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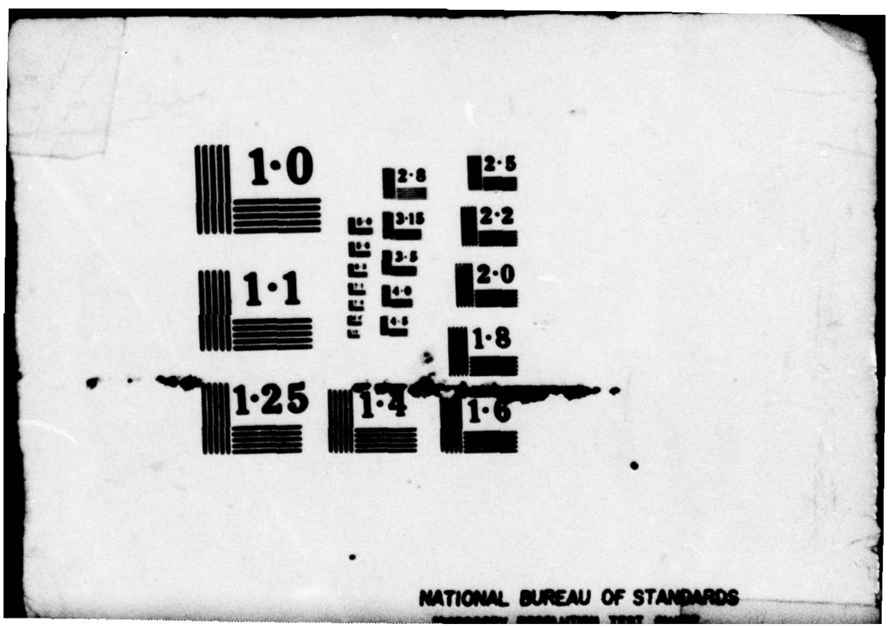
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CIVIL ENGINEERING LABORATORY
Naval Construction Battalion Center
Port Hueneme, California

Sponsored by
NAVAL FACILITIES ENGINEERING COMMAND

COAL-FIRED BOILERS AT NAVY BASES, NAVY ENERGY GUIDANCE STUDY PHASES II & III

May 1979

An Investigation Conducted by

BECHTEL NATIONAL, INC.
San Francisco, California

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Conceptual design and parametric cost studies of steam and power generation systems using coal-fired stoker boilers and stack gas scrubbers in several sizes were performed. Central plants containing four equal-sized boilers and central flue gas desulfurization facilities were shown to be less expensive than decentralized facilities with the four boilers plus scrub-

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Block 20. Abstract (Cont'd)

bers at diverse sites. Life-cycle costs of steam generation in new central coal-fired facilities were shown to be lower than those for continued burning of fuel oil in existing boilers, when coal costs \$30/ton (\$1.41/10^6 Btu) and oils costs \$3.16/10^6 Btu. It is cost-effective to add extra facilities to cogenerate electric power along with steam in new coal-fired systems, compared to purchasing electricity at a price of \$0.033 (33 mills) per kilowatt-hour, because of the low cost per unit of coal energy. High steam-transmission pressures (600 psia) lead to lower-cost piping systems than lower pressures (300 psia and 100 psia). Coal and waste haul costs are small compared to other system costs.

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ABSTRACT

Conceptual design and parametric cost studies of steam and power generation systems using coal-fired stoker boilers and stack gas scrubbers in several sizes were performed.~~for the Civil Engineering Laboratory at the Naval Construction Battalion Center at Port Hueneme, California. The work constituted Phases II and III of Contract N68305-77-C-0003 entitled "Navy Energy Guidance Study."~~ Central plants containing four equal-sized boilers and central flue gas desulfurization facilities were shown to be less expensive than decentralized facilities with the four boilers plus scrubbers at diverse sites. Life-cycle costs of steam generation in new central coal-fired facilities were shown to be lower than those for continued burning of fuel oil in existing boilers, when coal costs \$30/ton (\$1.41/10^6 Btu) and oil costs \$3.16/million ~~10~~^{6} Btu. It is cost-effective to add extra facilities to cogenerate electric power along with steam in new coal-fired systems, compared to purchasing electricity at a price of \$0.033 (33 mills) per kilowatt-hour, because of the low cost per unit of coal energy. High steam-transmission pressures (600 psia) lead to lower-cost piping systems than lower pressures (300 psia and 100 psia). Coal and waste haul costs are small compared to other system costs.

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Section 1
SUMMARY

The work described in this report was performed as Phases II and III of Contract N68305-77-C-0003 with the Civil Engineering Laboratory of the Naval Construction Battalion Center, Port Hueneme, California. The contract was titled "Energy Guidance Study." Phase I of the study was presented in Reference (1), Cogeneration at Navy Bases, dated May, 1978. The purpose of Phases II and III was to perform parametric cost analyses to compare central steam generation with decentralized generation, and to compare cogenerated electricity with purchased power.

The study included general parametric analyses and conceptual designs for decentralized and central plants. Parametric cost evaluations were prepared for steam distribution, coal and waste handling, and air pollution control equipment, and for systems with decentralized and central boilers and central cogeneration plants.

BASIS OF COMPARISON

Stoker boilers having output capacities of 25, 50, 100, and 200 x 10^6 Btu/hr (millions of British thermal units per hour) were considered. Systems were sized at 100, 200, 400, and 800 x 10^6 Btu/hr, and each contained four 1/4-capacity boilers. Coals with sulfur contents of less than 1 percent, between 1 and 3 percent, and greater than 3 percent were evaluated. The cost of electricity produced by cogeneration at central plants was compared with the cost of electricity purchased at a 1978 price of \$0.033 per kWhr (kilowatt-hour). A heating steam load factor of 33 percent (Reference 2) was assumed in computing steam and electricity generation costs. A nominal coal cost of \$30/ton was assumed.

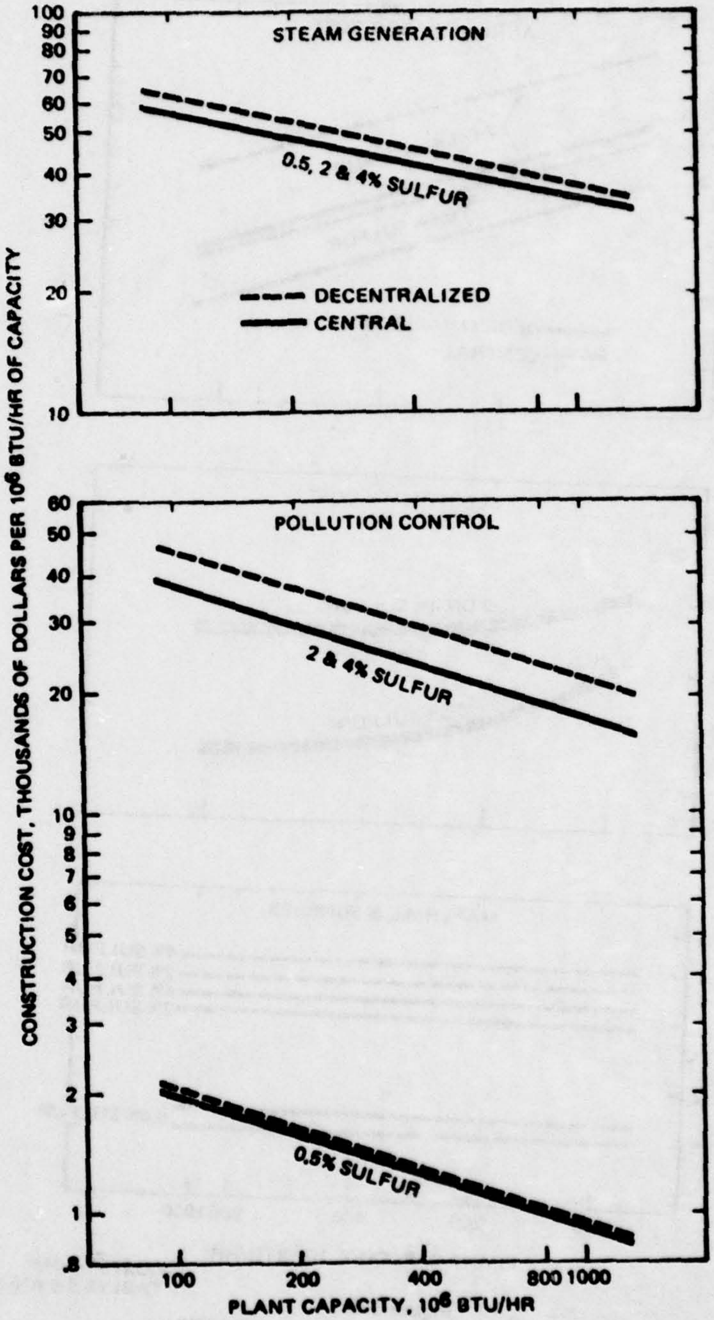
STUDY RESULTS AND CONCLUSIONS

Central and Decentralized Steam Plants

Construction and annual costs for parts of steam generation systems are shown in Figures 1-1 and 1-2. The part labeled "steam generation" includes coal handling facilities and boiler plants. The part labeled "air pollution control" includes a baghouse, a flue gas desulfurization (FGD) system if necessary, and on-base waste-haul activities. The figures show costs per 10^6 Btu/hr of $40,000 for steam generation and $25,000 for air pollution control in central systems containing four 100 x 10^6 Btu/hr (100,000 lb/hr) boilers and cleanup devices for coal with 2 percent sulfur. Where flue gas desulfurization can be omitted (0.5 percent sulfur), air pollution control costs drop dramatically. Scrubber raw material costs are not a large fraction of air pollution control annual costs.

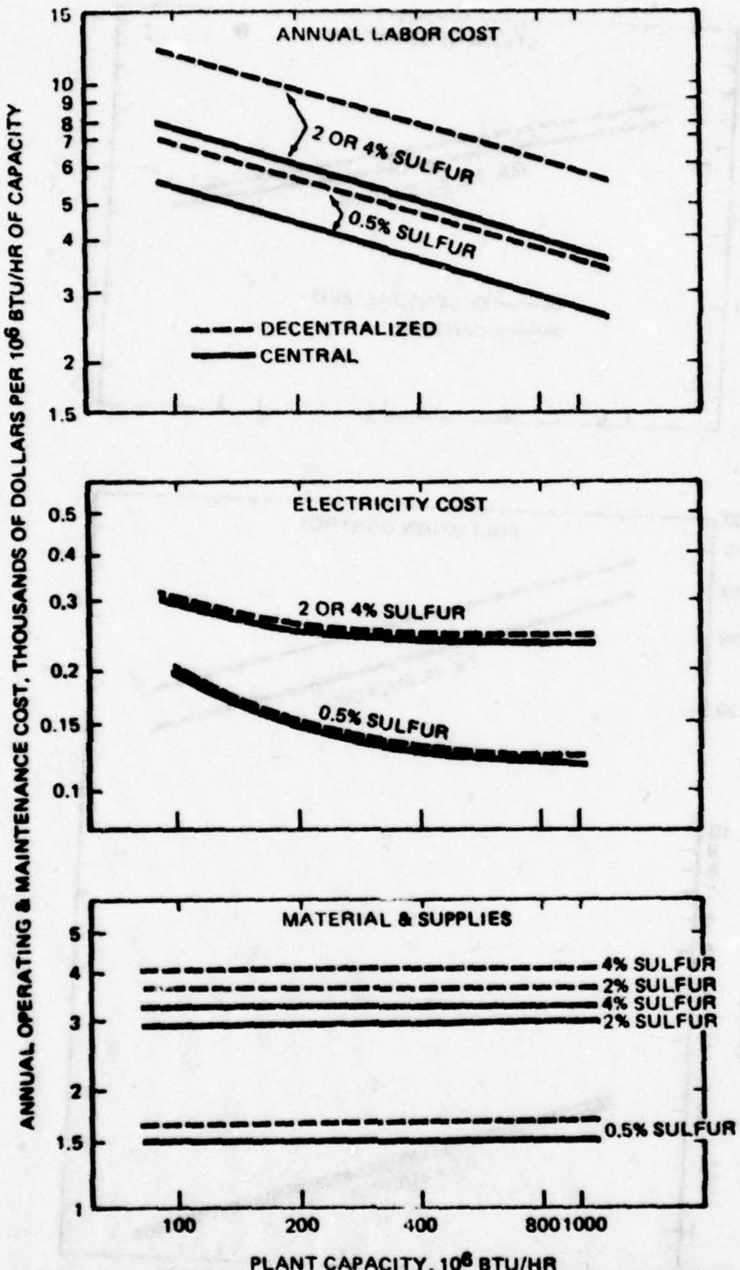
Construction and annual costs for complete central and decentralized systems are shown in Figures 1-3 and 1-4. Life cycle costs derived from them are displayed in Figure 1-5. Central systems are shown to be significantly less expensive than decentralized systems. However, the central system costs do not include costs of piping to transmit steam to the locations served by decentralized plants.

For comparison with Figure 1-5, the levelized cost of burning fuel oil is $\$10.40/10^6$ Btu. This cost assumes that the oil is priced at $\$3.16/10^6$ Btu and that it is burned in existing central oil-fired boilers with 100 x 10^6 Btu outputs. It can be seen that most coal-fired central systems in Figure 1-5 have levelized costs lower than the cost of burning fuel oil.



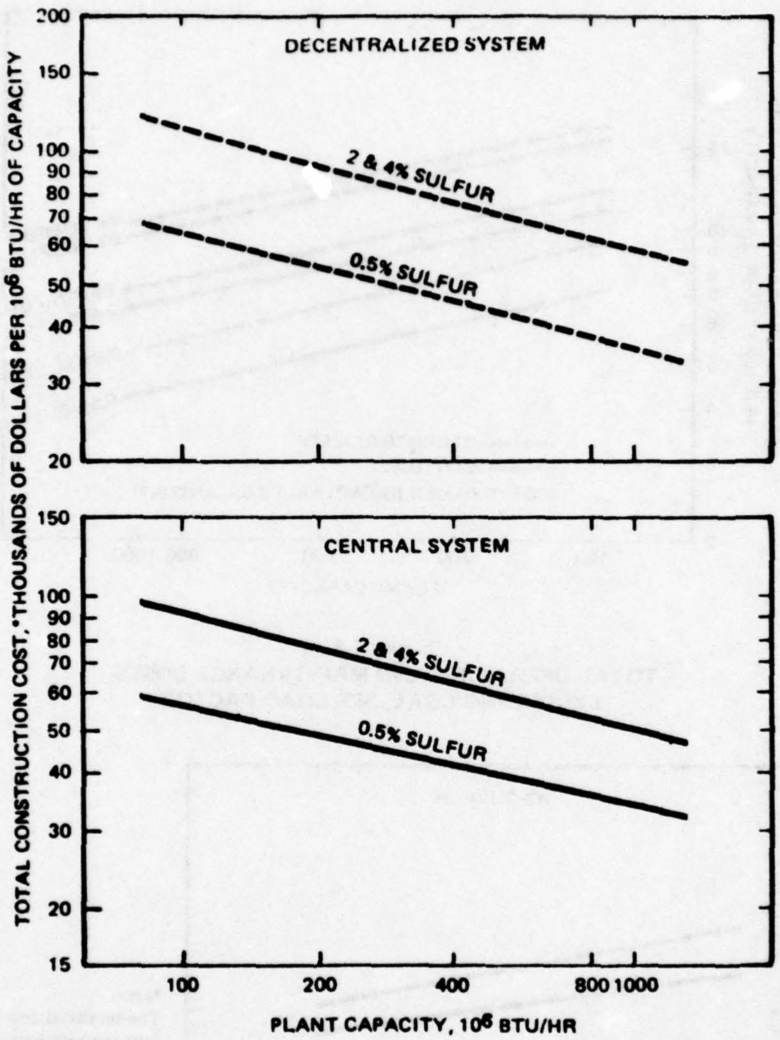
(COSTS FROM TABLES 8-6 AND 8-7)

Figure 1-1
TOTAL CONSTRUCTION COSTS, STEAM GENERATION AND POLLUTION CONTROL



(COSTS FROM TABLES 8-6 AND 8-7)

Figure 1-2
OPERATING AND MAINTENANCE COSTS, STEAM GENERATION AND POLLUTION CONTROL, 33% LOAD FACTOR



*Add 11% Startup for Capital Cost

(COSTS FROM TABLES 8-6 AND 8-7)

Figure 1-3
TOTAL CONSTRUCTION COSTS, STEAM GENERATION SYSTEMS

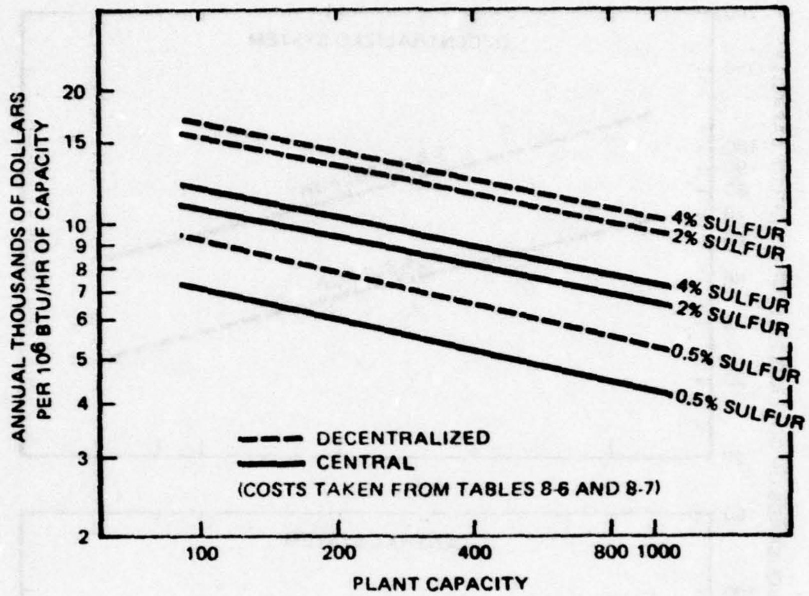
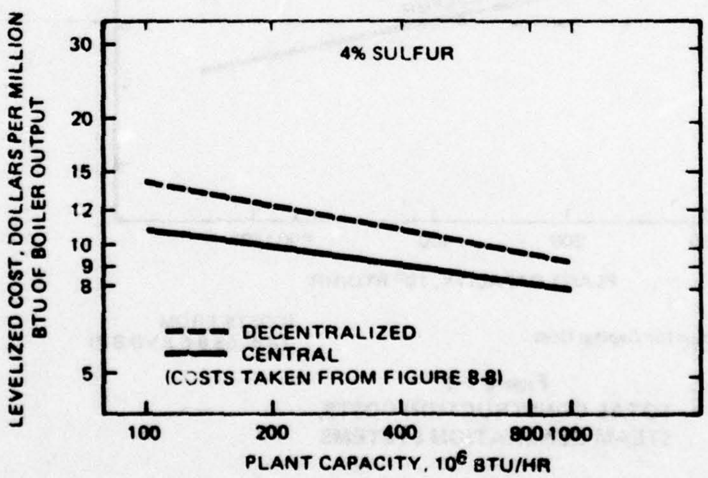


Figure 1-4
TOTAL OPERATING AND MAINTENANCE COSTS, EXCLUDING COAL, 33% LOAD FACTOR



Note:
The levelized cost takes into account expected future energy escalation and discounting of future cash flows. See definition in Appendix F.

Figure 1-5
LIFE-CYCLE LEVELIZED COST COMPARISON, DECENTRALIZED VERSUS CENTRAL STEAM SYSTEMS

Cogeneration of Electricity

Figure 1-6 compares the levelized cost of cogenerated electric power with the cost of purchased power for four central plant sizes. New facilities for cogeneration provide power more economically than purchase, because of the low cost per unit of coal energy. With coal, it is advantageous to operate the high-pressure boilers and turbine-generator units at full capacity continuously. By contrast, Reference (1) showed that with oil-fired facilities it is advantageous to use condensing generation only for peak shaving. In both cases, as much power as possible is made by "strict cogeneration," in which steam for heating loads is obtained by extraction from the turbine after partial expansion. Reference (1) also showed that it is not economical to include a cogeneration capability in a new steam generation facility when oil is the fuel. Here, Figure 1-6 shows that it is economical to include this capability when coal is the fuel.

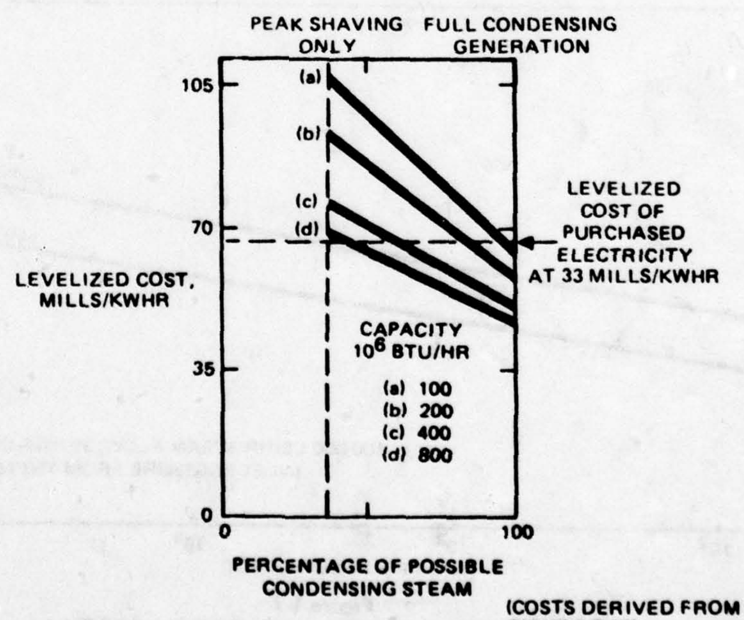


Figure 1-6
LIFE-CYCLE COST OF COGENERATED POWER
(2% S COAL, 33% LOAD FACTOR)

Piping Systems

Figure 1-7 shows installed unit costs of uninsulated pipe as a function of length for a steam flow rate of 100,000 pounds per hour. The figure shows that piping system costs are lower when the inlet pressure is higher. Boilers producing 600 psia steam cost roughly the same as boilers producing 150 psia steam, so a higher pressure system would appear more economical. A calculation in Section 10 shows a 15-percent increase in piping costs for a given circuit when the inlet pressure is dropped from 300 psia to 150 psia. In the same example, heat losses from 300 psia piping amounted to 6 percent of the annual fuel consumption.

Coal and Waste Haul Costs

Coal and waste haul costs were not found to be a substantial part of the annual costs of decentralized boiler systems.

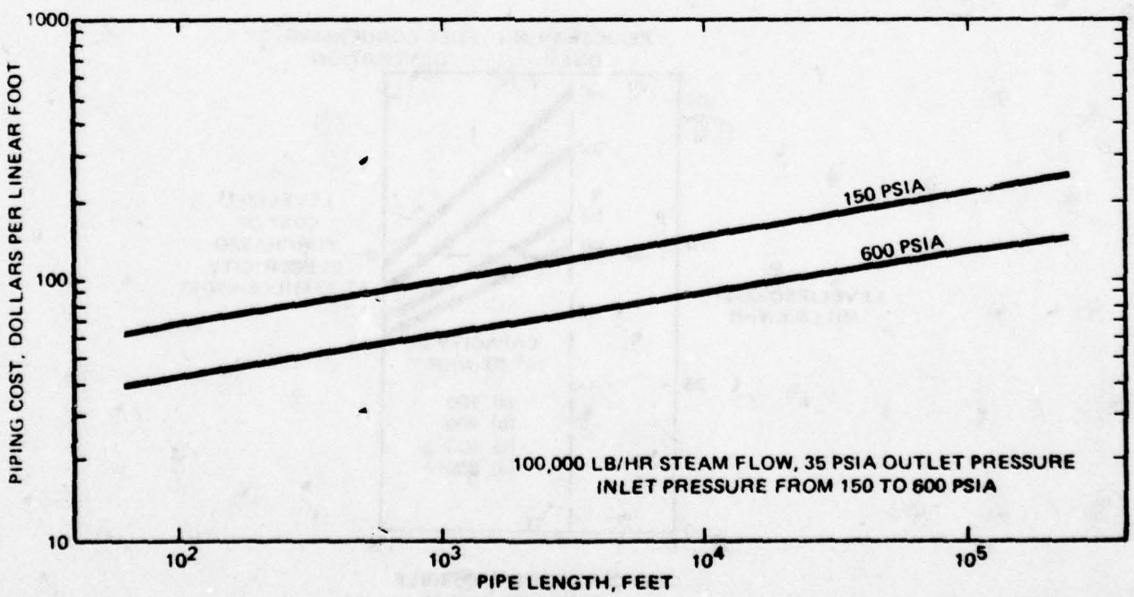


Figure 1-7
ABOVEGROUND PIPE COSTS VERSUS LENGTH

Stoker Coal

The study confirmed that double-screened coal for existing Navy stoker boilers will be available on the coal market. The premium charged for double-screening will be between 6 and 8 dollars per ton. New spreader-stoker boilers will not require double-screening of coal.

Sensitivity of Costs

The price of coal strongly affects steam and power costs. Energy costs are quite sensitive to changes in capital cost and relatively insensitive to changes in annual labor cost.

RECOMMENDATIONS

For a Navy base evaluating decentralized versus central coal-fired steam plants, the following recommendations are made:

- The cost of steam transmission piping can be the decisive cost factor in the decision to construct decentralized or central plants. This cost should be evaluated first. If, in combination with plant costs of Section 8, the central plant cost is obviously higher than that of a decentralized plant, the major study effort should be directed toward decentralized plants.

- For a specific site, as opposed to a hypothetical study site, annual labor costs should be evaluated in detail.

- Coal price, physical and chemical character, availability, and contract conditions should be studied for a specific site before steam generator selection is made.

- Boiler and FGD vendors should be contacted early in the study of a specific site. FGD vendor quotes used as part of this study are much less firm than boiler prices. FGD selection and cost may influence overall plant capacity and the question of decentralized versus central plant configuration.

For Navy bases evaluating cogenerated power versus purchased electric power, the following recommendations are made:

- Sufficient evaluation should be performed to ensure an accurate cost of purchased electricity, and to establish a firm understanding of the utility pricing structure as it affects the Navy base. Utilities may include penalties and benefits with the price schedule which will cause the purchased power price (the basis for comparing alternatives) to change as cogeneration strategies change.

- A strategy optimization study should be performed for each proposed new facility and should include analysis of past and anticipated future steam and electricity demand profiles, and calculations of energy consumption and costs under alternative strategies.

- As with steam generation, coal price and character should be firmly defined.

Section 2

BACKGROUND

The work described in this report was performed as Phases II and III of Contract N68305-77-C-0003 with the Civil Engineering Laboratory of the Naval Construction Battalion Center, Port Hueneme, California. The contract was titled "Energy Guidance Study." The purpose of Phases II and III was to compare coal-fired decentralized versus central steam plants and cogeneration versus purchased electricity.

The study involved technical parametric analysis and conceptual design, and economic evaluations of capital, operating and maintenance, life-cycle, and levelized costs. Parametric cost versus capacity curves form a significant portion of the data produced.

SCOPE OF WORK

Objectives

The objectives of the study were to perform parametric cost analyses of steam generation by decentralized boilers and by central steam plants, and economic comparisons of power generated on-base versus purchased electricity. All facilities involve new construction, using the lowest-cost commercially available equipment.

The study results include the following:

- Decentralized boiler costs versus capacity
- Central boiler costs versus capacity
- Air pollution control costs versus capacity and sulfur content of coal

- Coal, ash, and sludge handling costs versus capacity and distance
- Steam distribution costs versus capacity and distance
- Economic feasibility of cogenerated power
- Effect of coal price on steam generation and cogeneration costs
- Data on present and future availability of stoker coal

Boiler Systems Compared

Decentralized and central stoker boilers were configured in conceptual designs for economic comparison. The nominal designs have the following common features:

- Individual boiler capacities are 25, 50, 100, or 200 x 10^6 Btu/hr
- Boiler outlet steam pressures range from 150 to 600 psig for steam generation and to 1450 psig for cogeneration
- Steam supply conditions of the ultimate user are not considered in the boiler comparison. Steam distribution is a separate comparison

The nominal systems are configured as follows:

- The decentralized plants consist of four boilers physically located at separate places on the base. The decentralized boilers are four 25 x 10^6 Btu/hr, four 50 x 10^6 Btu/hr, four 100 x 10^6 Btu/hr, or four 200 x 10^6 Btu/hr steam generators. Thus, total capacities are 100, 200, 400, and 800 x 10^6 Btu/hr. The 400 x 10^6 Btu/hr plant is the baseline case

- The central plants consist of four boilers at a single location. Plant total capacities are 100, 200, 400, and 800 x 10^6 Btu/hr, and each plant is made up of four one-quarter capacity boilers. The 400 x 10^6 Btu/hr plant is the baseline case

Air Pollution Control Systems Compared

The air pollution control systems consist of particulate removal and flue gas desulfurization (FGD) equipment. All boilers require FGD except those smaller than 250 x 10^6 Btu/hr and burning coal that produces less than 1.2 pounds of sulfur dioxide per million Btu of coal heat content.

Limestone and double-alkali FGD systems were considered. The double-alkali system was selected for reliability and ease of maintenance. Particulate removal is accomplished in a filter-type baghouse prior to scrubbing.

Boiler and Air Pollution Control Combined Systems Compared

Each decentralized boiler requiring FGD equipment is combined with FGD and particulate removal equipment sized for the boiler. Decentralized boilers without FGD require particulate removal equipment.

Because of the requirement of a 4:1 turndown ratio for air pollution control equipment, the central plants consist of four boilers combined with two air pollution control systems, each with a 60-percent capacity. FGD vendor information indicates that the 4:1 turndown is about maximum for a single FGD unit. Thus, by using two FGD units, each with a 4:1 turndown ratio, air quality can be maintained with a single boiler generating at half-capacity.

Cogeneration Systems Compared

The 400 x 10^6 Btu/hr central plant was selected as the baseline cogeneration case. Because of the continuous requirement for heating/service steam, the plant comprises two low-pressure and two high-pressure boilers. The high-pressure boilers generate steam for a single condensing-extraction turbine generator for power production. Coal receiving and preparation, air pollution control, and waste disposal complete the baseline cogeneration plant facilities. Steam distribution is not part of the comparison.

Other Systems Compared

In addition to the above systems, several components required for coal-fired boiler operation are individually evaluated in parametric studies of capital and operating and maintenance (O&M) costs.

The items so evaluated include:

- Steam distribution
- Coal receiving and preparation
- Coal haulage for decentralized boilers
- Ash and sludge handling and waste disposal

Cost Comparisons

The following costs are estimated for boiler and air pollution control combinations, the cogeneration plant, and individual equipment units:

- Capital costs
- Annual operating and maintenance costs
- Life-cycle costs using Navy methods
- Levelized costs
- Capital and annual costs are given in actual dollars and in dollars per 10^6 Btu heating value. For cogeneration, costs are displayed for dollars per 10^6 Btu steam generated, dollars per kilowatt of generating capacity, and mills per kilowatt-hour
- Air pollution control parametric costs versus capacity and gas flow, and coal sulfur content
- Decentralized boilers, costs versus capacity
- Central boilers, costs versus capacity
- Combined systems (boilers and air pollution controls) costs versus capacity and coal sulfur content

Special parametric cost evaluations were performed for the following items:

- Steam distribution costs versus capacity and distance
- Central plant coal handling costs versus capacity (weight)
- Decentralized plant coal handling costs versus weight and distance
- Ash and sludge handling costs versus weight and distance

Finally, an appendix was prepared on stoker designs and coal requirements.

THE STRUCTURE OF THIS REPORT

The technical and economic basis of the study is presented in Section 3. Sections 4 through 7 present data on steam system components:

- Section 4 — steam generation facilities
- Section 5 — air pollution control facilities
- Section 6 — steam transmission piping
- Section 7 — coal and ash handling facilities

Section 8 compares central and decentralized steam generation systems using information on component facilities from Sections 4, 5, and 7.

Section 9 treats cogeneration of electric power along with steam in central systems.

Section 10 is entitled "Navy Energy Guidance Handbook." It indicates by a lengthy example the way the information in previous sections can be used for comparing plant configuration alternatives.

The report has several appendices:

- Appendices A, B, and C support the piping system analyses of Section 6
- Appendix D provides data on stokers and coal
- Appendices E, F, and G describe life-cycle cost methods
- Appendix H supports the cogeneration analysis of Section 9

Section 3

TECHNICAL AND ECONOMIC BASIS

Certain items used for technical and economic evaluations apply to all parts of the study. These items are identified and discussed in this section.

TECHNICAL BASIS

The following items were used as a basis for parametric analysis and conceptual design.

Coal

The study required investigation of boiler and air pollution control equipment for coals with sulfur contents of less than 1 percent, between 1 and 3 percent, and greater than 3 percent. The effect of sulfur content in coal is most strongly reflected by the increased cost of plants requiring flue gas desulfurization (FGD) equipment. Boilers of less than 250×10^6 Btu per hour capacity do not require FGD when burning 1 percent or less sulfur coal with a heating value of 13,000 Btu per pound. Three nominal coals were selected for the study evaluations. The compositions of the coals are shown in Table 3-1.

Ratings and Efficiencies

Table 3-2 shows the ways of designating boiler capacity which are considered nominally equivalent throughout this report.

Table 3-1

NOMINAL COAL COMPOSITIONS

	Composition (wt%)		
	0.5%S	2%S	4%S
Carbon	60.47	60.47	60.47
Hydrogen	3.70	3.70	3.70
Nitrogen	1.41	1.41	1.41
Sulfur	0.50	2.00	4.00
Oxygen	5.96	5.96	5.96
Ash	22.96	21.47	19.46
Moisture	5.00	5.00	5.00
Total	100.00	100.00	100.00
Higher Heating Value (Btu/lb)	10,589	10,672	10,783

Table 3-2

EQUIVALENT DESIGNATIONS OF BOILER CAPACITY

Consumption of fuel (10^6 Btu/hr)	31	63	125	250
Consumption of fuel (tons/hour)	1.5	3	6	12
Production of steam (10^3 lb/hr)	25	50	100	200
Transfer of heat (10^6 Btu/hr)	25	50	100	200

The entries in Table 3-2 are based on the following approximate conversion relations:

- The heat transferred into steam energy is 80 percent of the heat content of the coal fuel (this is the boiler efficiency)
- For each pound of steam generated, 1000 Btu of heat must be transferred into the steam system by the boiler
- Each ton of coal has a heat content of 20×10^6 Btu (or 10,000 Btu/lb)

Unless otherwise stated, in this report all capacities in 10^6 Btu/hr refer to heat transferred into the steam system by the boiler.

Load Factor

A plant load factor of 33 percent is assumed throughout unless otherwise stated, where

$$\left(\begin{array}{l}\text{Load}\\\text{Factor}\end{array}\right) = \left(\frac{\text{Annual average steam demand}}{\text{Maximum design steam demand}}\right)$$

Site surveys in Reference (2) suggest that a 33 percent load factor is typical for Navy bases.

Transportation and Availability of Coal

The study assumed the availability of coal and its delivery by commercial surface transportation. Neither transportation nor availability considerations were within the main study scope. However, coal availability is discussed in Appendix D.

Environmental Considerations

Air pollution control systems in this study are based on controlling sulfur dioxide emission levels to 1.2 pounds per 10^6 Btu of fuel heat content, controlling particulate emissions to less than 0.1 pound per 10^6 Btu of heat input, and opacity to less than 20 percent.

Equipment Selection

Only state-of-the-art technology was considered. The lowest-cost commercially available equipment was selected from a group of possible vendors contacted during the study. Flue gas desulfurization equipment for the smaller-size plants has not been produced in commercial quantities, but has been manufactured for pilot-type operations. The costs supplied by vendors and used in the study reflect an N^{th} plant concept where engineering and development expenses are spread over many units of production. The cost for a single unit, for example in a demonstration plant, could be significantly greater than the quoted prices for multiple production units. Only new equipment was considered, and no credit was allowed for existing equipment or structures. Land was assumed to be available for all cases at no cost. Boilers for all plants will be dual-fired with an oil-burning capability, and oil was assumed available at the plant limits.

CAPITAL COST BASIS

The estimates are based on conceptual design and engineering information prepared for the study in the form of engineering drawings, outline specifications, and equipment lists. Estimating methods consistent with the conceptual nature of the design information were employed; estimators drew upon informal vendor data as well as extrapolation from Bechtel historical information. The estimate anticipates an engineer-constructor direct-hire operation employing field construction labor forces.

The following items were used consistently in the study for decentralized and central steam plants, cogeneration plants, and separate cost evaluations of coal and waste handling and steam distribution.

Pricing Level

The estimates are at second quarter, 1978 price and wage levels.

Direct Field Costs

Direct field costs include equipment and materials plus direct construction labor.

Direct construction labor costs for the installation of plant equipment and materials were estimated using recent productivity experience and a \$13/manhour wage rate based on an average continental United States location. This wage rate reflects a craft mix appropriate to the type of construction together with a five-percent allowance for casual overtime and one-percent for craft-furnished supervision. Sufficient manual labor to complete the project is assumed to be available in the project vicinity.

Indirect Field Costs

Indirect field costs are those items of construction cost that cannot be ascribed to direct portions of the facility and thus are accounted separately. They were estimated by modifying experience on similar plants, resulting in an assessment of 80 percent of direct labor costs, which has been distributed over the installation of direct equipment and materials as a function of the installation costs.

The items covered by indirect field costs are:

- Temporary Construction Facilities: Temporary buildings, working areas, roads, parking areas, utility systems, and general-purpose scaffolding.
- Miscellaneous Construction Services: General job cleanup, maintenance of construction equipment and tools, materials handling, and surveying.
- Construction Equipment and Supplies: Construction equipment, small tools, consumable supplies, and purchased utilities.
- Field Office: Field labor of craft supervisors, engineering, procurement, scheduling, personnel administration, warehousing, first aid, and the costs of operating the field office.

- Preliminary Checkout and Acceptance Testing: Testing of materials and equipment to ensure that components and systems are operable.

Engineering Services

Engineering services include engineering costs, other home office costs, and fee. Engineering includes preliminary engineering, optimization studies, specifications, detail engineering, vendor-drawing review, site investigation, and support to vendors. Other home-office costs comprise procurement, estimating and scheduling services, quality assurance, acceptance testing, and construction and project management. Fee is included as a function of the total project cost.

The sum of these three categories falls into historically consistent percentages in the range of 10 to 20 percent depending on the complexity of the project. For this study a figure of 12 percent of field construction costs has been used.

Contingency

Included in each estimate and each tabulated line item is a 20-percent contingency or allowance for the uncertainty that exists within the conceptual design in quantity, pricing, or productivity and that is under the control of the constructor and within the scope of the project as defined. Implicitly, the allowance will be expended during the design and construction of the project and it cannot be considered as a source of funds for overruns or additions to the project scope. Thus, if the conceptual arrangement of the plant components contains major uncertainties, or the design duty of plant components proves to be more severe than anticipated, or if additional major subsystems are ultimately found to be necessary, then the scope of the project is deemed to have been inadequately defined and this then would not be covered by the allowance.

Startup

Startup costs were estimated as a percentage of total construction cost. The figure used for this study was 11 percent and reflects experience for similar plants. It includes process royalties, spare parts inventory, initial charge of catalysts and chemicals, actual plant startup operations, training of operators, and the owner's home office costs for management, reports, permits, etc.

Exclusions

The following items are excluded from the project scope and are not therefore included in the estimates:

- Any special construction such as widening and strengthening existing roads
- Railroads
- Switchyard and power transmission lines beyond the plant high-voltage terminals
- Client engineering and other client costs
- Site investigation and land acquisition

The Term "Total Construction Cost"

All itemized capital costs in this report contain the following functional costs described above:

- Direct field costs
- Indirect field costs
- Engineering services
- Contingency

Costs containing these elements are known as "total construction costs," or costs "at the total construction cost level." When itemized costs are added, the sums are also frequently designated as total construction costs. The meaning of the term will be clear in context.

ANNUAL COST BASIS

Labor Rate

A labor rate of $20/manhour was used throughout to obtain total labor costs from direct operating manpower requirements. The rate includes overhead, administration, and supervision, as follows:

• Base wage per hour		$ 8.00
• Payroll tax and insurance	+ 8%	+ 0.65
• Allowance for paid absences	+13%	+ 1.05
• Social and retirement benefits	+11%	+ 0.90
• Total direct labor		10.60
• Supervision as a percentage of direct labor	+25%	+ 2.70
• Total direct plus supervision		13.30
• Administration and overhead as a percentage of direct labor and supervision	+50%	+ 6.70
• Total labor rate		$20.00

Coal Price

Except where otherwise stated, the coal price used is $30/ton.

Electric Power Price

Except where otherwise stated, the price of electric power is $0.033/kilowatt hour.

Prices of Scrubber Chemicals

The following prices have been used for flue gas desulfurization raw materials:

Lime at $50/ton
Soda at $70/ton

Costs Included in Annual Costs

The following costs are included in annual costs:

- Coal

- Electricity

- Operating labor, computed from manpower requirements

- Maintenance labor, often computed as a factor times capital costs or times capacity, according to experience and vendor information

- Raw materials other than coal

- Operating supplies, often computed as a factor times operating labor

- Maintenance supplies and materials, often computed as a factor times capital costs or times capacity, according to experience and vendor information

Operating labor costs for all plant operations except coal and waste haul were calculated assuming that a full crew would be required during the entire year, regardless of load factor.

Coal, chemicals, and coal and waste haul were assumed proportional to load factor.

LIFE-CYCLE COST BASIS

The Navy Present Value Methodology

The Navy's methodology for computing life-cycle costs in Reference (3) has been used. A short description of that methodology is given in Appendix E. Present values are computed for each project year as a product of costs at the zero of time and a discount factor based on a discount rate that is 10 percent after general inflation has been removed. Thus, the discount rate is equivalent to a private-sector 18 percent capital charge in periods when the general inflation is 8 percent.

Differential Inflation Rates

Energy costs are anticipated to rise faster than general inflation. Annual long-term differential inflation rates set forth in Reference (4) are as follows:

- Labor and materials 0%
- Coal +5%
- Fuel oil +8%
- Electricity
  - Pacific Coast, New England +7%
  - All other states +6%

The 6 percent electricity value was used in this report. The introduction of differential inflation leads to special discount factors given in Reference (3) and reproduced for convenience in Appendix G.

One-Time and Recurring Discount Factors

The tables in Appendix G give discount factors for each single year in a project life. They also give cumulative uniform series discount factors for costs which recur for several years.

Assumed Project Schedule

The zero of time is assumed to be May 1978, the reference time of the costs presented in this study. All plants are assumed to startup in May 1981, and to operate continuously for 25 years. Plant construction is expected to begin in May 1979 and last 24 months for systems with capacities of 400 and 800 x 10^6 Btu/hr. It begins in May 1980 and lasts 12 months for systems with capacities of 100 and 200 x 10^6 Btu/hr. Three years of construction beginning May 1978 have been assumed for cogeneration plants.

Calculation of Present Values

The example in Table 3-3 below shows the pattern for calculation of present values in Sections 8, 9, and 10. The discount factors for years 4 to 28 in Table 3-3 are derived in Table E-1. The single year factors are taken directly from Appendix G. For systems with 12-month construction periods, all construction costs would appear the third project year.

Unit Present Values

The unit present values presented in this report assumed operations beginning in the fourth project year. They are lower than the standard unit present values used by the Naval Facilities Engineering Command (NAVFAC), which have operations beginning the first project year. To convert unit values in this report to the NAVFAC form, multiply by 1.33309. This factor is derived in Appendix E. Thus, the $\$2.13/10^6$ Btu unit present value in Table 3-3 would be $\$2.83/10^6$ Btu in NAVFAC Form. For electrical energy, unit present values may be expressed in \$/kWhr. A kilowatt hour is 3412 Btu.

Table 3-3

PRESENT VALUE CALCULATION PATTERN

Line Number	Cost Element	Differential Inflation Rate	Project Year	Amount, Thousands of Dollars		Discount Factor	Present Value Thousands of Dollars
				One Time	Recurring		
	0.5% SULFUR						
(1)	First Year Construction	+0	2	6,900		0.867	5,982
(2)	Second Year Construction	+0	3	13,800		0.788	10,874
(3)	Total Investment			20,700			16,856
(4)	Coal	+5	4-28		2,000	12.853	25,706
(5)	Electricity	+6	4-28		50	14.588	729
(6)	Operating and Maintenance Labor and Materials	+0	4-28		2,550	7.156	18,248
(7)	Total Operating Cost				4,600		44,683
(8)	Total Project Present Value						61,539
(9)	Energy Available Over 25 Years, 10^9 Btu						28,900
(10)	Energy Unit Present Value, $\$/10^6$ Btu						2.13

Levelized Costs

Reference (5) describes the calculation of levelized unit energy costs. These costs have the "feel" of private sector $\$/10^6$ Btu costs, but with energy contributions augmented to take into account differential inflation. Levelized costs are described in Appendix F. There, the levelized cost for the case in Table 3-3 is shown to be $\$7.44/10^6$ Btu. To get levelized costs from unit present values in this report, multiply by 3.49.

Fuel Oil for Comparison

Reference (6) compared continued use of fuel oil in existing boilers with use of coal in new facilities. One case considered was an existing facility with two oil-fired boilers, each with 100×10^6 Btu/hr output and operating with a load factor of 50 percent. That facility had annual costs in thousands of dollars as follows:

• Oil at $\$3.16/10^6$ Btu	3460
• Electricity	75
• Operating and maintenance labor and material	255

By the methods of Appendix F, the corresponding levelized cost for this facility is \$10.40.

Section 4

STEAM GENERATION

Facilities with coal-fired stoker boilers transferring 25, 50, 100, and 200 x 10^6 Btu/hr and generating 25, 50, 100, and 200 x 10^3 lb/hr of steam are described in this section.

The study was restricted to stoker boilers, since they are available in all sizes in this range, and their capital costs are lower than the pulverized-coal boiler alternatives.

Both low-pressure and high-pressure boilers were evaluated. The low-pressure boilers are intended for production of heating and service steam. Low-pressure facilities generating saturated steam at pressures of 150, 300, and 600 psig all entail roughly the same costs, and a 300-psig pressure was selected as nominal for system descriptions and vendor quotes.

The high-pressure boilers are intended for central plant cogeneration facilities. These boilers produce steam superheated to $1000^{o}F$ at 1450 psig.

The boiler facilities are to be included either in centralized steam plants containing four boilers, or they will be dispersed in a decentralized system. These will be discussed in Section 8.

SYSTEM DESCRIPTION

The 300-psig steam generation system was evaluated as a complete operating facility and includes:

- Coal-fired stoker boiler package
- Feedwater system

- Water treatment system
- Stack
- Building, foundations, and site preparation
- Process pipe and instrumentation
- Process electrical equipment and materials

The boiler package quoted by vendors includes the component elements: boiler pressure parts, economizer, setting and insulation, refractory, lagging, complete gas duct system from the boiler outlet to the induced-draft fan discharge, complete air duct system from the forced-draft fan outlet to the stoker air chamber, structural steel supports and buckstays, platforms and walkways, manually operated steam blowing sootblowers, forced and induced draft fans with motor drives, insulation for hot items external to the boiler setting, traveling-grate spreader stoker, coal feeders, over-fire air system, ash hopper complete with ash doors, auxiliary oil burners, combustion controls, flame safeguard system, and all required erection labor. Erection labor is 30 percent of the quoted price.

A block diagram of the 100 x 10^6 Btu/hr steam generation system burning two-percent-sulfur coal is shown in Figure 4-1.

Stoker boiler operation begins as the fuel is continuously and automatically fed from the fuel receiving hoppers, advanced across the distributor plate by a pusher block system, picked up by revolving rotor blades, and distributed into the furnace. High-pressure over-fire airjets provide turbulence and thorough mixing of the fuel and air to assure complete combustion. Smaller particles of fuel are burned rapidly in suspension while coarser, heavier particles are spread evenly on the forward-moving grates, forming a thin, fast-burning fuel bed. The fuel feed and air supply rates conform to variations in load and are automatically regulated by mechanical connection to the combustion control system. To compensate

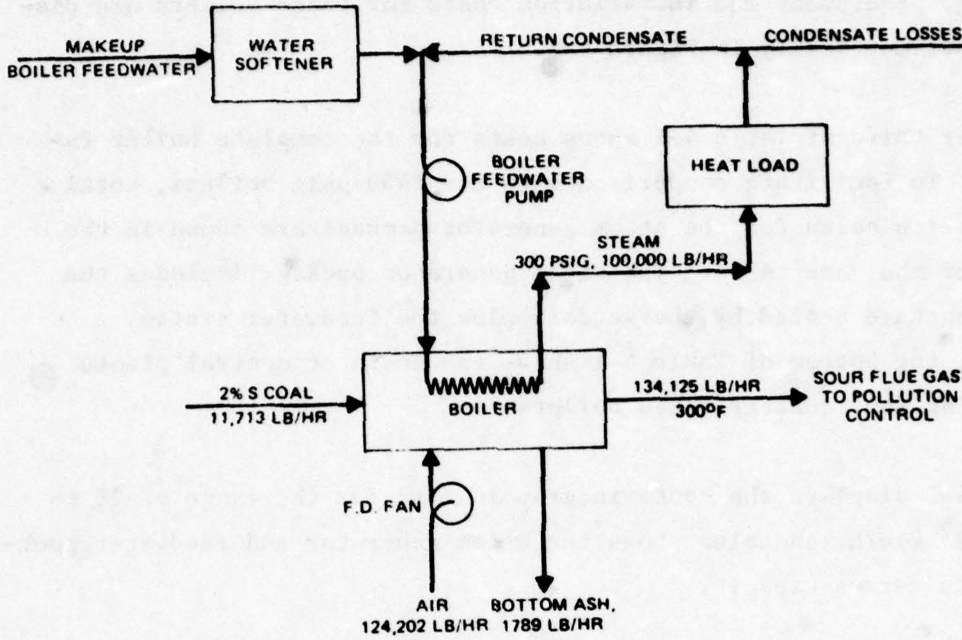


Figure 4-1
100 x 10^6 BTU/HR STEAM GENERATION SYSTEM BLOCK DIAGRAM

for variation of the ash content in the fuel, the grate speed can be adjusted from 0 to approximately 30 feet per hour. The ash is continuously discharged over the front end of the grate into an ash pit or hopper.

The 1450-psig steam generation system was evaluated for use in later portions of the study where such units will be incorporated into the cogeneration plant.

STEAM GENERATION CAPITAL COSTS

Boiler vendors were contacted early in the study for cost and technical information. Evaluation of quoted equipment costs resulted in the costs shown in Table 4-1 for boilers with an outlet pressure of 300 psig. Equipment and installation costs for these boilers are displayed parametrically in Figure 4-2.

The upper third of Table 4-1 shows costs for the complete boiler facility. To facilitate comparison with the 1450-psig boilers, total construction costs for the steam generator package are shown in the middle of the same table. The steam generator package includes the boiler package quoted by the vendors plus the feedwater system. Finally, the bottom of Table 4-1 shows the costs of central plants containing four quarter-sized boilers.

Figure 4-2 displays the costs in graphic form for the range of 25 to 200 x 10^6 Btu/hr and also shows the steam generator and feedwater package costs versus capacity.

Table 4-2 and Figure 4-3 supply similar data for the 1450-psig boiler package plus feedwater system. Also, Table 4-2 shows the incremental cost of substituting a single 1450-psia boiler for a 300 psia-boiler in a central plant.

OPERATING AND MAINTENANCE COSTS

Annual water and electric power requirements for 300-psig boiler systems are shown in Table 4-3. These were computed from flows in Figure 4-1 and the 33-percent load factor defined in Section 3.

Manpower requirements for single decentralized boilers are shown in Table 4-4.

Wages for operating labor, prices of power and water, and factored operating and maintenance costs were given in Section 3. These were used to produce the costs in Table 4-5. The total costs are plotted in Figure 4-4. The costs do not include coal costs.

Table 4-1

TOTAL CONSTRUCTION COSTS,
300-PSIG STOKER STEAM GENERATORS

Single Decentralized Steam Generator Facility**				
Heat Transferred, 10^6 Btu/hr	Thousands of Dollars*			
	25	50	100	200
Equipment	830	1400	2200	3895
Labor	400	670	1200	1800
Total Construction Cost	1230	2070	3400	5695

Steam Generator Package†				
Heat Transferred, 10^6 Btu/hr	Thousands of Dollars*			
	25	50	100	200
Equipment	560	1100	1750	3050
Labor	340	500	950	1650
Total Construction Cost	900	1600	2700	4700

Central Plant with Four Quarter-Sized Boilers**				
Heat Transferred, 10^6 Btu/hr	Thousands of Dollars*			
	100	200	400	800
Equipment	3000	5000	8400	14500
Labor	1500	2700	4400	7200
Total Construction Cost	4500	7700	12800	21700

*Second quarter 1978 prices.
**Costs include the boiler package and feedwater system, plus water treatment, steel frame buildings and foundations, piping, instrumentation, and electrical.
†Costs include the boiler package and feedwater system only.

Table 4-2

TOTAL CONSTRUCTION COSTS,
1450-PSIG STOKER STEAM GENERATORS

Single Steam Generator Packages*

	Thousands of Dollars**			
Heating Steam Output, 10^6 Btu/hr	25	50	100	200
Equipment	900	1750	3050	5350
Labor	500	950	1650	2850
Total Construction Cost	1400	2700	4700	8200

Incremental Cost of Substituting One 1450-psia Boiler
for a 300-psia Boiler in a Central Plant

	Thousands of Dollars**			
Heating Steam Output, 10^6 Btu/hr	25	50	100	200
Total Construction Cost	1050	2000	3600	6000

*Includes boiler package and feedwater system only.
**Second quarter 1978 prices.

Table 4-3

ANNUAL UTILITY REQUIREMENTS,
30C-PSIG STOKER STEAM GENERATORS
(33% Load Factor)

Boiler Capacity, 10^6 Btu/hr Heat Transferred	Makeup Water, 10^3 gal	Electricity, 10^3 kWh
25	90	70
50	180	140
100	370	280
200	740	560

Table 4-4

OPERATING MANPOWER,
300-PSIG STOKER BOILER PLANTS

Type of Plant	Plant Capacity, 10^6 Btu/hr Heat Transferred	Men Employed
Single Decentralized Boilers	25	2.4
	50	3.6
	100	6.2
	200	10.0
Central Plant with Four Quarter-Size Boilers	100	7.0
	200	10.1
	400	17
	800	29.2

Table 4-5

ANNUAL OPERATING AND MAINTENANCE COSTS,
DECENTRALIZED AND CENTRAL BOILER PLANTS

Type of Plant	Plant Capacity, 10^6 Btu/hr Heat Transferred	Thousands of Dollars*		
		Material	Labor	Total Annual O&M
Single Decentralized Boilers	25	20	123	143
	50	43	193	236
	100	98	328	426
	200	203	538	741
Central Plants with Four Quarter-Size Boilers	100	80	380	460
	200	180	590	770
	400	300	980	1340
	800	770	1690	2460

*Second quarter 1978 pricing level, 33 percent load factor.

