash Hoppers
- Coal and Limestone Feeders
- Fluidizing Grid
- Auxiliary Burner System for Start-up, Shutdown and Auxiliary Fuel Firing
- Primary and Secondary (F.D.) Fans
- Primary and Secondary Fan Air Distribution Systems
- Auxiliary Burner Air System
- Ash Removal and Cooling System Superheater, if applicable
- Attemperator, if applicable
- Boiler Refractory, Insulation and Lagging
- Erection
- Boiler Instruments and Controls
- Erection and Start-up Supervision
- Boilout and Initial Operator Training
- Boiler Operation Manuals
- Freight

Bubbling Fluid-Bed

- Boiler Pressure Parts and Drums
- Combustion Chamber with Membrane Walls
- Boiler Trim and Soot Blowers
- Boiler Non-Return and Block Valves
- Boiler Steel
- Economizer
- Hot Cyclone Separators with Hot Gas Ducts between Cyclones and Combustion Chamber and between Cyclones and Superheater, if applicable
- Ash Hoppers
- Coal and Limestone Feeders

Coal-Oil Slurry

- Boiler Pressure Parts and Drums
- Boiler Steel
- Economizer or Air Preheater
- Burner
- Boiler Refractory, Insulation and Lagging
- F.D. Fan
- F.D. Fan Air Ducts
- Superheater, if applicable
- Attemperator, if applicable
- Main Steam Non-Return and Block Valves
- Freight
- Erection Supervisor and Start-up Supervision
- Boiler Instruments
- Boilout and Initial Operator Training
- Boiler Operation Manuals

Coal-Water Slurry

- Boiler Pressure Parts and Drums
- Boiler Steel
- Burner
- Boiler Refractory, Insulation and Lagging
- F.D. Fan
- F.D. Fan Air Ducts
- Superheater, if applicable
- Attemperator, if applicable

Attemperator, if applicable
Main Steam Non-Return and Block Valves
Freight
Erection Supervisor and Start-up Supervision
Boiler Instruments
Boilout and Initial Operator Training
Boiler Operation Manuals

Excluded from the boiler costs are items such as foundations, tie-ins for electrical controls and piping to and from the boilers. These items are part of the associated installation costs listed as labor, bulk materials, and construction indirects.

The boiler cost equations are all linear and are shown as a function of the steam production rate or maximum continuous rating (MCR) of the boiler. The cost equations are based on a bituminous coal. For other than bituminous coal, the boiler cost equations are multiplied by the following factors: anthracite, 1.00; subbituminous, 1.08; and lignite, 1.12.

Typically, as the fuel decreases in value (on a Btu/lb basis), the ash and moisture content increase. As these values increase, the boiler must be made physically larger to accommodate these poorer fuels. Therefore, the cost increases. Anthracite, being a high quality coal, has a lower percentage of volatile matter and thus requires almost the same overall physical boiler size, although of different design. The cost, therefore, is estimated to be the same as for a bituminous coal boiler.

The estimated boiler costs are a function of the boiler type, outlet steam pressure, temperature, and steam flow (MCR). The costs are estimated by:

Stoker Boilers

1. 250 psig Saturated Steam
   Range up to 200,000 lb/hr
   Cost = [(0.01867)(MCR/1000) + 1.12] Million

2. 600 psig and 750°F Steam
   Range up to 200,000 lb/hr
   Cost = [(0.019)(MCR/1000) + 1.55] Million

3. 1300 psig and 1000 °F Steam
   Range up to 200,000 lb/hr
   Cost = [(0.025)(MCR/1000) + 1] Million

Recirculating Fluid-Bed Boilers

1. 250 psig Steam
   Range 50,000 - 200,000 lb/hr
   Cost = [(0.0213)(MCR/1000) + 1.14] Million

2. 600 psig and 750 °F Steam
   Range 50,000 - 200,000 lb/hr
   Cost = [(0.0273)(MCR/1000) + 0.75] Million

3. 1300 psig and 1000 °F Steam
   Range 100,000 - 200,000 lb/hr
   Cost = [(0.026)(MCR/1000) + 1.1] Million

Bubbling Fluid-Bed Boilers

1. 250 psig Steam
   Range up to 200,000 lb/hr
   Cost = [(0.0213)(MCR/1000) + 1.14] Million

2. 600 psig and 750 °F Steam
   Range 50,000 - 200,000 lb/hr
   Cost = [(0.025)(MCR/1000) + 0.85] Million

3. 1300 psig and 1000 °F Steam
   Range 100,000 - 200,000 lb/hr
   Cost = [(0.026)(MCR/1000) +1.1] Million

Coal-Oil Slurry Boilers

1. 250 psig Steam
   Range up to 200,000 lb/hr
   Cost = (8.36)(MCR) - 22,000

2. 600 psig and 750 °F Steam
   Range up to 200,000 lb/hr
   Cost = (9.02)(MCR) + 66,000

3. 1300 psig and 1000 °F Steam
   Range 50,000 - 200,000 lb/hr
   Cost = (12.5)(MCR) + 140,000

Coal-Water Slurry Boilers

1. 250 psig Steam
   Range up to 200,000 lb/hr
   Cost = (9.5)(MCR)

2. 600 psig and 750 °F Steam
   Range up to 200,000 lb/hr
   Cost = (10.25)(MCR) + 75,000

3. 1300 psig and 1000 °F Steam
   Range 50,000 - 200,000 lb/hr
   Cost = (14.2)(MCR) + 160,000

The desuperheater includes a pressure reducing valve (PRV) to reduce main steam pressure and temperature to the lower system requirement level. This allows a high-pressure system to provide steam that heats the feedwater. It also allows a cogeneration system ("bypassing" the turbine) to send steam to the heating system and/or feedwater system. The desuperheater estimated cost is an option, with an allowance cost of $8,000 for all systems.

The air heater is necessary for coal-water slurry boilers only. (All other boilers include either an economizer or air heater.) The heater is a regenerative type sized to produce up to 450 °F combustion air. The air heater includes: structural framework and supports, insulation and lagging, inlet and outlet duct breeching, baskets, and a basket washer or blower.

The air heater estimated cost is provided by:

Cost = 9.8(Combustion Air ACFM) + 85,000

Coal Handling System

The coal handling system is divided into the following categories; truck receiving, truck receiving with stock and reclaim system, rail receiving, rail receiving with stock and reclaim system, car heating, coal silo, car dumper, coal pile runoff pond, and railroad. To determine coal handling costs, the program requires user input on whether rail or truck will be used, if a stock/reclaim system should be included, if car heating is required, and, if a coal silo is required, how many days of storage is required for the silo. The estimated cost of these systems is:

Truck Receiving

Cost ($) = 5000(TPH) + 100,000

Parameters: Minimum Cost = $350,000
Maximum Cost is @ 150 TPH
The system does not include a stock/reclaim system or a silo.

Truck Receiving with Stock/Reclaim

Cost ($) = 6550(TPH) + 140,000

Parameters: Minimum Cost = $450,000
Maximum Cost is @ 150 TPH
The system does not include a silo.

Rail Receiving

Cost ($) = 2400(TPH) + 775,000

Parameters: Minimum Cost = $1,000,000
Maximum Cost is @ 250 TPH
The system does not include a silo, a stock/reclaim system, nor car heating.

Rail Receiving with Stock/Reclaim

Cost ($) = 4350(TPH) + 760,000

Parameters: Minimum Cost = $1,200,000
Maximum Cost is @ 250 TPH
The system does not include a silo or car heating.

Car Heating

Cost ($) = 367(TPH) + 23,000

Parameters: Minimum Cost = $50,000
Maximum Cost is @ 250 TPH

Coal Silo

Cost ($) = (Tons of Storage) - 40,000

Car Dumper

The car dumper installed cost is estimated at $2.2 million this includes rotary car dumper, house, positioners, railroad over pit, pit, and coal hopper.

Railroad

The railroad cost is $85 per linear foot of track.

Coal Pile Runoff Pond

The pond receives storm water runoff from the long-term coal storage area. Technical Manual 5-848-3, dated March 1984, requires the pond to be sized to contain the runoff from a 10-year, 24-hour storm maximum with 2 ft of freeboard. The sizing method uses an average pond water depth of 4 ft and sizes the pond for 4 in. of rain in 24 hours, with no absorption. The pond cost is estimated at $1200 per 1000 (or $1.20/sq ft). The major cost items include excavation and liner costs.

Fuel Handling

The Fuel Handling Subsection is used in the coal-slurry boiler plants. This subsection consists of the long-term storage tanks and transfer pumps. The size and number of tanks is determined in the equipment sizing section. The cost is:

Cost = (0.179)(gallons) + 83,000

The Day Fuel Storage Tank cost is:

Range 2,000 to 36,000 gallons
Cost = (0.553)(gallons) + 200

Ash Handling

The ash removal and handling system is a pneumatic system. The size and cost is based on the amount of ash in the fuel, the boiler type, and other equipment (dry scrubbers) that add material the ash system must handle. The boiler type (stoker,

fluid-bed, coal-slurry) determines the ash conveying systems. The system size and the size and cost of the mechanical exhausters and ash receiver determines its cost. These costs, along with the ash silo and control system costs, are added together to determine the total ash system costs. The ash system costs are derived as follows:

Ash Pipe Length Estimate.

Equation A: Bottom Ash Pipe Length = (Bldg. Length - 25) + (Bldg. Width + 15)+ Ash Silo Height + 25
Note that the building length & width are calculated in Table 13.

Equation B: 1. Settling Chamber Ash Pipe = Mechanical Collector Ash Pipe Length

2. Mechanical Collector Ash Pipe Length = (Bldg. Length - 25)

Table 13. Width and length of boiler houses.

Stoker	Width (ft)	Length (ft)
3-Boiler	[(0.0913)(PMCR)/1000)] + 49	[(0.34)(PMCR/1000)] + 89
4-Boiler	[(0.0913)(PMCR)/1000)] + 49	$(9[1-([500 - (PMCR/1000)]^2/304{,}704)])^{1/2} + 0.3$
5-Boiler	[(0.0913)(PMCR)/1000)] + 49	[(0.433)(PMCR/1000)] + 119
CFBC		
3-Boiler	[(0.1)(PMCR)/1000)] + 55	[(0.1125)(PMCR/1000)] + 153
4-Boiler	[(0.11)(PMCR)/1000)] + 53	[(0.1)(PMCR/1000)] + 220
5-Boiler	[(0.105)(PMCR)/1000)] + 54	[(0.1)(PMCR/1000)] + 210
BFBC		
3-Boiler	[(0.112)(PMCR)/1000)] + 57	[(0.31)(PMCR/1000)] + 80
4-Boiler	[(0.112)(PMCR)/1000)] + 57	[(0.345)(PMCR/1000)] + 110
5-Boiler	[(0.08)(PMCR)/1000)] + 65	[(0.42)(PMCR/1000)] + 120
COS		
3-Boiler	[(0.1429)(PMCR)/1000)] + 50	[(0.01)(PMCR/1000)] + 130
4-Boiler	[(0.1429)(PMCR)/1000)] + 50	[(0.12)(PMCR/1000)] + 154
5-Boiler	[(0.1429)(PMCR)/1000)] + 50	[(0.129)(PMCR/1000)] + 180
COS		
3-Boiler	[(0.175)(PMCR)/1000)] + 62	[(0.01)(PMCR/1000)] + 130
4-Boiler	[(0.175)(PMCR)/1000)] + 62	[(0.12)(PMCR/1000)] + 154
5- Boiler	[(0.175)(PMCR)/1000)] + 62	[(0.129)(PMCR/1000)] + 180

Equation C: Scrubber Residue Ash Pipe Length = (Bldg. Length) + (Ash Silo Height + 25)

Equation D: Baghouse Residue Ash Pipe Length = (Bldg. Length) + (Ash Silo Height + 25) + [(No. of Boilers)(Baghouse Size + 15 ft)

Branch Line Gates.

Equation E: Stoker Boiler: Eqn. = (No. of Boilers) + 5
3-Blr. Hse.: Gates = 8
4-Blr. Hse.: Gates = 9
5-Blr. Hse.: Gates = 10

Equation F: Recirculating Fluid-Bed: Eqn. = (No. of Boilers) + 4
3-Blr. Hse.: Gates = 7
4-Blr. Hse.: Gates = 8
5-Blr. Hse.: Gates = 9

Equation G: Bubbling Fluid-Bed: Eqn. = (No. of Boilers) + 4
3-Blr. Hse.: Gates = 7
4-Blr. Hse.: Gates = 8
5-Blr. Hse.: Gates = 9

Equation H: Coal-Slurry: Eqn. = (No. of Boilers) + 1
3-Blr. Hse.: Gates = 4
4-Blr. Hse.: Gates = 5
5-Blr. Hse.: Gates = 6

Fly Ash Intakes.

Stoker

Equation I: Eqn. = (No. Blrs.)[3 + (0.6)(Baghouse Approx. Sizing)]

Recirculating Fluid-Bed

Equation J: Eqn. = (No. Blrs.)[2 + (0.6)(Baghouse Approx. Sizing)]

Bubbling Fluid-Bed

Same as Recirculating Fluid-Bed - Equation J

Coal Slurry

Equation K: Eqn. = (No. of Blrs.)[1+ (0.6)(Baghouse Approx. Sizing)

Bottom Ash Intakes.

Equation L: Eqn. = 2 * (No. of Blrs.)

Ash Pipe System Size.

Bottom Ash

Equation M: Pipe Size = (0.1143)(TPH) + 5.42

Parameters:

a. If less than 5 TPH, size pipe = in.,
b. If greater than 40 TPH, pipe = 12 in.,
c. Eqn. to be rounded up to nearest whole number
TPH = (Bottom Ash)(3)/2000

Fly Ash (Mechanical Collector, Settling Chamber, Scrubber Residue, Baghouse)

Equation N: Pipe Size = (0.1667)(TPH) + 3.66

Parameters:

a. If less than 2 TPH, pipe size = 4 in.,
b. Range = 2 to 20 TPH
c. Eqn. to be rounded up to nearest whole number.

Equation O: Pipe Size = (0.08)(TPH) + 5.8 - Range of 20 to 40 TPH

Equation P: Pipe Size = (0.086)(TPH) + 5.55 - Range of 40 to 75 TPH

Equation Q:
1. Bottom Ash Pipe Cost ($/ft) = (Eqn. M)(8.75) + 25
2. Fly Ash Pipe Cost ($/ft) = (Pipe Size)(8.75) + 25

Note that the Pipe Size = Eqn. N, O, or P.

Ash Pipe System Cost ($).

Equation R: Bottom Ash Pipe ($) = (Eqn. A)(Eqn. Q.1)

Equation S: Settling Chamber Ash Pipe ($) = (Eqn. B.1)(Eqn.Q.2)

Equation T: Mechanical Collector Ash Pipe($) = (Eqn. B.2)(Eqn.Q.2)

Equation U: Scrubber Residue Ash Pipe ($) = (Eqn. C)(Eqn. Q.2)

Equation V: Baghouse Residue Ash Pipe ($) = (Eqn. D)(Eqn. Q.2)

Total Ash Piping System Cost.

Stoker Boiler
Equation W: Cost = Eqn. R + S + T + U + V

Recirculating Fluid-Bed Boiler
Equation X: Cost = Eqn. R + S + T + V

Bubbling Fluid-Bed Boiler
Equation Y: Cost = Eqn. X (Same as Recirculating Fluid-Bed)

Coal Slurry Boiler
Equation Z: Cost = Eqn. T + V

Air Operated Branch Line Gate Cost/Gate.

Equation AA: Bottom Ash System - Gate Size Costs ($) =

1. Gate Cost = (33.333)(Eqn. M) + 120
   Where: Eqn. M = 6 to 9 in.

2. Gate Cost = (250)(Eqn. M) + 1000
   Where: Eqn. M = 10 to 12 in.

Equation BB: Mech. Collector or System Gate Size Cost ($) or Settling Chamber - Gate Size Cost ($) or Scrubber Residue - Gate Size Cost ($) or Baghouse Residue - Gate Size Cost ($).

Equation BB.1: Cost = (Eqn. N, O, or P)(200) + 200
Where: Eqn. N, O, or P = 4" - 6"

Equation BB.2: Cost = (Eqn. N, O or P)(33,333) + 1200
Where: Eqn. N, O, or P = 6" - 9"

Equation BB.3: Cost = (Eqn. N, O, or P)(250) + 1000
Where: Eqn. N, O, or P = 10" - 12"

Air Operated Branch Line Gate Costs.

Equation CC: Stoker Boilers: Gate Cost = (Eqn. AA 1 or 2)(2) + (Eqn. BB 1 or 2 or 3)(3) + (No. of Boilers)

Equation DD: Recirculating Fluid-Bed = Bubbling Fluid-Bed Cost = (Eqn. AA 1 or 2)(2) + (Eqn. BB 1 or 2 or 3)(2) + (No. of Boilers)

Equation EE: Coal Slurry Boilers: Gate Cost = (Eqn. BB 1, 2 or 3) + (No. of Boilers)

Air Operated Fly Ash Intake Cost ($).

Equation FF: Stoker Cost = (Eqn. I)(1400)

Equation GG: Recirculating Fluid-Bed & Bubbling Fluid-Bed Cost= (Eqn. J)(1400)

Equation HH: Coal Slurry Cost = (Eqn. K)(1400)

Manual Bottom Ash Intake Cost ($).

Equation II: Cost = (Eqn. L)[(Eqn. M)(62.5) + 125]

Mechanical Exhauster Cost ($).

Stoker & FBC
Equation JJ: Cost = [(Eqn. M)(6872) - 7500] (3)

Coal Slurry
Equation KK: Cost = [(Eqn. N,O,P)(6872) - 7500] (3)

Receiver Cost ($).

Stoker & FBC
Equation LL: Cost = (Eqn. M)(5833) + 5000

Coal Slurry
Equation MM: Cost = (Eqn. N,O,P)(5833) + 5000

Parameters:

a. Range 6 to 12 in. pipe.
b. If less than 6 in., then use 6 in.

Ash Silo with Steel, Manhole, Fluidizing & Paddle Mixer Unloader Cost ($).

Equation NN: Cost = (Ash Silo Capacity - Tons)(588) + 4400
Note that the range is 200 - 1200 Tons for Ash Silo Capacity.

or

Equation OO: Cost = (Ash Silo Capacity in Tons)(166.67) + 510,000
Note that the range is 1200 - 2000 Tons for Ash Silo Capacity

Control Costs ($).

Stoker & FBC
Equation PP: Cost = (Eqn. M)(10,833) - 30,000

Coal Slurry
Equation QQ: Cost = (Eqn. N,O, or P)(10,833) - 30,000

Total System Costs ($).

