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**COMPUTERIZED OPERATING COST
MODEL FOR INDUSTRIAL STEAM GENERATION**

By
T. D. Powers

February 1983

Work Performed Under Contract No.: DE-AC21-81MC14521

For
U. S. Department of Energy
Office of Fossil Energy
Morgantown Energy Technology Center
Morgantown, West Virginia

By
EG&G Washington Analytical Services Center
Morgantown, West Virginia

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COMPUTERIZED OPERATING COST MODEL FOR INDUSTRIAL STEAM GENERATION

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EXECUTIVE SUMMARY

Pending EPA regulations, establishing revised emission levels for industrial boilers are perceived to have an effect on the relative costs of steam production technologies. To aid in the comparison of competitive boiler technologies, the Steam Cost Code was developed which provides levelized steam costs reflecting the effects of a number of key steam cost parameters. The Steam Cost Code is a user interactive FORTRAN program designed to operate on a VAX computer system. The program requires the user to input a number of variables describing the design characteristics, capital costs, and operating conditions for a specific boiler system. Part of the input to the Steam Cost Code is the capital cost of the steam production system. The capital cost is obtained from a program called INDCEPT, developed by Oak Ridge National Laboratory under Department of Energy, Morgantown Energy Technology Center sponsorship. The levelized steam costs are sensitive to the following input variables:

- The size of the boiler unit.
- The number of units.
- The sulfur removal level.
- The particulate removal level.
- The average operating capacity.
- The rate for return on investment.

INDCEPT and the Steam Cost Code provide detailed cost information for 66 different reference model systems. The reference systems consist of 24 models for both pulverized coal and stoker-fired steam systems, two atmospheric fluidized-bed combustion models, and six oil-fired reference systems. Also included are two product gas boiler models for combusting gas produced by coal gasification. The user can select from a total of eight coal gasification systems for producing either low- or medium-Btu product gas. Product gas can be produced using smaller single-user plants or larger multi-user plants designed to provide gas for a group of centrally located users such as an industrial park. Gasifier types include Koppers-Totzek, Wellman-Galusha, and Stoic for single-user plants and Texaco gasifiers for multi-user plants. Gasification models only consider costs associated with producing the product gas which is capable of pipeline transport and not costs associated with steam generation.

Reference plant models using coal are designed specifically for an eastern high-sulfur bituminous coal or a western low-sulfur sub-bituminous coal. Systems requiring sulfur removal can select from four types of flue gas desulfurization (FGD) methods: sodium scrubbing, dual alkali, lime/limestone scrubbing, and spray drying. Equipment costs are available for systems designed for 70 and 94 percent sulfur removal. Options for particulate collection include electrostatic precipitators (ESP) and baghouses.

To obtain steam costs for a specific boiler plant, the INDCEPT Code provides a capital cost estimate indicating costs for individual system components and allowances for contingencies, escalation, and interest during construction. The cost estimate considers the length of the construction period and other site-specific location factors. The general operating procedure required to

obtain a capital cost estimate from INDCEPT is to generate the required input data for the code using a separate computer program (INPUT.FOR). Once the input data exists, the cost estimate can be obtained by entering the command statement, @INDCEPT, which executes a command file containing the required command statements to complete the cost estimate procedure.

The Steam Cost Code calculates levelized steam costs for the reference steam plants and product gas costs for coal gasification systems. The levelized steam cost represents the minimum cost of steam (\$/MMBtu of gross boiler output) required to recover all costs considered (including return on investment) after the effects of taxes, expressed as a constant cost over a specific operating period. The Steam Cost Code has user options available to vary individual escalation rates and other economic parameters used to calculate the steam costs. Although INDCEPT and the Steam Cost Code operate independently, they can be executed sequentially to obtain a detailed capital cost estimate from INDCEPT and an operating cost breakdown from the Steam Cost Code indicating the contributing cost sources of steam production. Shown below is a simplified overview of the overall computer package.

Simplified Overall Computer Package Structure

INDCEPT and the Steam Cost Code can be used to perform analyses to determine detailed cost information for a specific steam system or to develop relationships pertaining to industrial steam plants in general. Generalizations relating to boiler and fuel-type selections can be made with respect to operating capacity factors and boiler size ratings. For low utilization factors, fuel oil and natural gas are competitive fuel choices because of the low capital cost for boilers firing these fuels. The higher fuel cost is offset by the low capital cost of the boiler. For high capacity factors, coal is the economic fuel choice, being the lowest cost raw fuel alternative. The extra cost of coal handling and emission control equipment is off-set by the lower fuel cost for coal except at the smaller size ranges where the boiler size limits the fuel savings that can result from using coal.

To demonstrate the investigative capabilities of the codes, an analysis was performed comparing pulverized-coal and atmospheric fluidized-bed combustion using cost data from the Chicago area. Chicago is located in an area where both eastern and western coals can be considered as competitive options without experiencing excessive delivery costs. The reference fuel costs used in the Steam Cost Code include delivery costs to a specific location.

For most comparisons made in the analysis, atmospheric fluidized-bed combustion was viewed as a mature technology and compared using an equal economic basis with pulverized-coal boiler options. Under this scenario, AFBC resulted in the lowest steam cost of the different boiler systems considered in the analysis. The lower steam costs result primarily because of the lower capital cost of an AFBC in comparison to the cost of a pulverized-coal boiler requiring separate flue gas desulfurization equipment. The specific steam costs from the analysis are summarized in the following table.

STEAM COSTS CALCULATED USING THE STEAM COST CODE

Model No. ^a	Size ^b	Capacity Factor				Capital ^c
		30%	50%	70%	90%	
Model 1	50	58.50	37.67	28.75	23.79	26,690
	200	33.83	22.69	17.92	15.26	52,623
	400	26.48	18.11	14.52	12.53	83,108
Model 5	50	54.21	34.94	26.67	22.08	18,376
	200	30.65	20.63	16.33	13.94	44,412
	400	23.79	16.35	13.16	11.39	70,059
Model 10	50	55.00	35.43	27.05	22.39	18,708
	200	31.10	20.91	16.55	14.13	45,134
	400	24.12	16.56	13.33	11.53	71,129
Model 13	50	55.21	35.50	27.05	22.36	19,477
	200	31.45	21.07	16.62	14.15	47,059
	400	24.45	16.71	13.39	11.55	74,211
Model 31	50	57.94	37.91	29.33	24.56	20,321
	200	34.33	23.51	18.88	16.30	49,842
	400	27.16	19.00	15.50	13.55	79,208
Model 36	50	60.85	39.68	30.60	25.56	21,073
	200	35.71	24.36	19.49	16.79	51,640
	400	28.14	19.60	15.94	13.91	82,018
Model 38	50	59.88	39.10	30.20	25.26	20,984
	200	35.38	24.17	19.37	16.70	51,419
	400	27.94	19.49	15.87	13.86	81,664
Model 49	50	52.70	33.95	25.91	21.45	19,071
	200	28.72	19.39	15.40	13.18	42,318
	400	21.76	15.07	12.20	10.60	63,870
Model 50	50	54.45	35.60	27.52	23.03	18,702
	200	30.29	20.89	16.86	14.62	41,710
	400	23.17	16.42	13.52	11.92	63,086

a Model 1 -- PC-EAST-SS-94%-ESP; Model 5 -- PC-EAST-DA-94%-ESP; Model 10 -- PC-EAST-LIME-94%-BH; Model 13 -- PC-EAST-DRY-94%-BH; Model 31 -- PC-West-SS-70%-ESP; Model 36 -- PC-WEST-LIME-70%-BH; Model 38 -- PC-WEST-DRY-70%-BH; Model 49 -- AFBC-EAST; Model 50 -- AFBC-WEST

b Gross boiler output in 10⁶ Btu/hr.

c Capital cost based on commercial operation date (1984) in \$1,000. Costs obtained from INDCEPT.

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CHAPTER 1

INTRODUCTION

1.1 New Source Performance Standards (NSPS) Legislation

The Environmental Protection Agency (EPA) is currently involved in determining allowable emission levels from stationary sources of pollution. These emission levels, or new standards of performance, will apply to new industrial steam boiler plants. These standards of performance for stationary sources are established under Section III of the Clean Air Act (42 U.S.C. 7411), which allows the EPA to "establish standards of performance for any category of new stationary source of air pollution which " . . . " causes, or contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare."

Before any emission levels are adopted into law, the EPA is required to perform background studies to determine the impacts the new performance standards will have on the environment and affected industries. The background study should indicate the level of emission reduction achievable considering the costs involved and any nonair environmental or health impacts (i.e., wastes generated by required emission control equipment) and energy requirements. Standards of performance are not intended to achieve any specific air quality levels, but are instead designed to set a maximum limit on the quantity of emissions that will be permitted from a particular source.

"New fossil fuel-fired industrial boilers with capacities greater than 250×10^6 Btu/hr are (currently) subject to 40 CFR 60 Subpart D, which limits NO_x , SO_x , and PM emissions. Subpart D also specifies an opacity limit for all boilers (1)." Any proposed changes to the performance standards would probably be limited to current emissions categories since no other type of emission was selected for investigation as a possible consideration by the EPA in their background study in support of potential new source performance standards. "State and local agencies if authorized by state law are free under Section 116 of the (Clean Air) Act to establish even more stringent emission limits than those established under Section 111 or those necessary to attain or maintain the National Ambient Air Quality Standards (NAAQS) under Section 110 (2)." Boilers located in certain geographical areas may also be restricted under the prevention of significant deterioration of air quality. This requires the source to control emissions using the Best Available Control Technology (BACT). The BACT is defined as ". . . an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation" . . . "through application of production processes and available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of each pollutant (3)."

1.2 Need for Investigation

The proposed New Source Performance Standards are expected to be more stringent than current emission levels and cover a wider range of industrial boiler classifications. The extent of emission control equipment required by the NSPS may have an effect on the relative costs of the

various boiler technology options currently available and being developed.

The cost of steam production varies widely depending upon the boiler and fuel type over the applicable size range of boilers used in the industrial

sector. There exists a need for a procedure to evaluate the absolute and marginal effects of emission control standards on the cost of steam

production. Oak Ridge National Laboratory, under Department of Energy,

METC sponsorship, developed a computer code to estimate capital investment costs of industrial boiler plants over a range of various emission

control alternatives. ORNL also developed an "analysis code" which would calculate regional average steam costs based on the distribution of

boiler types, sizes, and capacity factors for a particular region. This

code was not documented and would be difficult to apply to studies requiring specific cost information. To provide further insight into the cost

of emission control equipment, a Steam Cost Code was developed to be used in conjunction with the ORNL computer code to calculate levelized steam

costs for a specific boiler system. This program can provide the information required to evaluate the different boiler options using life cycle

cost analysis. The trade-offs between high-capital, low-operating cost

options (coal-fired boilers) versus low-capital, high-operating cost

alternatives (oil and gas boilers) can be better evaluated with the use

of the Steam Cost Code.

Once the proposed NSPS are established by the EPA, a need will exist for

determining the absolute and marginal effects due to any changes of

emission standards for stationary sources. The Steam Cost Code will be

able to provide cost information for competitive boiler options that can

aid in developing the most cost effective NSPS, and subsequently for

industrial fuel choice decisions. The Steam Cost Code can not be the sole decision-making criteria used in selecting new boiler installations due to the large number of intangibles involved in a specific boiler installation. The Steam Cost Code can provide detailed cost information that can be used to access competitive boiler options for comparing relative costs.

CHAPTER 2

INDUSTRIAL STEAM BOILER SYSTEMS -- BACKGROUND INFORMATION

2.1 Classification and Terminology

Industrial boilers are most often referred to by the combustion method and fuel type. Boiler systems can be further classified by the boiler type (watertube, firetube, and cast iron) and by the method of construction (packaged and field erected). Boilers firing coal are often referred to by the combustion method consisting of stoker-fired (spreader, underfeed, and overfeed), pulverized coal, and atmospheric fluidized-bed combustion. The following sections provide a brief description of the different classifications of industrial boilers and the terminology used in describing specific boiler characteristics.

2.1.1 Boiler Type

Industrial boilers are classified by boiler type, fuel type, and method of construction. The boiler type relates to the heat transfer method of the boiler. The different methods consist of watertube, firetube, and cast iron. Watertube boilers have the water passing through heat transfer tubes as it is being heated by the combustion gases. The firetube boilers have water surrounding the heat transfer tubes that contain the combustion gases. Cast

iron boilers are similar to the firetube boilers but the units are constructed of iron rather than stainless steel and actual applications are limited to very small sizes ($<10 \times 10^6$ Btu/h).

2.1.2 Fuel Type

The primary fuels used for industrial boilers consist of coal (and coal-derived fuels), oil, natural gas, and process by-products. Nonfossil fuels are also used for combustion for industrial steam production. These types of fuels consist of wood, bagasse (an agricultural waste), and general solid wastes (refuse and garbage). The nonfossil fuel-fired boilers (NFFB) are considered by the EPA as a separate source category because of the contrasts with fossil fuel-fired boilers (4).

2.1.3 Method of Construction

Two general methods of construction are used for industrial boilers, packaged and field erected. Packaged boilers are factory-assembled units and are limited in size by transportation restrictions. Most packaged boilers are delivered by rail or barge. Field-erected units are constructed on-site and constitute the majority of the industrial boiler-installed capacity. Factory assembly permits packaged boilers to have a substantially lower capital investment as compared to a field-erected unit. Many packaged boilers fire oil or natural gas due to the fuel handling requirements and costs associated with coal. Despite the higher fuel

costs resulting from burning oil or natural gas, the use of a packaged boiler for a small to medium capacity requirement has several advantages over field-erected units. These advantages consist of (5):

- Minimum capital investment.
- Minimum space requirements.
- Minimum operator attention.
- Fully automatic controls.
- Multiple units, providing flexibility (turn up/turn down capability).
- Minimum delivery time.
- Minimum foundation requirements.
- Arrangement versatility.

Most packaged boilers are designed for a specific grade of fuel which results in operating limitations with respect to fuel variation capabilities.

2.1.4 Stoker-Fired Coal Boilers

Boilers firing coal can be further classified by the fuel feed system. Coal-fired boilers consist of stoker and pulverized coal-fired boilers. Stoker boilers are identified by different coal-firing methods consisting of spreader, underfeed, and overfeed stokers. Spreader stokers have the coal thrown by a rotating spreader into the combustion chamber with some of the smaller particles being burned in suspension. Overfeed stokers have the coal on a continuous link-moving grate that passes through the combustion chamber. The boiler is designed to burn the coal in one pass through the boiler. Underfeed stokers have the coal fed to the combustion chamber intermittently by gravity or by a ram-feeding system. The ash is removed from the sides or the back of the combustion chamber.

2.1.5 Pulverized Coal Boilers

Pulverized coal boilers fire coal crushed to a fine powder which is injected into the furnace. Combustion efficiency is improved over stoker-fired boilers because the coal is burned while in suspension. Pulverized coal-fired boilers dominate the larger boiler size ranges. Smaller coal boilers are usually stoker fired due to the coal grinding equipment costs required for a pulverized coal boiler. Stoker boilers are also limited in size by the fuel feed system capacity.

2.1.6 Atmospheric Fluidized-Bed Combustion

An emerging technology that provides an alternative to conventional coal-fired boilers is atmospheric fluidized-bed combustion (AFBC). In an AFBC, the coal particles are combusted in a limestone bed material fluidized by forced air. The advantages of AFBC is the sulfur capture capabilities of the limestone bed material which eliminates the need for a separate flue gas desulfurization device and low NO_x formation in the uncontrolled state.

2.1.7 Coal Gasification

Coal gasification is an emerging technology which is capable of achieving significant reductions for all three major emission categories (SO₂, NO_x, and particulates) (6) at the expense of being a high cost technology. The coal gasification process involves converting raw coal into a clean combustible gas that can be fired directly in a boiler without requiring separate post combustion emission control devices. Two types of product gas can be produced, low- and medium-Btu gas. Coal gasifiers exist in sizes for on-site gasification and central gasification for multi-users located in one area such as an industrial park.

2.2 Emission Control Equipment

The primary pollutants associated with industrial steam generation consist of sulfur dioxide, nitrogen oxides, and particulate material (dust and fly-ash). Federal emission levels currently exist (for boilers larger than

250 MMBtu/h) limiting the emissions of these pollutants to the environment. To meet emission levels, separate emission control equipment may have to be installed on boiler systems depending on the boiler and fuel type. Different types of equipment are available for controlling each type of emission. The selection of emission control equipment for a specific boiler system depends on such factors as removal efficiency, boiler and fuel type, boiler size, and in some instances, the geographical location of the boiler system. The selection of the most economical and efficient emission control equipment is not an obvious decision for a particular boiler system. The following sections provide a brief description of the emission control equipment options being considered, indicating the major design parameters and operating characteristics:

2.2.1 Particulate Collection

Particulate collection equipment is designed to remove flyash and other combustion particles found in the flue gas from coal and residual oil-fired boilers. Natural gas and distillate oil boilers generally have low particulate emissions in the uncontrolled state due to the nature of the fuel. High particulate collection efficiencies can be obtained by electrostatic precipitators (ESP) and baghouses. Lower collection efficiency equipment may be used as a preliminary collection device to remove larger particles from the flue gas before entering an ESP or baghouse to improve the overall collection efficiency.

2.2.1.1 Electrostatic Precipitator

The methods used to control particulate material for industrial boilers consist primarily of electrostatic precipitators (ESP) and baghouses. The procedure used to collect particulates in an ESP is to impart an electric charge on suspended particles in the flue gas. The charged particles will migrate towards an oppositely charged collection electrode while subject to a diverging electric field (7). As the particulate matter begins to build up on the electrode, the collection efficiency decreases requiring removal of the material. Common methods of removal are mechanical rapping or vibration. The primary design parameters that determine the collection efficiency are the specific collection area (SCA) and the electrode spacing. The SCA is the ratio of the total collection plate area to the maximum gas flow rate. The electrode plate spacing is determined by the height, length, and distance between the plates. The air flow distribution characteristics through the ESP is critical in obtaining high collection efficiencies. The operating parameters of an ESP consist of flue gas flow rate, rapping frequency, voltage applied to the electrodes, particle size distribution in the flue gas, and the electrical resistivity of the particles to an electric charge (8). Some of the operating parameters are determined by the coal type and fuel firing method.

2.2.1.2 Baghouse

Baghouses consist of fabric filter elements to remove the particulate material from the flue gas. The fabric filter weave is made of a durable material, usually fiberglass coated with graphite, silicone, or teflon. Unlike an ESP, the baghouse collection efficiency increases as the filters become coated with particulate material causing a sieving effect. However, this effect will eventually cause pressure drops and bag damage which requires periodic cleaning of the filters. Three methods of cleaning are used for baghouses: reverse flow, mechanical shaking, and pulse jet. The major design parameters for a baghouse consist of the air-to-cloth ratio and the fabric filter weave. The air-to-cloth ratio is the volume of gas (CFM) divided by the available filtering area. The operating conditions affecting the collection efficiency are the cleaning frequency, fuel characteristics, and the baghouse temperature. Low flue gas temperatures can cause corrosion problems and caking on the filters resulting in reduced bag life and collection efficiency (9).

2.2.2 Sulfur Removal Methods

Flue gas desulfurization (FGD) involves the removal of sulfur dioxide from the combustion gases before exiting the stack. Four desulfurization techniques being considered consist of sodium scrubbing, dual alkali, lime/limestone scrubbing, and spray drying.

2.2.2.1 Sodium Scrubbing

The sodium scrubbing FGD system is considered a "wet" scrubbing system because of the sulfur impaction method used and the aqueous waste product generated. The sodium scrubbing system is considered to be relatively simple in design and requires less equipment than the other systems. The procedure involves spraying an alkaline solution (usually NaOH or NaCO₃) from an absorption tower to quench the inlet gas. A series of chemical reactions occur converting the SO₂ in the flue gas into water soluble compounds.

Approximately 85 percent of the sorbent is reused with the remainder processed for waste disposal. The most common method for treating the spent sorbent is evaporation ponding due to the large amount of liquid waste generated. Nearly all the sodium scrubbing systems are located in arid regions that are suitable for rapid evaporation.

Sodium scrubbing is capable of high sulfur removal rates over a range of SO₂ inlet concentrations (10). The most critical operating parameter is the liquid-to-gas ratio which determines the amount of scrubbing liquid circulated and the sorbent feed rate which is a measure of the amount of sorbent recycle. The major disadvantages of sodium scrubbing is the high cost of the sorbent and the large amount of waste product generated.

2.2.2.2 Lime/Limestone Scrubbing

The lime/limestone scrubbing system requires more equipment than the sodium scrubbing system and is primarily only used on larger boilers to benefit from the economy of scale.

This process uses a different procedure to contact the sulfur in the flue gas. The gas is routed through a jet bubble reactor which "bubbles" the gas through a limestone slurry resulting in a solid gypsum crystalline formation in the slurry. The sludge waste product is dried and disposed of as a solid waste-using landfill. The key operating conditions involve the gas-liquid contact time determined by the residence time in the slurry and the pH of the slurry.

2.2.2.3 Dual Alkali

The dual alkali FGD system uses two sorbent chemicals, usually sodium and calcium. The sodium is used for SO_2 removal and the calcium is used to precipitate solids from the scrubbing liquor. This results in a manageable by-product and improves the regeneration capability of the relatively expensive sodium sorbent. The process consists of four steps (11): flue gas quenching, regeneration, solids separation, and waste disposal.

Dual alkali is an effective method of removing sulfur from flue gas containing a high percentage of sulfur. When the sulfur level falls to around 1 percent or less, the system develops problems such as scaling and generally exhibits poor collection efficiency. For this reason, dual alkali was not considered for systems firing western low-sulfur coal. Due to the similarity to the sodium scrubbing system, many of the key operating parameters are the same.

2.2.2.4 Spray Drying

Spray drying combines flue gas desulfurization and particulate collection in one process. The procedure used is to contact the gas with a lime spray atomized scrubber liquid. The SO_2 in the gas is converted to sulfates and sulfites. The temperature of the flue gas evaporates the water droplets leaving behind a solid powder mixture. The flue gas is then passed through a baghouse to remove the increased amount of dry particulate material. Further SO_2 removal can occur on the filters in the baghouse due to contact with any unreacted sorbent. The dry waste product can be disposed of as landfill. The most important operating condition is maintaining proper flue gas temperature to prevent condensation from occurring in the baghouse.

2.2.2.5 AFBC as a Sulfur Control Method

A separate FGD system is not required on an AFBC boiler due to the sulfur capture that occurs during the combustion process in the bed material. The bed materials best suited for sulfur capture are limestone and dolomite. Limestone is more common but dolomite tends to be less sensitive to bed temperature for sulfur capture efficiency.

There are a number of factors that determine the sulfur capture capabilities using AFBC. The main boiler design characteristics consist of the bed depth and fluidizing velocity which determine the residence time in the bed. Increasing the residence time improves the sulfur capture and increases the cost and size of the boiler. A number of operating conditions also have an effect on the sulfur removal level. The most important factor appears to be the calcium-to-sulfur ratio determined by the replacement rate of the bed material. Other sulfur capture related conditions are bed temperature, sorbent particle size, fuel firing method, and excess air levels (12).

AFBC is not considered to be a proven commercial combustion method, however, several vendors offer AFBC boiler units. AFBC is expected to be a competitive commercial technology by 1985.

2.2.3 Nitrogen Oxide Control

NO_x pollutants consist of NO and NO_2 . These pollutants have two sources of origin: fuel NO_x and thermal NO_x . Fuel NO_x is created by fuel bound nitrogen and oxygen in the combustion chamber. Thermal NO_x is formed by atmospheric nitrogen and oxygen in the combustion chamber. The amount of thermal and fuel NO_x created is determined by the combustion conditions and therefore the reduction of NO_x emissions is commonly done with combustion control techniques. Although post combustion techniques exist for NO_x removal, generally, they are not commercially used because lower cost combustion control techniques can achieve current emission levels if properly designed and operated.

2.2.3.1 Low Excess Air (LEA)

The combustion techniques are low capital cost modifications which primarily limit the formation of NO_x in the combustion chamber by limiting the excess oxygen and reducing flame temperatures. Low excess air (LEA) is one method that controls the amount of excess air in the combustion chamber by limiting the air flow through the windbox into the combustion chamber. Using LEA will also improve the thermal efficiency by decreasing the volume of heated gas released to the atmosphere through the stack.

2.2.3.2 Staged Combustion, Low NO_x Burners, and Flue Gas Recirculation

Staged combustion is another technique that consists of diverting a fraction of the combustion air away from the burner and injecting it into the furnace beyond the burner. This technique lowers the peak flame temperature and reduces oxygen availability in the combustion zone. Other commonly used methods include low NO_x burners and flue gas recirculation (FGR). Low NO_x burners are designed specifically to reduce peak flame temperature and improve local combustion product recirculation. Flue gas recirculation involves recirculating a fraction of the flue gas back to the windbox to reduce the oxygen levels (less fresh air) and lower combustion temperatures by absorbing combustion heat.

Most NO_x control techniques increase combustion efficiency, lower fuel costs, reduce opacity (especially for stoker-fired boilers), and are relatively low capital cost modifications to perform. These control techniques, however, require increased boiler operator supervision possibly resulting in increased labor costs.

CHAPTER 3

INDUSTRIAL BOILER CHARACTERISTICS AND SELECTION CRITERIA

3.1 Differences in Emissions From Major Fuel Alternatives

The major fuels used for industrial boilers consist of coal, oil, and natural gas. For boilers firing coal, the amount of particulate material generated is determined mainly from the ash content of the coal, combustion method, amount of excess air, and load firing rate. The SO₂ emissions are closely related to the sulfur content of the fuel [approximately 95 percent of the fuel sulfur levels (13)]. The NO_x emissions are dependent on the combustion method, excess air levels, and firing rates.

For boilers firing fuel oil, two grades of oil are used, distillate and residual. The particulate emissions from residual oil is mainly determined by the sulfur content of the fuel and carbon residue. The particulate emissions from distillate oil are generally very low. The sulfur emissions are directly related to the sulfur content of the fuel. The NO_x emissions are related to the atomization method, fuel nitrogen, and the amount of air preheat and excess air.

The particulate and SO₂ emissions from natural gas boilers are very low. The NO_x emissions are influenced by the flame temperatures and amount of excess air. The flame temperature is determined by the boiler size and amount of air preheat.

3.2 Current Federal Emission Levels

Currently, Federal emission levels exist for industrial boilers greater than 250×10^6 Btu/h. Boilers smaller than 250×10^6 Btu/h are controlled by individual state requirements. The individual state requirements vary greatly but are generally less stringent than the Federal emission limits. Emission limits are usually expressed in terms of pounds per 10^6 Btu (lbs/MMBtu), percent removal from the uncontrolled emission level, or both. The present emission levels are expressed in terms of pounds per 10^6 Btu for industrial boilers. This gives an advantage to fuel sources that are naturally low in sulfur. Certain low-sulfur coals can meet the sulfur emission limit without any control device. The percent reduction limit (currently applied to utility boilers as well as lbs/ 10^6 Btu limits) would require control devices for all types of coal. The current Federal emission levels are summarized in Table I.

TABLE I

Emission Limits for New Fossil Fuel-Fired Industrial Boilers with Capacities Greater than 250×10^6 Btu/hr (Established Under 40 CFR 60, Subpart D)^b

Boiler Type	PM ^a	SO _x ^a	NO _x ^a
Coal	.10	1.2	.70
Fuel Oil	.10	.8	.30
Natural Gas	.10	--	.20

^a expressed in terms of lbs/ 10^6 Btu.