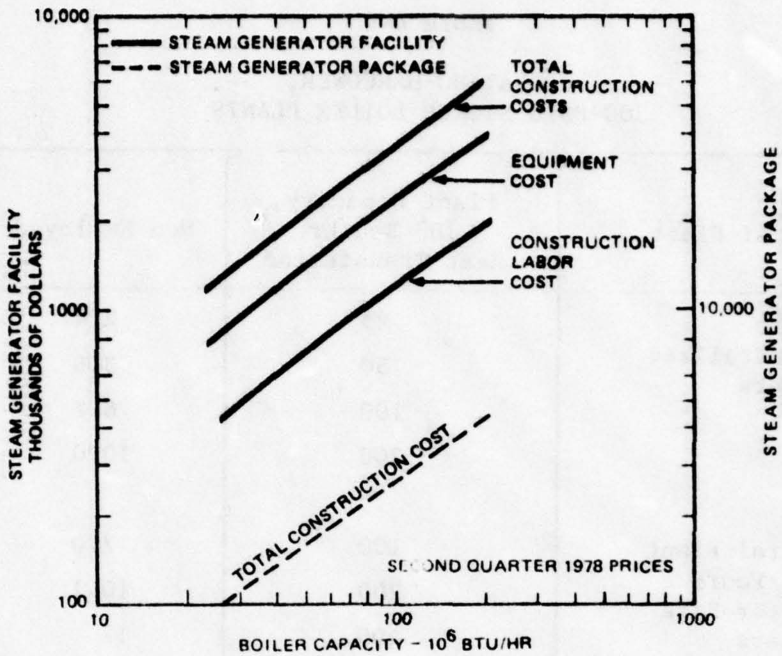


Figure 4-2
TOTAL CONSTRUCTION COSTS, SINGLE DECENTRALIZED
300 PSIG STOKER STEAM GENERATOR FACILITIES AND PACKAGES

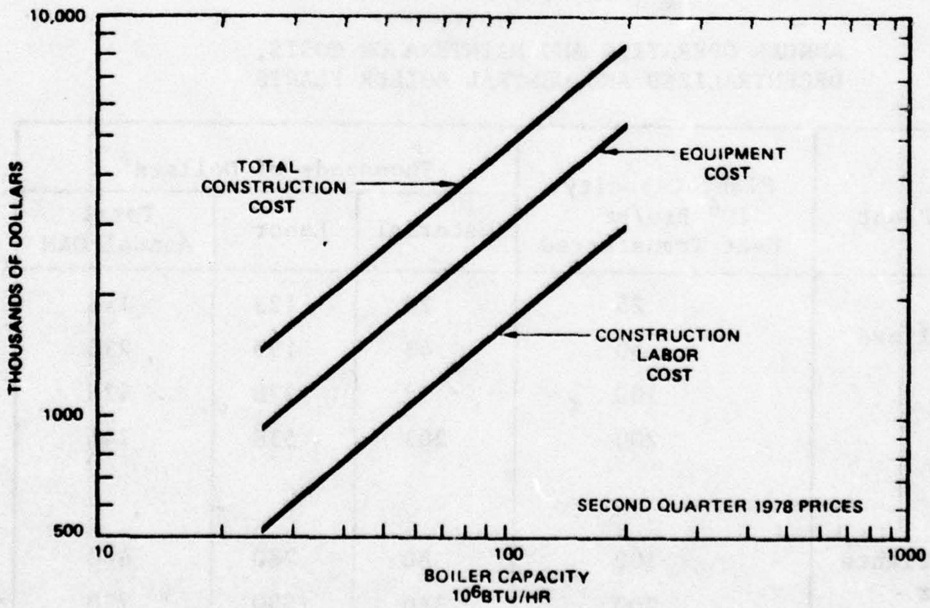


Figure 4-3
TOTAL CONSTRUCTION COSTS,
1450 PSIG STOKER STEAM GENERATOR PACKAGES

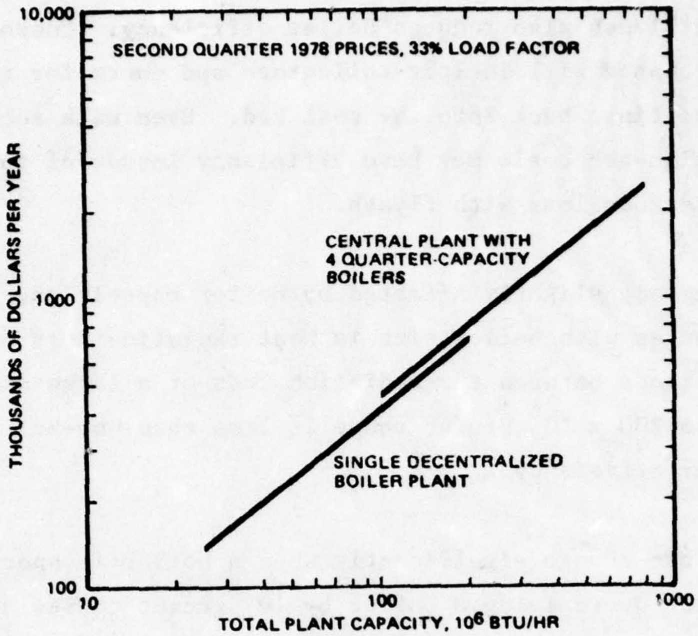


Figure 4-4
ANNUAL OPERATING AND MAINTENANCE COSTS, DECENTRALIZED AND CENTRAL BOILER PLANTS

BOILER PERFORMANCE AND EFFICIENCY

Boilers are sized to operate at the condition most frequently encountered. Occasionally (twice a month or less frequently) units can be overdriven to a 10-percent overcapacity load without damage to the equipment. Turn-down ratios for stoker boilers are in the range of 3:1. The ratio applies with or without scrubbers. For the boilers considered in this study, a nominal efficiency of 80 percent was assumed.

A major factor affecting boiler efficiency is the addition of economizers or air heaters to reduce stack temperature at the back end of the boiler. The use of economizers or air heaters increases efficiency from about 78 to 85 percent.

Moisture in the coal decreases boiler efficiency by about one percent for each ten percent moisture in the coal.

Carbon lost with flyash also reduces boiler efficiency. Consequently, most stokers purchased will include collectors and ducts for recycling a fraction of the fines back into the coal bed. Even with such equipment, however, high-ash coals may have efficiency losses of four percent due to residual carbon loss with flyash.

Efficiencies are only slightly affected by boiler capacities. The major factor which changes with boiler size is heat radiation loss from the unit. The difference between the radiation loss of a large and a small unit in the 25 to 200 x 10^6 Btu/hr range is less than one-half percent of overall boiler efficiency.

Efficiency does not change significantly when a boiler is operated off its rated output. Overdriving a boiler by 10 percent causes a drop in efficiency of 0.5 to 1.0 percent. Operating a boiler below its rated output can cause a slight rise in efficiency due to reduced carbon losses.

SENSITIVITY TO OPERATING CONDITIONS

Response and sensitivity to off-optimum or off-design conditions are largely related to coal composition and discussed on the following page.

An important feature of stoker boilers is their relatively slow response to load swings. Upward fluctuations can be accommodated rapidly only by supplemental firing with oil or gas. Sudden reductions in load necessitate venting steam while the coal on the grate is consumed. Also, if a unit is designed for operation with superheated steam at a particular temperature, reduced boiler load causes reduced superheated steam temperatures unless specific design provisions have been made for temperature control. While it is fairly easy to maintain temperature for 10 to 20 percent load reductions, if steam temperature must be maintained and loads reduced to 50 to 60 percent of design capacity, the effect on installation and operating costs can be significant. Partially for this reason, the cogeneration plant discussed later includes two low-pressure and two high-pressure, high-temperature units.

Another factor which is quite important in proper performance of a stoker boiler is the uniform distribution of fuel throughout the boiler cross-section. Deviations in size distribution of coal particles from that for which coal spreaders are adjusted may cause classification of coal particles across the boiler furnace and uneven heat input. This will reduce unit efficiency.

EFFECT OF COAL COMPOSITION

Parts of the following discussion involve pulverized coal-fired boilers as well as stoker boilers. The information is included here because pulverized coal boilers may be an alternative to the stoker-fired boilers used in the study and, secondly, the descriptions serve to emphasize the need to define coal characteristics and to consult with equipment manufacturer early in any steam generation project.

The key design parameter for coal-fired boilers is the coal analysis. Figure 4-5 shows a sample format for itemizing coal properties.

From the ultimate coal analysis and other information, slagging and fouling characteristics can be calculated. These characteristics are used to size the furnace and convection section. However, slagging and fouling characteristics are not major factors in boiler design except with the lower-grade fuels.

Although ash fouling affects convection tube spacing requirements, the amount of ash has little effect on boiler design. The amount does have a major impact on the design of ash-handling and particulate removal equipment. With stoker-fired boilers, combustion takes place on an air-cooled bed of ash in the furnace bottom, and smaller quantities of entrained ash particles are carried to the convection section of the boiler. Ash quantity may vary between 3 and 25 percent in domestic coals.

SOURCE (STATE/COUNTY/COMPANY/MINE/SEAM) ____________

CLASSIFICATION BY RANK ____________

Proximate Analysis—as received (percent by weight)
- Volatile Matter ____________
- Fixed Carbon ____________
- Ash ____________
- Moisture (Total) ____________
- Equilibrium Moisture ____________

Grindability—Hardgrove[b] ____________
- Feed Size (Sieve Analysis) ____________

Sulfur ____________
- Forms of Sulfur
  - Pyritic ____________
  - Organic ____________
  - Sulfates ____________

Heating Value—BTU/lb.
- as received ____________

Ultimate Analysis—as received (percent by weight)
- Moisture ____________
- Carbon ____________
- Chlorine ____________
- Hydrogen ____________
- Nitrogen ____________
- Oxygen ____________
- Sulfur ____________
- Ash ____________

Float Sink Fraction (1.6 sp.gr.) ____________

Ash Fusion Temperatures (°F)

	Reducing	Oxidizing
Initial deformation	____________	____________
Softening (H=w)	____________	____________
Hemispherical (H=½w)	____________	____________
Fluid	____________	____________

Ash Analysis (percent by weight)
- SiO_2 ____________
- Fe_2O_3 ____________
- Al_2O_3 ____________
- CaO ____________
- MgO ____________
- P_2O_5 ____________
- Na_2O ____________
- K_2O ____________
- TiO_2 ____________
- SO_3 ____________
- NAF[c] ____________
- Viscosity[d] ____________

Burning Profiles[e] ____________

Bulk Density (as delivered) ____________

Free Swelling Index ____________

Reactivity Index[f] ____________

ASTM TEST METHODS

1. Proximate Analysis—D3172,D3173,D3174,D3175,D3177,D2013
2. Ultimate Analysis—D3173,D3174,D3176,D3177,D3178,D3179, D2361
3. Heating Valve (BTU)—D2015,D3286
4. Grindability—D409
5. Moisture—D2013,D3173,D3302
6. Bulk Density—D291
7. Free Swelling—D720
8. Ash Analysis—D2795
9. Ash Fusion Characteristics—D1857
10. Classification by Rank—D388
11. Sampling Methods—D2234
12. Sampling Preparation—D2013
13. Chlorine—D2361
14. Forms of Sulfur—D2492
15. A Test for Sieve Analysis of Crushed Bituminous Coal—311-30

[b] Note: Grindability for at least three moisture levels should be determined when low rank coals are analyzed (e.g. Sub—C or Lignite).

[c] Not accounted for.

[d] Corey, Richard C., "Measurement and Significance of the Flow Properties of Coal Ash Slag," Bur. Mines Bull, Vol. 618, 1964.

[a] Please use one form for *each* coal specification; do not list property ranges or composite properties.

[d] Moore, G. F. and Ehrler, R. F., Western Coals—Laboratory Characterization and Field Evaluations of Cleaning Requirements, ASME paper No. 73-WA/FU-1 Detroit, Mich., November 1973.

[e] Wagoner, C. L. & Winegartner, E. C., "Further Developments of the *Burning Profile*," *Journal of Engineering* for Power, Trans ASME, Series A, Vol. 95, No. 2, April 1973.

[e] Moore, G. F. and Ehrler, R. F., Western Coals—Laboratory Characterization and Field Evaluations of Cleaning Requirements, ASME Paper No. 73-WA/FU-1 Detroit, Mich., November 1973.

[f] See *Reactivity of Solid Fuels* by A. A. Orning, "Industrial and Engineering," Pages 813, Vol. 36 (1944).

Figure 4-5

RECOMMENDED ABMA COAL GUIDE SPECIFICATION FORM

Designing to the maximum of the range will result in larger ash-handling systems, ash ponds, ash hoppers, baghouses/precipitators, and related coal-handling equipment. These items for a high-ash coal might cost five times as much for a low-ash coal.

Coal heating values range widely between coals and can significantly affect coalyard handling, storage, coal conveying, crushing, and transport equipment. Steam generators of a given capacity require a fixed heat input regardless of coal heating value. If the actual heating value of the coal is reduced by 50 percent, the time-rated capacity of all of the above-mentioned equipment is doubled. For example, in doubling storage capacity, the height and structural supports must be increased; thus coal conveyors become longer and horsepower requirements larger. Therefore, lowering coal heating value has a compounding effect on fuel-handling, preparation, and conveying equipment. The cost of such equipment may be 2.5 times as high for low heating values as for high.

Increased coal moisture reduces its heating value and therefore also increases costs of coalyard handling, conveying, storage, size reduction, and transport equipment. For example, for the same Btu/hour firing rate, 40 percent more pounds per hour of 30-percent-moisture coal would have to be fired than of 5-percent-moisture coal. Also, high moisture coal often requires special additional equipment such as coal dryers, ice-breakers, bunker vibrators, and special attention to such items as coal hopper slopes, feeder types, coal chute materials and geometries, air heater materials and design temperatures, baghouse/precipitator velocities, temperature and performance effects, ductwork, and stack materials. In this example, the cost of coal-handling equipment may be 1.5 times as high for the high-moisture coal as for a low-moisture coal.

Increased coal moisture increases the size of furnace equipment slightly by requiring larger flow rates of coal for the same rated capacity. Also, as noted before, increased coal moisture decreases boiler efficiency, and larger volumes of air and flue gas will be required for the same rated capacity. A ten-percent increase in moisture content will lead roughly to a one-percent decrease in efficiency and approximately one percent larger sizes for all equipment sized proportionally to gas volume (furnace size, fan sizes). The fan power will increase proportionally. The larger gas volume will also affect the size of the stack and the size of pollution control equipment.

The volatile content of American coals ranges from approximately 2 to 55 percent. This factor directly affects combustibility in coal boilers. For pulverized-coal boilers, required fineness increases as volatile content decreases, resulting in significant sizing variations, and burner designs often must vary to accommodate low-volatile coal carbon loss combustion requirements. For extremely-low-volatile fuel, furnace geometries and firing methods must often be drastically and expensively altered from the more conventional firing styles. Low volatility can increase furnace, burner, pulverizer, conveying equipment, instrumentation, and control cost by as much as 100 percent.

Grindability most strongly affects pulverized-coal boilers. Hardgrove index values for coals in this country can vary from approximately 35 to 110, with mill sizing ranges of up to 4:1. This range can vary the required number of crushers/pulverizers, bunkers, feeders, piping, burners, instruments, and controls.

While coal abrasivity is somewhat difficult to identify in advance, coals which contain relatively high quantities of quartz, feldspar, and other abrasive impurities may require special conveying system design. Lined chutes, classifiers, and coal-piping abrasion resistance can double the cost for this equipment. As coal quality continues to deteriorate, it can be expected that expenditures for abrasion protection will become more important.

Since fuel nitrogen content can significantly affect NO_x emissions, even seemingly small variations in this value can have a significant effect on unit designs. Dry basis coal nitrogen content usually ranges from 0.6 to 1.6 percent, and, although the exact rates of conversion to NO_x are still subject to much controversial conjecture, most sources report high emission rates for high-nitrogen coals. The fact that several conventional NO_x control methods are ineffective in controlling fuel nitrogen-generated NO_x only adds to the design costs for controlling this pollutant in the combustion process. The cost impact of this fuel parameter can vary from zero for very low fuel nitrogen levels to doubling burner and furnace costs.

The bulk of fuel sulfur converts into gaseous pollutants in the combustion process. The cost impact of sulfur removal equipment is treated in Section 5.

Additionally, while the major components of boiler design are relatively unaffected by coal sulfur content, operating costs, boiler efficiency, and, to a small degree, initial costs can be affected by the corrosion potential in the low-temperature regions of the boiler convection pass. Sulfur in the fuel is burned primarily to SO_2, but approximately one to two percent of the total sulfur oxides is converted to SO_3. This SO_3 combines with the water vapor in the flue gas to form sulfuric acid, which then condenses at the lower temperatures sometimes experienced on economizer surfaces and in air heaters at the boiler back end. The amount of sulfur in the fuel, the moisture content of the flue gas, and, to some extent, the boiler feedwater temperature and/or ambient air temperature, determine how much corrosion-inducing condensation takes place. Another factor involved is the relative alkalinity or acidity of the boiler ash itself. Low-sulfur Western coals, which contain a relatively high percentage of alkaline ash, almost never suffer from cold-end corrosion. Acidic ash, high-sulfur coals will have some potential for corrosion problems.

The effect of high-sulfur coals due to this corrosion potential may be to require increased exit gas temperatures (reducing boiler efficiency), use of a feedwater heater to protect economizer surfaces, or use of a steam-coil air preheater to warm the ambient air before introduction to the air heater. For example, one vendor recommends for regenerative air heating equipment a cold-end average temperature (arithmetic average of incoming air and exit flue gas temperatures) of approximately 155 F with 1½ percent sulfur coal, and 185 F with 3½ percent sulfur coal.

Coal impurity constituents have a significant effect on pulverized-coal steam generator design. By designing a boiler for a severe slagging coal rather than a low slagger, furnace size (area) would be increased by approximately 50 percent, while superheater and reheater surfaces would be enlarged by approximately 35 percent. Severe slagging coals must have larger furnace cooling zones to:

- Cool ash particles below their liquid plastic viscosity limit before they contact close-spaced convective heating surfaces
- Prevent the formation of running (wet) slag deposits anywhere on the furnace walls

Dry deposits will form on the furnace cavity for medium, high, and severe slagging coals, although the deposits are normally self-limiting and easily removed with furnace wall blowers.

These dry deposits may have a significant effect on furnace effectiveness and/or resultant furnace exit-gas temperatures. Tests have shown differences of $180^{\circ}F$ in furnace exit-gas temperature between low and severe slagging coal in units of similar design. Such variations can affect steam temperature by at least $50^{\circ}F$.

Also to control steam temperature with a high or severe slagging fuel, the furnace must have bands of wall blowers over its entire area. The function of the blowers is to eliminate the dry deposit buildup. This is needed to ensure compatibility between furnace performance and the ability of the steam temperature control system to maintain design temperature.

Designing furnaces to handle a coal slagging range from low to severe requires sootblower selection for the severe slagging coal. This increases the cost of the sootblower system by a factor of 4.0 over the requirements for only low slagging coal.

The fouling potential of coals dictates convective rear-pass boiler tube spacing. Severe fouling coals require greater tube clearance (open area) in order to prevent bridging of coal ash, in comparison to low fouling coals. This greater open area results in lower gas velocities and thus lower heat-transfer coefficients, and to achieve the desired heat transfer in the convection pass, approximately 35 to 40 percent additional surface is necessary.

As fouling potential increases so also does the number of rear-pass sootblowers. Generally 50 percent more sootblowers are needed in the rear pass for a severe fouling coal.

Much of the above information on the effect of coal composition was taken from Reference (7) and is provided as general information. The major purpose of the foregoing discussion was to emphasize how steam generation design and costs can vary with site-sensitive factors, especially fuel selection, and the level of detail that must be examined prior to actual design and construction. The economic evaluations provided in this and following sections are valid for parametric comparison of decentralized versus central plants and cogeneration versus purchased electricity. However, as indicated above, actual costs can deviate significantly from the estimates of an average or typical installation. References (8) to (10) provide additional information on factors affecting boiler design and costs.

Section 5

AIR POLLUTION CONTROL

Air pollution control equipment is examined in this section for systems with the following ranges of parameters:

- Decentralized boilers with capacities of 25 to 200 x 10^6 Btu/hr heat transferred
- Central boiler plants with total capacities of 100 to 800 x 10^6 Btu/hr heat transferred
- Coals with 0.5, 2, and 4 percent sulfur

Air pollution control requires the following cleanup operations for the above systems:

- Particulate removal systems for all cases
- Flue gas desulfurization (FGD) for the cases with two and four percent sulfur

In this report, the flue gas to be treated is assumed to have been generated in coal-fired stoker boilers under the following conditions:

- Coal compositions as given by Table 3-1
- Excess combustion air of 40 percent
- Unburned carbon with ash equivalent to four percent of total coal
- 40 percent of ash and unburned carbon becoming flyash
- Boilers with economizers and air preheaters discharging flue gas at 300°F

Table 5-1 lists the pollutant removal requirements used for equipment selection and costing in this section. The emission limits assumed are the Environmental Protection Agency (EPA) New Source Performance Standards (NSPS) of 1.2 pounds of SO_2 and 0.1 pound of particulates for each 10^6 Btu of fuel consumed. Federal regulations actually impose these limits for boilers firing more than 250×10^6 Btu/hr of coal. However, it has been assumed that Federal or local regulations will in the future extend these limits to the smaller boilers considered here.

SELECTION OF BAGHOUSES AND DOUBLE-ALKALI FGD

Several vendors were contacted to provide economic and technical information on flue gas desulfurization and particulate removal equipment. The results indicate that dry removal of flyash by a bag filter followed by a double-alkali wet scrubbing system for SO_2 removal is most applicable to Navy base installations when both flyash and SO_2 must be removed.

In arriving at this conclusion, three treatment system configurations were examined in detail. These are shown in the following tabulation:

Case	Particulate Removal	SO_2 Removal
1	Baghouse or Precipitator	Double-Alkali Wet Scrubber
2	Baghouse or Precipitator	Lime Wet Scrubber
3	Lime Wet Scrubber	Lime Wet Scrubber

The recommended baghouse/double-alkali system is generally applicable to a wide range of coal and abatement requirements. It could thus be standardized for use in all Navy base boiler applications. It has several technical advantages:

- The flyash removal capability of the bag filter is the best currently attainable, and its performance does not have the sensitivity to variable flyash chemistry that electrostatic precipitators have

Table 5-1

FLUE GAS POLLUTANT REMOVAL REQUIREMENTS
(To meet EPA limits of 1.2 pounds of SO_2 per 10^6 Btu and 0.1 pound of particulates per 10^6 Btu)

DECENTRALIZED SINGLE BOILERS

Boiler Capacity 10^6 Btu/hr	Raw Flue Gas Flow at 300°F ACFM	Wet Flue Gas Flow at 120°F ACFM	Required SO_2 Removal		Required Flyash Removal		
			2% S Coal lb/hr	4% S Coal lb/hr	0.5% S Coal lb/hr	2% S Coal lb/hr	4% S Coal lb/hr
25	10,400	8,460	80	194	315.1	297.6	269.9
50	20,800	16,910	159	389	630.1	595.2	537.7
100	41,500	33,830	319	777	1260.3	1190.3	1075.3
200	83,000	67,650	637	1555	2520.5	2360.7	2150.7

CENTRAL MULTIPLE BOILERS

Combined Capacity	Total Raw Flue Gas Flow at 300°F ACFM	Total Wet Gas Flow at 120°F ACFM	Required SO_2 Removal		Required Flyash Removal		
			2% S Coal lb/hr	4% S Coal lb/hr	0.5% S Coal lb/hr	2% S Coal lb/hr	4% S Coal lb/hr
100	41,500	33,830	319	777	1260.3	1190.3	1075.3
200	83,000	67,650	637	1555	2520.5	2360.7	2150.7
400	166,000	135,000	1274	3110	5041.0	4721.0	4300.0
800	332,000	270,000	2548	6220	10082.0	9442.0	8600.0

Required SO_2 Removal = 0% - 0.5% S Coal
= 68% - 2% S Coal
= 83.8% - 4% S Coal

Required Flyash Removal = 99.1% - 0.5% S Coal
99% - 2% S Coal
98.9% - 4% S Coal

Allowable SO_2 concentration in stack gas = 489 ppm (wet basis)
Allowable particulate concentration in stack gas = 0.02 grain/ACF

- The SO_2 removal capability of the double-alkali process is also very high, and the nature of the absorbent minimizes mechanical problems (scaling and erosion) encountered with lime slurry scrubbing

- The soluble nature of the double-alkali sorbent permits the use of the more efficient types of mist eliminators, thus minimizing entrainment and downstream fouling and particulate emission

- The soluble nature of the double-alkali sorbent also permits longer operator response times for absorber upsets and thus makes operation of the system significantly easier than with lime slurry scrubbing

The disadvantages of the baghouse/double-alkali system over the combined removal of flyash and SO_2 by lime scrubbing include:

- More items of equipment both for flyash removal (separate baghouse) and SO_2 removal (regeneration)

- Separate soda feed and handling for the double-alkali sodium makeup

Stoker boilers normally operate with flue gas discharge temperatures of 300°F to 550°F. The 550°F temperature represents the upper limit of bag filter applicability. The useful life of filter fabric decreases with increasing flue gas temperature. In the case of an existing boiler operating with a flue gas discharge temperature of 500+°F, the use of an electrostatic precipitator instead of a baghouse should be considered.

Figures 5-1, 5-2, and 5-3 illustrate the three flue gas treating systems that were compared. Each includes a flue gas reheater between the SO_2 absorber and the stack. Each consumes lime and each produces waste solids containing both flyash and solid and liquid products of sulfur removal. Table 5-2 presents flow data for the lime and double-alkali FGD systems considered.

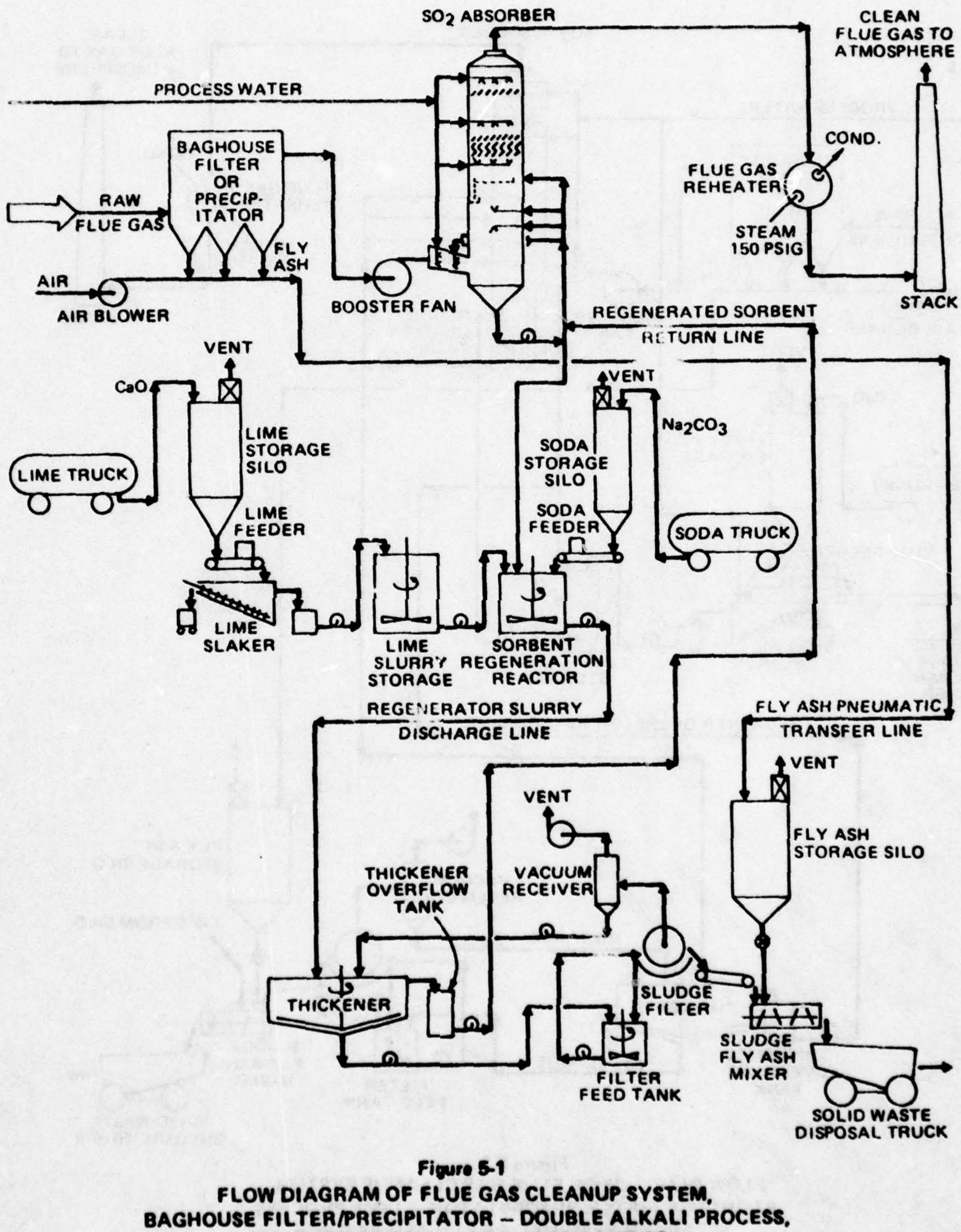


Figure 5-1
FLOW DIAGRAM OF FLUE GAS CLEANUP SYSTEM, BAGHOUSE FILTER/PRECIPITATOR – DOUBLE ALKALI PROCESS, SEPARATE REMOVAL OF FLY ASH AND SO_2

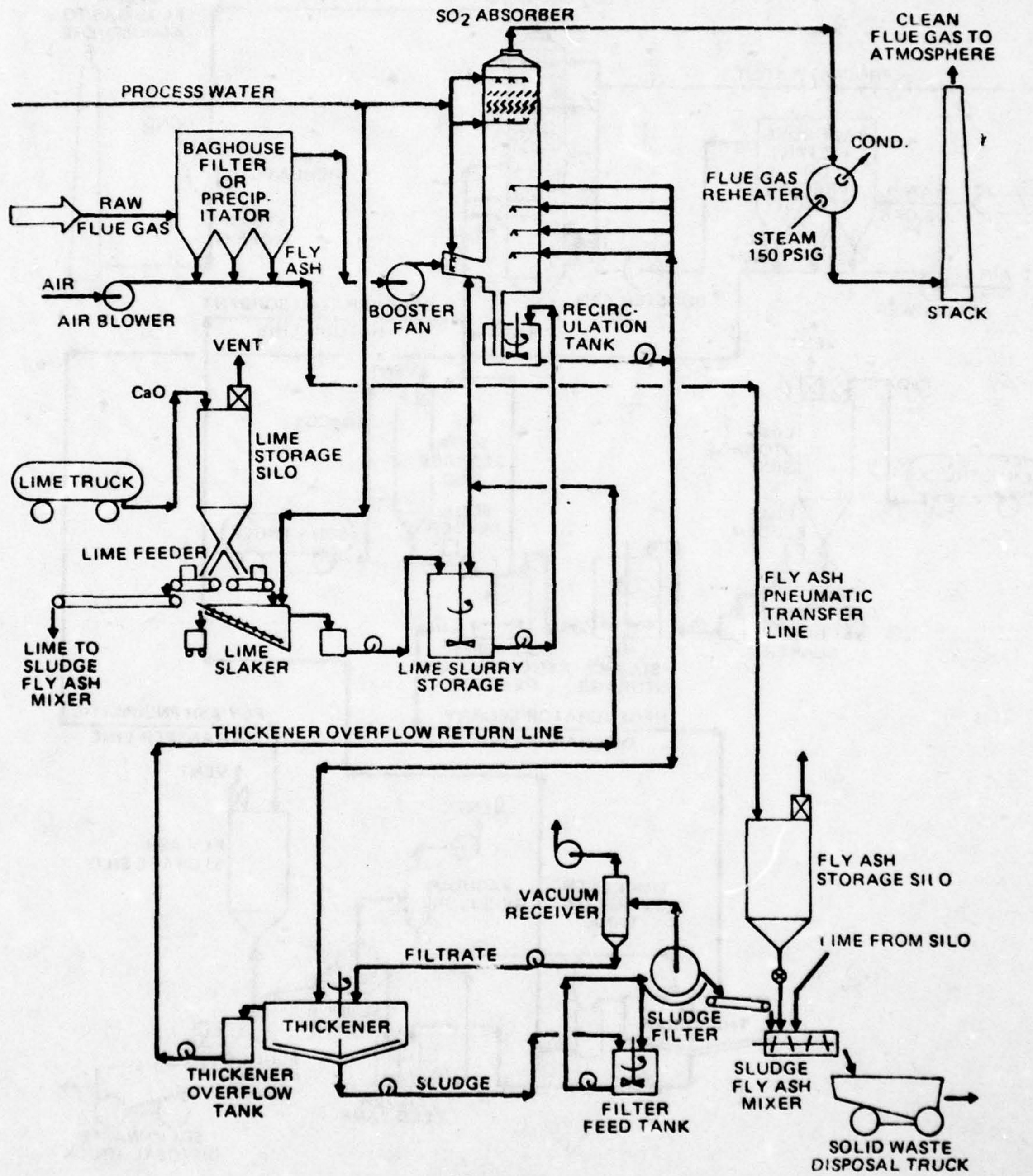


Figure 5-2
FLOW DIAGRAM OF FLUE GAS CLEANUP SYSTEM, BAGHOUSE FILTER/PRECIPITATOR – LIME PROCESS, SEPARATE REMOVAL OF FLY ASH AND SO_2

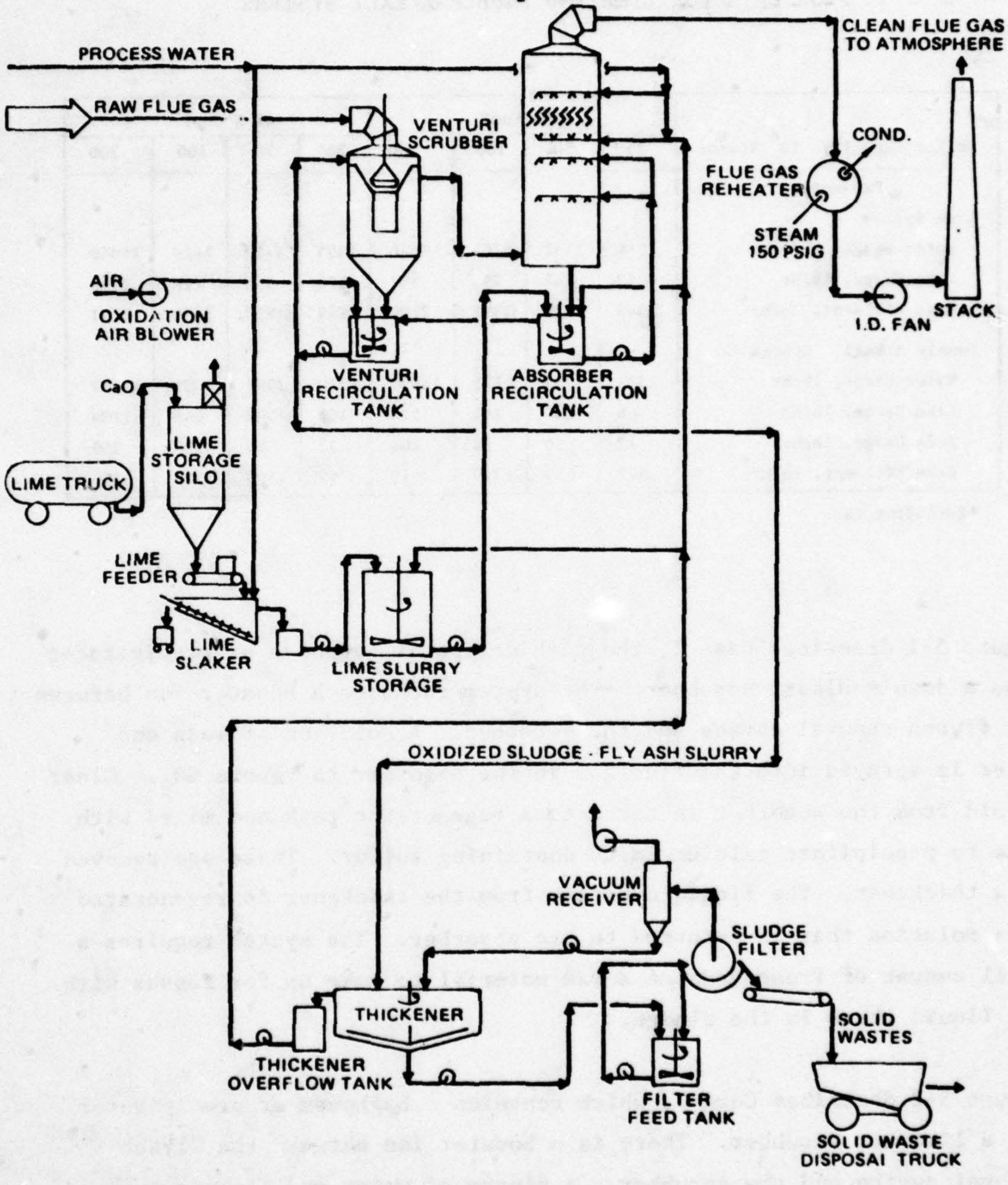


Figure 5-3

FLOW DIAGRAM OF FLUE GAS CLEANING SYSTEM, VENTURI SCRUBBER – LIME PROCESS WITH SLUDGE OXIDATION, JOINT REMOVAL OF FLY ASH AND SO_2

Table 5-2

FLOW DATA FOR LIME AND DOUBLE-ALKALI SYSTEMS

	2% S Coal				4% S Coal			
Boiler Capacity, 10^6 Btu/hr	25	50	100	200	25	50	100	200
Parameter								
Lime System								
Water Usage, lb/hr	1566	3132	6264	12528	1855	3710	7420	14840
Lime Usage, lb/hr	73	147	293	587	179	358	716	1432
Cake Effluent, lb/hr*	348	696	1391	2782	849	1698	3336	6791
Double Alkali System								
Water Usage, lb/hr	1531	3063	6125	12250	1770	3541	7081	14162
Lime Usage, lb/hr	66	132	264	528	161	322	645	1289
Soda Usage, lb/hr	13	26	53	106	32	64	129	258
Cake Effluent, lb/hr*	327	655	1310	2619	799	1598	3197	6393

*Excluding ash

Figure 5-1 describes Case 1, the combination of baghouse or precipitator plus a double-alkali scrubber. The system includes a booster fan between the flyash removal device and the scrubber. A solution of soda and water is sprayed into the flue gas in the absorber to remove SO_2. Clear liquid from the absorber is taken to a regenerator tank and mixed with lime to precipitate calcium salts containing sulfur. These are removed in a thickener. The liquid overflow from the thickener is regenerated soda solution that is returned to the absorber. The system requires a small amount of fresh soda as a raw material to make up for losses with the liquid phase in the sludge.

Figure 5-2 describes Case 2, which contains a baghouse or precipitator and a lime wet scrubber. There is a booster fan between the flyash removal device and the scrubber. A slurry of water and lime is sprayed into the flue gas in the absorber to remove SO_2. Special equipment is necessary to prevent plugging and erosion by the lime solids in the absorber. The slurry underflow is pumped to a thickener to remove the solid calcium salts containing sulfur.

Figure 5-3 describes Case 3, which uses lime scrubbing for simultaneous removal of flyash and SO_2. It has a Venturi scrubber followed directly by the spray tower absorber. The system includes an induced draft fan ahead of the stack. The slurry underflow from the absorber contains flyash as well as calcium salts that contain sulfur.

No case was considered with simultaneous removal of flyash and SO_2 by a double-alkali system, since a principal purpose in the development of the double-alkali system was to avoid suspended solids in the absorber.

Quotations on double-alkali scrubbers were provided by FMC. Research Cottrell (offering Bahco scrubbers) and Envirotech provided quotations on lime scrubbers. Both Case 2 and Case 3 designs would be available from either of the latter two vendors.

BAGHOUSE/DOUBLE-ALKALI SYSTEM DETAILS

The recommended system contains the following components shown in Figure 5-1:

- Baghouse, which removes flyash from the flue gas as it passes through a system of filters
- Absorber, which provides contact between flue gases and soda ash and lime bearing liquor so that SO_2 in the flue gas can be absorbed. The liquor enters at the top of the vessel and leaves at the bottom. Gas enters at the bottom and leaves at the top
- Mist eliminator, which is usually located in the upper portion of the absorber vessel, and removes entrained scrubbing liquor from the cleaned flue gases. Most of the makeup water is added here

- Lime and soda receiving storage and mixing system. Lime and soda are received from trucks and stored in silos, then mixed with liquor that is to be regenerated

- Dewatering thickener and vacuum filter system to reduce moisture content of the sludge, and facilities to mix the flyash and sludge to ready it for disposal

- Booster fan to drive flue gas through the FGD system to the stack

- Cleaned-gas reheater, to restore gas buoyancy lost by evaporative cooling in the absorber

The sludge produced by the air pollution control system contains the following constituents:

- Calcium sulfite hemihydrate, $CaSO_3 \cdot 0.5H_2O$. This is the major sludge component formed. Since it is considered a pollutant, a pond at the final waste disposal site must be lined and runoff water must be collected and treated. This compound does not give good sludge consistency

- Calcium sulfate dihydrate, $CaSO_4 \cdot 2H_2O$. This compound is called gypsum. It is inert, and therefore nonpolluting. It improves the consistency of sludge, allowing it to be handled as a loose solid that can be stacked, rather than as a fluid

- Sodium salts, Na_2SO_3 and Na_2SO_4

- Ash, which improves the solid consistency of the sludge

- Liquor, a solution of sodium salts in water that remains mixed with the solids after filtration

The sludge properties used in computing raw material and sludge haul requirements are as follows:

- Sulfur in the sludge is distributed in the following molar ratios:

  - 54 percent as $CaSO_3 \cdot 0.5H_2O$ (solid)

  - 36 percent as $CaSO_4 \cdot 2H_2O$ (solid)

- 6 percent as $NaSO_3$ (dissolved)
- 4 percent as $NaSO_4$ (dissolved)

- Solid impurities from the lime are 5 percent of the lime feed
- The liquor (water plus dissolved sodium salts) forms 50 weight percent of the sludge before mixture with ash
- The density of the sludge is roughly 100 pounds per cubic foot
- Flyash and boiler bottom ash are mixed with the sludge before disposal

AIR POLLUTION CONTROL CAPITAL COSTS

A preliminary assessment of flue gas desulfurization economics indicates that the overall cost of cleanup systems does not vary much between options. The baghouse/double-alkali system was selected as more flexible and easier to operate and maintain for Navy bases for coals requiring SO_2 removal. For coals requiring particulate removal only, baghouses alone have been priced.

The cleanup systems priced in this section are as follows:

- Single train cleanup systems are provided for single decentralized boilers with capacities from 25 to 200 x 10^6 Btu/hr
- Two parallel 60-percent capacity cleanup systems are provided for central plants with multiple boilers with combined capacities from 100 to 800 x 10^6 Btu/hr

Costs presented here have been developed from data provided by Envirotech, FMC, and Research Cottrell for a typical U.S. site. Factors which may make costs differ from those at a specific site are the following:

- Boiler configuration
- Availability of space for the cleanup system

- Availability and cost of raw materials
- Availability and cost of utilities

The total construction costs, with indirect costs, engineering services, and 20 percent contingency included, are shown in Table 5-3 for the single-train baghouse and double-alkali cleanup system. A similar breakdown of costs for the two 60-percent capacity train system is displayed in Table 5-4. Parametric cost versus capacity and gas flow curves are provided in Figure 5-4 for both systems.

For all estimates, balance-of-plant items such as foundations, site preparation, and interconnecting bulk materials have been added to the vendor-supplied costs for equipment plus installation to form a complete cleanup facility.

OPERATING AND MAINTENANCE COSTS

The annual requirements for FGD raw materials are shown in Table 5-5. These were computed using Table 5-2 and the load factor of 33 percent defined in Section 3.

Operating manpower requirements for cleanup systems for decentralized and central plants are shown in Table 5-6.

Tables 5-7 and 5-8 display estimated annual labor and material costs for operating and maintenance. The total costs are plotted in Figure 5-5 for the systems using coal with two and four percent sulfur.

DESIGNS FOR ALTERNATIVE STANDARDS

All coal-fired boilers under consideration in this study are smaller than the minimum size unit subject to the EPA emission controls. However,

Table 5-3

TOTAL CONSTRUCTION COSTS, AIR POLLUTION CONTROL SYSTEMS FOR SINGLE DECENTRALIZED BOILERS

	0.5% S Coal				2% S Coal				4% S Coal			
Boiler Capacity, 10^6 Btu/hr	25	50	100	200	25	50	100	200	25	50	100	200
Cost Item*												
Baghouse												
Equipment	30	50	80	110	30	50	80	110	30	50	80	110
Labor	20	30	50	70	20	30	50	70	20	30	50	70
Subtotal	50	80	130	180	50	80	130	180	50	80	130	180
Scrubber												
Equipment	-	-	-	-	630	800	1250	2060	660	970	1700	2700
Labor	-	-	-	-	540	740	1150	1890	610	870	1500	2450
Subtotal	-	-	-	-	1170	1540	2400	3950	1270	1840	3200	5150
Total Construction Cost	50	80	130	180	1220	1620	2530	4130	1320	1920	3330	5330

*Thousands of dollars, second quarter, 1978 prices.

Table 5-4

TOTAL CONSTRUCTION COSTS, AIR POLLUTION CONTROL SYSTEMS FOR CENTRAL BOILER PLANTS

	0.5% S Coal				2% S Coal				4% S Coal			
Boiler Capacity, 10^6 Btu/hr	100	200	400	800	100	200	400	800	100	200	400	800
Cost Item*												
Baghouse												
Equipment	120	170	310	430	120	170	310	430	120	170	310	430
Labor	80	130	190	270	80	130	190	270	80	130	190	270
Subtotal	200	300	500	700	200	300	500	700	200	300	500	700
Scrubber												
Equipment	-	-	-	-	1620	2540	4160	6690	1940	3020	4640	7810
Labor	-	-	-	-	1480	2360	3840	6210	1760	2780	4260	7190
Subtotal	-	-	-	-	3100	4900	8000	12900	3700	5800	8900	15000
Total Construction Cost	200	300	500	700	3300	5200	8500	13600	3900	6100	9400	15800

*Thousands of dollars, second quarter, 1978 prices.

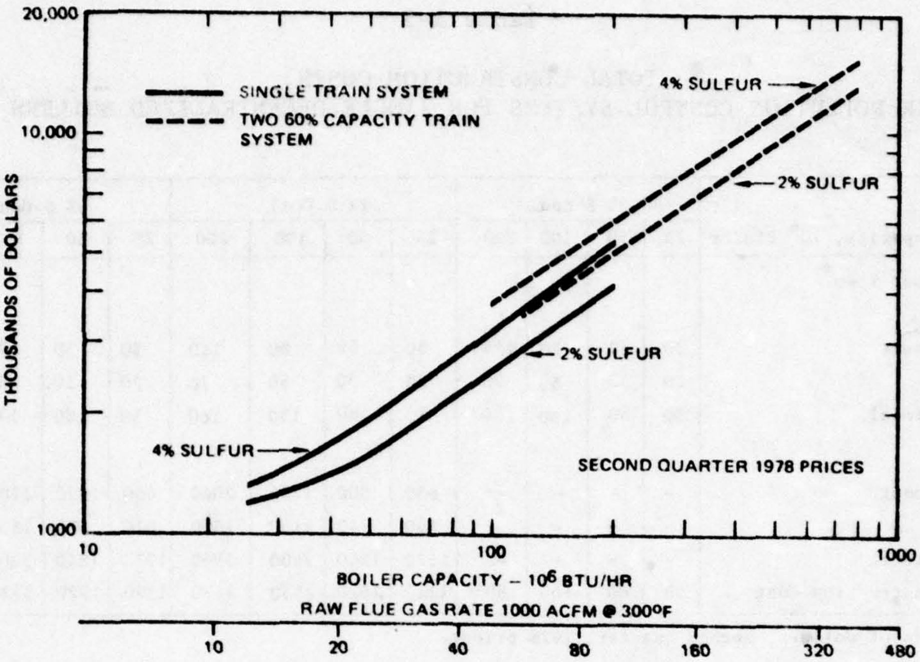


Figure 5-4
TOTAL CONSTRUCTION COSTS,
AIR POLLUTION CONTROL SYSTEMS FOR 2% AND 4% S COAL

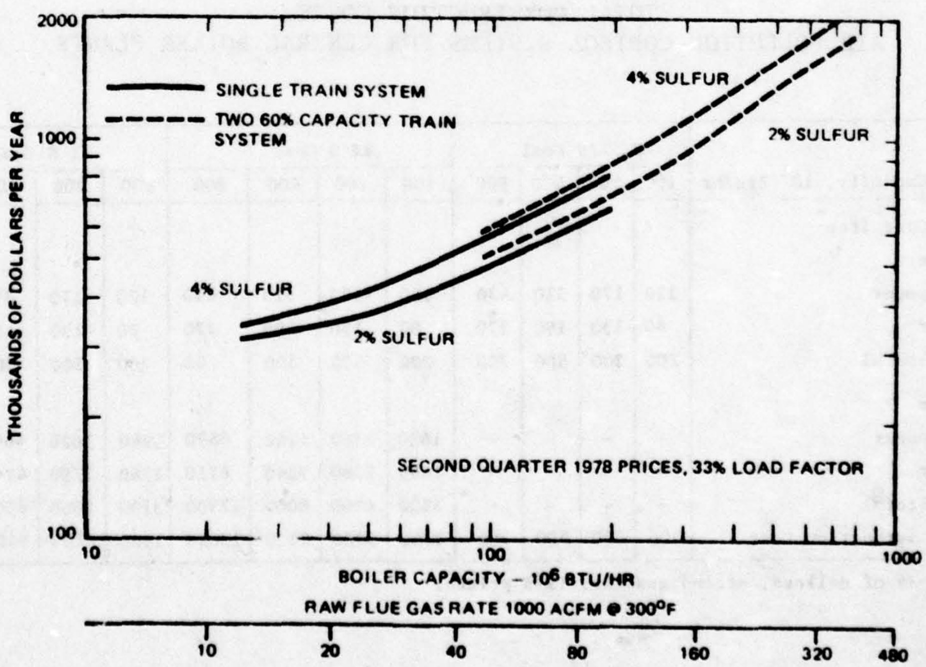


Figure 5-5
OPERATING AND MAINTENANCE COSTS,
AIR POLLUTION CC.. 'ROL EQUIPMENT FOR 2% AND 4% S COAL

Table 5-5

ANNUAL RAW MATERIAL AND UTILITY REQUIREMENTS, DOUBLE-ALKALI FGD SYSTEMS (33% Load Factor)

Coal % S	Boiler Plant Capacity 10^6 Btu/hr	Lime, Tons	Soda, Tons	Water, 10^3 gal	Electricity, kWh
2	25	100	20	540	90
2	50	190	40	1080	180
2	100	380	80	2170	350
2	200	760	150	4340	710
2	400	1530	300	8670	1420
2	800	3060	600	17340	2830
4	25	230	50	620	90
4	50	460	90	1230	180
4	100	930	190	2460	350
4	200	1860	370	4920	710
4	400	3770	750	9850	1420
4	800	7450	1490	19700	2830

Table 5-6

OPERATING MANPOWER, AIR POLLUTION CONTROL SYSTEMS

SINGLE DECENTRALIZED BOILERS		
Boiler Capacity 10^6 Btu/hr	Men Employed	
	0.5% S Coal	2 and 4% S Coal
25	0.5	5.6
50	0.5	5.6
100	0.5	7.0
200	0.5	7.0

CENTRALIZED BOILER PLANTS		
Combined Capacity 10^6 Btu/hr	Men Employed	
	0.5% S Coal	2 and 4% S Coal
100	2.0	7.0
200	2.0	7.0
400	2.0	12.0
800	2.0	12.0

Table 5-7

ANNUAL OPERATING AND MAINTENANCE COSTS, AIR POLLUTION CONTROL SYSTEMS FOR SINGLE DECENTRALIZED BOILERS

Coal %S	Boiler Capacity 10^6 Btu/hr	Thousands of Dollars*			
		Chemicals	Other Materials	Labor	Total Annual O&M
0.5	25	–	5	30	35
0.5	50	–	5	50	55
0.5	100	–	10	90	100
0.5	200	–	20	150	170
2	25	5	65	250	320
2	50	10	90	260	360
2	100	25	155	340	520
2	200	50	260	370	680
4	25	15	65	260	340
4	50	30	100	270	400
4	100	60	170	360	590
4	200	120	280	400	800

Table 5-8

ANNUAL OPERATING AND MAINTENANCE COSTS, AIR POLLUTION CONTROL SYSTEMS FOR CENTRAL BOILER PLANTS

Coal %S	Combined Capacity 10^6 Btu/hr	Thousands of Dollars*			
		Chemicals	Other Materials	Labor	Total Annual O&M
0.5	100	–	5	30	35
0.5	200	–	5	50	35
0.5	400	–	10	90	100
0.5	800	–	10	90	100
2	100	25	145	350	520
2	200	50	250	390	690
2	400	100	480	630	1210
2	800	200	850	730	1780
4	100	60	170	370	600
4	200	120	270	410	800
4	400	240	480	640	1360
4	800	480	870	770	2120

*Second quarter 1978 prices, 33 percent load factor.

the emissions may be subject to local regulations. For the purpose of this study, it is assumed that the installations will have to meet one of the following emissions standards:

- The same standards as those imposed by the EPA New Source Performance Standard (NSPS) for boilers firing more than 250×10^6 Btu/hr of coal
  - Particulate emissions must not exceed 0.1 lb/10^6 Btu of heat input
  - Opacity must not exceed 20 percent
  - SO_2 emissions must not exceed 1.2 lb/10^6 Btu of heat input
- California South Coast District regulations which:
  - Prohibit use of coal containing more than 0.5 percent sulfur without providing an SO_2 emission abatement system
  - Require application of the best emission abatement technology for all sources of potential emissions exceeding 15 lb/hr or 150 lb/day of any pollutant whose ambient concentration is restricted
- A local regulation that limits SO_2 emissions to the equivalent of unabated emission from a boiler firing 1 percent sulfur coal with a higher heating value of 13,000 Btu/lb on a moisture-free basis

Local regulations that merely extend the EPA emission abatement requirements to smaller boilers are not likely to present any process design difficulties. Most systems have in fact been developed to meet such requirements, and considerable experience has been amassed with their industrial performance for the concurrent removal of flyash and SO_2. However, the mechanical design of equipment for an FGD system for use on small single boilers may require further development. The existing mechanical designs were developed for use on large industrial or utility boilers. Boilers with capacities of 25 to 100×10^6 Btu/hr require smaller installations similar to various pilot plants tested in the past; but these may not have been designed for a long operating life in an industrial environment.

The *California South Coast* District regulations are more severe than the current EPA NSPS and require the use of systems with high particulate and SO_2 removal capacity. In the South Coast District area, multistage absorbers for SO_2 removal may be necessary to meet the local requirements.

The local regulations that require SO_2 emission reductions to the equivalent of unabated emissions from the combustion of one percent sulfur coal are less stringent than the EPA emission limitations. In this case, standard types of emission control systems will be more than adequate.

SENSITIVITY TO OFF-DESIGN CONDITIONS

The response and sensitivity to off-optimum or off-design conditions is not considered a problem for the baghouse/double-alkali cleanup system. The particulate removal *and* SO_2 *cleanup equipment* have large reserve capacities and will operate over a sufficiently wide range of coal ash and sulfur contents so that the full range of U.S. coals could be burned.

As described in later sections, changes in conditions will affect operating costs because, as more ash and sludge are created, they will require disposal, and, as sulfur increases, more soda and lime chemicals will have to be consumed to clean the flue gas.

The baghouse and double-alkali system is relatively insensitive to changes in operating conditions. The major criterion affecting baghouse conditions is that the flue gas discharge temperature be maintained below 550°F to control filter fabric deterioration.

The double-alkali wet-scrubbing process requires removal of flyash prior to admitting the flue gas to the scrubber. If flyash is added to the sorbent solution, problems of erosion and equipment plugging are likely.

Discussions with vendor representatives confirm that a single scrubber is capable of a 4 to 1 maximum turndown ratio.

EFFECT OF COAL COMPOSITION

The major items of coal composition affecting the air pollution control system are the quantity of flyash and the sulfur content. Capital costs of baghouses are proportional to flue gas quantity, and thus capital costs are insensitive to the actual quantity of flyash. Operation of the baghouse is more strongly affected by the quantity of ash; more filter cleaning steps are required as waste from a high-ash coal collects at a faster rate.

While the quantities of flue gas are proportional to boiler capacity and independent of coal sulfur content, the required SO_2 removal does vary with sulfur content. For the range studied, the amount of sulfur does not affect scrubber size or design, but does affect operating costs. Because better removal is required for high-sulfur coals, more chemicals must be used and more waste is created which must be disposed of. The cost of double alkali scrubber chemicals as a function of coal sulfur level is shown in Figure 5-6.