Stoker Boiler Cost = Eqn. W + Eqn. CC + Eqn. FF + Eqn. II + Eqn. JJ + Eqn. LL + (Eqn. NN or OO) + Eqn. PP

Fluid-Bed Boiler Cost = Eqn. X + Eqn. DD + Eqn. GG + Eqn. II + Eqn. JJ + Eqn. LL + (Eqn. NN or OO) + Eqn. PP

Coal Slurry Cost = Eqn. Z + Eqn. EE + Eqn. HH + Eqn. II + Eqn. KK + Eqn. MM + Eqn. (MN or OO) + Eqn. QQ

Ash Silos. The ash silos are of steel construction with flat bottoms. Components consist of manholes, relief valves, a fluidizing system, a paddle wheel unloader, ash floors with steel siding, enclosure for the ash receiver, stairs, ladders, and platforms. The cost is for materials only. Construction items such as tie-ins, foundations, erection, etc. are accounted for in the associated cost factors. The material costs are provided with the ash system costs (see Eqn. NN or Eqn. OO).

Boiler Water Treatment

Equipment costs for the water treatment systems are based on budget and escalated costs. The systems are divided into four categories: zeolite softeners, dealkalizers, demineralizer unit, and mixed bed unit. The costs are a function of cubic feet of resin or cubic feet for the decarbonator.

The equipment costs include a skid type unit with valves, controls, interconnecting piping, and regeneration equipment. All installed costs and tie-ins are accounted for in the labor, bulk material, and construction indirects. The equipment costs are determined as follows.

Zeolite Softeners

Range: 20 to 100 cf
Cost = (352)(cf of Resin)(2)

Range: 200 to 800 cf
Cost = (248)(cf of Resin)(3)

Dealkalizer

Range: 20 to 225 cf
Cost = (430)(cf)

Range: 225 to 700 cf
Cost = (400)(cf)

Range: 700 to 1600 cf
Cost = (370)(cf)

Demineralizer

Range: 20 to 250 cf
Cost = ([(1215)(cf - Resin)] + 130,000)(2)

Range: 250 to 1700 cf
Cost = ([(775)(cf - Resin)] + 130,000)(3)

Mixed-Bed

Range: 10 to 70 cf
Cost = [(1620)(cf - Resin) + 54,000](2)

Range: 70 to 200 cf
Cost = [(1135)(cf - Resin) + 54,000](3)

Mixed-Bed for Condensate Polishing
Range: 10 to 70 cf
Cost = [(1620)(cf - Resin) + 54,000

Range: 70 to 200 cf
Cost = [(1135)(cf - Resin) + 54,000

Chemical Injection Skid. The facility has a single boiler system, chemical injection skid. The skid contains equipment necessary to inject chemicals (phosphates, amines or chelants, and/or antifoaming agents) into the boiler drum and an oxygen scavenging chemical (hydrazene or other) into the deaerator. The skid has three 55-gallon polyurethane mix tanks with agitators, piping, and valves. Included with the skid are six positive displacement chemical feed pumps that transfer the chemicals to the boiler drum or the deaerator. The displacement pumps are conceptually sized at 0 to 10 gal per hour and have a discharge pressure of 800 psig. (For higher pressure units, the drum chemicals would be injected into the feedwater system.)

The skid is sized at 14 x 12 ft. The installed cost of the skid is estimated as $20,000 for the heating facility and $30,000 for the co-generation facility.

Boiler Water Laboratory. The boiler water laboratory is provided as a means to analyze boiler steam and water for purity. The laboratory includes items such as a water sampling cabinet with drains, sample coolers (where required), chemical storage compartments, laboratory bench or table with sink, chemicals, beakers, bottles, flasks, and exhaust hood. The estimated costs are $20,000 installed for the heating facility and $40,000 installed for the cogeneration facility.

Deaerator. The deaerator is composed of two sections, a deaerating heater and a boiler feedwater storage section. Within the deaerating heater, treated water is deaerated by heating the water to its saturation temperature and scrubbing it with steam to carry away the dissolved gases.

The deaerators are carbon steel and are of the spray-tray type. Depending on user input, the storage tanks have 5 to 30 minutes of water storage. The default value is 10 minutes of storage. The deaerators have 1/8 in. corrosion allowance and include a deaerator section, steam nozzle, water trays and sprays, thermometers, storage tank,

gauge glass, oxygen test kit, vacuum breaker, relief valve and other components. The estimated costs are:

Cost = (0.0896)(Water Flow in lb/hr) + 20,590

Mechanical Collector

The mechanical collector is placed in the flue gas ductwork to remove particulates. The collector works on a 3-in. pressure drop and has an 85 percent collection efficiency at full gas flow. The cost of the collector is estimated as a function of gas flow (ACFM) and is provided by:

Cost = (0.40)(ACFM) + 20,000

Dry Scrubber and Lime System

The dry scrubber is a parallel flow type unit that uses lime as a reagent and deposits a dry product at the base and outlet of the scrubber vessel.

The unit uses a slurry of slaked lime atomized into fine droplets. The lime system is an integral component of the dry scrubber and consists of a lime receiving and handling system, lime day bin, two 100 percent slakers, degritters, lime dilution tank, lime pumps, piping to and from the scrubbers, and a back flush system. The lime system is sized for the total facility PMCR. The cost for the long-term lime silo is estimated separately. The dry scrubber-lime system equipment and installation cost is estimated as a function of flue gas flow (ACFM) into the scrubber and is provided by:

Cost = (2.0)(ACFM) + 240,000

The silo provides long-term storage for the lime for the dry scrubbers. The silo is of steel construction and includes fill pipe, a bin activation system, and a dust vent collection system. The estimated installed costs are:

Range: 100 to 1200 tons
Cost = (588)(tons) + 4400

Range: 1200 to 2000 tons
Cost = (166.67)(tons) + 510,000

Limestone Handling System

This system is for the fluid-bed boilers and includes the long-term limestone silo with fill pipe, bin activator system, dust collection system, and conveyor system that transports limestone from the long-term storage silo to the day storage silo. The estimated cost of the system is provided by:

Cost = (270.83)(Tons of Storage) + 65,000

The silo estimated installed costs are:

Range: 100 to 1200 tons
Cost = (588)(tons) + 4400

Range: 1200 to 2000 tons
Cost = (166.67)(tons) + 510,000

Baghouses and I.D. Fans

The budget capital baghouse costs represent a typical baghouse subcontract. The baghouse includes:

One Baghouse Per Boiler
Filter Bags
Internal Inlet and Outlet Manifolds
Cleaning System
Preheat System for Residue Hoppers
Maintenance Enclosures for Fabric Filters
External Inlet and Outlet Flue Gas Ducts
Control System, Programmable Logic Controller
Insulation and Lagging
Ash Hoppers, two Per Module
Access Doors, Ladders, Stairs, Platforms, Etc.
Purge Air System
Field Supervision During Erection
Start-up Services
Freight
Operation Manuals, and
Spare Bags.

These costs represent equipment material costs only. Each baghouse cost is estimated as a function of gas flow and is provided by:

Baghouse Cost ($) = (5.087)(ACFM) + 230,000

The I.D. fans draw the boiler flue gas out of the boiler, through the mechanical collector, dry scrubber and baghouse, and exhaust the gases into the boiler stack flue. The fan is sized for the combustion gases plus air leakage into the boiler-dry scrubber/baghouse system. For the conceptual design, each fan is sized for 100 percent of the flue gas flows plus 15 percemt leakage, at a static pressure of 20 in. of water.

The foundations, tie-ins, and other construction costs are included as part of the labor, bulk material, and construction indirects. The equipment cost is estimated as a function of flue gas flow (ACFM) entering the fan.

Range: (ACFM) 2,000 - 18,000
Cost = (0.382)(ACFM) + 3,000

Range: (ACFM) 18,000 - 110,000
Cost = SQRT [(6935)(ACFM)] + 9000

Pumps

There are five categories of pumps. Category one includes the Boiler Feedwater Pumps (BFWP). Category two contins the Plant Centrifugal Pumps, including the condensate pumps and the makeup or treated water pumps. Category three contains the Miscellaneous Centrifugal Sump Pumps, including the rail-track hopper pumps, truck hopper pump, reclaim hopper pumps, neutralization tank pumps, brine wastewater sump pump, and the coal pile runoff pond neutralization pumps. Category four includes the circulating water pumps, and category five includes is the fuel slurry oil pumps. The chemical feed pumps are included in the chemical feed skid.

Boiler Feedwater Pumps. The boiler facility includes two classes of boiler feedwater pumps. One is a motor-driven, multi-stage, centrifugal pump. The second is a steam turbine driven, multi-stage, centrifugal pump. The estimated equipment costs are a function of pump flow and discharge pressure. They are as follows:

Motor Driven BFWP

300 psig: 10 to 150 gpm
Cost = (45.86)(gpm) + 2510

500 psig: 30 to 150 gpm
Cost = (22.92)(gpm) + 11,750

800 psig: 50 to 1200 gpm
Cost = (5.75)(gpm) + 41,500

1500 psig: 100 to 1500 gpm
Cost = (116.36)(gpm) + 40,500

Turbine Driven BFWP

300 psig: 20 to 150 gpm
Cost = (45.86)(gpm) + 4000

500 psig: 30 to 150 gpm
Cost = (22.92)(gpm) + 17,500

800 psig: 50 to 1200 gpm
Cost = (85.6)(gpm) + 41,000

1500 psig: 100 to 1500 gpm
Cost = (196.7)(gpm) + 35,300

Centrifugal Pumps. Centrifugal pumps move water from various areas of the plant as required. The treated water pumps remove treated water from the storage tank and deliver it to the deaerator. The condensate pumps remove condensate from the storage tank and also deliver the water to the deaerator. These pumps are of one- or two-stage design. The head they must operate against is largely a matter of piping loss and static-elevation pressure. They are horizontal, end section, centrifugal sumps with constant speed motors and include the pump, motor, coupling, base plates, and guards. The estimated costs are a function of pump flow. The cost includes pump, motor, coupling, and starter. The installation and tie-in are included in the labor, bulk material, and construction indirects. The estimated equipment cost is:

Cost = (7.7)(gpm) 0.94 + 600

Circulating Water Pumps. The circulating water pumps are high capacity, low head pumps. They circulate the "cold" cooling tower water through the turbine condenser and plant auxiliary coolers, and then back to the tower for cooling. The conceptual design uses three circulating water pumps for the facility. Each pump is sized at 40

percent of the maximum circulating water flow rate, and for a 30 psi (70 ft) discharge pressure.

The estimated equipment costs are a function of water flow and include pump, motor, couplings, and starter.

Cost = (4.53)(gpm) + 20,000

Slurry Pumps. The slurry pumps are positive displacement pumps with hard surfaced ductile iron made to pump a 2000 SSU fluid. These pumps are for the coal-oil and coal-water fuel delivery/storage boiler systems. The estimated equipment costs are a function of pump flow.

Range: 10 to 300 gpm
Cost = (20)(gpm) + 8000

Range: 450 to 600 gpm (Delivery System)
Cost = $145,000/Pump

Sump Pumps. These pumps include the neutralization sump pumps for the water treatment and pond treatment areas. Equipment costs are estimated at $3500 each for 100 gpm pumps, $3800 each for 150 gpm pumps, and $4000 each for 300 gpm pumps.

Tanks

The facility's tanks can be divided into three categories: carbon steel tanks, stainless steel tanks, and fiberglass tanks. The various carbon steel tanks can include the condensate storage, high-temperature hot water tank, condensate return tank, fuel (coal-oil, coal-water) storage tanks, and blowdown tanks. The stainless steel tanks can include the treated water storage, condensate storage, and condensate return tanks. The fiberglass tank is for underground fuel oil storage.

Blowdown Tanks. The estimated cost of the continuous blowdown tank is a function of the blowdown entering it and is estimated by:

Cost = (0.05)(Blowdown Flow in lb/hr) + 500

The estimated cost of the intermittent blowdown tank is estimated at double the cost of continuous blowdown tank.

Carbon Steel Tanks. The carbon steel tanks are dome roofed, atmospheric type tanks. They are erected on site, on a suitable foundation. The estimated cost includes erection. The foundation costs are included in the labor, bulk material, and construction indirects. The estimated cost is a function of gallons of storage and is provided by:

Range: 50,000 - 5 million gallons
Cost = (0.179)(gallons) + 83,000

Smaller carbon steel tanks are used for water, acid, and caustic storage. Their costs are provided by:

Range: 2,000 - 36,000 gallons
Cost = (0.553)(gallons) + 200

Stainless Steel Tanks. The stainless steel tanks are atmospheric type tanks. They are sized from 30,000 to 300,000 gallons. Their cost includes tank saddles and erection. The labor, bulk material, and construction indirects include the foundations. The estimated cost is a function of gallons of storage and is provided by:

Cost = (0.808)(gallons) + 63,400

Smaller stainless steel tanks sized at 2,000 to 30,000 gallons, have a cost calculated by the following:

Cost = (1.45)(gallons) + 12,300

Neutralization Tanks. The neutralization tanks are concrete lined. Installation and erection costs for a tank sized at 1,000 to 36,000 gallons are estimated by:

Cost = (0.8974)(gallons) + 7,600

Fiberglass Tanks. These tanks are for storage of No. 2 diesel fuel. The tank is underground, has dual walls and includes such items as a fill line, vent line, pump-out line, and leak detection system. The installation costs are included in the labor, bulk material, and construction indirect costs. The tank cost is a function of gallons of storage and is estimated by:

Range: 4,000 - 24,000 gallons
Cost = (1.417)(gallons) + 9,700

Air Compressors

General facility and instrument air compressors are either reciprocating or rotary screw type units. Each compressor is water cooled and includes the compressor, motor, guards, intake filters, silencers, oil filter, air receiver, aftercooler, and air dryer. The compressor is conceptually sized in actual cubic feet per minute by the plant size. There are two 100 percent air compressors per plant. The estimated cost is a function of the ACFM requirement and is given by:

$$\text{Cost} = (101.85)(\text{ACFM}) + 5047$$

Wastewater Treatment

The facility has four types of wastewater flow systems: the sanitary waste, process (boiler system), storm water, and coal pile runoff pond discharge wastewater systems. Each system's conceptual design is described in the following subsections.

Sanitary Waste. The sanitary waste includes all the wastewater collected from water closets, sinks, and potable waster systems (such as floor drains in the offices and lunch room for example.) The wastewater is collected and discharged to an existing sanitary sewer system. The sanitary system cost includes such items as water closets, urinals, sinks, water heater, drinking fountains, emergency eyewash stations, floor drains, showers, and other similar fixtures. The cost of the system is estimated as a function of plant size or steam flow and is also developed with the labor, bulk material, and construction indirect costs. The sanitary system cost is estimated by:

$$\text{Cost} = (0.1)(\text{PMCR}) + 15{,}000$$

Process Wastewater. Process wastewater is generated by the boiler systems and includes wastewater from the treated water system, the boiler blowdowns, and equipment cooling water. Since the process wastewater is also discharged into the sanitary sewer system, it not contain oil, heavy metals, or other material that would make the wastewater unacceptable for such discharge.

Blowdown Water. Blowdown water is also sent to the sanitary sewer. The estimated cost of this is included in the blowdown tank and the sanitary system costs.

Other Process Water. Other process water is from bearing cooling, facility washdown, and other such sources. The estimated cost of treating this wastewater is included with the other equipment/system costs.

Pond Neutralization. The pond neutralization system uses programmable controllers for caustic, coagulant, acid feed rate, and pH control. Each system controller also directs the operation of all automatic valves, pumps, mixers, and conveyors associated with the system. The cost of pond neutralization, excluding the pumps, is estimated as a function of pond size and is provided by:

Cost = (16.43)(Pond Acres) + 9000

Storm Sewer System. The storm water collection system channels the collected rainwater to an acceptable drainage area. This system also collects the wash water from the ash and coal area drains. These drains include the appropriate traps or settling basins to collect the ash and coal particles. The cost of the storm sewer collection and drainage system is estimated as a function of plant size. The system does not include a major collection sump. The estimated cost is provided by:

Cost = (9450)(Plant Acres) + 5200

Piping

The estimated cost is an allowance item for a new facility and is duvuded into three categories: water/steam: boiler liquid fuel: and liquid fuel receiving, distribution, and collection piping. Water/steam piping includes all pipe, valves, fittings, hangers, etc. necessary for the boiler/steam system.

For heating facilities, the cost of piping is estimated as $5 per pound of steam at 300 psig or less; $6.50 per pound of steam at 650 psig or less or $10 per pound of steam for 1300 psig or less.

These estimated costs reflect the price difference between systems; i.e., standard weight carbon steel, standard weight and "extra strong" carbon steel with some alloy steel, alloy steel with carbon steel. For cogeneration facilities the cost of the piping is estimated to be 20 percent more than the cost of the heating facility. This cost includes the condenser, additional feedwater heaters, circulating water pipe, and other such structures.

Fuel piping includes the pipe, valves, fittings, joints, and other components necessary to feed liquid fuel (coal-oil, coal-water) to the boilers from the day fuel tank. The cost of the piping system with fuel heaters is estimated as a function of facility size at $1.25 per pound of steam where the minimum cost is $150,000.

The fuel storage pipe line includes pipes, valves, fittings, joints, and other components necessary to distribute a liquid fuel (coal-oil and coal-water systems) from the fuel receiving area to the long-term storage area and transport the fuel from storage to the facility day tank. The cost of the system is $150,000 at the minimum. It is estimated as a function of fuel storage and is provided by:

Cost = (0.15)(gallons of Storage)

Stack

Facility stacks are freestanding chimneys that enclose steel flues (one flue per boiler). Depending on the number of boilers, the design has one or two chimneys. The three-boiler facility has a single chimney that houses three individual boiler flues. The four-boiler facility has two chimneys, each housing two boiler flues. The five-boiler facility has two chimneys, one chimney housing two boiler flues, and the second housing three boiler flues. The steel flues are insulated, have stack sampling ports, and are independently bottom supported.

The freestanding chimneys are designed for a wind load of 100 mph and include testing platforms, a safety ladder to the top, interior and exterior lighting, and FAA lights. The cost of the stack includes erection, but not the foundation. The foundation cost is included in the labor, bulk material, and construction indirects. The erected cost is estimated as follows with the minimum stack height equal to 100 ft and the maximum equal to 325 ft:

Two-flue stack cost = (1,456)(Stack Height) + 418,000

Three-flue stack cost = (3,760)(Height) + 200,000

Instrumentation

Continuous Emission Monitors (CEM). The CEM system provided includes SO_2, NO_x, and opacity monitors and conforms to applicable Feral, State and local codes. The system has a remote mounted microprocessor based control unit. The equipment automatically maintains and generates reports as required by local, State, or Federal agencies. The cost of the system is estimated as follows: $350,000 for a single stack with two flues, $600,000 for dual stacks, and $400,000 for a single stack with three flues.

