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USER'S MANUAL FOR THE INTEGRATED AIR POLLUTION CONTROL SYSTEM DESIGN AND COST-ESTIMATING MODEL, VERSION II

VOLUME I

by

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16. ABSTRACT The manual describes and is a guide to the user of Version II of the Integrated Air Pollution Control System (IAPCS-II), a computerized simulation model for estimating the costs and predicting the performance of sulfur dioxide, nitrogen oxides, and particulate matter control systems for coal-fired utility boilers. It gives the design bases of the modules comprising the model and the structure of the program itself, as well as the bases for a number of model enhancements available to the user. The model includes conventional and emerging technologies that effect pre-, in situ, and post-combustion emission control. The model can accept any combination of the technology modules built into the system. Interactions are reflected in a material balance tabulation of the exit of each module. Alterations in the material balance are used to account for integrated performance and cost effects. The emission control technologies contained in IAPCS-II can be selected in either isolated or integrated configurations. IAPCS-II incorporates a number of enhancements to the design premises of the emission control modules, as well as the model's user access and versatility. Enhancements to the control modules involved upgrades to five modules: wet desulfurization, low-NOx combustion, limestone injection multistage burner (LIMB), electrostatic precipitator, and fabric filter.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS		b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group	
Pollution	Coal	Pollution Control	13B	21D
Cost Estimating	Combustion	Stationary Sources	05A,04A	21B
Mathematical Models	Emission	Particulate	12A	14G
Economics	Sulfur Dioxide	LIMB	05C	07B
Boilers	Nitrogen Oxides	Fabric Filters	13A	
Utilities	Particles			

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NOTICE

ABSTRACT

The Integrated Air Pollution Control System (AIPCS) is a computerized simulation model developed for EPA's Air and Energy Engineering Research Laboratory (AEERL) to estimate the costs and predict the performance of sulfur dioxide (SO_2), nitrogen oxides (NO_x), and particulate matter (PM) emission control systems for coal-fired utility boilers. The model includes conventional and emerging technologies that effect pre-, in situ, and post-combustion emission control. The model can accept any combination of the technology "modules" built into the system. Interactions are reflected in a material balance tabulation of the exit of each module. Alterations in the material balance are used to account for integrated performance and cost effects. The emission control technologies contained in IAPCS can be selected in either "isolated" or "integrated" configurations.

This version of IAPCS (IAPCS-II) was completed in April 1986. It incorporates a number of enhancements to the design premises of the emission control modules as well as the model's user access and versatility. Enhancements to the control modules involved upgrades to the wet flue gas desulfurization (FGD) module, upgrades to the low-NO_x combustion module, upgrades to the limestone injection multistage burner (LIMB) module, and upgrades to the electrostatic precipitator (ESP) and fabric filter (FF) modules. Other important enhancements to IAPCS-II include expanding the solid waste handling and disposal module, housing the model on a microcomputer (personal computer), providing EPRI and TVA economic premises, and expanding the user-activated parameter file.

The User's Manual describes the second version of IAPCS. This manual provides a guide to the user of the model. It presents the design bases of the individual modules comprised by the model and the structure of the program itself, as well as the bases for a number of model enhancements now available to the user.

Since program "bugs" and other errors may be discovered by model users, it is requested that the errors be conveyed to the AEERL project officer by mail (U.S. EPA, MD-4, Research Triangle Park, NC 27711) or by phone (919/541-2556). If and when the model is upgraded, the compiled version (diskette) will be changed and dated to identify it. Users may contact the AEERL Technical Information Service (phone 919/541-2218) to determine the latest version of the model, and how to obtain it.

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METRIC EQUIVALENTS

Nonmetric units are used, for the most part, in this manual for the reader's convenience. Readers more familiar with metric units may use the following factors to convert to that system.

Nonmetric	Times	Yields metric
acre	4047	m^2
Btu	1.06	kJ
°F	5/9(°F-32)	°C
ft	0.305	m
ft^2	0.093	m^2
ft^3	28.3	L
gal.	3.79	L
hP	9.81	kW
in.	2.54	cm
lb	0.454	kg
ton	907.2	kg
yd^2	0.836	m^2
yd^3	0.765	m^3

SECTION 1

BACKGROUND AND PURPOSE

The cost of installing and operating air emission control equipment to meet sulfur dioxide (SO_2), particulate matter (PM), and nitrogen oxide (NO_x) emission standards have grown significantly and now represent a large portion of the total powerplant costs. The significance of these costs has led to the emergence of the concept of integrated environmental control of utility powerplant air emissions within the last several years.

One logical means of addressing the design and operation of an air emission control system is to consider that system as an integral part of the powerplant. By optimizing the interactions of control devices, the integrated control concept can effect the necessary control level at a minimal cost.

The Integrated Air Pollution Control System (IAPCS) is a computerized simulation model developed for the Air and Energy Engineering Research Laboratory (AEERL) of EPA to estimate the costs and predict the performance of SO_2, NO_x, and PM emission control systems for coal-fired utility boilers. The model includes conventional and emerging technologies that effect pre-, in situ, and post-combustion emission control. The model can accept any combination of the technology "modules" built into the system. Interactions are reflected in a material balance tabulation of the exit of each module. Alterations in the material balance are used to account for integrated performance and cost effects. The emission control technologies contained in IAPCS can be selected in either "isolated" or "integrated" configurations.

The power of IAPCS lies in its ability to reflect integrated effects of various control configurations. This allows the analyst to identify synergistic interactions and thus optimize performance and cost in terms of integrated cost effectiveness. The specific technologies that are contained in IAPCS are presented in Table 1-1.

The first version of IAPCS (IAPCS-I) was developed in November 1983. This version was a mainframe computer model housed at EPA's National Computer Center (NCC). The second version of IAPCS (IAPCS-II) was completed in April 1986. This version incorporates a number of enhancements to the design premises of the emission control modules as well as the model's user access and versatility. Enhancements to the control modules involved upgrades to the flue gas desulfurization (FGD) module (the latest version of the Shawnee FGD model was incorporated; see Subsection 4.6, flue gas desulfurization); upgrades to the low-NO_x combustion module (see Subsection 4.2, Low-NO_x Combustion); upgrades to the limestone injection multistage burner (LIMB) module (see Subsection 4.3, Limestone Injection Multistage Burner); and upgrades to the electrostatic precipitator (ESP) and fabric

TABLE 1-1. IAPCS CONTROL MODULES

Type	Technology	Pollutant(s) controlled
Pre-combustion	Physical coal cleaning	SO_2/PM/NO_x[a]
In situ	Low-NO_x combustion	NO_x
	LIMB	SO_2
Post-combustion	ESP	PM
	Fabric filter	PM
	Spray humidification	SO_2/PM[b]
	Dry sorbent injection	SO_2
	Wet FGD	SO_2/PM[c]
	Lime spray drying FGD	SO_2/PM[d]

[a] The product coal is de-ashed and desulfurized. Some NO_x reduction is reflected due to alteration of the combustion conditions and nitrogen content of the cleaned coal.

[b] Spray humidification improves PM collection by conditioning the gas upstream of the ESP. Some SO_2 may be absorbed by the spray water.

[c] Some FGD configurations provide supplemental PM control in the scrubbing system.