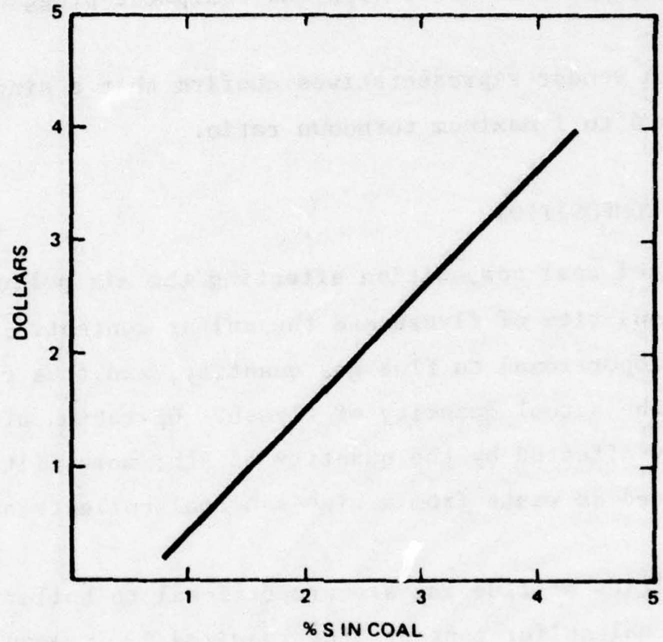


Figure 5-6
SCRUBBER CHEMICAL COSTS PER TON OF COAL BURNED

Section 6

STEAM TRANSMISSION

A major expense for any new heating or process steam system is the transmission piping required to deliver the energy to users and return condensate to the steam generation plant.

This section treats the following types of piping systems for transmission of saturated steam:

- Aboveground insulated pipelines resting on concrete and steel supports
- Buried insulated pipelines enclosed in concrete conduits

Methods are given for computing costs of steam piping systems over the following ranges of design parameters:

- Inlet pressures of 150, 300, and 600 psia
- Mass flow rates between 10^3 and 10^6 lb/hr
- Lengths between 10^2 and 10^5 feet
- Insulation thicknesses of 2, 5, and 8 inches

MATERIAL SELECTION

Carbon steel pipe was selected for all installations. The ASTM pipe schedule to be used depends primarily on steam pressure, as shown in Appendix B. Schedules 20 and 30 pipes are available only for larger pipe diameters. Table 6-1 indicates schedules to be selected.

Table 6-1

RECOMMENDED CARBON STEEL PIPE SCHEDULES

Pressure (psia)	Actual Pipe Inside Diameter	Schedule
600	All diameters	40
300	Less than 12 inches	40
	12 inches and greater	30
150	Less than 16 inches	40
	16 inches and greater	20

INSTALLATION

A typical aboveground steam pipe support system is shown in Figure 6-1. Forty-foot sections of carbon steel pipe are laid along a prepared right of way, welded into larger sections, and placed on the supports. The pipe welds are X-rayed in place and insulation and a protective aluminum weather jacket are installed.

A typical buried pipeline is also shown in Figure 6-1. Similar to the aboveground system, carbon steel pipe is laid along a prepared right of way and trench. The pipe is welded above ground, X-rayed, and insulation and jacketing installed. The pipe is lowered into a concrete conduit, and the conduit is closed before the trench is backfilled. Excess dirt (spoil) is leveled and left along the right of way. Haulage and disposal of spoil may be necessary at some locations, but has not been included as part of this conceptual scheme.

Trench depths, conduit, and backfill requirements vary with the diameter of pipe. The concrete conduit is sized for the steam and condensate lines. Some representative sizes of conduits are:

Nominal Pipe Diameter (inches)	Conduit Inside Dimensions
30	4 ft square
16	2.5 ft square
4	2 ft square
2	1.33 ft square

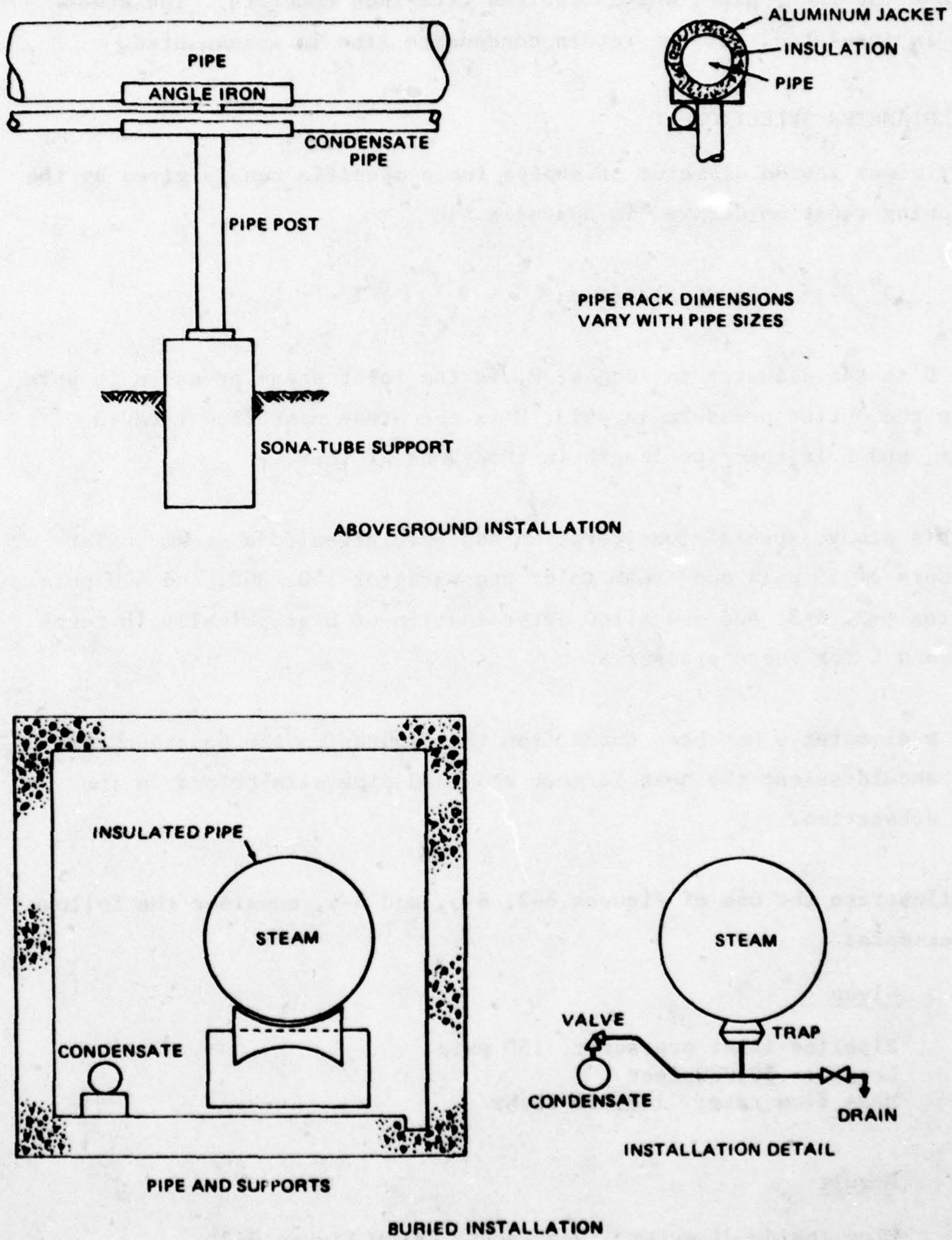


Figure 6-1
TYPICAL ABOVEGROUND AND BURIED STEAM PIPE INSTALLATION

The conduit is four-inch thick concrete for all cases except for the largest (30-inch) pipe, which requires five-inch concrete. The steam pipe is insulated, but the return condensate line is uninsulated.

PIPE DIAMETER SELECTION

The minimum inside diameter of a pipe for a specific run is given by the following equation derived in Appendix A:

$$D^{5.21} = [(0.00015)(460)/(P_i^{\,2} - P_o^{\,2})]\ \dot{M}^2 L$$

Here D is the diameter in inches, P_i is the inlet steam pressure in psia, P_o is the outlet pressure in psia, $\dot{M}$ is the steam mass flow rate in lb/hr, and L is the pipe length in thousands of feet.

In this study, special consideration has been given to a steam outlet pressure of 35 psia and steam inlet pressures of 150, 300, and 600 psia. Figures 6-2, 6-3, and 6-4 allow determination of D graphically in terms of $\dot{M}$ and L for these pressures.

Once a diameter D has been found from the figures on the equation, the user should select the next largest standard pipe size priced in the next subsection.

To illustrate the use of Figures 6-2, 6-3, and 6-4, consider the following example:

<u>Given</u>

Pipeline inlet pressure: 150 psia
Length: 30,000 feet
Mass flow rate: 100,000 lb/hr

<u>Result</u>

Pipe inside diameter: 9.5 inches (from Figure 6-2)

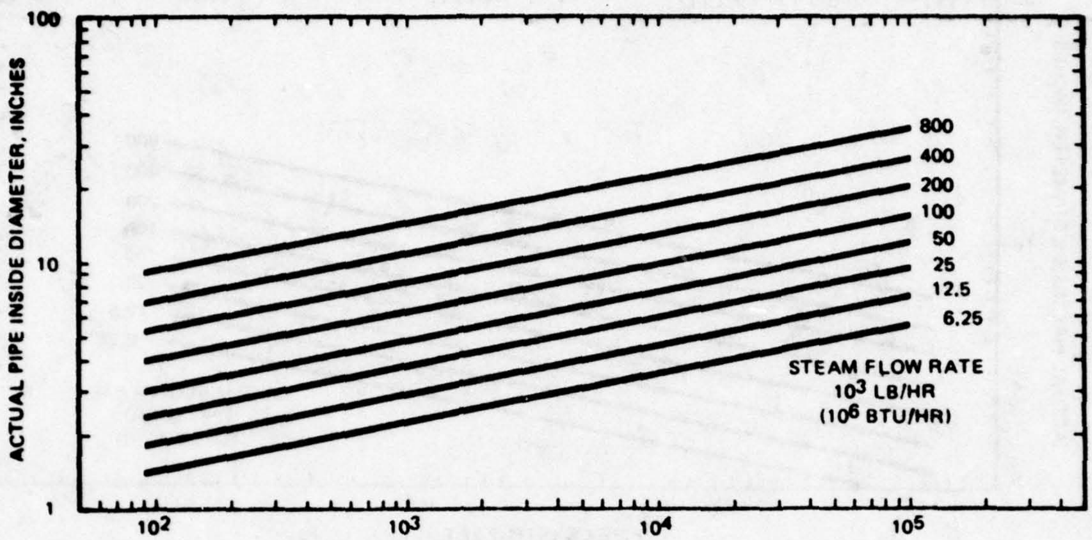


Figure 6-2
PIPE DIAMETER VERSUS LENGTH,
150 PSIA INLET AND 35 PSIA OUTLET PRESSURE

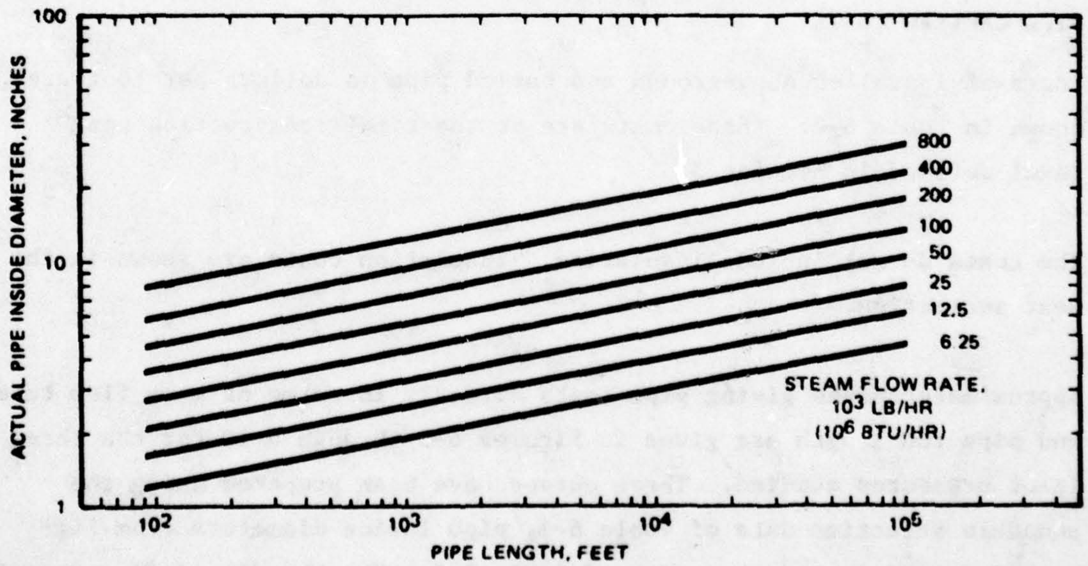


Figure 6-3
PIPE DIAMETER VERSUS LENGTH AND FLOW RATE,
300 PSIA INLET AND 35 PSIA OUTLET PRESSURE

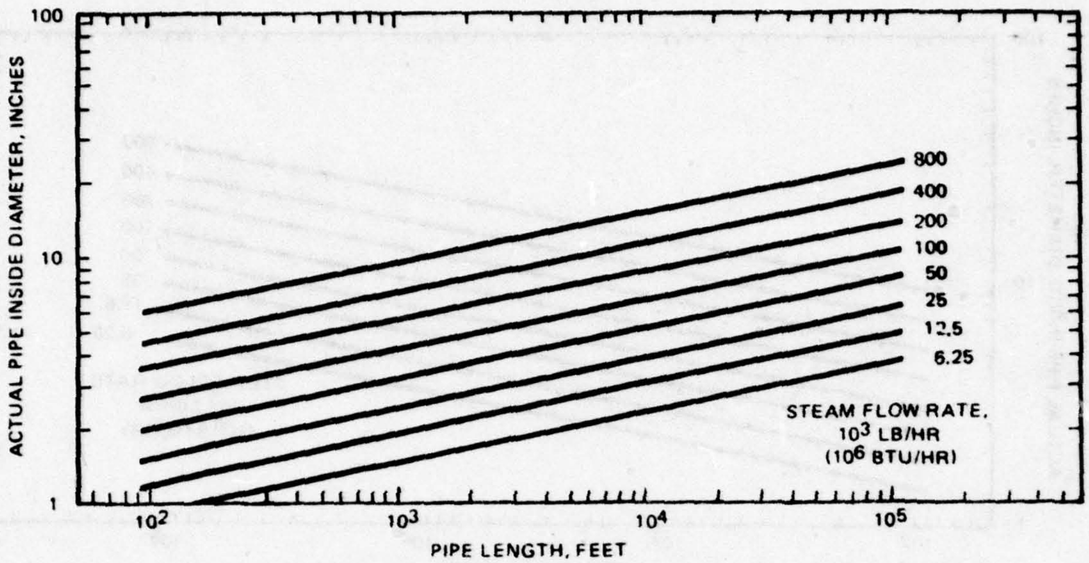


Figure 6-4

PIPE DIAMETER VERSUS LENGTH AND FLOW RATE,
600 PSIA INLET AND 35 PSIA OUTLET PRESSURE

PIPE CAPITAL COSTS

Costs of installed aboveground and buried pipe in dollars per foot are shown in Table 6-2. These costs are at the total construction cost level defined in Section 3.

The costs do not include insulation. Insulation costs are shown in the next subsection.

Approximate curves giving pipe costs directly in terms of mass flow rate and pipe run length are given in Figures 6-5 through 6-10 for the three inlet pressures studied. These curves have been prepared using the schedule selection data of Table 6-1, pipe inside diameters from Figures 6-2 to 6-4, and the costs of Table 6-2. The benefit of Figures 6-5 through 6-10 is that they give the costs directly as functions of the

Table 6-2

TOTAL CONSTRUCTION COSTS, ABOVEGROUND AND BURIED UNINSULATED STEAM PLUS CONDENSATE PIPES

Schedule	Nominal Pipe Diameter, inches	Actual Pipe Inside Diameter, inches	Costs,* Dollars per Foot	
			Aboveground	Buried
40	1	1.049	41.0	62.8
	2	2.067	45.3	68.2
	4	4.026	57.3	86.9
	6	6.065	83.8	114.6
	8	7.981	119.3	127.1
	10	10.020	131.4	139.1
	12	11.938	152.2	159.9
	16	15.000	201.9	232.1
	20	18.812	279.8	299.6
	24	22.624	330.8	350.7
	30	28.595	377.1	445.1
	36	34.500	417.9	486.0
30	12	12.090	146.4	149.1
	16	15.250	183.8	214.1
	20	19.000	256.8	299.1
	24	22.876	298.7	318.5
	30	28.750	312.9	380.9
	36	34.750	341.5	409.6
20	16	15.376	173.4	220.1
	20	19.250	236.1	255.9
	24	23.250	263.1	282.9
	30	29.000	296.7	374.2
	36	35.000	333.1	401.1

*Second quarter, 1978 price level

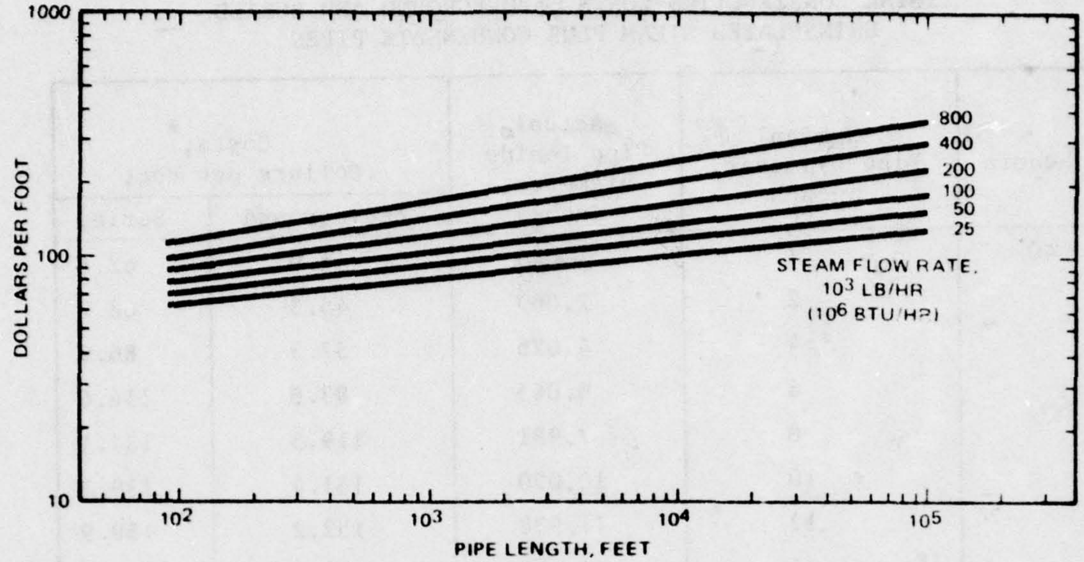


Figure 6-5
ABOVEGROUND PIPE COSTS VERSUS LENGTH AND FLOW RATE, 150 PSIA INLET AND 35 PSIA OUTLET PRESSURE

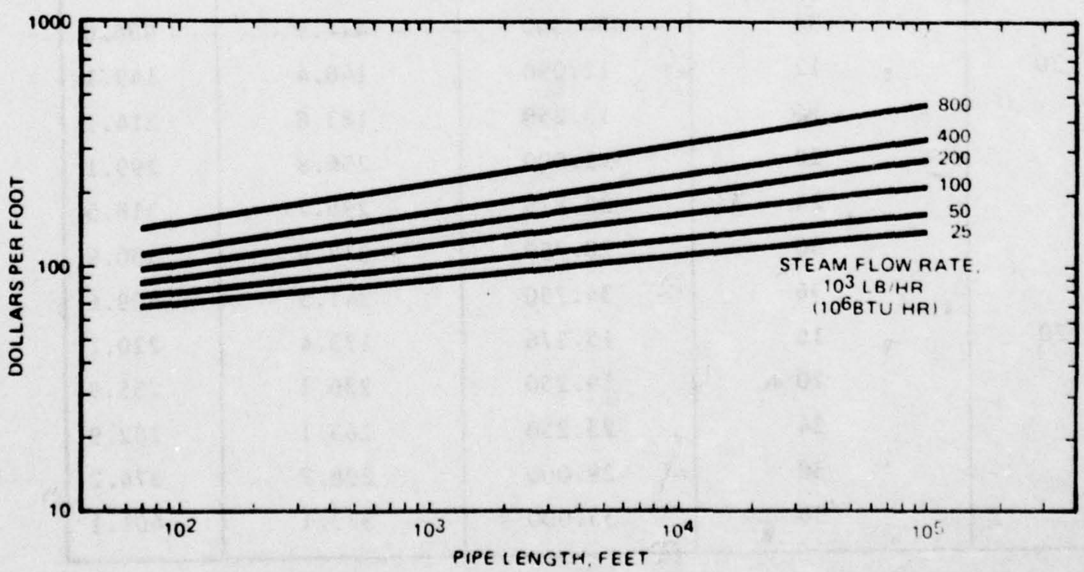


Figure 6-6
BURIED PIPE COSTS VERSUS LENGTH AND FLOW RATE, 150 PSIA INLET AND 35 PSIA OUTLET PRESSURE

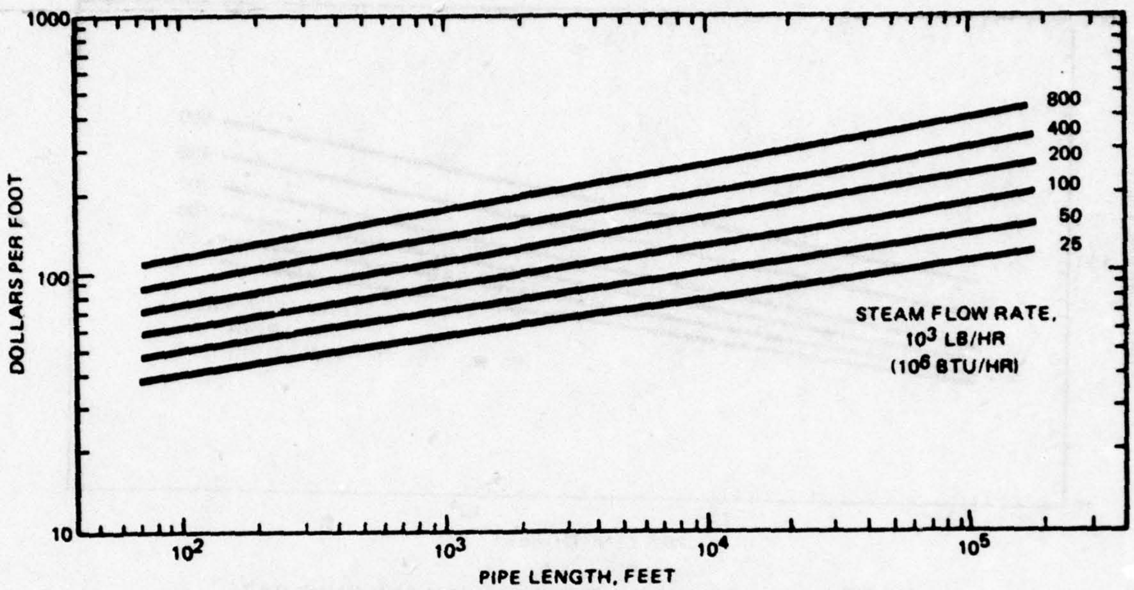


Figure 6-7
ABOVEGROUND PIPE COSTS VERSUS LENGTH AND FLOW RATE, 300 PSIA INLET AND 35 PSIA OUTLET PRESSURE

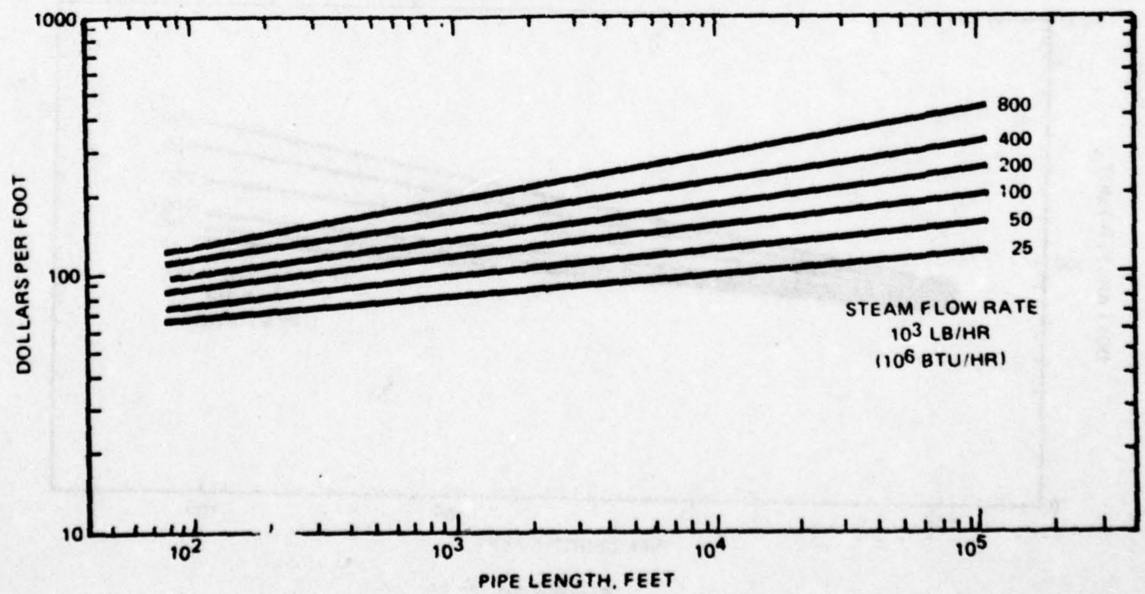


Figure 6-8
BURIED PIPE COSTS VERSUS LENGTH AND FLOW RATE, 300 PSIA INLET AND 35 PSIA OUTLET PRESSURE

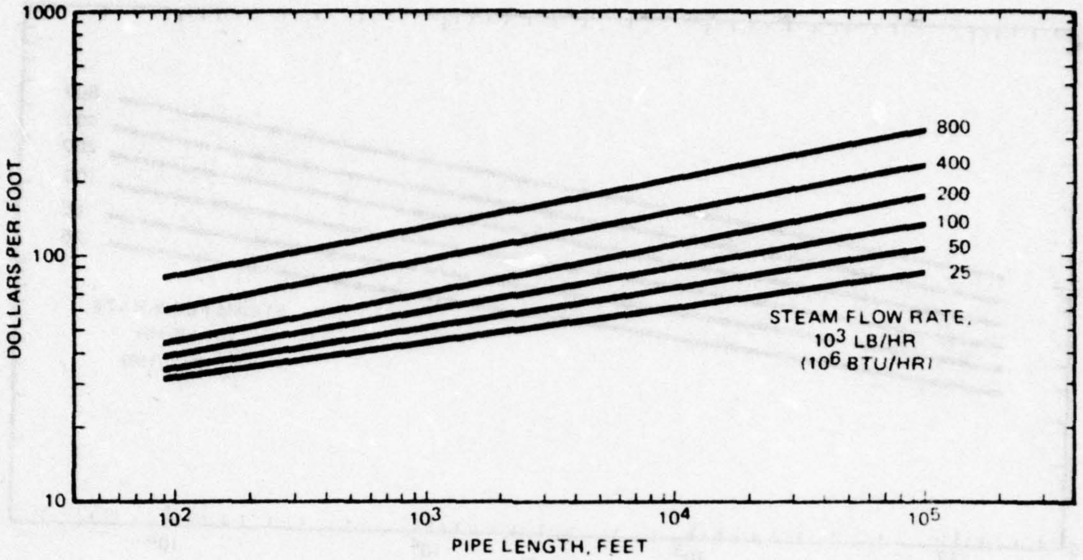


Figure 6-9
ABOVEGROUND PIPE COSTS VERSUS LENGTH AND FLOW RATE, 600 PSIA INLET AND 35 PSIA OUTLET PRESSURE

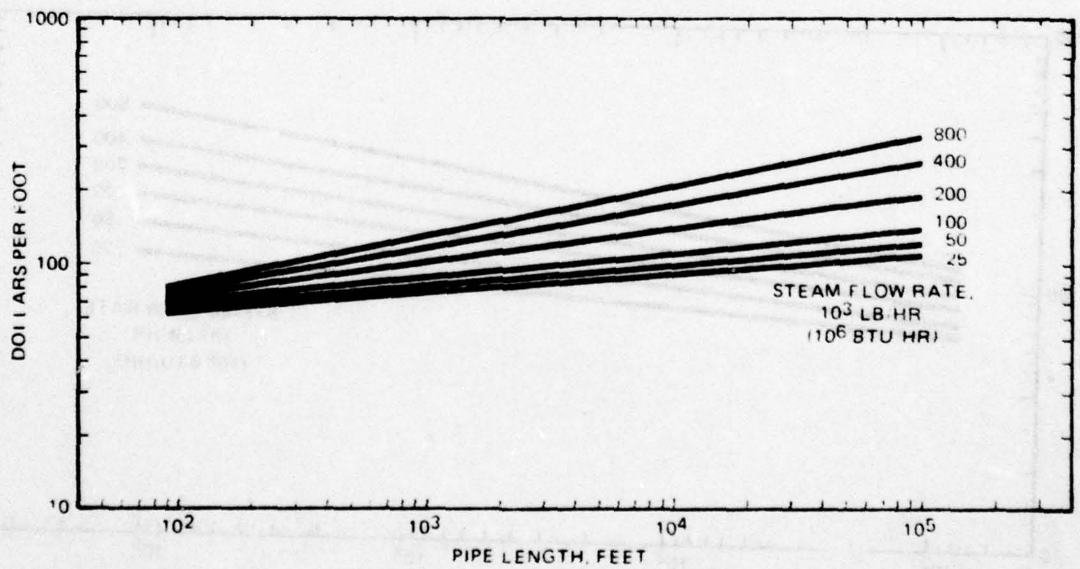


Figure 6-10
BURIED PIPE COSTS VERSUS LENGTH AND FLOW RATE, 600 PSIA INLET AND 35 PSIA OUTLET PRESSURE

design parameters $\dot{M}$ and L without diameter as an intermediate variable. Figures 6-5 to 6-10 use straight lines to approximate the actual step-wise cost curves that are obtained when pipe sizes are selected exactly. Any cost from these figures should deviate no more than ±25 percent from the correct cost, and errors in the costs of several pipes in a given system should compensate when the costs are summed.

To illustrate the use of the cost data, continuing with the same example just used for diameter calculation:

Given

Pipeline type: Aboveground

Results (by detailed calculation)

Pipe schedule: 40 (from Table 6-1)
Next highest nominal diameter: 10 inches
Cost: \$131.40 per foot (from Table 6-2)

Results (by Figure 6-5)

Cost: \$120 per foot

INSULATION COSTS

The cost of insulation as a function of pipe nominal diameter is given in Table 6-3. It was assumed that certain insulation thicknesses would not be used on certain pipe sizes as a practical matter, for example five inches of insulation on a two-inch pipe. The costs are also shown in Figure 6-11. Aluminum protective jackets used to cover insulation for aboveground and buried systems are included in the costs. The insulation cost must be added to the cost determined for pipe on earlier graphs to price a system.

TOTAL PIPING SYSTEM PRICING

Figure 6-12 provides a situation which includes calculation of costs of both pipe and insulation for more than one pipeline. In Figure 6-12,

Table 6-3

TOTAL COSTS, INSULATION PLUS PROTECTIVE JACKET
(Dollars per Foot*)

Pipe Nominal Diameter, Inches	Insulation Thickness, Inches 2	5	8
1	11.0		
2	14.7		
4	20.1		
6	24.5		
8	27.8		
10	34.4	60.4	
12	36.8	80.6	
16	49.1	95.6	110.3
20	61.2	125.0	136.7
24	64.6	153.9	165.6
30	73.3	164.2	207.6
36	84.3	195.4	247.0

*Second quarter, 1978 level

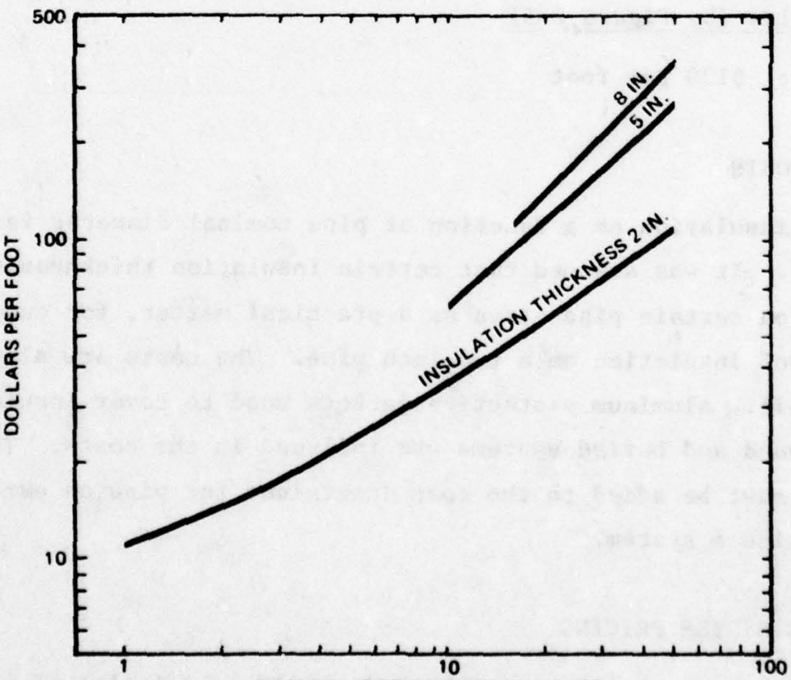
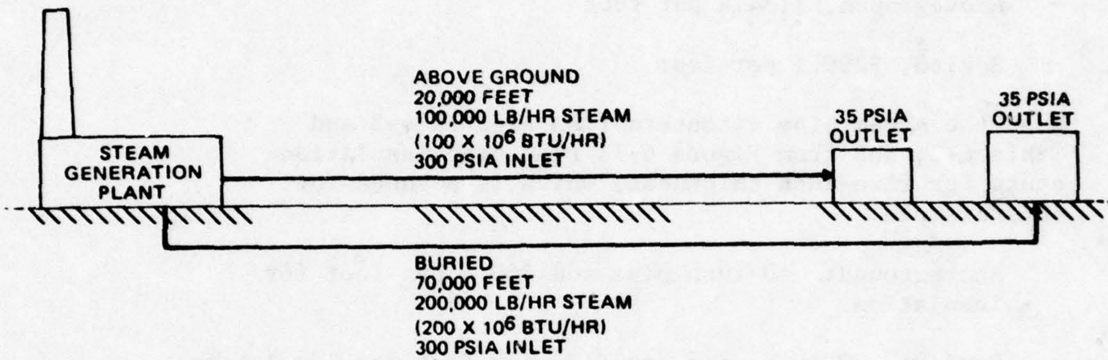


Figure 6-11
INSULATION COST VS PIPE DIAMETER AND INSULATION THICKNESS



	COST (DOLLARS)
ABOVE GROUND	
(1) PIPE, 20,000 FEET AT \$131.4/FOOT	2,628,000
(2) INSULATION AT \$60.4/FOOT	1,208,000
(3) SUBTOTAL	3,836,000 (192/FOOT)
BURIED	
(4) PIPE, 70,000 FEET AT \$299.1/FOOT	20,937,000
(5) INSULATION AT \$125/FOOT	8,750,000
(6) SUBTOTAL	29,687,000 (424/FOOT)
(7) TOTAL	33,523,000 (373/FOOT)

(1) COST FROM FIGURE 6-7

(2) PIPE DIAMETER OF 10" FROM FIGURE 6-3 AND TABLE 6-2; COST FROM FIGURE 6-11 (5" THICKNESS ASSUMED)

(4) COST FROM FIGURE 6-8

(5) PIPE DIAMETER OF 20" FROM FIGURE 6-3 AND TABLE 6-2; COST FROM FIGURE 6-11 (5" THICKNESS ASSUMED)

(7) SUM OF (3) AND (6)

Figure 6-12
SAMPLE STEAM DISTRIBUTION CONFIGURATION

two points are to be supplied with steam from a plant. The following steps are necessary to estimate steam distribution costs:

- From Figures 6-7 and 6-8, select the cost of pipe for aboveground and buried piping, from the intersection of distance and demand requirements (mass flow):

  - Aboveground, \$134.4 per foot

  - Buried, \$299.1 per foot

- Read the steam pipe diameters from Figures 6-3 and Table 6-2, and from Figure 6-11 read pipe insulation costs for five-inch thickness, which is assumed for this example

  - Aboveground: 10-inch pipe and \$60.4 per foot for insulation

  - Buried: 20-inch pipe and \$125 per foot for insulation

The cost data in this section can be used to estimate more complex piping systems than runs of single-diameter pipe. However, the method becomes more complex when steam is directed from the main line to secondary demand points and the line diameters (and thus cost) change over the length of the line. Estimating costs for more complex systems requires calculation of mass flows and inlet steam pressures at various points in the more complex system. A method to estimate such costs is shown in the Handbook, Section 10.

HEAT LOSSES FROM INSULATED PIPE

The insulation thickness chosen for a given pipeline should be the result of a tradeoff study between the cost of insulation and the cost of heat losses. Methods for calculating heat losses from pipes under various conditions are given in Appendix C. Figures 6-13 and 6-14 present heat losses for buried and aboveground pipe under typical conditions.

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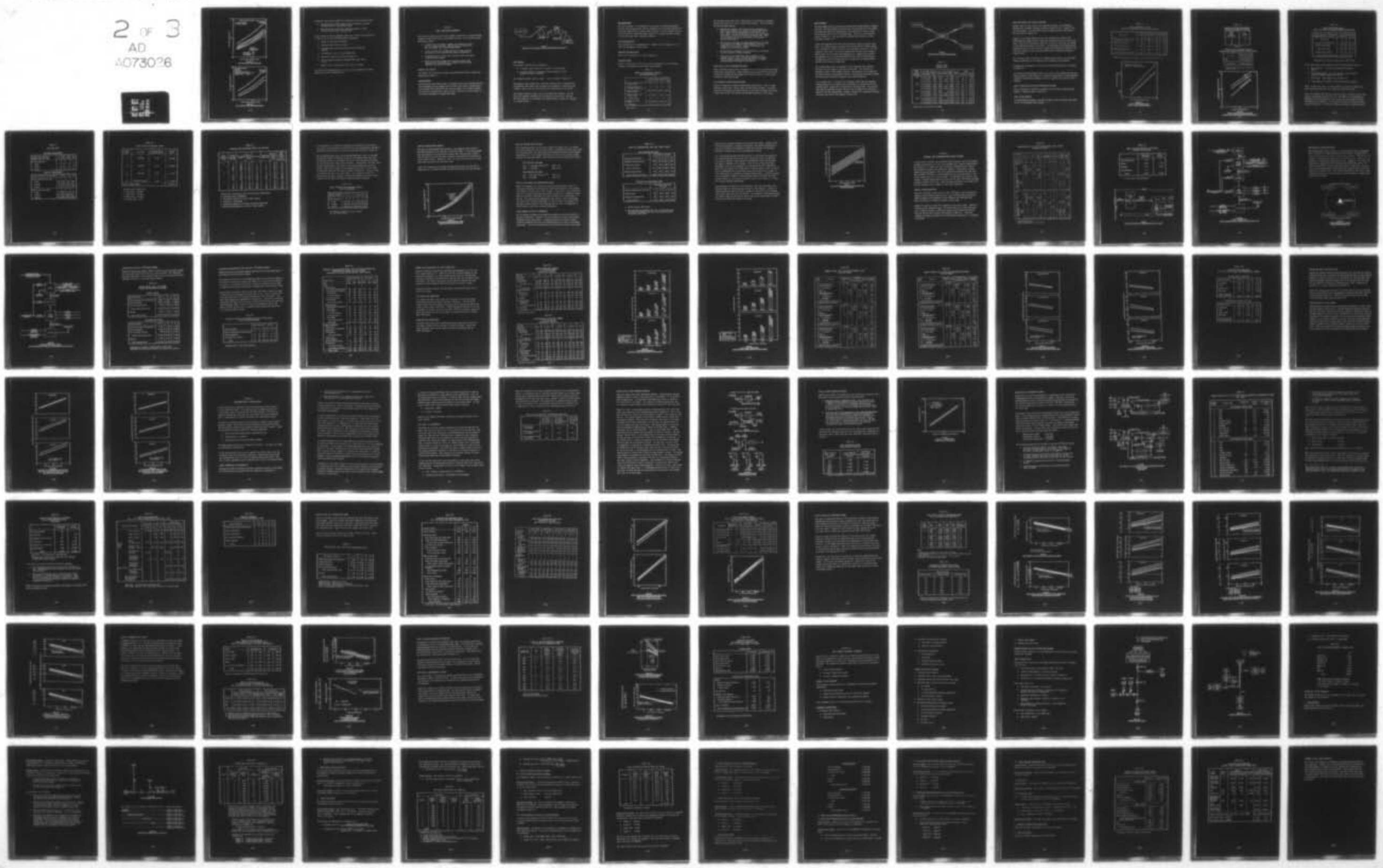

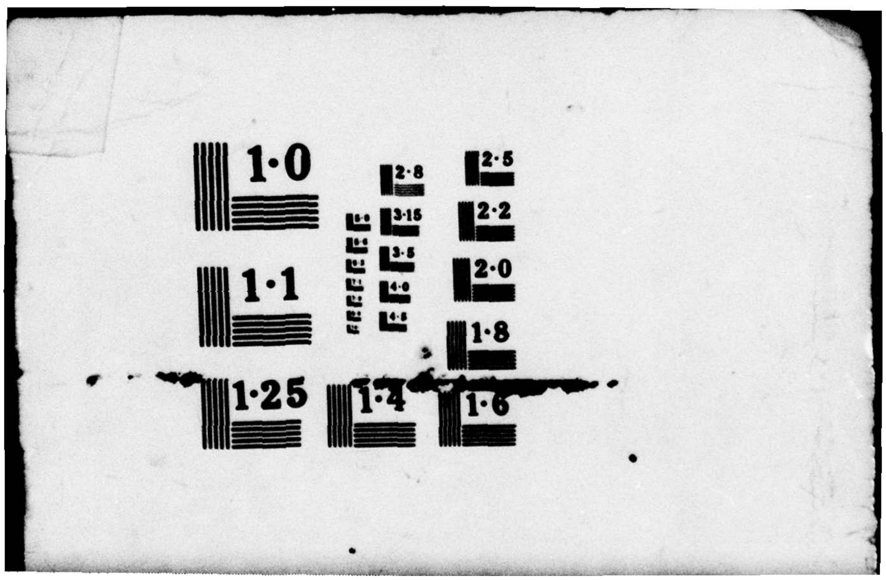
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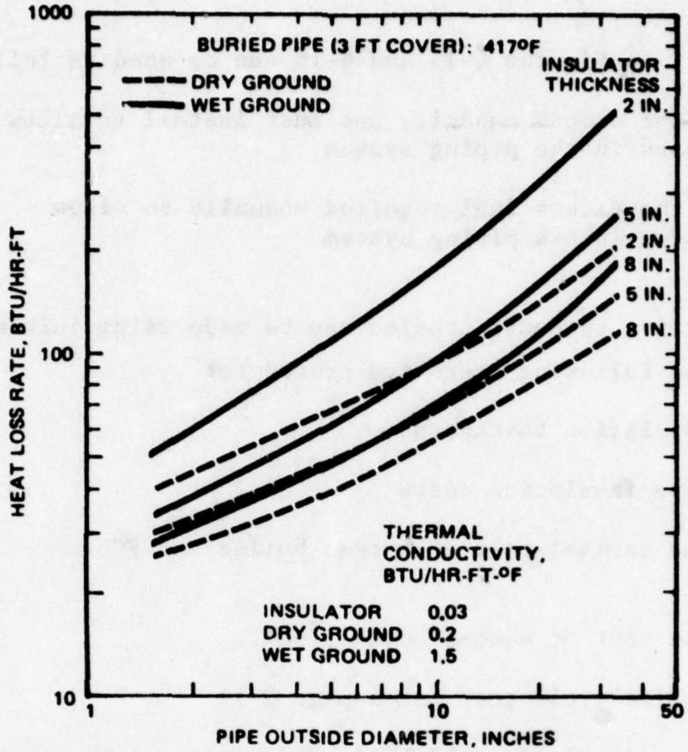

Figure 6-13

HEAT LOSS RATE FOR BURIED PIPE

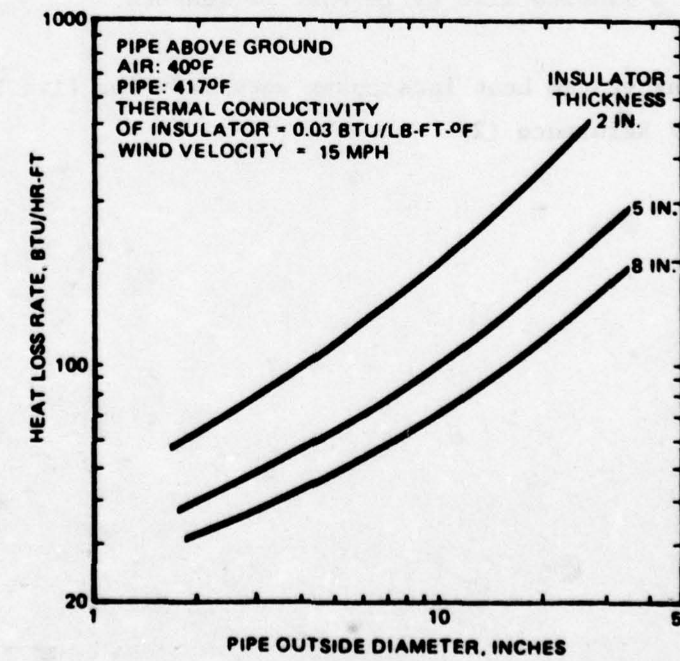

Figure 6-14

HEAT LOSS RATE FOR ABOVEGROUND PIPE

Information like that in Figures 6-13 and 6-14 can be used as follows:

- Calculating the excess capacity one must install to allow for heat losses in the piping system

- Calculating the excess fuel required annually to allow for heat losses in the piping system

Piping system insulation tradeoff studies can be made using information in this report by the following iterative procedure:

1. Assume an insulation thickness

2. Calculate pipe insulation costs

3. Calculate the capital cost of excess boiler and FGD capacity

4. Calculate the cost of excess annual fuel

5. Calculate a life cycle cost as on page 3-11

6. Revise assumed insulation thickness and repeat steps 2 to 5

7. Repeat until a minimum life cycle cost is reached

Calculations of piping system heat loss costs were made for five Navy bases in the study of Reference (2).

Section 7

COAL AND WASTE HANDLING

This section contains technical and economic information on solids handling systems for both central and decentralized concepts. The following system description covers:

- A central coal receiving, storage, and preparation facility at a single location. This facility is required for both the central and decentralized plants.
- A minor facility for storage and feed to each decentralized boiler in the decentralized system configuration.
- Transportation of coal by truck from the central stockpile to decentralized plants.
- Removal of ash and sludge waste from both central and decentralized steam plants to a temporary waste holding terminal near the base boundary.

CENTRAL COAL FACILITY

The central coal receiving, storage, and preparation system is shown schematically in Figure 7-1.

Coal Receiving

Coal arriving at the base by rail is unloaded in the coal receiving facility. Bottom-dumping cars are emptied into an under-track hopper equipped with a belt conveyor that carries the coal from the hopper to a storage conveyor. The hopper and conveyors are sized so that a train with a week's supply of coal can be unloaded in a single work shift.

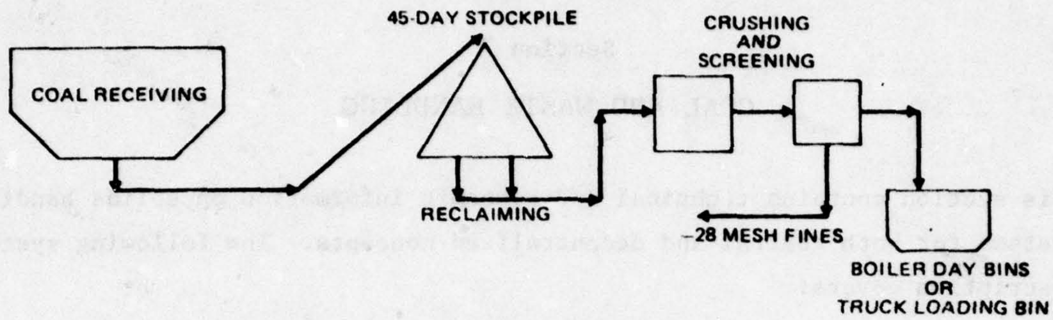

Figure 7-1
CENTRAL COAL RECEIVING, STORAGE AND PREPARATION FACILITY

Coal Storage

Two methods of storage were considered:

- A concrete silo sufficient to contain a 45-day supply
- An open stockpile containing the same quantity of coal stored in form of a windrow

The stockpile option, which is lower in cost, is shown in Figure 7-1.

Advantages of silo storage are reduction of wind losses, elimination of contaminated rain runoff, and reduction of the danger of spontaneous combustion. Also, silos are aesthetically more pleasing than coal piles.

The storage conveyor in each case is a 24-inch belt conveyor. For the silo, the conveyor transfers the coal directly to the top of the silo. For the stockpile, it discharges to a stacker feeder conveyor for transfer to a radial stacker.

Coal Reclaiming

As coal is needed, it is withdrawn from storage by reclaiming equipment. For the silo storage option, coal is withdrawn from the bottom through four vibrating feeders onto a transfer belt conveyor. For the stockpile option, coal is moved by a front-end loader vehicle to a hopper and falls through a vibratory feeder onto a transfer conveyor.

Coal Size Reduction

The reclaimed coal is transported to a crusher for size reduction to -3/4 inch, and screened to remove fines.

Temporary Storage System

Sized coal is conveyed to a 3-day storage bin.

Facility Sizing

Table 7-1 indicates the coal flow for which elements of the receiving, storage, and preparation system have been designed.

Table 7-1

CENTRAL COAL RECEIVING, STORAGE, AND PREPARATION DATA

	Steam Plant Capacity, 10^6 Btu/hr			
	100	200	400	800
Peak Coal Consumption Rate* **(Tons per hour)**	6.25	12.5	25	50
Design Coal Handling and Preparation (Tons per hour)	5	10	20	40
Design Coal Receiving (Tons per year)	44,000	88,000	176,000	352,000
Design Coal Delivery Rate (Tons per week)	840	1,680	3,360	6,720
(Trains per week)	1	2	4	8
Design Stockpile Size (Tons)	5,400	10,800	21,600	43,200
(Days Supply)	45	45	45	45

***See Table 3-2.**

The facilities have been sized to 80 percent of the maximum consumption rate of the boilers as a way to achieve cost savings. This is possible for the following reasons:

- Weather data suggest that boilers will be operating at full design capacity only on the two coldest days of the year. Space heating requirements will be less at all other times. On the average over a year, the coal demand rate will be 33 percent of the boiler design load. This is the significance of the load factor of 33 percent defined in Section 3.

- The receiving, storage, and preparation systems are sized to provide a full 168-hour week's supply of coal in a single 40-hour work week. During a cold spell, the equipment can be worked overtime.

- Solids handling equipment can be overdriven by 10 percent for short periods without detriment.

- Each boiler has holding bins that accommodate a full weekend supply of coal. This surge capacity decouples the coal supply system from the requirement to follow instantaneous load swings of the boilers.

FACILITIES FOR EACH DECENTRALIZED PLANT

Minor additional capital plant investment is required for the decentralized steam plant configuration. This includes at each decentralized boiler site a three-day storage bin with feeder and a small conveyor to connect with the boiler stoker feed system.

COAL HAULING TO DECENTRALIZED BOILERS

Figure 7-2 shows the assumed decentralized configuration. Coal is transported by truck from a central point to each boiler location. The study evaluated this method of transportation for the range of system total capacities (100 to 800 x 10^6 Btu/hr) and distances from one to five miles.

WASTE DISPOSAL

Ash and sludge from both central and decentralized steam plants is removed by truck. The haul distance for both cases varies from one to five miles, with allowance made for consolidation of a truck load of waste at each decentralized site before it is hauled away. Amounts to be removed are shown in Table 7-2. The coal used to evaluate waste disposal is that described in Table 3-1.

Flyash from baghouses and bottom ash from boilers make up an inert material. The sludge material produced by the double-alkali scrubber system is in the form of a filter cake that was described in Section 5. For the purpose of this study, it has been assumed that the ash and the double-alkali waste will be hauled and disposed of as a single waste material. The addition of ash to the double-alkali filter cake will add physical strength and reduce the weight percent of liquid in the combined waste material when ultimately deposited.

The trucks hauling the waste deposit it in a temporary waste holding facility near the limits of the naval reservation. The facility is designed to hold a 3-day supply of waste. The capital cost is small and has been included in the capital costs for central coal receiving, storage, and preparation facilities presented in the next subsection.

It is assumed that a contractor will transport waste from the temporary holding facility to a disposal site consisting of a lined pond with controlled runoff, located 10 to 50 miles from the naval base. The costs of this off-base disposal activity have not been included in the costs presented in the next subsections. However, formulas for computing such costs are given, and used in the example in Section 10.

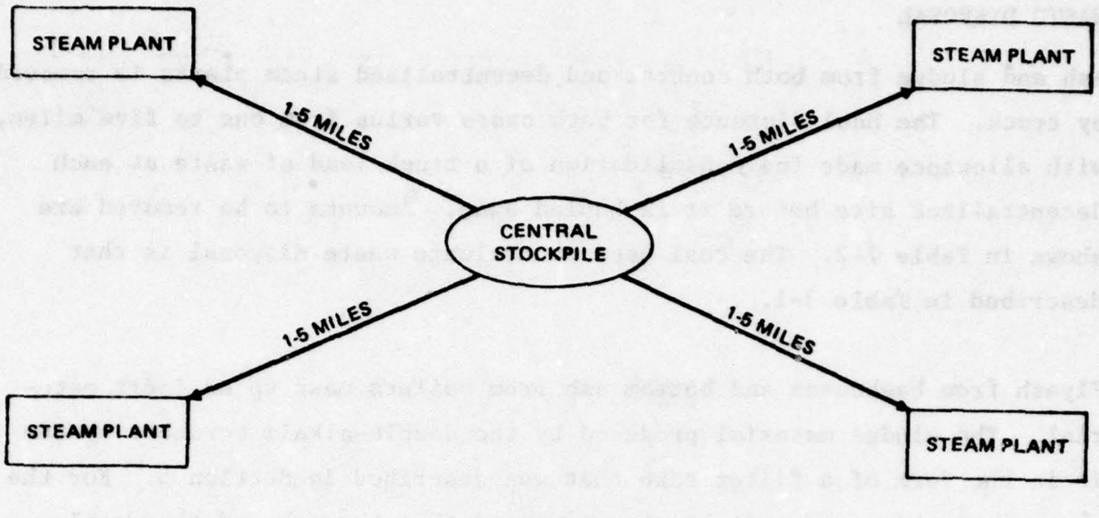

Figure 7-2

DECENTRALIZED PLANT CONFIGURATION

Table 7-2

NOMINAL WASTE
DISPOSAL DATA

Total Boiler Capacity 10^6 Btu/hr	% S in Coal	Lb/Hr Coal Burned	Lb/Hr Bottom Ash	Lb/Hr Flyash	Lb/Hr Sludge	Lb/Hr Total Waste	T/Hr Waste	T/Day 4 Boilers	T/Day 1 Boiler
100	0.5	11,700	1800	1200		3000	1.5	36	9.0
	2.0	11,700	1790	1194	1310	4300	2.2	53	13.2
	4.0	11,700	1750	1175	3199	6100	3.1	74	18.5
200	0.5	23,400	3600	2400	—	6000	3.0	72	18.0
	2.0	23,400	3580	2386	2619	8600	4.3	103	25.8
	4.0	23,400	3500	2350	6393	12,200	6.1	146	36.5
400	0.5	46,800	7200	4800	—	12,000	6.0	144	36.0
	2.0	46,800	7157	4772	5291	17,200	8.6	206	51.5
	4.0	46,800	7000	4700	12,786	24,500	12.2	293	73.2
800	0.5	93,600	14,400	9600	—	24,000	12.0	288	72.0
	2.0	93,600	14,314	9544	10,582	34,400	17.2	413	103.2
	4.0	93,600	14,000	9400	25,600	49,000	24.5	588	147.0

Numbers may not add because of rounding.