Controls.

Heating Facility. The control systems for the facility are divided into two basic areas of control; the boiler/steam block and the yard area. The boiler block includes the controls necessary for the boilers, steam header, and other boiler associated equipment or systems. The boiler block control system is a conventional analog or digital control system linking each boiler. Each boiler control is configured for single loop integrity and has a single control panel with dedicated annunciator windows, motor control, and status indicators for operations overview. Each boiler control is also interfaced with the total boiler system control for regulation of feedwater, fuel, airflow, boiler output, steam control, and combustion. The cost of the heating facility controls is estimated as 1% of the total boiler cost or a minimum cost of $200,000.

Cogeneration Facility. The control systems for the facility are also divided into the same basic areas of control; the boiler/steam block and the yard area. The boiler block includes the controls necessary for the boilers, steam header, and other boiler associated equipment or systems. The boiler block control system is a conventional analog or digital control system linking each boiler. Each boiler control is configured for single loop integrity and has a single control panel with dedicated annunciator windows, motor control, and status indicators for operations overview. Also included are auto/manual stations for combustion controls, steam outlet controls and control switches, as well as status indicators for the boiler auxiliaries. Each boiler control is interfaced with the total boiler system control for regulation of feedwater, fuel, airflow, boiler output, steam control, and combustion. Boiler auxiliary controls include monitoring and control of heat cycle equipment, boiler feed pumps, feedwater system, condensate system, and auxiliary electrical system.

The power or turbine control system includes the controls necessary to interface the boilers and turbine; start-up, operate, and shut down the turbine; and control the turbine-generators auxiliaries. The turbine control system uses the same type of control and monitoring equipment as the boiler, with the addition of subpanels for turbine supervisory control, governor control, and turbine water induction protection.

The turbine control system provides for operator control from a central location and complete interlocking for all turbine systems and turbine auxiliaries. The cost of the cogeneration controls is estimated as the following with a minimum coast of $350,000:

Cost = 0.015 (cost of boilers and turbines)

Electrical Facilities Equipment Costs

Diesel Generator. The skid mounted diesel generator system provides emergency power to enable safe shutdown of the facility plus some power for emergency lights, pumps, controls, etc. The system is skid mounted. The equipment cost is estimated to be a function of kilowatts (kW) output.

Cost = (182.5)(kW) - 39,700

Substation - Heating Facility. The heating facility requires an electrical substation to receive power from the grid. The cost is estimated as an allowance cost and is based on two types of substations. One type steps the incoming voltage down from 13.8 KV to a 480 volt bus system. The other steps the incoming voltage down from 13.8 KV to a 2400 volt bus system and then steps down to the 480 volt bus. The main reason for the second substation is the high horsepower motors required by the fluid bed (circulating and bubbling) boiler systems.

The 13.8 KV to 480 volt substation system is a double ended substation that includes two main stepdown transformers with oil filled breakers and other necessary equipment. The equipment allowance cost is estimated as a function of plant size and is calculated by:

Cost = (0.3625)(PMCR) + 240,000

The 13.8 KV to 2400 volt substation is also a double ended substation. This substation consists of 13.8 KV fused primary high voltage disconnect switches, 13.8/2.4 KV transformers furnished with safety and indicating devices plus transition pieces, secondary fused medium voltage disconnect switches and all required fused disconnects, plus combination motor starters for large horsepower motors (above 125) or low voltage (480 volt) switchgear. A tie breaker allows servicing of the secondary section of the substation from either of the high voltage transformers in case of an unscheduled shutdown. The transformers can be sized so that either transformer can carry the total purchased power load of the heating plant.

The low voltage (480 volt) switchgear can also be a double ended unit consisting of medium voltage (2400 volt), primary switches, and 2400/480 V transformers with the above noted accessories. This second substation is estimated as a function of plant size.

Cost = (0.1875)(PMCR) + 500,000

Substation - Cogeneration Facility. The substation for a cogeneration facility includes a 13.8 KV system generating to the grid. Most of this system's cost is included with

the turbine generator cost. An allowance is added to cover grid protection and tie-in costs and is estimated to be a lump sum of $30,000. Therefore, the estimated cost of the cogeneration substation for nonfluidized bed units is:

$$\text{Cost} = (0.3625)(\text{PMCR}) + 270{,}000$$

The estimated cost of the cogeneration substation for fluidized bed units is:

$$\text{Cost} = (0.1875)(\text{PMCR}) + 530{,}000$$

General Facility. This represents the electrical equipment necessary for the facility. The estimated cost is 6 percent of items covered on pages 143 through 166 and pages 174 through 175.

Site Work

Site Development. The site development cost includes work necessary to prepare a site for construction. Since this factor is highly site specific, the program only provides a very rough estimate of this cost as a function of total site acres (plant plus fuel pile plus runoff pond). The cost is estimated as $2,500 per acre.

Fuel Storage Area. Coal pile storage area development costs represent the work necessary to prepare the site for construction, removal of the overburden, and installation of an impermeable layer under the storage pile, and drainage that discharges, to the pond. The estimated cost is $22,000 per acre or $0.50 per sq ft.

Liquid fuel storage area development costs represent the work necessary to prepare the site for construction, removal of the overburden, and installation of diked areas around the storage tanks. The estimated cost is $11,000 per acre or $0.25 per sq ft.

Site Improvements. This category is an allowance item that provides for such things as site landscaping, architectural improvements, sidewalks, parking lots, fences, etc. The cost of this allowance is estimated as a function of plant size and is calculated by:

$$\text{Cost} = (0.5)(\text{PMCR}) + 100{,}000$$

Building & Services

Building. The building is the structure that houses the boilers, feedwater treatment, turbine-generator (cogeneration) plant offices, maintenance rooms, locker rooms, and other personnel related areas. This building is a stand-alone structure with insulated

metal siding, windows, roof vents, and sidewall louvered vents. Building construction is concrete slab on grade and other upper area floor areas with most upper floors as grating. The building includes floors, stairs, platforms, windows, vents, handrails, etc. The rough cost of the building is provided as a function of cubic feet of building area. It is estimated as $4.75 per cubic foot of building volume.

Elevator. The facility includes one freight/personnel elevator. It is 6 ft by 8 ft (internal) and will operate from the first floor elevation to the top of the boiler. The elevator is a traction type and has automatic functions. The cost is a function of height or rise and the number of stops. Cost is provided as:

40 ft rise with two stops
Cost = $100,000

70 ft rise with three stops
Cost = $150,000

120 ft rise with five stops
Cost = $225,000

Communications. The communications system includes telephone stations, attendant console, private automatic branch exchange (PABX), amplifiers, battery, battery charger, paging speakers and horns, wiring systems, and all necessary conduits. Units installed in high noise areas, (i.e., the boiler floor), are provided with acoustic booths and noise limiting devices on the telephone receiver. Other features include call forwarding, direct station-to-station calls within PABX without attendant assistance, direct outward dialing for outside and long distance calls, direct access to paging system, and night answering. The system cost is an allowance item based on plant size with a minimum cost of $5000.

Range: PMCR 50,000 to 500,000 lb/hr
Cost = (0.111)(PMCR) - 500

Fire Protection. The fire protection system is a wet pipe system for protecting the facility from fire. The system includes a separate firehouse, two 1500 gpm @ 125 psig diesel driven fire water pumps, (each with an 8-hour diesel storage tank), a jockey pump, fire water storage tank, and fire department connections. The following items are also included: an outside plant loop distribution system with fire hydrants; individual water loop systems fed from the plant loop system to service the boiler house, coal handling system, baghouse, personnel areas, and turbine-generator area; an inert Halon gas system to suppress plant electrical room fires by oxygen

ing; and items such as alarms and water gongs, portable fire extinguishers, fire hose cabinets, water monitors, sprinkler heads, etc. The cost allowance of the fire protection is estimated as 3 percent of the items covered on pages 143 through 168 and pages 172 through 175.

Furniture. Furniture required to furnish plant offices, lunch room, locker rooms, maintenance shop and other areas is included in the conceptual design. The furniture requirement specifically includes desks, swivel chairs, 2- and 4-drawer file cabinets, bookcases, side chairs, stacking chairs, lunch room tables, benches and cabinets with counter tops, lockers, locker room benches, supervisor floor desks, metal storage bins, racks, and other necessary items. Furniture is an allowance item for a new facility. Cost is based on the plant size.

$$\text{Cost} = (0.2875)(\text{PMCR})$$

Heating, Ventilation, and Air Conditioning. The Heating, Ventilating, and Air Conditioning (HVAC) system design is confined to the facility's offices, lunch room, locker rooms, and electrical equipment room. The remainder of the facility is not air conditioned. The air conditioning system is complete with cooling coils, fans, ductwork, insulation, and controls. Costs of such an air conditioning system, including installation, is estimated as:

$$\text{Cost} = (0.405)(\text{PMCR}/1000) + 1013.5$$

The general facility heating design includes a steam or hot water coil system. The coils are installed to include air makeup units throughout the plant in such places as the offices and lunch rooms. The cost of the heating system is an allowance item based on the size of the facility. The cost of the heating coils (makeup air units) is estimated as:

$$\text{Cost} = (0.5375)(\text{PMCR}) + 8{,}000$$

Mobile Equipment, Spare Parts, and Tools

Mobile Equipment. The cost of the equipment is provided as an allowance cost per unit.

The front-end loader is a four-wheel drive articulating vehicle. It is diesel powered with foam filled tires and has a 4-cu yd (6-ton) bucket. Each unit is $210,000.

The light-duty front-end loader which is a fdiesel powered four-wheel drive vehicle. It has foam filled tires and a 1 cu yd bucket. Each unit is $75,000.

The forklift, provided for general plant maintenance, has four-wheel drive and is also diesel powered. It has pneumatic tires and is rated at 5,000 pounds capacity. Each unit is $20,000.

A dump truck is included for general plant use. It is sized with a 5-yard dump body and has a 5-ton capacity. Each unit is $25,000.

The pickup truck with a 3/4-ton carrying capacity, is diesel powered and has 8-ply tires. The vehicle meets all necessary local, State, and Federal safety and emission control regulations. Each unit is $14,000.

One power sweeper is included for general internal and external plant maintenance. The sweeper is diesel powered and comes with the wet/dry cleaning option. Each unit is $5,000.

A drop box is provided for the lime grit from the slaker and other general plant maintenance use. The box is of heavy-duty steel construction, has a 40-cu yd capacity, drip-proof seals, and can be picked up with a tilt frame (roll-off) truck or other vehicle. Each unit is $8,000.

Spare Parts. Spare parts for major equipment and systems are a requirement for any new facility. These costs are allocated and estimated as a function of plant size and equipment costs.

> Cost = [2.62 - (0.0022)(PMCR)/1000][(cost of items on pages 143 through 168 and pages 172 through 175.

Facility Consumables - Initial Inventory. A new facility must begin with an initial inventory of consumables. These items are normally considered as yearly operational needs, but a new facility must have an initial inventory to begin operations. Items included in this category are packing seals, grease, oil, small parts, rags, light bulbs, buckets, mops, cleaning agents, towels, and other such necessities. The estimated cost is provided by:

> Cost = (0.35)(Spare Parts Cost)

Tools. A new facility essentially has two types of tools that need to be included. One type is the hand tools that are those used to perform maintenance on the equipment. The other type is major tool room equipment and includes metal lathes, grinders, welders, drill stand or press, hydraulic press,and milling machine. These costs are an

allocation cost and estimated as a function of plant size. The estimated allowance or cost is:

Cost = (0.4375)(PMCR) + 106,000

Condenser

The condenser is a two-pass, shell and tube surface type sized for full turbine throttle flow. It condenses at 2.5 in. HgA or 3 in. HgA depending on the steam turbine system. Its estimated allowance can be determined by:

Cost = (1.10)(PMCR) + 12,000

Cooling Tower

The wooden cooling tower is a multi-cell, induced draft counterflow evaporative tower mounted on a concrete basin and foundation. The foundation, concrete basin, and tie-in costs are included as part of the labor, bulk material, and construction indirects. The cooling tower cost, equipment, and erection is a function of water circulation rate and is estimated by:

Cost = (35.5)(Circ. Rate in gpm) - 42,000

Feedwater Heaters

The feedwater heaters are used in the regenerative cycle to heat the feedwater before it enters the boilers. The feedwater heaters are of a “closed” shell and tube design.

The cost of the feedwater heaters is a function of operating pressure and square feet of tube surface; tube surface being a function of feedwater flow and design temperature rise. The estimated heater costs are as follows:

50 psig or less
Cost = (10)(sq ft of Surface Area) + 5000

50 to 175 psig
Cost = (9.33)(sq ft of Surface Area) + 6700

175 to 500 psig
Cost = (14.3)(sq ft of Surface Area) + 8000

Turbine-Generator

The conceptual design of the cogeneration facility uses a single extraction-condensing turbine-generator. It generates electricity and provides the heating system and process steam requirements for the plant. The 600 psi and 750 °F design steam turbine has a maximum of two steam extractions. The extractions are 170 psig, which is used for the heating system or proces steam, and 35 to 50 psi, which is used for the feedwater heating. Total allowable steam extraction is maximized at 80 percent of full turbine throttle flow steam rate. This allows a minimum of 20 percent flowing to the turbine exhaust. This minimum steam is necessary to keep the exhaust stages of the turbine cool. The turbine is conceptually designed for full flow condensing.

The generator is a 3-phase, 60-cycle, synchronous, air-cooled type with brushless exciters. The generator's voltage is 13.8 KV and rated at 150 MVA with a 0.85 P.F. (Power Factor). The installation is included as labor, bulk material, and construction indirects. The estimated costs are a function of full throttle flow, pressure, and temperature. Condensing flow and pressure, number of extractions and maximum extraction flows, and extraction pressures are included. The cost estimate for the turbine-generator is as follows:

600 psig and 750 °F Turbine
Range 50,000 - 100,000 lb/hr Throttle Flow
Cost = [(47.5)(PMCR) - 1.85] Million
Note: Gear Type Turbine

600 psig & 750 °F Turbine
Range 100,000 - 600,000 lb/hr Throttle Flow
Cost = [(5.867)(PMCR) + 2.76] Million
Note: Direct Drive Turbine

1300 psig & 900 °F Turbine
Range 250,000 - 600,000 lb/hr Throttle Flow
Cost = [(4.5)(PMCR) + 4.1] Million

Steam Distribution System

The steam distribution system's design depends on the type of system and the distance the system must extend. The model allows the user to select from four types of steam system designs listed below and shown in Figures 13 through 16.