^b U.S. Environmental Protection Agency. Fossil Fuel-Fired Industrial Boilers -- Background Information, Volume 1: Chapters 1-9 (EPA-450/3-82-0062), p. 3-57.

3.3 Size Distribution of Industrial Boilers by Fuel Type

Boiler capacities are often expressed in terms of pounds per hour (lbs/hr) of steam produced or thermal heat rates in terms of million Btu's per hour (10^6 Btu/hr). The range of capacities considered in the industrial boiler population vary greatly due to the variety of uses for industrial applications. The majority of industrial boiler systems provide steam for process use and to a lesser extent for space heating and electricity generation. Steam is required for a number of types of industries ranging from chemical and steel to canning and paper industries. The major steam-using industries are listed in Table II based on fossil fuel usage data. These eight major industries use a large percentage of their total fossil fuel consumption for steam generation which contributes a significant amount towards the total operating expenses of these industries.

Boiler capacities measuring thermal heat rates can be a measure of the fuel input rate or the gross heat output from the boiler. Both values are directly related by the boiler efficiency. Table III indicates the distribution of boiler and fuel type with respect to selected size ranges based on the thermal heat input rate of the fuel in terms of million Btu's per hour.

The data from Table III indicates the largest concentration of boiler capacity is in the $10-50 \times 10^6$ Btu/h size range with 28 percent of the total installed capacity. The next largest size range is boilers larger than 250×10^6 Btu/h with 24 percent of the installed capacity. Based on this data, slightly over 75 percent of the total installed capacity of

TABLE II

Fuel Usage Data for Major Steam-Using Industries^a

SIC Code	Industry	Total Fossil Fuel Consumption ^{b,c} (10 ¹² Btu)	Percentage of Total Fossil Fuel Consumption ^a Used to Operate Boilers.
20	Food	756.3	83
22	Textiles	213.2	81
26	Paper	1,129.9	87
28	Chemicals	2,405.3	66
29	Petroleum Refineries	1,322.7	26
32	Stone, Clay, and Glass	1,070.1	4
3312			
3315-17	Steel	917.1	30
3334			
3353-55	Aluminum	261.1	64

^a U.S. Environmental Protection Agency. Fossil Fuel-Fired Industrial Boilers -- Background Information, Volume 1: Chapters 1-9. (EPA-450/3-82-0062). p. 9-5.

^b Energy and Environmental Analysis, Inc. The Industrial Sector Consumption Data Base (ECDB) for 1975 and 1976. December 15, 1980.

^c Excludes raw materials, feedstock, and use in vehicles. Includes coal, distillate and residual fuel oil, and natural gas.

TABLE III

Industrial Boiler Installed Capacity by Fuel Type^{a, b}

Boiler and Fuel Type	Watertube <10	(%)	Firetube <10	(%)	Watertube 10-50	(%)	Firetube 10-50	(%)	Watertube 50-100	(%)	Watertube 100-250	(%)	WaterLube >250	(%)
Coal-Fired:			19,270				26,530							
Pulverized	0				0				0		67,800		137,000	
Spreader-Stoker	240				15,900				21,060		69,000		37,600	
Underfeed-Stoker	2,300				48,000				58,900		24,200		17,800	
Overfeed-Stoker	290				11,800				15,200		12,100		12,000	
Total (Coal)	2,830	(7%)	19,270	(5%)	75,700	(16%)	26,530	(8%)	95,160	(23%)	173,100	(31%)	204,400	(30%)
Oil-Fired:														
Residual	13,500		120,330		164,000		88,200		122,000		153,000		148,600	
Distillate	8,700		60,610		28,200		53,790		14,600		21,700		13,900	
Total (Oil)	22,200	(55%)	180,940	(45%)	192,200	(41%)	141,990	(41%)	136,600	(33%)	174,700	(31%)	162,500	(23%)
Natural Gas Fired	15,300	(38%)	201,630	(50%)	197,500	(43%)	177,790	(51%)	182,800	(44%)	216,000	(38%)	327,200	(47%)
Subtotal	40,330	(9%)	401,840	(91%)	465,400	(57%)	346,310	(43%)						
Totals	442,170		(15.1%)		811,710		(27.7%)		414,560	(14.2%)	563,800	(19.3%)	694,100	(23.7%)

^a U.S. Environmental Protection Agency. Fossil Fuel-Fired Industrial Boilers -- Background Information, Volume 1: Chapters 1-9. (EPA-450/3-82-0062). pp. 3-12, 3-13. Original Source: EPA-600/7-79-178a.

^b Capacities based on 10⁶ Btu/h ratings.

NOTE: Percentages for Total (Coal), Total (Oil), and Natural Gas Fired Total to 100% for each vertical column.

1:jj:532e

industrial boilers are not presently covered by Federal emission levels. The table also indicates the distribution of boilers by fuel type. Boilers less than 50×10^6 Btu/h are primarily fueled by oil and natural gas and consist mostly of packaged boilers. Coal-fired boilers contribute an increased percentage of installed capacity for boilers greater than 50×10^6 Btu/h but still does not exceed the installed capacity of natural gas-fired boilers. The total installed capacity of boilers greater than 50×10^6 Btu/h firing oil and coal are almost identical ($472,660 \times 10^6$ Btu/hr for coal and $473,800 \times 10^6$ Btu/hr for oil).

The capacity distribution of the boilers alone does not accurately indicate the fuel consumption for industrial boilers due to the variations in utilization rates of the boilers for different industries. This information must be determined by actual fuel usage data.

3.4 General Economics of Boiler and Fuel Type Selections

The selection of the lowest cost boiler and fuel type for a particular application involves a large number of variables consisting of site-related considerations as well as long-term uncertainties relating to fuel prices and availabilities. Other concerns exist relating to environmental regulations (existing and proposed revisions of NSPS) and waste disposal costs (bottom ashes and any wastes generated by emission control equipment).

The size of a new boiler installation can be determined by the maximum steam demand that will be required for a particular application. The capacity requirement will determine the construction method (packaged or

field erected) of the boiler and the time required to construct the boiler. Packaged boilers are usually significantly cheaper to construct than a comparable field-erected unit. The length of the construction period can become a significant cost consideration. Also, escalating costs during the construction period add to the cost of a field-erected boiler system. The significance of these types of costs (interest and escalation during construction) can be investigated using the INDCEPT code.

The utilization factor (or capacity factor) is a critical variable in determining the selection of the most economical boiler/fuel type for a particular application. The capacity factor is a measure of a boiler's actual utilization as a percentage of its maximum capacity output. Depending upon a particular boiler application, the capacity factor range may fluctuate widely (as in the food and canning industry) or remain relatively constant (boilers supplying steam for an industrial process such as in the chemical industry).

The capacity factor is an important criteria in selecting a boiler fuel for a particular boiler size. For low utilization factors, fuel oil and natural gas are competitive fuel choices because of low capital costs for boilers firing these fuels. At low utilization factors, the higher fuel cost is off-set by the low capital cost of the boiler. For high capacity factors, coal is the economic fuel choice, being the lowest cost raw fuel alternative. The extra cost of coal handling and emission equipment is off-set by the lower fuel cost for coal except at the smaller size ranges where the boiler size limits the fuel savings that can result from using coal.

3.5 Overview of Cost Estimating Procedure; INDCEPT and the Steam Cost Code

The INDCEPT computer code was developed by Oak Ridge National Laboratory (ORNL) under Department of Energy, METC sponsorship to provide a means of estimating capital investment costs for industrial steam production systems under various levels of air emission criteria. To provide further information concerning the associated costs of emission control for the different boiler and pollution control technologies available, the Steam Cost Code was developed that takes into account the operating costs to calculate a minimum required steam cost for an individual boiler plant with respect to specific system components and emission levels. The INDCEPT computer code is used as the source of the capital cost estimate and is part of the input information to the Steam Cost Code. To be compatible with INDCEPT, the Steam Cost Code is based around the INDCEPT format and reference steam production systems.

The INDCEPT computer code consists of the main program and two auxiliary programs that are used to provide capital cost estimates for 58 industrial steam generation systems and 8 coal gasification plants. Boiler types considered are stoker and pulverized coal, AFBC, oil, and product gas boilers burning low- or medium-Btu gas produced by coal gasification. Conventional boilers (stoker-fired, pulverized-coal fired, and oil-fired) are considered with applicable combinations of selected flue gas desulfurization and particulate collection equipment. The output produced by INDCEPT consists of a capital cost breakdown indicating costs for individual system components of a specific steam production system. The component costs are totalled and allowances for escalation, interest during construction, and contingencies are included to provide a total

capital cost estimate considering the length of the construction period and other site-specific location factors. A number of options are available to the user to generate capital cost estimates under relatively specific conditions.

The Steam Cost Code calculates levelized steam costs for the reference steam production systems and product gas costs from coal gasification systems for the reference models considered by INDCEPT. The levelized steam cost represents the minimum cost of steam (\$/MMBtu of gross boiler output) required to recover all costs considered (including return on investment) after the effects of taxes, expressed as a constant cost over a specific operating period. The Steam Cost Code has user options available to vary individual cost escalation rates and other economic parameters used to calculate the steam costs. Although INDCEPT and the Steam Cost Code operate independently, they can be executed sequentially to obtain a detailed capital cost estimate from INDCEPT and an operating cost breakdown from the Steam Cost Code indicating the contributing cost sources of steam production.

The INDCEPT Computer Code was originally designed to operate on an IBM system and required modifications to become compatible with the VAX system (DIGITAL Electronics Corporation). To operate INDCEPT and the Steam Cost Code on the VAX, a number of auxiliary programs and data files are required. The required VAX files for INDCEPT and the Steam Cost Code are listed in Appendix B. The general operating procedure required to obtain a capital cost estimate from INDCEPT is to generate the required input data for the code using a separate computer program (INPUT.FOR). Once the input data

exists, the cost estimate can be generated by executing a command procedure that performs the required commands to complete the cost estimate. Once the capital cost has been determined using INDCEPT, the Steam Cost Code can be executed to obtain the resulting steam cost. The Steam Cost Code is an interactive FORTRAN program which prompts the user for the required input information at the computer terminal. Command procedures are provided to perform the required assignment statements for the relating data files needed for the cost estimate. The general operating procedures are outlined in a documentation file called STEAM.DOC and is shown in Figure 3.1.

FIGURE 3.1

OVERVIEW OF COST ESTIMATING PROCEDURE
FOR
INDCEPT AND THE STEAM COST CODE

NOTE: Information available to user as a documentation file (steam.doc)

CHAPTER 4

THE INDCEPT COMPUTER CODE

4.1 Purpose of the INDCEPT Code

The INDCEPT computer package was developed by ORNL under DOE, METC sponsorship to provide a means of estimating capital investment costs for industrial steam boilers for various boiler and pollution control technologies. The boiler options included are conventional pulverized coal and stoker-fired boilers, atmospheric fluidized-bed combustion, and low- and medium-Btu gas-fired boilers. Oil-fired boilers are included to provide reference costs. The investment costs take into consideration a number of parameters such as location, size, fuel type, construction dates, and emission levels. The emission levels considered are expected to bracket present and future EPA regulations concerning sulfur dioxide and particulate pollutants present in the stack gas. The cost estimates are broken down into seven major cost accounts except for the gasifier estimates which contain five major accounts. Each major account (two-digit reference number) is further broken down into detailed cost accounts (three-digit reference number) as shown in Table IV. All costs for each account are categorized under factory equipment, site labor, and site materials. The conceptual plant designs, engineering characteristics, and operating requirements were developed by Foster Wheeler Corporation under subcontract to Oak Ridge National Laboratory.

TABLE IV

Cost Accounts for INDCEPT Output

All Models Except Gasifiers		Gasifier Models Only	
Number	Description	Number	Description
20	LAND AND SITE WORK	80	LAND AND SITE WORK
210	Site Work	801	Site Work
220	Land	802	Land
30	BOILER PLANT	81	GASIFICATION PROCESS
310	Boiler House	811	Air Separation/Comp.
320	Boiler	812	Gasification
330	Fans	813	Gas Compression
340	Stack	814	Gas Desulfurization
350	Pulverizer	815	Process Steam
360	Boiler Feedwater System		
40	BOILER SUPPORT FACILITIES	82	AUXILIARY SYSTEMS
410	Coal Handling System	821	Sour Water Systems
420	Ash Handling System	822	Cooling Tower System
430	Limestone Handling System	823	Flare
440	Oil Storage Tank	824	Waste Water Treatment
450	Waste Water Treating	83	GASIFICATION SUPPORT
50	PARTICULATE REMOVAL SYSTEM	831	Coal Preparation
510	Electrostatic Precipitator	832	Ash Handling
520	Baghouse	833	Utilities
		834	General Facilities
		835	Buildings
60	FLUE GAS DESULFURIZATION	90	INDIRECT COSTS
610	Absorbers	910	Field Indirect Costs
620	Liquid Handling System	920	Home Office Costs
630	Sorbent Handling System	930	Start-Up Supervision
640	Waste Handling		
650	Miscellaneous		
70	SUPPORT FACILITIES		
710	Fire Protection System		
720	Mobile Solids Handling Equipment		
730	Facilities Building		
740	Electrical		
750	Interconnecting Piping		
90	INDIRECT COSTS		
910	Field Indirect Costs		
920	Home Office Costs		
930	Start-Up Supervision		

The purpose of the INDCEPT code is to aid in the comparison of the relative costs of the different boiler technologies under various air emission criteria. Currently, there is a lack of detailed cost data available to accurately compare existing and emerging boiler design options. Also, the effects of the New Source Performance Standards (currently in proposal stage) for controlling emission levels covering a wide range of industrial boilers will have some impact on the relative costs of the systems. This code was developed to provide the information needed to determine specific cost sensitivities in order to identify competitive options and areas for further development resulting in cost reductions and improvements in efficiency.

4.2 Description of the INDCEPT Code

The INDCEPT computer package consists of the INDCEPT program and two auxiliary programs, INDTAC and CONLAM. The INDTAC program is used to generate the reference cost model data file that is accessed by INDCEPT. Each reference cost model contains all the detailed cost information for a particular boiler system at reference conditions (size, time, location, etc.). The INDTAC program can also be used to modify existing reference cost models or add new reference cost models to the data file. The CONLAM program is used to read historical cost trends and create a second data file containing 15 years (1966.5-1981.5) of historical equipment, labor, and material costs. These costs exist for 22 actual cities and one hypothetical city as shown in Figure 4.1. CONLAM is also used to update the data file (currently being performed at 6-month intervals). CONLAM will delete the oldest time interval automatically to maintain 15 years of

FIGURE 4.1

CITIES USED FOR HISTORICAL COST DATA*

ORNL-DWG 72-13375

1 ATLANTA	7 CLEVELAND	13 MINNEAPOLIS	19 SAN FRANCISCO
2 BALTIMORE	8 DALLAS	14 NEW ORLEANS	20 SEATTLE
3 BIRMINGHAM	9 DENVER	15 NEW YORK	21 MONTREAL
4 BOSTON	10 DETROIT	16 PHILADELPHIA	22 TORONTO
5 CHICAGO	11 KANSAS CITY	17 PITTSBURGH	23 MIDDLETOWN
6 CINCINNATI	12 LOS ANGELES	18 ST. LOUIS	

*ORNL/TM-8146

historical data. The INDCEPT program uses this information to calculate cost indices in order to adjust the reference cost model data obtained from INDTAC to a specific time and location. Each time these auxiliary programs are executed, new data files are created. They do not have to be executed every time a cost estimate is made by INDCEPT, but only when modification or updating of the existing files is performed. With the use of the two data files, INDCEPT separates the reference model plant costs into individual components; applies appropriate cost indices for equipment, labor, and materials; and totals the adjusted components to generate a new cost estimate (14).

There are a total of 66 reference cost models available for INDCEPT. There are five types of boiler units and four methods of coal gasification included in the reference cost model data. A total of four types of flue gas desulfurization are included in various combinations with applicable boiler types. Two levels of sulfur removal rates were included, 70 percent and 94 percent. Two types of particle removal systems were considered, electrostatic precipitators and baghouses. The 66 reference cost models describing each model's specific characteristics are listed in Table V. The different boiler, fuel, particulate removal system, FGD, and FGD efficiencies considered for the data sets are summarized in Table V.

Only technically desirable options were considered in the data sets. For example, baghouses are not considered for oil-fired systems because of blinding problems with the fabric filter due to the sticky nature of the flue gas. ESP's were not considered with dry scrubbing systems because

TABLE V-A

Industrial Steam Boiler Plant Cost Model

Data Sets Available in INDCEPT*

Cost Model Name	Gross Output (MBtu/h)	Boiler ^a	Fuel ^b	FGD ^c	FGD Efficiency ^d	Particulate Removal ^e
MODEL 1	250	PC	EAST	SS	94	ESP
MODEL 2	250	PC	EAST	SS	94	BH
MODEL 3	250	PC	EAST	SS	70	ESP
MODEL 4	250	PC	EAST	SS	70	BH
MODEL 5	250	PC	EAST	DA	94	ESP
MODEL 6	250	PC	EAST	DA	94	BH
MODEL 7	250	PC	EAST	DA	70	ESP
MODEL 8	250	PC	EAST	DA	70	BH
MODEL 9	250	PC	EAST	LIME	94	ESP
MODEL 10	250	PC	EAST	LIME	94	BH
MODEL 11	250	PC	EAST	LIME	70	ESP
MODEL 12	250	PC	EAST	LIME	70	BH
MODEL 13	250	PC	EAST	DRY	94	--
MODEL 14	250	PC	EAST	DRY	70	--
MODEL 15	250	SF	EAST	SS	94	ESP
MODEL 16	250	SF	EAST	SS	94	BH
MODEL 17	250	SF	EAST	SS	70	ESP
MODEL 18	250	SF	EAST	SS	70	BH
MODEL 19	250	SF	EAST	DA	94	ESP
MODEL 20	250	SF	EAST	DA	94	BH
MODEL 21	250	SF	EAST	DA	70	ESP
MODEL 22	250	SF	EAST	DA	70	BH
MODEL 23	250	SF	EAST	LIME	94	ESP
MODEL 24	250	SF	EAST	LIME	94	BH
MODEL 25	250	SF	EAST	LIME	70	ESP
MODEL 26	250	SF	EAST	LIME	70	BH
MODEL 27	250	SF	EAST	DRY	94	--
MODEL 28	250	SF	EAST	DRY	70	--
MODEL 29	250	PC	WEST	SS	94	ESP
MODEL 30	250	PC	WEST	SS	94	BH
MODEL 31	250	PC	WEST	SS	70	ESP
MODEL 32	250	PC	WEST	SS	70	BH
MODEL 33	250	PC	WEST	LIME	94	ESP
MODEL 34	250	PC	WEST	LIME	94	BH
MODEL 35	250	PC	WEST	LIME	70	ESP
MODEL 36	250	PC	WEST	LIME	70	BH
MODEL 37	250	PC	WEST	DRY	94	--
MODEL 38	250	PC	WEST	DRY	70	--

TABLE V-A
Industrial Steam Boiler Plant Cost Model
Data Sets Available in INDCEPT*
(continued)

Cost Model Name	Gross Output (MBtu/h)	Boiler ^a	Fuel ^b	FGD ^c	FGD Efficiency ^d	Particulate Removal ^e
MODEL 39	250	SF	WEST	SS	94	ESP
MODEL 40	250	SF	WEST	SS	94	BH
MODEL 41	250	SF	WEST	SS	70	ESP
MODEL 42	250	SF	WEST	SS	70	BH
MODEL 43	250	SF	WEST	LIME	94	ESP
MODEL 44	250	SF	WEST	LIME	94	BH
MODEL 45	250	SF	WEST	LIME	70	ESP
MODEL 46	250	SF	WEST	LIME	70	BH
MODEL 47	250	SF	WEST	DRY	94	--
MODEL 48	250	SF	WEST	DRY	70	--
MODEL 49	250	AFB	EAST	--	--	--
MODEL 50	250	AFB	WEST	--	--	--
MODEL 51	250	OIL	OIL	SS	94	ESP
MODEL 52	250	OIL	OIL	SS	70	ESP
MODEL 53	250	OIL	OIL	LIME	94	ESP
MODEL 54	250	OIL	OIL	LIME	70	ESP
MODEL 55	250	OIL	OIL	DRY	94	ESP
MODEL 56	250	OIL	OIL	DRY	70	ESP
MODEL 57	250	GAS	LBG	--	--	--
MODEL 58	250	GAS	MBG	--	--	--

^a Type of Boiler

PC -- Pulverized coal fired.
SF -- Stoker fired.
AFB -- Atmospheric fluidized bed.
OIL -- Oil fired.
GAS -- Gas fired.

^b Type of Fuel

EAST -- Eastern high-sulfur bituminous coal.
WEST -- Western low-sulfur sub-bituminous coal.
OIL -- No. 6 oil (Bunker C).
LBG -- Low-Btu gas.
MBG -- Medium-Btu gas.

TABLE V-A

Industrial Steam Boiler Plant Cost Model
Data Sets Available in INDCEPT*
(continued)

^c Type of Flue Gas Desulfurization (FGD) System

SS -- Sodium scrubbing.

DA -- Dual alkali.

LIME -- Lime/limestone scrubbing (conventional tower
and jet bubbling reactor).

DRY -- Dry FGD system.

^d Efficiency of FGD

70 -- 70 percent removal of SO₂.

94 -- 94 percent removal of SO₂.

^e Method of Particulate Removal

ESP -- Electrostatic precipitator.

BH -- Baghouse.

TABLE V-B

Coal Gasification Plant Cost Model
Data Sets Available in INDCEPT*
(continued)

Cost Model Name	Net Output (MBtu/h)	Product Gas ^a	Fuel ^b	Plant ^c
MODEL 59	299	MBG	EAST	Small on-site coal gasification plant dedicated to provide fuel for a single industrial steam boiler plant.
MODEL 60	299	MBG	WEST	
MODEL 61	316	LBG	EAST	
MODEL 62	316	LBG	WEST	
MODEL 63	2300	LBG	EAST	Large central coal gasification plant providing fuel for several distributed industrial steam boiler plants.
MODEL 64	2300	LBG	WEST	
MODEL 65	2300	MBG	EAST	
MODEL 66	2300	MBG	WEST	

^a Product Gas

MBG -- Medium-Btu gas.
LBG -- Low-Btu gas.

^b Fuel

EAST -- Eastern high-sulfur bituminous coal.
WEST -- Western low-sulfur sub-bituminous coal.

^c Gasifier Type

Models 59 and 60 -- Koppers-Totzek.
Model 61 -- Wellman-Galusha.
Model 62 -- Stoic.
Models 63-66 -- Texaco.

* ORNL (ORNL/TM-8146).

of a limited number of actual applications (15). Dual alkali was not considered for western coals because it was not considered a competitive option due to the potential for severe scaling that exists with sulfur levels around 1 percent or less. Sulfur removal levels were not included as part of the model reference conditions for AFBC because of the various methods available for controlling sulfur removal rates (see Table V-A). Sulfur removal in an AFB is determined by the gas velocity, bed depth, type of limestone, amount of limestone (calcium-to-sulfur ratio), elutriated carbon recycle, and temperature of the bed (12). The effects of the Ca/S and the bed temperature are considered to be the more critical factors.

4.3 Designed Operation of the INDCEPT Code

The input data to the INDCEPT code must consist of the standard input data and can also include two optional data sets, the nonstandard input data and time-dependent escalation data. The standard input data consists of the minimal input information required to execute INDCEPT. The nonstandard input data is used to override specific data stored in the reference cost model data sets and other constants used in INDCEPT. The time-dependent escalation data is used to override the calculated escalation rates and cost indices for equipment, labor, and materials.

The standard input data consists of a single card (or line on a video terminal) containing the specific information for a steam generation system and the values for seven "flag" variables which control certain options available in INDCEPT including the use of the two optional data sets. The

standard input information consists of the size of the unit, model number identifying the steam system components (systems listed in Table V), location, construction dates, interest rate during the construction period, and the values for the flag options. The location and format of the standard input variables is shown in Figure 4.2. Notice the absence of a decimal point for the interest rate and construction dates. The standard input variables and flag options are described in Table VI as defined by ORNL.

The optional nonstandard input data can be used to temporarily modify various reference and calculated costs at program execution time. This option uses a NAMELIST routine (IBM utility function) that permits changes to be made to a number of internal calculations and variables during the execution of the INDCEPT program. The use of the NAMELIST routine is controlled by two flag variables in the standard input data, ILAZ and IFLAG. The ILAZ variable controls the save and retrieve options of the NAMELIST utility and IFLAG is used to read the optional NAMELIST input data. The NAMELIST input cards follow after the standard input data and have the following format (16):

Card	Column	Description
2	2-8	&CONOPT -- This identifies the following as a NAMELIST named CONOPT that contains optional data.
2	10-80	Data changes start with this card in Column 10; data items are separated by commas. The form of the data may be (1) variable name = constant, where the variable name may be a subscripted array name or a single variable name; (2) array name = set of constants (separated by commas). The array name is not subscripted. The number of constants must be less than or equal to the

number of elements in the array. Successive occurrences of the same constant can be represented in the form $k \times \text{constant}$. The last data entry is followed by a comma.

3 or more	2-80	If required, Columns 2-80 of additional cards can be used with each data item separated by commas.
Last	2-5	&END must be the last card for each set of NAMELIST data.

The NAMELIST option permits changes to be made before calculating the historical cost data (first NAMELIST call) and/or after escalation and other specific cost adjustments are performed (second NAMELIST call) as described by the definition of IFLAG in Table VI. A list of the variables that can be changed during the first NAMELIST call (IFLAG=1) are described in Table VII as defined by ORNL. Table VIII describes the variables that can be changed during the second NAMELIST call (IFLAG=2). Both NAMELIST calls are used when IFLAG=3.

The second option available is the time-dependent escalation data that is used to override the calculated cost indices and escalation rates for equipment, labor, and materials. The format of the time-dependent escalation card consists of an "A" field and a "B" field for each of the seven, two-digit cost accounts. The "A" field represents the cost index and the "B" field represents the escalation rate in the $(1 + \text{esc})$ form for each cost account. This format is repeated for three cards representing equipment, labor, and materials, respectively. The end of the third card contains the effective date for the new input. Any "A" or "B" field left blank on any of the cards will use the originally calculated value by INDCEPT. This three-card sequence can be repeated any number of times and the last set must be followed by a card with -1. in columns 78-80. The time-dependent escalation data follows after the standard input data and the NAMELIST cards if used. The format of the time-dependent escalation data cards is shown in Figure 4.3.

INDCEPT DATA SHEET

REQUEST NO.

NAME _____

FLAG OPTIONS

[illegible]

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TABLE VI

Standard Input Variables*

Column	Variable Name	Description
1-4	SIZE	The unit rating, or size, in millions of Btu/h, (MBtu/h), right justified in the field. Format I4.
6-13	TYPE	Plant model name (see Tables 3.1 and 3.2), left justified in the field. Format A8.
15-30	CITY	The city where the plant is to be located (see Figure 4.1), left justified in the field. Format 2A8.
32-39	IDENT	Any alphanumeric data. Format A8.
41-47	YREQP	Date major equipment (i.e., boiler or gasifier) is purchased. Format F7.3.
48-54	YRCON	Date construction is started. Format F7.3.
55-61	YRCOP	Date of initial commercial operation. Format F7.3.
62-66	RIB	Average annual interest rate for interest during construction (in percent). If not input, 8 percent/year will be used. Format F5.3.
68	ILAZ	Flag for saving and retrieving optional NAMELIST input data for use in subsequent cases (IFLAG > 0): VAX → 0 -- NAMELIST input data are neither saved nor retrieved. 1 -- Save NAMELIST input data for use in subsequent case. 2 -- Retrieve NAMELIST input data that have been saved in a previous case. 3 -- Retrieve NAMELIST input data that have been saved in a previous case and read additional NAMELIST input data.
70	IFLAG	Flag for reading optional NAMELIST input data: VAX → 0 -- No NAMELIST input.