COSTS FOR CENTRAL COAL HANDLING FACILITY

Capital costs for the central coal receiving, storage, and preparation facility with stockpile storage are shown in Table 7-3 for a range of 5 to 40 tons per hour. The same costs with the range extended to 50 tons per hour are shown in Figure 7-3.

Figure 7-3 also shows results of the cost evaluation for central coal handling plants using silos for long-term storage instead of an open stockpile. Due to the silo option's high cost, the use of silos was not pursued in the remaining portion of the study. A brief study of the operating and maintenance costs of the silo option showed small difference between it and the open stockpile option, entirely insufficient to balance the greater capital costs.

For a facility with all boilers in a single central plant, the costs shown therein constitute all the capital costs involved in coal handling.

The manpower requirements for the central coal handling facility are shown in Table 7-4.

The operating and maintenance costs of a central coal handling facility are shown in Table 7-5 and Figure 7-4. Material requirements of solids handling equipment are generally a higher fraction of capital costs than for other modules.

COST OF MINOR FACILITIES FOR DECENTRALIZED BOILERS

Minor facilities are needed for temporary coal storage at decentralized boilers. These are shown in Table 7-6.

COST OF COAL HAULAGE

For decentralized systems, coal must be hauled from the central coal facility to the individual boiler plants.

Table 7-3

TOTAL CONSTRUCTION COSTS,*
CENTRAL COAL HANDLING FACILITY WITH STOCKPILE

Cost Item	Design Coal Rate, Tons Per Hour			
	5	10	20	40
Equipment and Materials	760	1060	2100	4000
Construction Labor	220	740	1500	2760
Total Field Cost	980	1800	3600	6760
Engineering Services	120	200	400	740
Total Construction Cost	1100	2000	4000	7500

*Costs in thousands of dollars, second quarter 1978 prices.

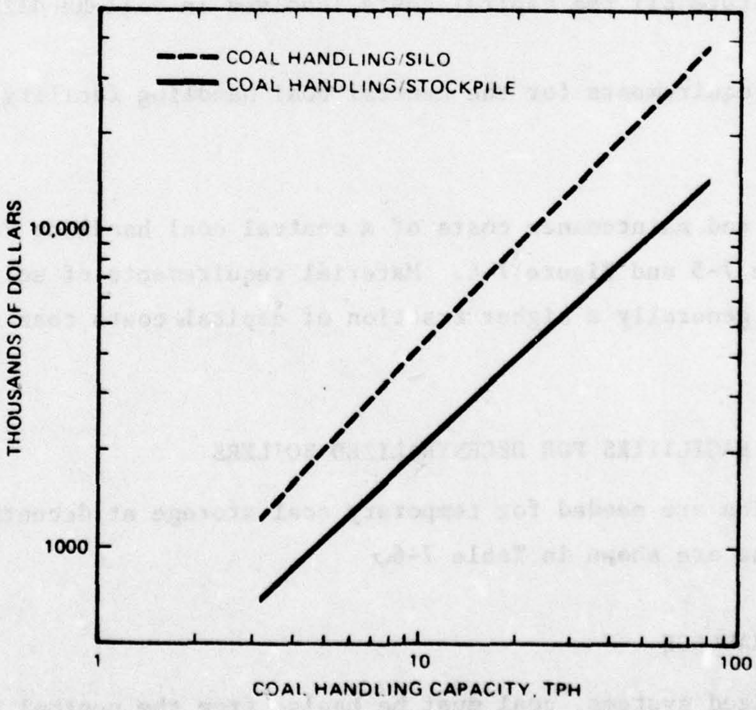

Figure 7-3
TOTAL CONSTRUCTION COSTS,
CENTRAL COAL HANDLING FACILITY

Table 7-4

OPERATING MANPOWER REQUIREMENTS, CENTRAL COAL HANDLING FACILITY

Design Coal Capacity, Tons per Hour	Men Employed
5	3.5
10	5.8
20	7
40	9

Table 7-5

OPERATING AND MAINTENANCE COSTS*, CENTRAL COAL HANDLING FACILITY WITH STOCKPILE

Cost Item	Design Tons per Hour			
	5	10	20	40
Labor	160	270	360	510
Supplies and Materials	70	120	190	360
Total O&M Cost	230	390	550	870

*Thousands of dollars per year, second quarter 1978 price level.

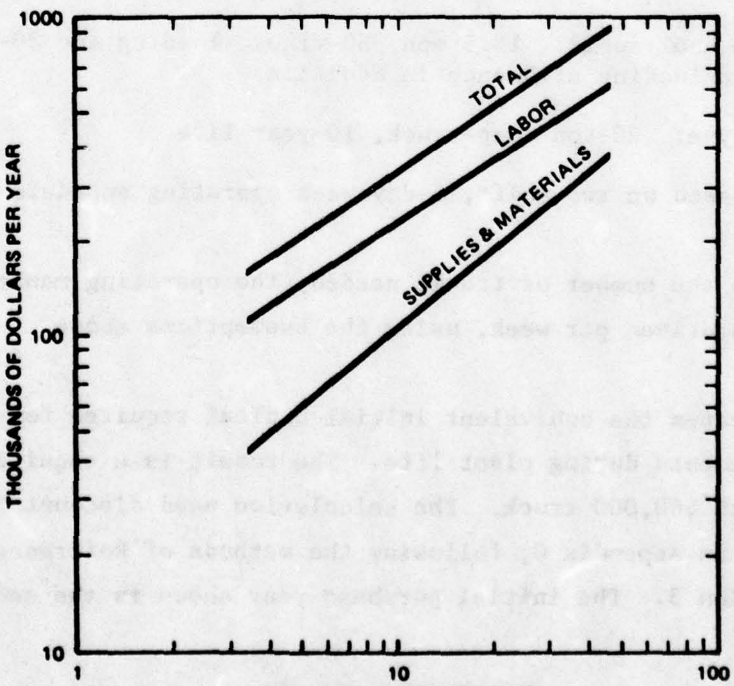

Figure 7-4

OPERATING AND MAINTENANCE COSTS, CENTRAL COAL HANDLING FACILITY WITH STOCKPILE

Table 7-6

EXTRA CONSTRUCTION COSTS*,
MINOR FACILITIES FOR SINGLE DECENTRALIZED BOILERS

Boiler Capacity, 10^6 Btu/hr Design Coal Rate, Tons/hr	25 1.25	50 2.5	100 5	200 10
Cost Item				
Equipment and Materials	15	25	40	70
Construction Labor	5	10	20	35
Total Field Cost	20	35	60	105
Engineering Services	5	5	5	5
Total Construction Cost	25	40	65	110

*Thousands of dollars, second quarter 1978 prices.

A truck haul operation was analyzed under the following assumptions:

- Fuel required: 1.25 miles per gallon and \$0.60 per gallon
- Average haul speed: 12.5 mph, 30-minute loading and 30-minute unloading allowance in addition
- Truck type: 20-ton dump truck, 10-year life
- Costs based on two-shift, 5-day week operating schedule

Table 7-7 gives the number of trucks needed, the operating manhours per week, and miles driven per week, using the assumptions above.

Table 7-8 indicates the equivalent initial capital required for each truck and its replacements during plant life. The result is a requirement of \$80,000 for each \$60,000 truck. The calculation used discount factors from Table G-1 in Appendix G, following the methods of Reference (3) discussed in Section 3. The initial purchase year shown is the second year

Table 7-7

COAL HAUL DATA

EQUIPMENT REQUIREMENTS

Design Tons per Hour	5	10	20	40
Design Trips per Week	42	84	168	336
Trucks Required				
1 Mile	1	2	3	6
3 Miles	1	2	3	6
5 Miles	1	2	4	8

OPERATING REQUIREMENTS

Annual Average Tons per Hour	5	10	20	40
Driver Manhours per Week				
1 Mile	48	96	195	390
3 Miles	62	124	248	495
5 Miles	76	152	304	608
Miles Driven per Week				
1 Mile	84	168	336	672
3 Miles	252	504	1008	2016
5 Miles	420	840	1680	3360

Table 7-8

CAPITAL COST* PER COAL HAUL TRUCK

Project Year	Cash Flow	Present Worth Discount Factor	Present Worth
1	0		
2	-$60,000	0.867	-$52,000
.	.		
.	.		
12	-$60,000	0.334	-$20,000
.	.		
.	.		
22	-$60,000	0.122	-$ 7,700
.	.		
.	.		
27	+$12,000 Salvage	0.080	+$ 1,000
Total Present Value			-$78,700

*Second quarter 1978 prices.

- Truck cost: $60,000
- Truck life: 10 years
- Plant life: 25 years
- Discount rate: 10%

Table 7-9

OPERATING AND MAINTENANCE COSTS* FOR COAL HAUL

Haul Distance, Miles	Annual Average Tons/Hr	Operating Labor	Maint-enance Labor	Gasoline	Operating Supplies	Maint-enance Mate-rials	Total Fuel, Supplies and Materials
1	1	10	8	—	—	12	12
	5	50	8	2	2	12	16
	10	100	12	4	4	24	32
	20	200	25	8	8	36	52
	40	400	50	16	16	72	104
3	1	12	8	2	1	12	15
	5	64	8	8	5	12	25
	10	129	12	16	10	24	50
	20	258	25	24	20	36	80
	40	516	50	48	40	72	160
5	1	16	8	2	1	12	15
	5	78	8	10	6	12	28
	10	157	15	20	12	25	57
	20	314	30	40	25	50	115
	40	628	60	80	50	100	230

*Thousands of dollars per year, second quarter 1978 prices.

- Operating labor $20/manhour.
- Maintenance labor as a factor times capital.
- Gasoline at $0.48/mile.
- Operating supplies as a factor times operating labor.
- Maintenance materials as a factor times capital.

of construction, as treated in life-cycle costs presented in Section 8. The result of the calculation in Table 7-8 is that approximately $80,000 in capital must be allocated for each truck required according to Table 7-7.

For calculating annual haul operating and maintenance costs, it has been assumed that labor is available as part of the general labor pool, and that during periods of low demand, the drivers and maintenance personnel will be occupied with other plant activities. Consequently, the haul costs should be calculated on the basis of the annual average tons per hour hauled. This is the product of the maximum tons per hour of coal fired to the boiler times the load factor defined in Section 3. Tables 7-9 and 7-10 present the haul costs that result. As indicated in Table 7-9, vehicles are assumed to require a substantially higher fraction of their capital cost for annual maintenance than stationary facilities.

Table 7-10

TOTAL OPERATING AND MAINTENANCE COSTS,*
COAL OR WASTE HAUL

Annual Average Tons per Hour	0.2	1	5	10	20	40
Haul Distance						
1 Mile	20	30	74	144	277	554
3 Miles	20	35	97	191	363	726
5 Miles	20	39	114	229	459	918

*Thousands of dollars per year, second quarter 1978 prices.

COSTS OF ON-BASE WASTE HAULAGE

The costs of hauling waste from boilers to the temporary hold facility have been computed in the same way as coal haul costs. It has been assumed that the same set of trucks would be used as for coal haul and a collection trip would be made only when a complete truck load has accumulated at a given boiler plant. Tables 7-7, 7-8, 7-9, and 7-10 can be used for waste haul costs as well as for coal haul costs.

Figure 7-5 presents the operating and maintenance costs for coal haul or waste haul as a function of annual average tons per hour and haul distance.

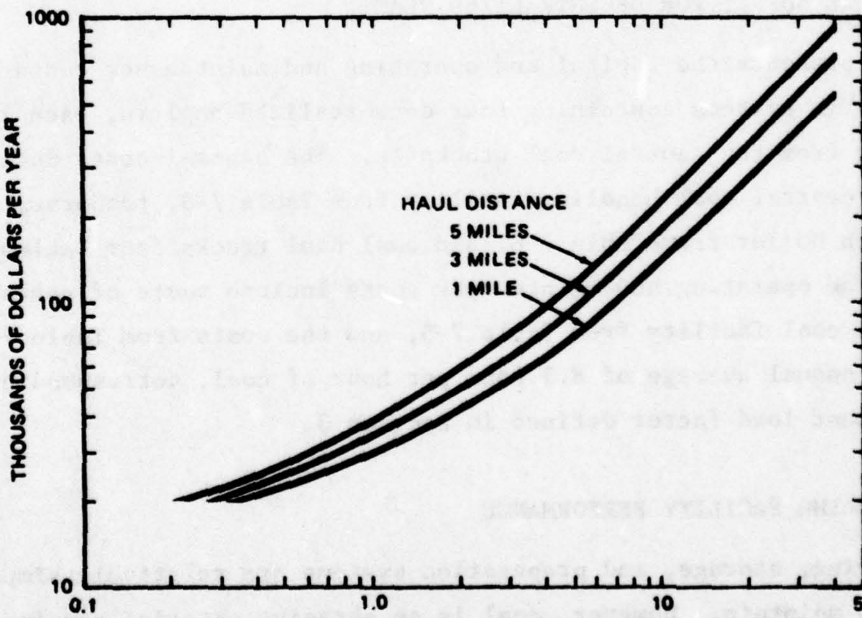

Figure 7-5
OPERATING AND MAINTENANCE COSTS, ON-BASE COAL OR WASTE HAULAGE

COSTS OF OFF-BASE WASTE DISPOSAL

The following equations can be used to obtain the annual cost of a subcontract for hauling waste from the Navy base to a permanent disposal site either 10 or 50 miles away. The equations were developed during the study reported in Reference (2). The parameter TPH (tons per hour) is the annual average tons per hour discussed above. The costs are in second quarter 1978 dollars.

Site 10 miles from base

$$\text{Cost} = \$135{,}000\ (\text{TPH}/2.8)^{0.6} \qquad ,\text{TPH} > 2.8$$

$$\text{Cost} = \$135{,}000 \qquad ,\text{TPH} \le 2.8$$

Site 50 miles from base

$$\text{Cost} = \$140{,}000\ (\text{TPH}/2.2)^{0.75} \qquad ,\text{TPH} > 2.2$$

$$\text{Cost} = \$140{,}000 \qquad ,\text{TPH} \le 2.2$$

COSTS OF COAL SUPPLY FOR DECENTRALIZED PLANT

Table 7-11 presents the capital and operating and maintenance costs for coal supply in systems containing four decentralized boilers, each located three miles from the central coal stockpile. The capital costs include the costs of a central coal handling facility from Table 7-3, temporary storage bins at each boiler from Table 7-6, and coal haul trucks from Tables 7-7 and 7-8. The operating and maintenance costs include costs of operating the central coal facility from Table 7-5, and the costs from Table 7-9 of hauling an annual average of 8.3 tons per hour of coal, corresponding to the 33 percent load factor defined in Section 3.

SOLIDS HANDLING FACILITY PERFORMANCE

Coal receiving, storage, and preparation systems are relatively simple to operate and maintain. However, coal is an abrasive material causing heavy equipment upkeep requirements. A sound preventive maintenance program should be established for any coal-handling system to minimize unscheduled maintenance. Such preventive measures are especially necessary since major

Table 7-11

COSTS FOR DECENTRALIZED PLANT COAL SUPPLY SYSTEM

TOTAL CONSTRUCTION COSTS

	Thousands of Dollars			
Design Tons per Hour	5	10	20	40
Equipment and Materials	900	1320	2500	4760
Construction Labor	240	780	1580	2900
Total Field Cost	1140	2100	4080	7660
Engineering Services	140	220	420	760
Total Construction Cost	1280	2320	4500	8420

OPERATING AND MAINTENANCE COSTS

	Thousands of Dollars Per Year			
Annual Average Tons per Hour	2.1	4.2	8.3	16.6
Annual Labor	190	330	480	750
Supplies and Materials	80	140	230	430
Total O*M Cost	270	470	710	1180

- Second quarter 1978 prices.
- Operating and maintenance costs for system with 3-mile haul between stockpile and each decentralized boiler, 33 percent load factor.

pieces of coal handling equipment are not normally spared. Prudent use of short-term stockpiles, preventive maintenance, and careful scheduling of coal use and heating requirements can make the front-end coal-handling operation a reliable part of a steam generation system.

The coal-handling systems described earlier are relatively insensitive to coal compositions and types except that the heating value of a selected coal must be matched to heat transfer requirements, boiler efficiencies, and usage to determine coal tonnages. Once the coal tonnage has been determined, costs can be estimated from the parametric cost information. While the cost versus size information is shown as smooth curves, it should also be remembered that any handling system can be used over a range, in some cases merely by speeding or slowing conveyor belts. A specific system can be designed to handle a relatively wide range of tonnages (and thus heating values) by oversizing bottlenecks, such as the crusher, to account for varying handling requirements.

Waste disposal is similar to coal handling in that the quantities to be removed depend on coal composition as well as coal quantity. Figure 7-6 permits quick calculation of waste tonnages on the basis of coal tonnage, coal sulfur level, and coal ash content. The parametric costs given earlier can then be used for any type of coal as long as the quantities to be disposed of are within the range of the study.

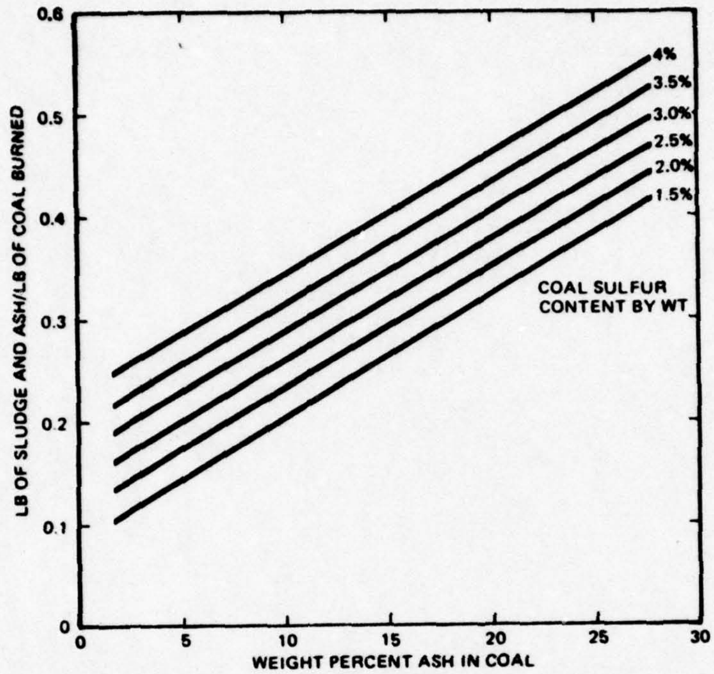

Figure 7-6
SOLID WASTE PRODUCTION AS A FUNCTION OF COAL ASH AND SULFUR CONTENT

Section 8

CENTRAL AND DECENTRALIZED STEAM SYSTEMS

In this section, boilers, air pollution control systems, and solid handling systems from Sections 4, 5, and 7 are assembled into complete steam systems. The purpose is to compare the costs of central systems with the costs of decentralized systems of the same total capacity. Differences in steam piping costs were ignored. The total capacities considered were 100, 200, 400, and 800 x 10^6 Btu/hr of heat transferred into the steam system. Coal sulfur levels were 0.5, 2, and 4 percent. A load factor of 33 percent was assumed. Detailed descriptions are given for the 400 x 10^6 Btu/hour systems burning 2 percent sulfur coal. Costs are given in detail for the 400 x 10^6 Btu/hour systems, and in summary for the other capacities.

CENTRAL SYSTEM DESCRIPTION

Figure 8-1 presents a plot plan for a 400 x 10^6 Btu/hr central system consisting of four quarter-sized boilers, a pair of 60-percent-sized double-alkali scrubbers plus baghouses, and an adjacent coal handling plant. Waste is hauled to a temporary terminal 3 miles away.

Figure 8-2 presents a block flow diagram for the central plant. Table 8-1 presents stream component flows. All flows shown are at full-rated capacity. Flows for plants of different capacity can be obtained by ratio. The coal used is the 2 percent coal defined in Table 3-1. Table 8-2 presents the annual utilities for the system when operating at a 33 percent load factor.

Table 8-1

STREAM FLOWS IN 400 X 10^6 BTU/HR CENTRAL PLANT SYSTEM BURNING 2% S COAL

Stream Number	1	2	3	4	5	6	7	8	9	10	11
Stream Name	Coal	Air	Ash	Sour Flue Gas	Flyash	Scrubber Water	Lime	Soda	Sludge	Sludge and Ash	Clean Stack Gas
Temperature, ^oF	77	77	—	300	—	—	77	77	—	—	170
Pressure, psia	14.7	14.7	—	14.7	—	—	14.7	14.7	—	—	14.7
Lb-mole/hr											
C	2,361.0	—	93.7	62.5	62.5	—	—	—	—	155.2	—
H_2	866.8	—	—	—	—	—	—	—	—	—	—
O_2	87.3	3,617.5	—	1,033.6	—	—	—	—	—	—	1,029.6
N_2	23.6	13,608.8	—	13,628.6	—	—	—	—	—	—	13,628.6
S	29.3	—	—	—	—	—	—	—	—	—	—
Ash as SiO_2	167.6	—	100.6	67.0	67.0	—	0.9	—	0.9	168.5	—
H_2O	130.1	—	—	996.8	—	1,361.1	—	—	130.9	130.9	2,207.3
SO_2	—	—	—	29.3	—	—	—	—	—	—	9.4
CO_2	—	—	—	2,204.5	—	—	—	—	—	—	2,206.7
CaO	—	—	—	—	—	—	17.9	—	—	—	—
Na_2CO_3	—	—	—	—	—	—	—	2.0	—	—	—
$CaSO_3 \cdot \frac{1}{2}H_2O$	—	—	—	—	—	—	—	—	10.7	10.7	—
$CaSO_4 \cdot 2H_2O$	—	—	—	—	—	—	—	—	7.2	7.2	—
Na_2SO_3	—	—	—	—	—	—	—	—	1.2	1.2	—
Na_2SO_4	—	—	—	—	—	—	—	—	0.8	0.8	—
NO	—	—	—	7.6	—	—	—	—	—	—	7.6
Total	3,665.7	17,226.3	194.3	18,029.9	129.5	1,361.1	18.8	2.0	151.7	475.5	19,089.2
Lb/hr											
C	28,331	—	1,125	750	750	—	—	—	—	1,875	—
H_2	1,734	—	—	—	—	—	—	—	—	—	—
O_2	2,792	115,761	—	33,075	—	—	—	—	—	—	32,948
N_2	661	381,045	—	381,601	—	—	—	—	—	—	381,601
S	937	—	—	—	—	—	—	—	—	—	—
Ash as SiO_2	10,054	—	6,032	4,022	4,022	—	53	—	53	10,107	—
H_2O	2,343	—	—	17,942	—	24,500	—	—	2,356	2,356	39,732
SO_2	—	—	—	1,875	—	—	—	—	—	—	601
CO_2	—	—	—	97,008	—	—	—	—	—	—	97,096
CaO	—	—	—	—	—	—	1,003	—	—	—	—
Na_2CO_3	—	—	—	—	—	—	—	212	—	—	—
$CaSO_3 \cdot \frac{1}{2}H_2O$	—	—	—	—	—	—	—	—	1,386	1,386	—
$CaSO_4 \cdot 2H_2O$	—	—	—	—	—	—	—	—	1,232	1,232	—
Na_2SO_3	—	—	—	—	—	—	—	—	151	151	—
Na_2SO_4	—	—	—	—	—	—	—	—	113	113	—
NO	—	—	—	228	—	—	—	—	—	—	228
Total	46,852	496,806	7,157	536,501	4,772	24,500	1,056	212	5,291	17,220	552,206

- Assumes 80% boiler efficiency.
- Mass flow rate based on full 400 x 10^6 Btu/hr output.

Table 8-2

ANNUAL UTILITIES FOR 400 x 10^6 BTU/HR CENTRAL BOILER SYSTEM

	Electricity 10^3 kWhr	Water 10^6 gal
Coal preparation	263	—
Boiler	1,120	1,470
Scrubber	1,416	8.670
Miscellaneous	171	—
Total	2,970	10,140

- 2% S coal, 33% load factor

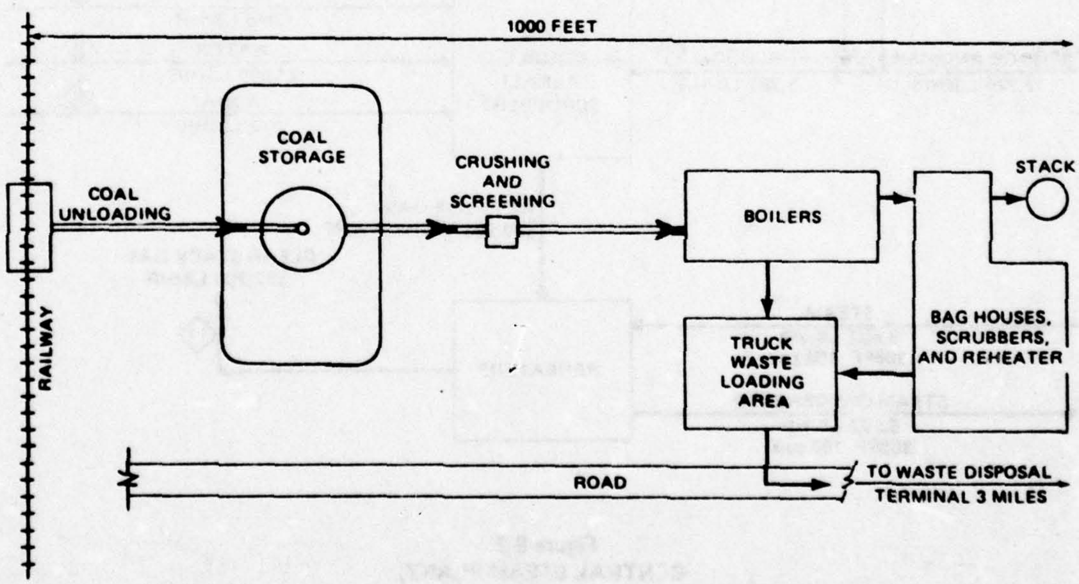

Figure 8-1
400 x 10^6 BTU/HR CENTRAL STEAM GENERATION PLANT LAYOUT

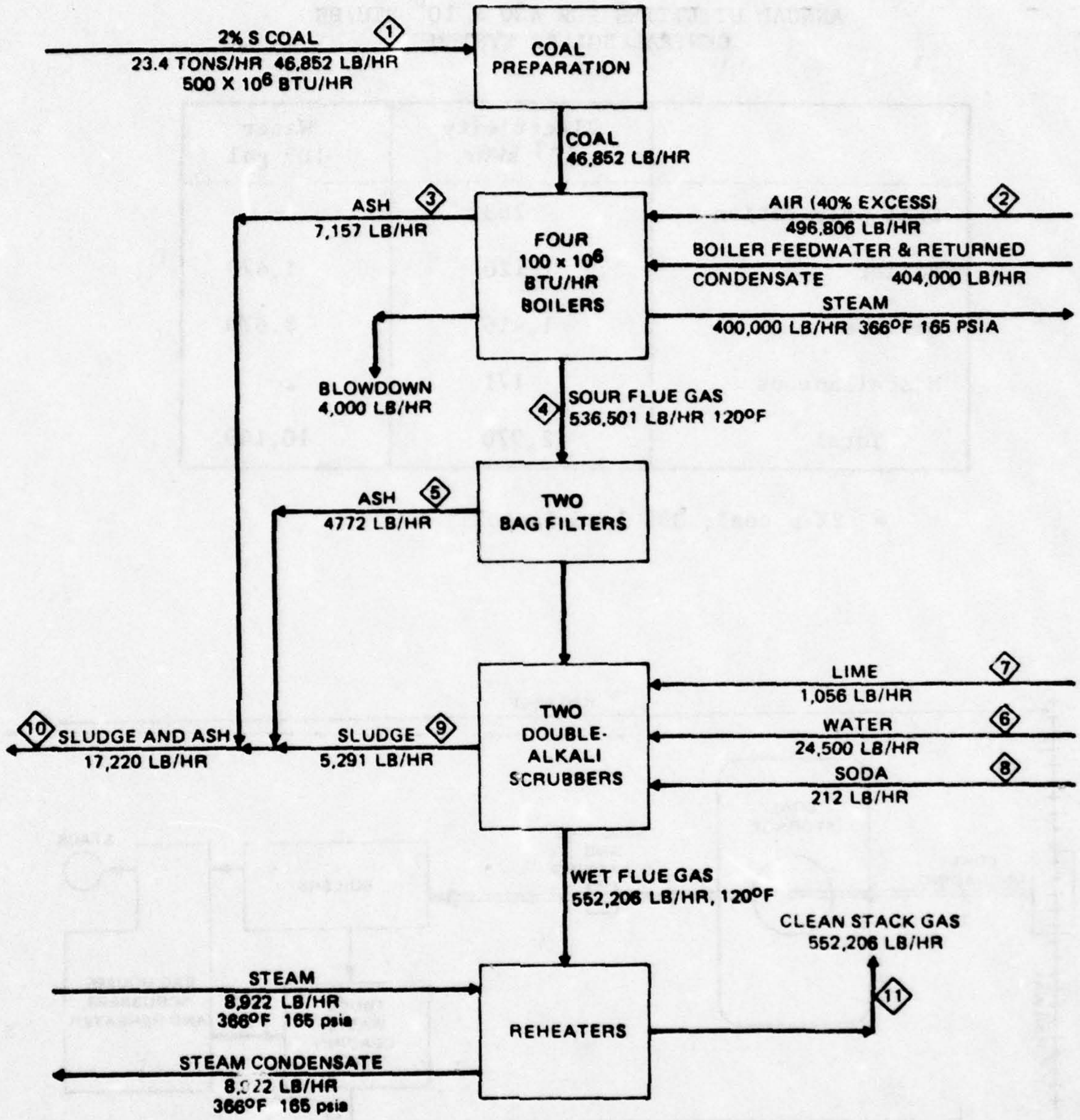

Figure 8-2
CENTRAL STEAM PLANT,
BLOCK DIAGRAM FOR 400 x 10^6 BTU/HR BURNING 2% S COAL

DECENTRALIZED SYSTEM DESCRIPTION

The decentralized system includes a coal handling facility to accommodate 400×10^6 Btu/hr of steam generation, plus four 100×10^6 Btu/hr boiler plants each three miles from the central coal stockpile. Waste haul on the average to the temporary terminal is five miles per trip. Figure 8-3 is a schematic for the decentralized system layout. Figure 8-4 is a block flow diagram for a single 100×10^6 Btu/hr decentralized boiler plant. The flows are one fourth of the corresponding flows in Figure 8-2. Four such boilers in the decentralized system have total combined flows identical to those in the central system. Each decentralized boiler plant has a single 100-percent-sized air pollution control system consisting of baghouse plus double-alkali scrubber.

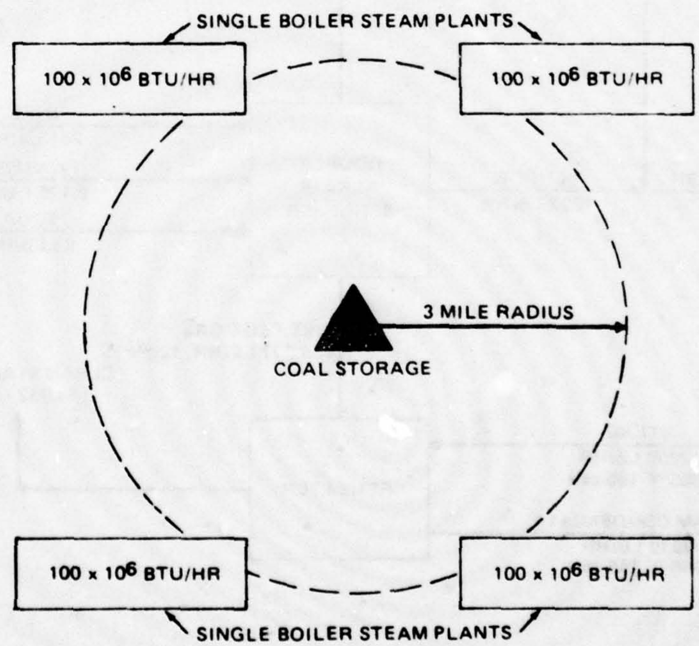

Figure 8-3
DECENTRALIZED PLANT LAYOUT
400×10^6 BTU/HR BASE CASE

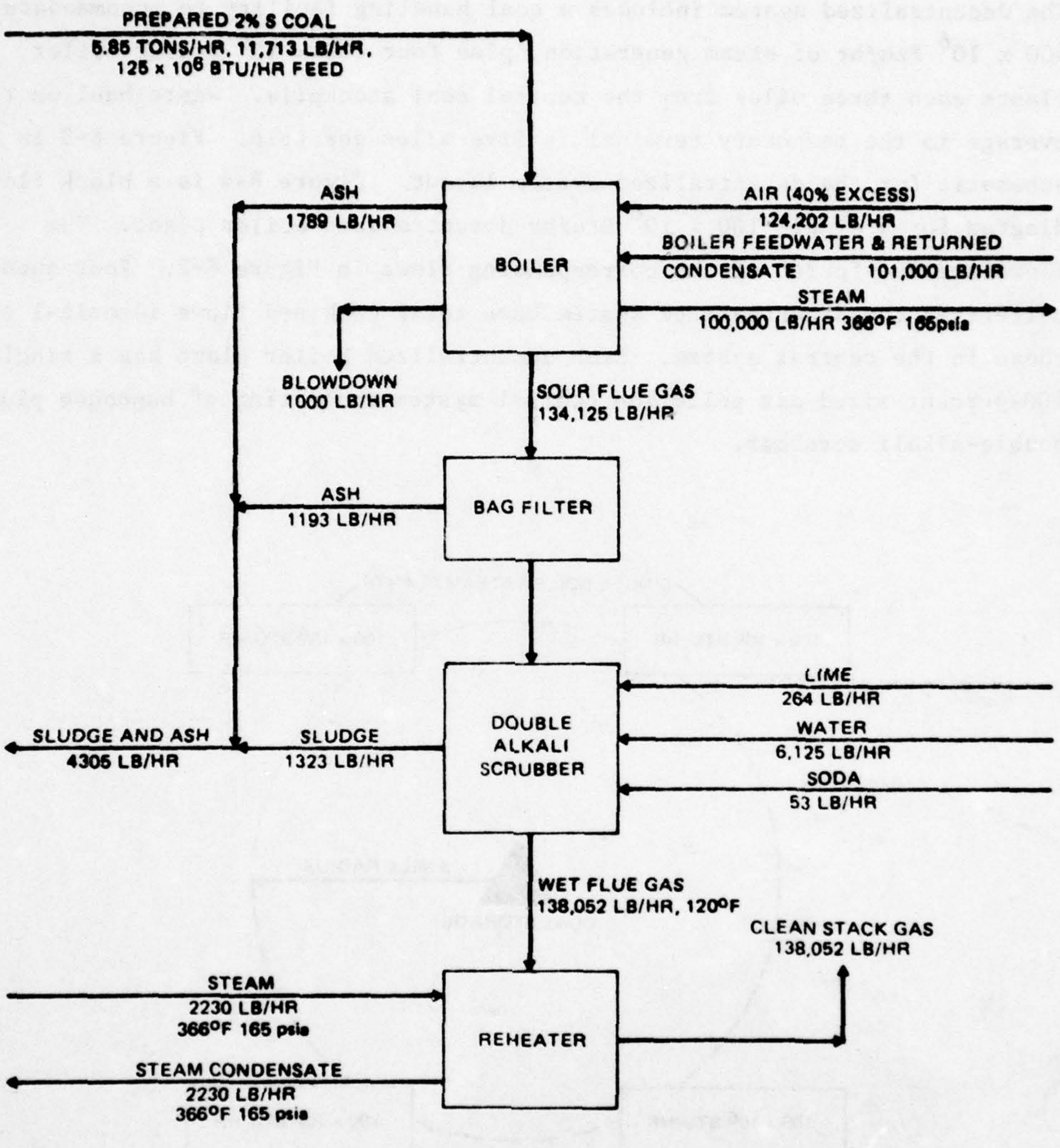

Figure 8-4
DECENTRALIZED BOILER PLANT,
BLOCK DIAGRAM FOR SINGLE 100 x 10^6 BTU/HR BURNING 2% S COAL

CAPITAL COSTS FOR 400 x 10^6 BTU/HR SYSTEMS

Table 8-3 compares the capital costs of central and decentralized systems for coals with sulfur levels of 0.5, 2, and 4 percent. The costs were prepared using Table 4-1 for boilers, Table 5-3 for air pollution control, and Tables 7-3 and 7-11 for coal supply systems.

Table 8-3

CAPITAL COSTS*, 400 x 10^6 BTU/HR
CENTRAL AND DECENTRALIZED SYSTEMS

CENTRAL SYSTEM

Percent Sulfur	0.5%	2%	4%
Coal Receiving and Preparation	4,000	4,000	4,000
Steam Generator	12,800	12,800	12,800
Air Pollution Control	500†	8,500	9,400
Total Construction Cost	17,300	25,300	26,200
Startup	1,900	2,800	2,900
Total Capital Cost	19,200	28,100	29,100

DECENTRALIZED SYSTEM

Percent Sulfur	0.5%	2%	4%
Coal Receiving and Preparation	4,500	4,500	4,500
Steam Generator	13,600	13,600	13,600
Air Pollution Control	500†	10,200	13,400
Total Construction Cost	18,600	28,300	31,500
Startup	2,100	3,100	3,500
Total Capital Cost	20,700	31,400	35,000

*Thousands of dollars, second quarter 1978 prices.
†Baghouse for particulate removal; FGD system not required.

OPERATING AND MAINTENANCE COSTS FOR 400 x 10^6 BTU/HR SYSTEMS

Table 8-4 gives the operating manpower required for fixed installations in the central and decentralized systems.

The manpower in Table 8-4 was computed from Table 4-4 for boilers, Table 5-6 for air pollution control systems, and Table 7-4 for central coal handling facilities. As explained in Section 7, additional manpower will be taken as needed from the general labor pool to operate coal and waste haul trucks.

Operating and maintenance costs for the 400 x 10^6 Btu/hr systems are given in Table 8-5 for the assumed 33 percent load factor. Coal, scrubber chemicals, and electricity are assumed proportional to the load factor. The other cost elements are independent of load factor. The costs in Table 8-4 were taken from Table 4-5 for boilers, Tables 5-7 and 5-8 for air pollution control systems, Table 7-5 for a central coal handling facility, and Table 7-10 for coal haul at 8.3 tons/hour annual average and waste haul at 3 tons/hour annual average.

Table 8-4

OPERATING MANPOWER REQUIREMENTS FOR FIXED INSTALLATIONS, 400 x 10^6 BTU/HR SYSTEMS

	Decentralized			Central		
Sulfur Content	0.5%	2%	4%	0.5%	2%	4%
Coal receiving and preparation*	7	7	7	7	7	7
Steam generator	25	25	25	17	17	17
Air pollution control	8	28	28	2	12	12
Total	40	60	60	26	36	36

*Single-shift, 5-day week operation.

Table 8-5

OPERATING AND MAINTENANCE COSTS, 400 X 10^6 BTU/HR CENTRAL AND DECENTRALIZED SYSTEMS (33% LOAD FACTOR)
(Thousands of Dollars, Second Quarter, 1978, Prices)

	Decentralized Plant			Central Plant		
Sulfur Content	0.5%	2%	4%	0.5%	2%	4%
COAL	2000	2000	2000	2000	2000	2000
LABOR						
Operating Labor						
Coal Receiving and Preparation	280	280	280	280	280	280
Coal Hauling (3-Mile Distance)	110	110	110	—	—	—
Steam Generator	1000	1000	1000	670	670	670
Total Steam Generator	1390	1390	1390	950	950	950
Air Pollution Control	80	1160	1160	80	460	460
Waste Disposal	20	60	60	10	30	30
Total Pollution Control	100	1220	1220	90	490	490
Maintenance Labor						
Coal Receiving and Preparation	80	80	80	80	80	80
Coal Hauling	10	10	10	—	—	—
Steam Generator	310	310	310	310	310	310
Total Steam Generator	400	400	400	390	390	390
Air Pollution Control	10	200	280	10	170	180
Waste Disposal	10	10	10	10	10	10
Total Pollution Control	20	210	290	20	180	190
TOTAL LABOR	1910	3220	3300	1450	2010	2020
MATERIAL AND SUPPLIES						
Electric Power	50	50	50	50	50	50
Coal Receiving and Preparation	190	190	190	190	190	190
Coal Hauling	40	40	40	—	—	—
Steam Generator	390	390	390	360	360	360
Total Steam Generator	670	670	670	600	600	600
Electric Power	—	50	50	—	50	50
Scrubber Chemicals	—	100	240	—	100	240
Other Air Pollution Control	10	620	680	10	480	480
Waste Disposal	10	20	20	10	20	20
Total Pollution Control	20	790	990	20	650	790
TOTAL MATERIAL AND SUPPLIES	690	1460	1660	620	1250	1390
TOTAL O&M COST	4600	6680	6960	4070	5260	5410

SUMMARY COST COMPARISONS FOR FOUR SYSTEM SIZES

Table 8-6 summarizes capital and operating and maintenance costs for all four central system sizes. Table 8-7 provides a similar summary for the decentralized systems. In these summaries, the costs of coal handling, coal haul, and boiler plants have been combined under the heading of steam generation. The costs of baghouses, double-alkali scrubbers, and waste disposal have been combined under the heading of pollution control.

Figures 8-5 and 8-6 present the same capital and operating costs in the form of bar charts.

LIFE-CYCLE COST COMPARISONS

The capital and annual costs above were combined in life-cycle present value calculations by methods explained in Section 3. The life-cycle present values can be divided by the energy output over system life to get a unit present value in $\$/10^6$ Btu. Tables 8-8 and 8-9 show details of the calculation of present values for the 400 x 10^6 Btu/hr systems. Figure 8-7 gives unit present values for the range of system sizes between 100 and 800 x 10^6 Btu/hr.

LEVELIZED COST COMPARISONS

Levelized life-cycle costs calculated by methods explained in Section 3 are shown in Table 8-10 for the 400 x 10^6 Btu/hr systems. Figure 8-8 shows levelized costs for the range of system sizes between 100 and 800 x 10^6 Btu/hr.

Table 8-6

CENTRAL SYSTEM COST SUMMARY
(33 % LOAD FACTOR)
(Thousands of Dollars)

10^6 Btu/Hr	100			200			400			800		
Sulfur Content	0.5%	2%	4%	0.5%	2%	4%	0.5%	2%	4%	0.5%	2%	4%
Capital Costs												
Steam Generation	5,600	5,600	5,600	9,700	9,700	9,700	16,800	16,800	16,800	29,200	29,200	29,200
Pollution Control	200	3,300	3,900	300	5,200	6,100	500	8,500	9,400	700	13,600	15,800
Total Construction Cost	5,800	8,900	9,500	10,000	14,900	15,800	17,300	25,300	26,200	29,900	42,800	45,000
Startup	600	1,000	1,000	1,100	1,600	1,700	1,900	2,800	2,900	3,300	4,700	5,000
Total Capital Cost	6,400	9,900	10,500	11,100	16,500	17,500	19,200	28,100	29,100	33,200	47,500	50,000
Operating and Maintenance												
Labor												
Steam Generation	520	520	520	830	830	830	1,340	1,340	1,340	2,200	2,200	2,200
Pollution Control	40	260	260	70	420	420	110	670	680	170	1,090	1,100
Total Labor	560	780	780	900	1,250	1,250	1,450	2,010	2,020	2,370	3,290	3,300
Electricity	20	30	30	30	50	50	50	100	100	100	200	200
Materials and Supplies												
Steam Generation	140	140	140	280	280	280	550	550	550	1,100	1,100	1,100
Pollution Control	10	150	190	10	300	370	20	600	740	30	1,200	1,480
Total Materials and Supplies	150	290	330	290	580	650	570	1,150	1,290	1,130	2,300	2,580
Coal at $30/ton	500	500	500	1,000	1,000	1,000	2,000	2,000	2,000	4,000	4,000	4,000
Total O&M Cost	1,230	1,600	1,640	2,220	2,880	2,950	4,070	5,260	5,410	7,600	9,790	10,080

Second Quarter, 1978 price level.

Table 8-7

DECENTRALIZED SYSTEM COST SUMMARY
(33% LOAD FACTOR)
(Thousands of Dollars)

10^6 Btu/Hr	100			200			400			800		
Sulfur Content	0.5%	2%	4%	0.5%	2%	4%	0.5%	2%	4%	0.5%	2%	4%
Capital Costs												
Steam Generation	6,200	6,200	6,200	10,600	10,600	10,600	18,100	18,100	18,100	31,200	31,200	31,200
Pollution Control	200	4,900	5,300	300	6,500	7,700	500	10,200	13,400	700	16,600	21,500
Total Construction Cost	6,400	11,100	11,500	10.900	17,100	18,300	18,600	28,300	31,500	31.900	47,800	52,700
Startup	700	1,200	1,300	1,200	1,900	2,000	2,100	3,100	3,500	3,500	5,300	5,800
Total Capital Cost	7,100	12,300	12,800	12,100	19,000	20,300	20,700	31,400	35,000	35,400	53,100	58,500
Operating and Maintenance												
Labor												
Steam Generation	680	680	680	1,100	1,100	1,100	1,790	1,790	1,790	2,900	2,900	2,900
Pollution Control	50	550	590	80	900	950	120	1,430	1,510	200	2,300	2,450
Total Labor	730	1,230	1,270	1,180	2,000	2,050	1,910	3,220	3,300	3,100	5,200	5,350
Electricity	20	30	30	30	50	50	50	100	100	100	200	200
Materials and Supplies												
Steam Generation	160	160	160	310	310	310	620	620	620	1,240	1,240	1,240
Pollution Control	10	190	240	10	370	470	20	740	940	40	1,480	1,880
Total Materials and Supplies	170	350	400	320	680	780	640	1,360	1,560	1,280	2,720	3,120
Coal at $30/ton	500	500	500	1,000	1,000	1,000	2,000	2,000	2,000	4,000	4,000	4,000
Total O&M Cost	1,420	2,110	2,200	2,530	3,730	3,880	4,600	6,680	6,960	8,480	12,120	12,670

Second Quarter, 1978 price level.

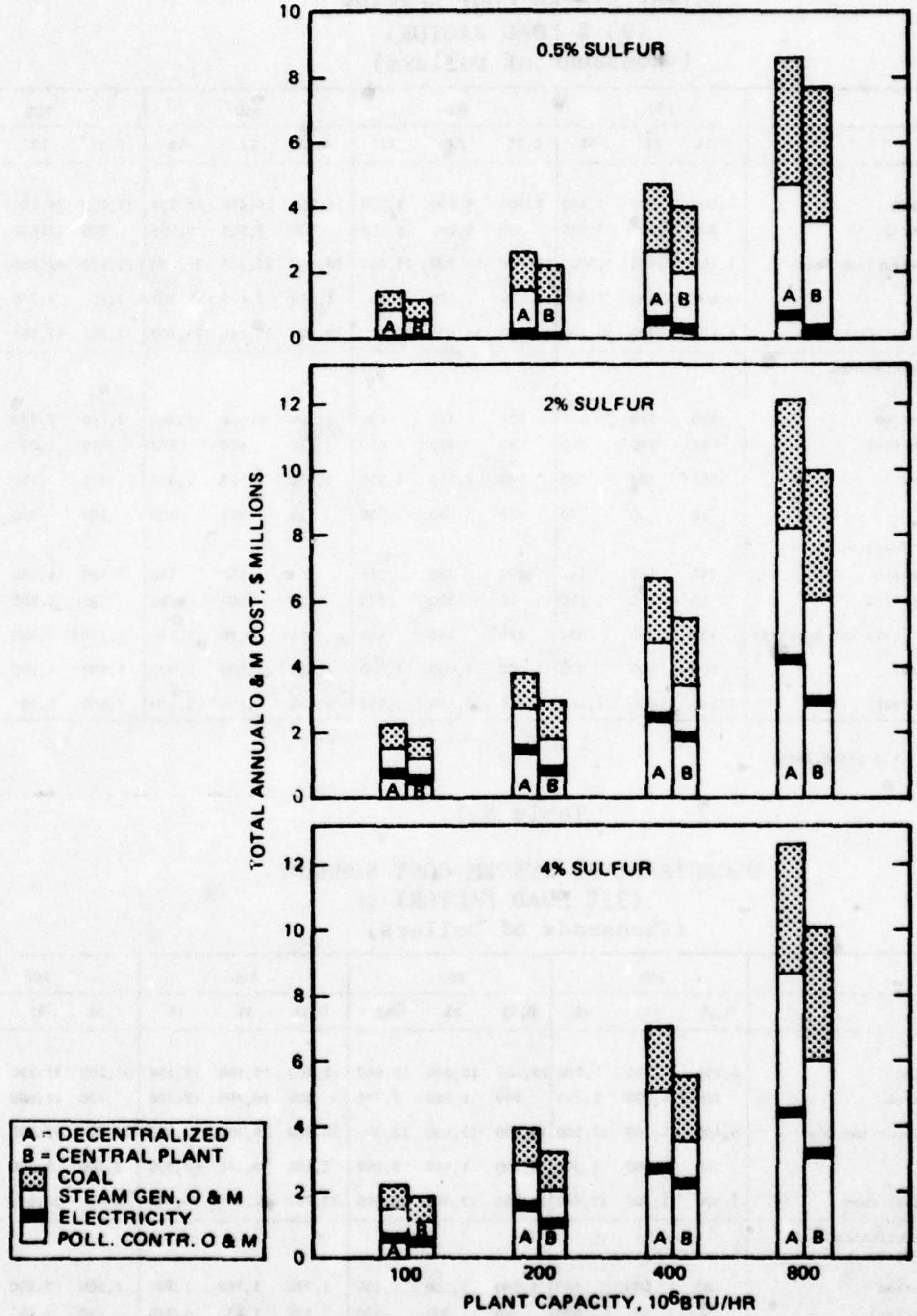

Figure 8-5
O & M COST COMPARISON, DECENTRALIZED VERSUS CENTRAL STEAM SYSTEMS

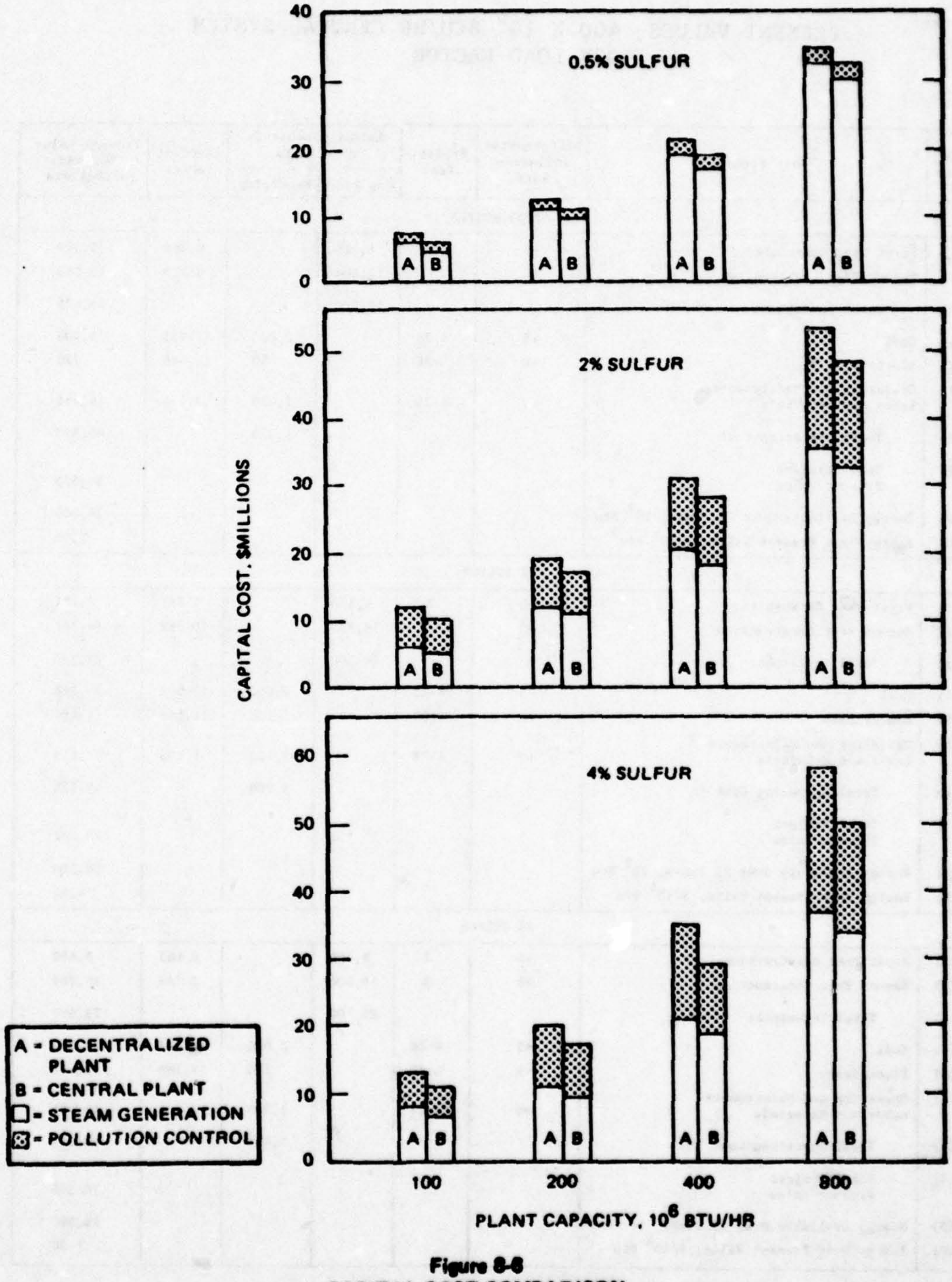

Figure 8-6
CAPITAL COST COMPARISON, DECENTRALIZED VERSUS CENTRAL STEAM SYSTEMS

Table 8-8

PRESENT VALUES, 400 X 10^6 BTU/HR CENTRAL SYSTEM
33% LOAD FACTOR

Line Number	Cost Element	Differential Inflation Rate	Project Year	Amount, Thousands of Dollars: One Time	Amount, Thousands of Dollars: Recurring	Discount Factor	Present Value Thousands of Dollars
	0.5% SULFUR						
(1)	First Year Construction	+0	2	6,400		0.867	5,549
(2)	Second Year Construction	+0	3	12,800		0.788	10,086
(3)	Total Investment			19,200			15,635
(4)	Coal	+5	4-28		2,000	12.853	25,706
(5)	Electricity	+6	4-28		50	14.588	729
(6)	Operating and Maintenance Labor and Materials	+0	4-28		2,020	7.156	14,455
(7)	Total Operating Cost				4,070		40,890
(8)	Total Project Present Value						56,525
(9)	Energy Available Over 25 Years, 10^9 Btu						28,900
(10)	Energy Unit Present Value, $/$10^6$ Btu						1.96
	2% SULFUR						
(1)	First Year Construction	+0	2	9,367		0.867	8,121
(2)	Second Year Construction	+0	3	18,733		0.788	14,762
(3)	Total Investment			28,100			22,883
(4)	Coal	+5	4-28		2,000	12.853	25,706
(5)	Electricity	+6	4-28		100	14.588	1,459
(6)	Operating and Maintenance Labor and Materials	+0	4-28		3,160	7.156	22,613
(7)	Total Operating Cost				5,260		49,778
(8)	Total Project Present Value						72,661
(9)	Energy Available Over 25 Years, 10^9 Btu						28,900
(10)	Energy Unit Present Value, $/$10^6$ Btu						2.51
	4% SULFUR						
(1)	First Year Construction	+0	2	9,700		0.867	8,410
(2)	Second Year Construction	+0	3	19,400		0.788	15,287
(3)	Total Investment			29,100			23,697
(4)	Coal	+5	4-28		2,000	12.853	25,706
(5)	Electricity	+6	4-28		100	14.588	1,459
(6)	Operating and Maintenance Labor and Materials	+0	4-28		3,310	7.156	23,686
(7)	Total Operating Cost				5,410		50,851
(8)	Total Project Present Value						74,548
(9)	Energy Available Over 25 Years, 10^9 Btu						28,900
(10)	Energy Unit Present Value, $/$10^6$ Btu						2.58