1. Tunnel construction,
2. Direct burial Ricwil casing,

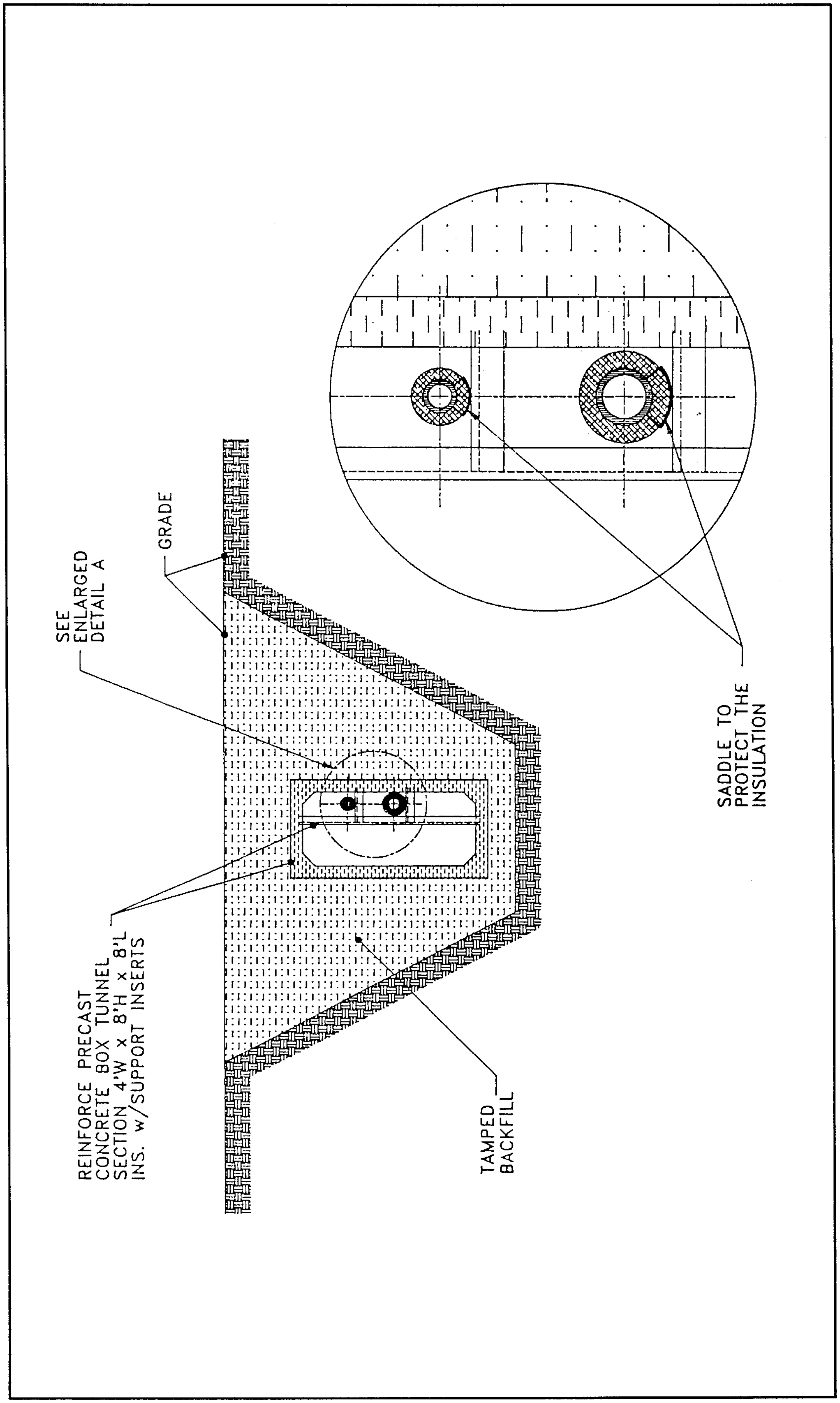

Figure 13. Steam distribution system design: tunnel contruction

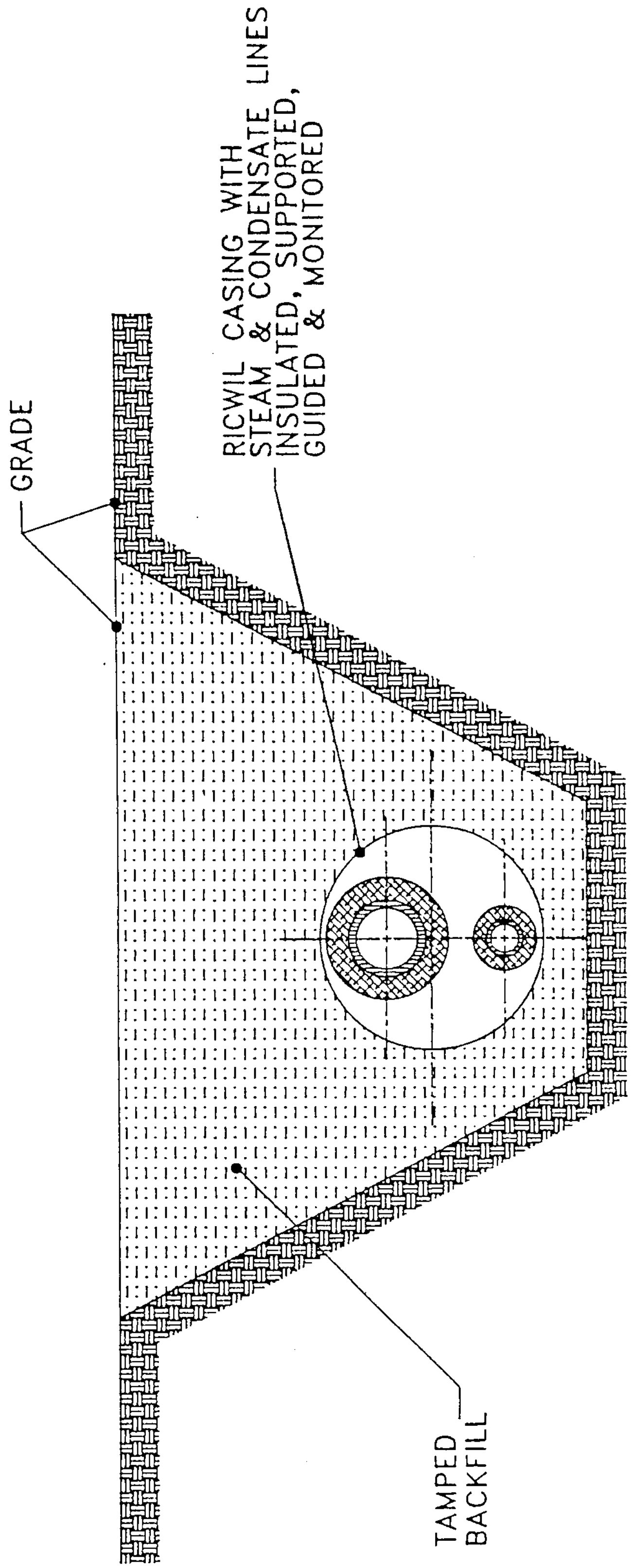

Figure 14. Steam distribution system design: direct burial Ricwil casing.

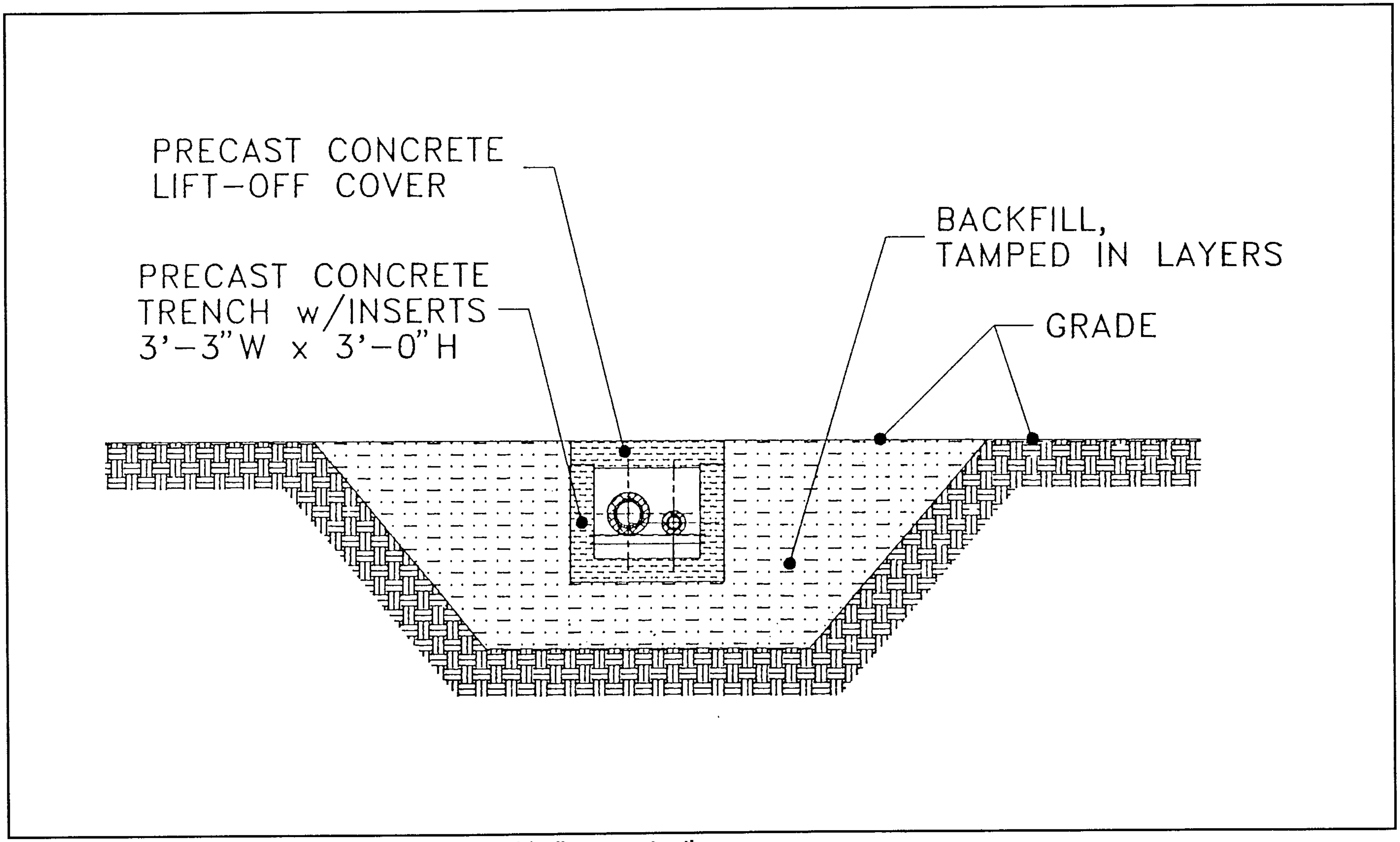

Figure 15. Steam distribution system design: shallow trench/walkway construction.

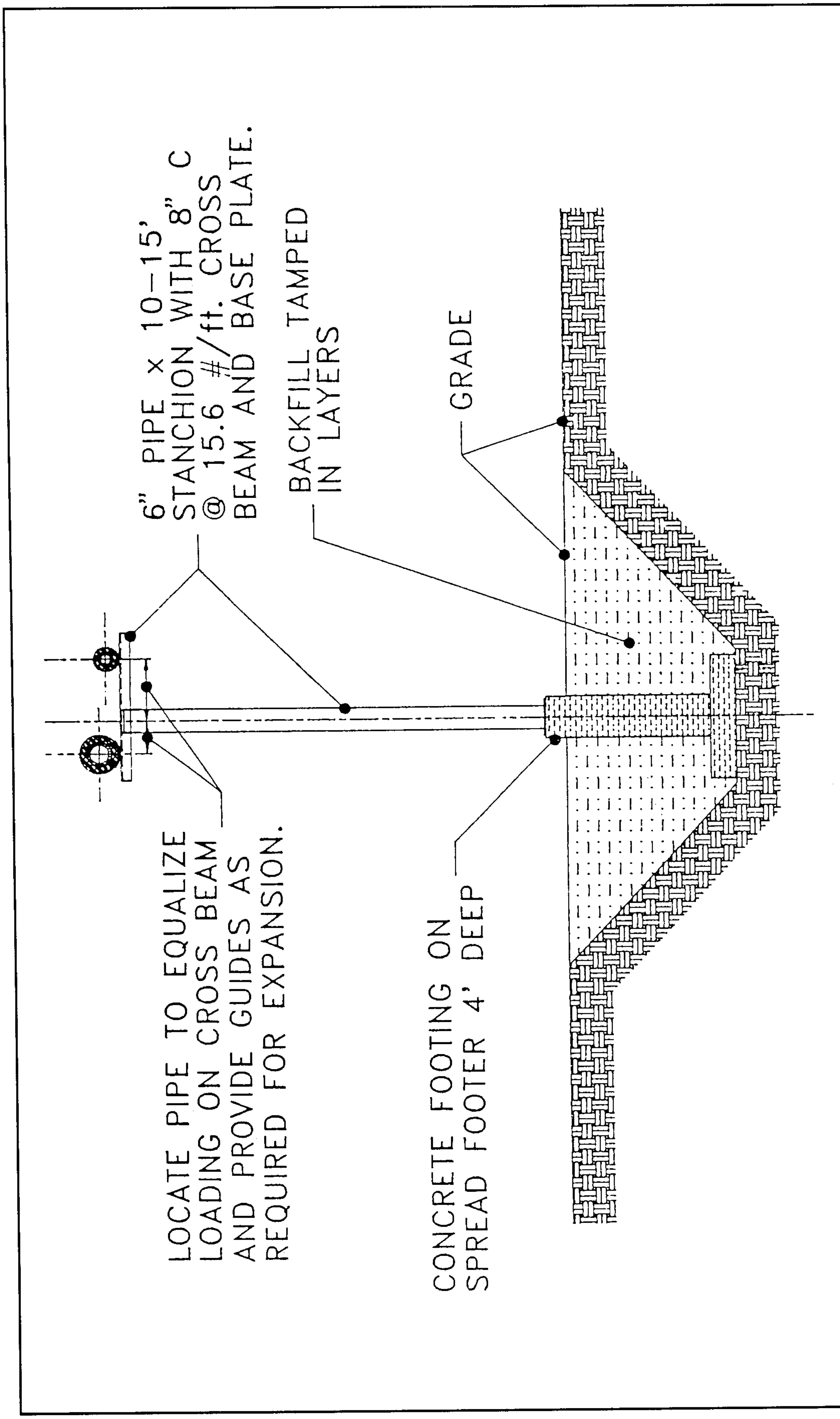

Figure 16. Steam distribution system design: above ground single stanchion construction.

3. Shallow trench/walkway construction,
4. Above-ground single stanchion construction.

After selecting the system to be used, input the length of each system and the number of branch lines or connections. The program uses this information to provide a budget estimate of the installed constructed cost of the steam distribution system. The estimated budgetary installed cost of the various steam distribution systems is:

Cost = [$/ft]/ft of Tunnel] [1+ ((% Mat'l. Escalation)+ (% Labor Escalation)/200)] [Labor Productivity Factor] [Labor Cost in $/hr/$20.00]

where: $/ft =
Tunnel construction = $700/ft
Direct burial Ricwil construction = $270/ft
Shallow Trench/Walkway Construction = $250/ft
Above-ground single stanchion = $275/ft

Branch Connections:

Cost = [Number of Connections][Cost/Connection][1+ ((% Mat'l. Escalation)+(% Labor Escalation)/200)][Labor Productivity Factor] [Labor Cost - $/hr/$20.00]

where:
The 1988 estimated fourth-quarter cost of Ohio construction is:

- Tunnel: $1500/Connection
- Direct Burial: $1000/Connection
- Trench: $ 600/Connection
- Overhead: $ 750/Connection

(Prices include an estimate for valves, tie-ins, and construction costs)

Freight Costs

This category covers the cost of freighting materials to the project site and is estimated as a percent of equipment cost. The estimation ranges for the various areas of the continental United States, from 1.5 to 4.5 percent. The value used is 2 percent of the total facility costs (pages 143 through 175).

The freight costs for bulk materials are included as part of the bulk material costs.

Installation Costs

The installation costs are derived by multiplying a series of factors by the equipment costs. These factors are used to identify the direct labor man-hours and the bulk material dollars. The actual labor costs are derived by multiplying a wage rate times the direct labor man-hours. The construction indirects are then derived by taking a percentage of the direct labor costs.

Direct Labor Man-Hours. The direct labor man-hours are the total craft man-hours required to build the plant and these include skilled workers such as pipefitters, boilermakers, electricians, insulators, painters, laborers, steelworkers, masons, and foremen. These factors, when multiplied by the equipment costs, yield the total direct labor man-hours associated with the installation of that equipment. They account for the labor man-hours for any foundations, structural steel, buildings, piping, electrical, instrumentation, painting, or insulation required to completely install that particular piece of equipment.

After the labor man-hours are derived, they are multiplied by a productivity adjustment. Using a 1.0 for labor productivity will result in direct labor man-hours for union construction in Ohio as presented in Table 14. The program includes union labor productivity adjustments for states other than Ohio.

As an example, assume that a New Jersey plant site was chosen. The program would multiply the labor man-hours by 0.97, reducing the total man-hours required to complete the installation. This reduction is due to the New Jersey construction crews being more productive than the Ohio crews. Conversely, multipliers greater than 1.0 increase total man-hours due to the construction crews being less productive than Ohio crews.

Direct Labor Cost. The direct labor costs are derived by multiplying the labor man-hours by the average base wage rate for that plant site. The base wage excludes all payroll benefits and burdens. In the program, the average base wage rate for the proposed plant location is represented by the pipefitters union base wage as presented in Table 14. The pipefitters base wage for each state is an average of the pipefitters union base wage rates for the major cities in that particular state.

Bulk Materials. Bulk materials include any permanent material (other than the equipment) required for the plant. These include concrete, pipe, wire, conduit, structural steel, etc. The factors from Table 15, multiplied by the equipment costs, yield the total bulk material costs associated with the installation of that equipment. They bulk material costs account for the materials for any foundations, structural

steel, buildings, piping, electrical, instrumentation, painting, or insulation required to completely install that particular piece of equipment.

Table 14. Productivity factors by state.

State	Productivity Multiplier	Average Wage
AK	0.87	27.00
AL	1.00	13.00
AR	1.00	8.00
AZ	1.00	17.85
CA	1.00	23.00
CO	1.00	12.00
CT	0.98	18.22
DE	1.00	18.05
FL	1.00	10.00
GA	1.00	10.00
IA	1.00	14.77
ID	1.00	17.63
IL	1.21	18.05
IN	0.98	18.17
KS	1.00	11.55
KY	1.13	10.00
LA	1.00	11.97
MA	0.87	18.09
MD	1.00	12.94
ME	0.87	14.35
MI	1.00	16.00
MN	1.00	17.50
MO	1.00	18.00
MS	1.00	9.00
MT	1.00	14.51
NC	1.00	6.75
ND	1.00	9.95
NE	1.00	12.91
NH	0.87	16.00
NJ	0.97	18.44

State	Productivity Multiplier	Average Wage
NM	1.00	11.30
NV	1.00	19.59
NY	1.00	18.50
OH	1.00	18.60
OK	1.00	9.81
OR	1.00	18.31
PA	0.98	17.08
RI	0.87	19.07
SC	1.00	4.45
SD	1.00	6.00
TN	1.00	10.00
TX	1.00	9.50
VA	0.87	14.61
VT	0.87	14.70
WA	1.00	18.00
WI	1.00	16.00
WV	0.93	16.97
WY	1.00	12.00
UT	1.00	14.41
HI	1.00	20.00

Table 15. Labor hours and bulk material cost factors.

System	Labor	Bulk
Boilers		
Stoker Boilers	0.0067	0.12
CFBC & BFBC Boilers	0.0012	0.12
COS & CWS Boilers	0.00045	0.12
Airheaters	0.008	0.05
Desuperheater	0.0161	0.18
Coal Handling	0.0065	0.15
Fuel Handling		
Long Term Storage Tanks	0.0242	0.22
Short Term Storage Tanks	0.01	0.16
Slurry Pumps	0.0134	0.15
Ash Handling	0.243	0.45

System	Labor	Bulk
Mechanical Collector	0.008	0.05
Dry Scrubber & Lime System		
Dry Scrubber & Lime System	0.0215	0.4
Lime Silo	0.0161	0.18
Limestone Handling	0.0215	0.18
Baghouse & ID Fan		
Baghouse	0.01344	0.28
I.D. Fan	0.018	0.18
Boiler Water Treatment		
Zeolite Softeners	0.0091	0.3
Dealkalizer	0.015	0.3
Demineralizer	0.015	0.3
Mixed Bed	0.0188	0.35
Condensate Polisher	0.0188	0.35
Chemical Injection	0.0081	0.15
Boiler Water Laboratory	0.0054	0.2
Deaerator	0.0188	0.28
Tanks		
Condensate Storage	0.0242	0.22
Treated Water Storage	0.0242	0.22
Acid & Caustic Tanks	0.01	0.16
Blowdown Tank - Cont.	0.0118	0.28
Blowdown Tank - Inter.	0.0172	0.28
HTHW Expansion Tank	0.0242	0.22
Condensate Return Tank	0.0242	0.22
Facility Fuel Oil Tank	0.0134	0.12
Neutralization Tanks	0.0269	0.05
Pumps		0
Motor Driven BFWP	0.0172	.18
Turbine Driven BFWP	0.0177	0.22
Centrifugal Pumps	0.0118	0.3
Circulating Water Pumps	0.0118	0.16
Sump Pumps	0.008	0.12
Air Compressors	0.0081	0.35
Wastewater Treatment		
Sanitary System	0.035	0.28
Neutralization Pond	0.0376	0.05
Storm Sewer System	0.0323	0.12
Piping		
Stack	0.0322	0.08
Piping	0.035	0.5

System	Labor	Bulk
Instrumentation		
Continuous Emission Monitors	0.0065	0.5
Controls	0.0242	0.4
Electrical		
Diesel Generator	0.0054	0.3
Substations	0.0242	0.33
General	0.0242	0.18
Building & Services		
Building	0.000323	0.2
Communications	0	0.25
Fire Protection	0.0188	0.12
Furniture	0.006	0.05
HVAC	0.0323	0.12
Elevator	0.0188	0.15
Site Development	0	0
Spare Parts, Tools, Mobile Equipment		
Mobile Equipment	0	0
Facility Consumables	0	0
Tools	0	0
Spare Parts	0	0
Condenser	0.0065	0.15
Cooling Tower	0.0081	0.35
Feed Water Heater	0.0215	0.12
Turbine Generator	0.0188	0.35

Indirect Costs

Construction indirect costs are for all field indirects, construction services, field staff, payroll benefits and burdens for direct and indirect labor, small tools and consumables, and the construction equipment. The field indirect costs include all temporary facilities such as service buildings and office trailers, temporary roads, parking, and material laydown areas. Construction services include job cleanup; medical supplies; construction equipment, handling, and maintenance; field office supplies; and telephone.