[d] Removal of PM (and the SO_2 reaction solid products) occurs in the spray dryer chamber and downstream PM control system.

filter (FF) modules (see Subsection 4.8, Electrostatic Precipitator, and Subsection 4.9, Fabric Filter). Other important enhancements to IAPCS-II include expanding the solid waste handling and disposal module, housing the model on a microcomputer (personal computer), providing EPRI and TVA economic premises, and expanding the user-activated parameter file.

This User's Manual describes the second version of IAPCS. This manual provides a guide to the user of the model. It presents the design bases of the individual modules comprised by the model and the structure of the program itself, as well as the bases for a number of model enhancements now available to the user.

The manual is organized into seven sections (Volume I) and three appendices (Volume I and Volume II). Section 2 describes the capabilities of the model. Section 3 describes the user input requirements and output format and options. Section 4 describes the specific design bases used for each of the control modules. Section 5 presents the integrated aspects of the model. Section 6 describes the program environment and structure and provides user information. Section 7 describes step-by-step procedures to operate and to troubleshoot the model in the event of operation problems. Appendices A, B, and C present a listing of the parameter files, example hardcopy output, and a program listing, respectively.

SECTION 2

CAPABILITIES OF IAPCS-II

The IAPCS-II design and cost-estimating model was developed to estimate the cost and performance of air emission control equipment for coal-fired utility boilers. The model includes both conventional and emerging control technologies. The following is a listing of the control technologies (modules) included:

- Physical coal cleaning (PCC)
- Low-NO_x combustion (LNC)
- Limestone injection multistage burner (LIMB)
- Electrostatic precipitator (ESP)
- Fabric filter (FF)
- Spray humidification (SH)
- Dry sorbent injection (DSI)
- Lime spray drying (LSD)
- Wet flue gas desulfurization (FGD)

As designed, the model accepts any combination of these technologies. System interactions are reflected in a material balance tabulation at the exit of each module. The PCC, LNC, and LIMB modules (pre-combustion and in situ technologies) are all applicable to the boiler unit; the effects of these devices are accounted in a material balance column reflecting flue gas conditions at the air heater exit. An "uncontrolled" material balance column is calculated before the boiler control modules are accounted so that the net effect of emission control can be calculated on a system basis. Output from the model reports the reduction in SO_2, PM, and NO_x emissions; associated capital and annualized costs of such reductions; and associated cost-effectiveness values (dollars per ton of pollutant removed across the entire emission control system).

A parameter file and a user-prompted optimization routine are two important features of this model. As each module was developed, the important design parameters were included in a parameter file. These parameters may be subsequently changed by the user for a given application. The parameter file is designed to permit the user to modify the important values to reflect those of choice.

The first run of the model for a user-specified control configuration makes use of default performance values for each module (i.e., the costs reflect the design-specified maximum performance levels of the control equipment). When the output from the initial run has been completed, the user can exercise the option to enter into an optimization routine which permits sequential revision of the performance levels of certain individual modules for a single pollutant. The user must iterate runs to effect a desired pollutant mass emission rate/overall system removal efficiency.

The model also includes certain other important design features. One of these includes an optional "debug" output in identifying interim calculated values for each control module in control system. An iteration of the input for each run is provided first to ensure that cost and performance data are attached to the specifics and date of that run.

The model is available as a computer program through NTIS in the form of MS-DOS formatted microcomputer diskettes (5.25-in. (double-sided) floppy disks). The model is structured in Microsoft FORTRAN 77™ (not necessary to run the program), and it can be used on an IBM PC/XT or AT (or compatible) microcomputer.

SECTION 3

GENERAL MODEL DESCRIPTION

This section describes the overall scope of IAPCS-II from its input requirements, cost formats, files and routines, and output formats to its optimization.

3.1 INPUT REQUIREMENTS

A typical run entails a number of requests for input from the user. The input questions are presented in Figure 3-1.

3.1.1 Input Format

These items either provide basic data for the given run or specifically affect the outcome of the run. Input requests include boiler data, fuel characteristics, and the control configuration. The boiler data are used to quantify the unit/system generating performance. The coal characteristics are used to estimate the emissions from firing a given quantity of coal, and the user specifies the controls to be utilized. The firing configuration (i.e., wall- or tangentially fired) is used to estimate uncontrolled emissions and to specify the appropriate NO_x control device from the LNC module.

With regard to requested boiler data, boiler size is limited to single units from 100 to 1300 MW. The capacity factor is used in annual cost calculations. The bottom ash configuration is

ENTER FIRING CONFIGURATION OF BOILER:
1. WALL-FIRED
2. TANGENTIALLY FIRED
ENTER BOILER SIZE IN MW>
ENTER BOILER CAPACITY FACTOR (%)>
ENTER CONSTRUCTION STATUS(1=NEW, 2=RETROFIT)>
ENTER DATE AND COMMERCIAL OPERATION OF BOILER>
ENTER TEMPERATURE AT AIR HEATER EXIT>
ENTER ACFM AT THE AIR HEATER EXIT:ENTER 0 TO CALCULATE>
ENTER SELECTION OF TYPICAL COAL(1) OR SPECIFIC CHARACTERISTICS(2)>
ENTER COAL CHOICE:
1. BITUMINOUS - PENNSYLVANIA
2. BITUMINOUS - OHIO
3. BITUMINOUS - WEST VIRGINIA
4. BITUMINOUS - ILLINOIS
5. SUBBITUMINOUS - WYOMING
6. LIGNITE - NORTH DAKOTA>
ENTER COAL CLEANING LEVEL:
1. RUN-OF-MINE SORTED AND SCREENED
2. PHYSICAL COAL CLEANING>
ENTER BOILER BOTTOM ASH CONFIGURATION:
1. DRY-BOTTOM
2. WET-BOTTOM>
SELECT IAPCS CONFIGURATION FROM THE FOLLOWING:

	MODULE	POLLUTANT(S)
1.	LOW-NO_x BURNERS, OVERFIRE AIR	NO_x
2.	LIMB	NO_x, SO_2
3.	COAL CLEANING	PART, SO_2
4.	SPRAY HUMIDIFICATION (SH)	PART, SO_2
5.	ESP	PART
6.	FABRIC FILTER (FF)	PART
7.	LIME SPRAY DRYING (LSD)	SO_2
8.	LIMESTONE/LIME FGD (FGD)	SO_2
9.	DRY SORBENT INJECTION (DSI)	SO_2

THE FOLLOWING RULES APPLY TO SELECTING A CONFIGURATION:
1 - METHOD 4 MAY NOT BE USED WITH METHODS 7 or 9
2 - METHOD 5 OR 6 MAY NOT PRECEDE (BUT MAY FOLLOW) 7 OR 9
3 - METHODS MUST BE IN ASCENDING NUMERICAL ORDER (EXCEPT AS IN 2 ABOVE)
4 - METHODS MAY NOT BE REPEATED IN THE SAME SYSTEM. (GENERALLY THE POST COMBUSTION MODULES FOLLOW THE GAS PATH)
ENTER OPTION NUMBERS IN ORDER (SEPARATE BY COMMAS)
SELECT OUTPUT OPTION:
1. OUTPUT TO PRINTER
2. OUTPUT TO SCREEN
3. BOTH ABOVE

Figure 3-1. IAPCS-II input requirements.

used in emission estimating. Flue gas temperature is an important parameter for flue gas material balance calculations and the design of all subsequent control modules.