Table 8-9

PRESENT VALUES, 400 X 10^6 BTU/HR DECENTRALIZED SYSTEM
33% LOAD FACTOR

Line Number	Cost Element	Differential Inflation Rate	Project Year	Amount, Thousands of Dollars One Time	Amount, Thousands of Dollars Recurring	Discount Factor	Present Value Thousands of Dollars
	0.5% SULFUR						
(1)	First Year Construction	+0	2	6,900		0.867	5,982
(2)	Second Year Construction	+0	3	13,800		0.788	10,874
(3)	Total Investment			20,700			16,856
(4)	Coal	+5	4-28		2,000	12.853	25,706
(5)	Electricity	+6	4-28		50	14.588	729
(6)	Operating and Maintenance Labor and Materials	+0	4-28		2,550	7.156	18,248
(7)	Total Operating Cost				4,600		44,683
(8)	Total Project Present Value						61,539
(9)	Energy Available Over 25 Years, 10^9 Btu						28,900
(10)	Energy Unit Present Value, $\$/10^6$ Btu						2.13
	2% SULFUR						
(1)	First Year Construction	+0	2	10,466		0.867	9,074
(2)	Second Year Construction	+0	3	20,934		0.788	16,496
(3)	Total Investment			31,400			25,570
(4)	Coal	+5	4-28		2,000	12.853	25,706
(5)	Electricity	+6	4-28		100	14.588	1,459
(6)	Operating and Maintenance Labor and Materials	+0	4-28		4,580	7.156	32,775
(7)	Total Operating Cost				6,680		59,940
(8)	Total Project Present Value						85,510
(9)	Energy Available Over 25 Years, 10^9 Btu						28,900
(10)	Energy Unit Present Value, $\$/10^6$ Btu						2.96
	4% SULFUR						
(1)	First Year Construction	+0	2	11,667		0.867	10,115
(2)	Second Year Construction	+0	3	23,333		0.788	18,386
(3)	Total Investment			35,000			28,501
(4)	Coal	+5	4-28		2,000	12.853	25,706
(5)	Electricity	+6	4-28		200	14.588	1,459
(6)	Operating and Maintenance Labor and Materials	+0	4-28		4,860	7.156	34,778
(7)	Total Operating Cost				6,960		61,943
(8)	Total Project Present Value						90,444
(9)	Energy Available Over 25 Years, 10^9 Btu						28,900
(10)	Energy Unit Present Value, $\$/10^6$ Btu						3.13

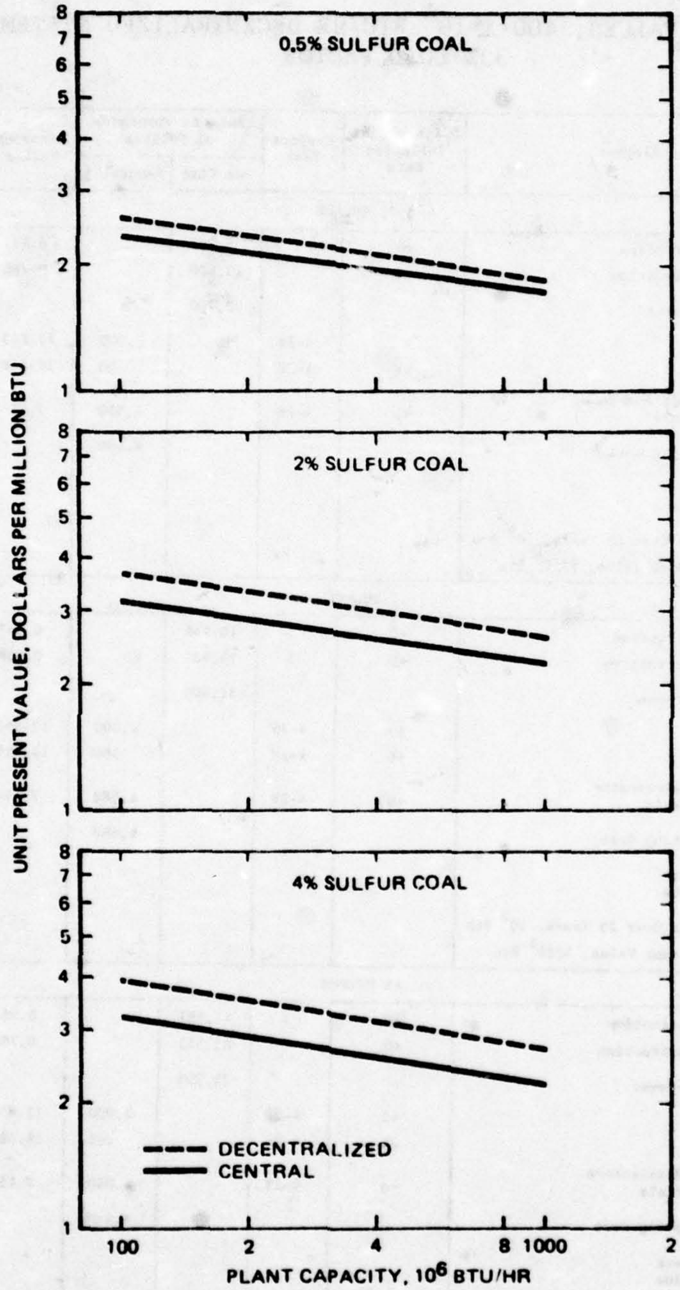

Figure 8-7
UNIT PRESENT VALUE COMPARISON, DECENTRALIZED VERSUS CENTRAL STEAM SYSTEMS

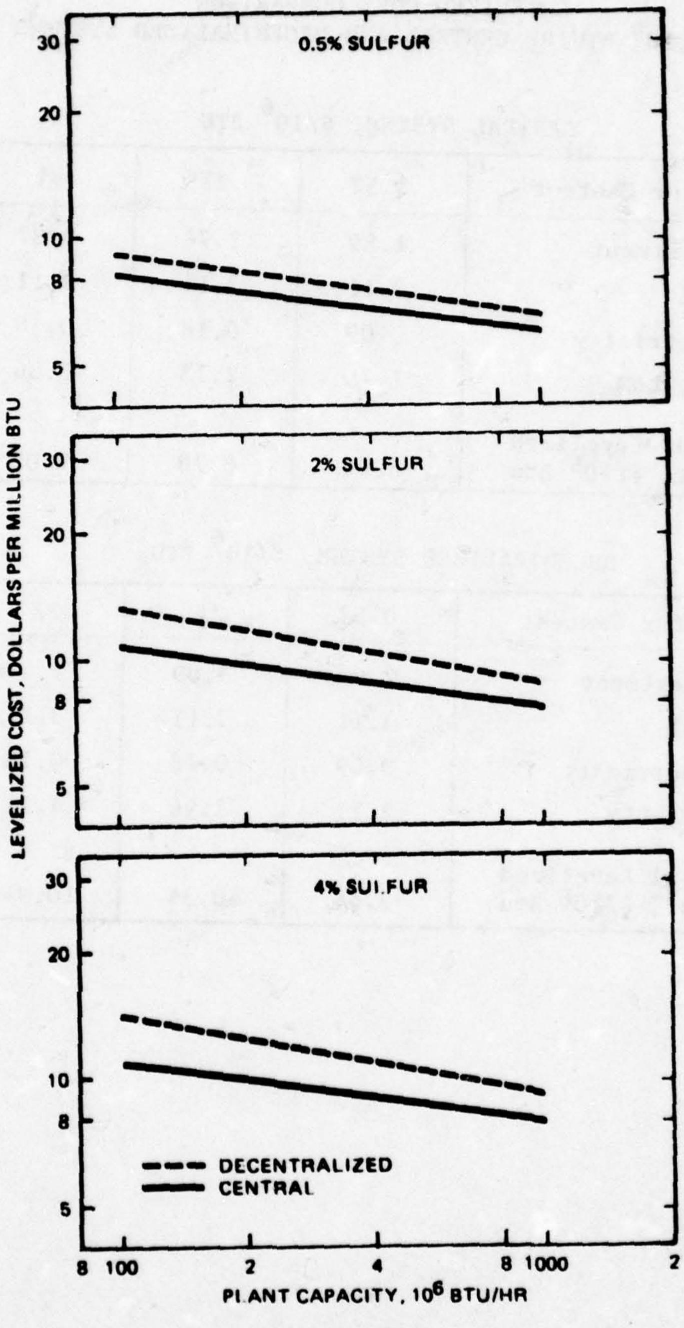

Figure 8-8
LEVELIZED COST COMPARISON,
DECENTRALIZED VERSUS CENTRAL STEAM SYSTEMS

Table 8-10

LEVELIZED COST COMPARISON
400 x 10^6 BTU/HR CENTRAL AND DECENTRALIZED SYSTEMS

CENTRAL SYSTEM, $/$10^6$ BTU

Sulfur Content	0.5%	2%	4%
Investment	1.89	2.76	2.87
Coal	3.11	3.11	3.11
Electricity	0.09	0.18	0.18
O&M, L&M	1.75	2.73	2.86
Total Levelized Cost, $/$10^6$ Btu	6.84	8.78	9.02

DECENTRALIZED SYSTEM, $/$10^6$ BTU

Sulfur Content	0.5%	2%	3%
Investment	2.03	3.09	3.44
Coal	3.11	3.11	3.11
Electricity	0.09	0.18	0.18
O&M, L&M	2.21	3.96	4.21
Total Levelized Cost, $/$10^6$ Btu	7.44	10.34	10.94

CONCLUSIONS ABOUT LIFE-CYCLE COSTS

Figures 8-7 (present value) and 8-8 (levelized cost) show that the central steam plants are more economical than decentralized units of equal capacity. However, to properly evaluate a new installation on a specific Navy base, steam transmission piping costs must also be considered, and such costs may well negate the advantage of central plants. Such a comparison is presented as a sample calculation in Section 10.

Table 8-10 indicates that costs for 0.5 percent sulfur coal not requiring flue gas desulfurization are approximately 20 percent lower than costs for 2 and 4 percent sulfur coal. Costs for 4 percent sulfur coal are only 6 percent higher than 2 percent sulfur coal.

COST SENSITIVITY TO COAL PRICES

Decentralized and central steam systems were evaluated for a range of coal prices from \$10 to \$100 per ton. Present values and levelized costs for the 400×10^6 Btu/hr base-case plants are compared in Figures 8-9 and 8-10. Because changes in coal price add a constant factor to the costs, there is no change in the relative economies of central versus decentralized plants. However, it is of major interest to see that one could pay approximately \$20 per ton more for 0.5 percent sulfur coal, and still equal the present value or levelized cost of plants burning 2 percent or 4 percent sulfur coal. This is of course due to the much larger capital and annual costs for air pollution control estimated for the higher-sulfur-coal plants.

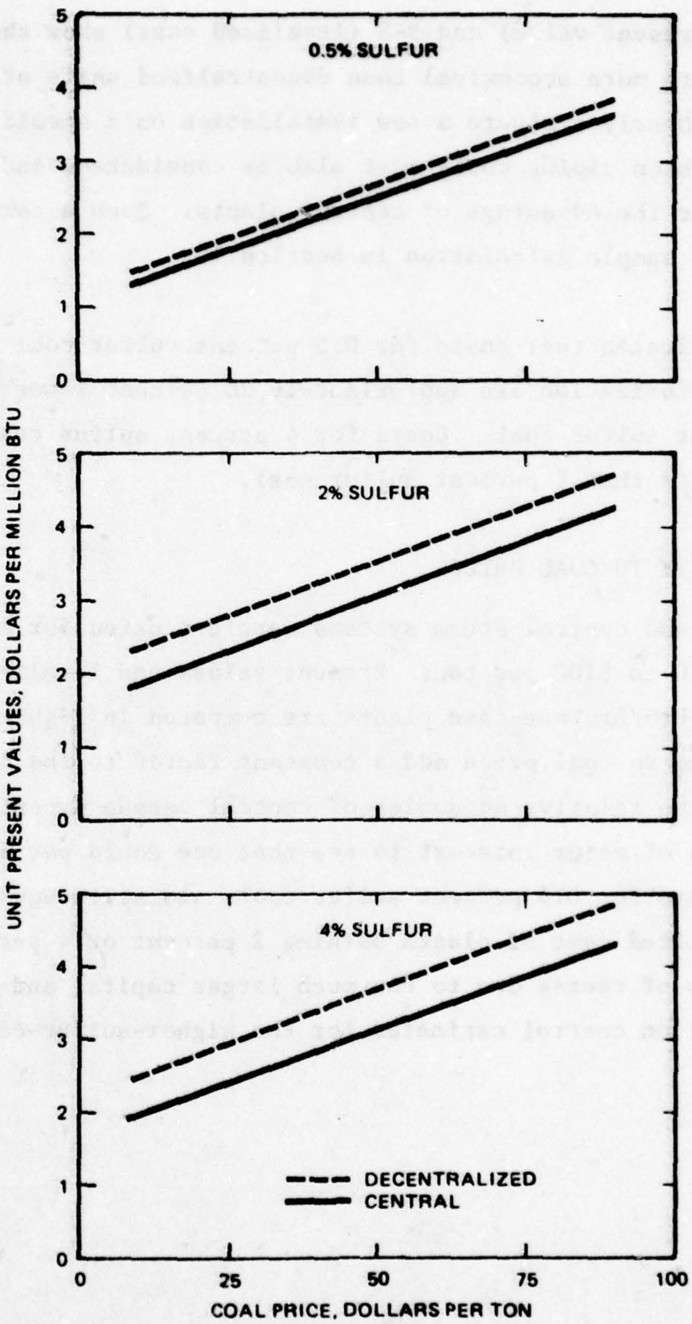

Figure 8-9
UNIT PRESENT VALUES VERSUS PRICE OF COAL, 400 x 10^6 BTU/HR PLANTS – DECENTRALIZED AND CENTRAL STEAM SYSTEMS

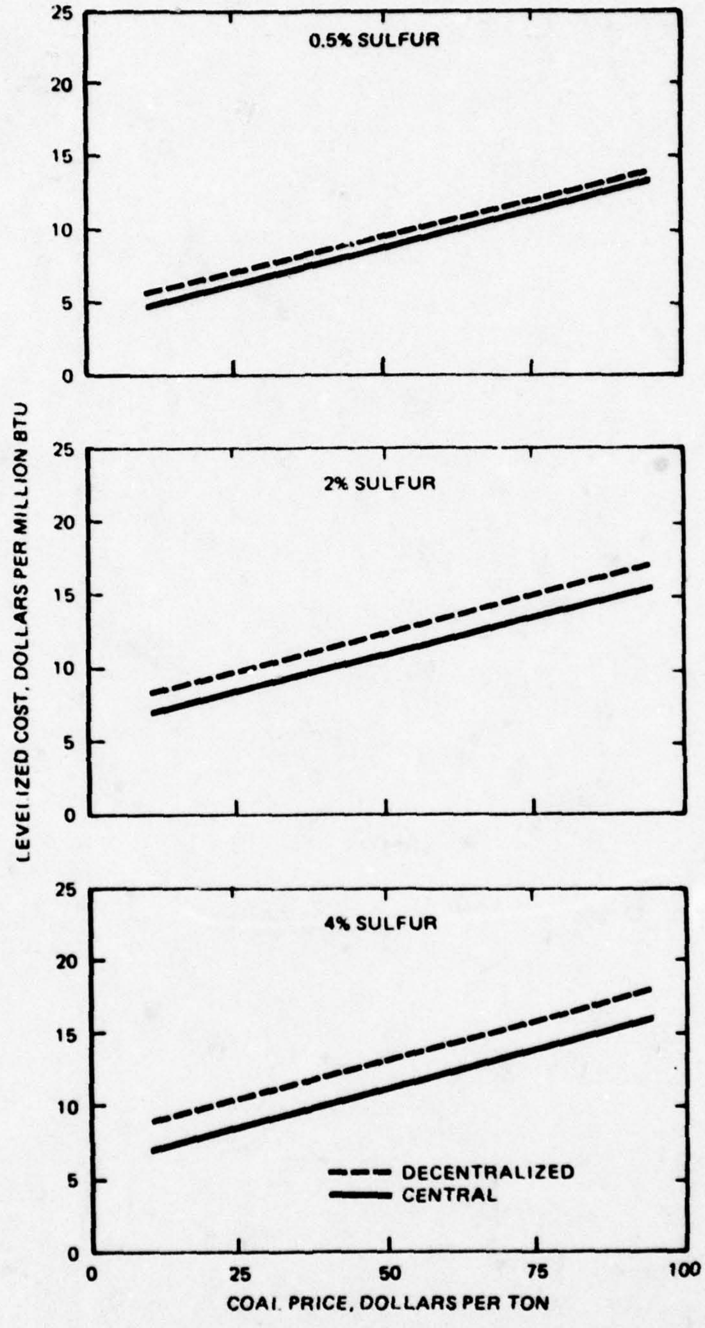

Figure 8-10
LEVELIZED COST VERSUS PRICE OF COAL, 400×10^6 BTU/HR PLANTS – DECENTRALIZED AND CENTRAL STEAM SYSTEMS

Section 9

COGENERATION OF ELECTRICITY

Electric power can be generated along with heating and process steam in a coal-fired boiler plant. This section defines systems and costs for central plants which can produce 100, 200, 400, and 800 x 10^6 Btu/hr of steam for heating use, and which also can produce electricity simultaneously. Such plants are currently referred to as cogeneration plants.

Electricity is generated from steam by passing it through a steam turbine-generator system. The turbine extracts mechanical power from the steam, and the generator converts the mechanical power into electric power. Cogeneration plants typically include the following components:

- Boilers producing high-pressure superheated steam
- Turbine-generator systems
- Heat-rejection and water-treatment equipment

The high-pressure boilers were discussed in Section 4. The other two items are discussed in this section.

In the analysis below, the costs of cogeneration will be taken to be the incremental costs of building and operating a cogeneration facility over the corresponding costs for a facility making heating steam alone. The cost of power cogenerated will be compared with the cost of purchased power.

ENERGY CONSUMPTION IN COGENERATION

Reference (1) dealt extensively with Navy cogeneration plants and developed the following two key concepts which are elaborated in Appendix H:

- The distinction between "strict cogeneration" and "condensing generation"

- The desirability of the highest feasible inlet temperature and pressure of steam entering the turbines

"Strict cogeneration" refers to power generated by steam which serves as heating steam after it leaves the turbine. "Condensing generation" refers to steam which is expanded to vacuum pressures and is then condensed in heat-rejection equipment.

In strict cogeneration, the steam leaves with residual useful energy which can be credited to the heat load that consumes it. Therefore, only the small amount of additional heat to superheat the steam is credited to electric power generation. In Appendix H it is shown that the steam system energy efficiency of strict cogeneration is 100 percent and its fuel-to-power efficiency is 80 percent. This efficiency is also often expressed as a "heat rate" of 4265 Btu of fuel consumed per kilowatt-hour of electricity produced. For the strict cogeneration cycle in this study, 17.29 pounds of steam produce one kilowatt-hour of power, plus heating steam.

In condensing generation, the steam leaving can perform no useful service. It must be condensed, with rejection of a large fraction of the heat supplied by the boiler. In this study, the condensing generation cycle rejects 69 percent of the heat transferred into the steam by the high-pressure boiler. Only 31 percent can be credited to electric power generation; the fuel-to-power efficiency is (31)(0.8) or 24.8 percent, and the heat rate is 13,770 Btu/kWhr. For the condensing generation cycle, 7.79 pounds of steam produce one kilowatt-hour of power.

A guideline in the present contract is that one kilowatt-hour can be delivered to a Navy base for each 11,600 Btu of fuel energy consumed by the local electric power company. Inspection shows that strict cogeneration conserves energy and condensing generation wastes energy compared to the 11,600 Btu/kWhr for public utility power.

In terms of energy conservation, then, it would be desirable to make as much power as possible at a Navy base by strict cogeneration. Also, if condensing generation is required, it should be done with the highest possible efficiency. Both these desiderata are met by providing the highest feasible steam temperatures and pressures at the turbine inlet. In this study, turbine inlet conditions have been chosen as follows:

- Temperature, 1000°F
- Pressure, 1450 psig

These are the highest conditions available in standard turbines in the sizes studied.

FUEL COSTS IN COGENERATION

The Reference (1) study treated cogeneration in plants burning fuel oil. There, the life-cycle cost of fuel oil was shown to be so high that, when fuel costs alone were considered, condensing generation was uneconomical except for "peak shaving," although strict cogeneration was economical. "Peak shaving" refers to power generation only during short periods of high Navy base electricity demand. By generating in the condensing mode then, it may be possible to reduce the "demand charge" cost in purchased electric power, so that the average cost in mills/kWhr is lower for each kilowatt-hour purchased. The utilities impose a demand charge as the cost for keeping generation equipment in readiness for infrequent periods of high purchaser demand. Peak shaving by the purchaser reduces the ratio between peak demand and average demand kilowatts.

At the coal and electricity prices considered in this study, both strict cogeneration and condensing generation are economical when fuel costs alone are considered. As mentioned in Section 3, the nominal coal and power costs are as follows:

- Coal: \$30/ton (10,672 Btu/lb, \$1.41/10^6 Btu)
- Purchased electricity: \$0.033/kWhr (33 mills/kWhr)

Table 9-1 is based on life-cycle parameters from Section 3 and Appendices E and F. It is apparent that if fuel were the only element in the power generation cost, on-base generation would be clearly more economical than purchasing power from the local power grid. However, capital and other operating costs must be included in the computation of cogenerated power costs. It will be seen that strict cogeneration alone may not be economical, but a combination of strict cogeneration and condensing generation can be.

Table 9-1

FUEL COST CONTRIBUTION TO COGENERATED POWER COST

	Fuel Cost For Power From Strict Cogeneration	Fuel Cost For Power From Condensing Generation	Cost of Purchased Electric Power
Current Cost, mills/kWhr	6	19.4	33
Unit Present Value, mills/kWhr	3.1	10.0	19.4
Unit Levelized Cost, mills/kWhr	10.8	34.8	67.2

DESCRIPTION OF POWER GENERATION MODULES

Figure 9-1 shows basic power generation modules. A noncondensing turbine-generator system is shown in the upper half of the figure. It is used for strict cogeneration. A condensing turbine-generator system is shown in the lower half of the figure. It is used for condensing generation, and it includes a vacuum condenser and cooling water system for heat rejection.

Figure 9-2 shows a condensing-extraction turbine-generator unit which combines both cogeneration and condensing generation capability. This is the most flexible unit, and it will be the basis for most of the studies in this section. The turbine consists of two parts, a high-pressure turbine and a low-pressure turbine. The three flow settings at the bottom of the figure illustrate some of its capabilities. At the left, the maximum amount of strictly cogenerated power is obtained. The maximum amount of steam that can flow through the high-pressure turbine is 193,000 lb/hr, a physical limitation of the turbine specified. Also, at least 9000 lb/hr of steam must always be run through the low-pressure turbine for cooling. The difference, 184,000 lb/hr, is the maximum amount of heating steam available. At this setting, the rated power output of 11.8 megawatts is obtained. In the bottom center, no steam is extracted, and all the steam flows through both the high- and low-pressure turbines. In this case, the full rated 11.8 megawatts is obtained by condensing generation only. The steam flow of 92,000 lb/hr is the physical upper limit for the low-pressure turbine. At the bottom right, a setting giving close to maximum power is shown. The maximum amount of steam flows through the high-pressure turbine. The heating steam demand is satisfied by extracting 110,000 lb/hr. The balance, 83,000 lb/hr, flows through the low-pressure turbine for condensing generation. The power output is now 17 megawatts. Any combination of flows through the high- and low-pressure turbines is possible as long as the flows do not exceed the upper or lower limits mentioned. (At very low flows, some losses of turbine efficiency occur.) A condensing-extraction unit is ideal for a situation in which the heating steam demand and the electric power demand both vary, as at Navy bases.

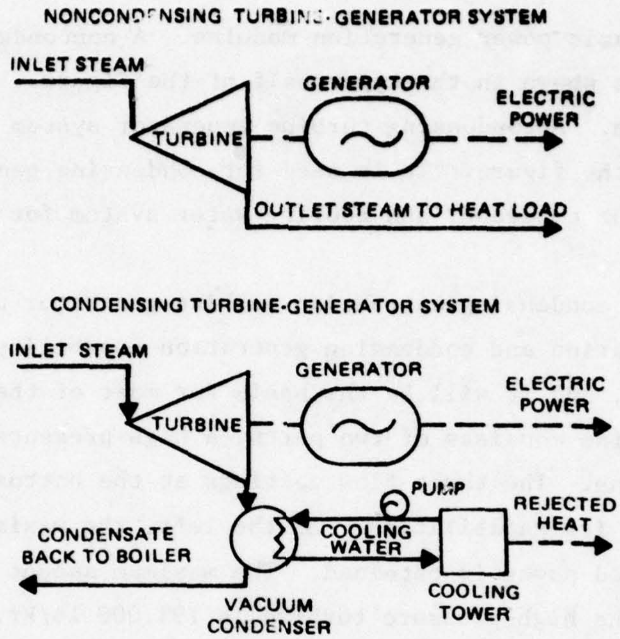

Figure 9-1
BASIC POWER GENERATION MODULES

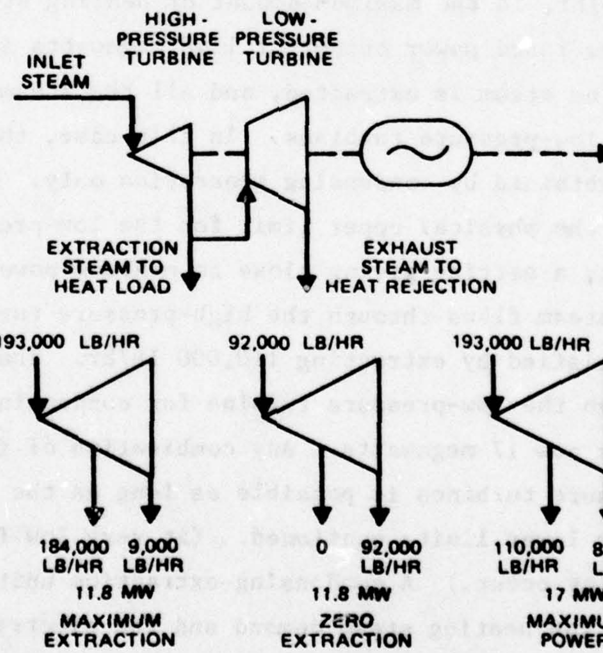

Figure 9-2
CONDENSING-EXTRACTION TURBINE-GENERATOR UNIT

COSTS OF POWER GENERATION MODULES

Table 9-2 and Figure 9-3 present the total construction costs for two of the kinds of power generation modules described above:

- System for strict cogeneration only. This includes a noncondensing turbine-generator unit which takes inlet steam at 1000°F and 1450 psia and discharges 150 psia steam. It also includes a device for blending the discharged steam with condensate to get saturated steam (the device is called a "desuperheater").

- System for both strict cogeneration and condensing generation. This includes a condensing-extraction turbine-generator unit which takes inlet steam at 1000°F and 1450 psia, and discharges 150 psia steam through the extraction outlet and condensing steam through the exhaust outlet. The module also includes a desuperheater and a heat rejection system consisting of a vacuum condenser, a cooling tower, cooling-water pumps, and associated piping.

In both cases, the total construction costs also include foundation and bulk materials (piping, electrical, and instrumentation components) as additional direct costs, plus the usual additional costs described in Section 3.

Table 9-2

TOTAL CONSTRUCTION COSTS, POWER GENERATION MODULES

Rated Electric Power Output, Megawatts	Noncondensing Turbine-Generator Modules	Condensing-Extraction Turbine-Generator Modules
2.6	2,300	
3.1		3,300
5.2	3,800	
6.25		5,100
10.45	6,200	
12.5		8,200
21.0	10,200	
25.0		14,800

Costs in thousands of dollars second quarter 1978 prices.

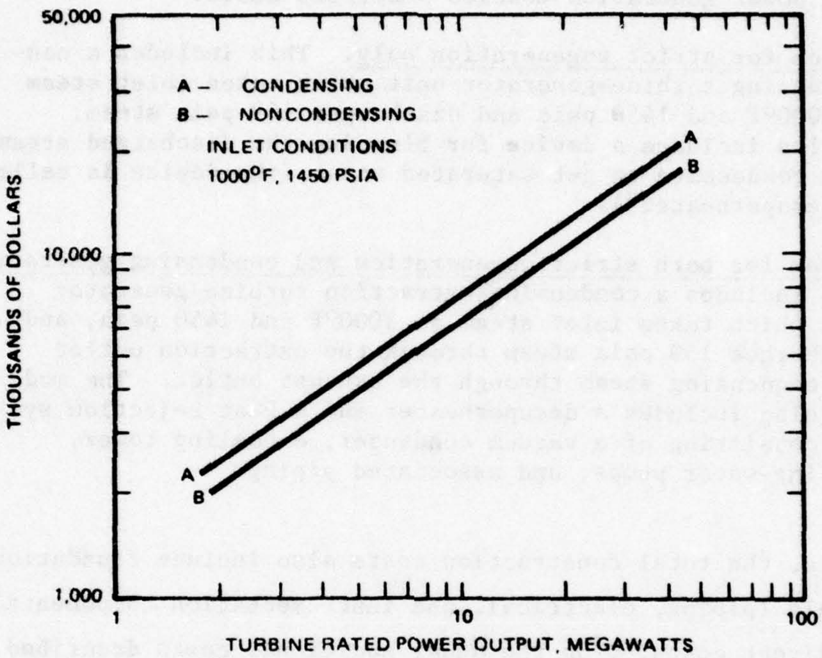

Figure 9-3

TOTAL CON. TRUCTION COSTS, POWER GENERATION MODULES

DESCRIPTION OF COGENERATION PLANTS

Figure 9-4 is a block flow diagram for a cogeneration plant containing a condensing-extraction turbine-generator module. The plant capacity is 400,000 pounds per hour of 150 psia saturated heating steam at maximum output, which is identical with that of the 400 x 10^6 Btu/hr "steam only" central plant described in Section 8. Table 9-3 is the associated table of stream flows.

The assumed annual heating steam demand profile has led to the configuration shown. The configuration has a high-pressure boiler and cogeneration system that can produce 200,000 lb/hr of heating steam. This system will produce heating steam with an annual load factor of 60 percent. A separate 200,000 lb/hr low-pressure system operates only when the heating steam demand exceeds 50 percent of total design demand. This boiler has an annual load factor of 6 percent. Between them, the two systems contribute the following to the total annual heating steam load factor:

High-pressure system	30 percent
Low-pressure system	3 percent
Total annual load factor	33 percent

The following components are included in the 400 x 10^6 Btu/hr system:

- One power generation module containing a condensing-extraction turbine-generator unit rated at 12.5 megawatts and with a maximum power output of 18 megawatts
- Two high-pressure steam boilers, each rated at 97,000 lb/hr of steam, consuming up to 160 x 10^6 Btu/hr in coal and transferring 128 x 10^6 Btu/hr of heat into the steam system
- A feedwater demineralization plant for the high-pressure boilers
- Two low-pressure steam boilers, each producing 100,000 lb/hr of steam

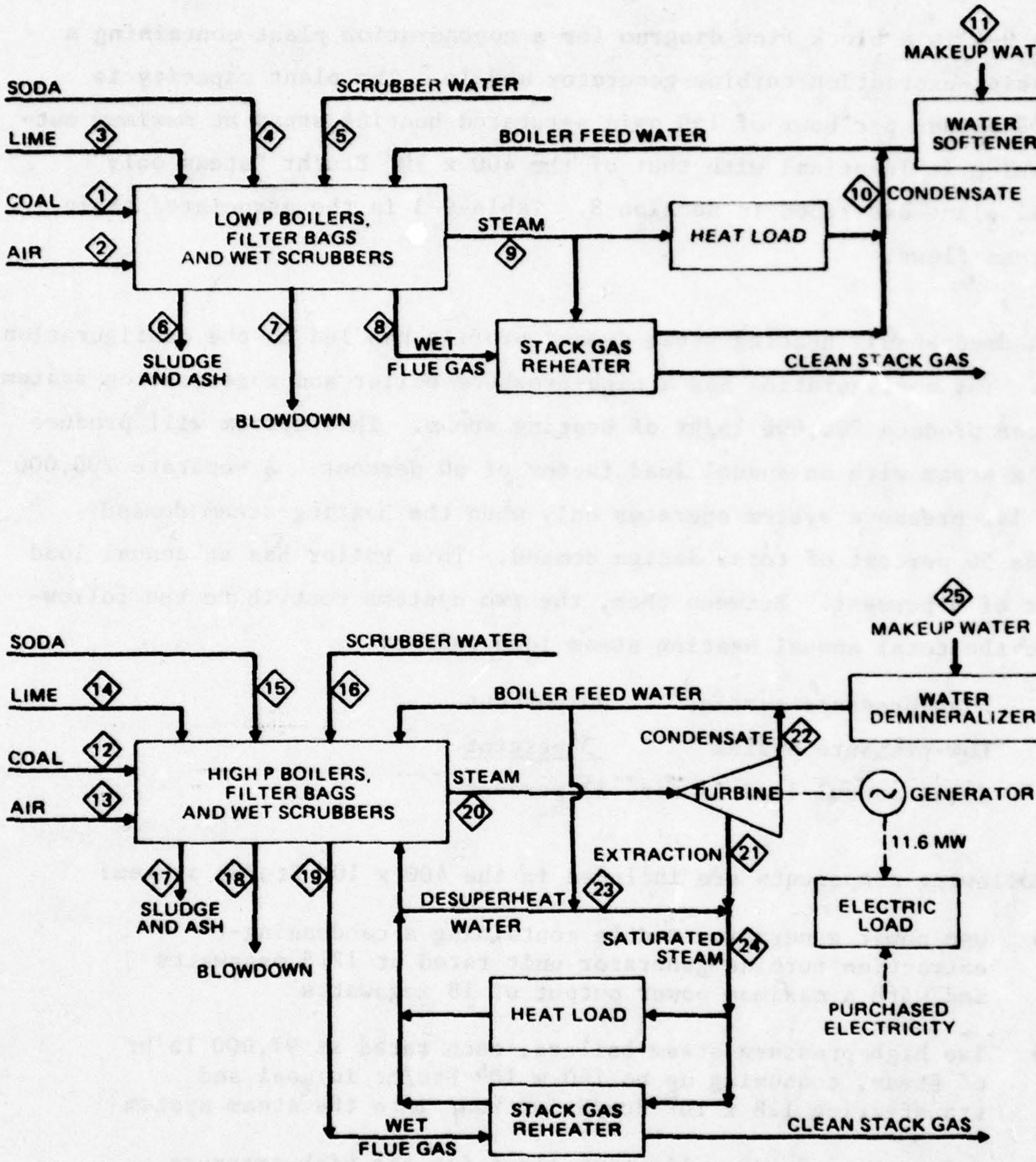

Figure 9-4
400 x 10^6 BTU/HR STEAM AND ELECTRICITY COGENERATION SYSTEM
BLOCK DIAGRAM
(2% S COAL)

Table 9-3

STREAM FLOWS FOR 400 x 10^6 BTU/HR STEAM AND ELECTRICITY COGENERATION SYSTEM (2% S COAL)

Stream Number	Stream Name	Temperature ^oF	Pressure psia	Mass Flowrate lb/hr
	LOW-PRESSURE STEAM BOILERS			
1	Coal	77	14.7	23,426
2	Air	77	14.7	248,403
3	Lime	77	14.7	528
4	Soda	77	14.7	106
5	Scrubber Water	77	14.7	12,250
6	Sludge and Ash	120	14.7	8,611
7	Blowdown	—	—	2,000
8	Wet Flue Gas	120	14.7	276,103
9	Low P Steam	366	165	200,000
10	Condensate	—	—	200,000
11	Makeup Water	77	14.7	2,000
	HIGH-PRESSURE STEAM BOILERS			
12	Coal	77	14.7	30,106
13	Air	77	14.7	319,238
14	Lime	77	14.7	679
15	Soda	7	14.7	136
16	Scrubber Water	77	14.7	15,743
17	Sludge and Ash	120	14.7	11,067
18	Blowdown	—	—	2,000
19	Wet Flue Gas	120	14.7	354,800
20	High P Steam	1,000	1,450	193,000
21	Turbine Extraction	540	165	184,000
22	Turbine Condensate	109	1.23	9,000
23	Desuperheat Condensate	109	—	16,000
24	Saturated Steam	366	165	200,000
25	Makeup Water	77	14.7	2,000

- A separate pair of 60-percent-capacity scrubbers for each of the two sets of boilers (for 2% and 4% S coal), plus corresponding baghouses

- A central coal handling system to supply 570×10^6 Btu/hr of coal heat content (a plant transferring 456×10^6 Btu/hr of heat)

Note that this system includes two pairs of scrubbers as compared with a single pair of larger scrubbers for the steam-only central plant of Section 8. If the larger single pair were substituted in this case, the cost of cogenerated power would be about 5 percent lower.

The base case for evaluating this system assumes that condensing generation is to be used only for peak shaving. The high-pressure system produces on the average 60 percent of its maximum output of heating steam. Over and above the amount of high-pressure steam necessary for this, 25 percent extra steam is fed on the average to the condensing generation system, for a combination of cooling and periodic peak shaving. A total of 7.37 megawatts is produced on the average, as follows:

- Cogeneration (60% of maximum) 6.36 MW
- Peak shaving 0.41 MW
- Cooling flow 0.60 MW*

Over a year, the total electrical energy generated is 64.6×10^6 kWhr.

Table 9-4 presents the annual utility requirements of the base case cogeneration plant for 2 percent sulfur coal. Table 9-5 summarizes the annual flows of materials and electricity for all three sulfur levels and compares them with the corresponding flows for a central steam-only plant from Section 8.

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*The cooling flow rate is so low that inefficiencies occur in the low-pressure turbine. Here, the cooling steam produces 0.45 megawatt less than calculated from the 7.79 pounds/kWhr steam rate presented earlier.

Table 9-4

ANNUAL UTILITIES FOR 400 x 10^6 BTU/HR
BASE CASE COGENERATION PLANT
(2% Sulfur)

	Electricity 10^3 kWhr	Water 10^3 Gallon
Coal preparation	350	-
L-P boilers	22	134
Scrubbers for L-P boiler	124	780
H-P boilers	1,813	1,336
Scrubbers for H-P boiler	1,679	10,750
Miscellaneous	202	40,600*
Total	4,190	53,600

Base Case: 33% Load Factor, peak shaving.

*Cooling tower evaporation 25,700 lb/hr and blowdown 12,900 lb/hr annual average.

It is useful to see how the energy saving was computed:

- The cogeneration plant will produce 64.60 x 10^6 kWhr per year. Subtracting the amount consumed by the plant yields net production.
- The central steam plant power consumption will not be purchased if a cogeneration plant is installed. Therefore, to calculate the difference, the amount is added to the net electricity produced, yielding the totals at the bottom of Table 9-5.

Table 9-6 presents the operating manpower requirements for the 400 x 10^6 Btu/hr cogeneration plant.

Table 9-5

ANNUAL FLOW COMPARISONS,
400×10^6 BTU/HR COGENERATION AND STEAM-ONLY PLANTS

Coal Sulfur Content		"Steam-Only" Central Plant			Base Case Cogeneration Plant		
		0.5%S	2%S	4%S	0.5%S	2%S	4%S
Annual Mass Flow	Coal, tons/yr	67,700	67,700	67,700	90,000	90,000	90,000
	Lime, tons/yr	—	1,500	3,700	—	2,000	4,910
	Soda, tons/yr	—	300	740	—	2,000	4,910
	Water, 10^3 gallons/yr	1,470	10,140	11,270	42,070	53,600	55,350
	Sludge & Ash Disposal, tons/yr	—	24,800	35,600	—	33,000	47,340
	Ash Disposal, tons/yr	17,150	—	—	22,800	—	—
	Plant Power Consumption, 10^6 kWhr/yr	1.47	2.97	2.97	2.19	4.19	4.19
Electricity	Electricity, Generated, 10^6 kWhr/yr	—	—	—	64.60	64.60	64.60
	Net Electricity Produced, 10^6 kWhr/yr	—	—	—	62.41	60.41	60.41
Net Electricity Not Purchased 10^6 kWhr/yr					63.88	63.38	63.38

Base Case: 33% load factor; peak shaving.
Each plant produces 1168×10^6 pounds per year of heating steam.

Table 9-6

OPERATING MANPOWER
400 X 10^6 BTU/HR COGENERATION PLANT

Sulfur Content	0.5%	2%	4%
Coal Receiving and Preparation	8	8	8
Steam Generation	9	9	9
Power Generation	13	13	13
Air Pollution Control	2	11	11
Waste Disposal	1	2	3
Total	33	43	44

COSTS OF BASE CASE COGENERATION PLANTS

Table 9-7 presents capital costs for the base case 400 x 10^6 Btu/hr cogeneration plant. Table 9-8 presents the annual operating and maintenance costs under the base case plan of operation. Table 9-9 summarizes capital and annual costs for plant sizes from 100 to 800 x 10^6 Btu/hr, under the same operating plan. Figure 9-5 plots the capital and annual costs.

Table 9-10 shows present values for the 400 x 10^6 Btu/hr plants. Figure 9-6 plots present values for all plant sizes.

Table 9-7

CAPITAL COSTS, 400 X 10^6 BTU/HR COGENERATION PLANT

Coal Sulfur Content	0.5%	2%	4%
Coal Receiving and Preparation	4,600	4,600	4,600
Steam Generation	20,000	20,000	20,000
Power Generation	8,200	8,200	8,200
Air Pollution Control	700†	11,300	13,300
Total Construction Cost	33,500	44,100	46,100
Startup	3,700	4,800	5,000
Total Capital Cost	37,200	48,900	51,100

Second Quarter, 1978, Price Level
†Baghouse only; FGD system not required
Plant contains condensing-extraction turbine-generator unit.
Costs in thousands of dollars.

Table 9-8

OPERATING AND MAINTENANCE COSTS
400 X 10^6 BTU/HR BASE-CASE COGENERATION PLANT

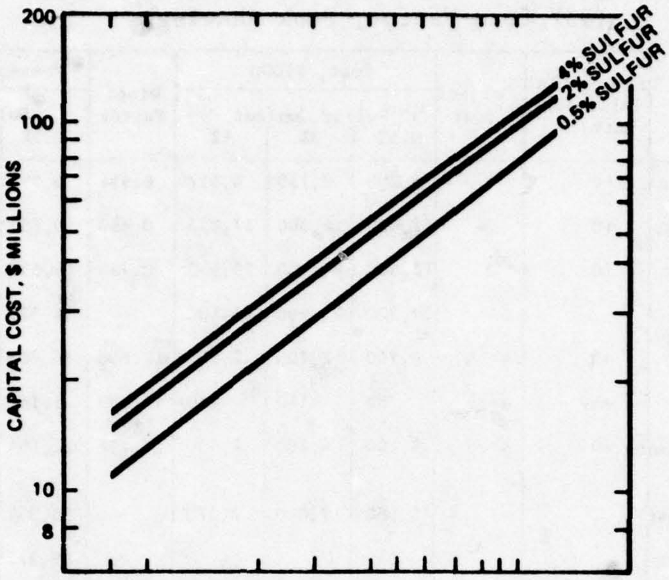
	$1000's		
Percent Sulfur	0.5%	2%	4%
Coal @ $30/ton	2700	2700	2700
Operating Labor			
Coal Receiving and Preparation	320	320	320
Steam and Power Generation	840	840	840
Total Steam & Power Generation	1160	1160	1160
Air Pollution Control	80	420	420
Waste Disposal	40	80	120
Total Pollution Control	120	500	540
Total Operations Labor	1280	1660	1700
Maintenance Labor			
Coal Receiving and Preparation	90	90	90
Steam and Power Generation	570	570	570
Total Steam & Power Generation	660	660	660
Air Pollution Control & Waste Disposal	20	230	270
Total Maintenance Labor	680	890	930
Total Labor	1960	2550	2630
Material and Supplies			
Electricity	80	80	80
Coal Receiving and Preparation	170	170	170
Steam and Power Generation	920	920	920
Total Steam & Power Generation	1170	1170	1170
Electricity	0	60	60
Air Pollution Control	30	510	760
Waste Disposal	20	50	50
Total Pollution Control	50	620	870
Total Materials & Supplies	1220	1790	2040
Total O&M Cost	5880	7040	7370

Base Case: 33% load factor; peak shaving.

Table 9-9

BASE CASE COGENERATION PLANT COSTS
THOUSANDS OF DOLLARS
(33% load factor, peak shaving)

	3,125 kW Capacity			6,750 kW Capacity			12,500 kW Capacity			25,000 kW Capacity		
Percent Sulfur	0.5%	2%	4%	0.5%	2%	4%	0.5%	2%	4%	0.5%	2%	4%
10^6 Btu/Hr	100			200			400			800		
Capital Costs												
Steam and Power Generation	11,600	11,600	11,600	19,200	19,200	19,200	32,800	32,800	32,800	57,500	57,500	57,500
Pollution Control	200	4,300	5,200	500	7,300	8,400	700	11,300	13,300	1,100	18,300	22,200
Total Construction Cost	11,800	15,900	16,800	19,700	26,500	27,600	33,500	44,100	46,100	58,600	75,800	79,700
Startup	1,400	1,800	1,800	2,100	3,000	3,000	3,700	4,800	5,000	6,400	8,400	8,800
Total Capital Cost	13,200	17,700	18,600	21,800	29,500	30,600	37,200	48,900	51,100	65,000	84,200	88,500
Central Steam Plant Capital Cost	6,400	9,900	10,500	11,100	16,500	17,500	19,[illegible]	28,100	29,100	33,200	47,500	50,000
Cogeneration less Steam Plant Cost	6,800	7,800	8,100	10,700	13,000	13,100	18,000	20,800	22,000	31,800	36,700	38,500
$/kW Generating Capacity	2,176	2,496	2,592	1,712	2,080	2,096	1,400	1,664	1,760	1,272	1,468	1,540
Operating and Maintenance Costs												
Labor												
Steam and Power Generation	700	700	700	1,130	1,130	1,130	1,820	1,820	1,820	2,940	2,940	2,940
Pollution Control	60	300	300	90	450	500	140	730	810	230	1,180	1,310
Total Labor	760	1,000	1,000	1,220	1,580	1,630	1,960	2,550	2,630	3,170	4,120	4,250
Electricity	20	40	40	40	70	70	80	140	140	160	280	280
Materials and Supplies												
Steam and Power Generation	280	280	280	550	550	550	1,090	1,090	1,090	2,180	2,180	2,180
Pollution Control	20	140	210	30	280	410	50	560	810	100	1,120	1,620
Total Materials and Supplies	300	420	490	580	830	960	1,140	1,650	1,900	2,280	3,300	3,800
Coal at $30/ton	700	700	700	1,400	1,400	1,400	2,700	2,700	2,700	5,400	5,400	5,400
Total O&M Cost	1,780	2,160	2,230	3,240	3,880	4,060	5,880	7,040	7,370	11,010	13,100	13,730



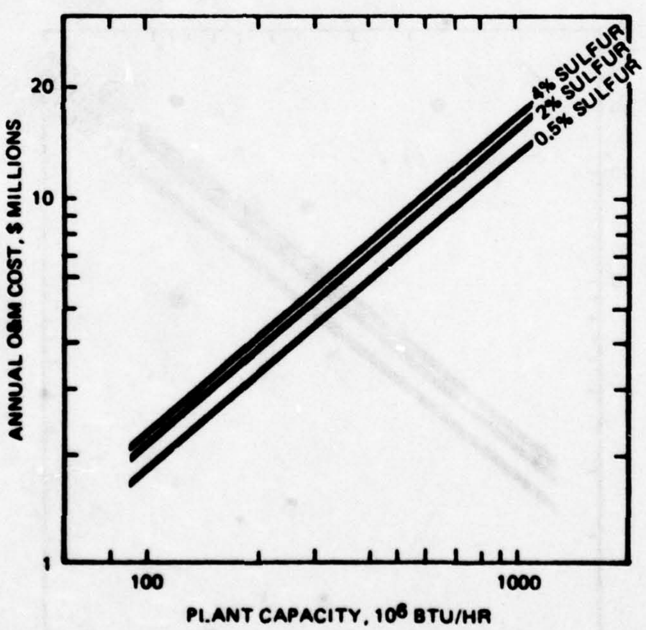


Figure 9-5
CAPITAL AND OPERATING AND MAINTENANCE COSTS, BASE CASE COGENERATION PLANTS (33% LOAD FACTOR; PEAK SHAVING)

Table 9-10

LIFE-CYCLE PRESENT VALUES,
400 x 10^6 BTU/HR BASE-CASE COGENERATION PLANT
(33% Load Factor; Peak Shaving)

Cost Element	Differential Inflation Rate, %	Project Year	Cost, $1000			Disc. Factor	Present Value, $1000		
			Sulfur Content				Sulfur Content		
			0.5%	2%	4%		0.5%	2%	4%
1st Year Construction	+0	1	6,200	8,150	8,517	0.954	5,915	7,775	8,125
2nd Year Construction	+0	2	12,400	16,300	17,033	0.867	10,751	14,132	14,768
3rd Year Construction	+0	3	18,600	24,450	25,550	0.788	14,657	19,267	20,133
Total Investment			37,200	48,900	51,100	—	31,323	41,174	43,026
Coal	+5	4-28	2,700	2,700	2,700	12.853	34,703	34,703	34,703
Electricity	+6	4-28	80	140	140	14.588	1,167	2,042	2,042
Operating and Maintenance Labor & Materials	+0	4-28	3,100	4,200	4,530	7.156	22,184	30,055	32,417
Total Operating Cost			5,880	7,040	7,370	—	58,054	66,800	69,162
Total Present Value							89,377	107,974	112,188

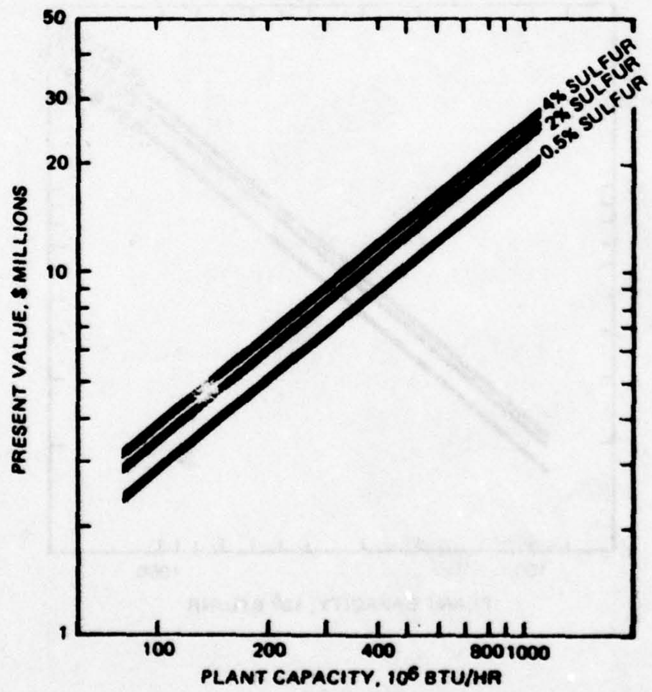


Figure 9-6
PRESENT VALUES, BASE CASE COGENERATION PLANTS
(33% LOAD FACTOR; PEAK SHAVING)

COSTS OF BASE-CASE COGENERATED POWER

Unit cost of cogenerated power is the difference in present values between cogeneration and steam-only plants, divided by the net life-cycle electric power produced (the amount at the bottom of Table 9-5, times 25 years). Table 9-11 derives unit present values in mills/kWhr for the 400 x 10^6 Btu/hr base case plants. Figures 9-7 and 9-8 show the unit present values and levelized costs for plant sizes between 100 and 800 x 10^6 Btu/hr.

Figures 9-9 and 9-10 show the effects of coal price on the unit present value and levelized costs of cogenerated power from a base-case plant. Although, at high coal prices, base-case cogeneration is uneconomical compared to a 33 mills/kWhr purchased electricity price, at higher electricity prices it may be economical. Table 9-12 converts the current price of power to corresponding unit present values and levelized costs using the methods of Section 3 and Appendices E and F.

Figures 9-11 and 9-12 show the sensitivity of base-case cogenerated power costs to capital costs and to operating labor costs, expressed in unit present values. It is clear from these figures that a 20-percent reduction in capital costs could lead to a significant reduction in cogenerated power costs, but a 20-percent reduction of the annual labor cost would not have a noticeable effect.

Table 9-11

UNIT PRESENT VALUES OF COGENERATED POWER
400 x 10^6 BTU/HR BASE CASE PLANT

Coal Sulfur Content	Cost Item	Cogen-eration	Steam Only	Differ-ence	Unit Present Values mills/kWhr
0.5%	Capital	31,323	15,635	15,688	9.8
	Fuel	34,703	25,706	8,997	5.6
	O&M	22,184	14,455	7,729	4.9
	Total	88,210	55,796	32,414	20.3
2%	Capital	41,174	22,883	18,291	11.5
	Fuel	34,703	25,706	8,997	5.7
	O&M	30,055	22,613	7,442	4.7
	Total	105,932	71,202	34,730	21.9
4%	Capital	43,026	23,697	19,329	12.2
	Fuel	34,703	25,706	8,997	5.7
	O&M	32,417	23,686	8,731	5.5
	Total	110,146	73,089	37,057	23.4

Notes

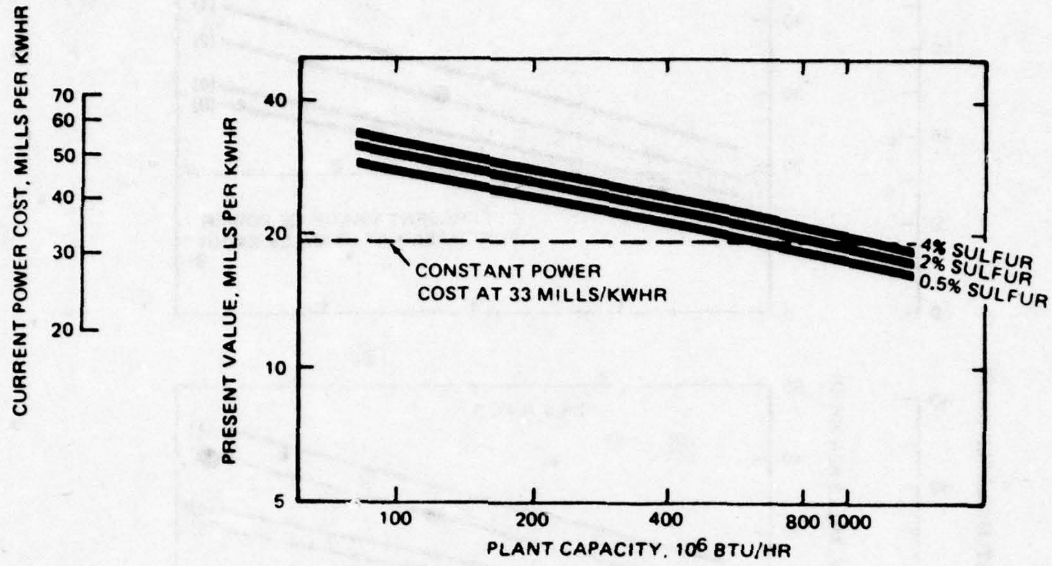
- Present values in thousands of second quarter 1978 dollars.
- Operating and Maintenance (O&M) excludes cost of electricity consumed by the plant.
- Coal at $30/ton.
- Net electricity not purchased over 25 years: 1,584 x 10^6 kWhr.
- Base Case: 33% load factor; peak shaving.

Table 9-12

CONVERSION OF CURRENT POWER PRICES
TO PRESENT VALUES AND LEVELIZED COSTS

Mills per kWhr		
Current Price	Present Value*	Levelized Cost
25	14.7	50.9
30	17.6	61.1
33	19.3	67.2
35	20.5	71.3
40	23.4	81.5
45	26.3	91.7
50	29.2	101.8

*Based on differential inflation rate of 6% per year for 25 years beginning fourth project year.