TABLE VI
Standard Input Variables*
(continued)

Column	Variable Name	Description
		<p>1 -- Permits changing YFIRST and YLAST prior to the analysis of historical equipment, labor, and materials cost data and permits overriding certain data stored in the cost models and in the main program prior to the detailed cost calculations.</p> <p>2 -- Permits overriding calculated direct and indirect costs after adjustment for size, time, location, number of units, and escalation to date of major equipment purchase.</p> <p>3 -- Two NAMELIST calls. The first is identical to IFLAG=1, and the second is identical to IFLAG=2.</p>
72	IOF	<p>Flag for optional output:</p> <p>0 -- Two-digit-level summary output only.</p> <p>1 -- Two-digit-level summary output with cumulative cash flow plot and table.</p> <p>2 -- Complete cost breakdown with cumulative cash flow plot and table.</p>
74	IESC	<p>Flag for escalation during construction:</p> <p>0 -- All cost accounts are escalated from date of reference case to date of major equipment purchase, and escalation during construction is shown as a separate lump-sum item.</p> <p>1 -- All cost accounts include implicitly both escalation from date of reference case to date of major equipment purchase and escalation during construction.</p> <p>2 -- All cost accounts are escalated from date of reference case to date of major equipment purchase, with no allowance for escalation during construction.</p>

TABLE VI
Standard Input Variables*
(continued)

Column	Variable Name	Description
76	IBS	Flag to specify time-dependent escalation data: 0 -- No input data are expected. 1 -- Input data are expected and will be saved for subsequent cases. 2 -- Retrieve data used when IBS was 1.
78	IAC	Flag to specify type of interest: 0 -- Simple interest. 1 -- Compound interest.
80	ISTACK	Flag to specify total number of identical boilers or gasifiers: 1 -- Single-unit plant. 2 -- Two-unit plant. 3 -- Three-unit plant. 4 -- Four-unit plant.

* ORNL (ORNL/TM-8146)

TABLE VII

Nonstandard Option Variables/
First NAMELIST Call*

Variable Name	Description
AA(I,J)	<p>Scaling coefficients for adjusting the direct and indirect costs as a function of size according to the relation for</p> $a + b \frac{(\text{MBtu/h})_{\text{new}}^c}{(\text{MBtu/h})_{\text{base}}}$ <p>each two digit account. The first dimension, I, varies from 1 to 3 representing a, b, and c, respectively. The second dimension, J, represents the two-digit accounts such that J=1,N for accounts 20-90 and N = number of two-digit accounts.</p>
AMAN	The direct labor man-hours in thousands of hours for the specific case being run.
APC(I)	<p>Initial productivity of labor at input location at the reference year of the cost model for each two-digit direct and indirect cost account such that I=1,N for accounts 20-90. Productivity is modeled by the equation:</p> $\text{PRODUCTIVITY} = \text{APC(I)} + \text{BPC(I)} \cdot \Delta\text{TIME}$ <p>where ΔTIME is time in years between major equipment purchase and reference year of the cost model.</p>
BPC(I)	Change in productivity of site labor at input location per unit of time for each two-digit direct and indirect cost account. I=1,N for accounts 20-90, see equation given for variable APC(I).
CECA(I,J)	Cash flow data for each two-digit direct and indirect cost account (I=2,N+1) in each of the 50 time periods between the major equipment purchase date and commercial operation date (J=1,50). The values when I=1 are the function of the design and construction period.
COB(I) COS(I)	Contractor's overhead burden factor for each two-digit direct and indirect cost account in the reference model (COB) and the specific case (COS). I=1,N for accounts 20-90.
CONTL(I) CONTM(I) CONTE(I)	Contingency percentage for labor, materials, and equipment, respectively, for each two-digit direct and indirect cost account.

TABLE VII
Nonstandard Option Variables/
First NAMELIST Call*
(continued)

Variable Name	Description
D(I,J)	Array containing lowest-digit-account direct and indirect costs divided into equipment, labor, and materials components (I=1,3) for a given account (J=1,60) in the reference plant cost model.
DEOT(I)	Coefficient for calculating the overall efficiency of an overtime workweek for each two-digit direct and indirect cost account; $EFF = 1.0 - DEOT (HRS -- 40)$. I=1,N for accounts 20-90.
FUN(I,J)	Multiplier used to reflect multiple identical boilers or gasifiers at a common site. I ranges from 1 to 4 according to the number of boilers. A FUN-array element exists for every detailed cost account (J=1,60) as described by the D-array.
HWI(J) HW	The number of hours worked per week for each two-digit direct and indirect cost account (J=1,N) for accounts 20-90, or, alternatively, the number of hours worked per week in all the accounts.
ISITE(J)	Array for site combinations up to J=20. If nonzero, the ISITE value indicates site (or city) number (see Figure 4.1) use in conjunction with weighting factor, FILS. For example, sites 12 and 16 might be combined by setting ISITE=12,16 and FILS=0.4,0.6 for 40 and 60 percent weighting of the respective sites.
OTP(I)	Overtime premium paid to labor (multiplier of straight-time rate) for time worked in excess of 40-hour workweek for each two-digit direct and indirect cost account (I=1,N) for accounts 20-90.
OVERS(I)	Overall efficiency of nonstandard workweek for each two-digit direct and indirect cost account (I=1,N) for accounts 20-90. Use of this variable overrides the calculations using variable DEOT(I).
RINT(J)	Interest rate expressed as a decimal number for each of the fifty time periods between the major equipment purchase date and commercial operation date (J=1,50).

TABLE VII
Nonstandard Option Variables/
First NAMELIST Call*
(continued)

Variable Name	Description
YFIRST	The first date to be considered in performing a linear regression on the historical equipment, labor, and materials file.
YLAST	The last date to be considered in performing a linear regression on the historical equipment, labor, and materials file.

* ORNL(ORNL/TM-8146)

TABLE VIII

Nonstandard Option Variables/
Either Namelist Call*

Variable Name	Description
CONTL(I) CONTM(I) CONTE(I)	Contingency percentage for labor, materials, and factory equipment, respectively, for each two-digit direct and indirect cost account (I=1,N) for accounts 20-90 and. N = number of two-digit accounts.
D(I,J)	Lowest-digit account direct and indirect costs divided into equipment, labor, and materials (I=1,3) for a given account (J=1,60). When IFLAG=1 and in the first NAMELIST call when IFLAG=3, the costs in the D array represent the reference cost model. When IFLAG=2 or in the second NAMELIST call when IFLAG=3, the costs in the D array are the costs adjusted for size and location and expressed in dollars current to the major equipment purchase date.
RINT(J)	Interest rate expressed as decimal number for each of the 50 time periods between the steam supply date and commercial operation date (J=1,50).

* ORNL(ORNL/TM-8146)

TIME-DEPENDENT ESCALATION INPUT FORMAT*

[illegible]

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4.4 Operation of the INDCEPT Code on the VAX

The INDCEPT code was originally written for use on an IBM 360 system. Transfer of the INDCEPT code from the IBM to the VAX system resulted in partial restriction in the designed operation of the code. The problem occurs with the NAMELIST routine used for the nonstandard input data. The current version of VAX will not accept the NAMELIST utility routine and will cause an error resulting in termination of the program. To operate the INDCEPT code on the VAX, the ILAZ and IFLAG input variables must be zero indicating the NAMELIST option will not be used. It is expected that the NAMELIST option will be compatible with the VAX as updated operating versions become available. The standard input data and the time-dependent escalation option will perform as designed on the VAX system. Since the nonstandard input data option cannot be used, the time-dependent escalation data will follow after the standard input data when used.

The standard input data format requires the input variables to be located in specific column locations as shown in Figure 4.2. Difficulties can occur identifying the column locations when entering the input data since the VAX system uses a video terminal as opposed to punch-cards as the information transfer media. To prevent column location errors from occurring, an interactive FORTRAN program was developed to organize the standard input data into the correct column locations. The program interactively requests the required input information and displays the data in the format required by INDCEPT. At this time, the user can correct any errors made entering the data until all the variables are as the user desires. If the ILAZ and

IFLAG variables are nonzero, a message will be displayed indicating an attempt to use the NAMELIST option. The program can also be used to enter time-dependent escalation data. If the IBS flag is input as 1 in the standard input data (indicating the use of time-dependent escalation data), the program will automatically prompt the user for the input data. The "A" and "B" fields are displayed to enable the user to enter the data in the correct column locations required by the time-dependent escalation data format as shown in Figure 4.3. Once the data is entered, it is displayed for verification by the user. If an error is made, the user may re-enter the data as many times as necessary.

The VAX system operates using command procedures that can be performed on "files." A file is a collection of logically related information such as a program or data set. Command procedures (or statements) are used to perform specific operations such as executing a program, creating programs or data sets, or editing (modifying a program or data set). Most programs require input data and create output which must be stored in different files than the program language statements.

The program used to organize the input information is a file called INPUT.FOR. No input data is required to operate INPUT.FOR since the purpose of the program is to create the input data file for the INDCEPT code. Before the program can create (or output) the desired data file, the output must be assigned a file name that can be identified by the write statements in the program. The write statements used in INPUT.FOR will write to logical unit number FORØ15 which has a default equivalence name

of FORØ15.DAT. This is an acceptable file name, however, it does not properly identify the purpose or contents of the file. Assignment statements can be used to give a logical unit number an identifiable name. Since the output provided by INPUT.FOR will be used as input to the INDCEPT code, the output file is called INPUTDATA.DAT. The DAT suffix is used to describe the file type indicating the file is a data file as opposed to a FORTRAN program file which is identified by a FOR file type. In order to run INPUT.FOR to create the input data file called INPUTDATA.DAT, the following statements must be executed:

```
( $\$$ ) assign inputdata.dat forØ15
( $\$$ ) run input
( $\$$ ) deassign forØ15
```

Once the input file exists, the INDCEPT program can be executed to obtain the desired capital cost estimate. The INDCEPT program reads data from three different files which must be assigned to the logical unit number used in the read statements in the program. The command statements required to operate INDCEPT on the VAX are as follows:

```
( $\$$ ) assign inputdata.dat forØØ5
( $\$$ ) assign indcept.out forØØ6
( $\$$ ) assign conlam.lbr forØØ8
( $\$$ ) assign costmod.lbr forØØ9
( $\$$ ) run indcept
( $\$$ ) deassign forØØ5
( $\$$ ) deassign forØØ6
( $\$$ ) deassign forØØ8
( $\$$ ) deassign forØØ9
( $\$$ ) print indcept.out
( $\$$ ) purge indcept.out
( $\$$ ) purge inputdata.dat
( $\$$ ) purge forØØ3.dat
```

These statements can be performed by executing a command file called INDCEPT.COM by entering:

```
( $\$$ ) @INDCEPT
```

The output file created by INDCEPT is INDCEPT.OUT and is automatically queued to the printer. Also, the old files are deleted and only the most recent file for INPUTDATA.DAT and INDCEPT.OUT exist. INDCEPT can also be executed by entering the statements in the command file one at a time if so desired.

4.5 Sample Capital Cost Estimating Procedure

An example is provided to demonstrate the procedure used to obtain a capital cost estimate using INDCEPT on the VAX. The first step is to create the input data for the cost estimate. This is performed by entering the assignment statement then executing INPUT.FOR. The program prompts the user for the 15 standard input variables and then displays the values for verification by the user in the required INDCEPT format. After the data is displayed for verification, an opportunity to change any of the input variables occurs. In the example problem, a change of the interest rate from 15 percent to 12 percent is specified. This process can be repeated until the standard input data is as the user desires. In this particular example, the IBS flag representing time-dependent data is one, indicating the input of escalation data. The program prompts the user for the data and displays the "A" and "B" fields in order to properly align the data input. In this problem, no cost indices were changed so the "A" fields

were left blank. The escalation rate for equipment was set to 10 percent, labor to 8 percent, and materials to 12 percent for all seven major cost accounts. The effective date was input as 1982. The user has the option to repeat the input process if any errors were made which would be seen when the data is displayed. When the user is satisfied with the input, the data is stored in a new version of INPUTDATA.DAT. To execute INDCEPT using the new data input, the user types @INDCEPT as described earlier.

The terminal display of the sample run of INPUT.FOR is shown in Figure 4.4.

The underlined information was input by the user. The output produced by INDCEPT for this example run is shown in Appendix A.

FIGURE 4.4

TERMINAL DISPLAY FOR EXAMPLE RUN OF INPUT.FOR

```

$ ASSIGN INPUTDATA.DAT FOR015
$ RUN INPUT
PROGRAM TO ORGANIZE STANDARD INDCEPT INPUT DATA
TO PROPER READABLE FORMAT BY THE INDCEPT CODE.
OPTIONAL INPUT DATA MUST BE INPUT BY EDITING
FILE INPUTDATA.DAT    TIME ESCALATION DATA CAN
BE ENTERED USING THIS PROGRAM. NAMELIST OPTION
CANNOT BE USED. (7/12/82)

Enter size of the boiler unit.(MBTU/H) 250
Enter the model name of the unit MODEL 6
Enter the reference city location NEW ORLEANS
Enter any extra identification, lin 8 spaces PROB 1
Enter seller purchase date.(include decimal part) 1982.
Enter date construction begins.(inc decimal) 1983.
Enter date of commercial operation.(inc decimal) 1985.
Enter interest rate(in %) during const.(inc decimal) 15.
Enter namelist flag for save & ret.'ILAZ' 0
Enter flag for reading namelist.'IFLAG' 0
Enter flag for output.'IOF' 2
Enter flag for esc during construction.'IESC' 0
Enter flag for time esc data.'IBS' 1
Enter flag for type of interest.'IAC' 1
Enter flag for number of units.'ISTACK' 1
THE FOLLOWING IS THE INPUT DATA AS RECORDED
250 MODEL 6 NEW ORLEANS    PROB 1    198200 198300 198500 15000 0 0 2 0 1 1 1
Do you wish to make any changes (Y/N) Y
The following is a list of the input data
1. size          8. interest
2. model         9. ILAZ
3. city         10. IFLAG
4. extra ident. 11. IOF
5. purch date   12. IESC
6. const date   13. IBS
7. oper date    14. IAC
                  15. ISTACK

Enter the number of the variable to be changed 8
Enter interest rate(in %) during const.(inc decimal) 12.
THE FOLLOWING IS THE INPUT DATA AS RECORDED
250 MODEL 6 NEW ORLEANS    PROB 1    198200 198300 198500 12000 0 0 2 0 1 1 1
Do you wish to make any changes (Y/N) N
Time-dependent escalation data required by IBS-1
Enter changes for equipment data, following A & B field
AAAAABBBBBBAAAAABBBBBBAAAAABBBBBBAAAAABBBBBBAAAAABBBBBBAAAAABBBBBB
1.10    1.10    1.10    1.10    1.10    1.10    1.10
Enter changes for labor data
AAAAABBBBBBAAAAABBBBBBAAAAABBBBBBAAAAABBBBBBAAAAABBBBBBAAAAABBBBBB
1.08    1.08    1.08    1.08    1.08    1.08    1.08
Enter changes for material data
AAAAABBBBBBAAAAABBBBBBAAAAABBBBBBAAAAABBBBBBAAAAABBBBBBAAAAABBBBBB
1.12    1.12    1.12    1.12    1.12    1.12    1.12
Enter effective date of esc. data.(inc dec) 1982.
The following is the time-esc data as input
1.10    1.10    1.10    1.10    1.10    1.10    1.10
1.08    1.08    1.08    1.08    1.08    1.08    1.08
1.12    1.12    1.12    1.12    1.12    1.12    1.12    1982.00
Do you wish to make any changes, (Y/N) N
FORTRAN STOP

```

CHAPTER 5

THE STEAM COST CODE (SCC)

5.1 Purpose of the Steam Cost Code

The Steam Cost Code was developed to provide a means of comparing the various industrial steam generation alternatives available, taking into consideration the cost associated with the production of steam including the capital and operating costs. The INDCEPT computer code only provides information relating to the capital costs which cannot be used to accurately compare different boiler technologies on a total cost of steam production basis. The Steam Cost Code uses the capital cost estimate of a boiler system from INDCEPT and considers the associated operating costs for the same boiler system to calculate a levelized steam cost over a defined period (20 years of operation). The Steam Cost Code separates the steam costs into nineteen different operating cost categories indicating the net contribution cost of each area to the total levelized steam cost. This detail permits the Steam Cost Code to be used as an analysis tool to determine significant cost factors and relationships. The code has the ability to perform selected sensitivity analyses such as determining the effects of varying six individual operating cost escalation rates, varying rates for return on investment, varying emission levels, and other cost parameters such as boiler size and capacity factor.

The Steam Cost Code is designed to be an extension of the INDCEPT code, providing additional information about the cost of steam production with respect to the significant contribution factors. The same boiler and gasification plant cost model data sets available in INDCEPT (Table V) are used in the Steam Cost Code. The source of the operating costs used in the Steam Cost Code is the same as for the capital cost estimates (Foster Wheeler Corp.) with some modifications by Oak Ridge National Laboratory.

The Steam Cost Code has the potential to investigate the effects of different air emission control levels (SO_2 , PM), different size and capacity factors, changes in specific cost escalation rates, and other correlating factors that are important in steam production. Both INDCEPT and the Steam Cost Code have user options available to change certain constants and factors to permit a cost estimation for a relatively specific situation. Costs associated with nitrogen oxide emission control (NO_x) are not considered to have a significant effect on the cost of steam and are not addressed as a separate issue in this study.

5.2 Economic Parameters and Cost Sources Used by the Steam Cost Code

The economic procedure used for the steam cost calculations is to combine the annual capital investment and operating costs to calculate a levelized cost of steam over the life of the steam production system based on the size and average operating capacity. The calculated steam cost represents the resulting cost or minimum price required (including taxes and a prescribed rate of return) to operate the plant in terms of \$/MMBtu of steam

produced. The levelized steam cost is expressed as a constant cost over the life of the boiler system. The rate of return on investment (input by user) is considered to be before the effects of inflation. For example, if a 6 percent constant inflation rate is assumed, an 18 percent return on investment would yield a "real" return of 12 percent after inflation.

The operating costs used by the Steam Cost Code were obtained from the Oak Ridge National Laboratory report, "Comparative Assessment of Industrial Boiler Options Relative to Air Emission Standards" (11). These costs were organized with respect to the 66 reference models (Table V) used for the INDCEPT code. The majority of the costs were organized into five major cost categories and stored in separate data files that are accessed by the Steam Cost Code. A total of 11 data files are used by the steam program and are described in detail in the data file description and organization section.

Separate escalation rates are used for different cost categories to obtain a particular cost in any given year. Default escalation rates for selected cost categories are:

<u>Cost Area</u>	<u>Default Escalation Rate</u>
Labor Rates	6 percent
Electricity	8 percent
Waste Disposal	6 percent
Maintenance Materials	8 percent
Chemical and Water	6 percent
Fuel	8 percent

All escalation rates are considered to include an inflation rate of 6 percent. Each individual reference escalation rate can be changed interactively when executing the program as part of the input procedure.

The Steam Cost Code uses a number of economic parameters to calculate steam costs. These parameters have the following default values:

Economic Parameters

Tax Rate	50 percent
Insurance Rate	.5 percent
Investment Life	20 years
Investment Tax Credit	10-percent capital cost
Capital Qualifying for ITC	90 percent capital cost
ACRS Depreciation Method	10-year class
Cost of No. 6 Oil (\$/MMBtu)	5.86
User Coal Cost Option (\$/MMBtu)	0.00

Each individual economic parameter can be changed interactively by the user during the input procedure. The options available for depreciation include a 5-, 10-, or 15-year class life using ACRS method depreciation. The user also has the option to input a specific fuel price in terms of \$/MMBtu for both coal- and oil-fired systems.

5.3 Description of Capital Cost Estimate from INDCEPT for Input to the Steam Cost Code

To obtain the correct capital cost estimate for input to the Steam Cost Code, the user must be aware of the procedures used by INDCEPT and the reference year dollar basis used for the cost estimate. The INDCEPT code will present costs using two different base years, the major equipment

purchase date and the date of commercial operation. The procedure used by INDCEPT is to first escalate the costs from the reference case^a to the major equipment purchase date. The total direct and indirect costs are then expressed using the equipment purchase year as the cost basis. To express the cost in terms of the commercial operation date, the costs are escalated using cost indices calculated from a regression of historical cost data. The escalation of the costs from the major equipment purchase to the date of commercial operation is dependent upon the length of the construction period and the cumulative cash flow distribution. Each system has a reference cash flow plot based on the three project dates that are required by INDCEPT. A typical distribution is shown below.

FIGURE 5.1

Cummulative Cash Flow Plot During Construction Period

The reference cash flow plot is adjusted to a specific case to maintain the same fraction of expenditures at the three project dates. The construction period is further divided into 50 separate time periods which

^a The reference costs are in 1981 dollar values.

are used to linearly remap the curve for the specific case. The remapping procedure involves dividing the total construction period into two sections, one before the date of the start of construction, and one after as shown by the dotted line in Figure 5.1. The slope of these lines is used to linearly adjust the cumulative cash flow over the 50 time intervals to generate the new cash flow curve for the specific case.

The escalation during construction is calculated by taking the ratio of the cost indices at each of the 50 time intervals to the index at the major equipment purchase date to determine the escalated cost expenditure during each period. The interest charges are then calculated based on the cumulative cash expenditures at each time interval. Additional detail on the procedure used to calculate the escalation and interest charges can be found in the CONCEPT 5 User's Manual (ORNL-5470) (17). The user has the ability to control these calculations through the use of the IESC input variable. This variable can have one of three different input values which will determine the base year representation of the cost estimate and the method for presenting the escalation and interest charges. The procedure used for the different values of IESC are described below.

Options Available for IESC Variable

IESC=0 When IESC=0, all the cost accounts are escalated from the date of the reference model costs (1981) to the date of the major equipment purchase. The total direct and indirect costs are calculated

and expressed in the year of the major equipment purchase. Escalation during construction and interest on both escalation and direct and indirect costs are shown as separate items and summed to give the total plant capital investment cost expressed in the year of commercial operation. The cost summary page for an example INDCEPT output when IESC=0 is shown in Figure 5.2.

IESC=1 All costs are expressed in the year of commercial operation and implicitly contain escalation from the date of the reference model costs and escalation during construction. Total interest during construction is shown as a separate item. Figure 5.3 is the cost summary page from INDCEPT for the same input data as Figure 5.2 except for the value of IESC.

IESC=2 When IESC=2, no escalation during construction is considered; therefore, the costs are based on the major equipment purchase date. Interest on direct and indirect costs is shown separately. Figure 5.4 is the summary page for the same example with IESC=2.

Depending on the value of IESC, INDCEPT will provide costs based on two different years, the major equipment purchase date and the year of commercial operation. These costs are presented in a variety of combinations with escalation and interest charges depending upon the value of the IESC variable. Figures 5.2, 5.3, and 5.4 are the different outputs that will result depending upon the value of IESC for the same example steam production system (pulverized coal boiler firing western coal, limestone FGD

FIGURE 5.2

INDCEPT COST SUMMARY FOR IESC=0

DATE 9-24-82 INDCEPT COST ESTIMATES

1 UNIT CAPITAL INVESTMENT SUMMARY (THOUSANDS OF DOLLARS)
 1X 250 MBTU/HR MODEL 35 (8-28-81) PLANT AT DENVER
 PULVERIZED COAL, WESTERN, LIMESTONE FGD, 70% EFF, E.S.P.
 COST BASIS: YEAR OF MAJOR EGP. PURCHASE
 DESIGN & CONSTRUCTION PERIOD:

PCUEST70

MAJOR EGP. PURCHASE: 1981.00
 START OF CONSTRUCTION: 1982.00
 COMMERCIAL OPERATION: 1985.00

ACCOUNT NUMBER	ACCOUNT TITLE	TOTAL COSTS	EQUIPMENT COSTS	LABOR MANHOURS	LABOR COSTS	MATERIAL COSTS
20	LAND AND SITE WORK	344	0. (	12.)	191.	152.
30	BOILER PLANT	13984	7856. (	202.)	2972.	3075.
40	BOILER SUPPORT FACILITIES	4995	2597. (	87.)	1281.	1116.
50	PARTICULATE REMOVAL SYSTEM	1301	574. (	29.)	430.	298.
60	FLUE GAS DESULFURIZATION	1721	604. (	31.)	469.	648.
70	SUPPORT FACILITIES	819	284. (	19.)	280.	255.
SUBTOTAL		23084	11916. (380.) 5622. 5544.			
90	INDIRECT COSTS	11464				
SUBTOTAL		11464				
DIRECT & INDIRECT COSTS		34548				
CONTINGENCY ALLOWANCE		6909				
TOTAL DIRECT & INDIRECT COSTS		41457				
ESCALATION DURING CONSTRUCTION (8.5%/YR)		9661				
TOTAL ESCALATED DIRECT & INDIRECT COSTS		51118				
INTEREST DURING CONSTRUCTION COMPOUND (12.000%/YR)		7487				
ON DIRECT & INDIRECT COSTS		1490				
ON ESCALATION DURING CONSTRUCTION		8977				
TOTAL INTEREST DURING CONSTRUCTION		8977				
TOTAL PLANT CAPITAL INVESTMENT		60095				

cost based on major equipment
purchase date

WEIGHTED AVERAGE ESCALATION (%/YR)
 EQUIPMENT 8.6 LABOR 8.5 MATERIAL 8.1

cost based on commercial operation

FIGURE 5.3

INDCEPT COST SUMMARY FOR IESC=1

DATE 9-24-82 INDCEPT COST ESTIMATES

1 UNIT CAPITAL INVESTMENT SUMMARY (THOUSANDS OF DOLLARS)
 1X 250 MBTU/HR MODEL 35 (8-28-81) PLANT AT DENVER
 PULVERIZED COAL, WESTERN, LIMESTONE FGD, 70% EFF, E.S.P.
 COST BASIS: YEAR OF COMMERCIAL OPERATION
 DESIGN & CONSTRUCTION PERIOD: MAJOR EQP. PURCHASE:

PCWEST70

START OF CONSTRUCTION: 1981.00
 COMMERCIAL OPERATION: 1982.00
 1985.00

ACCOUNT NUMBER	ACCOUNT TITLE	TOTAL COSTS	EQUIPMENT COSTS	LABOR MANHOURS	LABOR COSTS	MATERIAL COSTS
20	LAND AND SITE WORK	346	0. (	12.)	192.	153.
30	BOILER PLANT	17175	9736. (	202.)	3674.	3765.
40	BOILER SUPPORT FACILITIES	6169	3219. (	87.)	1583.	1367.
50	PARTICULATE REMOVAL SYSTEM	1607	711. (	29.)	531.	364.
60	FLUE GAS DESULFURIZATION	2122	749. (	31.)	580.	793.
70	SUPPORT FACILITIES	1010	352. (	19.)	346.	312.
		SUBTOTAL	14767. (	380.)	6907.	5755.
90	INDIRECT COSTS	28429 14169				
		SUBTOTAL				
	DIRECT & INDIRECT COSTS	14169				
	CONTINGENCY ALLOWANCE	42598 8520				
						
	TOTAL DIRECT & INDIRECT COSTS	51118				
	INTEREST DURING CONSTRUCTION COMPOUND (12.000%/YR)					
	TOTAL INTEREST DURING CONSTRUCTION	8977				
						
	TOTAL PLANT CAPITAL INVESTMENT	60095				

← cost based on commercial operation

FIGURE 5.4

INDCEPT COST SUMMARY FOR IESC=2

DATE 9-24-82 INDCEPT COST ESTIMATES

1 UNIT CAPITAL INVESTMENT SUMMARY (THOUSANDS OF DOLLARS)
 1X 250 MBTU-HR MODEL 35 (8-28-81) PLANT AT DENVER
 PULVERIZED COAL, WESTERN, LIMESTONE FGD, 70% EFF, E.S.P.
 COST BASIS: YEAR OF MAJOR EGP. PURCHASE
 DESIGN & CONSTRUCTION PERIOD: MAJOR EGP. PURCHASE: 1981.00
 START OF CONSTRUCTION: 1982.00
 COMMERCIAL OPERATION: 1985.00

ACCOUNT NUMBER	ACCOUNT TITLE	TOTAL COSTS	EQUIPMENT COSTS	LABOR MANHOURS	LABOR COSTS	MATERIAL COSTS
20	LAND AND SITE WORK	344	0. (	12.)	191.	152.
30	BOILER PLANT	13904	7856. (	202.)	2972.	3075.
40	BOILER SUPPORT FACILITIES	4995	2597. (	87.)	1281.	1116.
50	PARTICULATE REMOVAL SYSTEM	1301	574. (	29.)	430.	298.
60	FLUE GAS DESULFURIZATION	1721	604. (	31.)	469.	648.
70	SUPPORT FACILITIES	819	284. (	19.)	280.	255.
SUBTOTAL		23084	11916. (	380.)	5622.	5544.
90	INDIRECT COSTS	11464				
SUBTOTAL		11464				
DIRECT & INDIRECT COSTS		34548				
CONTINGENCY ALLOWANCE		6909				
TOTAL DIRECT & INDIRECT COSTS		41457	← cost based on major equipment purchase			
INTEREST DURING CONSTRUCTION COMPOUND (12.000%/YR)		7487				
TOTAL INTEREST DURING CONSTRUCTION		7487				
TOTAL PLANT CAPITAL INVESTMENT		48944	← cost includes interest during construction but no escalation			

designed for 70 percent removal, and an ESP to control particulates for a plant located in Denver). Table IX indicates the cost of the steam system for the different cost categories and breakdowns from Figures 5.2 through 5.4.