Field staff covers the salaries and subsistence for contractor field staff. Subsistence includes meals, lodging, travel expenses, etc. Also included is the site security, medical, warehouse, and clerical personnel. The payroll benefits include vacation, holidays, sick time, and medical insurance. The burdens include social security, Federal and State unemployment insurance.

The program uses a range of 75 percent of the direct labor dollars to account for construction indirect costs. This is based on data from a number of similar projects using union construction crews. This percentage will probably increase for open shop scenarios because, as labor costs decrease as in the case of open shop construction, the percentage for construction indirects tends to increase.

Permit Development Costs

This category provides an estimate to develop, apply, and obtain the necessary U.S. Environmental Protection Office (USEPA), State, and local permits to begin construction. The permit development cost estimate is provided as a function of plant size.

$$\text{Cost} = (2.222)(\text{PMCR}) + 390{,}000$$

Engineering Costs

This category represents the contract engineering required to design the plant. The cost includes the design engineering as well as the engineer's fee. This category accounts for the cost of preparing the specifications and drawings, soliciting bids for equipment, and preparing bid evaluations. It covers all of the engineer's salaries and the overheads such as reproduction, computer services, travel, final drawings, field changes, etc. The estimated cost of these services is 12 percent of the total facility cost (pages 172 through 175).

Construction Management Costs

This category represents the contract management to build or construct a facility. The construction management is responsible for managing the construction of the facility, obtaining construction bond, site security, insurance, etc. These services are estimated as 7 percent of the total facility cost (pages 172 through 175).

Construction Contingencies

The contingency costs are intended to cover inaccuracies associated with the estimating approach and to cover any items that must be performed to complete the project as originally defined. This cost is not intended to cover scope changes. The contingency is estimated as 15 percent of the total cost of the facility through construction (pages 172 through 175).

Owner's Management

This category covers the owner's cost of building a project and includes payment to the main contractor, quality assurance of the project, schedule management, etc. The estimated cost is 6 percent of the items on pages 143 through 185.

Start-up Costs

This category covers the cost of initially starting up and troubleshooting the equipment and systems for integrated operation. The category also includes such items as start-up fuel, line and system cleaning, boiler cleaning and blows, turbine starts, purchase power, etc. This estimated cost is provided as a function of plant size and is calculated by:

$$\text{Cost} = (0.833)(\text{PMCR}) + 133{,}000$$

Retrofit Capital Costs

This section includes all the retrofit conversion costs for each of the following conversions:

- Heavy oil stoker to coal stoker,
- Coal stoker to slagging combustion,
- Heavy oil package boiler to slagging combustion,
- Heavy oil package boiler to coal-oil slurry,
- Heavy oil package boiler to coal-water slurry,
- Heavy oil package boiler to micronized coal(70% thru 325 mesh), and
- Heavy oil stoker to fluidized bed combustion.

For each of these seven boiler retrofit technologies, a series of cost algorithms is provided for five separate boiler plant subsystems. The five categories or subsystems are: a fuel receiving, handling, preparation and delivery system; a combustion/burner system; a boiler system and plant structural modifications; an air pollution control system; and an ash collection, conveying, and storage system.

The user must add to the equipment costs such items as preliminary engineering, permit development, owner's management, contractor management, site acquisition, site development, detail engineering design, construction contingency, start-up, spare parts, initial facility consumables (operational supplies), tools, and other such items.

These generic cost programs were developed to provide a budget cost estimate for each of the retrofitted technologies. Keep in mind that actual retrofit costs are highly dependent on such things as: boiler type and design, physical boiler plant design and layout, total facility layout, location and specific site parameters. The cost algorithms were developed for generic facilities having the following characteristics.

1. Enough physical room to install: new fuel receiving, handling, preparation, and delivery systems; new ash removal and storage equipment/systems; new air pollution control equipment/system; new boiler/combustion control system; fuel burning equipment; necessary ductwork, piping, etc., to connect the new equipment; and other boiler equipment such as an air heater for coal-water mixture combustion, a fluid-bed combustion system, or an ash pit for the slagging combustor.
2. An adequate boiler system that requires no major boiler/equipment modifications or structural changes.
3. An adequate electric bus system that can support the modification technology.
4. A fuel receiving system compatible with truck or railroad car delivery. The specific type of receiving system depends on the amount of fuel to be used.
5. A facility that does not require a new stack.
6. Adequate boiler plant equipment (i.e., feedwater pumps, deaerator, condensate system, raw water treatment system, etc.) in a good state of repair.
7. An adequate auxiliary fuel system that will support the retrofit design technology.

In the following subsections, each retrofit technology is individually presented with its applicable category cost algorithms. The overall retrofit budget estimate is developed by summing together the equipment category cost estimates. This total represents the cost of a horizontally designed retrofitted boiler/facility. The base costs in the program are 1988, fourth-quarter dollars.

The model's base plant location is Cleveland, Ohio for which union construction labor is used. Deviations from this base location can be accounted for by entering actual labor cost inputs or altering such costs for the location with standard cost factors.

Heavy Oil Stoker to Coal Stoker

Fuel Receiving, Handling, Preparation, and Delivery System. This system includes the following components: new coal system controls, new coal handling conveyors, new motors on the coal handling equipment (i.e., conveyors, crushers, vibrators, motor-operated gates, etc.), and new coal chutes.

The total system cost is a function of plant size. Costs are estimated according to the following equations.

One boiler:	Range 20,000-200,000 lb/hr Cost $ = (1.67)(PMCR) + 267,000
Two boilers:	Range 40,000-400,000 lb/hr Cost $ = (1.14)(PMCR) + 450,000
Three boilers:	Range 60,000-600,000 lb/hr Cost $ = (1.35)(PMCR) + 500,000
Four boilers:	Range 80,000-800,000 lb/hr Cost $ = (1.40)(PMCR) + 500,000

Combustion/Burner System. This system includes: a new grate, seals, refractory, grate support structure, etc; new combustion controls, grate drives, etc; new secondary or overfire air fan; new windboxes, coal fines removal system, etc.; and ash pits.

The combustion system cost is also a function of plant size and is estimated by the following.

One boiler:	Range 20,000-200,000 lb/hr Cost $ = (2.38)(PMCR) + 180,000
Two boilers:	Range 40,000-400,000 lb/hr Cost $ = (1.92)(PMCR) + 350,000
Three boilers:	Range 60,000-600,000 lb/hr Cost $ = (1.77)(PMCR) + 520,000
Four boilers:	Range 80,000-600,000 lb/hr Cost $ = (1.65)(PMCR) + 650,000

Boiler System and Plant Structural Modifications. This system includes: structural support of the ash pits, coal chutes, feeders, other ash hoppers, etc.; new sootblowers; structural work for the new coal handling conveyors; rebuilding of coal hoppers and storage bunkers; and air heater repair. The system cost is estimated as follows.

One boiler:	Range 20,000-200,000 lb/hr Cost $ = (1.50)(PMCR) + 100,000

Two boilers: Range 40,000 - 400,000 lb/hr
Cost $ = (1.20)(PMCR) + 180,000

Three boilers: Range 60,000 - 600,000 lb/hr
Cost $ = (1.18)(PMCR) + 240,000

Four boilers: Range 80,000 - 600,000 lb/hr
Cost $ = (1.15)(PMCR) + 265,000

Air Pollution Control System. This system includes: rebuilding mechanical collectors; new dry scrubber with lime system; new baghouse; new air pollution system controls; all ductwork, breeching, piping, electrical, etc., necessary to connect the systems; new I.D. fan(s); and foundations for all new equipment. The system cost is estimated as follows.

One boiler: Range 20,000-200,000 lb/hr
Cost $ = (2.75)(PMCR) + 375,000

Two boilers: Range 40,000 - 400,000 lb/hr
Cost $ = (2.40)(PMCR) + 650,000

Three boilers: Range 60,000 - 600,000 lb/hr
Cost $ = (2.32)(PMCR) + 900,000

Four boilers: Range 80,000 - 600,000 lb/hr
Cost $ = (2.35)(PMCR) + 1,250,000

Ash Collection, Conveying, and Storage System. This system includes: new ash gates, valves, and pneumatic conveyor lines for the boiler ash, fly ash, scrubber residue, and baghouse ash; new ash receiving/separation equipment; new ash exhausters; new ash system controls; rebuilding of the ash storage silo; and rebuilding of the ash conditioner. The system cost is estimated as follows.

One boiler: Range 20,000-200,000 lb/hr
Cost $ = (1.20)(PMCR) + 250,000

Two boilers: Range 40,000 - 400,000 lb/hr
Cost $ = (1.17)(PMCR) + 400,000

Three boilers: Range 60,000 - 600,000 lb/hr
Cost $ = (1.00)(PMCR) + 550,000

Four boilers:	Range 80,000 - 600,000 lb/hr Cost $ = (0.95)(PMCR) + 700,000

Coal Stoker to Slagging Combustor

Fuel Receiving, Handling, Preparation, and Delivery System. This system includes: new coal handling conveyors; new coal handling controls; new motors on the coal handling equipment (i.e., conveyors, crushers, vibrators, motor-operated gates, etc.); and new coal chutes. The system cost is estimated as follows.

One boiler:	Range 20,000-200,000 lb/hr Cost $ = (2.83)(PMCR) + 350,000
Two boilers:	Range 40,000 - 400,000 lb/hr Cost $ = (2.47)(PMCR) + 400,000
Three boilers:	Range 60,000 - 600,000 lb/hr Cost $ = (2.35)(PMCR) + 500,000
Four boilers:	Range 80,000 - 800,000 lb/hr Cost $ = (1.90)(PMCR) + 600,000

Combustion/Burner System. This system includes: new combustion controls; new slagging combustors; boiler modification for combustors; and a slag collection system for combustors. The system cost is estimated as follows.

One boiler:	Range 20,000-200,000 lb/hr Cost $ = (2.33)(PMCR) + 180,000
Two boilers:	Range 40,000 - 400,000 lb/hr Cost $ = (2.35)(PMCR) + 300,000
Three boilers:	Range 60,000 - 600,000 lb/hr Cost $ = (1.45)(PMCR) + 500,000
Four boilers:	Range 80,000 - 600,000 lb/hr Cost $ = (1.20)(PMCR) + 650,000

Boiler System and Plant Structural Modifications. This system includes: structure supporting the combustor, lime, and coal feed system; structural supports for coal system; rebuilding coal hoppers and storage bunker; and air heater repair. The system cost is estimated as follows.

One boiler:	Range 20,000-200,000 lb/hr Cost \$ = (0.60)(PMCR) + 310,000
Two boilers:	Range 40,000 - 400,000 lb/hr Cost \$ = (0.70)(PMCR) + 600,000
Three boilers:	Range 60,000 - 600,000 lb/hr Cost \$ = (1.10)(PMCR) + 600,000
Four boilers:	Range 80,000 - 600,000 lb/hr Cost \$ = (1.25)(PMCR) + 700,000

Air Pollution Control System. This system includes: lime systems for receiving through the slagging combustor injection system; new baghouse with inlet and outlet ductwork or breeching to connect the baghouse to the boiler and I.D. fan; new I.D. fan with breeching to the stack; lime systems control; and air pollution system controls. The system cost is estimated as follows.

One boiler:	Range 20,000-200,000 lb/hr Cost \$ = (4.0)(PMCR) + 250,000
Two boilers:	Range 40,000 - 400,000 lb/hr Cost \$ = (5.0)(PMCR) + 300,000
Three boilers:	Range 60,000 - 600,000 lb/hr Cost \$ = (5.1)(PMCR) + 500,000
Four boilers:	Range 80,000 - 600,000 lb/hr Cost \$ = (5.1)(PMCR) + 700,000

Ash Collection, Conveying, and Storage System. This system includes: a slagging combustor slag removal and conveyor system; new ash gate valves and conveyor lines for the boiler fly ash and baghouse ash; new ash receiving/separation equipment; new

ash exhausters; new ash system controls; rebuilding of the ash storage silo; and rebuilding of the ash conditioner. The system cost is estimated as follows.

One boiler:	Range 20,000-200,000 lb/hr Cost $ = (1.25)(PMCR) + 300,000
Two boilers:	Range 40,000 - 400,000 lb/hr Cost $ = (1.20)(PMCR) + 475,000
Three boilers:	Range 60,000 - 600,000 lb/hr Cost $ = (1.10)(PMCR) + 650,000
Four boilers:	Range 80,000 - 600,000 lb/hr Cost $ = (1.05)(PMCR) + 800,000

Heavy Oil Package Boiler to Slagging Combustor

Fuel Receiving, Handling, Preparation, and Delivery System. This system includes: a new coal receiving hopper; new coal handling conveyors; new coal handling controls; new motors on the coal handling equipment (i.e., conveyors, crushers, vibrators, motor-operated gates, etc.); new coal chutes; and new fuel preparation and delivery system. The system cost is estimated as follows.

One boiler:	Range 20,000-200,000 lb/hr Cost $ = (3.65)(PMCR) + 550,000
Two boilers:	Range 40,000 - 400,000 lb/hr Cost $ = (2.70)(PMCR) + 900,000
Three boilers:	Range 60,000 - 600,000 lb/hr Cost $ = (2.60)(PMCR) + 1,000,000
Four boilers:	Range 80,000 - 800,000 lb/hr Cost $ = (2.20)(PMCR) + 1,240,000

Combustion/Burner System. This system includes: new combustion controls; new slagging combustors; boiler modification for combustors; and slag collection system for combustors. The system cost is estimated as follows.

One boiler:	Range 20,000-200,000 lb/hr Cost $ = (2.40)(PMCR) + 200,000

Two boilers: Range 40,000 - 400,000 lb/hr
Cost $ = (2.45)(PMCR) + 325,000

Three boilers: Range 60,000 - 600,000 lb/hr
Cost $ = (2.00)(PMCR) + 550,000

Four boilers: Range 80,000 - 600,000 lb/hr
Cost $ = (1.50)(PMCR) + 780,000

Boiler System and Plant Structural Modifications. This system includes: boiler structural changes for removing ash; structure supporting the combustor, lime, and coal feed systems; structural supports for coal system and receiving hoppers; new coal storage and storage bunker; and a new air heater. The system cost is estimated as follows.

One boiler: Range 20,000-200,000 lb/hr
Cost $ = (1.35)(PMCR) + 400,000

Two boilers: Range 40,000 - 400,000 lbshr
Cost $ = (1.50)(PMCR) + 650,000

Three boilers: Range 60,000 - 600,000 lb/hr
Cost $ = (1.80)(PMCR) + 700,000

Four boilers: Range 80,000 - 600,000 lb/hr
Cost $ = (1.90)(PMCR) + 750,000

Air Pollution Control System. This system includes: lime systems for receiving through the slagging combustor injection system; new baghouse with inlet and outlet ductwork or breeching to connect the baghouse to the boiler and I.D. fan; new I.D. fan with breeching to the stack; lime system control; and air pollution system controls. The system cost is estimated as follows.

One boiler: Range 20,000-200,000 lb/hr
Cost $ = (4.0)(PMCR) + 250,000

Two boilers: Range 40,000 - 400,000 lb/hr
Cost $ = (5.0)(PMCR) + 300,000

Three boilers: Range 60,000 - 600,000 lb/hr
Cost $ = (5.1)(PMCR) + 500,000

Four boilers:	Range 80,000 - 600,000 lb/hr Cost $ = (5.1)(PMCR) + 700,000

Ash Collection, Conveying, and Storage System. This system includes: a slagging combustor slag removal and conveyor system; new ash gate valves and conveyor lines for the boiler fly ash and baghouse ash; new ash receiving/separation equipment; new ash exhausters; new ash system controls; new ash storage silo; and new ash conditioner. The system cost is estimated as follows.

One boiler:	Range 20,000-200,000 lb/hr Cost $ = (1.30)(PMCR) + 325,000
Two boilers:	Range 40,000 - 400,000 lb/hr Cost $ = (1.40)(PMCR) + 500,000
Three boilers:	Range 60,000 - 600,000 lb/hr Cost $ = (1.20)(PMCR) + 750,000
Four boilers:	Range 80,000 - 600,000 lb/hr Cost $ = (1.15)(PMCR) + 900,000

Heavy Oil Package Boiler to Coal-Oil Mixture

Fuel Receiving, Handling, Preparation, and Delivery System. This system includes: a new COM day storage tank (1 day) with heating and agitator; new COM boiler delivery pumps; and new fuel system piping. The system cost is estimated as follows.

One boiler:	Range 20,000-200,000 lb/hr Cost $ = (0.60)(PMCR) + 40,000
Two boilers:	Range 40,000 - 400,000 lb/hr Cost $ = (0.75)(PMCR) + 60,000
Three boilers:	Range 60,000 - 600,000 lb/hr Cost $ = (1.20)(PMCR) + 80,000
Four boilers:	Range 80,000 - 800,000 lb/hr Cost $ = (1.75)(PMCR) + 100,000

Combustion/Burner System. This system includes: new COM controls; new COM burners; boiler modification for COM burning; and a boiler ash collection system. The system cost is estimated as follows.

One boiler:	Range 20,000-200,000 lb/hr Cost \$ = (1.5)(PMCR) + 100,000
Two boilers:	Range 40,000 - 400,000 lb/hr Cost \$ = (1.7)(PMCR) + 175,000
Three boilers:	Range 60,000 - 600,000 lb/hr Cost \$ = (2.2)(PMCR) + 275,000
Four boilers:	Range 80,000 - 600,000 lb/hr Cost \$ = (2.5)(PMCR) + 400,000

Boiler System and Plant Structural Modifications. This system includes: a boiler supporting the ash collection system and soot blowers; structural supports for COM burners; rebuilding long-term oil storage tank for COM; and air heater repair. The system cost is estimated as follows.