With regard to requests concerning coal characteristics, coal may be identified by either of two mechanisms. The user may select a "typical coal" or input the characteristics of any specific coal to be used. So that the fuel cost premium and emissions from firing cleaned coal can be evaluated, these properties must be input before and after cleaning. If the user selects a standard coal, the coal-cleaning level input allows the program to use run-of-mine (ROM) or cleaned coal characteristics for these standard cases.

3.1.2 Default Values - The Standard Case Option

The user may opt for an interactive run or enter the name of an input batch file on disk. Depending on the selected option:

- The user will specify data for specific runs via the questions presented in Figure 3-1.
- The model will search a data disk for a specific input file and use it to initiate the run.

Any number of input files are possible (up to the maximum that are stored on a disk). This option permits a run to be input very quickly, and it requires only two responses from the user. Standard case runs are for demonstrational purposes, but a sequential batch of input files can be used to make a series of runs.

3.2 COST FORMATS

Emission control cost estimates must be comparable in terms of base year dollars, cost categories, and overall content (i.e., cost components). To facilitate comparisons, IAPCS-II has adopted the bases and format of cost estimation used by the Tennessee Valley Authority (TVA)[1] and the Electric Power Research Institute (EPRI),[2] which are generally accepted as "industry standards."

3.2.1 Capital Cost Formats

The format for the direct capital costs entails one or several line items for each of the control modules in a given control configuration. Major components for a given module are itemized.

Indirect components, which are an integral part of capital cost estimates, are standardized and presented at the system level in IAPCS-II. The two formats, TVA and EPRI, are presented in Figures 3-2 and 3-3, respectively.

Interpretation of the TVA and EPRI guidelines resulted in the assignment of percentages in IAPCS-II for each of the indirect components for each of the control modules. The TVA indirect costs are calculated as percentages of the total direct investment (except for contingency, working capital, interest during construction, and allowance for startup and modifications). The EPRI indirect costs are calculated as a percentage of the process capital cost (except for the preproduction costs, inventory capital, and land). The IAPCS-II values for indirect costs in the TVA and EPRI formats are provided in Tables 3-1 and 3-2, respectively.

INDIRECT INVESTMENT

Engineering design and supervision
Architect and engineering contractor
Construction expense
Contractor fees
Contingency
Disposal area indirects

Total fixed investment

OTHER CAPITAL INVESTMENT

Allowance for startup and modifications
Interest during construction
Royalties
Land
Working capital

TOTAL CAPITAL INVESTMENT

Figure 3-2. TVA indirect capital cost format.

PROCESS CAPITAL

General Facilities
Engineering/Home Office
Project Contingency
Process Contingency
Sales Tax

TOTAL PLAN COST

Royalty Allowance
Preproduction Costs
Inventory Capital
Initial Catalyst
Land

TOTAL CAPITAL REQUIREMENT

Figure 3-3. EPRI indirect capital cost format.

Indirect Component	LNC	LIMB	FGD	LSD	DSI	SH	ESP	FF
Engineering design and Supervision	6	8	6-8	7	6	6	6	6
Architect and engineering contractor	1	3	1-3	2	1	1	1	1
Construction expense	14	18	14-18	16	14	14	14	14
Contractor fees	4	6	4-6	5	4	4	4	4
Contingency[b]	20	20	10	20	20	20	20	20
Total (% of TDI)	50	62	37.5-48.5	56	50	50	50	50
Royalties	0	0	0	0	0	0	0	0
Working capital	c	c	c	c	c	c	c	c
Interest during construction	4.84[d]	4.84[d]	15.6[e]	15.6[e]	4.84[d]	4.84[d]	15.6[e]	15.6[e]
Allowance for startup and modifications[f]	10	10	8	10	10	10	10	10
Land[g]	NA[h]	$4700/acre[i]	$4700/acre	$4700/acre	$4700/acre	NA	$4700/acre	$4700/acre

[a] Percentage of total direct investment, except as noted.

[b] Percentage of direct plus indirect.

[c] 1 month of raw materials
1.5 months of conversion costs
1.5 months of plant and administrative overhead
3% of total direct investment

[d] Assumes 1-year construction schedule.

[e] Assumes 3-year construction schedule.

[f] Percentage of direct plus indirect plus contingency.

[g] TVA's $6000/acre (1985 dollars) deescalated by 8-1/2 % per year.

[h] Not applicable.

[i] Metric equivalents are given in front matter of this manual.

TABLE 3-2. EPRI INDIRECT COST FORMAT[a]

Indirect Component	LNC	LIMB	FGD	LSD	DSI	SH	ESP	FF
General facilities	10	10	10	10	10	10	10	10
Engineering and home office fees	10	10	10	10	10	10	10	10
Project contingency	15	30	15	15	20	20	15	15
Process contingency	10	30	10	15	20	20	10	10
Sales tax	0	0	0	0	0	0	0	0
Total % of process capital	45	80	45	50	60	60	45	45
Royalty allowance	0	0	0	0	0	0	0	0
Preproduction costs	b	b	b	b	b	b	b	b
Inventory capital	c	c	c	c	c	c	c	c
Initial catalyst	0	0	0	0	0	0	0	0
Land[d]	NA	$6215/ acre	$6215/ acre	$6215/ acre	$6215/ acre	NA	$6215/ acre	$6215/ acre

[a] Percentage of process capital cost, except as noted.

[b] 1 month of fixed operating cost
1 month of variable operating cost
2% of total plant investment
Fuel cost (see text)

[c] 60-day supply of consumables.

[d] $5500 in 1980 dollars escalated at 8.5%/yr = $6215 in mid-1982 dollars (based on EPRI's apparent escalation rate).

NA - Not applicable.

3.2.2 Annual Cost Formats

As in the case of capital cost estimates, TVA and EPRI use different formats and bases to present annual costs. Figure 3-4 presents TVA's format and Figure 3-5 presents EPRI's format. Each format stops short of providing the particular method and line item components used for levelizing the costs. These procedures are described later (in Section 3.3.6).

The maintenance labor and materials estimated by the TVA format for a given system are actually percentages of the total direct investment rather than man-hours and actual material estimates for FGD. This idea was expanded to include all IAPCS-II modules; the percentages used are presented in Table 3-3.

These same percentages are used to estimate maintenance labor and materials in the EPRI format. The number is distributed as 40 percent labor and 60 percent materials, and the labor man-hours are back-calculated.

In the EPRI format, annual O&M costs are presented as a fixed and variable component. Equations presented in the EPRI Technical Assessment Guide[2] provide the basis for calculating these components.

3.2.3 Unit Costs

Costs of labor, certain materials, reagents and chemicals, and waste disposal are specified in Table 3-4 for TVA and EPRI cost formats. Calculations performed by IAPCS-II yield the quantities of labor, materials, and waste generated by a specific configuration, and unit costs are applied to estimate the annual cost.

	Annual quantity	Unit cost, $	Total annual cost
Direct Costs - First Year			
Raw materials			
Limestone	Tons	/ton	
Lime	Tons	/ton	
Nahcolite	Tons	/ton	
			______
Conversion costs			
Operating labor and supervision			
System	Man-h	/man-h	
Solids disposal facility	Man-h	/man-h	
Solids disposal cost			
Wet	Tons	/ton	
Dry	Tons	/ton	
Utilities	Tons	/ton	
Process water	10^3 gal	/10^3 gal	
Electricity	kWh	/kWh	
Reheat	10^6Btu	/10^6Btu	
Maintenance			
Labor and material			
Analysis	Man-h	/man-h	______
Total conversion costs			
Total direct costs			
Indirect Costs - First Year			
Overheads			
Plant and administrative			
Marketing (10% of byproduct sales)			
Total first-year operating and maintenance costs			

Figure 3-4. Example of TVA annual cost format.