TABLE IX

Cost Estimate for Example Steam System

Major Cost Areas	Cost (\$1,000)	Base
Total Direct and Indirect Costs	\$41,457	Equipment Purchase
Escalation During Construction	9,661	
Interest on Direct and Indirect Costs	7,487	
Interest on Escalation During Construction	1,490	
Total Interest During Construction	8,977	
Total Plant Capital Investment	60,095	Commercial Operation

To accommodate the INDCEPT cost representation, the Steam Cost Code presents the costs based on the equipment purchase date and the commercial operation date. Both capital cost estimates are required input to the Steam Cost Code. Since both costs are needed, use IESC=0 when operating INDCEPT to calculate the capital cost estimates because both costs are presented on the cost summary page as indicated in Figure 5.2.

5.4 Input Procedures for the Steam Cost Code

Since the Steam Cost Code is based upon the organization of INDCEPT, some of the input information required to operate INDCEPT is required for the steam cost calculations. The Steam Cost Code interactively prompts the user for the required input data. The following is a list of the required input information for the Steam Cost Code.

Required Input Information

Model number of boiler system from INDCEPT (1 through 66).
Boiler output (MMBtu/h).
Total plant capital investment cost from INDCEPT (equipment purchase).
Total plant capital investment cost from INDCEPT (commercial operation).
The FGD level in percent SO₂ removal.
The particulate emission level in lbs/MMBtu.
The average capacity factor.
The number of units (1 through 4).
The major equipment purchase date.
The commercial operation date.
The rate for return on investment.

When executed, the program first reads the data files and stores them in matrices. The user is then prompted for the required input information. Upon completing the input of these variables, the input data is displayed as it was recorded by the computer. Figure 5.5 is an example of the input procedure used for the Steam Cost Code. As shown in the figure, each input variable is given a number when displayed for verification. To change a value of an input variable, enter the number of that variable and the user will be prompted for the new value. After reentering the variable, all the input variables are again displayed for verification. Any of the input variables can be reentered until all the input variables are as the user desires. In Figure 5.5, a change in the size of the boiler was demonstrated.

Once the required input information is completed, the reference escalation rates are displayed. The values of the escalation rates can be changed using the same procedure as the input information. A change of the waste disposal escalation rate from 6 to 9 percent was demonstrated in Figure 5.5. Again, the user can change any of the rates until all values are as the user desires.

FIGURE 5.5

EXAMPLE INPUT PROCEDURE FOR STEAM COST CODE

```

$ @STEAMIN
$ RUN STEAM
PROGRAM TO CALCULATE STEAM COSTS USING CAPITALIZED
COST ESTIMATE FROM INDCEPT. BASE OPERATING COSTS WERE
OBTAINED FROM ORNL.
Enter cost model number of steam system from indcept 35
Enter gross output of unit in MBTU/h 205
Enter capital investment cost from indcept based on
major equip. purchase in $1000 41457
Enter capital investment cost from indcept based on
commercial operation date in $1000 60095
Enter FGD efficiency in % SO2 removal 70
Enter particulate emission level in lb/MBTU .1
Enter the average capacity factor in % (10 through 99) 75
Enter the number of units (1 through 4) 1
Enter year of major equipment purchase (inc dec pnt) 1981.
Enter the year for start of commercial operation (inc dec pnt) 1985.
Enter rate for return on investment 18

```

THE FOLLOWING IS THE INPUT DATA AS RECORDED

NUMBER	VARIABLE DESCRIPTION	
1	Model number of steam unit.....	35
2	Size of the unit(MBTU/hr).....	205
3	The FGD level in % SO2 removal.....	70
4	The particulate removal level (lb/MBTU).....	0.10
5	The average capacity factor (%).....	75
6	The number of units.....	1
7	The year of equipment purchase.....	1981.0
8	The year of commercial operation.....	1985.0
9	Capital cost based on equip purchase (\$1000)..	41457
10	Capital cost based on commercial oper.....	60095
11	Rate for return on investment.....	18

Do you wish to change any of the values (Y/N) Y
Enter the number of value to be changed 2
Enter gross output of unit in MBTU/h 250

THE FOLLOWING IS THE INPUT DATA AS RECORDED

NUMBER	VARIABLE DESCRIPTION	
1	Model number of steam unit.....	35
2	Size of the unit(MBTU/hr).....	250
3	The FGD level in % SO2 removal.....	70
4	The particulate removal level (lb/MBTU).....	0.10
5	The average capacity factor (%).....	75
6	The number of units.....	1
7	The year of equipment purchase.....	1981.0
8	The year of commercial operation.....	1985.0
9	Capital cost based on equip purchase (\$1000)..	41457
10	Capital cost based on commercial oper.....	60095
11	Rate for return on investment.....	18

Do you wish to change any of the values (Y/N) N

The following escalation rates are used in the analysis

NUMBER	COST AREA	RATE(%)
1.....	LABOR RATES.....	6
2.....	ELECTRICITY.....	8
3.....	WASTE DISPOSAL.....	6
4.....	MAINTENANCE MATERIALS.....	8
5.....	CHEMICAL AND WATER.....	6
6.....	FUEL.....	8

Do you wish to change any of the rates?(Y/N) Y

Enter number for cost area to be changed 3

Enter the new escalation rate (%) 9

1.	LABOR COSTS	6
2.	ELECTRICITY	8
3.	WASTE DISPOSAL	9
4.	MAINTENANCE MATERIALS	8
5.	CHEMICAL AND WATER	6
6.	FUEL	8

Do you wish to change any of the rates?(Y/N) N

The following economic parameters are used in the analysis

NUMBER	PARAMETER	
1	tax rate =	50%
2	insurance rate =	.5%
3	investment life =	20 years
4	investment tax credit =	10% capital cost
5	capital qualifying for ITC =	90% capital cost
6	ACRS depreciation class =	10 year class
7	cost of No. 6 oil (\$/MBtu) =	5.86
8	user coal cost option =	0.00

Do you wish to change any of the values (Y/N) N

Select one of the following cities to be used

for coal cost calculation using proper type of coal

HIGH SULFUR	LOW SULFUR
BOSTON	SEATTLE
NEW YORK	SAN FRANCISCO
PHILADELPHIA	DENVER
ATLANTA	CHICAGO
CHICAGO	DALLAS
DALLAS	KANSAS CITY
KANSAS CITY	

Enter city to be used (in CAPITALS) MORGANTOWN

Enter city to be used (in CAPITALS) DENVER

Once the user is satisfied with the values for the escalation rates, the default economic parameters are displayed. The values of the economic parameters can be changed interactively using the same procedure as the required input information. For the example input procedure, no changes were made to the economic parameters.

The final input procedure involves the reference conditions for fuel usage. If coal is the required boiler or gasification fuel (determined from the model number), the reference city to be used for coal prices must be input. The 10 regional reference cities used for coal costs are displayed with respect to high- or low-sulfur coal. Three cities (Chicago, Dallas, and Kansas City) include reference costs for both types of coal. The user is then prompted for the reference location to be used. The reference location must be entered using capital letters. If the city entered is not one of the reference locations, the user will be prompted again for the input of the reference city. For the example input, Morgantown was entered but was not accepted as a reference location. Since the model number of the example problem represents a boiler system designed for western coal, Denver was selected for the regional coal prices. If oil is to be used as the boiler fuel, the reference coal cost selection is not performed. If the boiler fuel is low- or medium-Btu gas (Models 57 and 58), the user is prompted for the gas cost in terms of \$/MMBtu for both reference cost base years (major equipment purchase and commercial operation). If the user specifies a specific coal price, the reference location selection for coal costs is not performed.

5.5 Output Produced by the Steam Cost Code

The Steam Cost Code produces both a hard copy output and a terminal display output. A scaled down version of the results is displayed to the terminal so the user will know if the program executed properly. Figure 5.6 shows the terminal display for the example problem used to demonstrate the input procedures in Figure 5.5. The first page of the hard copy output consists of a summary of the input variables, escalation rates, and economic parameters used in the analysis. Figure 5.7 is the first page of the detailed output for the example problem. Figure 5.8 displays the second page of the output. The steam costs are broken down into 19 detailed cost areas and are also grouped into 9 major cost categories. The operating cost breakdowns and detailed costs grouped under each major cost heading are indicated in Table X. The results are presented for each cost area indicating the steam contribution cost in terms of \$/MMBtu. Also indicated is the percent contribution of the cost area to the overall cost of steam. For example, the boiler labor cost represents about 5 percent of the cost of steam for the example boiler system. The steam contribution cost represents the net cost for each area including the effects of taxes and return on investment in terms of \$/MMBtu.

The third page of the output is similar in structure to the second page except the figures represent the annual levelized cost in thousands of dollars for each cost area before taxes. The percent column represents the percent contribution of each cost for each major grouping. For example, the first grouping consists of the 19 detailed operating costs and the percent column represents the percent contribution to the total

FIGURE 5.6

EXAMPLE TERMINAL DISPLAY FOR STEAM COST CODE

LEVELIZED COSTS FOR MODEL 35 OVER A TWENTY YEAR PERIOD

THE FOLLOWING INPUT DATA WAS USED FOR THE ANALYSIS

SIZE OF THE UNIT(MBTU/MR)..... 250
 THE FGD LEVEL IN % SO2 REMOVAL.....70
 THE PARTICULATE REMOVAL LEVEL(LB/MBTU).....0.10
 THE AVERAGE CAPACITY FACTOR (%).....75
 THE NUMBER OF UNITS.....1
 FIRST YEAR OF COMMERCIAL OPERATION.....1985.0

BASE EQUIP *DETAILED COST INFORMATION* BASE EQUIP

COST AREA	LEVELIZED COST(\$1000)	PERCENT
BOILER LABOR	1010.3	5.45
FGD LABOR	578.7	3.12
PARTICULATE LABOR	9.6	0.05
BOILER FIXED ELEC.	76.0	0.41
BOILER VAR ELEC.	176.7	0.95
FGD ELECTRICITY	213.9	1.16
PARTICULATE ELEC.	53.5	0.29
FGD WASTE DISPOSAL	69.3	0.37
BOILER WASTE DISPOSAL	91.6	0.49
BOILER MATERIAL	996.9	5.38
FGD MATERIAL	71.3	0.39
PARTICULATE MATERIAL	66.7	0.36
BOILER CHEMICALS	43.2	0.23
FGD CHEMICALS	3.1	0.02
LIMESTONE COSTS	24.7	0.13
LINE COST	0.0	0.00
SODA ASH COST	0.0	0.00
ANNUAL FUEL	3677.1	19.85
SULFUR REVENUES	0.0	0.00

*** COST BREAKDOWN BY RELATED AREAS ***

CAPITAL COST	7047.8	56.73
LABOR COSTS	1598.6	8.63
ELECTRICITY	520.1	2.81
WASTE DISPOSAL	161.0	0.87
MAINT. MATERIALS	1134.8	6.13
WATER AND TREATMENT	46.3	0.25
DESULFURIZATION CHEM	24.7	0.13
FUEL	3677.1	19.85
MISCELLANEOUS	322.3	4.60

***** OPERATING COST GROUPINGS *****

BOILER RELATED	2394.7	68.70
SULFUR REMOVAL RELATED	961.1	27.57
PARTICULATE RELATED	129.8	3.72

COST OF STEAM(\$/MBTU) EQUIP IS 11.31 YR OPERATION 15.86

FIGURE 5.7

EXAMPLE FIRST PAGE OUTPUT FOR STEAM
COST CODE/SUMMARY OF INPUT PERFORMANCE

***** LEVELIZED STEAM COSTS FOR MODEL 35 OVER A TWENTY YEAR PERIOD *****

REFERENCE SYSTEM COMPONENTS FOR MODEL 35

BOILER TYPE.....PULVERIZED-COAL FIRED
FUEL TYPE.....WESTERN LOW-SULFUR COAL
FGD TYPE.....LINE/LIMESTONE SCRUB
PARTICULATE.....ESP

THE FOLLOWING INPUT DATA WAS USED FOR THE ANALYSIS

SIZE OF THE BOILER UNIT(MBTU/HR)..... 250
THE FGD LEVEL IN % SO2 REMOVAL.....70
THE PARTICULATE REMOVAL LEVEL (lb/MBTU).....0.10
THE AVERAGE CAPACITY FACTOR (%).....75
THE NUMBER OF UNITS.....1
THE YEAR OF EQUIPMENT PURCHASE.....1981.0
FIRST YEAR OF COMMERCIAL OPERATION.....1985.0

ECONOMIC PARAMETERS USED IN THE ANALYSIS

TAX RATE.....50%
INSURANCE RATE.....0.50%
INVESTMENT LIFE.....20 YEARS
INVESTMENT TAX CREDIT.....10% CAPITAL COST
CAPITAL QUALIFYING FOR ITC..90% CAPITAL COST
ACRS DEPRECIATION CLASS.....10 YEAR CLASS
USER COAL COST OPTION.....0.00

THE FOLLOWING ESCALATION RATES WERE USED

ESCALATION RATE FOR LABOR COSTS 6%
ESCALATION RATE FOR ELECTRICITY 8%
ESCALATION RATE FOR WASTE DISPOSAL 9%
ESCALATION RATE FOR MAINTENANCE MATERIALS 8%
ESCALATION RATE FOR CHEMICAL AND WATER 6%
ESCALATION RATE FOR FUEL 8%

RATE FOR RETURN ON INVESTMENT 18%

REFERENCE CITY USED FOR FUEL COST WAS DENVER

NET STEAM AVAILABLE FOR PROCESS(MBTU/H)..... 213.3

TOTAL CAPITAL COST(\$1000) BASED ON EQUIPMENT PURCHASE 41457

TOTAL CAPITAL COST(\$1000) BASED ON COMMERCIAL OPERATION 60095

FIGURE 5.8

EXAMPLE SECOND PAGE OUTPUT FOR STEAM
COST CODE/STEAM CONTRIBUTION COSTS

***** LEVELIZED STEAM COSTS FOR MODEL 35 OVER A TWENTY YEAR PERIOD *****

>>>> STEAM COST CALCULATED USING BASE YEARS AS YEAR OF <<<<
>>>> MAJOR EQUIPMENT PURCHASE AND COMMERCIAL OPERATION <<<<

CGST OF STEAM (\$/MBTU) 11.31

DOLLAR VALUES BASED ON MAJOR EQUIPMENT PURCHASE DATE

BASE EQIP *DETAILED COST INFORMATION* BASE EQIP

COST AREA	STEAM CONTRIBUTION COST(\$)	PERCENT
BOILER LABOR	0.6163	5.45
FGD LABOR	0.3533	3.12
PARTICULATE LABOR	0.0059	0.05
BOILER FIXED ELEC.	0.0464	0.41
BOILER VAR ELEC.	0.1079	0.95
FGD ELECTRICITY	0.1306	1.16
PARTICULATE ELEC.	0.0327	0.29
FGD WASTE DISPOSAL	0.0423	0.37
BOILER WASTE DISPOSAL	0.0559	0.49
BOILER MATERIAL	0.6086	5.38
FGD MATERIAL	0.0435	0.39
PARTICULATE MATERIAL	0.0407	0.36
BOILER CHEMICALS	0.0264	0.23
FGD CHEMICALS	0.0019	0.02
LIMESTONE COSTS	0.0151	0.13
LINE COST	0.0000	0.00
SODA ASH COST	0.0000	0.00
ANNUAL FUEL	2.2445	19.85
SULFUR REVENUES	0.0000	0.00

*** COST BREAKDOWN BY RELATED AREAS ***

CAPITAL COST	6.4145	56.73
LABOR COSTS	0.9760	8.63
ELECTRICITY	0.3175	2.81
WASTE DISPOSAL	0.0983	0.87
MAINT. MATERIALS	0.6928	6.13
WATER AND TREATMENT	0.0283	0.25
DESULFURIZATION CHEM	0.0151	0.13
FUEL	2.2449	19.85
MISCELLANEOUS	0.5201	4.60

COST OF STEAM (\$/MBTU) 15.86

DOLLAR VALUES BASED ON COMMERCIAL OPERATION DATE

BASE OPER *DETAILED COST INFORMATION* BASE OPER

COST AREA	STEAM CONTRIBUTION COST(\$)	PERCENT
BOILER LABOR	0.7787	4.91
FGD LABOR	0.4460	2.81
PARTICULATE LABOR	0.0074	0.05
BOILER FIXED ELEC.	0.0631	0.40
BOILER VAR ELEC.	0.1468	0.93
FGD ELECTRICITY	0.1777	1.12
PARTICULATE ELEC.	0.0444	0.28
FGD WASTE DISPOSAL	0.0598	0.38
BOILER WASTE DISPOSAL	0.0790	0.50
BOILER MATERIAL	0.8280	5.22
FGD MATERIAL	0.0592	0.37
PARTICULATE MATERIAL	0.0554	0.35
BOILER CHEMICALS	0.0333	0.21
FGD CHEMICALS	0.0024	0.02
LIMESTONE COSTS	0.0191	0.12
LINE COST	0.0000	0.00
SODA ASH COST	0.0000	0.00
ANNUAL FUEL	3.0542	19.25
SULFUR REVENUES	0.0000	0.00

*** COST BREAKDOWN BY RELATED AREAS ***

CAPITAL COST	9.2983	58.62
LABOR COSTS	1.2321	7.77
ELECTRICITY	0.4320	2.72
WASTE DISPOSAL	0.1387	0.87
MAINT. MATERIALS	0.9426	5.94
WATER AND TREATMENT	0.0357	0.23
DESULFURIZATION CHEM	0.0191	0.12
FUEL	3.0542	19.25
MISCELLANEOUS	0.7103	4.48

TABLE X

Detailed Operating Cost Breakdown by Related Areas

- I. Capital Cost
- II. Labor Costs
 - 1. Boiler labor (fixed)
 - 2. FGD labor (fixed)
 - 3. Particulate labor (fixed)
- III. Electric Power Costs
 - 4. Boiler fixed electricity (fixed)
 - 5. Boiler variable electricity (variable)
 - 6. FGD electricity (variable)
 - 7. Particulate electricity (variable)
- IV. Waste Disposal Costs
 - 8. FGD waste disposal (variable)
 - 9. Boiler waste disposal (variable)
- V. Maintenance Material and Subcontractor Labor Costs
 - 10. Boiler material (fixed)
 - 11. FGD material (fixed)
 - 12. Particulate material (fixed)
- VI. Chemical and Water Costs
 - 13. Boiler chemicals and water (fixed)
 - 14. FGD chemicals and water (variable)
- VII. Desulfurization Commodity Costs
 - 15. Limestone cost (variable)
 - 16. Lime cost (variable)
 - 17. Soda ash cost (variable)
 - 18. Sulfur revenues (variable)
- VIII. Fuel Costs
 - 19. Annual fuel cost (variable)
- IX. Miscellaneous
 - a. Working Capital (calculated)
 - b. Insurance (calculated)

Note: Roman numerals represent the 9 major cost categories.

Arabic numbers 1 to 19 represent the detailed cost areas grouped under each major cost category.

FIGURE 5.9

EXAMPLE THIRD PAGE OUTPUT FOR STEAM COST
CODE/LEVELIZED COST BREAKDOWN

***** LEVELIZED STEAM COSTS FOR MODEL 35 OVER A TWENTY YEAR PERIOD *****

>>>> STEAM COST CALCULATED USING BASE YEARS AS YEAR OF <<<<
>>>> MAJOR EQUIPMENT PURCHASE AND COMMERCIAL OPERATION <<<<

COST OF STEAM (\$/MBTU) 11.31

DOLLAR VALUES BASED ON MAJOR EQUIPMENT PURCHASE DATE

BASE EQIP	*DETAILED COST INFORMATION*	BASE EQIP
COST AREA	LEVELIZED COST(\$1000)	PERCENT
BOILER LABOR	1010.3	14.10
FGD LABOR	578.7	8.08
PARTICULATE LABOR	9.6	0.13
BOILER FIXED ELEC.	76.0	1.06
BOILER VAR ELEC.	176.7	2.47
FGD ELECTRICITY	213.9	2.99
PARTICULATE ELEC.	53.5	0.75
FGD WASTE DISPOSAL	69.3	0.97
BOILER WASTE DISPOSAL	91.6	1.28
BOILER MATERIAL	996.5	13.92
FGD MATERIAL	71.3	1.00
PARTICULATE MATERIAL	66.7	0.93
BOILER CHEMICALS	43.2	0.60
FGD CHEMICALS	3.1	0.04
LIMESTONE COSTS	24.7	0.35
LINE COST	0.0	0.00
SODA ASH COST	0.0	0.00
ANNUAL FUEL	3677.1	51.34
SULFUR REVENUES	0.0	0.00

*** COST BREAKDOWN BY RELATED AREAS ***

CAPITAL COST	7047.9	48.50
LABOR COSTS	1592.6	11.60
ELECTRICITY	520.1	3.58
WASTE DISPOSAL	161.0	1.11
MAINT. MATERIALS	1134.8	7.81
WATER AND TREATMENT	46.3	0.32
DESULFURIZATION CHEM	24.7	0.17
FUEL	3677.1	25.39
MISCELLANEOUS	322.3	2.22

***** OPERATING COST GROUPINGS *****

BOILER RELATED	2394.7	68.70
SULFUR REMOVAL RELATED	961.1	27.57
PARTICULATE RELATED	129.8	3.72

COST OF STEAM (\$/MBTU) 15.86

DOLLAR VALUES BASED ON COMMERCIAL OPERATION DATE

BASE OPER	*DETAILED COST INFORMATION*	BASE OPER
COST AREA	LEVELIZED COST(\$1000)	PERCENT
BOILER LABOR	1275.5	13.30
FGD LABOR	730.6	7.62
PARTICULATE LABOR	12.1	0.13
BOILER FIXED ELEC.	103.4	1.08
BOILER VAR ELEC.	240.4	2.51
FGD ELECTRICITY	291.1	3.04
PARTICULATE ELEC.	72.8	0.76
FGD WASTE DISPOSAL	97.9	1.02
BOILER WASTE DISPOSAL	129.4	1.35
BOILER MATERIAL	1356.2	14.14
FGD MATERIAL	97.0	1.01
PARTICULATE MATERIAL	90.7	0.95
BOILER CHEMICALS	54.6	0.57
FGD CHEMICALS	3.9	0.04
LIMESTONE COSTS	31.2	0.33
LINE COST	0.0	0.00
SODA ASH COST	0.0	0.00
ANNUAL FUEL	5002.7	52.17
SULFUR REVENUES	0.0	0.00

*** COST BREAKDOWN BY RELATED AREAS ***

CAPITAL COST	10216.5	50.48
LABOR COSTS	2018.2	9.97
ELECTRICITY	707.6	3.50
WASTE DISPOSAL	227.2	1.12
MAINT. MATERIALS	1543.9	7.63
WATER AND TREATMENT	58.5	0.29
DESULFURIZATION CHEM	31.2	0.15
FUEL	5002.7	24.72
MISCELLANEOUS	431.5	2.13

***** OPERATING COST GROUPINGS *****

BOILER RELATED	3159.4	68.88
SULFUR REMOVAL RELATED	1251.7	27.29
PARTICULATE RELATED	175.6	3.83

operating costs. For this example problem, boiler labor represents 15 percent of the total annual operating costs. An additional grouping of the operating costs occur indicating the boiler-related, sulfur removal-related, and particulate-related costs and contributions. For this example problem, 69 percent of the total operating costs were boiler related, 27 percent were sulfur removal related, and about 4 percent were associated with particulate removal. The third page of the output is shown in Figure 5.9.

The last page of the output is shown in Figure 5.10 and indicates the cost sensitivity with respect to capacity factor. The steam cost is presented for 30, 50, 70, and 90 percent operating factors for both base years. As can be seen from the results for the example problem, the operating capacity factor has a major impact on the cost of steam.

Also shown on the last page is the yearly steam price requirement if the steam price is escalating each year at a constant rate. The year-by-year escalating steam cost is economically equivalent to the levelized steam cost. A comparison of the two steam cost representations are shown below in a cash flow diagram.