One boiler:	Range 20,000-200,000 lb/hr Cost \$ = (1.05)(PMCR) + 85,000
Two boilers:	Range 40,000 - 400,000 lb/hr Cost \$ = (1.25)(PMCR) + 100,000
Three boilers:	Range 60,000 - 600,000 lb/hr Cost \$ = (1.50)(PMCR) + 200,000
Four boilers:	Range 80,000 - 600,000 lb/hr Cost \$ = (2.00)(PMCR) + 300,000

Air Pollution Control System. This system includes: new baghouse with inlet and outlet ductwork or breeching to connect the baghouse to the boiler and I.D. fan; new I.D. fan with breeching to the stack; and air pollution system controls. The system cost is estimated as follows.

One boiler:	Range 20,000-200,000 lb/hr Cost \$ = (2.2)(PMCR) + 270,000

Two boilers:	Range 40,000 - 400,000 lb/hr Cost \$ = (2.5)(PMCR) + 350,000
Three boilers:	Range 60,000 - 600,000 lb/hr Cost \$ = (3.0)(PMCR) + 400,000
Four boilers:	Range 80,000 - 600,000 lb/hr Cost \$ = (3.5)(PMCR) + 500,000

Ash Collection, Conveying, and Storage System. This system includes: a boiler ash removal and conveyor system; new ash gate valves and conveyor lines for the boiler fly ash and baghouse ash; new ash receiving/separation equipment; new ash exhausters; new ash system controls; new ash storage silo; and new ash conditioner. The system cost is estimated as follows.

One boiler:	Range 20,000-200,000 lb/hr Cost \$ = (1.00)(PMCR) + 100,000
Two boilers:	Range 40,000 - 400,000 lb/hr Cost \$ = (1.15)(PMCR) + 200,000
Three boilers:	Range 60,000 - 600,000 lb/hr Cost \$ = (1.30)(PMCR) + 250,000
Four boilers:	Range 80,000 - 600,000 lb/hr Cost \$ = (1.40)(PMCR) + 325,000

Heavy Oil Package Boiler to Coal-Water Mixture

Fuel Receiving, Handling, Preparation, and Delivery System. This system includes: a new CWM day storage tank (1 day) with heating and agitator; new CWM boiler delivery pumps; and new fuel system piping. The system cost is estimated as follows.

One boiler:	Range 20,000-200,000 lb/hr Cost \$ = (0.65)(PMCR) + 40,000
Two boilers:	Range 40,000 - 400,000 lb/hr Cost \$ = (0.90)(PMCR) + 60,000
Three boilers:	Range 60,000 - 600,000 lb/hr Cost \$ = (1.30)(PMCR) + 85,000

Four boilers:	Range 80,000 - 800,000 lb/hr Cost $ = (2.00)(PMCR) + 125,000

Combustion/Burner System. This system includes: new CWM controls; new CWM burners; boiler modification for CWM burning; and boiler ash collection system. The system cost is estimated as follows.

One boiler:	Range 20,000-200,000 lb/hr Cost $ = (1.60)(PMCR) + 125,000
Two boilers:	Range 40,000 - 400,000 lb/hr Cost $ = (1.90)(PMCR) + 200,000
Three boilers:	Range 60,000 - 600,000 lb/hr Cost $ = (2.40)(PMCR) + 350,000
Four boilers:	Range 80,000 - 600,000 lb/hr Cost $ = (2.65)(PMCR) + 525,000

Boiler System and Plant Structural Modifications. This system includes: a boiler supporting the ash collection system and soot blowers; structural supports for CWM burners; rebuilding long-term oil storage tank for CWM; and air heater repair. The system cost is estimated as follows.

One boiler:	Range 20,000-200,000 lb/hr Cost $ = (1.05)(PMCR) + 85,000
Two boilers:	Range 40,000 - 400,000 lb/hr Cost $ = (1.25)(PMCR) + 100,000
Three boilers:	Range 60,000 - 600,000 lb/hr Cost $ = (1.50)(PMCR) + 200,000
Four boilers:	Range 80,000 - 600,000 lb/hr Cost $ = (2.00)(PMCR) + 300,000

Air Pollution Control System. This system includes: a new baghouse with inlet and outlet ductwork or breeching to connect the baghouse to the boiler and I.D. fan; a new I.D. fan with breeching to the stack; and air pollution system controls.

One boiler:	Range 20,000-200,000 lb/hr Cost $ = (2.2)(PMCR) + 270,000
Two boilers:	Range 40,000 - 400,000 lb/hr Cost $ = (2.5)(PMCR) + 350,000
Three boilers:	Range 60,000 - 600,000 lb/hr Cost $ = (3.0)(PMCR) + 400,000
Four boilers:	Range 80,000 - 600,000 lb/hr Cost $ = (3.5)(PMCR) + 500,000

Ash Collection, Conveying and Storage System. This system includes: boiler ash removal and conveyor system; new ash gate valves and conveyor lines for the boiler fly ash and baghouse ash; new ash receiving/separation equipment; new ash exhausters; new ash system controls; new ash storage silo; and a new ash conditioner. The system cost is estimated as follows.

One boiler:	Range 20,000-200,000 lb/hr Cost $ = (1.00)(PMCR) + 100,000
Two boilers:	Range 40,000 - 400,000 lb/hr Cost $ = (1.15)(PMCR) + 200,000
Three boilers:	Range 60,000 - 600,000 lb/hr Cost $ = (1.30)(PMCR) + 250,000
Four boilers:	Range 80,000 - 600,000 lb/hr Cost $ = (1.40)(PMCR) + 325,000

Heavy Oil Package Boiler to Micronized Coal

Fuel Receiving, Handling, Storage, Preparation, and Delivery System. This system includes: a new coal receiving hopper; new coal handling conveyors; new coal handling controls; new motors on the coal handling equipment (i.e., conveyors, crushers,

vibrators, motor-operated gates, etc.); new coal chutes; and a new fuel preparation and delivery system. The system cost is estimated as follows.

One boiler:	Range 20,000-200,000 lb/hr Cost \$ = (3.75)(PMCR) + 600,000
Two boilers:	Range 40,000 - 400,000 lb/hr Cost \$ = (3.00)(PMCR) + 1,000,000
Three boilers:	Range 60,000 - 600,000 lb/hr Cost \$ = (2.85)(PMCR) + 1,200,000
Four boilers:	Range 80,000 - 800,000 lb/hr Cost \$ = (2.40)(PMCR) + 1,500,000

Combustion/Burner System. This system includes: new burner controls; new micronized coal and igniters burners; boiler modification for burning micronized coal; and a boiler ash collection system. The system cost is estimated as follows.

One Boiler:	Range 20,000-200,000 lb/hr Cost \$ = (1.3)(PMCR) + 175,000
Two Boilers:	Range 40,000 - 400,000 lb/hr Cost \$ = (1.5)(PMCR) + 225,000
Three Boilers:	Range 60,000 - 600,000 lb/hr Cost \$ = (2.5)(PMCR) + 350,000
Four Boilers:	Range 80,000 - 600,000 lb/hr Cost \$ = (2.7)(PMCR) + 550,000

Boiler System and Plant Structural Modifications. This system includes: a boiler supporting the ash collection system and soot blowers; structural supports for micronized coal and fuel piping; new coal storage bunker (1 day); new coal feeder supports; pulverizer supports; coal conveyor supports; and air heater repair. The system cost is estimated as follows.

One Boiler:	Range 20,000-200,000 lb/hr Cost \$ = (1.55)(PMCR) + 150,000

Two Boilers:	Range 40,000 - 400,000 lb/hr Cost $ = (2.25)(PMCR) + 265,000
Three Boilers:	Range 60,000 - 600,000 lb/hr Cost $ = (2.80)(PMCR) + 410,000
Four Boilers:	Range 80,000 - 600,000 lb/hr Cost $ = (3.35)(PMCR) + 515,000

Air Pollution Control System. This system includes: a new baghouse with Inlet and Outlet Ductwork or Breeching to connect the baghouse to the boiler and I.D. fan; new I.D. fan with breeching to the stack; and air pollution system controls. The system cost is estimated as follows.

One Boiler:	Range 20,000 - 200,000 lb/hr Cost $ = (2.2)(PMCR) + 310,000
Two Boilers:	Range 40,000 - 400,000 lb/hr Cost $ = (2.5)(PMCR) + 400,000
Three Boilers:	Range 60,000 - 600,000 lb/hr Cost $ = (3.0)(PMCR) + 450,000
Four Boilers:	Range 80,000 - 600,000 lb/hr Cost $ = (3.5)(PMCR) + 540,000

Ash Collection, Conveying and Storage System. This system includes: a boiler ash removal and conveyor system; new ash gate valves and conveyor lines for the boiler fly ash and baghouse ash; new ash receiving/separation equipment; new ash exhausters; new ash system controls; new ash storage silo; and a new ash conditioner. The system cost is estimated as follows.

One Boiler:	Range 20,000 - 200,000 lb/hr Cost $ = (1.0)(PMCR) + 125,000
Two Boilers:	Range 40,000 - 400,000 lb/hr Cost $ = (1.15)(PMCR) + 230,000
Three Boilers:	Range 60,000 - 600,000 lb/hr Cost $ = (1.3)(PMCR) + 285,000

Four Boilers: Range 80,000 - 600,000 lb/hr
Cost $ = (1.4)(PMCR) + 350,000

Heavy Oil Stoker to Fluidized Bed Combustion

Fuel Receiving, Handling, Preparation, and Delivery System. This system includes: new coal system controls; new coal handling conveyors; new motors on the coal handling equipment (i.e., conveyors, crushers, vibrators, motor-operated gates, etc.); new coal chutes; and new coal feeders. The system cost is estimated as follows.

One Boiler: Range 20,000 - 200,000 lb/hr
Cost $ = (1.75)(PMCR) + 280,000

Two Boilers: Range 40,000 - 400,000 lb/hr
Cost $ = (1.25)(PMCR) + 475,000

Three Boilers: Range 60,000 - 600,000 lb/hr
Cost $ = (1.43)(PMCR) + 520,000

Four Boilers: Range 80,000 - 800,000 lb/hr
Cost $ = (1.50)(PMCR) + 530,000

Combustion/Burner System. This system includes: a new fluid-bed combustion system that includes the air distribution grate and lower air chamber, refractor-lined combustion chamber, etc.; new combustion controls; new secondary air fan; new windboxes; fluid-bed ash removal and cooling system; and new F.D. and secondary air fans. The system cost is estimated as follows.

One Boiler: Range 20,000 - 200,000 lb/hr
Cost $ = (5.5)(PMCR) + 700,000

Two Boilers: Range 40,000 - 400,000 lb/hr
Cost $ = (7.6)(PMCR) + 1,000,000

Three Boilers: Range 60,000 - 600,000 lb/hr
Cost $ = (10.7)(PMCR) + 1,200,000

Four Boilers: Range 80,000 - 600,000 lb/hr
Cost $ = (12.6)(PMCR) + 1,530,000

Boiler System and Plant Structural Modifications. This system includes: structural support of the bubbling fluidized bed combustion chamber, ash pits, feeders, boiler ash hoppers, etc.; new sootblowers; structural work for the new coal handling conveyors; rebuilding of coal hoppers and storage bunkers; air heater repair; and lime feed system supports. The system cost is estimated as follows.

One Boiler:	Range 20,000 - 200,000 lb/hr Cost \$ = (1.70)(PMCR) + 200,000
Two Boilers:	Range 40,000 - 400,000 lb/hr Cost \$ = (1.80)(PMCR) + 250,000
Three Boilers:	Range 60,000 - 600,000 lb/hr Cost \$ = (2.00)(PMCR) + 290,000
Four Boilers:	Range 80,000 - 600,000 lb/hr Cost \$ = (2.15)(PMCR) + 350,000

Air Pollution Control System. This system includes: rebuilding mechanical collectors; a new lime storage and feed system; new baghouse; new air pollution system controls; all ductwork, breeching, piping, electrical, etc., necessary to connect the systems; new I.D. fan(s); and foundations for all new equipment. The system cost is estimated as follows.

One Boiler:	Range 20,000 - 200,000 lb/hr Cost \$ = (2.60)(PMCR) + 300,000
Two Boilers:	Range 40,000 - 400,000 lb/hr Cost \$ = (2.15)(PMCR) + 500,000
Three Boilers:	Range 60,000 - 600,000 lb/hr Cost \$ = (2.30)(PMCR) + 600,000
Four Boilers:	Range 80,000 - 600,000 lb/hr Cost \$ = (2.35)(PMCR) + 750,000

Ash Collection, Conveying and Storage System. This system includes: new ash gates, valves, and pneumatic conveyor lines for the boiler ash, fly ash and baghouse ash; new ash receiving/separation equipment; new ash exhausters; new ash system

controls; rebuilding of the ash storage silo; and rebuilding of the ash conditioner. The system cost is estimated as follows.

One Boiler:	Range 20,000 - 200,000 lb/hr Cost \$ = (1.30)(PMCR) + 250,000
Two Boilers:	Range 40,000 - 400,000 lb/hr Cost \$ = (1.25)(PMCR) + 400,000
Three Boilers:	Range 60,000 - 600,000 lb/hr Cost \$ = (1.10)(PMCR) + 550,000
Four Boilers:	Range 80,000 - 600,000 lb/hr Cost \$ = (1.00)(PMCR) + 700,000

6 Facility Operations and Maintenance Cost

This section provides operation and maintenance cost estimates for new steam production and cogeneration power plants. These estimated costs are divided into operational costs and major maintenance costs. Operational costs are the day-to-day costs of operating and maintaining a steam or cogeneration facility. Costs for significant equipment rebuilds, however (i.e., turbine rebuilds, baghouse rebagging, major boiler outages, boiler feedwater pump rebuilds, water treating resin replacement, etc.), are included in major maintenance costs. After calculating these costs, the program adds them to estimate the total yearly costs of operation. The estimates provided by the cost algorithms are based on fourth-quarter 1988 dollars and are escalated yearly for the development of future costs. The operating and maintenance costs are then used with the capital costs to determine the total life cycle cost of the conceptual new facility being evaluated.

Operational Cost Components

Cost components included in this category estimate the day-to-day costs of operating and maintaining a steam or cogeneration facility. The costs included in this category are discussed below.

Labor

The labor category is divided into four classifications: management, operations and maintenance, yard or fuel storage, and steam system. Management includes the personnel required to manage and direct the total operations of the facility; included in this are the plant manager, assistant plant manager, plant engineers, plant secretary, clerks, janitor and instrumentation technicians. These personnel will handle the responsibilities of overall operations, maintenance, and planning of the facility; payroll and accounting; receptionist and secretarial responsibilities; maintenance parts inventory control; ordering and restocking; cost control; and other necessary duties.

Operations personnel include a shift supervisor, operators, assistant operators, and laborers. Operations personnel are responsible for plant operations and minor and

preventive maintenance such as painting, seal repacking, greasing, oiling, etc., when not busy with plant duties.

Fuel storage personnel are responsible for long-term fuel storage area operations. This includes fuel stocking, reclaim, and unloading.

Maintenance personnel include mechanical and electrical maintenance technicians and general laborers. Maintenance personnel are responsible for plant maintenance and the repair, rebuilding, or replacement of pumps, small fans, soot blower, nominal boiler repairs, air compressors, instrumentation, plant electrical system, and other such tasks. When required, these personnel also have a responsibility to assist in plant operations; for example, coal unloading and handling, and ash handling.

Steam system labor includes the personnel required to maintain the steam distribution system.

Table 16 lists the default wages and the default values for each type of labor. The estimated cost of labor was developed as a function of plant size, number of boilers, whether the facility is a heating or cogeneration facility, fuel type, personnel salary, and productivity level. The user can specify the salary level, percent fringe benefit multiplier, and percent overtime for each type of personnel. The program will then compute the salary cost in dollars per year. Alternatively, the suggested default total operations and maintenance labor cost estimates are provided as discussed in the following paragraphs.

Heating Ffacility Stoker and Fluid Bed Boilers. 3-Boiler Facility Cost ($/yr) = [(1.137)(PMCR) + 688,000] [1 + % labor Escalation/100] [Labor Productivity Factor] [(labor cost in $/hr) / 20.25].

Table 16. Default labor categories and wages.

Labor Category	Salary, (Dollars per Hour)	Overtime
Plant Engineer	22.00	No
Plant Secretary	10.50	No
Shift Supervisor	17.00	Yes
Operator	12.00	Yes
Assistant Operator	10.00	Yes
Laborer	8.50	Yes

Notes: Overtime is equal to 15% of base salary.
Fringe benefits are equal to 42% of base salary.

Parameters:

a. The labor cost in dollars per hour is the average cost of total plant personnel salaries, including fringe benefits and 15 percent overtime for operations and maintenance personnel. For Ohio in 1988, labor costs were $20.25/hr.
b. The minimum 1988 cost was $760,000 per year.
c. The maximum 1988 cost was $1,150,000 per year.

4- and 5-Boiler Facility Cost ($/yr) = [(1.429)(PMCR) + 777,000] [1 + % Labor Escalation/100] [Labor Productivity Factor] [(Labor Cost in $/hr) / 19.75]

Parameters:

a. The labor cost in dollars per hour is the average cost of total plant personnel salaries, including fringe benefits and 15 percent overtime for operations and maintenance personnel. For Ohio in 1988, labor costs equaled $19.75 per hour.
b. The minimum 1988 cost was $870,000 per year.
c. The maximum 1988 cost was $1,350,000 per year.

Heating Facility Coal Slurry Boilers. 3-Boiler Facility Cost ($/yr) = [(0.7)(PMCR) + 620,000] [1 + % Labor Escalation/100] [Labor Productivity Factor] [(Labor Cost in $/hr) / 20.00]

Parameters:

a. The labor cost in dollars per hour is the average cost of total plant personnel salaries, including fringe benefits and 15 percent overtime for operations and maintenance personnel. For Ohio in 1988 labor costs equaled $20.00 per hour.
b. The minimum 1988 cost was $700,000 per year.
c. The maximum 1988 cost was $920,000 per year.

4- and 5-Boiler Facility Cost ($/yr) = [(0.64)(PMCR) + 96,000][1 + % Labor Escalation/100] [Labor Productivity Factor] [(Labor Cost in $/hr) / 20.25]

Parameters:

a. The labor cost in dollars per hour is the average cost of total plant personnel salaries , including fringe benefits and 15 percent overtime for operations and

maintenance personnel. For Ohio in 1988, labor costs equaled $20.25 per hour.

b. The minimum 1988 cost was $890,000 per year.
c. The maximum 1988 cost was $1,100,000 per year.