COAL AT $30 PER TON

33% LOAD FACTOR; PEAK SHAVING

Figure 9-7

UNIT PRESENT VALUES, BASE CASE COGENERATED POWER

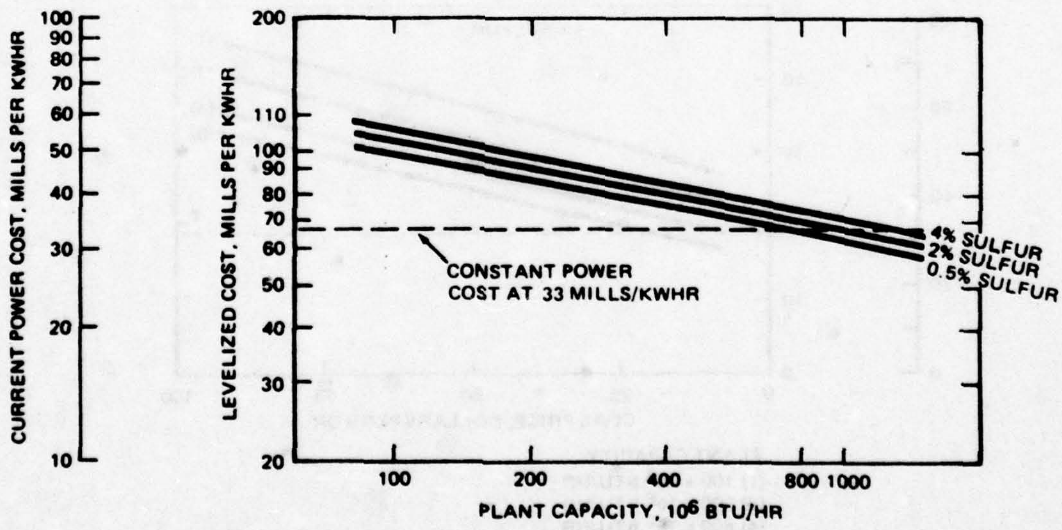
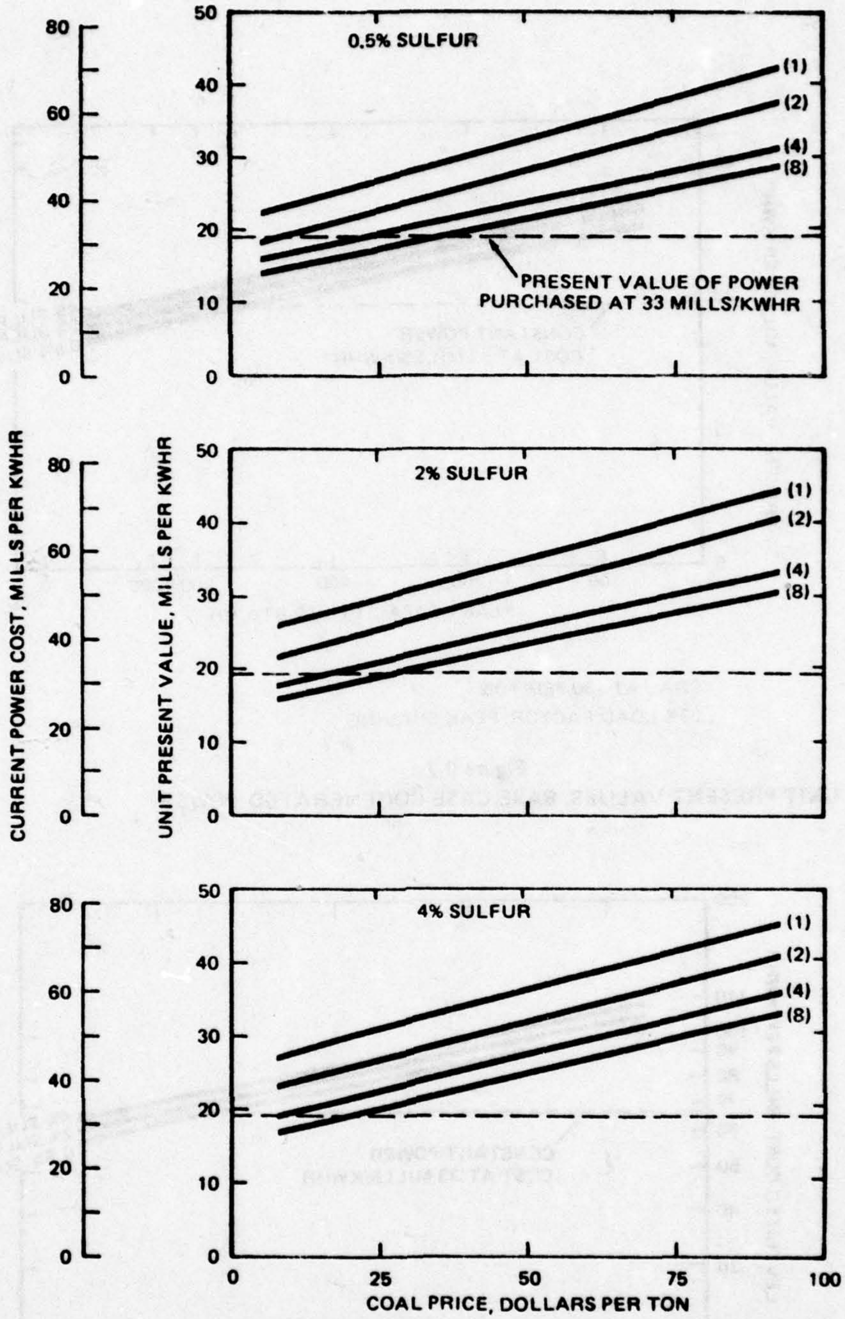


Figure 9-8

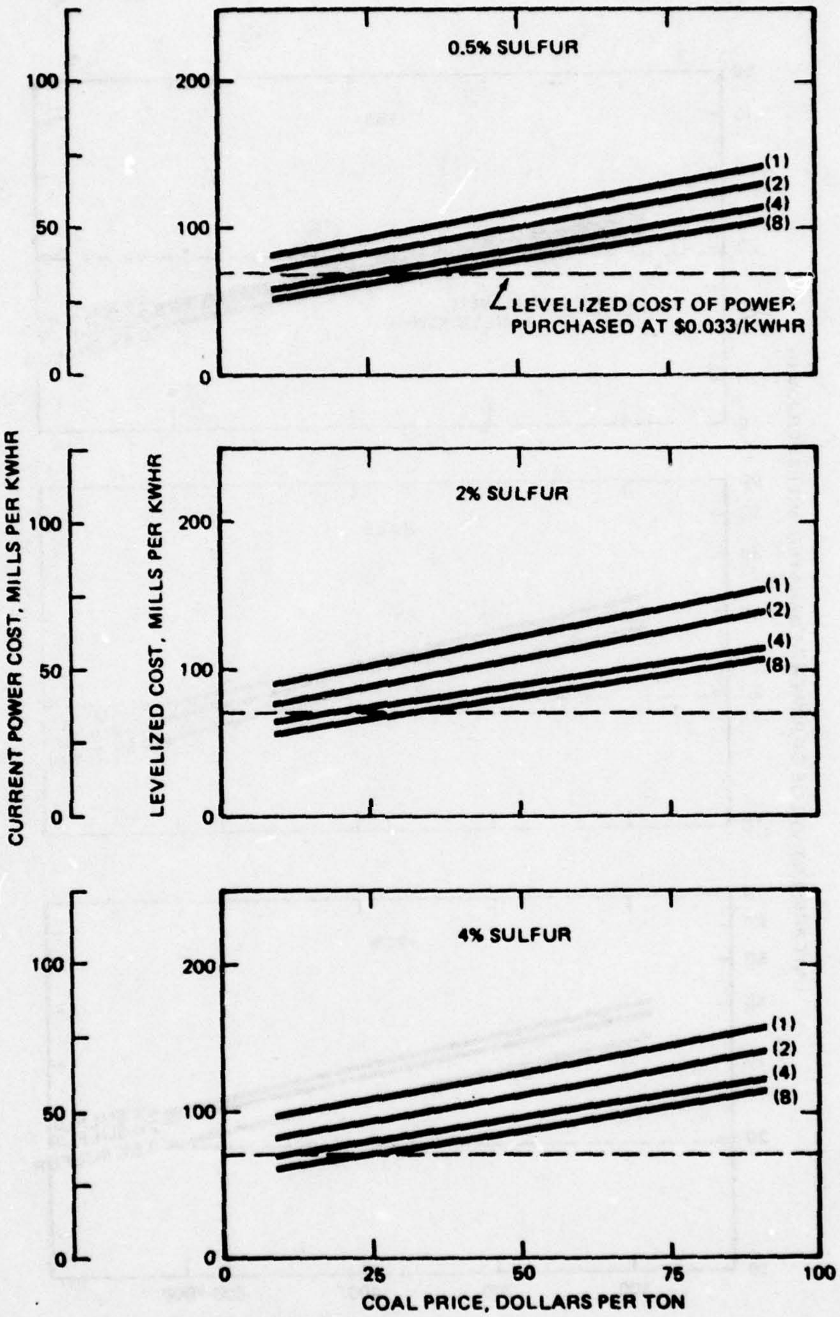
LEVELIZED UNIT ENERGY COSTS, BASE CASE COGENERATED POWER (33% LOAD FACTOR; PEAK SHAVING)



PLANT CAPACITY:
(1) 100 x 10^6 BTU/HR
(2) 200 x 10^6 BTU/HR
(4) 400 x 10^6 BTU/HR
(8) 800 x 10^6 BTU/HR

Figure 9-9

EFFECT OF COAL PRICE ON UNIT PRESENT VALUE OF COGENERATED POWER, BASE CASE (33% LOAD FACTOR, PEAK SHAVING)



PLANT CAPACITY =
(1) 100×10^6 BTU/HR
(2) 200×10^6 BTU/HR
(4) 400×10^6 BTU/HR
(8) 800×10^6 BTU/HR

Figure 9-10
EFFECT OF COAL PRICE ON LEVELIZED COST OF COGENERATED POWER, BASE CASE (33% LOAD FACTOR, PEAK SHAVING)

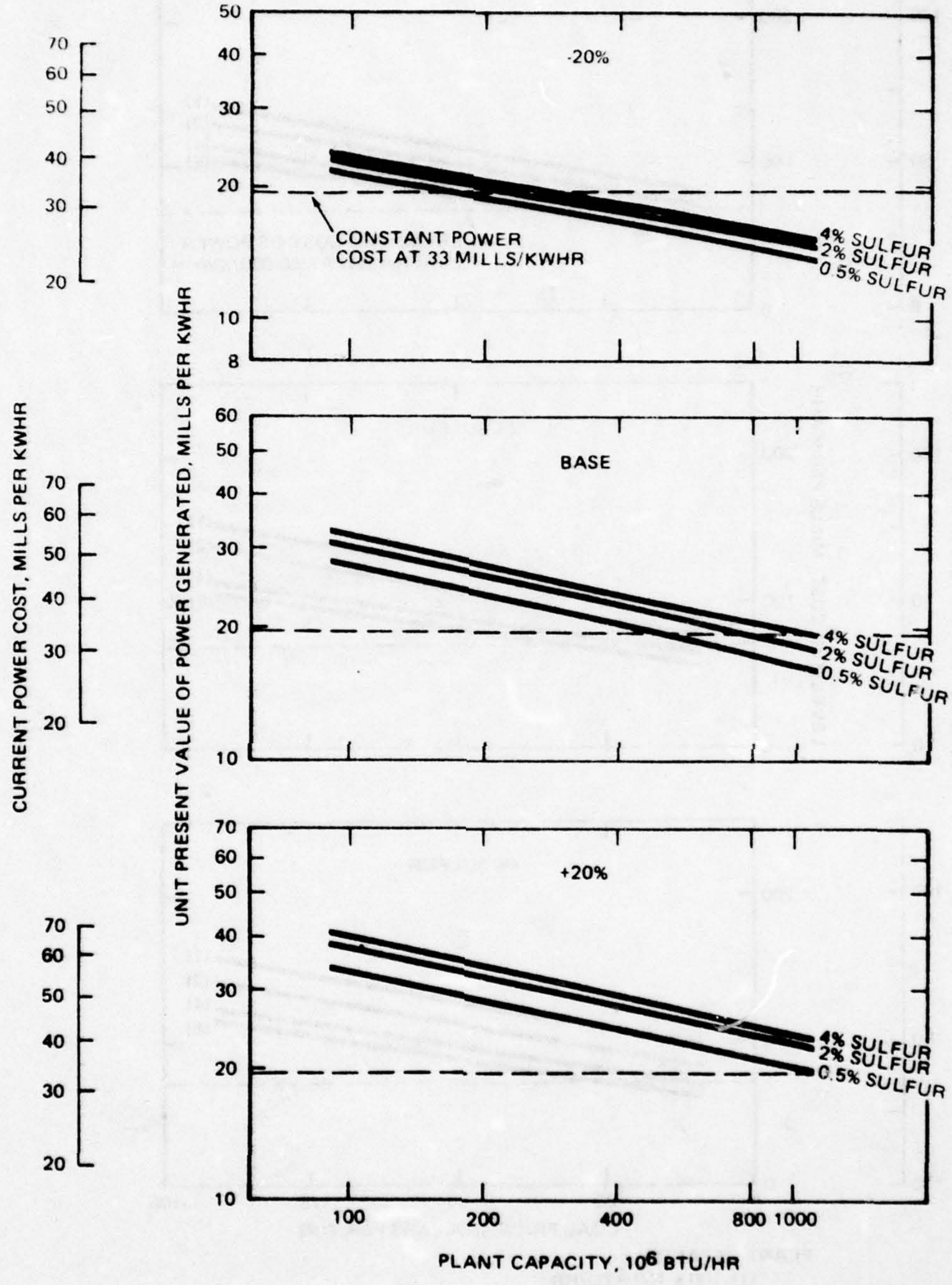


Figure 9-11
SENSITIVITY TO CAPITAL COST OF COGENERATED POWER COST, BASE CASE (33% LOAD FACTOR; PEAK SHAVING)

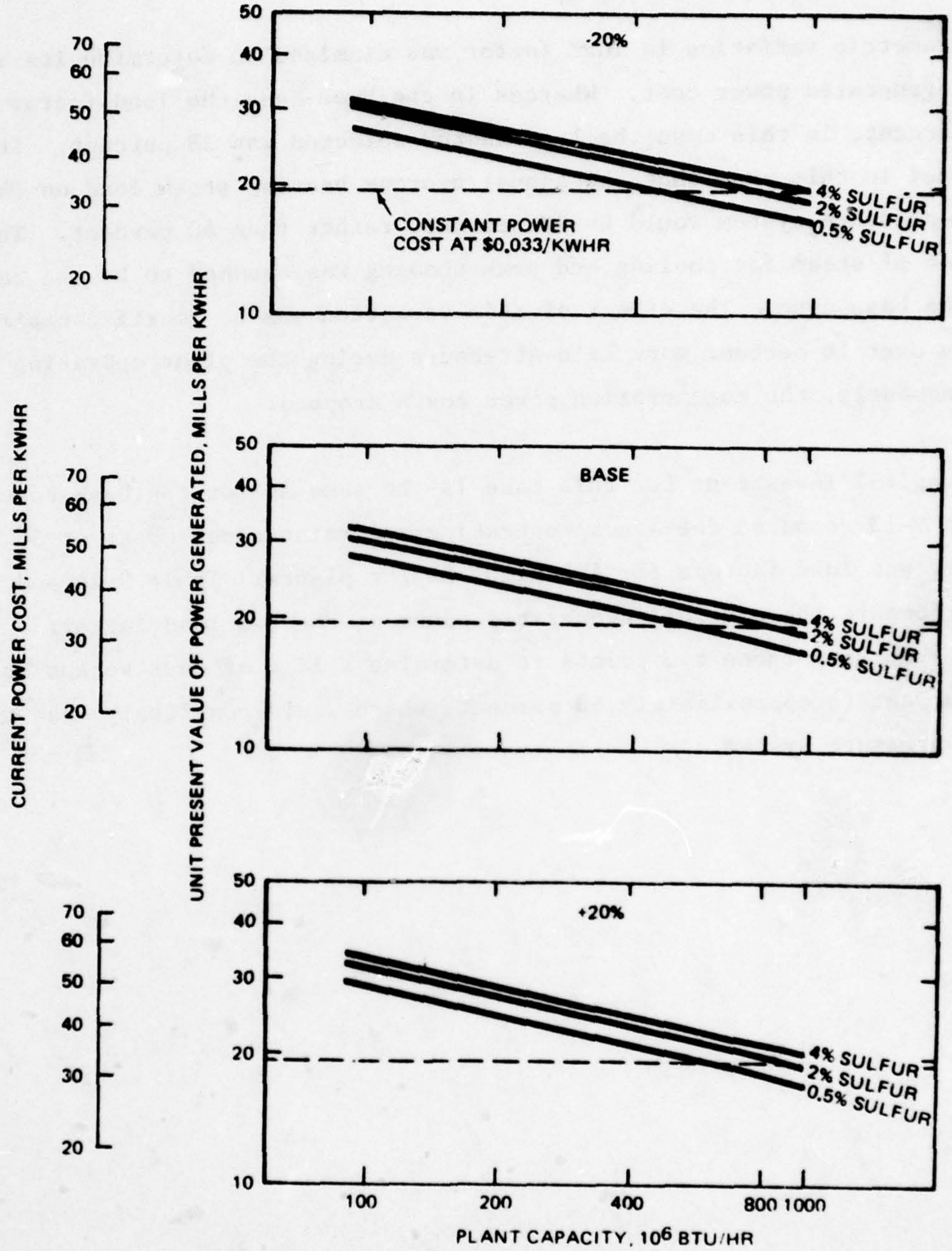


Figure 9-12
SENSITIVITY TO ANNUAL LABOR COST OF COGENERATED POWER COST, BASE CASE (33% LOAD FACTOR, PEAK SHAVING)

EFFECT OF INCREASED LOAD FACTOR

A parametric variation in load factor was examined to determine its effect on cogenerated power cost. Whereas in the base-case the load factor was 33 percent, in this case the load factor selected was 38 percent. It was assumed in this case that the annual average heating steam load on the high-pressure system would be 70 percent, rather than 60 percent. The amount of steam for cooling and peak shaving was assumed to be the same as in the base case. The effect of this variation was to amortize capital costs over 16 percent more kilowatt-hours during the plant operating life. Consequently, the cogeneration power costs dropped.

The capital investment for this case is the same as for the base case. Table 9-13 compares the annual operating and maintenance costs at 38 and 33 percent load factors for 400 x 10^6 Btu/hr plants. Table 9-14 and Figure 9-13 compare the cost of cogenerated power at the two load factors. Figure 9-14 then uses those two points to determine a line of cost versus load factor out to approximately 50 percent, which would completely load the high-pressure system.

Table 9-13

EFFECT OF LOAD FACTOR ON
ANNUAL OPERATING AND MAINTENANCE COSTS
(400 X 10^6 BTU/HR PLANTS, 2% S COAL, PEAK SHAVING)

Plant	Cogeneration		Steam Only	
Load Factor	33%	38%	33%	38%
Coal at $30/T	2700	3070	2000	2340
Electricity	140	160	100	110
Labor	2550	2550	2010	2010
Materials and Supplies	1605	1650	1150	1150
Total	7040	7430	5260	5610

Costs in thousands of second quarter 1978 dollars.

Table 9-14

EFFECT OF LOAD FACTOR ON THE
UNIT PRESENT VALUE OF COGENERATED POWER
(400 X 10^6 BTU/HR PLANTS, 2% S COAL, PEAK SHAVING)

	33% Load Factor				38% Load Factor			
	Cogen-eration	Steam Only	Differ-ence	Mills/kWhr	Cogen-eration	Steam Only	Differ-ence	Mills/kWhr
Capital	41,174	22,883	18,291	11.5	41,174	22,883	18,291	10.1
Fuel	34,703	25,706	8.997	5.7	39,459	30,076	9,383	5.2
O&M	30,055	22,613	7,442	4.7	32,389	24,217	8,172	4.5
Total	105,932	71,202	34,730	21.9	113,022	77,176	35,846	19.8

- Present values in thousands of second quarter 1978 dollars.
- Life-cycle power saving for 38% load factor is 1897 x 10^6 kWhr.
- Operating and maintenance (O&M) cost excludes cost of electricity consumed by the plant.

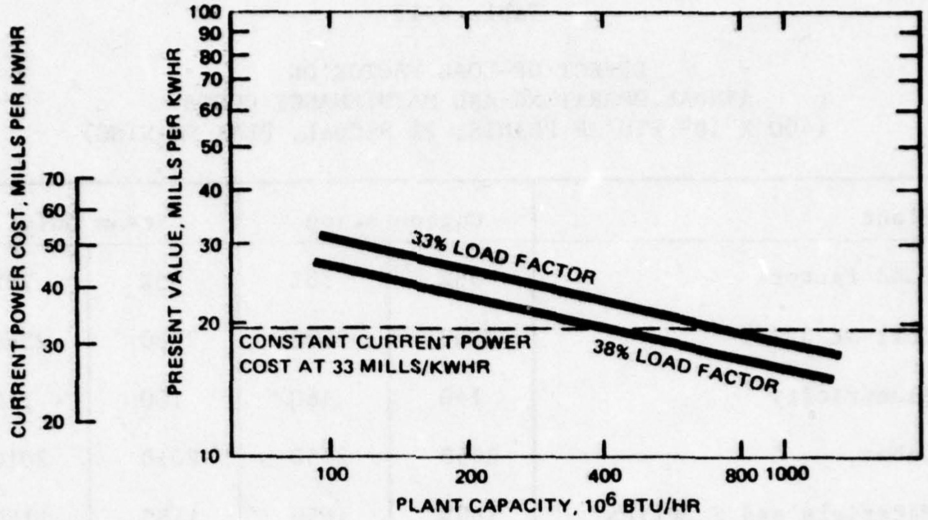


Figure 9-13

EFFECT OF LOAD FACTOR ON COST VERSUS PLANT SIZE FOR COGENERATED POWER (2% SULFUR COAL)

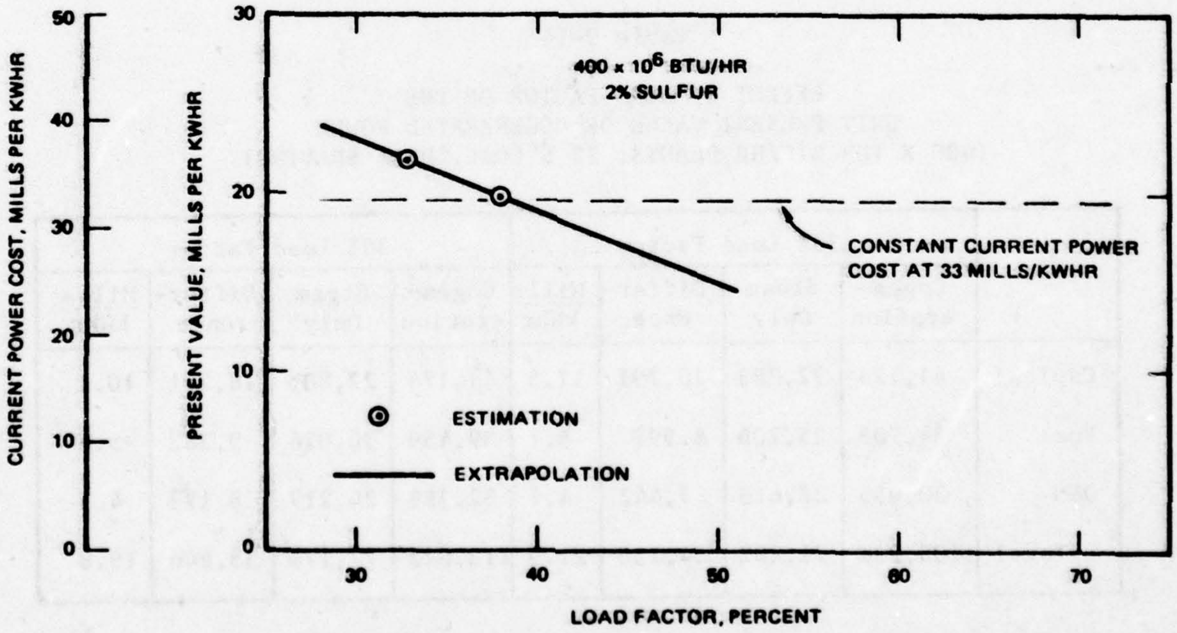


Figure 9-14

COST VERSUS LOAD FACTOR, COGENERATED POWER

(400 x 10^6 BTU/HR PLANT, 2%S, PEAK SHAVING)

EFFECT OF MAXIMUM CONDENSING GENERATION

A parametric variation was performed on the amount of condensing generation to determine its effect on cogenerated power cost. In the base-case strategy, condensing generation was used only for peak shaving. In this case, the maximum possible flow of condensing steam was selected, consistent with the cogeneration steam flow for a 33-percent load factor. The turbine flows are those shown at the bottom right of Figure 9-2.

The results are shown in Table 9-15 and Figure 9-15. It can be seen that maximum condensing generation now makes even the smallest central cogeneration plant economically feasible, whereas, with peak shaving only, all the cogeneration plants were marginal.

COSTS WITH A NONCONDENSING TURBINE

As a final study, a noncondensing turbine was substituted for the condensing-extraction turbine considered so far. In this case, only strict cogeneration can now occur, since there are no provisions for condensing generation in the equipment.

Table 9-16 compares the capital and annual costs of cogeneration facilities with the two types of turbine systems. The unit present values of cogenerated power for the two systems are plotted versus plant capacity in Figure 9-16, for the 33% load factor and 2% sulfur coal. It can be seen that a noncondensing turbine system offers a very slight reduction in cost compared to the condensing-extraction turbines with the peak shaving strategy.

Table 9-15

EFFECT OF MAXIMUM CONDENSING GENERATION ON THE COST OF COGENERATED POWER

Capacity, 10^6 Btu/Hr	Coal % S	Peak Shaving Unit Present Value	Maximum Condensing Unit Present Value	Maximum Condensing Levelized Cost
800	0.5	18.7	13.4	46.9
800	2	20.0	14.0	48.9
800	4	21.2	14.5	50.7
400	0.5	20.3	14.1	49.2
400	2	21.9	14.8	51.7
400	4	23.4	15.5	54.1
200	0.5	23.9	15.7	54.8
200	2	26.7	16.9	59.1
200	4	27.8	17.4	60.7
100	0.5	27.9	17.4	60.9
100	2	30.5	18.6	64.8
100	4	32.0	19.2	67.0

Costs in mills/kWhr.
33% heating steam load factor.

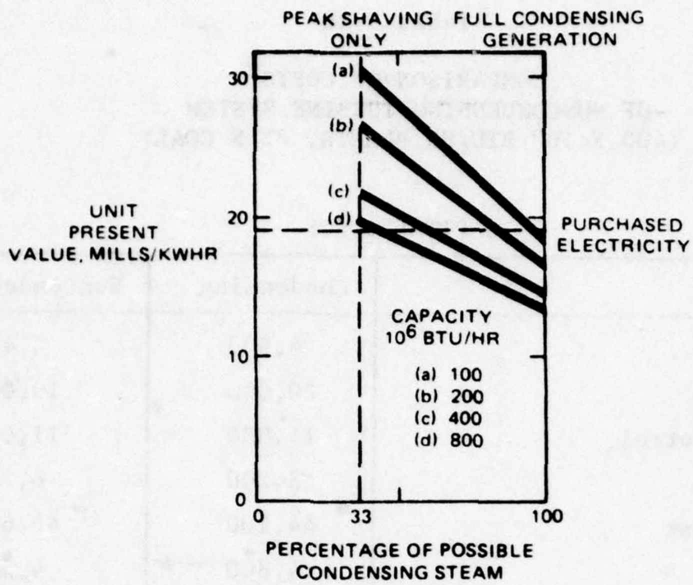


Figure 9-15
EFFECT OF MAXIMUM CONDENSING STEAM ON COST OF COGENERATED POWER (2% S COAL, 33% LOAD FACTOR)

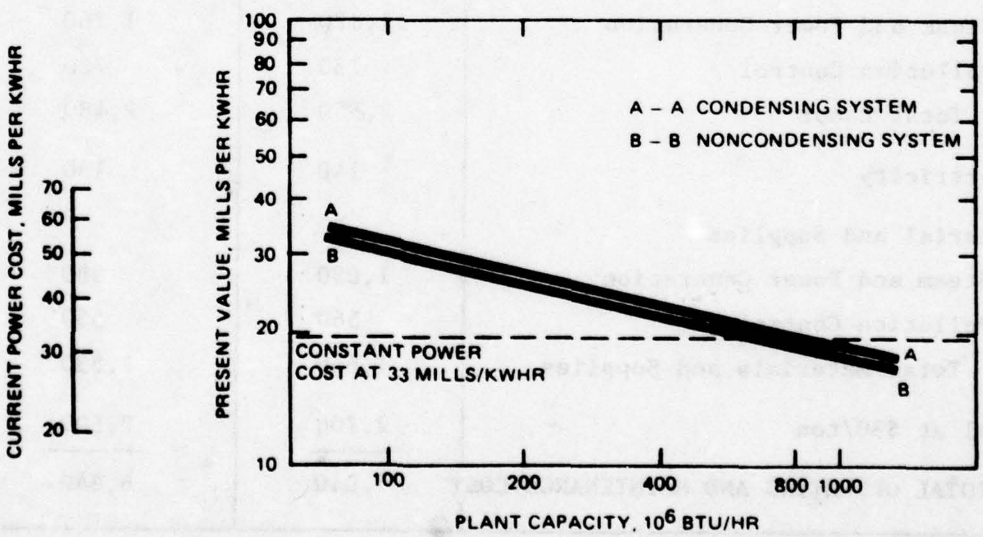


Figure 9-16
COMPARISON OF NON-CONDENSING SYSTEM FOR COGENERATED POWER COST

Table 9-16

COMPARISON OF COSTS*
OF NONCONDENSING TURBINE SYSTEM
(400×10^6 BTU/HR PLANTS, 2% S COAL)

CAPITAL COSTS

	Condensing	Noncondensing
Coal Prep. & Rec.	4,600	4,400
Steam Generation	20,000	19,000
Air Pollution Control	11,300	11,000
Power Generation	8,200	6,200
Total Constr. Cost	44,100	40,600
Startup	4,800	4,500
TOTAL CAPITAL COST	48,900	45,100

OPERATING AND MAINTENANCE COSTS

Labor		
Steam and Power Generation	1,820	1,760
Pollution Control	730	720
Total Labor	2,550	2,480
Electricity	140	130
Material and Supplies		
Steam and Power Generation	1,090	980
Pollution Control	560	550
Total Materials and Supplies	1,650	1,530
Coal at $30/ton	2,700	2,500
TOTAL OPERATING AND MAINTENANCE COST	7,040	6,640

*Thousands of second quarter 1978 dollars.

Section 10

NAVY ENERGY GUIDANCE HANDBOOK

This section is a guide for applying the methods presented earlier in this report to estimating the costs of plants. The presentation follows a sample comparison worked out in detail for a hypothetical load distribution on a Navy base. The comparison considers three ways to satisfy the load distribution:

- A decentralized system
- A central "steam-only" system
- A central cogeneration system

SUMMARY OF THE PROCEDURE

The following overall procedure is recommended for making the indicated comparisons:

- Establish problem basis
- Compare decentralized and central "steam-only" systems
- Compare central "steam-only" and cogeneration systems

The recommended order of the detailed calculations is as follows:

Establish Problem Basis

1. Determine load features
   - Load locations and demands
   - Load factor

2. Determine steam facility features

   - Locations for system elements

   - Choice of steam pressure

3. Determine raw materials

   - Coal properties
   - Coal price
   - Scrubber chemical prices
   - Purchased electricity price

<u>Compare "Steam-only" Systems</u>

1. Determine pipe diameters
2. Determine heat losses in piping systems
3. Determine solids flow rates and other flow rates
4. Determine total construction costs of modules
   - (a) Piping
   - (b) Coal handling
   - (c) Steam generation and power generation
   - (d) Air pollution control
5. Determine total capital costs
6. Determine operating and maintenance costs
   - (a) Coal handling and haulage
   - (b) Steam generation and power generation
   - (c) Air pollution control
   - (d) Waste disposal
   - (e) Coal
   - (f) Electricity

7. Prepare cost summary

8. Compute life-cycle costs

Compare Cogeneration with "Steam-only" Systems

Follow the same sequence as in the comparison of decentralized and central "steam-only" systems.

SAMPLE PROBLEM BASIS

Load and facility features of the sample problem are presented in Figures 10-1 and 10-2:

- Total system peak steam demand is 600 x 10^6 Btu/hr
- Loads are distributed as in the two figures
- Facilities for a central plant are shown in Figure 10-1
- Facilities for a decentralized plant are shown in Figure 10-2

Other system facts are:

- The annual load factor is 40 percent
- Steam piping inlet pressure is 300 psia for "steam-only" systems, 150 psia for cogeneration
- Insulation thickness is 2 inches
- Temporary waste disposal terminal is located at coal stockpile
- Waste disposal is subcontracted for a haul distance of 50 miles from base

Raw material information is as follows:

- Coal composition: as in Table 10-1
- Coal price: $30/ton

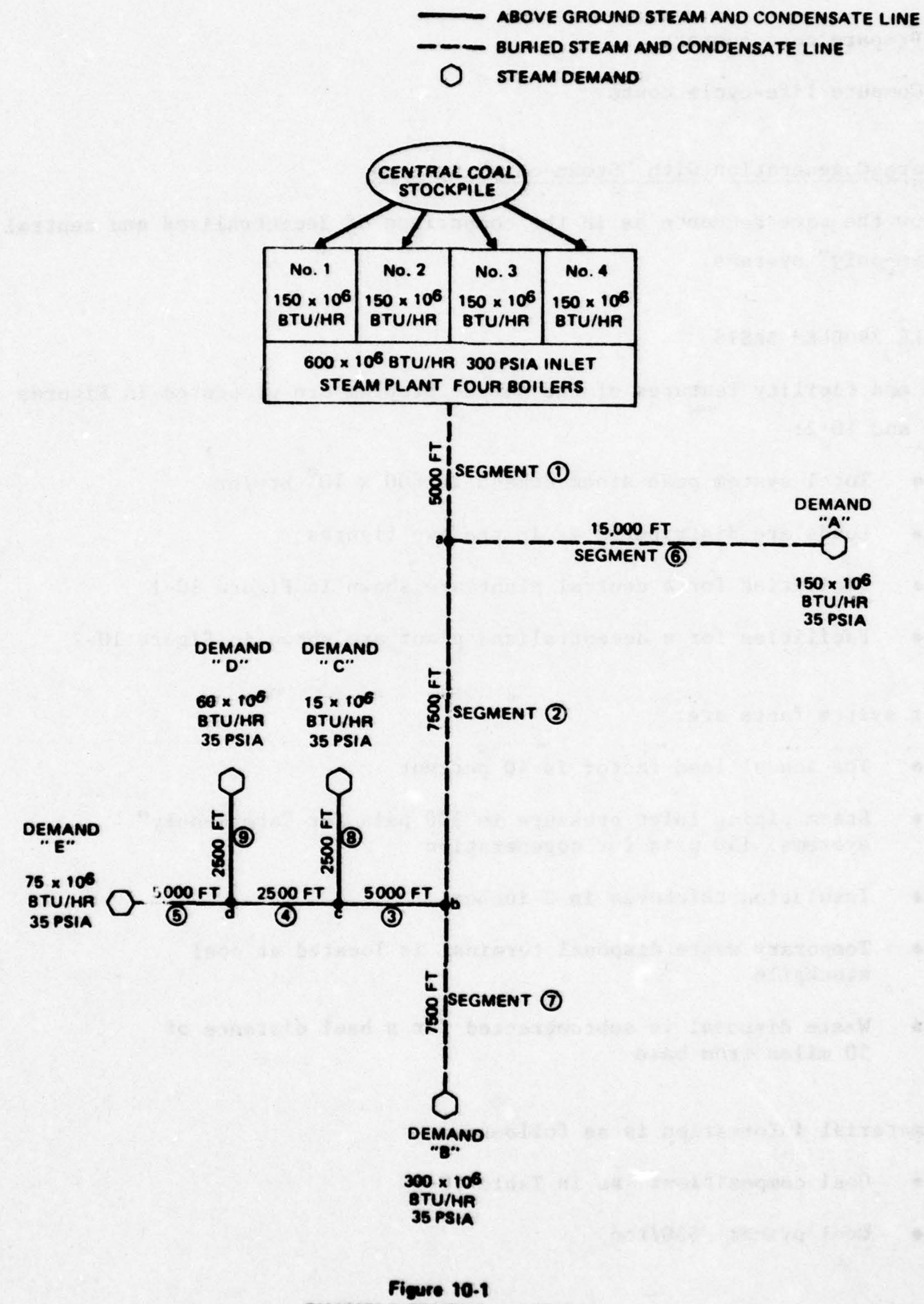


Figure 10-1
EXAMPLE CENTRAL PLANT

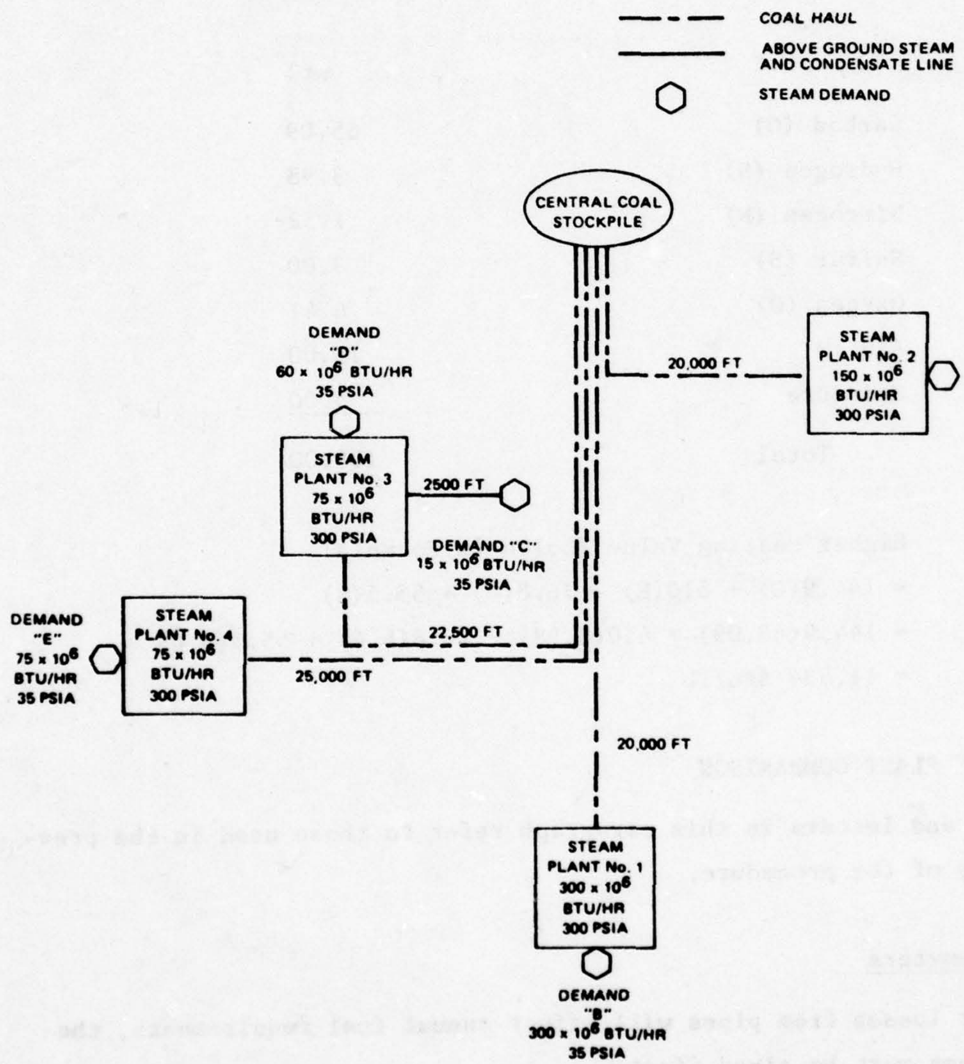


Figure 10-2
EXAMPLE DECENTRALIZED PLANT

- Chemical prices: Lime \$50/ton, Soda \$70/ton
- Purchased electricity price: 25 mills/kWhr

Table 10-1

COAL SPECIFICATION ASSUMED IN EXAMPLE CASES

	wt%
Carbon (C)	65.09
Hydrogen (H)	3.98
Nitrogen (N)	1.52
Sulfur (S)	3.00
Oxygen (O)	6.41
Ash	15.00
Moisture	5.00
Total	100.00

Higher Heating Value (Dulong's Formula)

$= 144.9(C) + 610(H) - 76.8(O) + 55.5(S)$

$= 144.9(65.09) + 610(3.98) - 76.8(6.4) + 55.5(3.0)$

$= 11{,}534$ Btu/lb

"STEAM-ONLY" PLANT COMPARISON

The numbers and letters in this paragraph refer to those used in the previous summary of the procedure.

1. Pipe Diameters

Because heat losses from pipes will affect annual fuel requirements, the piping systems must be sized first.

Decentralized System. Figure 10-2 shows only a single 2500-foot run carrying a maximum of 15×10^6 Btu/hr (15,000 lb/hr) of steam. For 300 psia steam inlet pressure, Figure 6-3 gives a 4-inch pipe diameter.

Central System. Figure 10-1 has a slightly complex pipe configuration, to illustrate methods of using the data in Section 6. The procedure for sizing pipes below achieves the following goals:

- It keeps the pressure profile through the largest multi-segment pipe run the same as it would be in a single pipe of the same total length.
- It assures that the outlet pressure of all branches is the same as at the end of the longest run.

The procedure is as follows:

- First, redraw the pipe layout with the longest run on the horizontal, enter the demand labels, number the segments, and label the intersections as in Figure 10-3.
- Tabulate facts about each segment as in Table 10-2. Entries in the last two columns have been filled in as a result of the calculations below. Flows in segments 2 to 5 are obtained by subtracting flows to upstream branch loads.
- Note the length of the longest run. In this case, it is the sum of the lengths of segments 1 to 5, or 25,000 feet.
- Determine the diameter of each segment on the longest run From Figure 6-3 and Table 6-1, assuming that it has the indicated segment flow and an equivalent run length of 25,000 feet. This is done because Figure 6-3 is based on total pipe runs with inlet pressure 300 psia and outlet pressure 35 psia. No single segment of the longest run fulfills both these conditions. See Figure 10-4.

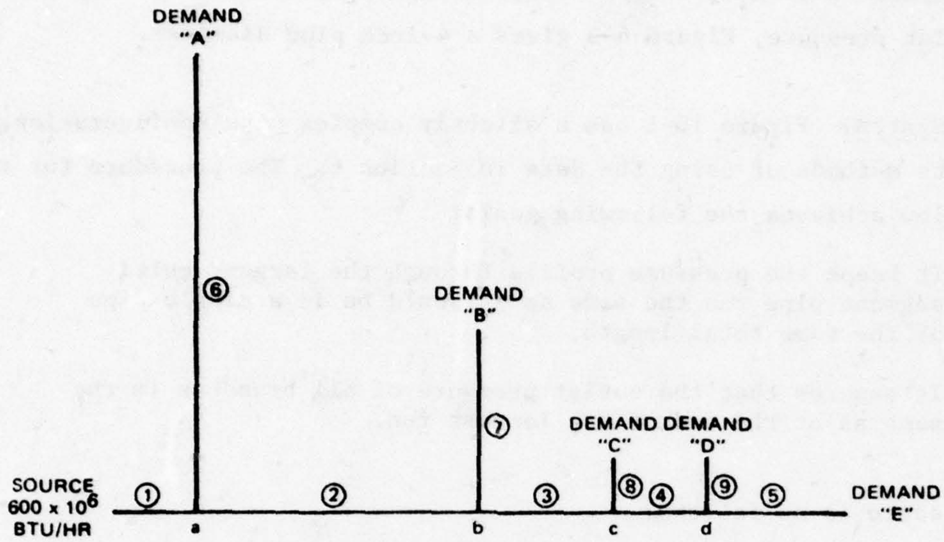


Figure 10-3
PIPING NETWORK OF FIGURE 10-1

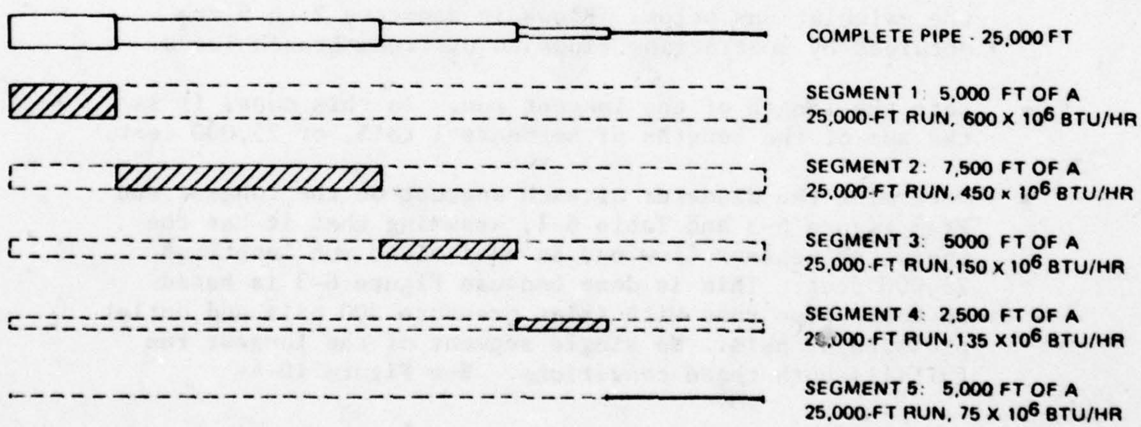


Figure 10-4
SEGMENTS ON LONGEST RUN OF FIGURE 10-3

Table 10-2

SEGMENT DATA FOR PIPING OF FIGURE 10-1

Segment	Given Data			Calculated Data	
	B=Buried A=Above-ground	Segment Length, Ft	Flow 10^6 Btu/Hr	Length of Equivalent Run Including Segment, Ft	Nominal Diameter, Inches
1	B	5000	600	25,000	24
2	B	7500	450	25,000	20
3	A	5000	150	25,000	16
4	A	2500	135	25,000	16
5	A	5000	75	25,000	10
6	B	15000	150	18,800	12
7	B	7500	300	15,000	16
8	A	2500	15	8,300	4
9	A	2500	60	12,500	8

- For each branch segment (segment not in the longest run), compute an equivalent run length as the product of the longest run length and the ratio of the segment length to the remaining downstream length of the longest run. The resulting equivalent run would have an inlet pressure of 300 psig, an outlet pressure of 35 psia, and the pressure that actually occurs at the inlet to the segment.

  — Segment 6 leaves the longest run at intersection (a). It is 15,000 feet long. The remaining downstream length of the longest run is 20,000 feet. Thus the equivalent run length is:

  (15,000/20,000)(25,000) = 18,000 ft

  Thus, segment 6 is considered to be the downstream 15,000 feet of an equivalent pipe run 18,800 feet long.

  — Similarly, the equivalent run lengths of the other branches are:

  Segment 7: (7500/12,500)(25,000) = 15,000 ft;
  Segment 8: (2500/7,500)(25,000) = 8300 ft;
  Segment 9: (2500/5,000)(25,000) = 12,500 ft.

- Determine the diameter of each branch segment on the basis of the segment flow and the equivalent run length, using Figure 6-3 and Table 6-1.

2. Heat Losses from Piping System

Use heat loss data from Figures 6-13 and 6-14 along with diameters and run lengths to compute the annual average rate of heat loss from the piping system.

Decentralized System. From a buried pipe 4 inches in diameter and 2500 feet long with 2 inches of insulation, the heat loss rate is:

$$(100 \text{ Btu/hr-ft})(2500 \text{ ft}) = 0.25 \times 10^6 \text{ Btu/hr}$$

Centralized System. Prepare a table in the form of Table 10-3, and sum the segment losses, getting 13.31×10^6 Btu/hr.

3. Solids Flow Rates

Use design flow rates, heating steam load factor, and piping heat losses to determine solids flow rates.

Decentralized System. The load factor is 0.4. The average heating steam demand is $(0.4)(600 \times 10^6)$ or 240×10^6 Btu/hr. The heat losses are 0.25×10^6 Btu/hr. Total average steam to be supplied is the sum: 240.25×10^6 Btu/hr.

The average coal requirement is computed from:

- Average coal rate = $\dfrac{\text{Total average steam rate}}{\text{(coal heating value)(boiler efficiency)}}$

- Average coal rate = $240.25 \times 10^6/(11{,}534 \times 0.8)$
  = 26,040 lb/hr = 13 tons/hr = 114,000 tons/yr

The average solid waste flow rate is computed from the coal rate, percent ash, and percent sulfur. The unit waste flow from Figure 7-6 for 15 percent ash and 3 percent sulfur is 0.35 lb/hr coal. The average waste rate is:

- Average waste rate = (0.35)(26,040) = 9114 lb/hr
  = 4.6 tons/hr

Central System. The following values are computed:

- Total average steam to be supplied = $(240 + 13.31) \times 10^6$ Btu/hr
  = 253.3×10^6 Btu/hr

Table 10-3

HEAT LOSSES FROM PIPING IN FIGURE 10-1

Given Data				Calculated Data	
Segment	Segment Length, Feet	Segment Length, Diameter Inches	B=Buried A=Above-ground	Unit Loss Rate*, Btu/hr-ft	Segment Loss Rate, 10^6 Btu/hr
1	5000	24	B	368	1.84
2	7500	20	B	320	2.40
3	5000	16	A	305	1.53
4	2500	16	A	305	0.76
5	5000	10	A	200	1.00
6	15000	12	B	210	3.15
7	7500	16	B	260	1.95
8	2500	4	A	100	0.25
9	2500	8	A	171	0.43
TOTAL					13.31

*Assumptions involved are:

- 2-inch-thick insulation
- 3-foot wet ground cover for buried pipe
- Thermal conductivities of 0.03 and 1.5 Btu/hr-ft-$^{\circ}$F for insulator and wet ground respectively
- Crosswind of 15 mph for aboveground pipe

- Average coal rate = $253.3 \times 10^6/(11{,}534 \times 0.8)$
  $= 27{,}470$ lb/hr = 13.7 tons/hr = 120,000 tons/yr
- Average waste rate = (0.35)(27,470) = 9615 lb/hr
  = 4.8 tons/hr

4. Total Construction Costs of Modules

(a) Total Construction Costs of Piping

Use diameters, lengths, and conditions from Section 6 to compute piping costs.

Decentralized System. A single aboveground pipe 2500 ft long, 4 inches in diameter, with 2-inch-thick insulation has a total cost of $193,500, based on the following items:

- Unit installed pipe cost $57.3/ft (Table 6-2)
- Unit insulation cost $20.1/ft (Table 6-3)
- Total unit cost $77.4/ft

Centralized System. The costs of segments are computed in Table 10-4. The sum is $12,518,000. Installed piping costs are taken from Table 6-2. Insulation costs are taken from Table 6-3. Pipe schedules are chosen according to Table 6-1.

(b) Total Construction Costs for Solids Handling

A central coal handling plant with stockpile is required for each case. For decentralized systems, temporary bins at boilers and haul trucks must be added.

Central System. The design size is 80 percent of maximum coal demand rate. Heat losses are ignored. The central handling facility cost from Figure 7-3 is $5,000,000.

- Design size = $(0.8)(600 \times 10^6) = 480 \times 10^6$ Btu/hr
- Design coal rate = $(480 \times 10^6)/(11{,}534 \times 0.8 \times 2000) = 26$ tons/hr

Table 10-4

TOTAL CONSTRUCTION COST OF TABLE 10-2 PIPING

Segment	Unit Piping Cost, $/ft	Unit Insulation Cost*, $/ft	Total Unit Cost, $/ft	Segment Cost, $1000
1	318.5	64.6	383.1	1916
2	299.1	61.2	360.3	2702
3	183.8	49.1	232.9	1164
4	183.8	49.1	232.9	582
5	131.4	34.4	165.8	829
6	149.1	36.8	185.9	2789
7	214.1	49.1	263.2	1974
8	57.3	20.1	77.4	194
9	119.3	27.8	147.1	368
TOTAL				12,518

*Insulation thickness 2 inches.

<u>Decentralized System</u>. The same central facility is used, costed at $5,000,000. Temporary storage bins at boilers are computed from Table 7-6 by power law interpolation. The total cost of storage is $320,000.

- Demand A: $ 80,000
- Demand B: 140,000
- Demand C&D: 50,000
- Demand E: 50,000

The haul trucks required for an average haul of 4 miles, and a coal and waste rate of 31 tons/hr are computed. Six trucks are required at $80,000, for a total cost of $480,000.

The total facility cost (the sum of the above) is $5,800,000.

(c) Total Construction Costs for Steam Generation

Data from Table 4-1 and Figure 4-2 are used.

Central System. Four low-pressure boilers are required in the central plant, each at 150,000 lb/hr capacity, with a total cost of $17,500,000.

Decentralized System. Four decentralized boilers are required, with a total cost of $17,700,000, composed of the following items:

- Demand A: $4,600,000
- Demand B: $7,700,000
- Demand C&D: $2,700,000
- Demand E: $2,700,000

(d) Total Construction Cost for Air Pollution Control

Data from Figure 5-4 and Tables 5-3 and 5-4 are used.

Central System. A pair of 60-percent capacity trains are required for a 600×10^6 Btu/hr facility, with a total cost of $12,000,000.

Decentralized System. Four boiler plants are required with a total cost of $14,800,000, composed of the following items:

- Demand A: $3,900,000
- Demand B: $6,300,000
- Demand C&D: $2,300,000
- Demand E: $2,300,000

5. Total Capital Costs

Total capital costs are computed from total construction costs by the addition of an 11-percent startup cost for all modules except piping, then adding piping construction costs.

Central System

Solids handling	5,000,000
Steam generation	17,500,000
Air pollution control	12,000,000
Total	34,500,000
Startup	3,800,000
Piping	12,500,000
Total Capital Costs	50,800,000

Decentralized System

Solids handling	5,800,000
Steam generation	17,700,000
Air pollution control	14,800,000
Total	38,000,000
Startup	4,200,000
Piping	200,000
Total Capital Costs	42,400,000

6. Operating and Maintenance Costs of Modules

(a) Operating and Maintenance Costs of Solids Handling

Central System. Operation of a central handling facility computed from Table 7-5 and Figure 7-4 for 26 tons/hr is $650,000.

Decentralized System. The total cost is $900,000, including the following items:

- Central handling facility as for the central system: $650,000
- Coal haul from Figure 7-5, with 13 tons and a 4-mile haul: $250,000

(b) Operating and Maintenance Costs of Steam Generation

Central System. For a central plant with four 150 x 10^6 Btu/hr boilers, the cost, computed from Figure 4-4, is $1,900,000.

Decentralized System. For four separate boiler stations, the total cost is $2,300,000, including the following items:

- Demand A: $ 580,000
- Demand B: $1,040,000
- Demand C&D: $340,000
- Demand E: $340,000

(c) Operating and Maintenance Costs of Air Pollution Control

Central System. The total cost is $1,680,000, including the following calculated items.

- Scrubber chemicals for 3-percent sulfur coal from Figure 5-6 = ($2.5/ton of coal)(120,000 tons coal/yr) = $300,000
- Other operating and maintenance costs from Table 5-8 and Figure 5-5 = $1,380,000

Decentralized System. The total cost is $2,600,000, including the following calculations:

- Scrubber chemicals = (2.5)(114,000 tons coal/yr) = $280,000
- Other operating and maintenance costs from Table 5-7 and Figure 5-5, totalling $2,320,000.
  - Demand A: $560,000
  - Demand B: $980,000
  - Demand C&D: $390,000
  - Demand E: $390,000

(d) Waste Disposal Subcontract Costs

Central System. Using the formulas in Section 7 for a site 50 miles from base, at 4.8 tons/hr, the total cost is $250,000.

Decentralized System. Using the above formula, at 4.6 tons/hr, the total cost is $240,000.

(e) Coal Costs

Central System. Coal supply of 120,000 tons/yr at $30/ton is $3,600,000.

Decentralized System. Coal supply of 114,000 tons/yr at $30/ton is $3,420,000.

(f) Electricity Costs

The power demand from both plants is taken as a ratio of capacity and load factor from the case of Table 8-2 (2.97×10^6 kWhr/yr).