Levelized and Escalated Steam Cost Comparison

FIGURE 5.10

EXAMPLE FOURTH PAGE OUTPUT FOR STEAM COST
CODE/COST SENSITIVITY TO CAPACITY FACTOR

STEAM COST SENSITIVITY TO CAPACITY FACTOR

BASE EQIP		BASE OPER	
CAP FACTOR (\$/MBTU)		CAP FACTOR (\$/MBTU)	
30%	23.96	30%	33.78
50%	15.52	50%	21.84
70%	11.91	70%	16.72
90%	9.90	90%	13.87

REQUIRED YEAR BY YEAR STEAM PRICE IF PRICE IS
ESCALATED AT A CONSTANT RATE

COST BASED ON COMMERCIAL OPERATION DATE
PRICE IS ESCALATING BY 6 PERCENT EACH YEAR

DATE	REQUIRED STEAM PRICE
1985.0.....	11.54
1986.0.....	12.23
1987.0.....	12.97
1988.0.....	13.74
1989.0.....	14.57
1990.0.....	15.44
1991.0.....	16.37
1992.0.....	17.35
1993.0.....	18.39
1994.0.....	19.50
1995.0.....	20.67
1996.0.....	21.91
1997.0.....	23.22
1998.0.....	24.61
1999.0.....	26.09
2000.0.....	27.66
2001.0.....	29.32
2002.0.....	31.08
2003.0.....	32.94
2004.0.....	34.92

5.6 Operation of the Steam Cost Code on the VAX

The Steam Cost Code consists of the FORTRAN source code and a total of 11 separate data files. The data file description and organization section (Appendix B) provides information describing the purpose of each data file. Each data file must be assigned to a logical unit number to allow access by the FORTRAN source code. The following statements must be entered to assign a logical unit number to each data file:

```
( $\$$ ) assign model.dat for030
( $\$$ ) assign rlabor.dat for031
( $\$$ ) assign elec.dat for032
( $\$$ ) assign waste.dat for033
( $\$$ ) assign chem.dat for034
( $\$$ ) assign scale.dat for035
( $\$$ ) assign skale.dat for036
( $\$$ ) assign icity.dat for038
( $\$$ ) assign coal.dat for039
( $\$$ ) assign iesc.dat for040
( $\$$ ) assign iname.dat for041
( $\$$ ) assign jname.dat for042
( $\$$ ) assign steam.out for050
```

These statements can be performed by executing the command file STEAMIN.COM. Since the FORTRAN source code is user interactive, it cannot be executed in a command file. After running the source code, the data files are de-assigned by executing the command file STEAMOVER.COM. The execution of the Steam Cost Code and a hard copy printout can be obtained by the following statements:

```
( $\$$ ) @STEAMIN
( $\$$ ) RUN STEAM
( $\$$ ) @STEAMOVER
( $\$$ ) PRINT STEAM.OUT
```

5.7 Obtaining Steam Costs for Gasifier Models

To obtain steam costs for low- and medium-Btu gas-fired boilers, the cost of the product gas must first be determined using on-site gasification (Models 59-62) or central gasification (Models 63-66). To obtain the cost of the gas, the Steam Cost Code is executed for the desired model for coal gasification. The output of executing the Steam Cost Code for gasification models calculates the levelized cost (or selling price) of the gas. This value is the cost of gas that is input to the Steam Cost Code when calculating the steam costs for the gas-fired boilers (Models 57 and 58). Therefore, it is necessary to execute INDCEPT twice (to obtain gasifier and gas boiler capital costs) and the Steam Cost Code twice (first to obtain the cost of the product gas) to obtain the resulting cost of steam for the gasification system.

To demonstrate the procedure used to obtain steam costs from coal gasification systems, an example using a medium-Btu central gasifier (Model 65) is provided. INDCEPT was executed to obtain the capital cost estimate, which is shown in Figure 5.11. The construction period consists of the major equipment purchase in 1981 and commercial operation in 1986. The total direct and indirect costs given in 1981 dollars (year of major equipment purchase) for the 2,300 MMBtu/h gasifier is \$337,613,000. After including escalation and interest during construction, the capital cost becomes \$548,342,000 in 1986 (the year of commercial operation). To obtain the levelized cost for the gas at the gasification site, the steam program is

FIGURE 5.11

CAPITAL COST ESTIMATE FROM INDCEPT OF CENTRAL GASIFIER MODEL 65

DATE 9-24-82 INDCEPT COST ESTIMATES

1 UNIT CAPITAL INVESTMENT SUMMARY (THOUSANDS OF DOLLARS)
 1X 2300 MBTU/HR MODEL 65 (9-03-81) PLANT AT DALLAS
 CENTRAL GASIFIER, MEDIUM BTU, EASTERN COAL, 2300 MBTU/HR
 COST BASIS: YEAR OF MAJOR EOP. PURCHASE
 DESIGN & CONSTRUCTION PERIOD: MAJOR EOP. PURCHASE: 1981.00
 START OF CONSTRUCTION: 1982.00
 COMMERCIAL OPERATION: 1986.00

MBC EAST

ACCOUNT NUMBER	ACCOUNT TITLE	TOTAL COSTS	EQUIPMENT COSTS	LABOR MANHOURS	LABOR COSTS	MATERIAL COSTS
80	LAND AND SITE WORK	0	0.	0.	0.	0.
81	GASIFICATION PROCESS	134905	60449.	1635.	21388.	53069.
82	AUXILIARY SYSTEMS	15586	6072.	182.	2385.	7129.
83	GASIFICATION SUPPORT	59570	24886.	406.	5320.	30163.
	SUBTOTAL	210061	90607.	2223.	29093.	90361.
90	INDIRECT COSTS	71283				
	SUBTOTAL	71283				
	DIRECT & INDIRECT COSTS	281344				
	CONTINGENCY ALLOWANCE	56269				
	TOTAL DIRECT & INDIRECT COSTS	337613				
	ESCALATION DURING CONSTRUCTION (9.1%/YR)	105421				
	TOTAL ESCALATED DIRECT & INDIRECT COSTS	443034				
	INTEREST DURING CONSTRUCTION COMPOUND (12.000%/YR)	83210				
	ON DIRECT & INDIRECT COSTS	22098				
	ON ESCALATION DURING CONSTRUCTION					
	TOTAL INTEREST DURING CONSTRUCTION	105308				
	TOTAL PLANT CAPITAL INVESTMENT	548342				

WEIGHTED AVERAGE ESCALATION (%/YR)
 EQUIPMENT 8.6
 LABOR 8.2
 MATERIAL 10.2

executed as shown in Figure 5.12. Notice the high rate of return on investment (23 percent) used in the gasification example. This is to allow for uncertainties using an emerging technology. The first and second page of the hard copy output from the Steam Cost Code indicating the cost of the product gas is shown in Figures 5.13 and 5.14.

Figure 5.15 is the INDCEPT capital investment summary for the medium-Btu boiler. Since the construction of the boiler is not as complex as the gasifier, the design and construction period is only 2 years (1984-1986). To obtain the resulting cost of steam for the system, the steam cost program was executed using the capital cost for the boiler. For the gas boilers, the selection of the location for reference coal prices is replaced by the input of the purchase price of the gas as shown in Figure 5.16. Figures 5.17 and 5.18 are the first two pages of the resulting output from the Steam Cost Code indicating the steam cost from the gasification system.

5.8 Operating Cost Scaling Procedures and Cost Sensitivities

Operating costs are considered as either fixed costs or variable costs. Variable costs are directly affected by the capacity factor. Table X indicates which costs were considered as fixed or variable. Costs were adjusted to off-reference conditions using exponential scaling relations and direct multipliers, depending upon the specific cost. The costs were affected by the size, SO₂ emission level, particulate emission level, and the number of units. The following is a list of the reference conditions used in the analysis.

FIGURE 5.12

INPUT TO STEAM COST CODE TO CALCULATE
COST OF GAS FROM CENTRAL GASIFIER

8 STEAMIN
9 RUN STEAM

PROGRAM TO CALCULATE STEAM COSTS USING CAPITALIZED
COST ESTIMATE FROM INDCEPT. BASE OPERATING COSTS WERE
OBTAINED FROM ORNL.

Enter cost model number of steam system from indcept 65
Enter gross output of unit in MBTU/h 2300
Enter capital investment cost from indcept based on
major equip. purchase in \$1000 337613
Enter capital investment cost from indcept based on
commercial operation date in \$1000 548342
Enter FGD efficiency in % SO2 removal 99
Enter particulate emission level in lb/MBTU .1
Enter the average capacity factor in % (10 through 99) 70
Enter the number of units (1 through 4) 1
Enter year of major equipment purchase (inc dec pnt) 1981.
Enter the year for start of commercial operation (inc dec pnt) 1986.
Enter rate for return on investment 23

THE FOLLOWING IS THE INPUT DATA AS RECORDED

NUMBER	VARIABLE DESCRIPTION	
1	Model number of steam unit.....	65
2	Size of the unit (MBTU/hr).....	2300
3	The FGD level in % SO2 removal.....	99
4	The particulate removal level (lb/MBTU).....	0.10
5	The average capacity factor (%).....	70
6	The number of units.....	1
7	The year of equipment purchase.....	1981.0
8	The year of commercial operation.....	1986.0
9	Capital cost based on equip purchase (\$1000)..	337613
10	Capital cost based on commercial oper.....	548342
11	Rate for return on investment.....	23

Do you wish to change any of the values (Y/N) N
The following escalation rates are used in the analysis

NUMBER	COST AREA	RATE(%)
1	LABOR RATES.....	6
2	ELECTRICITY.....	8
3	WASTE DISPOSAL.....	8
4	MAINTENANCE MATERIALS.....	8
5	CHEMICAL AND WATER.....	6
6	FUEL.....	8

Do you wish to change any of the rates? (Y/N) N
The following economic parameters are used in the analysis

NUMBER	PARAMETER	
1	tax rate =	50%
2	insurance rate =	.5%
3	investment life =	20 years
4	investment tax credit =	10% capital cost
5	capital qualifying for ITC =	90% capital cost
6	ACRS depreciation class =	10 year class
7	cost of No. 6 oil (\$/MBtu) =	5.86
8	user coal cost option =	0.00

Do you wish to change any of the values (Y/N) N

Select one of the following cities to be used
for coal cost calculation using proper type of coal

HIGH SULFUR	LOW SULFUR
BOSTON	SEATTLE
NEW YORK	SAN FRANCISCO
PHILADELPHIA	DENVER
ATLANTA	CHICAGO
CHICAGO	DALLAS
DALLAS	KANSAS CITY
KANSAS CITY	

Enter city to be used (in CAPITALS) DALLAS

FIGURE 5.13

FIRST PAGE OF OUTPUT FOR GAS COSTS

***** PRODUCT GAS COSTS FOR MODEL 65 OVER A TWENTY YEAR PERIOD *****

REFERENCE SYSTEM COMPONENTS FOR MODEL 65

BOILER TYPE.....MEDIUM-BTU GASIFIER
FUEL TYPE.....EASTERN HIGH-SULFUR COAL
FGD TYPE.....NOT APPLICABLE
PARTICULATE.....NOT APPLICABLE

THE FOLLOWING INPUT DATA WAS USED FOR THE ANALYSIS

SIZE OF THE GASIFIER IN MBTU/HR.....2300
THE FGD LEVEL IN % SO2 REMOVAL.....99
THE PARTICULATE REMOVAL LEVEL (lb/MBTU).....0.10
THE AVERAGE CAPACITY FACTOR (%).....70
THE NUMBER OF UNITS.....1
THE YEAR OF EQUIPMENT PURCHASE.....1981.0
FIRST YEAR OF COMMERCIAL OPERATION.....1986.0

ECONOMIC PARAMETERS USED IN THE ANALYSIS

TAX RATE.....50%
INSURANCE RATE.....0.50%
INVESTMENT LIFE.....20 YEARS
INVESTMENT TAX CREDIT.....10% CAPITAL COST
CAPITAL QUALIFYING FOR ITC..90% CAPITAL COST
ACRS DEPRECIATION CLASS.....10 YEAR CLASS
USER COAL COST OPTION.....0.00

THE FOLLOWING ESCALATION RATES WERE USED

ESCALATION RATE FOR LABOR COSTS 6%
ESCALATION RATE FOR ELECTRICITY 8%
ESCALATION RATE FOR WASTE DISPOSAL 6%
ESCALATION RATE FOR MAINTENANCE MATERIALS 8%
ESCALATION RATE FOR CHEMICAL AND WATER 6%
ESCALATION RATE FOR FUEL 8%

RATE FOR RETURN ON INVESTMENT 23%

REFERENCE CITY USED FOR FUEL COST WAS DALLAS

NET STEAM AVAILABLE FOR PROCESS(MBTU/h).....2300.0

TOTAL CAPITAL COST(\$1000) BASED ON EQUIPMENT PURCHASE 337613

TOTAL CAPITAL COST(\$1000) BASED ON COMMERCIAL OPERATION 548342

FIGURE 5.14

SECOND PAGE OF OUTPUT FOR GAS COSTS

***** LEVELIZED STEAM COSTS FOR MODEL 65 OVER A TWENTY YEAR PERIOD *****

>>>> GAS COST CALCULATED USING BASE YEARS AS YEAR OF <<<<
>>>> MAJOR EQUIPMENT PURCHASE AND COMMERCIAL OPERATION <<<<

COST OF GAS (\$/MBTU) 13.50

DOLLAR VALUES BASED ON MAJOR EQUIPMENT PURCHASE DATE

BASE EQIP *DETAILED COST INFORMATION* BASE EQIP

COST AREA	GAS CONTRIBUTION COST(\$)	PERCENT
BOILER LABOR	0.5811	4.30
FGD LABOR	0.0000	0.00
PARTICULATE LABOR	0.0000	0.00
BOILER FIXED ELEC.	0.0811	0.60
BOILER VAR ELEC.	0.1577	1.17
FGD ELECTRICITY	0.0000	0.00
PARTICULATE ELEC.	0.0000	0.00
FGD WASTE DISPOSAL	0.0000	0.00
BOILER WASTE DISPOSAL	0.1209	0.90
BOILER MATERIAL	0.7321	5.42
FGD MATERIAL	0.0000	0.00
PARTICULATE MATERIAL	0.0000	0.00
BOILER CHEMICALS	0.0029	0.02
FGD CHEMICALS	0.0003	0.00
LIMESTONE COSTS	0.0000	0.00
LIME COST	0.0000	0.00
SODA ASH COST	0.0000	0.00
ANNUAL FUEL	3.1179	23.09
SULFUR REVENUES	-0.0622	-0.46

***** COST BREAKDOWN BY RELATED AREAS *****

CAPITAL COST	0.0013	59.25
LABOR COSTS	0.5811	4.30
ELECTRICITY	0.2388	1.77
WASTE DISPOSAL	0.1209	0.90
MAINT. MATERIALS	0.7321	5.42
WATER AND TREATMENT	0.0032	0.02
DESULFURIZATION CHEM	-0.0622	-0.46
FUEL	3.1179	23.09
MISCELLANEOUS	0.6817	5.05

COST OF GAS(\$/MBTU) 20.99

DOLLAR VALUES BASED ON COMMERCIAL OPERATION DATE

BASE OPER *DETAILED COST INFORMATION* BASE OPER

COST AREA	GAS CONTRIBUTION COST(\$)	PERCENT
BOILER LABOR	0.7777	3.70
FGD LABOR	0.0000	0.00
PARTICULATE LABOR	0.0000	0.00
BOILER FIXED ELEC.	0.1192	0.57
BOILER VAR ELEC.	0.2317	1.10
FGD ELECTRICITY	0.0000	0.00
PARTICULATE ELEC.	0.0000	0.00
FGD WASTE DISPOSAL	0.0000	0.00
BOILER WASTE DISPOSAL	0.1618	0.77
BOILER MATERIAL	1.0757	5.12
FGD MATERIAL	0.0000	0.00
PARTICULATE MATERIAL	0.0000	0.00
BOILER CHEMICALS	0.0038	0.02
FGD CHEMICALS	0.1209	0.58
LIMESTONE COSTS	0.0000	0.00
LIME COST	0.0000	0.00
SODA ASH COST	0.0000	0.00
ANNUAL FUEL	4.5812	21.82
SULFUR REVENUES	-0.0832	-0.40

***** COST BREAKDOWN BY RELATED AREAS *****

CAPITAL COST	12.9956	61.91
LABOR COSTS	0.7777	3.70
ELECTRICITY	0.3509	1.67
WASTE DISPOSAL	0.1618	0.77
MAINT. MATERIALS	1.0757	5.12
WATER AND TREATMENT	0.1247	0.59
DESULFURIZATION CHEM	-0.0832	-0.40
FUEL	4.5812	21.82
MISCELLANEOUS	1.0082	4.80

CAPITAL COST ESTIMATE FROM INDCEPT FOR
MEDIUM-BTU GAS FIRED BOILER MODEL 58

DATE 9-24-82 INDCEPT COST ESTIMATES

1 UNIT CAPITAL INVESTMENT SUMMARY (THOUSANDS OF DOLLARS)
1X 250 MBTU/HR MODEL 58 (9-18-81) PLANT AT DALLAS MBTU/BOIL
MEDIUM BTU GAS FIRED BOILER
COST BASIS: YEAR OF MAJOR EQP. PURCHASE
DESIGN & CONSTRUCTION PERIOD: MAJOR EQP. PURCHASE: 1984.00
START OF CONSTRUCTION: 1985.00
COMMERCIAL OPERATION: 1986.00

ACCOUNT NUMBER	ACCOUNT TITLE	TOTAL COSTS	EQUIPMENT COSTS	LABOR MANHOURS	LABOR COSTS	MATERIAL COSTS
20	LAND AND SITE WORK	107	0. (	3.)	55.	52.
30	BOILER PLANT	6691	3608. (	74.)	1240.	1842.
40	BOILER SUPPORT FACILITIES	135	0. (	2.)	49.	86.
50	PARTICULATE REMOVAL SYSTEM	0	0. (	0.)	0.	0.
60	FLUE GAS DESULFURIZATION	0	0. (	0.)	0.	0.
70	SUPPORT FACILITIES	583	59. (	14.)	232.	293.
		SUBTOTAL				
90	INDIRECT COSTS	7516 3430	3667. (	93.)	1576.	2273.
		SUBTOTAL				
	DIRECT & INDIRECT COSTS	10946				
	CONTINGENCY ALLOWANCE	2189				
						
	TOTAL DIRECT & INDIRECT COSTS	13135				
	ESCALATION DURING CONSTRUCTION (8.8%/YR)	1759				
	TOTAL ESCALATED DIRECT & INDIRECT COSTS	14894				
						
	INTEREST DURING CONSTRUCTION COMPOUND (12.000%/YR)	792				
	ON DIRECT & INDIRECT COSTS	96				
	ON ESCALATION DURING CONSTRUCTION					
	TOTAL INTEREST DURING CONSTRUCTION	888				
						
	TOTAL PLANT CAPITAL INVESTMENT	15782				

WEIGHTED AVERAGE ESCALATION (%/YR)
EQUIPMENT 8.6 LABOR 8.2 MATERIAL 10.2

FIGURE 5.16

INPUT TO STEAM CODE FOR GAS-FIRED BOILER MODEL 58

```

$ @STEAMIN
$ RUN STEAM
PROGRAM TO CALCULATE STEAM COSTS USING CAPITALIZED
COST ESTIMATE FROM INDCEPT. BASE OPERATING COSTS WERE
OBTAINED FROM ORNL.
Enter cost model number of steam system from indcept 58
Enter gross output of unit in MBTU/h 250
Enter capital investment cost from indcept based on
major equip. purchase in $1000 13135
Enter capital investment cost from indcept based on
commercial operation date in $1000 15782
Enter FGD efficiency in % SO2 removal 90
Enter particulate emission level in lb/MBTU .1
Enter the average capacity factor in % (10 through 99) 70
Enter the number of units (1 through 4) 1
Enter year of major equipment purchase (inc dec pnt) 1984.
Enter the year for start of commercial operation (inc dec pnt) 1986.
Enter rate for return on investment 23

```

THE FOLLOWING IS THE INPUT DATA AS RECORDED

NUMBER	VARIABLE DESCRIPTION	VALUE
1	Model number of steam unit.....	58
2	Size of the unit (MBTU/hr).....	250
3	The FGD level in % SO2 removal.....	90
4	The particulate removal level (lb/MBTU).....	0.10
5	The average capacity factor (%).....	70
6	The number of units.....	1
7	The year of equipment purchase.....	1984.0
8	The year of commercial operation.....	1986.0
9	Capital cost based on equip purchase (\$1000)...	13135
10	Capital cost based on commercial oper.....	15782
11	Rate for return on investment.....	23

Do you wish to change any of the values (Y/N) N

The following escalation rates are used in the analysis

NUMBER	COST AREA	RATE(%)
1	LABOR RATES.....	6
2	ELECTRICITY.....	8
3	WASTE DISPOSAL.....	6
4	MAINTENANCE MATERIALS.....	8
5	CHEMICAL AND WATER.....	6
6	FUEL.....	8

Do you wish to change any of the rates? (Y/N) N

The following economic parameters are used in the analysis

NUMBER	PARAMETER	VALUE
1	tax rate	50%
2	insurance rate	.5%
3	investment life	20 years
4	investment tax credit	10% capital cost
5	capital qualifying for ITC	90% capital cost
6	ACRS depreciation class	10 year class
7	cost of No. 6 oil (\$/MBtu)	5.86
8	user coal cost option	0.00

Do you wish to change any of the values (Y/N) N

Enter purchase price (yr equip. purchase) of gas to be used in boiler 13.50

Enter purchase price (yr operation) of gas to be used in the boiler 20.99

FIGURE 5.17

FIRST PAGE OF OUTPUT FOR STEAM COSTS

***** LEVELIZED STEAM COSTS FOR MODEL 58 OVER A TWENTY YEAR PERIOD *****

REFERENCE SYSTEM COMPONENTS FOR MODEL 58

BOILER TYPE.....MEDIUM-BTU GAS FIRED
FUEL TYPE.....MEDIUM-BTU GAS
FGD TYPE.....NOT APPLICABLE
PARTICULATE.....NOT APPLICABLE

THE FOLLOWING INPUT DATA WAS USED FOR THE ANALYSIS

SIZE OF THE BOILER UNIT(MBTU/HR)..... 250
THE FGD LEVEL IN % SO2 REMOVAL.....90
THE PARTICULATE REMOVAL LEVEL (lb/MBTU).....0.10
THE AVERAGE CAPACITY FACTOR (%).....70
THE NUMBER OF UNITS.....1
THE YEAR OF EQUIPMENT PURCHASE.....1984.0
FIRST YEAR OF COMMERCIAL OPERATION.....1986.0

ECONOMIC PARAMETERS USED IN THE ANALYSIS

TAX RATE.....50%
INSURANCE RATE.....0.50%
INVESTMENT LIFE.....20 YEARS
INVESTMENT TAX CREDIT.....10% CAPITAL COST
CAPITAL QUALIFYING FOR ITC..90% CAPITAL COST
ACRS DEPRECIATION CLASS.....10 YEAR CLASS
USER COAL COST OPTION.....0.00

THE FOLLOWING ESCALATION RATES WERE USED

ESCALATION RATE FOR LABOR COSTS 6%
ESCALATION RATE FOR ELECTRICITY 8%
ESCALATION RATE FOR WASTE DISPOSAL 6%
ESCALATION RATE FOR MAINTENANCE MATERIALS 8%
ESCALATION RATE FOR CHEMICAL AND WATER 6%
ESCALATION RATE FOR FUEL 8%

RATE FOR RETURN ON INVESTMENT 23%

REFERENCE CITY USED FOR FUEL COST WAS PRODUCT GAS USED

NET STEAM AVAILABLE FOR PROCESS(MBTU/h)..... 223.3

TOTAL CAPITAL COST(\$1000) BASED ON EQUIPMENT PURCHASE 13135

TOTAL CAPITAL COST(\$1000) BASED ON COMMERCIAL OPERATION 15782

FIGURE 5.18

SECOND PAGE OF OUTPUT FOR STEAM COSTS

***** LEVELIZED STEAM COSTS FOR MODEL 58 OVER A TWENTY YEAR PERIOD *****

>>>> STEAM COST CALCULATED USING BASE YEARS AS YEAR OF <<<<
>>>> MAJOR EQUIPMENT PURCHASE AND COMMERCIAL OPERATION <<<<

COST OF STEAM (\$/MBTU) 21.84

DOLLAR VALUES BASED ON MAJOR EQUIPMENT PURCHASE DATE

BASE EQIP DETAILED COST INFORMATION BASE EQIP

COST AREA	STEAM CONTRIBUTION COST(\$)	PERCENT
BOILER LABOR	0.4950	2.27
FGD LABOR	0.0400	0.00
PARTICULATE LABOR	0.0000	0.00
BOILER FIXED ELEC.	0.0547	0.25
BOILER VAR ELEC.	0.0025	0.01
FGD ELECTRICITY	0.0000	0.00
PARTICULATE ELEC.	0.0000	0.00
FGD WASTE DISPOSAL	0.0000	0.00
BOILER WASTE DISPOSAL	0.0000	0.00
BOILER MATERIAL	0.2686	1.23
FGD MATERIAL	0.0000	0.00
PARTICULATE MATERIAL	0.0000	0.00
BOILER CHEMICALS	0.0314	0.14
FGD CHEMICALS	0.0000	0.00
LIMESTONE COSTS	0.0000	0.00
LINE COST	0.0000	0.00
SODA ASH COST	0.0000	0.00
ANNUAL FUEL	16.1200	73.85
SULFUR REVENUES	0.0000	0.00

***** COST BREAKDOWN BY RELATED AREAS *****

CAPITAL COST	2.8639	13.11
LABOR COSTS	0.4950	2.27
ELECTRICITY	0.0572	0.26
WASTE DISPOSAL	0.0000	0.00
MAINT. MATERIALS	0.2686	1.23
WATER AND TREATMENT	0.0314	0.14
DESULFURIZATION CHEM	0.0000	0.00
FUEL	16.1200	73.85
MISCELLANEOUS	1.9958	9.14

COST OF STEAM (\$/MBTU) 32.77

DOLLAR VALUES BASED ON COMMERCIAL OPERATION DATE

BASE OPER DETAILED COST INFORMATION BASE OPER

COST AREA	STEAM CONTRIBUTION COST(\$)	PERCENT
BOILER LABOR	0.6624	2.02
FGD LABOR	0.0000	0.00
PARTICULATE LABOR	0.0000	0.00
BOILER FIXED ELEC.	0.0803	0.25
BOILER VAR ELEC.	0.0037	0.01
FGD ELECTRICITY	0.0000	0.00
PARTICULATE ELEC.	0.0000	0.00
FGD WASTE DISPOSAL	0.0000	0.00
BOILER WASTE DISPOSAL	0.0000	0.00
BOILER MATERIAL	0.3947	1.20
FGD MATERIAL	0.0000	0.00
PARTICULATE MATERIAL	0.0000	0.00
BOILER CHEMICALS	0.0420	0.13
FGD CHEMICALS	0.0000	0.00
LIMESTONE COSTS	0.0000	0.00
LINE COST	0.0000	0.00
SODA ASH COST	0.0000	0.00
ANNUAL FUEL	25.0777	76.52
SULFUR REVENUES	0.0000	0.00

***** COST BREAKDOWN BY RELATED AREAS *****

CAPITAL COST	3.4411	10.50
LABOR COSTS	0.6624	2.02
ELECTRICITY	0.0840	0.26
WASTE DISPOSAL	0.0000	0.00
MAINT. MATERIALS	0.3947	1.20
WATER AND TREATMENT	0.0420	0.13
DESULFURIZATION CHEM	0.0000	0.00
FUEL	25.0777	76.52
MISCELLANEOUS	3.0716	9.37

Reference Conditions Used in the Analysis

System Sizes

Conventional, AFBC, and oil	250 MBtu/h
On-site gasification	250 MBtu/h
Central gasification	2300 MBtu/h

<u>Number of Units</u>	1
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Sulfur Removal Levels

Boilers	
Eastern coal	94
Western coal	70
Gasifiers	
Eastern coal	99
Western coal	92

<u>Particulate Emission Level</u>	.1 lb/MMBtu
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Table IX describes the steam cost sensitivities to off-reference conditions and the method used to scale each cost. As shown in the table, all costs are scaled for size and number of units. The variable costs are adjusted by the capacity factor. A total of seven variables are affected by the sulfur removal rate, but only one cost is affected by the particulate removal level.