Cogeneration Facility Stoker and Fluid-Bed Boilers. 3-Boiler Facility Cost ($/yr) = [(1.25)(PMCR) + 746,750] [1 + % Labor Escalation/100] [Labor Productivity Factor] [(Labor Cost in $/hr)/20.00]

Parameters:

a. The labor cost in dollars per hour is the average cost of total plant personnel salaries , including fringe benefits and 15 percent overtime for operations and maintenance personnel. For Ohio in 1988, labor costs equaled $20.00 per hour.
b. The minimum 1988 cost was $821,000 per year.
c. The maximum 1988 cost was $1,250,000 per year.

4- and 5-Boiler Facility Cost ($/yr) = [(1.45)(PMCR) + 845,000] [1 + % Labor Escalation/100] [Labor Productivity Factor] [(Labor Cost in $/hr) / 20.00]

Parameters:

a. The labor cost in dollars per hour is the average cost of total plant personnel salaries, including fringe benefits and 15 percent overtime for operations and maintenance personnel. For Ohio in 1988, labor costs equaled $20.00 per hour.
b. The minimum 1988 cost was $930,000 per year.
c. The maximum 1988 cost was $1,500,000 per year.

Cogeneration Facility Coal Slurry Boilers. 3-Boiler Facility Cost ($/yr) = [(0.58) (PMCR) + 787,000] [1 + % Labor Escalation/100] [Labor Productivity Factor] [(Labor Cost in $/hr) / 19.75]

Parameters:

a. The labor cost in dollars per hour is the average cost of total plant personnel salaries, including fringe benefits and 15 percent overtime for operations and maintenance personnel. For Ohio in 1988, labor costs equaled $19.75 per hour.
b. The maximum 1988 cost was $1,020,000 per year.

4- and 5-Boiler Facility Cost ($/yr) = [(0.69)(PMCR) + 935,000] [1 + % Labor Escalation/100] [Labor Productivity Factor] [(Labor Cost in $/hr) / 20.00]

Parameters:

a. The labor cost in dollars per hour is the average cost of total plant personnel salaries, including fringe benefits and 15 percent overtime for operations and maintenance personnel. For Ohio in 1988, labor cost equaled $20.00 per hour.
b. The minimum 1988 cost was $980,000 per year.

Coal Fuel Storage. Up to 150 TPH: cost ($/yr) = [$103,500/yr] [1 + % Labor Escalation] [(Labor Cost in $/hr)/16.58]

Parameters:

The 1988 labor cost in dollars per hour is the cost of labor, includeing fringe benefits and 15 percent overtime. For Ohio in 1988, labor costs equaled $16.58 per hour.

From 150 to 250 TPH: cost ($/yr) = [$141,175/yr] [1 + % Labor Escalation] [(Labor Cost in $/hr)/16.58] [Labor Productivity Factor]

Parameters:

The 1988 labor cost in dollars per hour is the cost of labor, including fringe benefits and 15 percent overtime. For Ohio in 1988, labor costs equaled $16.58 per hour.

Coal Slurry Fuel Storage. Cost ($/yr) = [70,600][1 + % Labor Escalation/100] [labor Productivity] [(Labor Cost in $/hr) / 16.58]

Parameters:

The 1988 labor cost in dollars per hour is the cost of labor, including fringe benefits and 15 percent overtime. For Ohio in 1988, labor costs equaled $16.58 per hour.

Steam Distribution System. Estimated Operations and Maintenance labor cost ($/yr) = [$120,000/yr] [1 + % Labor Escalation/100] [Labor Productivity] [(Labor Cost in $/hr) / 16.58]

Parameters:

The 1988 labor cost in dollars per hour is the cost of labor, including fringe benefits and 15 percent overtime. For Ohio in 1988, labor costs equaled $16.58 per hour.

Fuel

This category is divided into two components, the primary and secondary fuel. Primary fuel is the fuel used to produce steam. Secondary fuel is the fuel used for starting the boilers, car thawing for coal receiving, plant vehicles, diesel generators, etc. Primary fuel cost is calculated by multiplying the amount of fuel used per year times the cost of the fuel.

Heating facility primary fuel use is estimated by using the average steam load per month divided by the maximum steam load times the fuel utilization rate at the maximum steam flow. The fuel consumption rate in pounds per hour is then multiplied by 24 hrs/day and the number of days per month for the monthly fuel rate. To calculate the 1988 yearly fuel cost, sum the monthly fuel rates and multiply by the fuel cost. For future costs, the 1988 cost is increased by the escalation rate.

Cogeneration facility primary fuel use is estimated by the following calculation. Keep in mind that 0.85 is the value of the power production factor developed from partial and total load loss due to boiler and turbine outages planned and forced.

Estimated fuel use = (fuel utilization rate in lb/hr@PMCR) (24 hrs/day) (365 days/yr) 0.85

Secondary fuel use rate is estimated by the following equations. The 1988 cost of the secondary fuel is determined by multiplying the fuel use in gallons times the fuel cost. For future costs, the 1988 costs are increased by the escalation rate.

Stoker Boilers.

Car thawing (gal No.2 Diesel/yr) = [(0.1)(PMCR)+21,000]

No car thawing (gal No.2 Diesel/yr) = [(0.004(PMCR)+16,000]

Fluid-Bed Boilers.

Car thawing (gal No.2 Diesel/yr) = [(0.11)(PMCR)+24,000]

No car thawing (gal No.2 Diesel/yr) = [(0.006)(PMCR)+17,000]

Coal Slurry.

Fuel use rate (gal No.2 Diesel/yr) = [(0.007)(PMCR)+50]

Lime or Limestone

The cost of the lime or limestone system components is calculated similar to the primary fuel cost. The lime or limestone monthly use rate is calculated for each month of the year and the yearly use is determined by summing the monthly rates. For cogeneration, the yearly use is estimated by multiplying the yearly rate by 0.96. The 1988 costs are then determined by multiplying lime use times cost per quantity. Future costs are then computed by escalating the 1988 costs.

Water

The water cost estimate is determined by multiplying the amount of water consumed by the cost of water. Summing the monthly rates determines the yearly consumption. The amount of water consumed is estimated by the following system uses.

1. Condensate makeup water use:
   Condensate makeup = (average monthly steam flow) (user input) (1 - % condensate return/100) (24 hr/day) (no. of days/month)

2. Blowdown makeup is determined similarly to condensate makeup using the percent blowdown input by the uses.

   No. of gallons per month = [(no. of gal/min @PMCR) (monthly average steam rate)] / [(PMCR) (24 hr/day) (no.of days/month)]

3. Plant water use includes ash conditioning and facility washdown. Ash conditioning is estimated as 10 to 40 percent by weight of the ash generated.

   Estimated monthly ash flow = [(ash produced) (average monthly steam flow)] / [PMCR (24hr/day) (no. of days/month)]

   Calculated ash conditioning = [(est.monthly ash flow)(user selected % water in ash)] / 100

Parameters:

a. Convert the amount of water to gallons
b. The user selected % water default value is 10%.

4. Facility washdown and miscellaneous water use is estimated as follows.

   Estimated use = 780,000 gal/yr = (25 gal/min)(60 min/hr) (3 hr/day)(7 day/wk) (52 wk/yr)

5. Personnel water use is estimated as 8,750 gallons per year per employee.

6. Cooling tower use is estimated by the following.

   Estimated use = (circulating cooling water makeup) (60 min/hr) (24 hr/day) (365 day/yr) (0.77)

7. The water treatment wastewater estimate depends on the type of water treatment system.

   Zeolite system wastewater estimated use = (wastewater/regeneration in gal)(no. of regenerations/yr)

   Demineralizer system wastewater estimated use = (cation and anion Vessels Backwash Water + Cation and Anion Rinse Water) (no. of regenerations/yr)

   Mixed-Bed system wastewater estimated use = (Mixed Bed Vessel Backwash + mixed bed Rinse Water) (no. of regenerations/yr)

   Condensate polisher system wastewater estimated use = (Mixed Bed Vessel Backwash + mixed bed Rinse Water) (no. of regenerations/yr)

   Number of regenerations per year is estimated by:

   [(Condensate Makeup/Yr + Blowdown Makeup/Yr)(0.15)(no. of Trains)] / [(Treated Water Flow/Train) 1440].

Parameters:

The number of trains is determined by the continuous treated water flow rate where from 0 to 600 gpm the system consists of two trains, and from 600 to 1200 gpm the system consists of three trains.

Sanitary Sewer

The estimated cost of the sanitary sewer is a direct function of the amount of waste sent to the sewer. The sewer flow is estimated by the following.

> Estimated cost = [0.5 (blowdown water makeup) + (facility washdown and miscellaneous water) + (personnel water use) + (cooling tower blowdown)] (sewer cost)

Parameters:

> The water rate estimate must be in the same units as the sewer cost rate, i.e., if cost is \$/gpm, then water rate must be gpm.

Ash Disposal

The estimated cost of ash disposal is a direct function of the amount or weight of waste (ash or residue plus moisture content) produced by the facility. The amount of waste per month is estimated by the following.

> Estimated waste = [(mass of waste/hr) (24 hours per day) (average monthly steam load) / PMCR] [no. of days/month (1 + % water added for ash conditioning / 100)]

Summing each monthly waste generation provides an estimate of the amount of waste generated per year. Multiplying this by the cost of waste disposal provides the estimated cost of waste disposal at the location of the disposal site. (Note: The amount of yearly waste must be in the same units as the cost of waste disposal; i.e., tons per year times dollars per ton). The program uses the cost of waste disposal inclusive of freight costs.

Electricity Consumption

The cost of electricity is divided into three categories; process use, general facility use and utility equipment and standby charges. Process charge is the cost of the electricity to operate the facility steam/power generation system. This cost is determined monthly; then monthly costs are summed for the yearly estimated cost. Each monthly charge is estimated by the following equation. Summing the monthly costs provides the yearly process electrical load costs.

Estimated process charge = (total system motor in kW/hr) (24hr/day) (no. of days/month) (month's average steam load) / PMCR (electricity cost)

Note that the total system motor kW includes such users as pump motors, fan motors, conveyor systems, etc.

The general facility electricity cost is estimated mainly as the facility lighting load. This is divided into the plant or building, and the facility area lighting. The plant and facility lighting yearly costs are estimated as follows.

Est. plant yearly cost = [0.10][building size in cu ft] [24 hr/day][365 days/year] [Electricity Cost in $/kWhr/hr]/[1000].

Est. facility yearly cost = [(Plant Acres) + (Long-Term Coal Storage Acres)] (43,560 sq ft/Acre)[(0.067 Watts/hr/hr.ft^2)/1000 watts/kW)] (12 hrs/Day) (365 Days/yr)(Electricity Cost in $/Kwhr/hr)

Utility equipment and standby charges are the cost of renting the facility substation, power lines into the facility, and a standby demand charge. These costs usually apply only to cogeneration facilities and depend totally on the location of the facility. The user must input these costs, where and if applicable. The total facility electrical yearly cost is then estimated by summing the process use yearly cost, general facility use yearly costs and utility equipment and standby charges yearly costs.

Facility Chemicals

The facility chemical use is divided into three main areas; boiler, water treating and cooling tower. All three depend on the steam load of the facility. Boiler chemical use depends on boiler water quality and blowdown rate. Usually the higher the water quality and/or blowdown rate, the less the amount of boiler chemicals required. For the design estimate, all boilers will use a coordinated phosphate treatment. This is a mixture of 60 percent by weight trisodium phosphate and 40 percent by weight disodium phosphate. The boiler drum water includes an ion concentration of 10 ppm PO_4^{3-}. The chemical monthly usage is estimated by the following.

lb 100% PO_4^{3-}/hr = (Average Steam Flow Rate/month/hr) (%Blowdown) / (1 x 105)

lb trisodium phosphate/hr = (0.6)(lbs 100% PO_4^{3-}/hr) / (0.58)

lb disodium phosphate/hr = (0.4)(lbs 100% PO_4^{3-}/hr) / (0.67)

lb trisodium phosphate/mo = (lbs trisodium phosphate/hr) (24)(days/month)

lb disodium phosphate/mo = (lbs disodium phosphate/hr) (24)(days/month)

The boiler chemical cost is then estimated by summing the monthly chemical use and multiplying by the cost of the chemicals. Water treating chemical use is divided into two categories: a water treatment system, and a deaerator or oxygen scavenger system. The oxygen scavenger system uses a deaerator to reduce the oxygen in the feedwater to a 0.005 ppm level. The scavenger chemical, hydrazine, then removes the remaining oxygen from the water. The monthly hydrazine use is estimated by the following.

Hydrazine use (lb/mo) = (5/1 x 108) (Average monthly Steam Flow in lb/hr) (1 + % Blowdown Flow/100) (1.5) (24 hr/day) (days/month)

Summing the monthly use provides the hydrazine use in pounds per year. Multiplying this by hydrazine cost ($/lb) estimates the yearly cost of the hydrazine. The water treatment chemicals depend on the type of system and the number of regenerations. Zeolite systems use salt and demineralizer systems (mixed-bed and condensate polishers also) use acid and caustic.

Estimated zeolite salt use:

NaCl (lb/yr) = (6)(Resin Vessel Area)(Resin Depth)(no. of regenerations/yr)

Estimated demineralizer system chemical use:

Acid (lb/yr) = [(Cation Vessel Acid/regeneration)(no. of regenerations/yr)] / (15.4)

Caustic (lb/yr) = [(Anion Vessel Caustic/regeneration)(no. of regenerations/yr)] / (12.8)

Estimated mixed-Bed and Polisher systems chemical uses:

Acid (lb/yr) = [(Mixed-Bed Vessel Acid/regeneration) (no. of regenerations/yr)] / (15.4)

Caustic (lb/yr) = [(Mixed-Bed Vessel Caustic/regeneration)(no. of Regenerations/ year)]/(12.8)

The chemical costs per year are then determined by multiplying the cost of the chemicals (i.e. dollars per pound, times the total chemical use in pounds per year). The cooling tower chemicals consist mainly of chlorine and a periodic shock treatment of a biocide. The chlorine use is estimated by the following.

Chlorine use (lb/yr) = (15/1 x 108) (circulating water flow) (60) (8.33) (1.5) (365) (0.90) (1.25)

The chlorine cost is then determined by multiplying the chlorine use by the cost of chlorine. The other biocide cost is estimated as 1.75 times the cost of chlorine. The total cooling tower chemical cost is estimated as 2.75 times the cost of chlorine.

Maintenance Parts

Maintenance parts are estimated as a function of plant size. The yearly spare parts cost is estimated as 85 percent of the spare parts capital cost. During the first year of operation, this cost is estimated as 15 percent of spare parts.

Facility Consumables

The consumable cost estimate is the same as that calculated in the capital costs. During the first year of operation this cost is estimated as 20 percent of consumable costs.

Facility Grounds Maintenance

This category is for the area or grounds maintenance, including such items as cutting the grass, road repair, railroad track maintenance, etc. This cost is estimated as a function of plant area acreage and is provided by the following.

Cost ($/yr) = ($7500/yr)(plant acres)(1 + % Labor Escalation/100) (Labor Productivity)(Labor Cost in $/hr/12)

Parameters:

The 1988 labor (in dollars per hour) is the cost of labor, including fringe benefits, profit, and overhead of an outside contractor. For Ohio 1988, the labor cost is estimated at $12.00/hr.

Insurance

This category is for general facility insurance and, for third party financing, for operation and potentially bond insurance. The general facility insurance is estimated as 0.05 percent of the capital equipment plus building cost of the facility escalated every 3 years. The bond insurance cost is estimated as 0.08 percent of the bonded cost of the facility; the bonded cost being conceptually estimated as the total capital cost of the facility times 1.33.

Mobile Equipment

This category is for maintaining the facility's mobile equipment. The cost is estimated as 8 percent of the mobile equipment capital cost.

Stack

The stack cost is for an outside contractor to maintain the FAA and beacon lights and for an annual inspection. The cost is estimated as:

Cost ($/yr) = ($12,000/yr)(1 + % Labor Escalation/100)(Labor Productivity Factor)(Labor Cost in $/hr/$20.00)(no. of Stacks)

Parameters:

The 1988 labor cost (in dollars per hour) is the cost of labor, including fringe benefits, profit and overhead of an outside contractor. For Ohio 1988, labor cost is estimated at $20.00/hr.

Steam Distribution Maintenance Parts

The steam distribution system's yearly spare parts and outside contracted services are estimated as a function of the type of system (i.e., tunnel, direct burial, etc.) and the capital cost of the system. The estimated costs of parts and outside services are provided by the following.

Cost ($/yr) = (0.005)(system construction cost)(System Factor) (1 + % Mat'l. Escalation/100)

Parameters:

a. The system construction cost is provided by steam distribution costs.

b. The system Factors are as follows.

Tunnel =	1.1
Direct Burial =	1.6
Shallow Trench =	1.0
Above Ground =	1.15

Major Maintenance

This category is for major equipment rebuilds (i.e., turbine, boiler, baghouse rebagging, water treatment resin replacement, etc.). Also included are the permit renewal fees/tests. The major maintenance costs included are as described in the following sections.

Boiler Maintenance

Each boiler will have yearly outages to perform maintenance. The cost of these outages is estimated as follows.

Type of boiler	Percent of the boiler capital cost
Coal slurry	0.7
Stoker	0.85
Bubbling fluid-bed	1.3
Recirculating fluid-bed	1.5

These costs should be escalated yearly as appropriate. In addition to the yearly outages, the boilers will experience extended outages periodically to replace/repair the boilers (i.e., superheater replacement, grate replacement, economizer repairs, safety

valve repair, fan repairs, etc.). These costs are estimated in lieu of the aforementioned cost estimate by and at the time as follows:

Type of boiler	Estimated cost
Coal slurry	Every 15 years, 6 percent of the boiler capital cost escalated
Stoker	Every 8 years, 3 percent of the boiler capital cost excalated
Bubbling fluid-bed	Every 5 years, 4 percent of the boiler capital cost escalated
Recirculating fluid-bed	Every 5 years, 2.5 percent of the boiler capital cost escalated; and every 15th year, 5 percent of the boiler capital cost escalated

Turbine-Generator Maintenance

The small, gear type, turbine-generator is estimated to have an outage every 8 years at a cost of 8 percent of the turbine-generator's capital cost escalated. The large, 600 psig and 750 °F direct drive turbine-generator is estimated to have an outage every 5 years at a cost of 10.5 percent of the turbine-generator's capital cost. The large, 1300 psig and 1000 °F direct drive turbine-generator is estimated to have an outage every 5 years at a cost of 12 percent of the turbine-generator's capital cost.