Central System. The total cost is $140,000, calculated as follows:

- (capacity ratio)(load factor ratio) = (600/400)(0.40/0.33) = 1.82
- Annual power = $(1.82)(2.97 \times 10^6) = 5.4 \times 10^6$ kWhr
- Cost = $(0.025)(5.4 \times 10^6)$ = $140,000

Decentralized System. The same calculations yield the same cost, $140,000.

7. Summary of Capital and Annual Costs

Table 10-5 presents the summary of costs just calculated.

8. Life Cycle Costs

Table 10-6 presents comparative life-cycle costs.

Table 10-5

SUMMARY OF CAPITAL AND ANNUAL COSTS*,
CENTRAL AND DECENTRALIZED STEAM PLANTS

	Central	Decentralized
CAPITAL COSTS		
Solids Handling	5,000	5,800
Steam Generation	17,500	17,700
Air Pollution Control	12,500	14,800
Subtotal	34,500	38,000
Startup	3,800	4,200
Steam Transmission	12,500	200
Total Capital Costs	50,800	42,400
ANNUAL COSTS		
Coal Handling	650	900
Steam Generation	1,900	2,300
Air Pollution Control	1,680	2,600
Waste Disposal Subcontract	250	240
Total Operating and Maintenance Labor and Material	4,480	6,040
Coal	3,600	3,420
Electricity	140	140
Total Annual Costs	8,220	9,600

*Thousands of second quarter 1978 dollars.

Table 10-6

LIFE-CYCLE COST COMPARISON,
CENTRAL VERSUS DECENTRALIZED STEAM PLANTS

Cost Element	Project Year	Amount, Thousands of Dollars		Discount Factor	Present Value, Thousands of Dollars	
		Central	Decentralized		Central	Decentralized
First-Year Construction	2	16,933	14,133	0.876	14,833	12,380
Second-Year Construction	3	33,867	28,267	0.788	26,687	22,274
Total Investment		50,800	42,400		41,528	34,654
Coal	4-28	3,600	3,420	12.853	46,271	43,957
Electricity	4-28	140	140	14.588	2,042	2,042
Operating and Maintenance Labor and Materials	4-28	4,480	6,040	7.156	32,059	43,222
Total Operating Cost			9,600		80,372	89,221
Total Project Present Value					121,900	123,875
Energy transferred over 25-year life: 52,560 x 10^9 Btu					Central	Decentralized
Unit Present Value, $/$10^6$ Btu					2.32	2.35
Unit Levelized Cost, $/$10^6$ Btu					8.09	8.22

COMMENTS ON THE SYSTEMS COMPARED

The central system appears as expensive as the decentralized system in this comparison. However, two of the decentralized boiler stations have such large demands to satisfy that their capacity would doubtless be split, perhaps into clusters of four boilers. This example does show that extensive piping systems can impose a substantial cost penalty on a central system. Note also that if the central plant had been located at the midpoint of the cluster of loads, pipe sizes and costs would have been lower.

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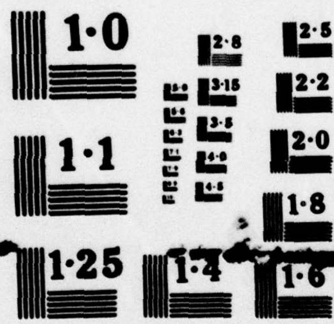
1·0
2·8
2·5
3·15
2·2
3·5
2·0
4·0
4·5
1·1
1·8
1·25
1·4
1·6

COGENERATION COMPARISON

In this comparison, the cost of the "steam-only" central plant is that of the central plant in the previous comparison. Only the cogeneration plant remains to be calculated. The system has two high- and two low-pressure boilers and a condensing-extraction turbine with a 20-megawatt rating and a 29-megawatt maximum output. The piping network has the same configuration as in Figure 10-1.

1. Piping Diameters and Costs

In the cogeneration case, the piping inlet pressure should be lower than 300 psia, to allow more extraction of steam energy by cogeneration. The inlet pressure will thus be 150 psia. Since the piping network is the source as shown in Figure 10-1, a short-cut method is possible which factors from the previous analysis. Let unprimed symbols refer to "steam-only" system parameters and primed symbols refer to cogeneration system parameters. When inlet pressure is the only parameter that changes, the equation presented at the beginning of Section 6 leads to

$$(D'/D)^{5.21} = (P_i^2 - P_o^2)/(P_i'^2 - P_o'^2)$$

with $P_o' = P_o = 35$ psia, $P_i = 300$ psia, and $P_i' = 150$ psia, $D' = 1.32$ D. Accordingly, all diameters increase by 32 percent.

In Tables 10-2 and 10-4, the 35,000 feet of buried pipe with mixed diameters cost the same as 35,000 feet of 16-inch pipe. The costs of 17,500 feet of aboveground pipe are equivalent to those for 17,500 of 11-inch pipe. From Figure 6-3, for 300 psia inlet pressure, the flow corresponding to a 35,000-foot 16-inch pipe is 275,000 lb/hr, and the flow corresponding to a 17,500-foot 11-inch pipe is 140,000 lb/hr. Next, from Figure 6-6 there is a $240/ft cost for a buried 35,000-foot pipe carrying 275,000 lb/hr with inlet pressure of 150 psia. Similarly, from Figure 6-5, the cost of a 17,500-foot aboveground pipe carrying 140,000 lb/hr is $160/ft.

For insulation costs, multiply the two diameters by the factor 1.32. The buried pipe diameter at 150 psia is 21 inches. Figure 6-11 gives a cost of $60/ft for 2-inch-thick insulation. The aboveground pipe diameter is 14 inches at 150 psia. Figure 6-11 gives the cost as $45/ft.

The costs of the equivalent 150-psia pipe runs are thus:

- Buried: (240 + 60) (35,000) = $10,500,000
- Aboveground: (160 + 45) (17,500) = 3,600,000

Total $14,100,000

2. Piping System Heat Losses

From Figure 6-13, the loss rate is 330 Btu/hr-ft for 21-inch diameter buried pipe with 2-inch-thick insulation in wet ground. From Figure 6-14, the loss rate is 220 Btu/hr-ft for 11-inch diameter aboveground pipe with 2-inch-thick insulation. The total rate of loss from the pipes is:

- Buried: (330)(35,000) = 11.6×10^6 Btu/hr
- Aboveground: (220)(17,500) = 3.9×10^6 Btu/hr

Total 15.6×10^6 Btu/hr

3. Solids and other Flow Rates

The cogeneration strategy is to use strict cogeneration to supply heating steam, and then use all remaining high-pressure steam capacity in condensing generation. Thus, the high-pressure boilers operate at 100 percent of capacity all year long. The low-pressure boilers are assumed to operate on the average at 6 percent of rated capacity.

Coal flows are obtained by ratio from Table 9-3. Needed factors include:

- Capacity ratio: $(600 \times 10^6$ Btu/hr$)/(400 \times 10^6$ Btu/hr$) = 1.5$
- Heating value ratio: (10,672 Btu/lb)/(11,534 Btu/lb) = 0.9253

Then the coal flows follow the formula:

$$\begin{pmatrix}\text{new}\\\text{coal}\\\text{rate}\end{pmatrix} = \begin{pmatrix}\text{load}\\\text{factor}\end{pmatrix}\begin{pmatrix}\text{capacity}\\\text{ratio}\end{pmatrix}\begin{pmatrix}\text{heating}\\\text{value}\\\text{ratio}\end{pmatrix}\begin{pmatrix}\text{Table}\\\text{9-3}\\\text{flow}\end{pmatrix}$$

Coal flows for high- and low-pressure boilers are:

- High Pressure: (1.0)(1.5)(0.9253)(30,100) = 41,784 lb/hr
- Low Pressure: (0.06)(1.5)(0.9253)(23,426) = 1,951 lb/hr

  Total 43,735 lb/hr

In tons, this is 21.9 tons/hour, or 192,000 tons/year.

Solid waste flows are calculated using the 0.35 lb waste/lb coal derived previously:

Waste flow = (0.35)(21.9) = 7.7 tons/hr

Maximum coal energy consumption rate is needed for scrubber sizing. This assumes both boiler systems are at full rated flow. The coal flows are:

- High Pressure: 41,784 lb/hr
- Low Pressure: (1.0)(1.5)(0.9253)(23,426) = 32,514 lb/hr

  Total 74,298 lb/hr

The energy rate is (74,298 lb/hr)(11,534 Btu/lb) = 857 x 10^6 Btu/hr.

The equivalent capacity for making low-pressure steam only in low-pressure boilers is:

$$(\text{boiler efficiency})(\text{coal heat input rate}) = (0.8)(857 \times 10^6) = 685 \times 10^6 \text{ Btu/hr}$$

Maximum coal flow rate is needed for solids handling system sizing. It is 37.1 tons/hour.

Electricity generated is computed as follows:

- The contribution of the high-pressure steam system to the annual load factor is 37 percent (3 percent is contributed by the low-pressure boilers). Then the high-pressure system delivers to loads:

  $(0.37)(600 \times 10^6 \text{ Btu/hr}) = 222 \times 10^6 \text{ Btu/hr}$

- The burden of pipe heat losses is assumed to fall entirely on the high-pressure system: 16×10^6 Btu/hr

- Thus, the total heating steam produced by cogeneration is 238×10^6 Btu/hr

- From the discussions in Section 9, the 110,000 lb/hr extraction flow at the bottom right of Figure 9-2 corresponds to a heating steam load of 120×10^6 Btu/hr = (30 percent load factor)(400×10^6 Btu/hr)

- Consequently, 238×10^6 Btu/hr of heating steam requires an extraction flow of (238/120) (110,000 lb/hr) = 218,000 lb/hr

- The maximum steam flow to the turbine can be obtained from stream 20 in Table 9-3 using the capacity ratio:

  $$(1.5)\ (193{,}000) = 290{,}000 \text{ lb/hr}$$

- The annual average condensing steam flow rate is the difference: 290,000 - 218,000 = 72,000 lb/hr

- The power output for the two modes of generation is calculated with the steam rates from Section 9:

  strict cogeneration = (218,000 lb/hr)/(17.5 lb/kWhr) = 12,460 kW

  condensing generation = (72,000 lb/hr)/(7.79 lb/kWhr) = 9,240 kW

  Total = 21,700 kW = 21.7 megawatts

  $= 190 \times 10^6$ kWhr/year

- Plant electricity consumed can be assumed to be proportional to the coal consumption rate. Using Table 9-5,

$$\begin{pmatrix}\text{electricity}\\ \text{consumed}\end{pmatrix} = \left(\frac{192{,}000 \text{ tons/yr}}{90{,}000 \text{ tons/yr}}\right)\left(4.19 \times 10^6 \ \frac{\text{kWhr}}{\text{yr}}\right) = 8.74 \times 10^6 \ \frac{\text{kWhr}}{\text{yr}}$$

4. Total Construction Costs of System Modules

(a) Total Construction Costs of Piping

As already calculated, this total is $14,100,000.

(b) Total Construction Costs of Solids Handling

The total cost of a central coal handling facility with stock pile from Figure 7-3, for a maximum coal rate of 37.1 tons/hr and a design rate of (0.8)(37.1), or 30 tons/hr is $5,800,000.

(c) Total Construction Costs of Steam and Power Generation

Costs for a central boiler plant with four quarter-sized low-pressure boilers can be obtained for 600 x 10^6 Btu/hr by power-law interpolation from Table 4-1. The total construction cost is $17,400,000.

Incremental costs of substituting two 150 x 10^6 Btu/hr high-pressure boilers can be found by power-law interpolation from Table 4-2. These costs are $9,700,000.

The cost of a 20-megawatt power generation module can be obtained from Figure 9-3. This cost is $12,200,000.

The total of these three costs is $39,300,000.

(d) Total Construction Costs for Air Pollution Control

A single pair of 60-percent capacity trains for 685 x 10^6 Btu/hr equivalent low-pressure steam boilers from Figure 5-4, interpolating to 3 percent sulfur, has a total construction cost of $13,100,000.

5. Total Capital Costs for Cogeneration System

The sum of the above items, plus the 11-percent allocation to startup, yields the following total capital cost:

Solids Handling	$ 5,800,000
Steam and Power Generation	39,300,000
Air Pollution Control	13,100,000
Total	58,200,000
Startup	6,400,000
Piping	14,100,000
Total Capital Costs	$78,700,000

6. Operating and Maintenance Costs

(a) Operating and Maintenance Costs of Coal Handling

Operation of the central handling facility can be computed from Table 7-5 and Figure 7-4 for a design coal rate of 37.1 tons/hour. The total cost is $830,000.

(b) Operating and Maintenance Costs of Steam and Power Generation

Costs, including coal handling for a 600×10^6 Btu/hr capacity can be obtained by power-law interpolation from Table 9-9. The total cost is $4,050,000. The components of this cost are:

- Labor: $2,410,000
- Material: $1,640,000

The coal handling costs from paragraph (a) above can be subtracted, yielding a balance of $3,220,000.

(c) Operating and Maintenance Costs of Air Pollution Control

The air pollution O&M cost total is $1,960,000. Its components are:

- Chemicals at $2.50 per annual ton of coal (for 3% S): $480,000
- Other costs by power-law and sulfur-level interpolation from Table 5-8: $1,480,000

(d) Waste Disposal Subcontract Costs

This cost is obtained from formulas in Section 7 for a site 50 miles from the base, with a waste rate of 7.7 tons/hour. The total is $360,000.

(e) Coal

The cost for 192,000 tons/year at $30/ton is $5,760,000.

(f) Electricity

Generation of electricity leads to a net amount of electricity that does not have to be purchased:

	10^6 kWhr/year
• Generated by plant	190.0
• Consumed by plant	- 8.7
• Net export	181.3
• Consumed by "steam-only" plant	+ 5.4
• Net reduction in purchase	186.7

7. Summary of Capital and Annual Costs

Table 10-7 compares the cogeneration costs just calculated with "steam-only" costs. The increments for cogeneration are the costs of power production.

8. <u>Life-Cycle Costs</u>

Table 10-8 calculates the life-cycle costs of cogeneration power.

CONCLUSIONS

Cogenerated power has a levelized cost of 48.1 mills/kWhr. By Table 9-12, purchased power at 25 mills/kWhr has a levelized cost of 50.9 mills/kWhr. Cogenerated power is less expensive.

Table 10-7

CAPITAL AND ANNUAL COSTS*
OF COGENERATED POWER

	Cogeneration Plant	"Steam-Only" Plant	Difference
CAPITAL COSTS			
Coal Handling	5,800	5,000	800
Steam and Power Generation	39,300	17,500	21,800
Air Pollution Control	13,100	12,000	1,100
Subtotal	58,200	34,500	23,700
Startup	6,400	3,800	2,600
Piping	14,100	12,500	1,600
Total Capital Costs	78,700	50,800	27,900
ANNUAL COSTS			
Coal Handling	830	650	180
Steam and Power Generation	3,220	1,900	1,320
Air Pollution Control	1,960	1,680	280
Waste Disposal	360	250	110
Total Operating and Maintenance Labor and Material	6,370	4,480	1,890
Coal	5,760	3,600	2,160
Total Annual Costs (Excluding Electricity)	12,130	8,080	4,050
Life-Cycle Cogenerated Power Gain: $(0.186 \times 10^9)(25) = 4.667 \times 10^9$ kWhr.			

*Thousands of second quarter 1978 dollars.

Table 10-8

LIFE-CYCLE COST OF COGENERATED POWER

Cost Element	Project Year	Differential Inflation, Percent Per Year	Amount, Thousands of Dollars		Discount Factor	Present Value, Thousands of Dollars
			One Time	Recurring		
First-Year Construction	1	+0	4,650		0.954	4,436
Second-Year Construction	2	+0	9,300		0.876	8,147
Third-Year Construction	3	+0	13,950		0.788	10,993
Total Investment			27,900			23,576
Coal	4-28	+5		2,160	12.583	27,179
Operating and Maintenance Labor and Material	4-28	+0		1,890	7.156	13,525
Total Operating Cost Without Electricity				4,050		40,704
Total Project Present Value						64,280
Life-Cycle Cogenerated Power Gain: 4.667 x 10^9 kWhr						
Unit Present Value, mills/kWhr:						13.8
Unit Levelized Cost, mills/kWhr:						48.1

Appendix A
PRESSURE DROPS IN PIPE

Appendix A explains the calculations used to determine pipe diameter for various lengths of steam transmission pipe at different flow rates and inlet and outlet pressures.

ASSUMPTIONS

- The saturated steam transported is an ideal gas
- Condensation of steam is negligible
- Wall friction is the main source of pressure drop. Dynamic head picked up by the steam during the course of expansion along the pipe causes negligible pressure drop
- Steam flow in the pipe is at isothermal condition

NOTATIONS

D = inside diameter of pipe, inches

P = steam pressure in general, lb_f/in^2 absolute

P_i = steam inlet pressure, lb_f/in^2 absolute

P_o = steam outlet pressure, lb_f/in^2 absolute

ρ = steam density, lb_m/ft^3

ρ_i = steam inlet density, lb_m/ft^3

V = steam specific volume, ft^3/lb_m

V_i = steam inlet specific volume, ft^3/lb_m

ℓ = axial distance along the pipe, thousands of feet

L = total pipe length, thousands of feet

$\dot{M}$ = mass flowrate of steam, pounds per hour

f_M = Moody friction factor, dimensionless

U = fluid velocity, feet per second

WORKING EQUATION

The pressure drop due to fluid friction in a pipe is derived as follows:

$$\begin{pmatrix}\text{force}\\ \text{resisting}\\ \text{flow}\end{pmatrix} = \frac{1}{4}\begin{pmatrix}\text{wet}\\ \text{contact}\\ \text{surface}\end{pmatrix}\begin{pmatrix}\text{fluid}\\ \text{dynamic}\\ \text{head}\end{pmatrix}\begin{pmatrix}\text{Moody}\\ \text{friction}\\ \text{factor}\end{pmatrix}$$

or

$$\left(\frac{\pi}{4} D^2\right) dP = \left(\frac{1}{4} \pi D\, d\ell\right)\left(\frac{1}{2} \rho U^2\right) f_M \tag{1}$$

Since steam is assumed to be an ideal gas,

$$\frac{\rho}{\rho_i} = \frac{P}{P_i} \tag{2}$$

Also, it is known that

$$\dot{M} = \left(\frac{\pi}{4} D^2 U\right) \rho \tag{3}$$

$$V = \frac{1}{\rho} \tag{4}$$

The use of equations (2) - (4) changes Equation (1) into

$$PdP = \left(\frac{8\dot{M}^2 f_M}{\pi^2} \frac{P_i V_i}{D^5}\right) d\ell \tag{5}$$

Integrating from the inlet to outlet conditions, Equation (5) becomes,

$$D^5 = \left(\frac{16}{\pi^2} \frac{\dot{M}^2 P_i V_i L f_M}{P_i^2 - P_o^2} \right) \quad (6)$$

Now, if D is in inches, $\dot{M}$ in lb_m/hr, P_o and P_i in psia, L in thousand feet, and V_i in ft^3/lb_m, Equation (6) becomes,

$$D^5 = 0.00671 \dot{M}^2 P_i V_i L f_M/(P_i^2 - P_o^2) \quad (7)$$

The Moody friction factor becomes constant in the asymptotic high Reynolds number region which is the most important in practical steam transport. The constant f_M, however, varies depending on the given pipe surface roughness. For clean steel pipes, the surface roughness can be in turn related to the pipe diameter. The resulting relation between f_M and the pipe diameter is shown in Figure A-1* from which it is found that:

$$f_M = 0.0223 D^{-0.21} \quad (8)$$

When substituted into Equation (7), it gives

$$D^{5.21} = 0.00015 \dot{M}^2 L (P_i V_i)/(P_i^2 - P_o^2) \quad (9)$$

For calculating the required pipe diameter from Equation (9), it may be helpful to have graphical representations of $P_i V_i$ as a function of P_i, and $(P_i^2 - P_o^2)$ as a function of various combinations of P_i and P_o. They are shown respectively in Figures A-2 and A-3.

*"Flow of Fluids through Valves, Fittings, and Pipe," Crane Co., Technical Paper No. 410, 4th ed. (1974), page A-25.

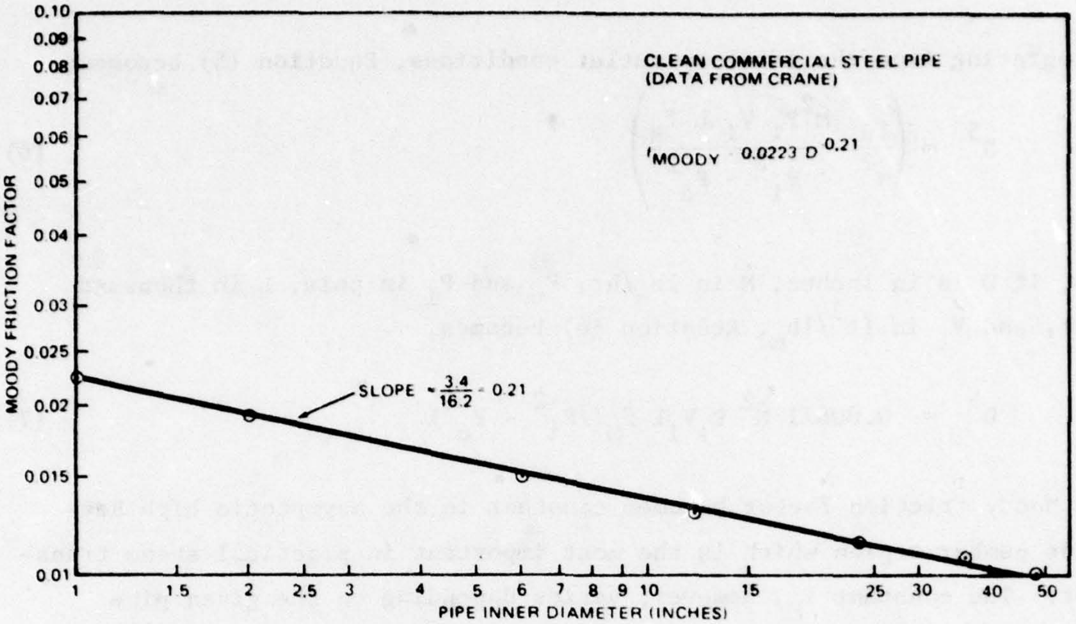

Figure A-1

RELATION BETWEEN MOODY FRICTION FACTOR AND PIPE INSIDE DIAMETER IN THE ASYMPTOTIC REYNOLDS NUMBER REGION

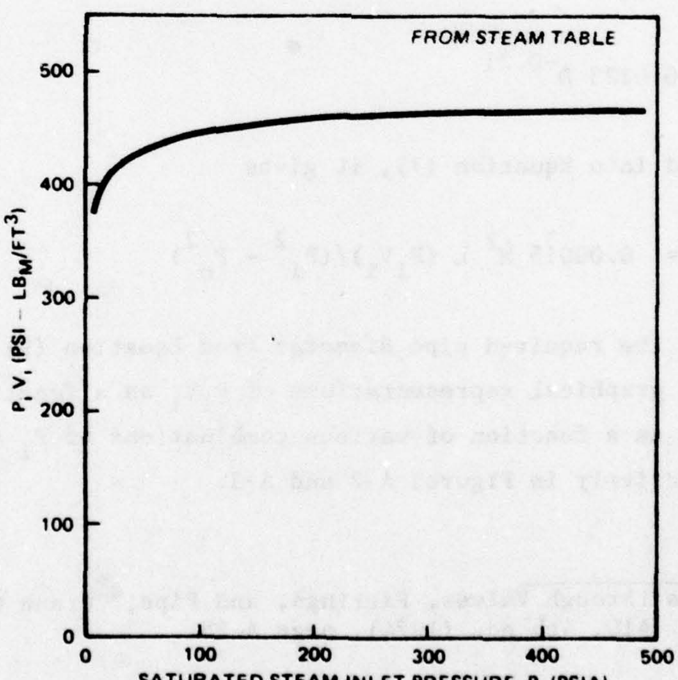

Figure A-2

RELATION BETWEEN P_i V_i AND P_i

DIAMETER TABULATIONS

Tables A-1, A-2, and A-3 display diameters calculated by Equation (9) at the three pressures 150, 300, and 600 psia. Each table contains diameters calculated for the possible combinations of eight steam flow rates and seven pipeline lengths.

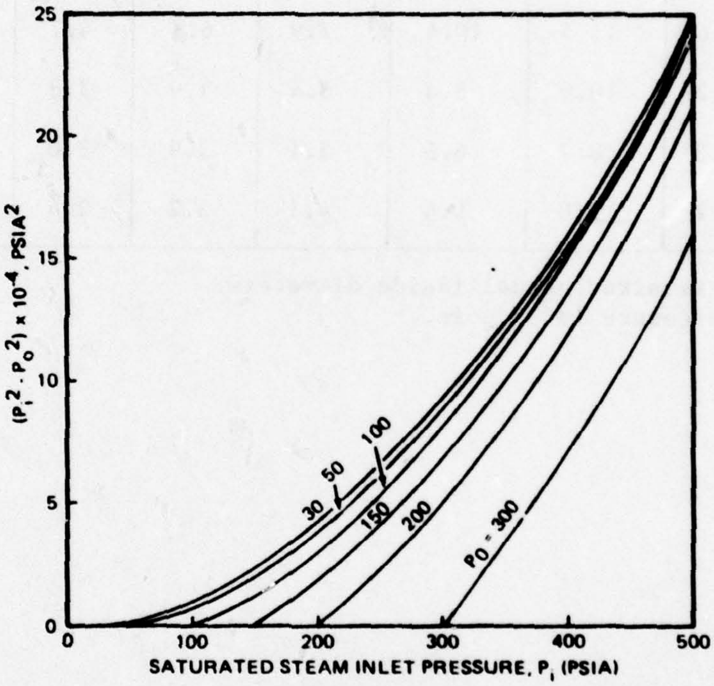

Figure A-3
$(P_i^2 - P_o^2)$ AS A FUNCTION OF P_i AND P_o

Table A-1

150 PSIA INLET PRESSURE CASE: PIPE DIAMETER AS A FUNCTION OF STEAM FLOW RATE AND PIPE LENGTH (Diameter in Inches)

Pipe Length, ft	Steam Flow Rate, lb/hr							
	800,000	400,000	200,000	100,000	50,000	25,000	12,500	6,250
10^5	34.6	26.5	20.3	15.6	11.9	9.2	7.0	5.4
$3x10^4$	27.5	21.1	16.2	12.4	9.5	7.3	5.6	4.3
10^4	22.2	17.0	13.0	10.0	7.7	5.9	4.5	3.5
$3x10^3$	17.6	13.5	10.4	7.9	6.1	4.7	3.6	2.7
10^3	14.2	10.9	8.4	6.4	4.9	3.8	2.9	2.2
$3x10^2$	11.3	8.7	6.6	5.1	3.9	3.0	2.3	1.8
10^2	9.2	7.0	5.4	4.1	3.2	2.4	1.9	1.4

Diameters are required actual inside diameters.
Steam outlet pressure is 35 psia.

Table A-2

300 PSIA INLET PRESSURE CASE: PIPE DIAMETER AS A FUNCTION OF STEAM FLOW RATE AND PIPE LENGTH
(Diameters in inches)

Pipe Length, ft	Steam Flow Rate, lb/hr							
	800,000	400,000	200,000	100,000	50,000	25,000	12,500	6,250
10^5	30.0	23.0	17.6	13.5	10.4	7.9	6.1	4.7
$3x10^4$	23.9	18.3	14.0	10.7	8.2	6.3	4.8	3.7
10^4	19.3	14.9	11.4	8.7	6.7	5.1	3.9	3.0
$3x10^3$	15.3	11.7	9.0	6.9	5.3	4.1	3.1	2.4
10^3	12.4	9.5	7.3	5.6	4.3	3.3	2.5	1.9
$3x10^2$	9.8	7.6	5.7	4.4	3.4	2.6	2.0	1.5
10^2	8.0	6.1	4.7	3.6	2.8	2.1	1.6	1.2

Diameters are required actual inside diameters.
Steam outlet pressure is 35 psia.

Table A-3

600 PSIA INLET PRESSURE CASE: PIPE DIAMETER AS A FUNCTION OF STEAM FLOW RATE AND PIPE LENGTH
(Diameters in inches)

Pipe Length, ft	Steam Flow Rate, lb/hr							
	800,000	400,000	200,000	100,000	50,000	25,000	12,500	6,250
10^5	23.3	17.8	13.7	10.5	8.0	6.2	4.7	3.6
$3x10^4$	18.5	14.2	10.9	8.3	6.4	4.9	3.8	2.9
10^4	14.9	11.4	8.8	6.7	5.2	4.0	3.0	2.3
$3x10^3$	11.9	9.1	7.0	5.3	4.1	3.1	2.4	1.8
10^3	9.6	7.4	5.6	4.3	3.3	2.5	2.0	1.5
$3x10^2$	7.6	5.8	4.5	3.4	2.6	2.0	1.5	1.2
10^2	6.2	4.7	3.6	2.8	2.1	1.6	1.3	1.0

Diameters are required actual inside diameters.
Steam outlet pressure is 35 psia.

Appendix B

WALL THICKNESS VERSUS PIPE DIAMETER

The following graph, Figure B-1, was prepared to show wall thickness requirements for various pressures and the relationship to standard schedule pipe of different diameters.

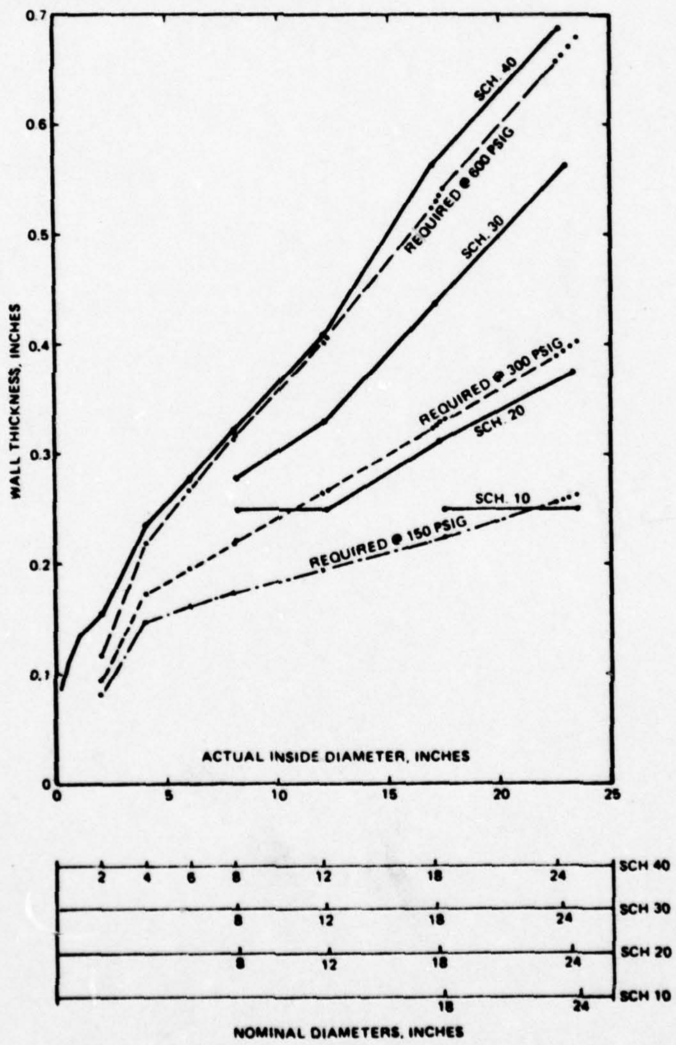

Figure B-1
PIPE WALL THICKNESS VERSUS DIAMETER

Appendix C

HEAT LOSSES FROM PIPE

Appendix C describes the heat losses which occur in aboveground and buried steam transmission lines. The methodology can be used to determine supply capacity required to meet demand at points distant from the steam source.

Table C-1 compares heat losses for various diameter pipes with insulation thickness of 2, 5, and 8 inches for underground and aboveground pipes. The methods of calculating these heat losses are explained below.

PIPE BURIED UNDERGROUND

Shown in Figure C-1 is a pipe buried underground, where D is the pipe outer diameter; X_i, the insulator thickness; X_o the feet of ground cover; and T_1, T_i, T_2, respectively, the surface temperatures of pipe, insulator, and ground. The pipe-steam interface and pipe wall have negligible thermal resistances relative to those offered by the insulator and ground. Under such conditions the heat loss rate per unit length of pipe, q, can be expressed as:*

$$q = \left[\frac{2\pi k_g k_i}{k_i \cosh^{-1}\left(\dfrac{2X_o + 2X_i + D}{2X_i + D}\right) + k_g \ln\left(\dfrac{2X_i + D}{D}\right)} \right] (T_1 - T_2)$$

where k_i and k_g are respectively the thermal conductivities of insulator and ground.

*F. Kreith, "Principles of Heat Transfer," 2nd ed., International Textbook Co., Scranton, Pa. (1965).

Table C-1

HEAT LOSSES FROM PIPE

Insulator Thickness, inch	Pipe Outside Diameter, inch	Heat Loss Rate, Btu/hr-ft Aboveground	Heat Loss Rate, Btu/hr-ft Buried Wet Ground	Buried Dry Ground
2	24	443.8	368.0	159.3
	18	341.9	293.1	136.6
	12	239.4	207.1	101.1
	8	170.5	155.1	88.8
	6	135.7	125.4	76.4
	4	100.3	94.4	62.2
	2	63.6	61.1	44.8
5	24	201.1	184.9	114.8
	18	158.7	147.8	96.9
	12	115.9	109.5	76.8
	8	86.7	82.9	61.5
	6	71.8	69.1	53.1
	4	56.3	54.5	43.7
	2	39.4	38.5	32.5
8	24	137.9	130.5	93.0
	18	110.8	105.7	78.4
	12	83.3	80.2	62.4
	8	64.3	62.3	50.5
	6	54.4	53.0	43.9
	4	43.9	43.0	36.6
	2	32.2	31.7	28.0

Where

Surface temperature of pipe = $417^{\circ}F$
Surface temperature of ground = $40^{\circ}F$
Thermal conductivity of insulator = 0.03 Btu/hr-ft-$^{\circ}F$
Wind speed across the pipe (aboveground) = 15 mph
Feet of ground cover (buried) = 3 ft
Thermal conductivity of ground (buried) = 0.2 and 1.5 Btu/hr-ft-$^{\circ}F$ (dry and wet ground)

Table C-1 contains the estimated heat losses from Equation (1) at various combinations of pipe outer diameters (2, 4, 6, 8, 12, 18, and 24 inches) and insulator thicknesses (2, 5, and 8 inches). The results are presented for both dry and wet ground, of which the thermal conductivities are assumed to be 0.2 and 1.5 Btu/hr-ft-^{o}F respectively. Other fixed conditions are a 3-ft ground cover, thermal conductivity of 0.03 Btu/hr-ft-^{o}F for the insulator, and pipe and ground surface temperatures of 417^{o}F and 40^{o}F respectively. The given pipe temperature, 417^{o}F, corresponds to a saturated steam at 300 psi.

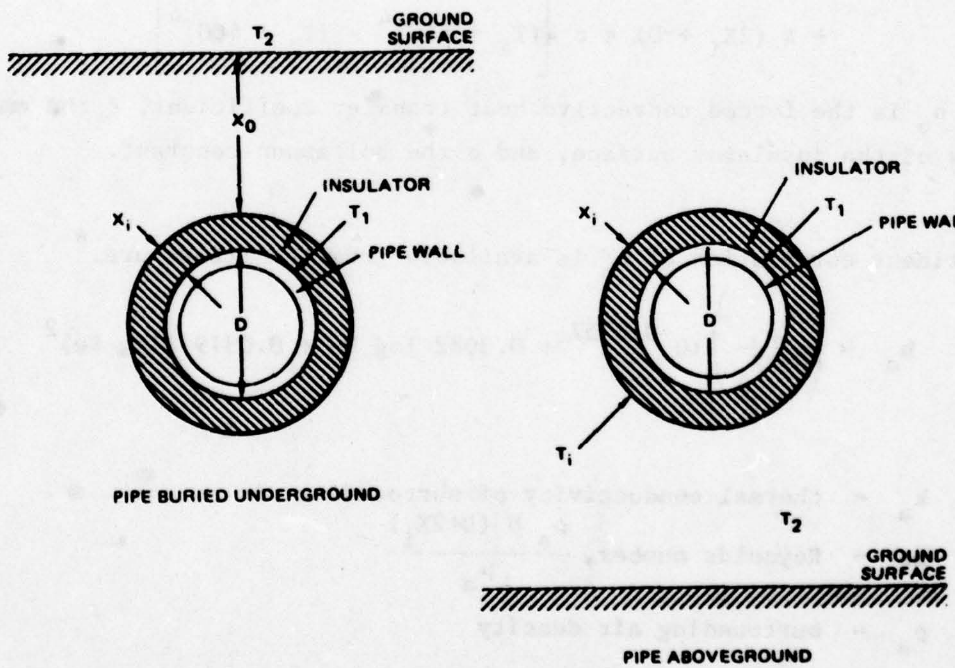

Figure C-1
TYPICAL BURIED AND ABOVEGROUND PIPE INSTALLATIONS

PIPE ABOVEGROUND

Figure C-1 also shows a pipe installed aboveground; T_2 in this case represents the surrounding air temperature. The wind is assumed to blow across the pipe at a given velocity, U. The heat loss rate can be expressed either in terms of the conductive resistance through the insulator or of the forced convective and radiation resistances from the pipe to surrounding air,

$$q = \frac{2\pi k_i}{\ell n\left(\frac{2X_i + D}{D}\right)} (T_1 - T_i) \tag{2}$$

$$\begin{aligned} q = \; & \pi (2X_i + D) h_o (T_i - T_2) \\ & + \pi (2X_i + D) \varepsilon \sigma \left[(T_i + 460)^4 - (T_2 + 460)^4\right] \end{aligned} \tag{3}$$

where h_o is the forced convective heat transfer coefficient, ε the emissivity of the insulator surface, and σ the Boltzmann constant.

A pertinent correlation of h_o is available from the literature.*

$$h_o = \left(\frac{k_a}{D+2X_1}\right) 10^{-0.0757 + 0.3082 \log Re + 0.0379 (\log Re)^2}$$

where

k_a = thermal conductivity of surrounding air

Re = Reynolds number, $\frac{\rho_a U (D+2X_i)}{\mu_a}$

ρ_a = surrounding air density

μ_a = surrounding air viscosity

The k_a, ρ_a, and μ_a above all vary with temperature,

$$k_a = 0.01328 + 2.471 \times 10^{-5}\ T - 4.247 \times 10^{-9}\ T^2$$

$$\rho_a = 0.0771 - 8.848 \times 10^{-5}\ T - 3.744 \times 10^{-8}\ T^2$$

$$\mu_a = 0.04 + 6.155 \times 10^{-5}\ T - 1.22 \times 10^{-8}\ T^2$$

where the T should be taken as an average of the T_i and T_2. The T is in ^oF, k_a in Btu/hr-ft-^oF, ρ_a in lb_m/ft^3, and μ_a in lb_m/ft-hr.

The heat loss rates should be the same as calculated from either Equation (2) or (3) if T_i is chosen correctly. The guess of a correct T_i can be made by trial and error manually or aided by computer.

For Table C-1 the heat loss rate calculations were carried out for the same pipe temperature (417^o F), pipe sizes (24, 18, 12, 8, 6, 4, 2 inches O.D.), insulator thicknesses (2, 5, 8 inches), and insulator thermal conductivity (0.03 Btu/hr-ft-^{o}F) as assumed for buried pipe. The surrounding air temperature is fixed at 40^{o}F and the velocity at 15 miles per hour.

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*D. N. Trujano, B. T. Garza, and S. C. Lecona, "How Ambient Conditions Affect Steam-Line Heat Loss," Oil and Gas J., p 83-86, Jan. 21, 1974.

Appendix D

STOKER COAL AVAILABILITY

This appendix presents a brief description of stoker types, coal requirements, and marketing and price information for stoker coal. Conclusions of the appendix are:

- Double-screened coal is not a necessity for new stoker-type boilers
- Stoker coal is readily available on the spot-coal market. If double-screened coal is required, a premium of about \$6 to \$8 per ton will be added to the fuel price.
- Coordination with stoker boiler manufacturers regarding use of locally available coal is important, and their recommendations should be evaluated in combination with coal price economics.

GENERAL

The number of coal-fired stoker-type boilers used by U.S. industry was estimated at over 100,000 in the early 1970's. The percentage breakdown by burner type was as follows:

	Rated Steam Capacity (10^6 Btu/hr)			
	10-16	17-100	101-250	251-500
Underfeed type	70	60	20	15
Overfeed	10	15	10	10
Spreader	15	20	50	30
Pulverized	-	-	15	40
Other	5	5	5	5
Percent	100	100	100	100

Pulverized coal firing was introduced for larger utility type boilers because of the greater reliability of pulverization equipment which is external to the boiler and independent from boiler operation. However, new models of stokers are also relatively trouble-free, automated equipment. In addition to the type of stoker available over a size range, boiler selection should al include the following considerations:

- Capital cost
- Fuel and labor costs
- Efficiency
- Pollution requirements

Recent studies were conducted to determine the probable demand for coal-fired stokers in the next decade.

Stokers were separated into four groups by the heat generative capacities:

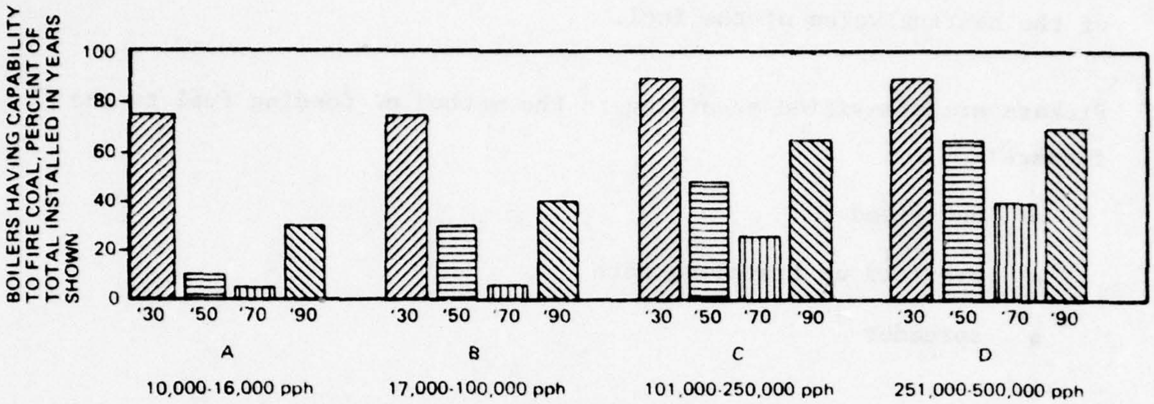
Category	Heat Output, 10^6 Btu/hr, or *Steam Output*, 10^3 lb/hr (pph)
A	10-16
B	17-100
C	101-250
D	251-500

Figure D-1 shows the estimated distribution of coal-fired boilers by type and year.

The conclusion is that, for the period between 1980 and 199?, spreader stoker types will be dominant for the range of steam capacity of 17 to 250 x 10^6 Btu/hr. Pulverized coal firing will remain economical only for the range above 250 x 10^6 Btu/hr. The underfeed stokers will remain economical for capacities below 17 x 10^6 Btu/hr.

CHARACTERIZATION OF STOKER TYPES

Stokers are mechanical devices which feed and distribute solid fuels for combustion and subsequent conversion of chemical energy in the fuel into thermal energy in the form of high-temperature water or steam.



ESTIMATED PERCENTAGE OF ALL BOILERS IN FOUR SIZE CATEGORIES INSTALLED IN 1930, 1950, AND 1970, AND FORECAST FOR 1990, HAVING A CAPABILITY TO FIRE COAL

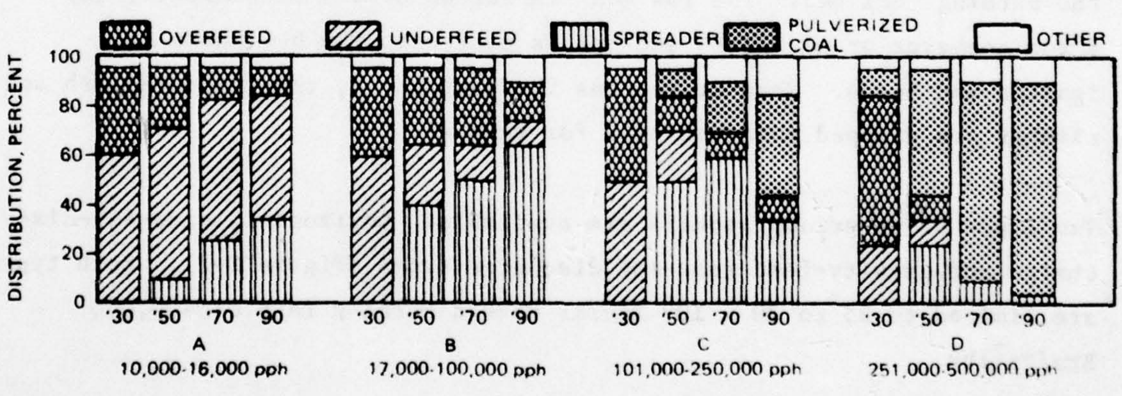


Figure D-1
ESTIMATED BREAKDOWN OF STOKER BOILERS BY TYPES

Devices and controls incorporated in the stoker design normally provide automatic control of feed, air supply, dust collecting devices to minimize emissions, and in most cases fly-carbon return systems for better utilization of the heating value of the fuel.

Stokers are classified according to the method of feeding fuel to the furnace:

- underfeed
- overfeed or traveling gate
- spreader

Each type of stoker has a capacity range and is designed to burn a characteristic type of coal. (See Table D-1.) A brief description of each stoker type and of the coal characteristics will explain the reason for this dependence of stoker selection on coal properties.

Underfeed Stokers

Operation. Underfeed stokers introduce raw coal into a retort from below the burning fuel bed. The raw coal is forced upward mechanically (by screw conveyor or plungers) and spills over onto the bed where it ignites and burns. When it reaches the dump gates, the remaining ash and clinker are dropped into ash pits for removal.

Two types of underfeed stokers are available: horizontal, side-ash-discharge and gravity-feed rear-end discharge types (Figure D-2). Both types are limited to 25 to 30 x 10^6 Btu/hr with a burning rate of 400,000 Btu/ft^2/hr.

Table D-1

CHARACTERISTICS OF VARIOUS TYPES OF STOKERS

Stoker Type and Subclass	Typical Capacity Range pph*	Maximum Burning Rate Btu/hr-ft^2	Characteristics
Spreader			
Stationary and dumping grate	20,000 to 80,000	450,000	Capable of burning a wide range of coals, best ability to follow fluctuating loads, high flyash carryover, low load smoke
Traveling grate	100,000 to 400,000	750,000	
Vibrating grate	20,000 to 100,000	400,000	
Underfeed			
Single or double retort	20,000 to 30,000	400,000	Capable of burning caking coals and a wide range of coals (including anthracite), high maintenance, low flyash carryover, suitable for continuous load operation
Multiple retort	30,000 to 500,000	600,000	
Chain grate and traveling grate	20,000 to 100,000	500,000	Characteristics similar to vibrating-grate stokers except these stokers experience difficulty in burning strongly caking coals
Vibrating grate	30,000 to 150,000	400,000	Low maintenance, low flyash carryover, capable of burning wide variety of weakly caking coals, smokeless operation over entire range

*pph = lb steam per hr; 1 pph = 1000 Btu/hr.

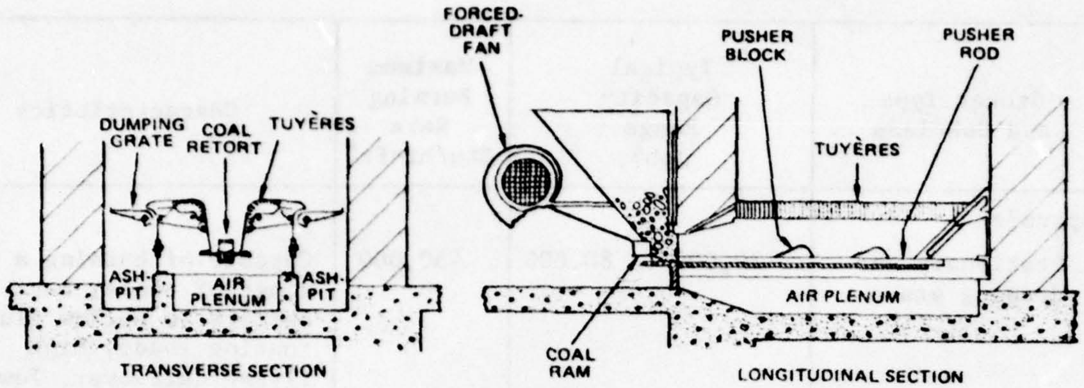


Figure D-2
HORIZONTAL UNDERFEED STOKER WITH SINGLE RETORT

Fuel. The underfeed-type of stoker is designed to burn low-grade, high-volatile or caking coals, and even the use of slack (minus 1/4 inch) coals or fines are common. Caking coals with various caking properties can be used. However, coals with low ash-fusion temperatures are not recommended because their exposure to the incandescent fuel bed causes clinker formation, and resultant ash removal problems.

Eastern caking and semi-caking bituminous coals and Midwestern free-burning coals are most frequently used with this type of stoker.

Size Considerations. Coal size is important to underfeed stoker operation. Usually a 2 to 1¼ inch top size is specified, and as much as 40 percent passing ¼ inch size is satisfactory. Double-screened coal is not required and is even inadvisable. Ash content of the ideal coal should be between 4 and 15 percent.

The multiple-retort design is a variation of the underfeed stoker and is similarly used with medium to high-volatile coals with 4 to 15 percent ash. The mixing of fuels can be tolerated but must follow a predetermined size pattern.

Overfeed or Traveling Grate Stoker

Operation. Traveling grate stokers are also known as chain-grate stokers, depending on the method of connecting individual links which comprise the traveling grate. During traveling grate stoker operation, coal is fed from a hopper onto the moving grate. The coal bed enters the furnace where it is ignited by furnace gases and by radiation from a hot refractory arch. The fuel bed continues to burn as it moves with the traveling grate. Ash is discharged at the far end of the grate into an ash pit.

The role of the refractory arch is to reflect heat onto the fuel bed and to assist with mixing and combustion of volatile gases. Some newer methods of traveling grate stokers use overfire air jets which eliminate the need for a refractory arch.

Fuel. The traveling grate stoker can burn a variety of fuels ranging from peat, lignite, subbituminous coals, bituminous coals, anthracite, and coke breeze, making it a very versatile stoker (Figure D-3).

The combustion of the high-carbon caking coals from the eastern Appalachian region is not satisfactory because such coals have a tendency to form a mat which prevents proper air distribution through the bed. However, high-ash clinkering coals from the Western fields and the Midwestern regions of the U.S. have been successfully fired in this stoker type.

Size Considerations. Bituminous coals should pass 2 to 1¼-inch round-hole screen and contain no more than 25 to 30 percent of minus ¼-inch undersize. Subbituminous coals are suitable for burning in even larger sizes.

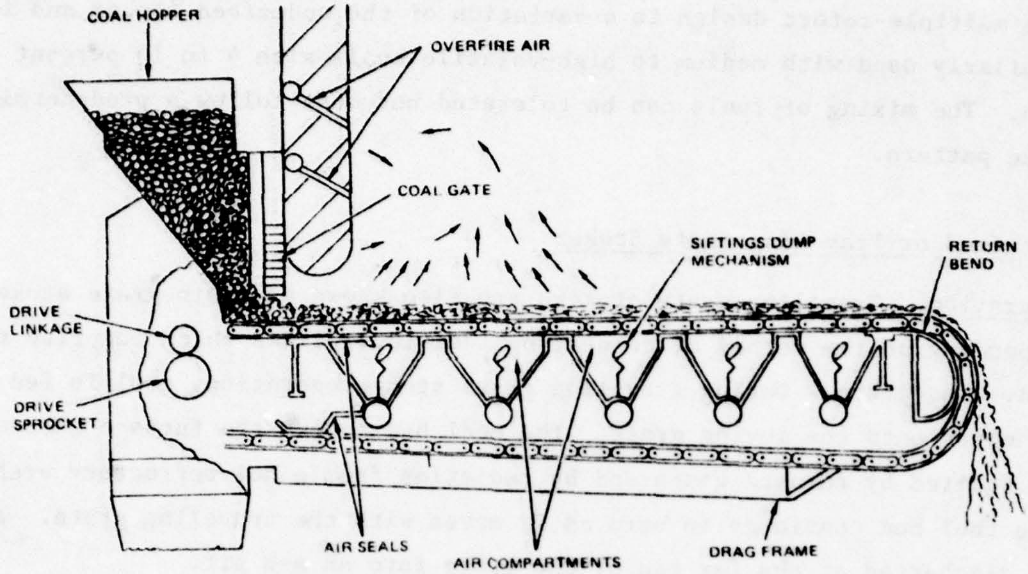


Figure D-3
CHAIN-GRATE STOKER

Lignite as a fuel should be limited to 1¼-inch top size with the fines retained in the stoker feed.

Spreader Stoker

Operation. The coal feed system for spreader stokers allows a combination of suspension burning of coal and burning on the grate (stationary or traveling type). Coal is fed into a retort from the coal hopper by the action of a rotating overthrow rotor. About 50 percent of fine coal remains in suspension where it is burned, while heavier coal particles settle onto the grate where they burn before being discharged to an ash pit (Figure D-4).

This combination method of burning coal provides excellent combustion control so that, by changing the feed rate, relatively rapid response can be made to fluctuating heat demands.

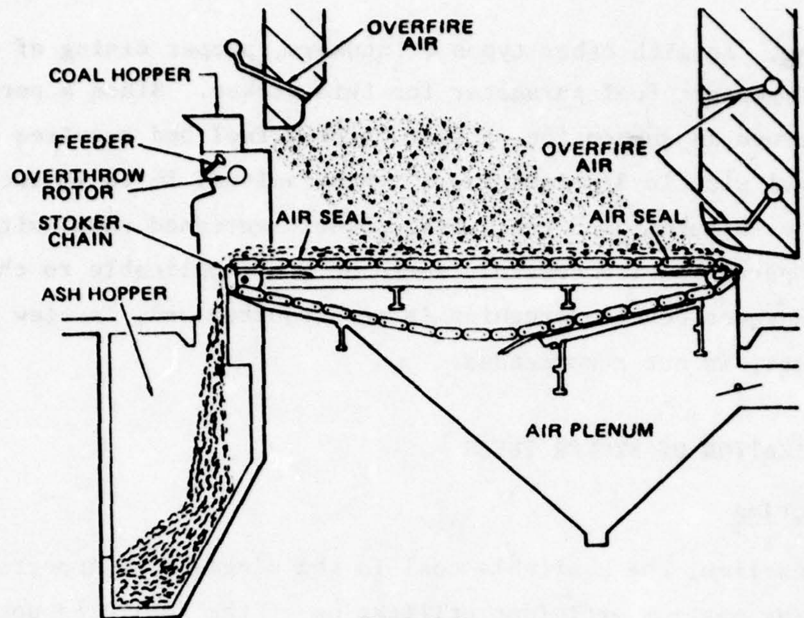


Figure D-4
SPREADER STOKER, TRAVELING-GRATE TYPE

This type of stoker is often used for a range of up to 400 x 10^6 Btu/hr, and is the stoker-type evaluated in earlier parts of the study. Spreader-stokers more efficiently burn fly-carbon particles which may be lost with the flue gas in other stoker types. A cyclone-type precipitator is included to separate and return to the furnace larger partially consumed particles still containing usable carbon. Bottom ash is discharged from the grate to a hopper for disposal.

Fuel. Spreader-stokers can burn fuels with a wider range of burning characteristics than any other type of stoker. Spreader stoker firing was developed to utilize the lower grades of coal with high ash content and low fusion temperatures. High-moisture, free-burning bituminous and lignite coals are also suitable for combustion. Low-volatile fuels such as coke breeze can be burned in a mixture with higher volatile coals; burning of anthracite is not recommended. Maximum heat-release rates of 450,000 Btu/hr/ft^2 are attainable for stationary grates, while the traveling grate is designed for up to 750,000 Btu/hr/ft^2.