TABLE XI

Steam Cost Sensitivity to Off-Reference Conditions

Type	Detailed Cost Area	Size		No. of Units			Capacity Factor	FGD Level		Particulate Level	
		Expo.	Direct	Own Scale	Overall Scale	Direct		Expo.	Direct	Expo.	Direct
FIX	Boiler Labor	X		X							
FIX	FGD Labor	X		X							
FIX	Boiler Fixed Electricity	X			X						
VAR	Boiler Variable Electricity		X			X	X				
FIX	Particulate Labor	X		X							
VAR	FGD Electricity		X			X	X	X			
VAR	Particulate Electricity		X			X	X			X ^a	
VAR	FGD Waste Disposal		X			X	X	X			
VAR	Boiler Waste Disposal		X			X	X				
FIX	Boiler Material		X		X						
FIX	FGD Material		X		X						
FIX	Particulate Material		X		X						
FIX	Boiler Chemicals		X			X					
VAR	FGD Chemicals and Water		X			X	X	X			
VAR	Limestone Costs		X			X	X	X			
VAR	Lime Cost		X			X	X		X		
VAR	Soda Ash Cost		X			X	X		X		
VAR	Sulfur Revenues		X			X	X		X		

Expo. = Used exponential scaling relation to adjust for off-reference condition.

Direct = Off-reference cost directly proportional to reference cost.

FIX = Considered as a fixed cost, not effected by capacity factor.

VAR = Variable cost, directly proportional to capacity factor.

^a = Particulate electricity adjusted for emission level for ESP only.

CHAPTER 6

APPLICATIONS AND ANALYSIS CAPABILITIES OF THE STEAM COST CODE

6.1 Economic Analysis Procedure

The economic analysis procedure involves determining the revenue requirements to completely recover all costs considered in the analysis after taxes and return on investment considerations. The required revenue can then be used to calculate the required steam costs in terms of \$/MMBtu of steam produced. The individual cost areas included in the analysis consist of the 18 detailed cost categories as shown in Table X, the fuel costs, capital costs, working capital, and insurance.

The fuel costs are calculated based on the size of the boiler, operating capacity factor, and the boiler efficiency. Since the boiler size is defined as the gross steam output, the thermal heat input rate of the fuel can be determined by the boiler efficiency. The hourly heat input rate to the boiler is adjusted for the capacity factor and converted to an annual fuel cost.

Each one of the 18 detailed operating costs has an associated escalation rate to reflect increasing costs over the operating period. The first year cost can be converted to an equivalent annual cost using the following multiplication factor:

$$\text{Equivalent Annual Cost} = \text{Cost}_1 \left[\frac{1.0 - \left[\frac{1 + \text{ESC}}{1 + \text{ROI}} \right]^n}{\text{ROI} - \text{ESC}} \right] \left[\frac{\text{ROI} (1.0 + \text{ROI})^n}{(1.0 + \text{ROI})^n - 1.0} \right]$$

where,

Cost₁ = cost during the first year of operation.
 ESC = annual cost escalation rate (specific to cost type).
 ROI = rate of return on investment.
 n = number of years of operation.

This procedure is performed using subroutines in the leveled cost calculation section of the program for the 18 detailed costs and the fuel costs.

The working capital is calculated based on 3 months operating expenses. The 18 detailed costs and the fuel costs are totalled and divided by four to represent the working capital. This value is multiplied by the rate for return on investment to represent the "interest charge" for the working capital. This interest charge is not an actual expense but represents the investment opportunity loss of the working capital.

The capital investment cost is considered to qualify for investment tax credit (ITC). Since some construction costs considered in the INDCEPT cost estimate may not qualify for ITC, a certain percentage of the cost is deducted before calculating the ITC. These two economic parameters have values assigned in the FORTRAN code which can be changed interactively during the input procedure. Unless changed, 90 percent of the capital cost estimate is considered to qualify for 10 percent investment tax credit. These two economic parameters will change the total capital investment cost by the following relationship:

$$\text{ADJUSTED CAPITAL COST} = (1.0 - \text{ITC} \times \text{PERQUAL}) \times (\text{TOTAL CAPITAL INVESTMENT})$$

where,

ITC = INVESTMENT TAX CREDIT.

PERQUAL = percent of total capital investment qualifying for ITC.

If not considering ITC, set PERQUAL to zero in program.

This cost is converted to an annual cost using a capital recovery factor

of the form:

$$\text{CAPITAL RECOVERY FACTOR (A/P)} = \frac{\text{ROI} (1.0 + \text{ROI})^n}{(1.0 + \text{ROI})^n - 1.0}$$

The equivalent annual capital expenditure can be expressed as:

$$\text{ANNUAL CAPITAL RECOVERY} = (\text{ADJUSTED CAPITAL COST}) \times (\text{A/P})$$

The insurance cost is assumed to be .5 percent of the capital cost investment. The depreciation is calculated based on the accelerated cost recovery system (ACRS). The depreciation that occurs each year is adjusted to the first year of the cost basis using the rate for return on investment as the time value of money. The total depreciation, expressed in the first year of the cost basis, is converted to an equivalent annual depreciation using the capital recovery factor (A/P). The equivalent annual depreciation deduction can be expressed as:

$$\text{E. A. Depreciation} = \left[\sum_{k=1}^n (\text{total capital investment}) \times (\text{percentage}_k) \times \frac{1.0}{(1.0 + \text{ROI})^k} \right] \times (\text{A/P})$$

where,

percentage_k = percent of capital investment that can be depreciated during year k, determined by the prescribed percentages based on the ACRS class life.

These calculations yield an equivalent annual depreciation deduction over the specified operating period.

Having all costs expressed as annual costs, the required annual revenues can be expressed by the relationship:

$$R = \text{CAPITAL RECOVERY} + \text{OPERATING COSTS} + \text{TAX PAYMENT}$$

Substituting in the costs used in this analysis, the revenue equation can be expressed as:

$$R + \text{SULFREV} = \text{CAPREC} + \text{WC} + \text{TOTOP} + \text{INS} + t [(R + \text{SULFREV}) - \text{ANLDEP} - \text{TOTOP} - \text{INS}]$$

where,

R = annual revenue requirement.
 CAPREC = annual capital recovery.
 WC = interest charge on working capital.
 INS = annual insurance expense.
 TOTOP = total annual operating costs (fuel costs and 18 detailed costs less sulfur revenues.
 SULFREV = annual sulfur revenues from gasifiers.
 t = tax rate.

Solving the equation for R, the expression becomes:

$$R = [\text{CAPREC} + \text{WC} + \text{TOTOP} + \text{INS} - \text{SULFREV} - t (\text{ANLDEP} + \text{TOTOP} + \text{INS} - \text{SULFREV})] \div (1.0 - t)$$

From the annual revenue requirement, the resulting steam cost in terms of \$/MMBtu can be determined based on the annual gross output of the steam production system. The levelized steam cost can be expressed as:

$$\text{LEVELIZED STEAM COST} = R \div (\text{SIZE} \times \text{CAPFAC} \times 8736)$$

where,

SIZE = gross output of boiler in terms of 10^6 Btu/hr.

CAPFAC = average capacity factor.

8736 = hrs/yr of operation based on 100 percent capacity for 52 weeks.

The steam contribution cost expresses the net cost in terms of \$/MMBtu that results from each cost category after the effects of taxes and return on investment. The procedure used to calculate the contribution cost is to take the levelized cost for each area and subtract the tax savings that result from the write-off since operating costs are tax deductible. The resulting contribution cost is calculated using the following relationship:

$$\text{STEAM CONTRIBUTION COST} = \frac{(\text{COST} - t \times \text{COST}) / (1.0 - t)}{\text{SIZE} \times \text{CAPFAC} \times 8736}$$

COST = equivalent annual cost for a specific detailed cost area.

The capital recovery contribution cost is the cost after the savings that result from the depreciation deduction.

The levelized steam cost can be expressed as an increasing steam cost using a constant escalation rate. The steam cost required during the first year of operation (if the cost is going to increase at a constant rate) can be calculated from the levelized steam cost using the following expression:

$$\text{Steam}_1 = \text{LEVELIZED STEAM COST} \div \left[\frac{1.0 - \left[\frac{1 + \text{ESCPRI}}{1 + \text{ROI}} \right]^n}{\text{ROI} - \text{ESCPRI}} \times (\text{A/P}) \right]$$

where,

Steam₁ = required steam cost during first year operation.

ESCPRI = annual steam cost escalation rate.

The steam cost for any specific year during the operating period can be determined from:

$$\text{STEAM COST}(m) = \text{STEAM}_1 \times (1 + \text{ESCPRI})^m$$

where,

STEAM COST(m) = steam cost during year m of the operating period
for m = 1,20.

The price escalation rate can be changed by editing the FORTRAN source code in the year-by-year escalating steam cost section of the program.

The current escalation rate is 6 percent per year.

6.2 Applications of the Steam Cost Code as an Interactive Economic Cost Model

The economic analysis procedure used to calculate levelized steam costs can be applied to any revenue requirement analysis with modifications to reflect the specific cost considerations for a particular application.

The general economic procedure can be applied to any type of production process to determine:

- o Minimum required selling price per unit (levelized and escalating unit cost).
- o Individual cost contributions to unit costs after the effects of escalation, taxes, and return on investment.
- o Effects of varying specific cost escalation rates.

- o Cost sensitivities to key process variables.
- o Significant cost components of the unit cost.
- o Trade-offs between capital investment expenditures and annual operating expenses on a unit production basis.

The detailed cost information provided, using this economic analysis procedure, enables the user to identify the resulting net cost of each individual cost after the effects of escalation, taxes, and return on investment to determine the actual contribution of a particular cost source to the unit production cost. This is a valuable advantage when determining the significant cost factors and/or performing a sensitivity analysis. The interactive structure of the program allows the user to perform this type of analysis with minimal difficulty.

To apply the economic analysis procedure to a specific manufacturing process, the significant production costs must be determined and evaluated to be incorporated into the model. The major production variables must be identified and cost data obtained for each variable over the applicable range of the variable to provide a base for performing a cost evaluation. For the steam production process, two key variables that impact steam costs are the boiler size and operating capacity factor. In order for the economic model to indicate cost trends for these variables, cost data was obtained for the different systems over the applicable range of these variables. The actual data base did not contain specific costs for different values of the size and capacity factors (costs used were at reference

values), but used exponential scaling equations which were determined from costs at specific values. This procedure enables the economic model to interpolate cost data for any value over the applicable range of these variables. The data collection is a critical step because the value of an economic model is directly related to the accuracy and detail of the cost data base.

Once the data is obtained, it must be organized into a logical format that is compatible for computerization. The cost data for the Steam Cost Code was organized using a matrix format. The columns contain costs for specific areas and the rows represent the 66 reference steam systems available. The entire data set could have been organized in one large matrix, however, related costs were grouped into individual matrices for easier location and identification. The structure of the data files enables all costs associated with a particular steam system to be on the same row in each of the major data files. The organizational procedure of the major data files is shown in Figure 6.1.

The economic analysis procedure begins with the general revenue equation:

$$R = \text{Capital Recovery} + \text{Operating Costs} + \text{Tax Payment}$$

The specific cost data for a particular application can be used to calculate an annual revenue requirement. The annual revenues can be converted to a unit production cost by dividing by the annual production quantity. The procedure used to calculate unit production costs is described in detail in the economic analysis section (6.1). The economic

FIGURE 6.1

ORGANIZATION OF MAIN DATA FILES

NOTE: Information available to user as a documentation file (steamdat1.doc)

ORGANIZATION OF DATA FILES USED FOR STEAM.FOR		
DATA FILE (DIMENSION)	COLUMN	DESCRIPTION
MAJOR REFERENCE COSTS DATA FILES	MODEL (66,7)	1. MODEL NUMBER OF SYSTEM (1 THROUGH 66) 2. GROSS OUTPUT OF REFERENCE SYSTEM 3. BOILER TYPE 4. FUEL TYPE 5. FGD TYPE 6. FGD REFERENCE EFFICIENCY 7. PARTICULATE REMOVAL METHOD
	RLABOR (66,6)	1. BOILER COMBUSTION EFFICIENCY 2. BOILER STEAM REQUIREMENTS 3. FGD STEAM REQUIREMENTS 4. BOILER LABOR COSTS 5. FGD LABOR COSTS 6. PARTICULATE LABOR COSTS
	ELEC (66,7)	1. FIXED BOILER ELECTRICITY COSTS 2. VARIABLE BOILER ELECTRICITY COSTS 3. PARTICULATE ELECTRICITY COSTS 4. FGD ELECTRICITY COSTS 5. FGD SULFUR ELECTRICITY SCALE FACTORS 6. FIXED BOILER ELEC SIZE SCALE FACTORS 7. PARTICULATE LEVEL ELEC SCALE FACTORS
	WASTE (66,6)	1. BOILER WASTE DISPOSAL COSTS 2. FGD WASTE DISPOSAL COSTS 3. FGD SULFUR DISPOSAL SCALE FACTORS 4. BOILER MAINTENANCE AND LABOR COSTS 5. FGD MAINTENANCE AND LABOR COSTS 6. PARTICULATE MAINTENANCE AND LABOR
	CHEM (66,6)	1. WATER AND TREATMENT CHEMICAL COSTS 2. SULFUR SCALE FACTORS FOR WATER COSTS 3. LIMESTONE COSTS 4. LIME COSTS 5. SODA ASH COSTS 6. SULFUR REVENUES FROM GASIFIERS

ADDITIONAL
DATA FILES
REQUIRED
FOR THE SCC

SCALE (9,3)	COLUMNS(3): COLUMNS REPRESENT NUMBER OF UNITS (1-3) ROWS(9): LABOR COSTS FACTORS FOR MULTIPLE NUMBER OF UNITS 1. STOKER-FIRED BOILER 2. PULVERIZED-COAL FIRED 3. AFBC 4. OIL-FIRED BOILER 5. LOW-BTU BOILER 6. MED-BTU BOILER 7. LOW-BTU GASIFIER 8. MED-BTU GASIFIER 9. FGD SYSTEM
	COLUMNS(3): COLUMNS REPRESENT NUMBER OF UNITS (1-3) ROWS(16): OVERALL MULTIPLE PLANT FACTORS 1. PULVERIZED-COAL EASTERN 2. PULVERIZED-COAL WESTERN 3. STOKER-FIRED EASTERN 4. STOKER-FIRED WESTERN 5. AFBC EASTERN 6. AFBC WESTERN 7. OIL-FIRED 8. LOW-BTU BOILER 9. MED-BTU BOILER 10. LOW-BTU GASIFIER EASTERN 11. LOW-BTU GASIFIER WESTERN 12. MED-BTU GASIFIER EASTERN 13. MED-BTU GASIFIER WESTERN 14. FGD SYSTEM 15. ESP 16. BAGHOUSE
SCALE (16,8)	COLUMNS(4): ALPHA DATA STORAGE ROWS(11): DOE REFERENCE CITY FOR EACH REGION FOR COAL COST CALCULATION 1. BOSTON 2. NEW YORK 3. PHILADELPHIA 4. ATLANTA 5. DENVER 6. SAN FRANCISCO 7. SEATTLE 8. CHICAGO 9. DALLAS 10. KANSAS CITY 11. OIL @5.86/MMBTU
ICITY (11,4)	ROWS(13): REPRESENT 10 DOE REGION REFERENCE CITY LOCATIONS COLUMNS(3): REFERENCE COAL COST DATA 1. COAL COST FOR SINGLE CAR DEL (\$/MMBTU) 2. COAL COST FOR UNIT TRAIN DEL (\$/MMBTU) 3. HEATING VALUE FOR FUEL (BTU/LB)
COAL (13,3)	COLUMNS(2): COLUMN 1 REPRESENTS ROW NUMBER COLUMN 2 REPRESENTS ESCALATION RATE ROWS(6): DEFAULT ESCALATION RATES 1. LABOR RATES 2. ELECTRICITY 3. WASTE DISPOSAL 4. MAINTENANCE MATERIALS 5. CHEMICAL AND WATER 6. FUEL
IESC (6,2)	

parameters (return on investment, tax rate, operating period, etc.) used in the analysis should reflect the specific application. The Steam Cost Code was designed to allow the individual user to select or change the economic parameters as part of the interactive input when running the program. This approach allows each individual user to modify the economic parameters to reflect a desired situation with minimal user difficulties. It is also easy to determine the effects of a specific economic parameter by incrementing a particular parameter and performing multiple runs.

The results of the economic analysis will calculate a levelized unit cost indicating the minimum selling price required to recover all costs considered in the analysis. The cost contribution calculation indicates the significance of each cost area on the levelized unit cost.

6.3 Interpretation of the Steam Cost Code Output

The Steam Cost Code was developed to provide insight into the cost of producing steam with respect to the different combustion methods, fuel types, and emission control levels. The output produced by the Steam Cost Code was presented in Figures 5.7 through 5.10. The particular boiler system used for this example was a pulverized-coal boiler firing western low-sulfur coal. The emission control equipment consisted of an ESP for particulate collection and a lime/limestone scrubber designed to remove 70 percent of the sulfur in the flue gas. The construction period consisted of the major equipment purchase in 1981, start of construction

in 1982, and commercial operation in 1985. The INDCEPT code was executed to obtain the capital cost estimate as shown in Figure 5.2. The output produced by the Steam Cost Code (Figures 5.7 through 5.10) separates the steam cost into the detailed costs comprising the total cost of steam production from this boiler system.

The second and third page of the INDCEPT output from the example run is repeated in Figures 6.2 and 6.3 to provide further information about the format of the output. The second page of the output (shown in Figure 6.2) consists of two sections that indicate the steam contribution costs. The first section consists of the 18 detailed costs (see Table X) and the fuel cost contribution in \$/MMBtu to the total cost of steam. The percent column indicates the percentage contribution to the cost of steam. The 19 costs shown in the first section do not account for the total cost of steam since capital costs, insurance, and working capital are not included. The second section consists of a cost breakdown by related areas. This section accounts for 100 percent of the cost of steam but is not presented on the same level of detail as in the first section.

The third page of the output is shown in Figure 6.3 and represents the levelized costs before the costs are adjusted for taxes and expressed as a unit cost. Three sections are used on this page with the first two following the same format as the second page. The third section groups the 18 detailed costs into three areas: boiler-related, sulfur removal-related, and particulate-related operating costs. Figure 6.3 indicates which detailed costs are grouped under each category.

FIGURE 6.2

STEAM COST CONTRIBUTION OUTPUT FORMAT/

PAGE 2 OF OUTPUT

===== LEVELIZED STEAM COSTS FOR MODEL 35 OVER A TWENTY YEAR PERIOD =====

)))) STEAM COST CALCULATED USING BASE YEARS AS YEAR OF <<<<
)))) MAJOR EQUIPMENT PURCHASE AND COMMERCIAL OPERATION <<<<

FIGURE 6.3

LEVELIZED OPERATING COST OUTPUT FORMAT/

PAGE 3 OF OUTPUT

***** LEVELIZED STEAM COSTS FOR MODEL 35 OVER A TWENTY YEAR PERIOD *****

 >>>> STEAM COST CALCULATED USING BASE YEARS AS YEAR OF <<<<
 >>>> MAJOR EQUIPMENT PURCHASE AND COMMERCIAL OPERATION <<<<

COST OF STEAM (\$/MBTU) 11.31

COST OF STEAM (\$/MBTU) 15.86

DOLLAR VALUES BASED ON MAJOR EQUIPMENT PURCHASE DATE

DOLLAR VALUES BASED ON COMMERCIAL OPERATION DATE

BASE EQIP *DETAILED COST INFORMATION* BASE EQIP

BASE OPER *DETAILED COST INFORMATION* BASE OPER

COST AREA	LEVELIZED COST (\$1000)	PERCENT
BOILER LABOR	1010.3	14.10
FGD LABOR	578.7	8.08
PARTICULATE LABOR	9.6	0.13
BOILER FIXED ELEC.	76.0	1.06
BOILER VAR ELEC.	176.7	2.47
FGD ELECTRICITY	213.9	2.99
PARTICULATE ELEC.	53.5	0.75
FGD WASTE DISPOSAL	69.3	0.97
BOILER WASTE DISPOSAL	91.6	1.28
BOILER MATERIAL	996.9	13.92
FGD MATERIAL	71.3	1.00
PARTICULATE MATERIAL	66.7	0.93
BOILER CHEMICALS	43.2	0.60
FGD CHEMICALS	3.1	0.04
LIMESTONE COSTS	24.7	0.35
LINE COST	0.0	0.00
SODA ASH COST	0.0	0.00
ANNUAL FUEL	3677.1	51.34
SULFUR REVENUES	0.0	0.00

*** COST BREAKDOWN BY RELATED AREAS ***

CAPITAL COST	7047.9	48.50
LABOR COSTS	1598.6	11.00
ELECTRICITY	520.1	3.58
WASTE DISPOSAL	161.0	1.11
MAINT. MATERIALS	1134.8	7.81
WATER AND TREATMENT	46.3	0.32
DESULFURIZATION CHEM	24.7	0.17
FUEL	3677.1	25.30
MISCELLANEOUS	322.3	2.22

***** OPERATING COST GROUPINGS *****

BOILER RELATED	2394.7	68.70
SULFUR REMOVAL RELATED	961.1	27.57
PARTICULATE RELATED	129.8	3.72

COST AREA	LEVELIZED COST (\$1000)	PERCENT
BOILER LABOR	1275.5	13.30
FGD LABOR	730.6	7.62
PARTICULATE LABOR	12.1	0.13
BOILER FIXED ELEC.	103.4	1.08
BOILER VAR ELEC.	240.4	2.51
FGD ELECTRICITY	291.1	3.04
PARTICULATE ELEC.	72.8	0.76
FGD WASTE DISPOSAL	97.9	1.02
BOILER WASTE DISPOSAL	129.4	1.35
BOILER MATERIAL	1356.2	14.14
FGD MATERIAL	97.0	1.01
PARTICULATE MATERIAL	90.7	0.95
BOILER CHEMICALS	54.6	0.57
FGD CHEMICALS	3.9	0.04
LIMESTONE COSTS	31.2	0.33
LINE COST	0.0	0.00
SODA ASH COST	0.0	0.00
ANNUAL FUEL	5002.7	52.17
SULFUR REVENUES	0.0	0.00

*** COST BREAKDOWN BY RELATED AREAS ***

CAPITAL COST	10216.5	50.48
LABOR COSTS	2018.2	9.97
ELECTRICITY	707.6	3.50
WASTE DISPOSAL	227.2	1.12
MAINT. MATERIALS	1543.9	7.63
WATER AND TREATMENT	58.5	0.29
DESULFURIZATION CHEM	31.2	0.15
FUEL	5002.7	24.72
MISCELLANEOUS	431.5	2.13

***** OPERATING COST GROUPINGS *****

BOILER RELATED	3159.4	68.88
SULFUR REMOVAL RELATED	1251.7	27.29
PARTICULATE RELATED	175.6	3.83

Figure 6.4 is a graphical representation of the steam contribution cost breakdown by related areas obtained from Figure 6.2. As shown in Figure 6.4, the capital cost of the steam system contributes over 50 percent of the cost of steam when operated at a 75 percent average capacity factor. The capacity factor has a major impact on the cost of steam as can be seen on the fourth page of the Steam Cost Code output in Figure 5.10. This results because steam boilers (especially coal-fired) are an extensive capital cost investment, and operating the boiler closer to the designated capacity will lower the cost of steam on a dollar per MMBtu basis. The next largest component of the steam cost is the fuel (coal) costs which contributes nearly 20 percent to the total steam production cost. Since the fuel cost is based on a \$/MMBtu basis, the steam contribution cost of the fuel will not be affected by the capacity factor. Factors affecting the steam contribution cost of fuel are the rate for return on investment, fuel cost escalation rate, boiler efficiency, and the reference fuel cost in the data file COAL. All other cost areas contributed less than 10 percent to the total cost of steam.

6.4 Capital Cost Components of the Levelized Steam Cost

One disadvantage of the Steam Cost Code is the capital cost component of the steam cost. The steam system capital cost is input to the code (for both cost base years) as a single number, with no indication of how much is associated with the emission control equipment or other specific cost areas considered by INDCEPT. Further detail can be provided by calculating the contribution percentages of the capital cost components using the INDCEPT cost estimate.

The capital cost estimate of the steam system used for the example Steam Cost Code output is shown in Figure 5.2 (INDCEPT cost summary page for IESC=0). The INDCEPT output presents the costs for the major cost accounts (two-digit reference numbers as given in Table IV) and lists separately the costs for the contingency, escalation, and interest charges. Assuming the contingency, escalation, and interest charges are applied proportionally to all accounts, the contribution percentages of each major cost account can be calculated directly from the INDCEPT output. Of particular interest are the cost accounts associated with flue gas desulfurization and particulate removal (accounts 60 and 50, respectively). To calculate the contribution percentages from the INDCEPT output, the major cost accounts are totalled and the contribution of each area is determined as shown in Table XII.

The purpose of calculating the capital cost contribution percentages is to determine the specific components of the large capital cost contribution to the levelized steam cost. The contribution of each major cost account could be calculated, however, of main concern are the individual cost of the FGD and particulate removal equipment. Accounts 20, 30, 40, 70, and 90 are considered as one area representing the boiler plant contribution. Accounts 50 and 60 are considered as separate areas. The capital cost contribution to the steam cost (calculated using the Steam Cost Code) for the example is \$9.30 out of a total steam cost of \$15.86 (commercial operation date). The capital cost contribution percentages, calculated from the INDCEPT cost estimate, can be applied to determine the levelized capital cost of the boiler-related, FGD-related, and particulate-related equipment costs in terms of \$/MMBtu. Using this approach, the steam cost can be represented in the manner shown in Table XIII.

TABLE XII

Capital Cost Representation for Model 35^a

MAJOR COST ACCOUNT	No.	COST (\$1,000)
Land and Site	20	344
Boiler	30	13,904
Boiler Support	40	4,995
Particulate	50	1,301
FGD	60	1,721
Facilities	70	819
Indirect	90	11,464
SUBTOTAL		34,548 -- DIRECT AND INDIRECT
Contingency (20 percent)		6,909
Escalation		9,661
Interest on:		
Direct and Indirect		7,487
Escalation		1,490
SUBTOTAL		25,547
TOTAL INVESTMENT -- 60,095		
BOILER PLANT RELATED (20, 30, 40, 70, 90)		91.25%
PARTICULATE RELATED (50)		3.75%
FGD RELATED (60)		5.00%

^a Pulverized-coal boiler firing western low-sulfur coal. The emission control equipment consists of an ESP for particulate collection and a lime/limestone scrubber designed to remove 70 percent of the sulfur in the flue gas. (Capital cost estimate from INDCEPT is shown in Figure 5.2.)