	Annual quantity	Unit cost, $	Total annual cost
Operating & maintenance costs			
Operating labor			
System	Man-h	/man-h	
Solids disposal	Man-h	/man-h	
Maintenance labor	Man-h	40%	
Maintenance material	$	60%	
Admin. & support labor	$	30% O&M	
Solids disposal			
Wet	Tons	/ton	
Dry	Tons	/ton	
Fixed component	$		
Variable component	$		
Consumables			
Limestone	Tons	/ton	
Lime	Tons	/ton	
Nahcolite	Tons	/ton	
Water	10^3gal	/10^3gal	
Reheat	10^6Btu	/10^6Btu	
Electricity	kWh	Mills/kWh	
Total O&M Costs			

Figure 3-5. Example of EPRI annual cost format.

TABLE 3-3. MAINTENANCE LABOR AND MATERIAL COST FACTORS

Maintenance labor and materials	LNC	LIMB	FGD	LSD	DSI	SH	ESP	FF
TVA factors (percent of total direct investment)	2	4	7-9[a]	5-7[a]	4	2	4	4
EPRI factors (percent of total process capital)	2	4	8	6	4	2	4	4

[a] Decreasing from high to low with increasing boiler size. For waste disposal, a fixed 3 percent of the waste disposal equipment plus construction cost is used.

TABLE 3-4. DEFAULT UNIT COSTS USED IN IAPCS-II
(June 1982 dollars)

Item	TVA	EPRI
Lime, \$/ton	71.49	47.47
Limestone, \$/ton	11.99	13.56
Nahcolite, \$/ton	-	-
Calcitic hydrate	71.49	70.00
Dolomitic hydrate	75.00	75.00
Calcitic pressure hydrate	85.00	85.00
Dolomitic pressure hydrate	90.00	90.00
Operating and supervision labor, \$/h	15.18	17.24
Waste facility labor rate, \$/h	19.18	17.24
Analysis labor rate, \$/h	20.77	
Electricity, mills/kWh	43.9	39.8
Water, \$/1000 gal	0.13	0.57
Waste disposal		
Wet, \$/ton	15.70	11.64
Dry, \$/ton	5.00	5.65
Overhead (plant)	60	-
% O&M Labor		
Steam reheat, \$/100 lb		
Reheat, \$/10^6 Btu	4.23	5.51

3.3 SYSTEM FILES AND ROUTINES

Several of the files and calculating routines used in IAPCS-II are "system-wide" (i.e., not limited to one particular control technology module). This important aspect of integrated design eliminates equipment redundancy.

3.3.1 Standard Coals

For simplification of input requirements regarding coal characteristics, a set of six standard coals is provided that contains the proximate analyses for run-of-mine (ROM) and physically cleaned coals. Weight recovery, Btu recovery, and total cost (in $/ton of raw coal) are also shown for the cleaned coal. Estimated characteristics of the standard coals are shown in Table 3-5.

3.3.2 Emission Calculations

Once IAPCS-II has been provided with the coal characteristics, a set of calculations is used to estimate the SO_2, NO_x, and PM emissions associated with that coal. The EPA AP-42 emission factors[3] used as a basis for these calculations are responsive to boiler bottom type (wet or dry) and coal type (rank) for PM; coal type for SO_2; and firing configuration, bottom type, and coal type for NO_x.

Some new features in IAPCS-II are based on EPA comments. For SO_2 emission calculations, the AP-42 basis is used; however, the user can select a separate default value of 100 percent conversion of sulfur to SO_2 through a parameter file option. This option permits easy comparison of FGD costs with those of TVA or allows a conservative design approach to be assumed.

TABLE 3-5. ESTIMATED CHARACTERISTICS AND COSTS OF RAW AND CLEANED COALS
(All analyses are on a whole coal basis.)

Raw coal	Coal 1 PA Armstrong	Coal 2 OH Jefferson	Coal 3 WVA Logan	Coal 4 IL No. 6	Coal 5 MN Rosebud	Coal 6 ND Lignite
Btu/lb	11,952	11,922	12,058	10,359	8,789	7,500
Ash, %	15.9	13.0	16.6	20.6	8.15	5.9
S, %	2.23	3.43	0.89	4.27	0.56	0.94
H_2O, %	3.3	5.0	3.5	9.6	25.2	32
Cleaned coal						
Btu/lb	12,596	12,845	13,611	11,507	9,050	7,840
Ash, %	10.0	6.6	4.6	10.7	6.46	5.3
S, %	1.42	2.74	0.83	3.50	0.43	0.54
H_2O, %	5.6	4.4	5.4	11	24	30
Wt. recovery, %	88	85	82.5	78	96.2	97.4
Btu recovery, %	95	91	95	88	97.5	98.9
PCC costs[9]						
Total capital, $\$10^6$	22.23	13.11	15.38	11.82	13.37	12.74
Annual capital, $/ton raw	1.77	1.05	1.22	0.94	1.07	1.02
O&M, $/ton raw	2.80	2.80	2.80	2.80	2.80	2.80
Total annual, $/ton	4.57	3.85	4.02	3.74	3.87	3.82

Note: Cited costs assume coal production of 500 tons/h, 11 h/day, 365 days/yr, and capital recovery factor (CRF) of 16%.

For PM, an 80/20 split of ash is assumed as the topside and bottom ash fractions in the calculations. In this case, the user has the option of applying the AP-42 emission factors contained in the parameter file. The AP-42 emission factors result in fly ash estimates significantly lower than the 80/20 split. This ratio has been used for a number of years, however, and is widely accepted for PM control device design.

The NO_x emissions are calculated by the same method that was used in IAPCS-I. These values are in excellent agreement with estimates of utilities and boiler manufacturers. All AP-42 emission factors are expressed as percentages in IAPCS-II.

3.3.3 Boiler Performance

The net heat rate of the boiler is calculated by IAPCS-II primarily to show the energy penalty the control system has on the operation of the unit. A standard routine is used to estimate the net heat rate.[4] The unit's thermal efficiency is based on the heating value of the coal. This thermal efficiency is used to adjust a minimum heat rate upward, and the losses to the system for auxiliaries are added (in Btu/kWh). The gross heat rate is then calculated, and power losses due to each of the control technology modules selected is added to the heat rate. In this case, the net heat rate reflects the total Btu/kWh required for the selected boiler and control system.

3.3.4 Fans

Another system-level calculation routine is provided to add booster fans for the selected integrated control system. The design of the induced-draft booster fans and the estimated costs are based on the total gas-side pressure drop and the gas flow rate. Many different control configurations are possible; therefore, the FANS module may be used to calculate forced-draft fan costs where appropriate. This user option is included in the parameter file for the FANS module. The basis for the module is a routine extracted directly from the Shawnee Model.[1]

3.3.5 Waste Disposal

The Shawnee Model routine for construction and operation of an onsite waste disposal is also used at the system level.[1] No pond options are provided in IAPCS-II because many of the control combinations could only make use of collected wastes in a dry form. Conventional FGD systems generate a wet waste, which must be disposed on a routine basis. The model permits three waste disposal scenarios:

- All of the waste can be disposed of offsite. For this option, the waste disposal fee is used to calculate an annual cost.
- The waste can be split (in any ratio) between offsite and onsite. This option results in a capital cost estimate for the onsite facility, annual costs for its operation, and annual offsite disposal costs.
- All of the waste can be disposed of on site. In this case, the capital costs of building the site and the annual costs for its operation and maintenance will be calculated.