Fuel Sizing. As with other types of stokers, proper sizing of feed coal is the most important fuel parameter for this stoker. Since a portion of the coal is burned in suspension, a fast burning fuel bed requires a small size coal. Ideal size is 3/4-inch top (with occasional 1¼ to 1½-inch size) to assure an even burning on the grate. Double-screened coal, with its higher degree of particle size control, would be most applicable to the spreader-stoker. However double-screening is not required and, in view of the premium cost, is not recommended.

CHARACTERIZATION OF STOKER FUELS

Fuel Selection

As noted earlier, the available coal is the single most important factor in obtaining maximum efficient utilization of the fuel. Economics of coal supplies include the contract conditions, long-term or spot prices, costs of preparation (as in double-screened coal), and transportation costs.

In addition to economic factors, selection of the stoker type is based on the analysis of the coal. Manufacturers of boilers usually have a comprehensive coal guide form which is analyzed for various combustion qualities. An example of the suggested coal information is shown in Table D-2. From this list, the slagging and fouling characteristics of coal ash can be calculated. These characteristics determine stoker size and design of the convection area.

Obviously, not all requirements of an ideal boiler-fuel match w ll be achieved simultaneously, but a balanced compromise can be assured by sufficient study and planning.

Figure D-5 summarizes the recommended coal size ranges for various types of stokers and tabulates the range of physical properties suitable for each type of stoker. The recent POWER handbook states that double-screening

Table D-2

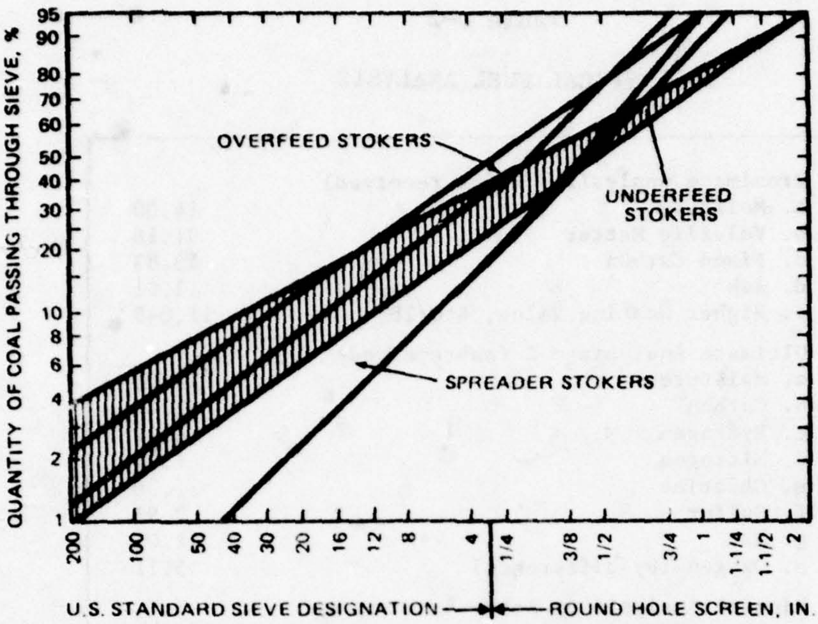
TYPICAL FUEL ANALYSIS

1. Proximate Analysis — % (as received)	
a. Moisture	14.00
b. Volatile Matter	31.16
c. Fixed Carbon	43.83
d. Ash	11.01
e. Higher Heating Value, Btu/lb	11,048
2. Ultimate Analysis — % (as received)	
a. Moisture	14.00
b. Carbon	61.18
c. Hydrogen	4.21
d. Nitrogen	1.24
e. Chlorine	.30
f. Sulfur	2.95
g. Ash	11.01
h. Oxygen (by difference)	5.11
3. Mineral Analysis of Ash — %	
a. Phosphate Pentoxide, P_2O_5	0.25
b. Silica, SiO_2	39.43
c. Alumina, Al_2O_3	15.63
d. Titania, TiO_2	0.83
e. Ferric Oxide, Fe_2O_3	28.95
f. Lime, CaO	10.99
g. Magnesia, MgO	0.68
h. Potassium Oxide, Ka_2O	1.99
i. Sodium Oxide, Na_2O	0.64
j. Undetermined	0.61
4. Ash Fusion Temperatures, $^{\circ}F$	
a. Reducing Atmosphere:	
(1) Initial Deformation (ID)	1980
(2) Softening (H=W)	2080
(3) Softening (H=½W)	2120
(4) Fluid Temperature (FT)	2520
(5) Temperature at 250 poise (T250)	2180
5. Grindability — Hardgrove Index	64.7

6. Moisture:
   a. The average equilibrium moisture of the coal is 14.0%. The normal range is 8% to 20% as received.
   b. All fuel firing equipment shall be designed at the capacities specified, with 12% surface moisture in addition to 8% inherent moisture.

7. Size: 100% through 1¼" ID ring.

8. Average Density: 45 lb/cu ft



RECOMMENDED LIMITS OF COAL SIZING FOR SPREADER, MASS BURNING, AND UNDERFEED STOKERS APPLY TO COAL ACTUALLY DELIVERED TO THE STOKER HOPPER. DEPENDING ON COAL'S FRIABILITY, ETC., THIS DIFFERS FROM LIMITS IN THE SPECIFICATION YOU GIVE YOUR SUPPLIER.

RECOMMENDED RANGE OF COAL PROPERTIES

FIRING EQUIPMENT	MOISTURE, %	VOLATILE MATTER, %	FIXED CARBON, %	ASH, %	AS-FIRED HEATING VALUE, BTU/LB (MINIMUM)	FREE SWELLING INDEX (MAXIMUM)	ASH-SOFTENING TEMPERATURE, F (MINIMUM)
SINGLE RETORT, STATIONARY GRATE	0-10	30-40	40-50	5-10	12,500	5	2500
SINGLE RETORT, UNDULATING GRATE	0-10	30-40	40-50	5-10	12,500	7	2500
MULTIPLE RETORT	0-10	30-40	40-50	5-10	12,500	7	2500
CHAIN GRATE/TRAVELING GRATE	2-15[1]	30-45	40-55	6[2]	11,000	5	1900[3]
SPREADER STOKER, DUMP GRATE	0-10	30-40	40-50	5-10	12,500		2300
SPREADER STOKER, CONTINUOUS CLEANING	0-10	30-40	40-50	5-15			2300
SPREADER STOKER, TRAVELING GRATE	0-10	30-40	40-50	5-15			2200

[1]FOR POROUS FUEL BEDS TEMPER COAL AS REQUIRED, UP TO A MAXIMUM OF 15% [2]MINIMUM VALUE, NO UPPER LIMIT [3]ASH SOFTENING TEMPERATURE IS FOR CHAIN GRATE; MINIMUM VALUE FOR TRAVELING GRATE IS 2200F

Figure D-5
MATCHING FIRING EQUIPMENT WITH THE SIZE AND TYPE OF COAL

and washing of coal is not necessarily required unless boiler and air-pollution control systems are specifically designed for this type of fuel, or a high-caking coal is used. Stoker manufacturers should be consulted before the coal and boiler combination is selected.

For the users of larger quantities of coal, the alternative exists of purchasing 2-inch by 0 coal, and crushing and screening the coal at the plant site. The coal could be double-screened and the 2-inch oversize crushed in a small hammermill and then mixed with the screening undersize to provide a balanced mix of coal particles. The coal preparation facility estimated in Sections 8 and 9 will accomplish this function.

STOKER COAL AVAILABILITY

Boiler vendors also indicate that double-screened coal is not necessary for modern stoker-fired boilers. While purchase of a double screened coal should reduce front-end coal preparation and handling, coal suppliers do not routinely stock or sell double-screened coal, and they estimate a premium cost of $6 to $8 per ton for the coal. This is a significant addition to fuel cost and, if a boiler were designed to use double-screened coal, the screening operation could be performed more economically at the site.

The following comment regarding stoker-coal availability applies to the more general types of stoker coal, as well as to double-screened coal.

Coal Marketing

Coal is priced and sold domestically by a variety of arrangements, the most common being the long-term contract. Such contracts normally call for the delivery of specified volumes of coal having certain chemical and physical characteristics for various periods of time.

In the United States, 80 to 85 percent of all noncaptive coal is priced and sold by long-term contracts. These contracts vary in length from a year or two to 20 years or more, and usually involve large volumes of coal.

The remaining 15 to 20 percent of noncaptive coal is priced and sold on the spot market. These transactions normally cover much smaller quantities of coal and may entail one shipment or multiple shipments over a relatively short time, usually only a few months to a year at most.

Most large coal companies maintain their own sales staffs, which handle all coal sales between the company and its customers. Generally, these sales organizations handle their own company's coal; however, some will also act as brokers for other companies. Smaller coal companies sometimes maintain their own marketing organizations, but more commonly they rely on independent coal brokers who charge sellers a fee for their services. These fees amount to several percent of the transaction and vary considerably, depending on coal qualities and quantities, sale prices, delivery terms, geographical locations, and other factors.

Coal Prices

The U.S. Bureau of Mines has maintained a historical series of average U.S. coal prices (f.o.b. mine), which is the longest running, consistent coal price statistical series in existence. Price data for 1900 through 1975 are shown in Figure D-6 in both current and constant prices as determined by the Gross National Product Implicit Price Deflator (1958 = 100).

The current cycle of increasing real prices is expected to peak at a constant price (1958 dollars) of about $16 per metric ton around the mid-1980s, and to begin declining slowly thereafter if a new round of improved technology and economies of scale become effective. However, the average prices in current dollars are expected to continue to rise throughout the remainder of this century, reaching perhaps around $50 per metric ton by 1985 (1985 dollars), and around $100 per metric ton in the year 2000 (2000 dollars).

Table D-3 contains prices of the typical U.S. steam coals for 1977.

Table D-3

TYPICAL U.S. STEAM COAL LONG-TERM CONTRACT PRICES FOR MID-1977

Producing District*	Btu/lb	Percent Sulfur	Percent Ash	F.O.B. Mine ($/metric ton)	
				Ask	Bid
Central Pennsylvania	12,000	2.0	15.9	$20.12	$19.29
Western Pennsylvania	12,000	2.0	14.4	19.84	19.01
Northern West Virginia	12,600	2.6	12.0	20.39	19.57
Ohio	11,100	3.5	16.1	20.94	19.84
Southeastern West Virginia and parts of Virginia	11,900	1.0	14.5	23.70	20.94
Southeastern West Virginia, eastern Kentucky, northern Tennessee, and parts of Virginia	11,900	1.3	12.9	22.60	20.67
Western Kentucky	11,900	3.7	14.2	19.84	18.46
Illinois	10,800	2.9	11.6	19.84	18.74
Indiana	10,800	2.9	10.7	19.57	17.36
Iowa	9,600	4.1	15.5	13.23	12.68
Alabama and southern Tennessee	11,800	1.4	14.2	22.05	19.84
Kansas, Missouri, and parts of Oklahoma†	10,400	4.4	17.9	15.16	14.61
Colorado and northeastern New Mexico	10,700	0.5	9.1	16.53	15.43
Parts of New Mexico and Arizona	9.800	0.6	16.2	12.68	12.40
Utah	11,200	0.6	10.7	17.09	15.98
Montana	9,000	0.6	7.5	8.82	7.16

*As defined by the Bituminous Coal Act of 1937.

†Excluding Texas lignite.

Source: Coal Week, May, 1977.

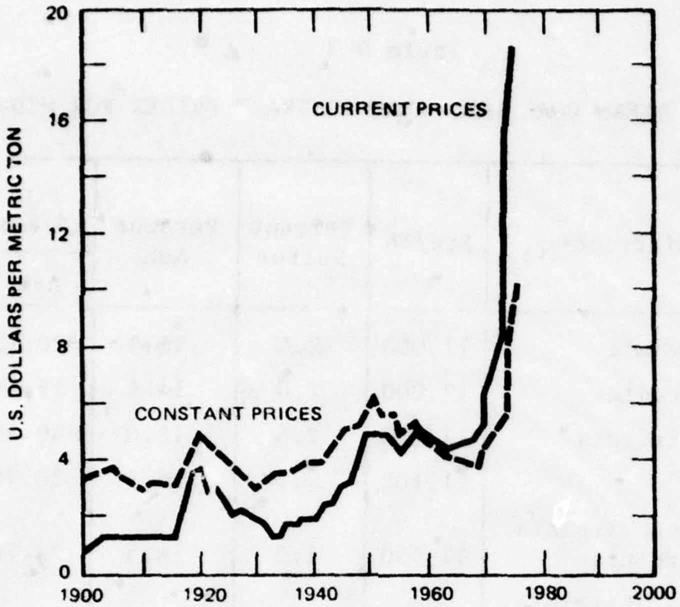


Figure D-6
HISTORICAL COAL PRICES

Regional Coal Sources

The location of the coal-fired stoker boilers was assumed to be one of the following:

- Atlantic coast area of Virginia
- Great Lakes area
- Southern Pacific Coast area of California

Geographically corresponding coal producing areas are associated with three provinces:

- Eastern (Appalachian Plateau)
- Interior Region (Illinois Basin)
- Rocky Mountains (Colorado Plateau)

The Appalachian Basin covers 40,000 square miles and constitutes the area physical geographers call "The Appalachian Plateau Province." The basin area includes parts of seven states — Pennsylvania, Ohio, Maryland, West Virginia, Kentucky, Tennessee, and Virginia.

Typical properties of both the run-of-mine and cleaned coal are given in Table D-4. The principal applications of the coal are for metallurgical purposes and steam generation. Thus, the coal is typical of many in the Appalachian Basin which may be used for both metallurgical and steam applications.

The Illinois portion of the Illinois Basin contains approximately 37,000 square miles of coal-bearing land. Illinois coals are all of high-volatile bituminous grade. The heating value of Illinois coals ranges from 10,000 Btu per pound in the northwest to over 14,000 Btu per pound in the southeast.

The southeast is the deepest part of the basin and No. 5 coal is often over 1000 feet down. The bed moisture drops from 20 percent to below 5 percent over the same distance. Illinois coals are typically high in sulfur content.

The most strongly caking coals are produced from seams No. 6 and 5 in southern Illinois (Gallatin, Saline, Jefferson, and Williamson counties). These coals are used in metallurgical coal blends.

Total in-place resources are estimated at 133 billion metric tons.

No. 6 is the state's most extensively mined coal; mining is concentrated in the south-southwest and west-central part of the state. The seam thins or disappears in an area stretching east to west between Springfield and Peoria and south to north between Marion and Shelby counties. In western Illinois, minability and quality are adversely affected by "white top" (an irregular clay replacement of the upper section of the seam). Typical coal analysis is shown in Table D-5.

The San Juan Basin is a major physiographic subdivision of the Colorado Plateau in northwestern New Mexico, southwestern Colorado, and northeastern Arizona. Coal deposits of the basin occur in three major zones of Cretaceous sequence. They are, in descending order, the Fruitland formation, the Mesaverde group, and the Dakota Sandstone.

Table D-4

TYPICAL PROPERTIES OF WEST VIRGINIA BITUMINOUS COAL

	Run-of-Mine	Prepared
Proximate analysis (wt %)		
Volatile matter	33.1%	34.2%
Fixed carbon	53.1	55.5
Ash	11.0	6.7
Moisture	2.8	3.6
Sulfur (wt %)	0.8%	0.5%
Gross calorific value (Btu/lb)	13,000	13,700
Free swelling index	7.0%	7.5%

Source: U.S. Coal Mine Production by Seam, 1975

Table D-5

TYPICAL PROPERTIES OF
ILLINOIS BITUMINOUS COAL

	Run-of-Mine
Proximate analysis (wt %)	
Volatile matter	34.9%
Fixed carbon	38.9
Ash	15.2
Moisture	11.0
Sulfur (wt %)	4.9%
Gross calorific value (Btu/lb)	10,000
Free swelling index	3.5%

Source: U.S. Coal Production by Seam, 1975

The Fruitland formation coals range from subbituminous A to high-volatile bituminous C, with the rank increasing toward the north. In some areas these coals are suitable for recovery by surface mining, which is currently being conducted on a fairly large scale. In the future, because of their generally more shallow occurrence, Fruitland formation coals will probably be the first to be mined by underground methods. Typical coal properties of the run-of-mine coal are given in Table D-6.

The coal supply areas described above were selected at the most favorable transporation distances of less than 500 miles. Since typical coal prices were given as f.o.b., mines, the typical railroad prices for coal transportation are given in Table D-7.

Transportation costs can vary widely, and the industry pricing mechanism is complex; thus transportation costs, delivery schedules, stockpile sizes, and other related items must bear separate examination for each site and plant capacity.

Table D-6

TYPICAL PROPERTIES OF
NEW MEXICO BITUMINOUS COAL

	Run-of-Mine
Proximate analysis (wt %)	
Volatile matter	35.9%
Fixed carbon	38.2
Ash	15.2
Moisture	10.7
Sulfur	0.9
Gross calorific value (Btu/lb)	10,200

Source: Keystone Coal Industry Manual (1976)

Table D-7

ESTIMATED COAL TRANSPORTATION COSTS
FOR THE UNITED STATES
(U.S. Dollars per Metric Ton)

District	Rail Costs
Appalachian-Norfolk, Va.	$ 9.95
Alabama-New Orleans, La.	12.50
Illinois-Chicago, Ill.	10.40
New Mexico-Long Beach, Calif.	21.95
Arizona-Long Beach, Calif.	13.75
Utah-Long Beach, Calif.	17.20
Colorado-Long Beach, Calif.	19.75

Source: SRI

Appendix E

UNIT PRESENT VALUES

A good measure for comparing life-cycle costs of alternative energy options is a unit present value in dollars per million Btu. To obtain a unit present value for an option, it is necessary to compute the entire project life cycle cost of the option, and then divide by the millions of Btu of energy. In this study, the energy basis is energy transferred to heat loads in boilers and fired heaters. This energy is 80 percent of the energy available in the fuel consumed.

THE NAVY LIFE CYCLE COST METHODOLOGY

The project life-cycle present value is calculated using the methodology of Navy document P-442. That method is summarized as follows:

- The Navy gets its funds from general government tax revenues. Since government projects do not pay taxes, the method does not consider depreciation.

- Funds spent by the Navy represent an opportunity cost to the private sector. That cost is assumed to be 10 percent per annum, in constant dollars. The value of 10 percent was reached by an Institute of Defense Analysis study of the opportunity cost of government projects, after removing the effects of inflation. The fixed 10 percent value for the opportunity cost in the Navy methodology is called the discount rate.

- When there is general inflation of "i" percent per year, the actual annual financing cost of a commercial venture equivalent to a government project would, on the average, be 10 + i. If i is 8 percent, the annual financing cost would be 18 percent. This annual financing cost is commonly referred to in industry as a capital charge. The discount rate is thus equal to the financing capital charge minus the annual inflation. The discount rate can also be referred to as the real rate of return or the time value of money after inflation effects are removed.

- Note that with the current 8 percent per year general inflation, the Navy methodology gives the equivalent of an 18 percent annual financing capital charge. Such a capital charge is consistent with financing costs encountered by public utilities for energy projects. An 18 percent capital charge would result as the sum of income taxes that take into account depreciation over 25 years, 16 percent annual after-tax return on equity, and 11 percent interest and principal on loans (assuming a 1 to 1 debt to equity ratio).

- The Navy economic methodology involves comparing life-cycle costs of all project alternatives in terms of present values. Suppose a cost one year from now in inflated dollars will be X_1. Suppose the annual financing capital charge is d + i, where d is the discount rate and i is the general inflation rate. The present value today of purchase X_1 one year from now is the amount of money invested today at an interest rate of d + i that would equal X_1 one year from now. Let the present value be P. Then:

$$X_1 = P(1 + d + i), \tag{1}$$

and

$$P = X_1/(1 + d + i). \tag{2}$$

- The use of present value analysis and a fixed dollars 10 percent discount rate d has the result of washing out general inflation, so that the actual level of general inflation i can be ignored. Suppose an item costs X_0 now. One year from now it will cost:

$$X_1 = X_0\ (1 + i) \tag{3}$$

The present value now of purchase X_1 made one year from now is

$$P = X_0\ (1 + i)/(1 + d + i) \tag{4}$$

$$P \cong X_0\ [1/(1 + d)] \tag{5}$$

The symbol $\cong$ means approximately equal.

Since uncertainties in the true correct values for both d and i exceed the error in the approximation of (5), equation (5) is considered the basic equation of the Navy methodology. This methodology is unusually convenient, because over the life of a typical project, inflation rate i is different each year. By equation (5), none of these annual general inflation rates needs to be considered at all.

- Energy costs are expected to escalate faster than general inflation for the foreseeable future. In the Navy methodology, it is not the total annual percent rise in an energy price which appears explicitly in the present value analysis, but rather the differential inflation, e, (often called differential escalation). Suppose an energy product costs Y_0 today, and its price is rising at an annual inflation rate that totals i + e. Then one year from now the price is expected to be Y_1.

$$Y_1 = Y_0 (1 + i + e) \tag{6}$$

The present value today of the purchase Y_1 made one year from now will be:

$$P = Y_1/(1 + d + i) \tag{7}$$

$$P = Y_0 (1 + i + e)/(1 + d + i) \tag{8}$$

$$P \cong Y_0[(1 + e)/(1 + d)] \tag{9}$$

Notice how the general inflation rate i has disappeared again as in equation (5). However, the differentiation inflation rate e does appear explicitly in equation (9).

- Equation (9) includes equation (5) as a special case when the differential inflation e is zero.

- Again, suppose an energy quantity costs Y_0 today. Consider purchasing the same amount n years from today. The present value of that purchase would be:

$$P = Y_0[(1 + e)^n/(1 + d)^n] \tag{10}$$

- Suppose that a certain amount of some commodity now costing Y_0 must be purchased each year from year 1 to year N. The present value at time zero for the entire series of purchases would be:

$$P = Y_0 \left[\sum_{n=1}^{n=N} (1 + e)^n/(1 + d)^n\right] \tag{11}$$

- If the same amount were to be purchased each year from year M to year N, the present value at time zero for the series of purchases could be obtained from two series of the form of equation (11) by difference using:

$$\sum_{n=M}^{n=N} = \sum_{n=1}^{n=N} - \sum_{n=1}^{n=M-1} \tag{12}$$

- The quantity in brackets in equation (10) is called a single amount inflation discount factor. The quantity in brackets in equation (11) is called a cumulative uniform series inflation discount factor.

- The discount factors shown explicitly in equations (10) and (11) are end-of-the-year discount factors. The Navy methodology assigns to a given project year the average of the end-of-year discount factor and a corresponding beginning-of-the-year discount factor (with n in equation (10) replaced by n-1 for year n). This was done because it is not clear when a purchase will be made in a given project year. Therefore, the average occurrence time would be at mid-year. The resulting formulas for the discount factors are slightly more complicated than those shown in equations (10) and (11).

- Notice that in equations (5), (6), (10), and (11) the costs to be inserted are those for year zero. This means that life-cycle costs for a project can be estimated from the cost elements computed at a single point in time called the zero of time.

BECHTEL'S PRESENT VALUES AND UNIT PRESENT VALUES

Table 3-3 in Section 3 shows the details of how present values were calculated in this study.

Once a life-cycle present value has been calculated, it can be divided by the number of million Btu of heat transferred over the operating life to get a unit present value, as is done in Table 3-3.

Some special comments are in order about Bechtel's present values and unit present values:

- For Bechtel's studies, the project zero of time has been taken as the date of the cost prices used.* The date of the commencement of plant operation is then assumed to be some years later, allowing a reasonable amount of time for decision making and financing, and in particular, allowing adequate time for plant construction. Coal conversion plants typically are expected to take 36 months to design and build. Coal boiler plants typically take 24 months. Typically, 50 percent of the project expenditures will be made during the first two-thirds of the construction period. When this is indicated in the project life cycle cash flow analysis, the Navy methodology adequately accounts for what industry calls "interest during construction."

- Bechtel's present values accordingly involve a zero of time that differs from the start of the first year of operation, even though many analyses for the Navy have the start of operations as the zero of time. Because the start of operations in Bechtel's studies will be several years after time zero, the present values at time zero of all operating costs will be lower than they would be if the zero of time occurred at the start of operations.

- For this study, the start of operations occurs at the beginning of the fourth year. The cumulative uniform series for the project years 4 through 28 is calculated by equation (12) from the factors tabulated in Appendix G, for each relevant value of differential inflation rate e, as shown in Table E-1.

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* For this study, the cost estimate was made in second quarter 1978 dollars .

Table E-1

COMPUTATION OF CUMULATIVE UNIFORM SERIES INFLATION DISCOUNT FACTORS FOR YEARS 4 TO 28

Commodity	General Wages & Prices	Coal	Electricity	Fuel Oil
Differential Inflation Rate	0	5	6	8
Series for Project Years 1 to 28	9.765	15.653	17.427	21.895
Series for Project Years 1 to 3	2.609	2.800	2.839	2.919
Series for Project Years 4 to 28 (Difference)	7.156	12.853	14.588	18.976

STANDARD NAVFAC UNIT PRESENT VALUES

The Naval Facilities Engineering Command (NAVFAC) examines energy projects with the zero of time at the start of the first year of operations. This is presumably because many small energy projects have relatively short times between initial capital outlay and the start of operations, and the capital costs can be considered to occur in the same project year that energy operations start. When unit present values are calculated in this way, the values are higher than Bechtel's values presented in this study.

It is useful to be able to convert the Bechtel unit present values to a basis approximately equivalent to that of NAVFAC. This can be done by multiplying the Bechtel unit present values by the ratio of the discount factors for zero differential inflation. The NAVFAC discount factor would be for project years 1 to 25. The discount factor from Appendix G of this report is 9.524. Thus, the Bechtel unit present values need merely to be multiplied by:

$$\frac{\text{Discount Factor Yrs 1 to 25}}{\text{Discount Factor Yrs 4 to 28}} = \frac{9.524}{7.156} = 1.3309$$

Appendix F

LEVELIZED UNIT ENERGY COSTS

Another way to display present value comparisons is in terms of levelized unit energy costs. This method has the advantage of putting the costs into a form that resembles the dollars per million Btu energy costs that are familiar in the private sector. For convenience, the latter are called "current dollar costs of energy."

CURRENT DOLLAR COSTS OF ENERGY

It is instructive to derive the current dollar cost of energy for the case treated in Table 3-3 of Section 3 of this report.

The analysis involves treating recurring annual costs and capital costs separately.

Recurring Annual Costs

Each of the recurring annual costs in Table 3-3 can be divided by the amount of heat transferred annually ($28,900 \times 10^9$ Btu/25 years). The results are shown in Table F-1.

Capital Costs

Capital costs are usually converted into an equivalent series of uniform annual charges. The result will be a percentage of the capital cost which is to be added to the recurring annual cost of Table F-1. This is commonly called the capital charge.

Table F-1

CURRENT DOLLARS COST OF ENERGY FOR RECURRING ANNUAL COSTS
(For Case of Table 3-3)

Cost Item	Amount, Thousands of Dollars	Dollars per Million Btu*
Coal	2,000	1.73
Electricity	50	0.04
Operating and Maintenance Labor and Materials	2,550	2.21
Total Recurring Operating Costs	4,600	3.98

*1156 x 10^9 Btu Per Year

The way a capital charge is converted into an equivalent annual charge depends on the way the cost of money is defined. Here, two alternatives may be considered:

- In the first, the cost of money is the sum of the time value of money (discount rate) plus the general inflation rate. This would lead to capital charges in the range of 18 to 20 percent per year.

- In the second, the cost of money is the time value of money alone (discount rate). This leads to capital charges in the range of 10 to 12 percent.

In either case, the equivalent series of uniform annual charges has the same present value as the capital cost.

The private sector uses the first type of capital charge in most cases. Naval projects would be analyzed with the second type of capital charges. The resulting increments in current cost of energy for both types of capital charges, are shown in Table F-2.

Table F-2

CURRENT DOLLARS COST OF ENERGY FOR CAPITAL CHARGES

Item	Annual Percent of Investment	Annual Capital Charge	
		Amount, Thousands of Dollars	Dollars Per Million Btu
Private Sectors Actual Inflating Dollars Cost of Money	19.4	4,016	3.47
Navy Analysis Discount Rate with Inflation Removed	11.38	2,356	2.04

Note that the private sector capital charge would be the one actually paid now if the plant in question had just started operating this year. Thus, it is the capital charge that gives the best feel of costs being charged at this time.

For Navy project comparisons, however, only the second kind of capital charge is in the correct ratio to annual costs for life-cycle costing.

LEVELIZED COSTS

The current dollar cost of energy does not take into account any differential inflation of energy costs. Consequently, it cannot represent a fair measure for comparison of energy projects if differential inflation is expected. The current dollar cost does not give sufficient weight to future energy costs, and hence it penalizes projects which have high investment costs, yet which save on future energy costs.

The Navy present value methodology described in Appendix E, on the other hand, does give fair comparisons of projects that include differential inflation. It would be desirable to have a measure that is equivalent to the present value measure, but which resembles the current dollar cost. Levelized costs constitute such a measure.

Levelized costs for an energy component in a project's life-cycle costs are obtained simply by multiplying the annual amount and the dollars per million Btu of that component by the ratio of two cumulative uniform series inflation discount factors that appear in the present value analysis of the problem. The ratio is:

$$\left(\frac{\text{Discount factor for energy component}}{\text{Discount factor with zero differential inflation}}\right)$$

In Table 3-3, the discount factor for operating and maintenance labor and material (with zero differential inflation) is 7.156. For coal (with 5 percent differential inflation), the discount factor is 12.853. Therefore, the appropriate levelizing multiplier is (12.853/7.156) = 1.7961.

Table F-3 presents the levelized costs for the case of Table 3-3.

Table F-3

LEVELIZED COSTS
(From Table 3-3)

Cost Element	Multiplier	Levelized Costs	
		Annual Cost Amount, Thousands of Dollars	Dollars per Million Btu
First Year Investment	0.1212	836	0.72
Second Year Investment	0.1101	1,519	1.31
Total Investment	0.1138	2,355	2.03
Coal	1.796	3,592	3.11
Electricity	2.039	102	0.09
Operating and Maintenance Labor and Material	1.0	2,550	2.21
Total Project		8,599	7.44

Capital costs have been included in the levelized cost display of Table F-3. Capital contributions to the levelized costs are calculated in the same way as for other cost elements:

$$\left(\frac{\text{Discount factor for cost element}}{\text{Discount factor for recurring costs with zero differential inflation}}\right)$$

The levelized costs of elements in Table F-3 have the following characteristics:

- They are in the same ratio to each other as are the present value costs
- The labor and materials recurring costs are unchanged by the levelizing process.

The levelized annual amounts in Table F-3 could have been obtained directly by dividing all present values in Table 3-3 by 7.156, the discount factor for the labor and materials cost element.

Table F-4 presents the three possible ways for expressing dollars per million Btu that have been suggested in this appendix:

- Current dollars costs with private sector capital charge
- Current dollars costs with Navy capital charge
- Levelized costs

It is axiomatic that a present value comparison is better for comparing life cycle costs than any other. The levelized costs, which are merely present values redisplayed another way, are clearly the best of the three measures in Table F-4. It then becomes clear that private-sector current dollars costs highly distort project comparisons. Capital contributions to costs are exaggerated, while energy costs are undervalued. Because of this, industry is moving away from current dollars comparisons to discounted cash flow analyses for comparing alternative projects. The levelized cost method above is equivalent to a discounted cash flow analysis.

Table F-4

THREE FORMS OF DOLLARS PER 10^6 BTU
(Based on Table 3-3)

Cost Element	Current Dollar Costs, Private Sector Capital Charge	Current Dollar Costs, Navy Capital Charge	Levelized Costs
Investment	3.47	2.04	2.03
Coal	1.73	1.73	3.11
Electricity	0.04	0.04	0.09
Operating and Maintenance Labor and Materials	2.21	2.21	2.11
Total Project	7.45	6.02	7.44

Appendix G

DISCOUNT FACTOR TABLES

The tables following are reprinted from Navy Publication P-442 for ease of reference during the calculations of Section 3 and Section 10.

Table G-1

PROJECT YEAR INFLATION-DISCOUNT FACTORS

Differential Inflation Rate = 0%*
Discount Rate = 10%

Project Year	Single Amount	Cumulative Uniform Series
1	0.954	0.954
2	0.867	1.821
3	0.788	2.609
4	0.717	3.326
5	0.652	3.977
6	0.592	4.570
7	0.538	5.108
8	0.489	5.597
9	0.445	6.042
10	0.405	6.447
11	0.368	6.815
12	0.334	7.149
13	0.304	7.453
14	0.276	7.729
15	0.251	7.980
16	0.226	8.209
17	0.208	8.416
18	0.189	8.605
19	0.172	8.777
20	0.156	8.933
21	0.142	9.074
22	0.129	9.203
23	0.117	9.320
24	0.107	9.427
25	0.097	9.524
26	0.088	9.612
27	0.080	9.692
28	0.073	9.765
29	0.066	9.831
30	0.060	9.891

* These factors are to be applied to cost elements which are anticipated to escalate at the same rate as the general price level.

Table G-2

PROJECT YEAR INFLATION-DISCOUNT FACTORS

Differential Inflation Rate = 5%*
Discount Rate = 10%

Project Year	Single Amount	Cumulative Uniform Series
1	0.977	0.977
2	0.933	1.910
3	0.890	2.800
4	0.850	3.650
5	0.811	4.461
6	0.774	5.235
7	0.739	5.974
8	0.706	6.680
9	0.673	7.353
10	0.643	[illegible].996
11	0.614	8.610
12	0.586	9.196
13	0.559	9.755
14	0.534	10.288
15	0.509	10.798
16	0.486	11.284
17	0.464	11.748
18	0.443	12.191
19	0.423	12.614
20	0.404	13.018
21	0.385	13.403
22	0.368	13.771
23	0.351	14.122
24	0.335	14.458
25	0.320	14.777
26	0.305	15.083
27	0.292	15.374
28	0.278	15.653
29	0.266	15.918
30	0.254	16.172

* These factors are to be applied to cost elements which are anticipated to escalate at a rate 5 percent faster than general price levels.

Table G-3

PROJECT YEAR INFLATION-DISCOUNT FACTORS

Differential Inflation Rate = 6%*
Discount Rate = 10%

Project Year	Single Amount	Cumulative Uniform Series
1	0.982	0.982
2	0.946	1.928
3	0.912	2.839
4	0.878	3.718
5	0.847	4.564
6	0.816	5.380
7	0.786	6.166
8	0.757	6.923
9	0.730	7.653
10	0.703	8.357
11	0.678	9.035
12	0.653	9.688
13	0.629	10.317
14	0.607	10.924
15	0.584	11.508
16	0.563	12.071
17	0.543	12.614
18	0.523	13.137
19	0.504	13.641
20	0.486	14.127
21	0.468	14.595
22	0.451	15.046
23	0.435	15.480
24	0.419	15.899
25	0.404	16.303
26	0.389	16.692
27	0.375	17.066
28	0.361	17.427
29	0.348	17.775
30	0.335	18.111

* These factors are to be applied to cost elements which are anticipated to escalate at a rate 6 percent faster than general price levels.

Table G-4

PROJECT YEAR INFLATION-DISCOUNT FACTORS

Differential Inflation Rate = 8%*
Discount Rate = 10%

Project Year	Single Amount	Cumulative Uniform Series
1	0.991	0.991
2	0.973	1.964
3	0.955	2.919
4	0.938	3.857
5	0.921	4.777
6	0.904	5.681
7	0.888	6.569
8	0.871	7.440
9	0.856	8.296
10	0.840	9.136
11	0.825	9.961
12	0.810	10.770
13	0.795	11.565
14	0.781	12.346
15	0.766	13.112
16	0.752	13.865
17	0.739	14.603
18	0.725	15.329
19	0.712	16.041
20	0.699	16.740
21	0.687	17.427
22	0.674	18.101
23	0.662	18.762
24	0.650	19.412
25	0.638	20.050
26	0.626	20.676
27	0.615	21.291
28	0.604	21.895
29	0.593	22.488
30	0.582	23.070

* These factors are to be applied to cost elements which are anticipated to escalate at a rate 8 percent faster than general price levels.

Appendix H

STEAM STATES, PROCESSES, AND CYCLES IN POWER GENERATION

This appendix provides some background information on steam thermodynamics that appeared in Reference (1). The purpose is to show the steam cycles for cogeneration and condensing generation of electricity, and to show why it is advantageous to have turbine inlet temperatures and pressures as high as possible.

Electric power is generated from steam by a two-component device called a turbine-generator. The turbine extracts mechanical work from the steam. The electric generator then converts this mechanical work into electric power with about 98-percent efficiency. Steam turbines can be discussed by reference to a diagram that represents states of steam in terms of two thermodynamic variables, entropy (S, along the horizontal axis) and enthalpy (H, along the vertical axis). A state of steam or water or a mixture of the two is uniquely defined by a single point on an S,H diagram as shown in Figure H-1. Four different steam states are shown as black circles in this figure. Each point has a unique set of values of S and H. Also, once S and H are specified, other state variables, such as temperature and pressure, are uniquely defined. Figure H-1 shows some typical constant temperature and constant pressure lines.

A process is a transition between two states of steam. In Figure H-1, three processes are shown with dotted lines. The final state is indicated by the arrowhead. A process takes place in a specific piece of equipment.

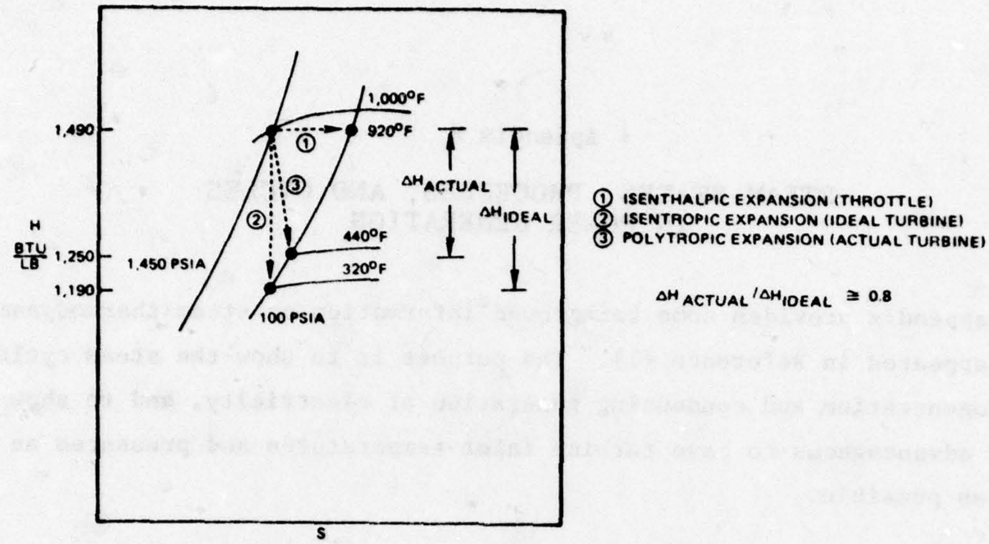

Figure H-1
STEAM STATES AND EXPANSION PROCESSES

Process 1, Isenthalpic Expansion, in Figure H-1 takes place in a throttle valve. It is often referred to as a simple pressure letdown. The term "expansion" signifies that the volume occupied by a pound of steam increases as a result of the process, or alternatively that the pressure decreases. The term "isenthalpic" signifies that the value of enthalpy H is constant through the process. Enthalpy H is the measure of the energy that can be extracted from the steam. Since the enthalpy of the final state is the same after the process as before the process, no energy is extracted in a throttle-valve expansion.

Process 2, Isentropic Expansion, in Figure H-2 would take place by expansion in an ideal turbine. In this process, the gas pressure has decreased to the same final pressure as for Process 1. However, in Process 2 the final value of enthalpy is below the initial value. Therefore, the difference Δ_{ideal}, has been extracted as mechanical energy. The term "isentropic" for the process signifies that the thermodynamic variable entropy, S, is constant during the process. A constant entropy expansion is an ideal process which serves as a limit for turbine expansions. The difference ΔH_{ideal} is the largest amount of mechanical energy that can be extracted from each pound of steam, given an initial steam state and a final steam pressure.

Process 3, Polytropic Expansion, in Figure H-1 takes place in an actual turbine. The same final pressure is achieved as for Process 1 and Process 2. However, the enthalpy change ΔH_{actual} that has taken place is only 80 percent of ΔH_{ideal}, and the entropy, S, has increased. The ratio of $\Delta H_{actual}/\Delta H_{ideal}$ will be between 75 and 85 percent for turbines considered in this study.

Figure H-2 shows the difference between a noncondensing expansion and a condensing expansion. Process 1 in Figure H-2 is the expansion from

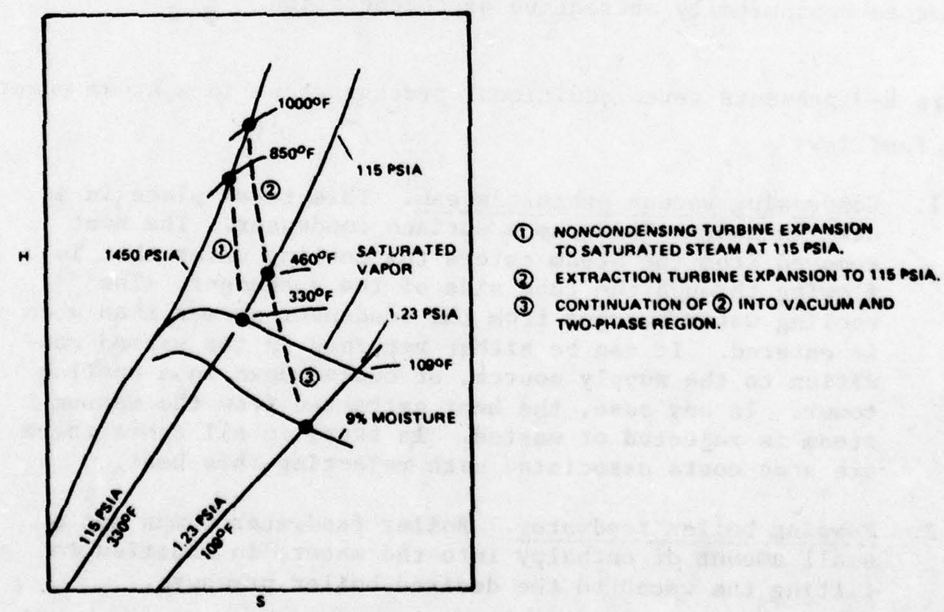

Figure H-2
NONCONDENSING AND CONDENSING STEAM TURBINE EXPANSION PROCESSES

1450 psia and 850^{o}F to the conditions of saturated steam at 115 psia. A noncondensing expansion produces steam which can be used for heating. Useful steam and electricity are generated together in a noncondensing expansion. This is strict cogeneration. Process 2 in Figure H-2 is also a noncondensing expansion through the high-pressure portion of a condensing-extraction turbine. "Extraction steam" is the term given to the heating steam removed through the extraction port of such a turbine. When all the steam is removed through the extraction port, the turbine is being used for cogeneration.

Process 3 in Figure H-2 is a condensing expansion. Also, any steam that undergoes both Process 2 and Process 3 has undergone a condensing expansion. The expansion is called condensing because the exhaust steam contains nine percent moisture that has condensed as a result of cooling during the turbine expansion. The steam-water mixture emerges at a vacuum pressure and a low temperature. Steam in such condition is not readily used for heating, and consequently the residual heat must be discarded. Because the exhaust steam is not used subsequently, power generation by condensing generation is not as economically attractive as cogeneration.

Figure H-3 presents seven additional process steps in a steam power generation facility:

1. Condensing vacuum exhaust steam. This takes place in a heat exchanger known as a surface condenser. The heat removed from the steam enters the cooling water that is flowing through the tube side of the exchanger. The cooling water emerges from the condenser warmer than when it entered. It can be either returned in the warmed condition to the supply source, or cooled down in a cooling tower. In any case, the heat extracted from the vacuum steam is rejected or wasted. In fact, in all cases there are some costs associated with rejecting this heat.

2. Pumping boiler feedwater. Boiler feedwater pumps put a small amount of enthalpy into the water, in addition to lifting the water to the desired boiler pressure.

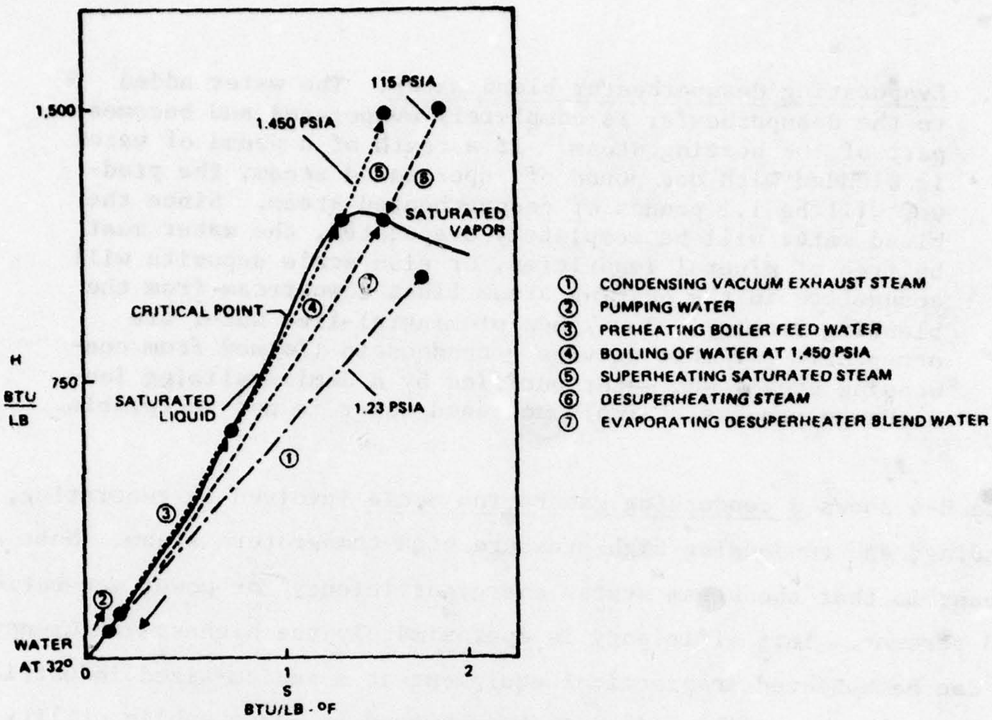

Figure H-3
ADDITIONAL UTILITY STEAM PROCESSES

3. Preheating boiler feedwater. The water to be boiled usually is preheated in separate coils up to the boiling temperature before entering boiling tubes. During preheating, the temperature rises while the pressure stays approximately constant.

4. Boiling water. This takes place in one bank of specially designed tubes inside a boiler. Boiling converts saturated liquid (water) into saturated vapor (steam) at a constant temperature and pressure.

5. Superheating steam. The saturated steam emerging from the boiling tubes is heated to a higher temperature at constant pressure in superheat tubes, which are in a second specially designed tube bank in a boiler.

6. Desuperheating steam. In some applications, more steam is occasionally needed for the heat loads than can be used in the turbines to satisfy the electric loads. The extra superheated steam must be throttled down to the heating steam pressure, and then cooled down to an acceptable heating steam temperature. This cooling of the steam is called "desuperheating." It is accomplished by blending the steam with water in a desuperheater.

7. Evaporating desuperheater blend water. The water added to the desuperheater is completely evaporated and becomes part of the heating steam. If a tenth of a pound of water is blended with one pound of superheated steam, the product will be 1.1 pounds of desuperheated steam. Since the blend water will be completely evaporated, the water must be free of mineral impurities, or else scale deposits will accumulate in the heating steam lines downstream from the blending station. Two kinds of mineral-free water are acceptable for this service – condensate (formed from condensing steam) and water purified by a demineralizing ion exchange process. Simple softened water is not acceptable.

Figure H-4 shows a condensing generation cycle involved in generating, expanding, and condensing high-pressure high-temperature steam. Most significant is that the steam system energy efficiency for power generation is 33 percent. This efficiency is approximately the highest efficiency that can be achieved in practical equipment at a medium-sized industrial facility. Higher efficiencies can be achieved in large public utility systems by starting at pressures too high for medium-sized equipment, and

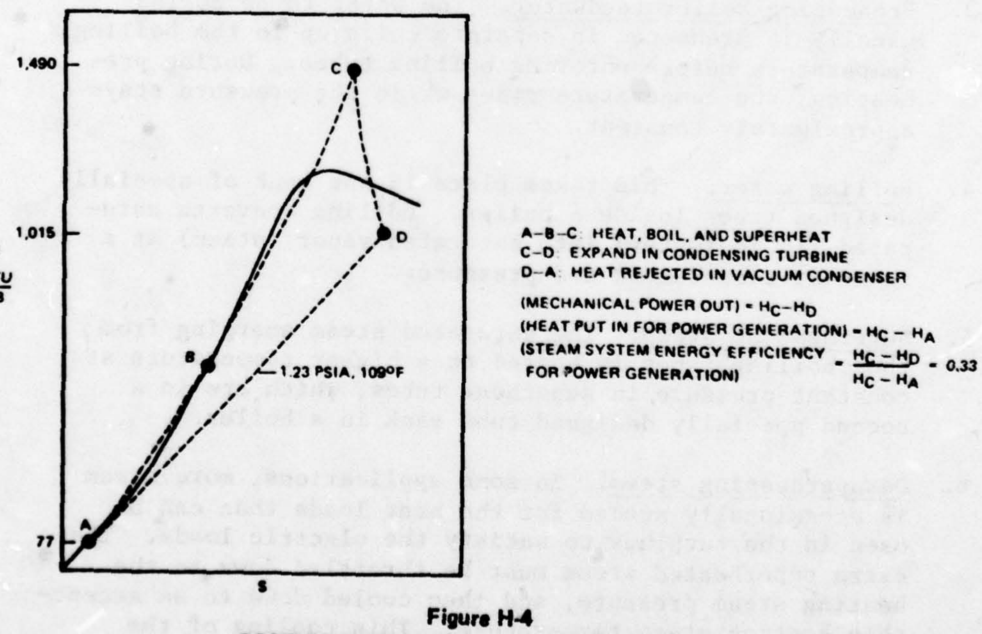

Figure H-4
CONDENSING GENERATION STEAM CYCLE

taking the steam through a second superheat process before introducing it into the condensing section of the turbine. Because public utilities can reach higher cycle efficiencies in power generation, power made by condensing generation at small industrial facilities will suffer an economic disadvantage compared to purchased power. It should also be noted that the boiler sustains energy losses in converting fuel gross heat content into energy transferred into the steam. Some of the energy leaves the boiler as stack gas, sensible heat, and water-vapor latent heat. A small additional amount is lost to the environment by heat transfer from boiler walls. Thus, boiler efficiencies are between 80 and 87 percent. The overall efficiency for power generation is the product of the steam system energy efficiency and the boiler efficiency.

Figure H-5 compares two condensing generation cycles that have different inlet conditions and the same exhaust condition. The figure reveals two advantages for higher inlet conditions:

- Higher energy efficiency for condensing generation. This occurs for higher inlet conditions. It reduces the amount of fuel needed to generate each kilowatt-hour in condensing generation.

- More energy per pound of steam. More energy is extracted during the expansion. Thus, the boiler supplying the steam for a turbine of a given power output capacity can be smaller.

Figure H-6 illustrates the principles of cogeneration. Suppose there is a demand for a certain amount of heating steam at 115 psia and 338°F. One alternative is to generate the steam directly at those conditions in a low-pressure boiler. A second option is to generate the steam at a higher temperature and pressure, and expand it down to the required conditions in a turbine. The second alternative permits the extraction of mechanical work and generation of power. However, the amount of additional enthalpy put into the steam to raise it to point B instead of point C in Figure H-6

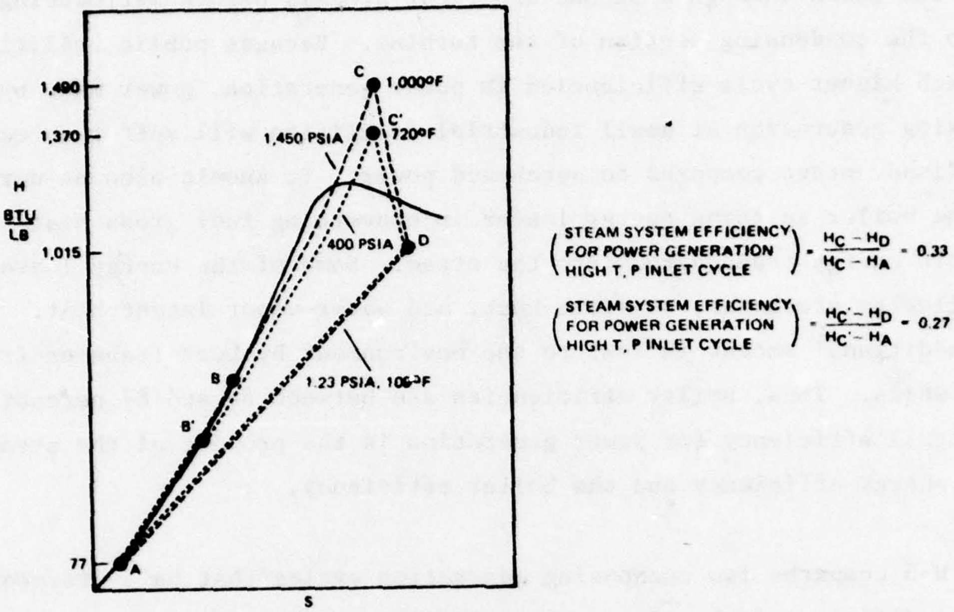

Figure H-5

THE ADVANTAGE OF HIGH INLET TEMPERATURES AND PRESSURES: MORE POWER PER POUND OF STEAM

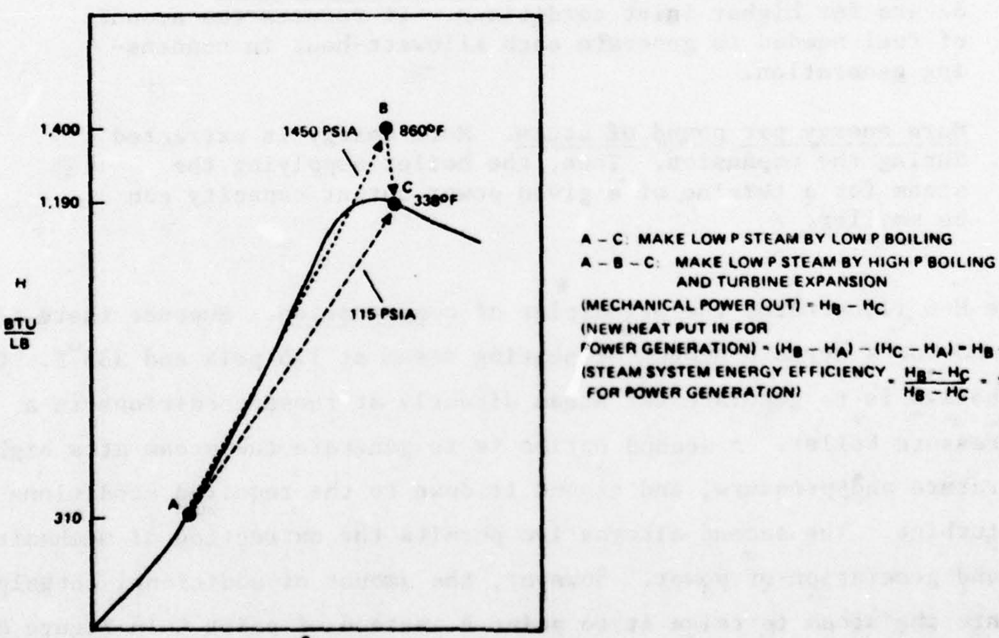

Figure H-6

THE ADVANTAGE OF STEAM CYCLE COGENERATION

is exactly equal to the amount of enthalpy converted to work in the expansion. Thus, the steam system energy efficiency is 100 percent for cogeneration. This is approximately three times as high as the condensing generation efficiency in the highest-performance medium steam boiler turbine-generator facility that is practical. This explains why cogeneration is attractive on a fuel conservation and fuel cost basis.

It was shown for condensing generation that the best system performance is obtained when the turbine inlet temperature and pressure are as high as possible. For cogeneration, the performance is also better for higher inlet conditions, because more electricity can be generated with each pound of steam extracted and sent to heat loads.

Appendix I

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