TABLE XIII

Steam Cost Breakdown for Model 35^a

COST AREA	\$/MMBtu	\$/MMBtu	
CAPITAL COST		9.30	
Boiler Plant Related (91.25%).....	8.49		
FGD Related (3.75%).....	.35		
Particulate Related (5%).....	.46		
OPERATING COSTS		5.85	
Boiler Plant Related.....	1.93		
FGD Related.....	.76		
Particulate Related.....	.11		
Fuel.....	3.05		
MISCELLANEOUS (Working Capital and Insurance)		.71	
TOTAL		15.86	Percent
COMBINED CAPITAL AND OPERATING			
Boiler Plant Related.....	10.42	65.7%	
FGD Related.....	1.10	6.9%	
Particulate Related.....	.57	3.6%	
Fuel.....	3.05	19.3%	
Miscellaneous.....	.71	4.5%	
TOTAL	15.86	100.0%	

^a Pulverized-coal boiler firing western low-sulfur coal. The emission control equipment consists of an ESP for particulate collection and a lime/limestone scrubber designed to remove 70 percent of the sulfur in the flue gas. Cost data obtained from Figure 6.2

6.5 Example Analysis Procedure Comparing Pulverized Coal and AFBC

Due to the large number of variables considered by INDCEPT and the Steam Cost Code, a number of parameters can be investigated using the codes. To demonstrate the investigative capabilities of the codes, an analysis is presented comparing pulverized coal boilers and atmospheric fluidized-bed combustion. Pulverized coal boilers were selected because they are currently the preferred method of firing coal (18) because of the high combustion efficiency and larger capacity potential over stoker-fired boilers. Pulverized coal will probably continue to be a competitive boiler option because of its proven reliability and wide range acceptance. Atmospheric fluidized-bed combustion is an emerging technology that could possibly become the standard method for firing coal in the future. AFBC has the advantage of emitting very low levels of SO_2 and NO_x in the uncontrolled state, eliminating the need for a separate FGD system. This is obtained at the expense of emitting a relatively large amount of particulate emissions, however, this problem can be controlled using existing particulate collection equipment.

A number of parameters can be investigated comparing pulverized coal and AFBC. The purpose of this analysis is to determine general cost trends and relationships between the two boiler options. Specifically, the results should indicate:

- o Effects of using different emission control equipment on the cost of steam.

- o Steam cost trends over different boiler sizes ranging from 50 to 400 MMBtu/hr.
- o Effects of using a western low-sulfur coal and an eastern high-sulfur coal.
- o Lowest cost alternatives over a range of rates for return on investment.

6.5.1 Analysis Parameters

INDCEPT contains two data sets for AFBC, representing the two different coal types (eastern and western). Reference sulfur removal levels are not included for the two AFBC models because of the different parameters that are used to control sulfur emission rates. Sulfur emissions are principally controlled by operating parameters (primarily by the bed material recycle) which do not significantly affect the capital cost of the boiler system. Particulate emissions are controlled by primary and secondary cyclones to remove larger particles before entering a baghouse.

A total of 24 models are available for pulverized coal with 14 firing eastern coal and 10 firing western coal. All combinations of the four FGD systems are considered with pulverized coal except dual alkali for the systems firing western coal. Options available for particulate collection include electrostatic precipitators and baghouses.

The parameters considered for the analysis include variations for size, capacity factors, coal type, and rates for return on investment. The location site selected for the analysis was Chicago due to the availability of both types of coals at this location. Four different rates of return on investment are considered: 12, 15, 18, and 23 percent. Most of the costs are calculated using 15 percent. This value may be considered low for evaluation of possible investment considerations. However, most investments in industrial boiler systems are to satisfy a specific steam requirement and are not usually investments that generate revenue, but instead, fulfill a required demand for steam by an industry. If the steam system is constructed for the purpose of supplying steam for both process use and the generation of electricity, an analyses using a higher rate of return would be appropriate. For the purpose of comparison and selection of the lowest cost option, the rate of return on investment simply determines the time value of money to permit economic comparisons of different systems on the same basis.

The rate of return on investment (ROI) primarily converts the capital and operating costs to the same economic basis. By applying standard compound interest formulas, both types of costs (capital and operating) can be expressed as an equivalent (uniform) annual cost. Since both costs are expressed on the same basis, they can be combined to represent the total equivalent annual cost of the investment. Assuming a constant utilization or production rate, the unit production costs can be calculated that represents a uniform unit cost over the operating period which is known as the

levelized unit cost. In reality, the production costs are going to be different for each year depending upon the financing of the capital investment and changes in operating and maintenance costs, resulting in fluctuating unit production costs. For cost estimates prepared for the purpose of comparison and evaluation, the levelized cost is an adequate representation of the production costs.

Changing the rate of return on investment affects the levelized capital cost and the levelized operating costs in an opposite manner. To convert the capital cost to an equivalent annual cost, the cost is multiplied by a capital cost recovery factor determined using compound interest formulas. The parameters used in calculating the interest factor are the length of the operating period and the rate for return on investment (ROI). Increasing the ROI for a constant operating period will increase the capital recovery factor thereby increasing the levelized capital cost.

The levelized operating costs are affected inversely by the rate for return on investment. Unlike the capital cost, the operating costs occur throughout the entire operating period, generally increasing every year. If the operating costs remain constant over the operating period, they could be combined directly with the levelized capital cost to obtain the total levelized cost of the investment. However, most operating costs increase during the operating period and this increase should be taken into consideration when calculating the levelized operating cost. If the cost is increasing at a constant rate each year, it can be converted to

an equivalent annual cost using the geometric series growth factors (see economic analysis procedure, Section 6.1). The parameters required for the geometric series factors are the operating period, ROI, cost during the first year, and the escalation rate for the cost. For the geometric series factors, increasing the rate for return on investment (holding the other parameters constant), will decrease the value of the factor thereby decreasing the value of the levelized operating cost. This occurs because increasing the rate for ROI changes the time value of money over the operating period. The procedure used to convert a geometric series to a levelized cost involves determining the present worth of the operating costs that occur each year during the operating period. The total net present value of the operating cost can then be converted to an equivalent annual cost using the capital recovery factor. The rate for return is used to determine the net present value as well as the capital recovery factor. Increasing the rate of return on investment will decrease the net present value of the operating cost and will increase the capital recovery factor. The result is a lower levelized (or equivalent annual) operating cost. Figure 6.5 indicates the effect the rate for return on investment has on the levelized operating cost for different cost escalation rates. As shown in the figure, the multiplication factors for the geometric series decrease as the rate for return on investment increases.

Increasing the ROI will increase the levelized capital cost and decrease the levelized operating cost. For most steam systems, the capital cost is the major cost component of the levelized steam

FIGURE 6.5

EFFECT OF ROI ON LEVELIZED OPERATING COSTS*

*FACTORS BASED ON 20 YEAR OPERATING PERIOD

cost, resulting in a net increase in the levelized steam cost when higher rates for return on investment are used. This cost trend should be taken into consideration when determining the effects of using different rates for return on investment.

6.5.2 Steam Systems Used in the Analysis

A total of nine different boiler systems were selected from the INDCEPT reference model data sets to be used in the analysis. Seven of the models are pulverized coal boilers with four using eastern coal and three firing western coal. Both of the models available for AFBC (representing eastern and western coal) are used in the analysis. The following is a summary of the boiler systems selected for use in the analysis.

Model No.	Boiler	Fuel	FGD/Efficiency	Particulate
Model 1	PC	East	SS/94%	ESP
Model 5	PC	East	DA/94%	ESP
Model 10	PC	East	Lime/94%	BAG
Model 13	PC	East	Dry/94%	BAG
Model 31	PC	West	SS/70%	ESP
Model 36	PC	West	Lime/70%	BAG
Model 38	PC	West	Dry/70%	BAG
Model 49	AFBC	East	--	--
Model 50	AFBC	West	--	--

To indicate the effect of size on the steam cost, three sizes were selected: 50, 200, and 400 MMBtu/h. Different construction periods were used for the three boiler sizes with all systems starting

commercial operation in 1984. The construction dates used as part of the input data for INDCEPT to calculate the capital costs of the different systems were:

Boiler Size	Construction Dates		
	Major Equip.	Purch./Const. Starts/Commercial Oper.	
50	1983	1983.5	1984
200	1982	1983	1984
400	1981	1982	1984

Interest during construction was calculated at 12 percent per year. All the costs presented in the analysis are based on the commercial operation date (1984). Systems firing western coal have costs based on a 70 percent sulfur removal rate. Costs for systems firing eastern coal are based on a 94 percent removal of sulfur. The particulate emission level was .1 lbs/MMBtu for all systems.

6.5.3 Results of the Analysis

The INDCEPT Code was executed using the parameters described earlier to obtain the capital cost estimates to be used as input to the Steam Cost Code to calculate the steam cost values used in the analysis. The different systems using eastern and western coal are compared separately in Figures 6.6 and 6.7, respectively. For the boiler systems firing eastern coal (Figure 6.6), the AFBC (model 49) resulted in the lowest steam cost over a boiler size range from 50 to 400 MMBtu/h. The difference between the AFBC

FIGURE 6.6

STEAM COST SENSITIVITY TO PLANT SIZE - EASTERN COAL

FIGURE 6.7

STEAM COST SENSITIVITY TO PLANT SIZE - WESTERN COAL

system and the lowest cost pulverized coal system (DA-ESP) was nearly \$1/MMBtu at a 400 MMBtu/h size when compared on an equal basis using a 15 percent rate of return. The AFBC system also had a lower capital cost (\$63,870,000 compared to \$70,059,000 for the 400 MMBtu/h size), over the pulverized coal DA-ESP system using the INDCEPT Code based on an equal 20 percent contingency allowance. The three lowest cost pulverized coal options from the systems selected (DA-ESP, Lime-BAG, and Dry-BAG) were relatively close together with the largest difference in steam cost being less than 1.5 percent. The sodium scrubbing option was the highest cost alternative at all boiler sizes for eastern coal.

Figure 6.7 indicates the steam costs for systems firing western coal. Again, AFBC (model 50) has a substantially lower steam cost than the pulverized coal systems amounting to nearly \$2/MMBtu at a 70 percent capacity factor. The three pulverized coal systems firing western coal (SS-ESP, Dry-BAG, and Lime-BAG) were close in cost with sodium scrubbing having the lowest steam costs, however, all the pulverized coal systems are within 5 percent of each other. The sodium scrubbing FGD system was assumed to use an evaporation pond for aqueous waste disposal which probably would not be applicable to Region 5. Evaporation ponding would not be feasible in Region 5 due to climatic conditions which would increase the cost of this technology because of high aqueous waste disposal costs. Sodium scrubbing is a competitive option in regions that exhibit high evaporation rates (Regions 8 and 9).

Figure 6.8 displays the steam cost sensitivity to the capacity factor for the two AFBC systems and the lowest cost pulverized coal systems using eastern and western coal for a plant size of 200 MMBtu/h. AFBC firing eastern coal yields the lowest steam cost with the pulverized coal dual alkali system being the second choice for capacity factors greater than 40 percent. AFBC firing western coal is close in cost to the pulverized coal system having a slightly lower cost at 30 percent capacity but being replaced by the pulverized coal system at higher capacity factors. The general trend indicates that eastern coal is more economical than western coal for comparative boiler systems using the emission levels indicated earlier. Note the significant effect of the capacity factor on the steam costs indicated in Figure 6.8.

Figures 6.9 and 6.10 indicate the effect the rate of return on investment has on the steam costs and how it affects the selection of the lowest cost alternative. Figure 6.9 demonstrates the steam cost sensitivity to the rate of return on investment. Steam costs are compared using a 12, 15, 18, and 23 percent rate of return on investment for a 400 MMBtu/h size and a 70 percent capacity factor. For the most part, the steam costs for the different systems increase at the same rate. The only ranking change occurs at 23 percent where AFBC western coal replaces pulverized coal dual alkali as the lower cost alternative. In Figure 6.9, the different systems are all being compared using the same rate of return, i.e., at 23 percent all of the steam costs are calculated using 23 percent.

STEAM COST SENSITIVITY TO CAPACITY FACTOR

REGION 5
CHICAGO
ROI = 15%
PLANT SIZE = 200

FIGURE 6.9

STEAM COST SENSITIVITY TO RATE FOR RETURN ON INVESTMENT

FIGURE 6.10

COMPETITIVENESS OF AFBC AS THE RATE FOR RETURN
ON INVESTMENT INCREASES

Figure 6.10 compares the different systems for increasing rates of return on investment. Steam costs for the two AFBC models are displayed using 18 and 23 percent ROI for comparison to the lowest cost pulverized coal systems using eastern and western coal calculated at 15 percent ROI. When 18 percent ROI is used for AFBC, pulverized coal dual alkali becomes the lowest cost option except at the 400 MMBtu/h size where AFBC-east has approximately the same steam cost. At 23 percent ROI, the steam costs increase in the range of \$1.80 to \$4.50 for the AFBC-east over the cost using 18 percent.

Appendix C provides the individual steam costs in tabular form used for the graphs comparing the different systems (Figures 6.6 through 6.10).

For most comparisons made in the analysis, atmospheric fluidized-bed combustion was viewed as a mature technology and compared on an equal economic basis with pulverized coal. Using this scenario, AFBC yields the lowest steam cost of the systems considered in the analysis. The lower steam costs result primarily because of the lower capital cost of an AFBC as compared to the cost of a pulverized coal boiler requiring separate flue gas desulfurization equipment. (The capital costs used in the analysis are presented in Appendix C.)

6.6 Appraisal of Overall Computer Package

There are several considerations the user of the INDCEPT and Steam Cost Code should be aware of concerning the capital cost estimates and steam cost calculations. One concern is the MMBtu/h size rating that is used in the cost estimates. The MMBtu/h rate represents the gross boiler output before any boiler or FGD steam requirements. This gross output, used for the capacity measurement (size) of the steam systems, is different than the thermal heat input rate and the net steam available for process use. Boiler capacities and emission levels are often based on the thermal heat input rate to the boiler, determined by the heating value of the fuel. Studies or cost estimates, based on the thermal heat input, should not be compared directly with costs based on the gross output rate. Differences will be primarily dependent upon the boiler efficiency and will be reflected in costs expressed in terms of \$/MMBtu. For example, assuming a conversion efficiency of 80 percent, a boiler with a heat input rate of 250 MMBtu/hr would produce 200 MMBtu/hr of gross steam output. A boiler with a gross heat output of 250 MMBtu/hr would have a fuel input rate of 312.5 MMBtu/hr. These boilers are not close enough in size to be compared directly (steam costs are sensitive to boiler size).

The user should also be aware of the operating cost categories for the AFBC (Models 49 and 50). Due to the nature of the technology, operating costs associated with sulfur removal and particulate collection are included in the boiler-related cost categories. Other concerns relating to the overall computer package are:

- o Operating costs are not sensitive to location (coal costs are location specific). Capital costs are location dependent.
- o Fuel-oil costs are not sensitive to location, however, the user can input a specific price.
- o Only 10 of the 22 cities available for INDCEPT cost estimates have reference coal prices available for the Steam Cost Code.

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APPENDIX A

INDCEPT OUTPUT FOR EXAMPLE PROBLEM

250 MODEL 6 NEW ORLEANS PROB 1 198200 198300 198500 12000 0 0 2 0 1 1 1

1.10 1.10 1.10 1.10 1.10 1.10 1.10

1.08 1.08 1.08 1.08 1.08 1.08 1.08

1.12 1.12 1.12 1.12 1.12 1.12 1.12 1982.00

-1.

IN.D.G.E.P.I...D.A.T.A...S.E.I.S...

P.L.A.N.I...I.Y.P.E...C.O.D.E.S

C.I.T.Y...N.A.M.E...C.O.D.E.S

1	MODEL 1	9-18-81	1	ATLANTA	GEORGIA
2	MODEL 10	9-18-81	2	BALTIMORE	MARYLAND
3	MODEL 11	9-18-81	3	BIRMINGHAM	ALABAMA
4	MODEL 12	9-18-81	4	BOSTON	MASSACHUSETTS
5	MODEL 13	8-10-81	5	CHICAGO	ILLINOIS
6	MODEL 14	8-10-81	6	CINCINNATI	OHIO
7	MODEL 15	8-10-81	7	CLEVELAND	OHIO
8	MODEL 16	8-10-81	8	DALLAS	TEXAS
9	MODEL 17	8-21-81	9	DENVER	COLORADO
10	MODEL 18	8-21-81	10	DETROIT	MICHIGAN
11	MODEL 19	8-25-81	11	KANSAS CITY	KANSAS
12	MODEL 2	9-18-81	12	LOS ANGELES	CALIFORNIA
13	MODEL 20	8-25-81	13	MINNEAPOLIS	MINNESOTA
14	MODEL 21	8-25-81	14	NEW ORLEANS	LOUISIANA
15	MODEL 22	8-26-81	15	NEW YORK	NEW YORK
16	MODEL 23	8-26-81	16	PHILADELPHIA	PENNSYLVANIA
17	MODEL 24	8-26-81	17	PITTSBURGH	PENNSYLVANIA
18	MODEL 25	8-26-81	18	ST. LOUIS	MISSOURI
19	MODEL 26	8-27-81	19	SAN FRANCISCO	CALIFORNIA
20	MODEL 27	8-27-81	20	SEATTLE	WASHINGTON
21	MODEL 28	8-27-81	21	MONTREAL	CANADA
22	MODEL 29	8-27-81	22	TORONTO	CANADA
23	MODEL 3	9-18-81	23	MIDDLETOWN	USA
24	MODEL 30	8-28-81			
25	MODEL 31	8-28-81			
26	MODEL 32	8-28-81			
27	MODEL 33	8-28-81			
28	MODEL 34	8-28-81			
29	MODEL 35	8-28-81			
30	MODEL 36	8-28-81			
31	MODEL 37	8-31-81			
32	MODEL 38	8-31-81			
33	MODEL 39	8-31-81			
34	MODEL 4	9-18-81			
35	MODEL 40	8-31-81			
36	MODEL 41	8-31-81			
37	MODEL 42	8-31-81			
38	MODEL 43	8-31-81			
39	MODEL 44	8-31-81			
40	MODEL 45	9-01-81			
41	MODEL 46	9-01-81			
42	MODEL 47	9-01-81			
43	MODEL 48	9-01-81			
44	MODEL 49	9-01-81			
45	MODEL 5	9-18-81			
46	MODEL 50	9-01-81			
47	MODEL 51	9-01-81			
48	MODEL 52	9-01-81			
49	MODEL 53	9-18-81			
50	MODEL 54	9-18-81			
51	MODEL 55	9-18-81			
52	MODEL 56	9-18-81			
53	MODEL 57	9-18-81			
54	MODEL 58	9-18-81			
55	MODEL 59	9-03-81			

INQ-GEPI-DATA-SEIS----

PLANT-TYPE-CODES

CITY-NAME-CODES

56	MODEL 6	9-18-81
57	MODEL 60	9-03-81
58	MODEL 61	9-02-81
59	MODEL 62	9-18-81
60	MODEL 63	9-02-81
61	MODEL 64	9-02-81
62	MODEL 65	9-03-81
63	MODEL 66	9-04-81
64	MODEL 7	9-18-81
65	MODEL 8	9-18-81
66	MODEL 9	9-18-81

IF THE PLANT TYPE OR CITY SELECTED WAS NOT USED
IN COMPUTATIONS, CHECK SPELLING AND FIELD JUSTIFICATION
WITH THE AVAILABLE PLANT TYPE AND CITY NAME CODES.

D-A-I-A--C-A-B-D--C-D-L-U-M-N-S--U-S-E-D

145

DATE 1-13-83 I N D E C E P T C O S T E S T I M A T E S
 1 UNIT CAPITAL INVESTMENT SUMMARY (THOUSANDS OF DOLLARS)
 1X 250 MTU/HR MODEL 6 () PLANT AT NEW ORLEANS PROB 1

COST BASIS: YEAR OF MAJOR EQP. PURCHASE

DESIGN & CONSTRUCTION PERIOD:	MAJOR EQP. PURCHASE:	1982.00
	START OF CONSTRUCTION:	1983.00
	COMMERCIAL OPERATION:	1985.00

CONIV CALLED - DATA FIT DONE ON LOUISIANA NEW ORLEANS

INPUT CARDS TO PRODUCE TIME DEPENDENT ESCALATION RATES-----

1.10	1.10	1.10	1.10	1.10	1.10	1.10
1.08	1.08	1.08	1.08	1.08	1.08	1.08
1.12	1.12	1.12	1.12	1.12	1.12	1.12

1982.00
-1.

SITE RATE AND ESCALATION USED IN COST PROJECTIONS

YFIRST = 1967.00 YLAST = 1981.50

ACCT	20	ACCT	30	ACCT	40	ACCT	50	ACCT	60	ACCT	70	ACCT	90
A	B	A	B	A	B	A	B	A	B	A	B	A	B
***** 1982.030 *****													
E	310.	1.100	310.	1.100	310.	1.100	310.	1.100	310.	1.100	310.	1.100	310.
L	14.9	1.080	14.9	1.080	14.9	1.080	14.9	1.080	14.9	1.080	14.9	1.080	14.9
M	27.9	1.120	27.9	1.120	27.9	1.120	27.9	1.120	27.9	1.120	27.9	1.120	27.9

DATE 1-13-83 I N D C E P T C O S T E S T I M A T E S
 1 UNIT CAPITAL INVESTMENT SUMMARY (THOUSANDS OF DOLLARS)
 1X 250 MBTU/HR MODEL 6 (9-18-81) PLANT AT NEW ORLEANS PROB 1
 PULVERIZED COAL, EASTERN, DUAL ALKALI FGD, 94% EFF, BAGHOUSE PARTICULATE REMOVAL
 COST BASIS: YEAR OF MAJOR EQP. PURCHASE

DESIGN & CONSTRUCTION PERIOD: MAJOR EQP. PURCHASE: 1982.00
 START OF CONSTRUCTION: 1983.00
 COMMERCIAL OPERATION: 1985.00

ACCOUNT NUMBER	A C C O U N T T I T L E	TOTAL COSTS	EQUIPMENT COSTS	LABOR MANHOURS	LABOR COSTS	MATERIAL COSTS
20	LAND AND SITE WORK	324	0. (	12.)	189.	135.
30	BOILER PLANT	11186	6662. (	159.)	2311.	2212.
40	BOILER SUPPORT FACILITIES	4537	2489. (	77.)	1129.	919.
50	PARTICULATE REMOVAL SYSTEM	2021	1105. (	29.)	430.	485.
60	FLUE GAS DESULFURIZATION	2433	992. (	43.)	639.	801.
70	SUPPORT FACILITIES	810	308. (	19.)	277.	226.
	SUBTOTAL	21311	11556. (	339.)	4976.	4779.
90	INDIRECT COSTS	10380				
	SUBTOTAL	10380				
	DIRECT & INDIRECT COSTS	31691				
	CONTINGENCY ALLOWANCE	6338				
		=====				
	TOTAL DIRECT & INDIRECT COSTS	38029				
	ESCALATION DURING CONSTRUCTION (9.5%/YR)	7718	WEIGHTED AVERAGE ESCALATION (\$/YR) EQUIPMENT 10.0	LABOR 8.0	MATERIAL 12.0	
	TOTAL ESCALATED DIRECT & INDIRECT COSTS	45747				
		=====				
	INTEREST DURING CONSTRUCTION COMPOUND (12.000%/YR)					
	ON DIRECT & INDIRECT COSTS	4516				
	ON ESCALATION DURING CONSTRUCTION	800				
	TOTAL INTEREST DURING CONSTRUCTION	5316				
		=====				
	TOTAL PLANT CAPITAL INVESTMENT	51063				

MAJOR EQP. PURCHASE:	1982.00
START OF CONSTRUCTION:	1983.00
COMMERCIAL OPERATION:	1985.00

ACCOUNT		FACTORY	SITE	SITE	
NUMBER	TITLE	EQUIPMENT	LABOR	MATERIALS	TOTAL
20	LAND AND SITE WORK				
210	SITE WORK	\$ 0.	\$ 189.	\$ 135.	324.
220	LAND	\$ 0.	\$ 0.	\$ 0.	0.
SUBTOTAL FOR ACCOUNT		\$ 0.	\$ 189.	\$ 135.	\$ 324.
CONTINGENCY (20.0%EQP-20.0%LABOR-20.0%MTL)		0.	38.	27.	65.
TOTAL FOR ACCOUNT 20		\$ 0.	\$ 227.	\$ 162.	\$ 389.

MAJOR EQP. PURCHASE:	1982.00
START OF CONSTRUCTION:	1983.00
COMMERCIAL OPERATION:	1985.00

ACCOUNT NUMBER	ACCOUNT TITLE	FACTORY EQUIPMENT	SITE LABOR	SITE MATERIALS	TOTAL
30	BOILER PLANT				
310	BOILER HOUSE	\$ 0.	\$ 472.	\$ 436.	909.
320	BOILER	\$ 4499.	\$ 1074.	\$ 1010.	6582.
330	FANS	\$ 237.	\$ 97.	\$ 131.	465.
340	STACK	\$ 524.	\$ 27.	\$ 44.	594.
350	PULVERIZER	\$ 1136.	\$ 555.	\$ 398.	2089.
360	BOILER FEEDWATER SYSTEM	\$ 267.	\$ 87.	\$ 194.	548.
	SUBTOTAL FOR ACCOUNT.	\$ 6662.	\$ 2311.	\$ 2212.	\$ 11186.
	CONTINGENCY (20.0% EQP-20.0% LABOR-20.0% MTL).	1332.	462.	442.	2237.
	TOTAL FOR ACCOUNT 30	\$ 7995.	\$ 2774.	\$ 2655.	\$ 13423.

MAJOR EQP. PURCHASE:	1982.00
START OF CONSTRUCTION:	1983.00
COMMERCIAL OPERATION:	1985.00

ACCOUNT NUMBER	ACCOUNT TITLE	FACTORY EQUIPMENT	SITE LABOR	SITE MATERIALS	TOTAL
40	BOILER SUPPORT FACILITIES				
410	COAL HANDLING SYSTEM	\$ 1838.	\$ 770.	\$ 472.	3080.
420	ASH HANDLING SYSTEM	\$ 469.	\$ 215.	\$ 327.	1010.
430	LIMESTONE HANDLING SYSTEM	\$ 0.	\$ 0.	\$ 0.	0.
440	OIL STORAGE TANK	\$ 0.	\$ 0.	\$ 0.	0.
450	WASTE WATER TREATING	\$ 182.	\$ 145.	\$ 120.	447.
	SUBTOTAL FOR ACCOUNT	\$ 2489.	\$ 1129.	\$ 919.	\$ 4537.
	CONTINGENCY (20.0%EQP-20.0%LABOR-20.0%MTL)	498.	226.	184.	908.
	TOTAL FOR ACCOUNT 40	\$ 2987.	\$ 1355.	\$ 1103.	\$ 5445.

MAJOR EQP. PURCHASE:	1982.00
START OF CONSTRUCTION:	1983.00
COMMERCIAL OPERATION:	1985.00

ACCOUNT NUMBER	ACCOUNT TITLE	FACTORY EQUIPMENT	SITE LABOR	SITE MATERIALS	TOTAL
50	PARTICULATE REMOVAL SYSTEM				
510	ELECTROSTATIC PRECIPITATOR	\$ 0.	\$ 0.	\$ 0.	0.
520	BAGHOUSE	\$ 1105.	\$ 430.	\$ 485.	2021.
SUBTOTAL FOR ACCOUNT		\$ 1105.	\$ 430.	\$ 485.	\$ 2021.
CONTINGENCY (20.0%EQP-20.0%LABOR-20.0%MTL)		221.	86.	97.	404.
TOTAL FOR ACCOUNT 50		\$ 1326.	\$ 517.	\$ 582.	\$ 2425.