3.3.6 Economics

The model permits escalation and deescalation of the base-year dollars for a given run. The system costs in 1982 dollars may be adjusted forward. Chemical Engineering cost indices or the annual inflation rate (both stored in the parameter file) are used to effect these adjustments to the base year. The costs of labor, reagents and chemicals, and utilities also must be adjusted, as the startup year costs (first-year O&M costs) usually differ from costs during the first year of construction (capital costs).

Several cost components are used to compute annual O&M costs. These include a capital component so that a single number representing a system cost may be used for comparative purposes. Capital cost components used in O&M calculations include:

- Depreciation
- Annual interim replacement
- Insurance and property taxes
- Federal income and investment credit taxes

These can be combined into a levelized annual capital charge, as shown by TVA[1] and EPRI.[2]

3.3.7 Parameter File

The parameter file is a critical facet of IAPCS-II. Through it, changes affecting the design, performance, and cost of individual modules may be facilitated. Access to this file permits the user to obtain maximum flexibility in depicting a given control scenario and to update and revise control technologies as data become available.

After the user has selected an interactive run (the first input question) and selected either the TVA or EPRI economic format (the second input question), he is presented with a menu of parameter file options:

1. Switch to another existing parameter file.

2. Edit parameter file/create a new parameter file.

3. Display parameter file explanation.

4. Print out parameter group.

5. Leave this menu and begin input sequence.

6. Stop the program without making a run.

When IAPCS-II is started, the default parameter file is loaded. The name of the default parameter file is "PARMFILE." This name, along with the economic format chosen, is displayed at the top of the screen. Every parameter file is associated with either the TVA or the EPRI economic format. It is possible for two parameter files with different economic formats to have the same name (e.g., there is a PARMFILE.TVA and a PARMFILE.EPR).

Option 1 allows the user to load in a different parameter file saved previously under the same economic format. Option 2 allows the user to change values in the current parameter file and subsequently save these changes for future use. The user will be prompted for a name for the new parameter file and warned if the file already exists. It is strongly suggested the user never save new parameters into the default parameter files (PARM-FILES). If the changes made to the parameter file are not saved, they will be in effect for the current run only.

Option 3 displays a brief description of the parameter file. Option 4 prints out a group of related parameters (e.g., LIMB parameters, economic parameters). Option 5 begins the main input section of the model, which is followed by model execution.

Option 6 allows the user to quit at this point; this permits the user to modify a parameter file without making a run.

The parameter file access method (menu option 2) has been revised in IAPCS-II so that the user can select the group desired and change the values of items in that group. Validation of parameter changes is reported with each model run. A summary listing of the parameter file is presented in Appendix A.

3.4 OUTPUT FORMAT AND OPTIONS

The model provides the user with eight separate outputs. Each of these is described in this section. An example run illustrating the output format of IAPCS-II is presented in Appendix B.

3.4.1 User Input Summary

For assurance that each run is complete, the first output is a reiteration of the inputs provided by the user. Any changes the user has made to the parameter file are reported, along with all of the requested input items. For a batch file run, the same report is generated by using these inputs.

3.4.2 Module-Specific Output

Brief statements describing the primary design characteristics of the selected control modules are reported for the user.

3.4.3 Boiler Performance

For heat input and coal consumption, the higher heating value of the coal must be used. It is important to note that heat rate and boiler thermal efficiency are for a unit with no controls and all auxiliaries included. After the energy penalty has been calculated from the sum of each module in a given control configuration, the gross heat rate or the system's net generation can be calculated. This value reflects actual capacity with the given control configuration relative to the input (nominal) boiler size.

Heat input, boiler efficiency, net heat rates, and coal consumption are calculated by using the ROM or cleaned coal characteristics (if selected). This permits quantification of the benefit in heat rate from firing the cleaned coal in the system. Only the performance parameters for the cleaned coal (if PCC is selected) are presented in the output table.

3.4.4 Material Balance

Material balance components are calculated at the exit of each control module. The "uncontrolled" column calculates a baseline estimate using the ROM coal characteristics so that the overall system pollutant reduction effects can be calculated; i.e., the uncontrolled column does not reflect any of the boiler-related (pre-combustion and in situ) controls (e.g., PCC, LIMB, or LNC).

3.4.5 Emission Reduction

The overall system emission reduction is reported in a summary table. This table presents the mass flow rate (lb/h), percent removal, and unitized mass and volume emission rates ($lb/10^6$ Btu and ppm) for PM, SO_2, and NO_x. Because this table is generated directly from the material balance, it is dependent on the emission estimation routine. The uncontrolled emissions of

PM, SO_2, and NO_x for a given coal are calculated at the boiler's air heater exit. Inasmuch as LNC, LIMB, and PCC may be used as a control option, the ROM coal properties are used to generate an initial uncontrolled baseline, which is reported in column 1 of the material balance. All emissions are estimated by using the heat input (from the performance routine) and AP-42 emission factors. If any of the three boiler controls is not used, the uncontrolled baseline is repeated in column 2; if any control configuration is specified, column 2 of the material balance reflects the effects.

3.4.6 Capital Cost Estimate

The capital cost estimate for the designated control configuration is the next output (See Appendix B).

3.4.7 Annual Cost Estimate

The annual cost estimate for the designated control configuration is the next output (See Appendix B).

3.4.8 Cost-Effectiveness

An output of the system's cost-effectiveness is then provided. The cost per ton ($/ton) of PM, SO_2, and NO_x removed is calculated for comparison purposes by using the levelized annual requirements.

3.5 OPTIMIZATION AND RERUN

At the completion of a run, the user is asked whether optimization of the selected control system is desired. A target emission rate (in $lb/10^6$ Btu) may be entered, and the system performance and costs will be rerun automatically.

This optimization routine allows the user to alter the effective efficiency of a chosen control device. If the user elects to optimize, the user will be prompted to enter a new "target" emission rate, in pounds per million Btu, for the pollutant appropriate to the control module selected. (It is only a "target" because if other modules are in the system, they may also affect the final emission rate, and only one module is optimizable at a time.) For the LIMB module, the SO_2 emission rate may be either higher or lower than the initial emission rate. For all other modules, the new emission rate must be higher than the initial emission rate.

The effective efficiency of a control module is changed either by simulating a bypass of a fraction of the gas stream (as is the case with the fabric filter and wet FGD modules) or by simply changing the capture efficiency of the control unit (LIMB, ESP, and Lime Spray Drying). In the former case, the emission rate should be selected such that a minimum of 10 percent of the gas stream will be bypassed because less than this amount would not be cost-effective.

With the exception of LIMB optimization with a lower emission rate, all optimizations have the effect of lowering the cost of the control system at the expense of increased emissions.

The bypass fraction and new removal efficiency are calculated as follows:

$$\text{Bypass fraction} = \frac{Ec - (1-\eta)Eu}{\eta Eu}$$

$$\text{Efficiency} = \text{MIN}(\eta, 1 - Ec/Eu)$$

where: Ec = Controlled emissions (lb/MM Btu)
Eu = Uncontrolled emissions (lb/MM Btu)
η = Maximum removal efficiency

The target emission rate should be chosen to ensure that impossible situations do not occur (e.g., emissions greater than those at the inlet to the control device). Once the target emission rate has been chosen, the calculational and output portion of the program will re-execute.