Baghouse Maintenance

The baghouse is estimated to have an outage every 3 years. This is mainly for bag replacement. The estimated cost is 5 percent of the capital cost of the baghouse. Every 12 years, the estimated cost is 7 percent of the capital cost.

Cooling Tower Maintenance

The cooling tower is estimated to have an outage every 15 years for wood replacement, fan repairs, and fill replacement/cleaning. The cost of this is estimated as 10 percent of the capital cost of the cooling tower.

General Facility Maintenance

Boiler Feedwater Pumps - Motor Driven. These pumps are estimated to require rebuilding every 15 years at an estimated cost of 40 percent of the pump's capital cost.

Boiler Feedwater Pumps - Turbine Driven. These pumps and turbines are estimated to require rebuiding every 12 years at an estimated cost of 60 percent of the pump's capital cost.

Coal Slurry Pumps. These pumps are estimated to require rebuilding every 3 years at an estimated cost of 45 percent of the capital cost escalated. These pumps are replaced every 12 years at the estimated capital cost.

Other Centrifugal Pumps. These pumps are estimated to require rebuilding every 18 years at an estimated cost of 40 percent of the capital cost.

Sump Pumps**.** These pumps are estimated to require rebuilding every 20 years at an estimated cost of 35 percent of the capital cost.

Circulation Water Pumps**.** These pumps are estimated to require rebuilding every 25 years at an estimated cost of 25 percent of the capital cost.

Deaerator. The deaerator is estimated to have a major outage for internal parts replacement every 20 years. The estimated cost is 25 percent of the capital cost.

Coal Conveyor Systems. The coal system is estimated to have the following equipment rebuilt at these time periods: bucket elevators, 38 percent capital cost every 8 years; coal crusher, 20 percent capital cost every 10 years; conveyor belts, 5 percent capital cost every 15 years.

Limestone or Lime Conveyor Systems. The limestone or lime systems are estimated to be 3 percent of the capital cost escalated every 5 years.

Ash System. The ash system estimate is based on rebuilding the system every 7 years at a cost of 22 percent of the capital cost escalated.

Water Treatment System. This system is estimated to have a major outage every 10 years for valve repairs, tank relining, and resin replacement. The estimated cost is 45 percent of the capital cost.

Stack. The stack is estimated to require major repair (i.e., top of stack repairs), every 20 years. The estimated cost is 1.0 percent of capital cost.

Air Heater. The air heater for coal-water slurry systems only is estimated to have an outage every 15 years for basket replacement. The estimated cost is 35 percent of the capital cost escalated.

Scrubber - Lime System. This equipment is estimated to require major repairs (i.e., atomizer rebuilds, slaker rebuilds, lime pump rebuilds, etc.) every 5 years. The estimated cost is 6 percent of the capital cost of the dry scrubber-lime system.

Building. The building is estimated to require a new roof, painting, etc., every 20 years. The estimated cost is 15 percent of the capital cost.

Fans. This estimated cost is for the I.D. fans only. Other fan repair/rebuild costs are included with the main equipment item. For example, F.D. fans are included in the boiler estimated repair costs and building vent fans are included in the building estimated repair costs. The I.D. fans are estimated for overhaul every 20 years. The cost estimate is 38 percent of the capital cost.

Permits. This category is to estimate the required periodic USEPA permit testing and renewal costs. The cost is estimated to be $30,000 in 1988 dollars every 3 years.

7 Life Cycle Cost Economic Analysis

The life cycle cost economic section of the coal-fired boiler evaluation program is designed to evaluate the relative financial merits of various coal-fired boiler technologies. The calculations use discounted cash flow (DCF) analysis techniques to assess the total lifetime (life cycle) costs of both new and retrofit central heat plants, and to help the user select the energy options that provide the lowest life cycle costs. These costs can be broadly classified into: initial investment costs, annual fuel costs, annual operating and maintenance costs, nonannual repair and replacement costs, and salvage values or residual costs of disposal. In addition, other factors (such as the facilities' energy requirements, the costs associated with renovating the system during its lifetime, and the option of cogenerating electricity) are considered. The goal of this program is to develop a method for easily and consistently identifying the technology alternatives that display the lowest combination of cost factors and produce a facility that maximizes life cycle cost efficiency. The various central heat plant alternatives that fulfill the performance requirements can be ranked according to several economic assessment criteria. They should be implemented according to the outcome of these ranking procedures.

The program is designed to automatically incorporate all relevant cost factors from the technology selected during the initial screening phase. These costs are assembled according to their time of occurrence within the project lifetime. They are discounted to determine their present values on the date of study. The most important cost factors are the energy costs. Energy costs escalate over time and must be estimated in the manner outlined by Department of Energy (DOE) projections in the Code of Federal Regulations. These energy escalation factors are contained in the program but may be modified to suit future market changes. All other relevant cost factors are also estimated and may be modified to meet future situations.

Assumptions

The model makes a number of assumptions designed to help the user perform the life cycle cost analysis. All the assumptions and methods are consistent with guidelines issued in the Life Cycle Costing Manual for the Federal Energy Management Programs, as well as the 1988 Code of Federal Regulations, part 436 - "Federal Energy

Management and Planning Programs," subpart A - "Methodology and Procedures for Life Cycle Cost Analyses." The major assumptions used in the model are as follows.

- All future dollar amounts are estimated in constant dollars which do not take into account the effects of inflation. All costs or benefits not escalated in the program are assumed to increase at the same rate as general inflation.
- The Federally mandated discount rate of 10 percent is used for discounting purposes.
- All costs and benefits are discounted by the appropriate discount rate to reflect their values as of the year of study.
- The study period for the analysis should match the useful life of the facility, but should not be greater than 25 years.
- All energy costs and O&M costs are assumed to begin at the commencement of facility operation, and are treated as occurring at the end of the year in which they take place.
- All investment costs are assumed to occur as a lump sum expenditure at a single time during the midpoint of construction.
- All nonannually recurring repair and replacement costs and salvage values are treated as occurring in a lump sum at the end of the year in which they take place. The net cost or benefit of salvaging equipment consists of the amount that the item can be resold for, minus the cost of removing or selling the item.
- Nonfuel cost elements such as O&M costs and repair and replacement costs are not escalated, but are assumed to increase over the life of the facility by the same rate as the level of general inflation.

LCC Program Inputs

The life cycle cost analysis of a new or retrofit heating plant requires 16 input entries, some of which are provided by the earlier screening phase of the program but may be modified before the final output is calculated. These values include the following.

1. The ANNUAL UNITS OF ENERGY REQUIRED will determine the total energy cost of the facility when multiplied by the energy cost escalation factors.
2. The DOE REGION NUMBER is used to select the appropriate set of energy escalation factors, and is imported from data tables within the program.
3. The BASE PRICE FOR STEAM COAL in the year of study is calculated by the program using the DOE indexes for the appropriate geographic region. The user may review and change this value if the DOE projections do not conform with observed market prices.

4. The ANNUAL OUTPUT OF THE FACILITY in Million Btus is used to compute the levelized cost of service. This value is calculated by the program according to the size and efficiency of the facility selected as well as the annual units of energy required.
5. The PLANT LIFE/STUDY LIFE should be appropriate for the facility under consideration, but cannot exceed 25 years.
6. The CURRENT SALVAGE VALUE OF THE EXISTING SYSTEM will determine the expected resale value that occurs when the existing facility is sold and replaced by a new facility.
7. The SALVAGE VALUE OF THE NEW OR RETROFIT SYSTEM will determine the expected resale value which occurs when the system is retired at the end of the project life.
8. The DISCOUNT RATE is given a default value of 10 percent but may be changed.
9. The appropriate YEAR OF STUDY must be entered. This will be the baseline year to which all costs will be discounted.
10. The BEGINNING YEAR OF FACILITY OPERATION will be estimated from the year of study using the appropriate construction timetable, but may be changed.
11. The TRANSPORTATION COST of coal is estimated by the program to be 2.18 cents per ton per mile.
12. The INVESTMENT COST EXCLUSION allows the user to select or omit the 10 percent exclusion for investment costs which may be applied to certain Federal energy programs.
13. The CAPITAL EQUIPMENT ESCALATION FACTOR should be entered using the current construction cost index from *Engineering News Record* (ENR) magazine. If the ENR index is not available, compute the capital cost adjustment factor using Army Regulation AR 415-17 *Cost Estimating For Military Programming* (15 February 1980).
14. The NON-LABOR OPERATING & MAINTENANCE ESCALATION FACTOR should be entered from the current steam power component of the "Marshall and Swift Equipment Cost Index" from *Chemical Engineering* (CE) magazine. If the CE index is not available, an alternative factor should be computed by a method comparable to AR No. 415-17, which should lead to a similar escalation factor of 1.04 as in the above example.
15. The OPERATING & MAINTENANCE LABOR ESCALATION FACTOR should be entered using the current Skilled Labor Index from *Engineering News Record* magazine, or a method consistent with AR No. 415-17.
16. The CONSTRUCTION LABOR ESCALATION FACTOR should be entered using the current Construction Labor Index from *Chemical Engineering* magazine, or a method consistent with AR No. 415-17.

Program Applications

The life cycle cost analysis as described above is suitable for three types of analysis: new facility versus another new facility; new facility versus a retrofit facility; and retrofit facility versus another retrofit facility.

These three types of analysis can be easily performed using the same general format of the life cycle cost approach. To assess a new or retrofit facility in comparison to the existing system, however, further information is needed concerning the existing system. Provisions for accepting such information on existing systems are not included in this program. To properly analyze the existing system as compared to new construction or retrofit options, information concerning the existing system would be needed in the following areas: annual fuel units purchased, current renovation costs if any, future renovation costs, annually recurring fuel and O&M costs, and nonannually recurring costs. This life cycle costing program relies on the assumption that the decision to repair or replace the facility has already been made, and that the alternative of continuing to operate the existing system is not feasible.

LCC Program Output

The Life Cycle Costing Program provides a detailed list of annual cash flows in the major cost categories, and computes two important measures of economic acceptability. These measures furnish different perspectives on economic performance, and allow the decision between competing technologies to be made with greater certainty. Also, the rankings of the various technologies should be compared in different ways to determine which project is most desirable.

The TOTAL LIFE CYCLE COST is the primary tool for evaluating project worth. The TLCC indicates the discounted value of all costs related to the project over its lifetime, including the costs required to produce the given amount of facility output. Selecting the cogeneration option will affect the TLCC by raising the initial cost of the facility, and by providing an annual electric credit that is used to offset a portion of annual operating costs. A lower TLCC indicates a lower financial burden of building, operating, and maintaining the facility. The TLCC discounts all future cash flows to the year of study. The TLCC is computed as the sum of the following components.

+ Present Value (PV) Investment Costs
+ PV Energy and Transportation Costs
+ PV Nonenergy O&M Costs
+ PV Repair & Replacement Costs

- PV Cogeneration Electric Credit(optional)
+/- PV Salvage Value of Existing System
+/- PV Salvage Value of New or Retrofit Facility

TOTAL LIFE CYCLE COST

The LEVELIZED COST OF SERVICE is a measure of the unit cost of providing output from the given facility, stated in the desired units of output such as $/MMBtu. The term "levelized" denotes that a financially-weighted average of the lifetime service costs is computed. This levelization is required because service costs will vary throughout the project lifetime, but a consistent basis of measurement is required to compare projects of differing lives and/or sizes. Because the levelized cost of service includes both the total life cycle cost the annual output of the facility, it can provide a true measure of the cost per unit of producing thermal output.

$$\mathrm{LCS} = \frac{\mathrm{(TLCC/PVA\ Factor)}}{\mathrm{Annual\ Output}}$$

$$\text{where the PVA Factor} = \frac{(1+i)^{n-1}}{i(1+i)^{n}}$$

These two measures of acceptability provide a forecast of future project economics. The accuracy of the predicted outcome greatly depends on the quality of the input information such as energy and operating costs. Various facility options should be ranked according to their TLCCs or Levelized Costs of Service to evaluate which are the most cost efficient.

To determine if the new or retrofit project should be undertaken, information regarding the existing system can be combined to produce a savings to investment ratio (a numerical ratio that measures the benefits of a project in relation to its size), or a net life cycle savings measure, which compares the discounted value of project savings to its associated costs. These two measures of performance can be calculated externally to the program to determine if the benefits of the new (or retrofit) facility outweigh the costs of conversion, or if the existing facility should be maintained.

8 Summary and Recommendations

This report provides the documentation of a microcomputer program developed for central heating plant economic evaluation. Screening and costing models have been developed for new and retrofit plants burning coal, oil, or natural gas. The evaluation method presented provides a consistent approach in evaluating competing combustion technologies with various type of fuel. Detailed conceptual facility design, costs, as well as economic measures of project acceptability including total life cycle costs and levelized costs are provided.

Sufficient flexibility was allowed in the program to determine sensitivities related to changes in boiler load, fuel price, escalation factors, discount rate, O&M costs, plant life, etc. Due to the volatile nature of fuel pricing and the changes in technology and market place, frequent updating of the cost algorithms appears to be warranted. Further program improvements are suggested below:

1. Incorporation of *The Central Heating Plant Status Quo Program* (M. J. Savoie, draft technical report, USACERL) would be beneficial. This would provide a baseline for comparing the life cycle costs of alternatives such as retrofit, modernization, and construction of a new plant.
2. Addition of a pulverized coal boiler option may be desirable although this technology is not widely used in the Army facilities. However, several Navy bases have plants firing pulverized coal.
3. Improvement of screening and scoring processes for boiler facilities considered for retrofit is needed. Detailed cost components for the retrofit option and expanded analysis including the possibility of using existing equipment and an estimate of the condition of the existing equipment are required to obtain a more realistic cost estimate.
4. Improvement of the program related to environmental issues such as ash disposal and storage is needed. Expansion of the air pollution control section to meet new Clean Air Act requirements for all fuel sources is also desired. This could have significant effect on the life cycle costs especially for gas/oil-fired boilers that may require NO_X/SO_X control devices.
5. Expansion of the cogeneration analysis program to include an engine based system, combined cycle gas turbine based system, and fuel cell is recommended. This will ensure that higher efficiency technologies are not overlooked.

6. Studies of alternative power sources such as biomass, wind, solar, and geothermal are suggested so that the most cost effective fuel can be chosen.
7. Expansion of the cost models to include heating plants less than 50 MBtu/hr, satellite plants, and stand alone systems is recommended to cover the majority of the Army plants.
8. Development of models to track the thermal and electric energy requirements for end users, and to develop reliable estimates of maximum, minimum, and average loads are needed. The models may be used in sizing satellite and central energy plants.
9. Development of models for sizing and costing nonelectric chiller systems to include thermal energy storage technologies is recommended. A cooling system is a major energy user and should be considered in overall plant economics.

With the above enhancements to the program, CHPECON could become a very powerful tool for long range utility planning.

Metric Conversion Table

1 in.	=	25.4 mm
1 ft	=	0.305 m
1 sq ft	=	0.093 m^2
1 cu yd	=	0.076 m^3
1 lb	=	0.453 kg
1 gal	=	3.78 L
1 psi	=	6.89 kPa
°F	=	(°C × 1.8) +32
1 ton (short)	=	0.907 t

Acronyms

ACFM	actual cubic feet per minute
AR	Army Regulation
AFBC	atmospheric fluidized bed combustion
ASME	American Society of Mechanical Engineers
BFBC	bubbling fluidized bed combustor
BFWP	boiler feedwater pumps
BHP	break horsepower
Btu	British thermal units
B&W	Babcock and Wilcox
CEMS	continuous emission monitoring system
CFBC	circulating fluidized bed combustion
CHPECON	Central Heating Plant Economic Evaluation Program
COM	coal-oil mixture (coal-oil slurry)
CWS	coal-water slurry
DOD	Department of Defense
EER	Energy and Environmental Research Corporation
ESP	electrostatic precipitator
F.D.	forced draft
FGD	flue gas desulfurization
FY	fiscal year
GSU	Gulf States Utilities
gpm	gallons per minute
HTHW	high temperature hot water
hp	horsepower

HVAC	heating, ventilation, and air conditioning
I.D.	induced draft
IGT	Institute of Gas Technology
MBC	multibed combustion
MCR	maximum continuous rating
MP&L	Mississippi Power and Light
mph	miles per hour
NSPS	New Source Performance Standards
O.A.	overfire air (fan)
PABX	private automatic branch exchange (telephone)
PC	pulverized coal
PL	Public Law
PRV	pressure reducing valve
PMCR	plant maximum continuous rating
psig	pounds per square inch gauge
PURPA	Public Utilities Regulatory Policy Act
SCC	slagging coal combustor
SCF	standard cubic foot
SSU	Saybolt Seconds Universal
TDS	total dissolved solids
TM	Technical Manual
TPD	tons per day
TPH	tons per hour
USACERL	U.S. Army Construction Engineering Research Laboratories
USACPW	U.S. Army Center for Public Works
USAREUR	U.S. Army Europe
USEPA	U.S. Environmental Protection Agency

USACERL DISTRIBUTION

Chief of Engineers
ATTN: CEHEC-IM-LH (2)
ATTN: CEHEC-IM-LP (2)
ATTN: CECC-R
ATTN: CERD-L
ATTN: DAIM-FDF-U

Secretary of Defense 22202
ATTN: P&L/EP

CECPW 22310-3862
ATTN: CECPW-FU-M
ATTN: Library

US Army Engr District
ATTN: Library (40)

US Army Engr Division
ATTN: Library (12)

US Army Europe
ATTN: AEAEN-ODCS 09014

US Army Materiel Command (AMC)
Alexandria, VA 22333-0001
ATTN: AMCEN-F

FORSCOM
Forts Gillem & McPherson 30330
ATTN: FCEN

TRADOC
Fort Monroe 23651
ATTN: ATBO-G

USARPAC 96858
ATTN: DPW
ATTN: APEN-A

CEWES 39180
ATTN: Library

CECRL 03755
ATTN: Library

USA AMCOM 61299
ATTN: AMSMC-IR
ATTN: AMSMC-IS

Walter Reed Army Medical Center 20307

National Guard Bureau 20310
ATTN: NGB-ARI

Naval Facilities Engr Command
ATTN: Code 1652B 22332-2300

Naval Facilities Engr Service Center 93043
ATTN: Code 241

US Army HSC
Fort Sam Houston 78234
ATTN: HSLO-F
Fitzsimons Army Medical Ctr
ATTN: HSHG-DPW 80045

Tyndall AFB 32403
ATTN: HQAFCESA Program Ofc

Defense Fuel Supply Center
ATTN: DFSC-PR 22314

Defense Tech Info Center 22304
ATTN: DTIC-FAB (2)

82
1/95