DATE 1-13-83 PROJECT COST ESTIMATES
 1 UNIT CAPITAL INVESTMENT DETAIL COSTS (THOUSANDS OF DOLLARS)
 1X 250 MTU/HR MODEL 6 (9-10-81) PLANT AT: NEW ORLEANS PROB 1
 PULVERIZED COAL, EASTERN, DUAL ALKA-1 FGD, 94% EFF, BAGHOUSE PARTICULATE REMOVAL
 COST BASIS: YEAR OF MAJOR EQP. PURCHASE

MAJOR EQP. PURCHASE: 1982.00
 START OF CONSTRUCTION: 1983.00
 COMMERCIAL OPERATION: 1985.00

ACCOUNT NUMBER	ACCOUNT TITLE	FACTORY EQUIPMENT	SITE LABOR	SITE MATERIALS	TOTAL
60	FLUE GAS DESULFURIZATION				
610	ABSORBERS	\$ 733.	\$ 462.	\$ 594.	1789.
620	LIQUID HANDLING SYSTEM	\$ 154.	\$ 102.	\$ 131.	387.
630	SORBENT HANDLING SYSTEM	\$ 105.	\$ 75.	\$ 76.	256.
640	WASTE HANDLING	\$ 0.	\$ 0.	\$ 0.	0.
650	MISCELLANEOUS	\$ 0.	\$ 0.	\$ 0.	0.
SUBTOTAL FOR ACCOUNT		\$ 992.	\$ 639.	\$ 80.	\$ 2433.
CONTINGENCY (20.0% EQP-20.0% LABOR-20.0% MTL)		198.	128.	160.	487.
TOTAL FOR ACCOUNT 60		1191.	767.	262.	2919.

DATE 1-13-83 I N D C E P T C O S T E S T I M A T E S

1 UNIT CAPITAL INVESTMENT DETAIL COSTS (THOUSANDS OF DOLLARS)

1X 250 MBTU/HR MODEL 6 (9-18-81) PLANT AT: NEW ORLEANS PROB 1

PJLVERIZED COAL,EASTERN,DUAL ALKALI FGD,94% EFF,BAGHOUSE PARTICULATE REMOVAL

COST BASIS: YEAR OF MAJOR EQP. PURCHASE

MAJOR EQP. PURCHASE: 1982.00

START OF CONSTRUCTION: 1983.00

COMMERCIAL OPERATION: 1985.00

ACCOUNT NUMBER	ACCOUNT TITLE	FACTORY EQUIPMENT	SITE LABOR	SITE MATERIALS	TOTAL
70	SUPPORT FACILITIES				
710	FIRE PROTECTION SYSTEM	\$ 32.	\$ 41.	\$ 35.	108.
720	MOBILE SOLIDS HANDLING EQUIPMENT	\$ 221.	\$ 0.	\$ 0.	221.
730	FACILITIES BUILDING	\$ 0.	\$ 86.	\$ 82.	168.
740	ELECTRICAL	\$ 55.	\$ 107.	\$ 55.	217.
750	INTERCONNECTING PIPING	\$ 0.	\$ 43.	\$ 55.	97.
SUBTOTAL FOR ACCOUNT		\$ 308.	\$ 277.	\$ 226.	\$ 810.
CONTINGENCY (20.0%EQP-20.0%LABOR-20.0%MTL)		62.	55.	45.	162.
TOTAL FOR ACCOUNT 70		\$ 369.	\$ 332.	\$ 271.	\$ 972.

DATE 1-13-83 I N D C E P T C O S T E S T I M A T E S
 1 UNIT CAPITAL INVESTMENT DETAIL COSTS (THOUSANDS OF DOLLARS)
 1X 250 MTU/HR MODEL 6 (9-18-81) PLANT AT: NEW ORLEANS PROB 1
 PJLVERIZED COAL,EASTERN,DUAL ALKALI FGD,94% EFF,BAGHOUSE PARTICULATE REMOVAL
 COST BASIS: YEAR OF MAJOR EQP. PURCHASE

MAJOR EQP. PURCHASE: 1982.00
 STATE OF CONSTRUCTION: 1983.00
 COMMERCIAL OPERATION: 1985.00

ACCOUNT NUMBER	ACCOUNT TITLE	FACTORY EQUIPMENT	SITE LABOR	SITE MATERIALS	TOTAL
90	INDIRECT COSTS				
910	FIELD INDIRECT COSTS	\$ 0.	\$ 6469.	\$ 0.	6469.
920	HOME OFFICE COSTS	\$ 1546.	\$ 1554.	\$ 639.	3739.
930	START-UP SUPERVISION	\$ 0.	\$ 172.	\$ 0.	172.
	SUBTOTAL FOR ACCOUNT	\$ 1546.	\$ 8195.	\$ 639.	\$ 10380.
	CONTINGENCY (20.0%EQP-20.0%LABOR-20.0%MTL)	309.	1639.	128.	2076.
	TOTAL FOR ACCOUNT 90	\$ 1855.	\$ 9835.	\$ 767.	\$ 12457.

DATE 1-13-83 I N D C E P T C O S T E S T I M A T E S

1 UNIT CAPITAL INVESTMENT DETAIL COSTS (THOUSANDS OF DOLLARS)

1X 250 MBTU/HR MODEL 6 (9-18-81) PLANT AT: NEW ORLEANS PROB 1

PULVERIZED COAL, EASTERN, DUAL ALKALI FGD, 94% EFF, BAGHOUSE PARTICULATE REMOVAL

COST BASIS: YEAR OF MAJOR EQP. PURCHASE

MAJOR EQP. PURCHASE: 1982.00

START OF CONSTRUCTION: 1983.00

COMMERCIAL OPERATION: 1985.00

	1982.0	1983.0	1984.0	1985.0	1986.0	
1						
2						
3						
4	55000 +					+ 55000
5	C	-				C
6	A	-				A
7	P					P
8	I	50000 +				I
9	T	-				T
10	A	-				A
11	L	-				L
12	45000 +					+ 45000
13	C	-				C
14	O	-				O
15	S	-				S
16	T	40000 +				+ 40000
17	C	-				C
18	T	-				T
19	H	35000 +				+ 35000
20	Q	-				Q
21	J	-				J
22	S	-				S
23	A	30000 +				+ 30000
24	N	-				N
25	D	-				D
26	S	-				S
27	I	25000 +				+ 25000
28	S	-				S
29	O	-				O
30	F	-				F
31	D	20000 +				+ 20000
32	J	-				J
33	L	-				L
34	L	-				L
35	A	15000 +				+ 15000
36	R	-				R
37	S	-				S
38	)	-				)
39	10000 +					+ 10000
40	-					-
41	-					-
42	-					-
43	5000 +					+ 5000
44	-					-
45	-					-
46	-					-
47	0					0
48						
49						
50						
51	1982.0	1983.0	1984.0	1985.0	1986.0	
52						
53						
54						
55						
56						
57						

DATE 1-13-83 I N D C E P T C O S T E S T I M A T E S
 1 UNIT CAPITAL INVESTMENT DETAIL COSTS (THOUSANDS OF DOLLARS)
 1X 250 MBTU/HR MODEL 6 (9-18-81) PLANT AT: NEW ORLEANS PROB 1
 PULVERIZED COAL, EASTERN, DUAL ALKALI FGD, 94% EFF, BAGHOUSE PARTICULATE REMOVAL
 COST BASIS: YEAR OF MAJOR EQP. PURCHASE

MAJOR EQP. PURCHASE: 1982.00
 START OF CONSTRUCTION: 1983.00
 COMMERCIAL OPERATION: 1985.00

C U M U L A T I V E C A S H F L O W

BOTH THE CASH FLOW CURVE SHOWN ABOVE AND THE FOLLOWING CASH FLOW TABLE
 HAVE COSTS EXPRESSED AS TOTAL COST INCURRED TO DATE (INCLUDING INTEREST CHARGES TO DATE).

DATE	COST TO DATE (THOUSANDS OF DOLLARS)
1982.00	0.
1982.06	0.
1982.12	394.
1982.18	396.
1982.24	399.
1982.30	402.
1982.36	599.
1982.42	603.
1982.48	508.
1982.54	612.
1982.60	656.
1982.66	660.
1982.72	665.
1982.78	669.
1982.84	714.
1982.90	719.
1982.96	724.
1983.02	771.
1983.08	984.
1983.14	1158.
1983.20	1292.
1983.26	1723.
1983.32	2160.
1983.38	3328.
1983.44	3823.
1983.50	4368.
1983.56	5918.
1983.62	6744.
1983.68	7976.
1983.74	10017.
1983.80	11195.
1983.86	12611.
1983.92	15838.
1983.98	18233.
1984.04	21957.
1984.10	23931.
1984.16	25930.
1984.22	29796.
1984.28	31855.
1984.34	33937.
1984.40	37451.
1984.46	39121.
1984.52	41284.
1984.58	43710.
1984.64	44967.
1984.70	46719.
1984.76	47523.
1984.82	48431.
1984.88	49497.

APPENDIX B

DESCRIPTION OF THE STEAM COST CODE AND REQUIRED VAX FILES

B.1 Data File Description and Organization

B.2 FORTRAN Source Code Organization

B.3 FORTRAN Listing of the Steam Cost Code

B.4 VAX Files Required to Operate INDCEPT
and the Steam Cost Code

APPENDIX B

B.1 Data File Description and Organization

The Steam Cost Code is organized around the 66 reference cost models used for INDCEPT. The operating and maintenance costs are organized in data files with respect to each reference model system. To allow for data modifications, the operating costs were grouped in related areas and stored in separate matrices. The majority of the operating costs are stored in five data files which are summarized below.

File Name	Dimension	Description
MODEL	(66,7)	The MODEL data file contains the basic information about each of the 66 reference model systems. The first column in the file contains the model number of the boiler system as given in the INDCEPT users manual. The second column contains the gross output of each boiler model. Column 3 indicates the boiler type using a number code to represent the different boilers available. Columns 4 and 5 use numbers to represent the fuel and FGD type in a similar fashion. The FGD efficiencies are listed in Column 6 and the method of particulate removal is indicated in Column 7. The purpose of this

data file is to have complete reference information for each boiler system by simply knowing the INDCEPT model number.

RLABOR	(66,6)	RLABOR contains the boiler operating requirements and labor costs. The first column contains the boiler efficiency in percent. Columns 2 and 3 indicate the boiler and FGD steam requirements. The last 3 columns contain the boiler, FGD, and particulate labor costs in millions of dollars.
ELEC	(66,7)	ELEC contains the electricity costs and corresponding scaling exponents. The first 2 columns indicate the fixed and variable boiler electricity costs. Columns 3 and 4 contain the particulate and FGD electricity costs. Column 5 represents the FGD electricity cost scale factors at alternate SO ₂ removal levels. Column 6 shows the boiler fixed electricity scaling exponents for size adjustments and Column 7 indicates the exponential scaling factors for particulate electricity costs at alternate levels.
WASTE	(66,6)	The data file WASTE contains the annual waste disposal costs and maintenance material and subcontractor labor costs. The first 2 columns represent the boiler and FGD waste disposal costs.

Column 3 lists the exponential scale factors for the FGD costs at different removal rates. Columns 4-6 contain the boiler, FGD, and particulate maintenance material and subcontractor labor costs.

CHEM	(66,6)	CHEM contains the water and chemical costs associated with the systems. The first column contains the water and water treatment chemical costs. Column 2 indicates the sulfur emission scale factor. Columns 3-5 contain the limestone, lime, and soda ash costs for appropriate systems. The last column lists the sulfur revenues for the gasifiers.
------	--------	--

The Steam Cost Code uses an additional seven data files in order to operate. Data file SCALE (9,3) contains the scaling factors for labor costs for a multiple number of units. SCALE (16,3) lists the overall multiple unit factors. Data file ICITY lists the city names representing the 10 DOE regions used for coal cost information. Data file COAL (13,3) contains the reference coal costs for delivery by single car or unit train in terms of \$/MMBtu and the heating value of the coal. File IESC (6,2) contains the default escalation rates for the different cost groups that can be overridden at program execution time. Data files INAME (8,6) and JNAME (31,6) list the titles of the operating cost groupings and the detailed cost breakdowns. Adjustments to the reference costs can be made by editing the data files to adjust for known costs or to determine the sensitivity of a specific cost.

B.2 FORTRAN Source Code Organization

The FORTRAN source code is STEAM.FOR and is divided into the following sections:

Dimension and read in data files.

Input data by user.

Input verification.

Escalation rate changes and input.

Economic parameters changes and input.

Reference coal cost selection.

Labor cost calculations.

Electricity cost calculations.

Waste disposal costs.

Calculation of maintenance material and subcontractor labor.

Chemical and water costs.

Fuel Cost Calculation.

Calculation of net boiler output.

Levelized cost calculations.

Economic analysis procedure.

Cost contribution percentages.

Year-by-year escalating steam cost.

Output of results to the terminal.

Hardcopy output to file FOR050.DAT.

Subroutine to adjust costs to equipment date.

Subroutine to calculate annual cost from geometric series.

Subroutine to calculate multiple plant factors.

Each section is labled in the program to allow for the identification of the calculations performed in each section.

```

c      |_____|
      write(6,60)
60     format(10x,'PROGRAM TO CALCULATE STEAM COSTS USING CAPITALIZED'
1      ,/,10x,'COST ESTIMATE FROM INDCEPT.  BASE OPERATING COSTS WERE'
2      ,/,10x,'OBTAINED FROM ORNL.')
64     continue
      write(6,65)
65     format('  Enter cost model number of steam system from indcept ',
1$)
      read(5,70) m
70     format(i2)
      if(icount.gt.0) goto 147
74     continue
      write(6,75)
75     format('  Enter gross output of unit in MBTU/h ',,$)
      read(5,80) size
80     format(i4)
      if(icount.gt.0) goto 147
84     continue
      write(6,85)
85     format('  Enter capital investment cost from indcept based on'
1      ,/, 'major equip. purchase in $1000 ',,$)
      read(5,90) icapt1
90     format(i8)
      if(icount.gt.0) goto 147
88     continue
      write(6,91)
91     format('  Enter capital investment cost from indcept based on'
1      ,/, 'commercial operation date in $1000 ',,$)
      read(5,92) icap2
92     format(i8)
      if(icount.gt.0) goto 147
93     continue
      write(6,100)
100    format('  Enter FGD efficiency in % SO2 removal ',,$)
      read(5,105) fgdlev
105    format(i2)
      if(icount.gt.0) goto 147
109    continue
      write(6,110)
110    format('  Enter particulate emission level in lb/MBTU ',,$)
      read(5,115) parlev
115    format(f3.2)
      if(icount.gt.0) goto 147
118    continue
119    continue
      write(6,120)
120    format('  Enter the average capacity factor in % (10 through 99)
1      ',,$)
      read(5,125) icapfc
125    format(i2)
      if(icapfc.lt.1) goto 118
      if(icount.gt.0) goto 147
129    continue
      write(6,130)
130    format('  Enter the number of units (1 through 4) ',,$)
      read(5,135) nunits
135    format(i1)
      if(icount.gt.0) goto 147
136    continue
      write(6,137)

```

```

137   format(' Enter year of major equipment purchase(inc dec pnt) ', $
1)
    read(5,139) yreqip
139   format(f6.1)
    if(icount.gt.0) goto 147
138   continue
    write(6,140)
140   format(' Enter the year for start of commercial operation (inc d
1ec pnt) ', $)
    read(5,145) yrcom
145   format(f6.1)
    if(icount.gt.0) goto 147
142   continue
    write(6,148)
148   format(' Enter rate for return on investment ', $)
    read(5,149) iescl
149   format(i2)
147   continue
    capfac=(icapfc/100.0)
    roi=iescl/100.0

```

c
c
c
c

INPUT VERIFICATION

```

    write(6,700)
700   format('0',10x,'THE FOLLOWING IS THE INPUT DATA AS RECORDED')
    write(6,705)
705   format('0',6x,'NUMBER',9x,'VARIABLE DESCRIPTION')
    write(6,712) m
712   format(1x,8x,'1',6x,'Model number of steam unit',26('.'),12)
    write(6,710) size
710   format(1x,8x,'2',6x,'Size of the unit(MBTU/hr)',25('.'),14)
    write(6,715) fgdlev
715   format(1x,8x,'3',6x,'The FGD level in % SO2 removal',22('.'),12)
    write(6,720) parlev
720   format(1x,8x,'4',6x,'The particulate removal level (lb/MBTU)',11(
1'.'),f4.2)
    write(6,725) icapfc
725   format(1x,8x,'5',6x,'The average capacity factor (%)',21('.'),12)
    write(6,730) nunits
730   format(1x,8x,'6',6x,'The number of units',34('.'),11)
    write(6,735) yreqip
735   format(1x,8x,'7',6x,'The year of equipment purchase',18('.'),f6.1
1)
    write(6,740) yrcom
740   format(1x,8x,'8',6x,'The year of commercial operation',16('.'),f6
1.1)
    write(6,742) icapt1
742   format(1x,8x,'9',6x,'Capital cost based on equip purchase ($1000)
1..',18)
    write(6,747) icap2
747   format(1x,7x,'10',6x,'Capital cost based on commercial oper.....
1...',18)
    write(6,757) iescl
757   format(1x,7x,'11',6x,'Rate for return on investment',23('.'),12)
    write(6,745)
745   format(' Do you wish to change any of the values (Y/N) ', $)
    read(5,750) iresp
750   format(a1)
    if(iresp.eq.jj) goto 765
    if(iresp.eq.jjj) goto 765

```

```

0001      subroutine annual(s,n,esc,roi,ap,a)
      c
      c-----
      c      SUBROUTINE TO CALC ANNUAL COST FROM GEOMETRIC
      c-----
0002      ap=(roi*((1+roi)**n))/(((1.0+roi)**n)-1.0)
0003      if(esc.ne.roi) goto 10
0004      a=s*(n/(1+roi))*ap
0005      goto 20
0006      10  ps=(1-(((1+esc)/(1+roi))**n))/(roi-esc)
0007      a=s*ps*ap
0008      20  continue
0009      return
0010      end

```

```

0001      SUBROUTINE SWITCH(PORT,RN,ESORT)
      c
      c-----
      c      SUBROUTINE TO ADJUST TO EQUIPMENT DATE
      c-----
0002      if(rn.lt.0.0) then
0003          port=port/((1.0+escrt)**(-rn))
0004      else
0005          port=port*(1.0+escrt)**(rn)
0006      endif
0007      return
0008      end

```

```

0001      subroutine multipl(m,numb,sclmul)
      c
      c-----
      c      SUBROUTINE TO CALCULATE MULTIPLE PLANT FACTOR
      c-----
0002      dimension skale(16,3)
0003      if(m.le.14) then
0004          sclmul=skale(1,numb)
0005      else if(m.le.28) then
0006          sclmul=skale(3,numb)
0007      else if(m.le.38) then
0008          sclmul=skale(2,numb)
0009      else if(m.le.48) then
0010          sclmul=skale(4,numb)
0011      else if(m.eq.49) then
0012          sclmul=skale(5,numb)
0013      else if(m.eq.50) then
0014          sclmul=skale(6,numb)
0015      else if(m.le.56) then
0016          sclmul=skale(7,numb)
0017      else if(m.eq.57) then
0018          sclmul=skale(8,numb)
0019      else if(m.eq.58) then
0020          sclmul=skale(9,numb)
0021      else if((m.eq.59).or.(m.eq.63)) then
0022          sclmul=skale(10,numb)
0023      else if((m.eq.60).or.(m.eq.64)) then
0024          sclmul=skale(11,numb)
0025      else if((m.eq.61).or.(m.eq.65)) then
0026          sclmul=skale(12,numb)
0027      else if((m.eq.62).or.(m.eq.66)) then
0028          sclmul=skale(13,numb)
0029      endif
0030      return
0031      end

```

B.4 VAX Files Required to Operate INDCEPT and the Steam Cost Code

The files required to operate INDCEPT and the Steam Cost Code are currently stored at DRC1:[TDP.STEAM]. The space needed to store the required files is 2,331 blocks. To operate the codes, the user should have around 3,000 blocks to allow for input and output files. To minimize space requirements, the FORTRAN source code files and list files are not included as part of the required VAX files. If these files are desired, they can be copied from DRC1:[TDP]. Below is a list of the minimum required VAX files needed to operate the codes. Three documentation files are included but are not required to operate the codes. These files are included for reference purposes and only require 25 blocks.

INDCEPT		Steam Cost Code			
File Name	Size	File Name	Size	File Name	Size
CONLAM.LBR	228	MODEL.DAT	3	IESC.DAT	1
COSTMOD.LBR	1888	RLABOR.DAT	6	INAME.DAT	1
INDCEPT.EXE	84	ELEC.DAT	6	JNAME.DAT	2
INPUT.EXE	13	WASTE.DAT	5	STEAMIN.COM	1
INDCEPT.COM	1	CHEM.DAT	5	STEAMOVER.COM	1
IDAY.FOR	1	SCALE.DAT	1	STEAM.EXE	48
IDAY.LIS	5	SKALE.DAT	1	STEAM.DOC	6
IDAY.OBJ	2	ICITY.DAT	2	STEAMDAT1.DOC	17
INDCEPT.DOC	2	COAL.DAT	1		

APPENDIX C

COST DATA USED FOR THE PULVERIZED COAL AND AFRC COMPARISON

C.1 Steam Costs Used for Figure 6.6

C.2 Steam Costs Used for Figure 6.7

C.3 Steam Costs Used for Figure 6.8

C.4 Steam Costs Used for Figure 6.9

C.5 Steam Costs Used for Figure 6.10

APPENDIX C

C.1 Steam Costs Used for Figure 6.6

Eastern Coal

Model 1 -- Pulverized Coal, Sodium Scrubbing, ESP

SIZE	30%	50%	70%	90%	CAPITAL ^a
50	58.50	37.67	28.75	23.79	21,690
200	33.83	22.69	17.92	15.26	52,623
400	26.48	18.11	14.52	12.53	83,108

Model 5 -- Pulverized Coal, Dual Alkali, ESP

SIZE	30%	50%	70%	90%	CAPITAL ^a
50	54.21	34.94	26.67	22.08	18,376
200	30.65	20.63	16.33	13.94	44,412
400	23.79	16.35	13.16	11.39	70,059

Model 10 -- Pulverized Coal, Lime/Limestone, Baghouse

SIZE	30%	50%	70%	90%	CAPITAL ^a
50	55.00	35.43	27.05	22.39	18,708
200	31.10	20.91	16.55	14.13	45,134
400	24.12	16.56	13.33	11.53	71,129

Model 13 -- Pulverized Coal, Spray Drying, Baghouse

SIZE	30%	50%	70%	90%	CAPITAL ^a
50	55.21	35.50	27.05	22.36	19,477
200	31.45	21.07	16.62	14.15	47,059
400	24.45	16.71	13.39	11.55	74,211

^a Cost based on commercial operation date (1984) in \$1,000.

Model 49 -- AFBC

SIZE	30%	50%	70%	90%	CAPITAL ^a
50	52.70	33.95	25.91	21.45	19,071
200	28.72	19.39	15.40	13.18	42,318
400	21.76	15.07	12.20	10.60	63,870

C.2 Steam Costs Used for Figure 6.7

Western Coal

Model 31 -- Pulverized Coal, Sodium Scrubbing, ESP

SIZE	30%	50%	70%	90%	CAPITAL ^a
50	57.94	37.91	29.33	24.56	20,321
200	34.33	23.51	18.88	16.30	49,842
400	27.16	19.00	15.50	13.55	79,208

Model 36 -- Pulverized Coal, Lime/Limestone, Baghouse

SIZE	30%	50%	70%	90%	CAPITAL ^a
50	60.85	39.68	30.60	25.56	21,073
200	35.71	24.36	19.49	16.79	51,640
400	28.14	19.60	15.94	13.91	82,018

Model 38 -- Pulverized Coal, Spray Drying, Baghouse

SIZE	30%	50%	70%	90%	CAPITAL ^a
50	59.88	39.10	30.20	25.26	20,984
200	35.38	24.17	19.37	16.70	51,419
400	27.94	19.49	15.87	13.86	81,664

^a Cost based on commercial operation date (1984) in \$1,000.

Model 50 -- AFBC

SIZE	30%	50%	70%	90%	CPAITAL ^a
50	54.45	35.60	27.52	23.03	18,702
200	30.29	20.89	16.86	14.62	41,710
400	23.17	16.42	13.52	11.92	63,086

C.3 Steam Costs Used for Figure 6.8

(200 MMBtu/h, ROI = 15%)

CAPACITY FACTOR→	30%	50%	70%	90%
Model 49	28.72	19.39	15.40	13.18
Model 50	30.29	20.89	16.86	14.62
Model 31	34.33	23.51	18.88	16.30
Model 5	30.65	20.63	16.33	13.94

C.4 Steam Costs Used for Figure 6.9

(400 MMBtu/h, 70% Capacity Factor)

ROI→	12%	15%	18%	23%	CAPITAL ^a
Model 49	11.37	12.20	13.15	14.95	63,870
Model 50	12.78	13.52	14.40	16.11	63,086
Model 31	14.50	15.50	16.60	18.86	79,208
Model 5	12.24	13.16	14.21	16.20	70,059

^a Cost based on commercial operation data (1984) in \$1,000.

C.5 Steam Costs Used for Figure 6.10

SIZE→	50	200	400	ROI
Model 31	29.33	18.88	15.50	15
Model 5	26.67	16.33	13.16	15
Model 49	28.33	16.69	13.15	18
Model 49	32.82	19.12	14.95	23
Model 50	29.80	18.06	14.40	18
Model 50	34.10	20.37	16.11	23

GLOSSARY OF TERMS :

New Source Performance Standards (NSPS) -- Proposed revisions to Federal emission levels for stationary sources of pollution limiting the maximum quantity of emissions that will be permitted from a particular source.

INDCEPT -- A computer code package developed under DOE-METC sponsorship by Oak Ridge National Laboratory (ORNL) to provide conceptual capital investment cost estimates for single- and multiple-unit industrial steam boiler plants under various air emission criteria.

Steam Cost Code -- An interactive FORTRAN computer program and associated data files that calculates levelized steam costs using the capital cost estimate from INDCEPT.

Levelized Steam Cost -- Cost of steam ($\$/10^6$ Btu of gross steam output before any boiler for FGD steam requirements) needed to recover all costs considered (including return on investment) after the affects of taxes, expressed as a constant unit cost over a specified operating period.

Equivalent Annual Cost -- Cost is expressed as a constant cost per year over a specified period of time reflecting the effects of escalation and return on investment. The equivalent annual cost is used to calculate the levelized steam cost by dividing by the total annual steam production.

GLOSSARY OF TERMS

(Continued)

Emerging Technology -- An emerging technology is considered to be under development and usually not available for sale on the commercial market. However, the potential exists for penetration into the market in the near future.

Mature Technology -- Technology has been proven in commercial markets and is considered to be a low-risk option with established operational ability and predictable costs.

ACRS -- Accelerated Cost Recovery System. ACRS is the new method of depreciation created by the Economic Recovery Tax Act of 1981. ACRS applies to most assets placed in service after December 31, 1980.

AFBC -- Atmospheric Fluidized-Bed Combustion.

EPA --Environmental Protection Agency.

FGD -- Flue Gas Desulfurization.

FGR -- Flue Gas Recirculation.

ITC -- Investment Tax Credit. ITC is a first year tax advantage for qualifying capital expenditures.

SCC -- Steam Cost Code.

LEA -- Low Excess Air.

MMBtu -- 10^6 Btu.

PM -- Particulate material.