It should be noted that although this process is called optimization, it will not necessarily result in a more cost-effective solution.

SECTION 4

DESCRIPTION OF IAPCS-II TECHNOLOGY MODULES

The IAPCS-II model is designed on a modular basis; i.e., a given control technology accepts the flue gas, coal, and unit characteristics from the previous module. These data are then used to generate the design, performance calculations, and estimates of capital and annual costs. The architecture of a modular program is such that it offers the user the greatest flexibility for revising any existing control device and for adding new technologies as they are identified.

This section presents the design and cost bases used for each of the nine modules in IAPCS-I.

4.1 PHYSICAL COAL CLEANING

Physical coal cleaning is a control module for both the typical and user-specified coal source. The PCC module either assumes the before and after characteristics (typical coal) or requires the user to provide the details.

Run-of-mine coal costs usually include cursory sorting and screening charges for coal preparation. Physical coal cleaning processes are specifically designed for the coal source and depend on the unique washability characteristics of the particular coal. Because coal characteristics and washability vary greatly, data from Versar, Inc.,[5] and Hoffman-Holt[6] were used for six typical coals in the United States.

Although different coal cleaning facilities are assumed for each of the six coals, they essentially reflect PCC capacity captive to a 500-MW unit. The fuel cost premium is that cost (in $/ton raw coal) required to generate adequate cleaned coal for the unit.

When the user specifies one of these coals, the costs and properties become the source of an annual fuel cost premium (if physically cleaned) and of emission calculations.

Ash properties, specifically alkalinity, are very important in the design of air emission control systems in the model. Because typical coal data do not include ash properties, default values were assumed on the basis of coal rank. These values for the major alkaline components of calcium oxide (CaO), magnesium oxide (MgO), and sodium oxide (Na_2O) are presented in Table 4-1.[7] The reactive fraction is that portion of alkalinity that is available for SO_2 reaction. These reactive fractions are based on a study of Combustion Engineering's information on the subject[8] and on engineering judgment. The CE text indicates the relative insignificance of potassium oxide (K_2O) as a reactive alkali; thus, it is not included in the listing of alkaline components.

TABLE 4-1. ESTIMATED ALKALINE COMPONENTS OF COAL BY RANK

Alkaline component of ash, %	Bituminous (Illinois)	Subbituminous (Montana)	Lignite (N. Dakota)
CaO	5.2	13.5	21.1
MgO	0.9	4.6	6.4
Na_2O	0.4	2.8	4.4
Total	6.5	20.9	31.9
Reactive fraction	0	25	20

If the user specifies a coal, all of the coal properties must be input for the ROM and PCC source. Alkalinity for a specified coal is the sum of CaO, MgO, and Na_2O components of the ash. The Na_2O content is identified separately because ESP design is highly dependent on this value.

The PCC module modifies the unit/system performance, emission calculations, and cost of downstream control equipment.

4.2 LOW-NO_x COMBUSTION

The low-NO_x combustion (LNC) technology module contained in IAPCS-II was originally part of the EPA LIMB Model[9] (see Subsection 4.3). Two low-NO_x combustion processes are offered in IAPCS-II: overfire air and low-NO_x burner. Overfire air (OFA) is most applicable to tangentially-fired boilers. Low-NO_x burner (LNB) is most applicable to wall-fired boilers (front and opposed). Both technologies are offered in IAPCS-II for both new and retrofit applications.

For tangentially-fired PC boilers, one OFA port is provided for each column of burners. A NO_x reduction of 25 percent is assumed for OFA. For wall-fired PC boilers, low-NO_x staged-combustion burners are provided. A NO_x reduction of 50 percent is assumed for LNB. For retrofit applications, all retrofit costs are built into the cost algorithms.

A summary of the design and operating parameters of the LNC module of IAPCS-II is presented in Table 4-2.

TABLE 4-2. DESIGN AND OPERATING PARAMETERS OF LNC MODULE OF IAPCS-II

Plant application	New/retrofit
Boiler application	Pulverized coal
Boiler firing configuration	Wall-fired and tangentially-fired
Plant size, MW	100 to 1300
Process options	Overfire air (tangentially-fired) Low-NO_x burner (wall-fired)
NO_x control, percent:	
Overfire air	25 (base case)
Low-NO_x burner	50 (base case)
Economic conditions	TVA premises EPRI premises

4.3 LIMESTONE INJECTION MULTISTAGE BURNER

The LIMB technology module of IAPCS-II has its genesis in two other models: IAPCS-I and the EPA LIMB Model.

The original version of IAPCS included a LIMB technology module. This module was developed on research information available at the time, which was admittedly sparse. The LIMB module was capable of predicting performance and estimating cost for limestone (calcite) injection only in a PC wall-fired, dry-bottom boiler using specially designed, staged-combustion, low-NO_x burners. The major capital cost elements of limestone storage and preparation, staged-combustion burners, additional soot-blowing capacity, and economizer upgrades were included. Modifications to the boiler's bottom configuration and the major convective structures of superheater, reheater, air heater, and cavity were excluded. Limestone consumption was established by setting the calcium-to-sulfur (Ca/S) molar stoichiometric ratio at 3:1 for 50 percent SO_2 capture. Downstream effects to the PM collection system were accounted for in the ESP and FF modules based on the additional solids loading and particle resistivity. The additional solid waste material was accounted for in the waste disposal module.

The enhancement of IAPCS from Version I to Version II involved extensive modifications and refinements to the LIMB module. A number of events occurred shortly after the release of IAPCS-I that facilitated these enhancements. A significant number of publications were released containing pertinent and detailed LIMB and LIMB-related research results. This was, in part, stimulated by the First Joint Symposium on Dry SO_2 and Simultaneous SO_2/NO_x Control Technologies sponsored by EPA and EPRI and held in November 1984. In addition, the LIMB Applications Branch of AEERL developed their own LIMB cost model (EPA LIMB Model) to support internal research activities.[9] This model incorporated a number of LIMB technology advancements and versatility not present in the LIMB module of IAPCS-I. Accordingly, a decision was made to upgrade the LIMB module by using the latest research results and incorporating a number of features of the EPA LIMB model.

The more significant improvements to the LIMB technology module of IAPCS-II included expansion in the selection of sorbents from one to eight, allowing the selection of sorbents prepared offsite (preprocessed) or on site (plant-site processing), updating SO_2 capture predictions based on the latest experimental data, incorporation of boiler quench rates as an SO_2 capture variable, expansion in the selection of furnace-firing configurations, expansion in the selection of sorbent injection methods, ability to uncouple sorbent injection and low-NO_x combustion, ability to cost upgrades to the existing boiler and ESP, improvements in the ability to tailor cost and performance estimates to conditions of existing boilers, and improvements in the sensitivity of the downstream ESP to alterations in particle resistivity. These improvements coincide with improvements made to the model's overall versatility and accessibility. A summary of the basic design and operating parameters of the LIMB module of IAPCS-II is presented in Table 4-3. Table 4-4 is a summary of the SO_2 captures of the LIML Module of IAPCS-II.

4.4 SPRAY HUMIDIFICATION

Spray humidification involves the injection of water into the flue gas stream upstream of the PM collection device. The primary objective of humidification is to reduce gas volume and, therefore, the size of the PM collection device. This will result in a concomitant reduction in the capital cost of the PM collection device; moreover, if the PM collection device is an ESP, additional secondary gains will result from a decrease in fly ash resistivity and an increase in surface conductivity. The FF module does not benefit from these secondary factors and may, in fact, experience blinding and cake release problems as the flue gas dew point is approached.

TABLE 4-3. DESIGN AND OPERATING PARAMETERS OF LIMB MODULE OF IAPCS-II[a]

Plant application	New/retrofit
Boiler application	Pulverized coal
Boiler firing configuration	Wall-fired and tangentially-fired
Plant size	100-1300 MW
Sorbent options	Limestone[b] Lime[b] Calcite[c] Dolomite[c] Calcitic hydrate[c] (base case) Dolomitic hydrate[c] Calcitic pressure hydrate[c] Dolomitic pressure hydrate[c]
Sorbent Ca/S Ratio	Specified by user (base case 2.0)
Boiler quench rate, °F/s	Specified by user (base case - 700)
SO_2 capture, percent	Specified by user selection of Ca/S and boiler quench rate (base case = 40)– 60
Sorbent injection	Upper-furnace injection
Process options	With/without low-NO_x conditions On-site/off-site sorbent preparation
Processing areas	
Sorbent storage, handling, and preparation	Dry ball mill (limestone) Slaker/dry ball mill (lime)
Sorbent injection	Pneumatic
Boiler modifications	Burners (LNB as separate module) Soot blowers Economizer (retrofit)
Downstream modifications	ESP upgrade (retrofit) ESP gas conditioning (retrofit)
Waste handling and disposal	System
Process design	Specified by user (LIMB parameter file)
Economic conditions	TVA premises EPRI premises

[a] Base case values represent model default conditions.

[b] On-site sorbent preparation.

[c] Off-site (preprocessed) sorbent preparation.

TABLE 4-4. SO_2 CAPTURES OF LIMB MODULE OF IAPCS-II[a]

	Ca/S			
	1	2	3	4
Quench rate = 900[b]				
limestone	15-16	26-29	35-43	42-56
hydrate	19-20	35-40	53-56	69-70
CPH[c]	27-33	48-54	68-71	88-94
Quench rate = 700				
limestone	17-19	29-31	38-44	45-57
hydrate	24-26	40-46	57-62	73-76
CPH	33-38	54-62	75-79	92-95
Quench rate = 500				
limestone	18-22	31-33	41-45	48-58
hydrate	28-32	45-52	61-68	77-82
CPH	40-43	60-70	81-89	95+
Quench rate 300				
limestone	19-25	32-36	44-46	51-59
hydrate	33-38	49-58	66-74	82-88
CPH	46-48	67-78	88-95	95+

[a] SO_2 capture is expressed as a percentage.

[b] Quench rate is expressed as °F per second for the sulfation "window" of 2200°F to 1600°F.

[c] CPH = calcitic pressure hydrate.

No experience with SH on a utility boiler at any level of application (pilot, prototype, demonstration, commercial) has been reported. Therefore, the design concept represents an approach which is based on a quench tower typically used to condition the flue gas stream prior to scrubbing.

The following design factors form the basis of the SH module:

- Gas residence time in the spray humidification chamber is 0.4 second (which is typical for a gas partial quench tower in a scrubbing application).
- The spray water feed rate is regulated by gas saturation approach temperature, which is assumed to be 160°F. Water feed requirements are designed to be three times the theoretical water feed requirements.
- The spray chamber is a typical horizontal section of duct run. These dimension assumptions preclude any significant PM dropout considerations in the spray chamber (i.e., no dropout below 3000 ft/min).
- The spray chamber is serviced by a circumferential spray ring at the inlet, a collection sump, a sloped duct wall (1-degree pitch) to aid drainage, and a mist eliminator with intermittent self-cleaning via sootblowers. The spray ring is a conventional design with feed nozzles placed at 60-degree intervals. The spray chamber is constructed of unlined, normal-gauge carbon steel. The mist eliminator is a vertical, single-stage, three-pass chevron design with wide vane spacing; it is constructed of thick-walled thermoplastic (e.g., Noryl).
- The mist eliminator pressure drop is nominally 1.0 in. H_2O. A freeboard (distance between the end of the spray chamber and the mist eliminator inlet) of approximately one-third the length of the spray chamber is provided for the mist eliminator. Self-cleaning is provided by intermittent water sprays using retractable high-pressure water lances (steam soot blowers).
- The collection/feed tank is a conventional vessel (no agitation) sized for 8-h surge capacity.

- The recycle pumps are conventional centrifugal design (one in service and one on standby). Pump capacity is sized at three times the theoretical water requirement plus 10 percent oversize.

- The feed pumps are conventional centrifugal design (one in service and one on standby). Pump capacity is sized to continuously replace the purge stream that is continuously discharged at a rate of 1 percent of total liquid inventory.

- No gaseous absorption, PM collection, or dropout occurs in the spray chamber. Approximately 1 percent of the moisture droplets remain entrained in the gas stream (99 percent knockout).

- A minimum 160°F saturation approach temperature precludes the necessity of downstream corrosion protection through the use of either protective liners or high alloys.

- A complete instrumentation complement is provided, including temperature-flow indicator/control for the spray humidification chamber, flow and level controls for the liquid circuit, and differential pressure control across the mist eliminator.

The moisture content, pressure, temperature, and volume are the only gas characteristics changed across the spray humidification chamber.

The primary downstream impact is the reduction in gas volume caused by a drop in temperature. The sizes of the approach duct and PM collection device are affected accordingly. Moreover, if the downstream collector is an ESP, changes in fly ash resistivity and surface conductivity will cause an additional reduction in the SCA of the ESP. For reasons previously outlined, the FF is not similarly affected.

A minimum saturation approach temperature of 160°F provides an ample safety margin above the saturation point; thus, special corrosion protection measures are not provided for the downstream equipment (e.g., special coatings or alloys).

4.5 LIME SPRAY DRYING[10-16]

This module, which was not updated in IAPCS2, represents state-of-the-art as of November 1983. Users interested in the most current Lime Spray Drying technology should see the user's manual for the EPA/TVA Lime Spray Drying model (EPA-600/8-86-016, June 1986).

Lime spray drying technology uses a concentrated alkali slurry in a spray dryer. The spray dryer for SO_2 control must be operated in conjunction with a PM control device. As the absorbent slurry is dried and SO_2 is absorbed by the alkali, PM is introduced into the flue gas. Approximately 70 percent of the PM can be entrained and must be removed by the downstream control device. A choice between the use of an FF or an ESP should not be based on economics alone. The ESP can process gases with a higher moisture content than can the FF, which allows the spray dryer to operate closer to the dew point of the gas and thus results in the introduction of more slurry to reduce the SO_2 level. Additional SO_2 removal, however, has been found to occur on the filter cake that forms on the bags in the FF. Because lowering the approach temperature tends to increase both the quantity of SO_2 removed and the possibility of downstream condensation, the LSD module is based on a 30°F approach temperature. This temperature permits up to 85 percent SO_2 removal in the spray dryer under certain conditions and not cause blinding in an FF due to excessive moisture. No incremental reduction in SO_2 is given for the use of an ESP; a maximum 20 percent removal of the incoming SO_2 into the FF is credited if that PM control option is chosen.

The absorbent slurry can be introduced into the gas stream either via a rotary atomizer or dual-fluid nozzles. Because more data are available and the technology has been proven, this model utilizes the rotary atomizer scheme. The absorbent reacts with the SO_2 during intimate contact as a liquid solution or slurry. Very little additional SO_2 removal takes place after the solution has dried. The liquid droplets dry before leaving the vessel and the dry reaction products and fly ash are removed from the flue gas by the downstream PM control equipment.

The spray dryer reduces the flue gas volume by lowering gas temperature and removing a fraction of the SO_2. In the design used, the flue gas temperature is lowered to 160°F (which is assumed to be 30°F above the typical saturation point). The system must be operated at a temperature above the saturation point to assure that all of the droplets dry before they reach the vessel walls or enter any downstream PM equipment. Another factor of concern is condensation in downstream ductwork and equipment, which could cause corrosion.

A key factor in the design of this system is the efficient utilization of the absorbent. This is accomplished by two means. The first is to allow a fairly close approach temperature (30°F) that permits longer drying times for evaporation of more liquid. With increased liquid rates, the amount of absorbent can be increased, which subsequently results in increased SO_2 removal efficiencies. The second means is to recycle a portion of the collected solids. The first pass of the lime absorbent yields approximately 50 percent utilization. The recycling of about 55 percent of all solid material back into the slurry system could raise this overall utilization to the 75 to 80 percent range.

Additional SO_2 can be removed by using the alkalinity available in the fly ash during a recycle scheme. The available alkalinity in the fly ash varies with coal type, and only about 80 percent utilization of the reactive alkalinity was assumed. An overall stoichiometric ratio was used that took into consideration the combined alkalinity from the fresh lime and the recycled lime, and alkalinity in the fly ash. The ratio is based on moles of calcium equivalents per mole of SO_2 in the flue gas. This definition differs from that normally shown for spray dryers of moles of calcium per mole of SO_2 removed. Although this definition makes calculations simpler, a comparison of the two ratios shows that this method results in values that appear to be low. The ratio used in this model is 1.53, which is the same as a ratio of 1.8 for an SO_2 removal of 85 percent.

Another factor that affects the design is the solids content of the slurry. The LSD module establishes the maximum amount of solids in the absorbent slurry at 35 percent, which is both well within the pumpable range and sufficiently high to achieve the desired SO_2 removal efficiencies.

Calculation of the fresh lime usage rate is based on the assumption that some of the needed alkalinity will be supplied by the recycle stream. More reactive solids leave the dryer in the gas stream rather than in the bottoms fraction. Approximately 30 percent of all solids in the slurry will be in the bottoms fraction and will be discarded. The 70 percent solids in the flue gas are captured in the PM control device. About 78 percent of the solids in the flue gas are recycled via a slurry system to the absorbent solution circuit, which equates to approximately 55 percent of all solids recycled. The fresh lime feed rate is determined on the basis of this recycle rate and a utilization of 50 percent of the lime alkalinity and 80 percent total of any fly ash alkalinity available, the difference of this summation, and the required alkalinity for maximum SO_2 removal. The maximum amount of water that can be evaporated at the inlet temperature and with the 30°F approach is used to check the maximum slurry content (35 percent). If the needed fresh lime exceeds the solids content allowable for the 85 percent SO_2 removal set point, a correction is made. The fresh lime feed rate is lowered, which not only reduces the solids content to the 35 percent mark but also reduces the overall SO_2 removal efficiency. The final quantity of lime needed is prepared in a ball mill/slaker.

Redundant components are provided for all major equipment items. These items include pumps, a ball mill, and a classifier. Spare spray dryers would be installed on medium to large systems to handle 25 percent capacity. The small systems can have up to 100 percent redundancy if only one dryer is needed to make the system operable.

The largest dryer module available has a 45-foot diameter and can handle 550,000 acfm with a residence time of 10 to 12 seconds. The total system pressure drop has been estimated at approximately 6 in. H_2O.

The ability of the user to decrease the overall efficiency of this system involves the use of a gas bypass. The system will then remove the SO_2 content of the quantity of flue gas that is to be treated. This treated gas is then mixed with the bypass gas before going to the next module.

As mentioned previously, two of the reasons for the popularity of LSD technology are 1) the waste streams are dry and 2) the system design is fairly simple. The dryer bottoms waste is conveyed to a storage silo for final disposition. Another benefit of the simplicity of the overall system is that it requires less energy to operate than wet FGD. The power consumption, including the PM control device for operational systems, is less than 1 percent of the gross unit generating capacity. This cost does not include the incremental fan horsepower required to overcome the system and PM control device pressure drop (which is treated in IAPCS-II on a system-wide basis).

A summary of the basic design and operating parameters of the LSD module of IAPCS-II is presented in Table 4-5.

4.6 WET FLUE GAS DESULFURIZATION

It is strongly recommended that the user obtain a copy of Reference 1 in order to understand the operation and parameters of this module.

TABLE 4-5. DESIGN AND OPERATING PARAMETERS OF LSD MODULE OF IAPCS-II

Process options	Lime slurry
Process design	Spray dryer--rotary atomizers
SO_2 removal efficiency, maximum percent	85
SO_2 removal across PM collector, percent:	
ESP	0
FF	Specified by user (base case = 20)
PM carryover, percent	70
Saturation approach temperature, °F	160
Reagent stoichiometric ratio, equivalent Ca/S	1.53
Sorbent utilization, percent	85
Reactive ash alkalinity, percent	80
Slurry recycle fraction, percent	55
Slurry recycle solids, percent by weight	35
Lime preparation	Ball mill/slaker
Spray dryer design (typical):	
Diameter, ft	45
Gas flow rate, acfm	550,000
Gas-side pressure drop, in H_2O	6
Residence time, seconds	10-12
Spare capacity, percent:	25-100

Flue gas desulfurization represents the most comprehensively modeled SO_2 emission control technology for coal-fired utility boilers. This is because of FGD's level of commercial development and widespread commercial application in the utility industry, the variety of FGD processes commercialized or under development, the controversial nature of FGD with respect to cost and performance expectations, and the perception of FGD technology as a benchmark for comparison with other SO_2 control technologies.

The majority of FGD modeling work has been sponsored by EPA and EPRI. The most recognized and comprehensive effort has been conducted by TVA under contract to EPA. From 1968 to 1980, EPA sponsored research on the development of lime/limestone slurry FGD technology at the Alkali Scrubbing Test Facility located at TVA's Shawnee Steam Plant. The experimental test data collected during these tests were used to develop a computer model to project conceptual designs and estimate costs for lime/limestone slurry processes. The computer model was developed through the integration of two separate computer programs to calculate material balances, flow rates, and stream compositions and economics. The resulting model contains two separate programs--one which calculates the major equipment requirements and costs and total capital investment and the other which calculates annual revenue requirements.

Development of the Shawnee Model commenced in 1974. During the subsequent 10-year period, the model was periodically updated to reflect refined technology and economic conditions. The most dramatic change came about in 1980 with the adoption of a revised set of design and economic premises. This change was attributed to changing economic conditions, fuel use patterns, developments in economic evaluation techniques, developments in FGD technology, and developments in environmental legislation.[17]

The most recent version of the model, the Shawnee Flue Gas Desulfurization Computer Model (Shawnee Model) was completed in July 1984 and released in March 1985.[1] The Shawnee Model is capable of projecting a complete conceptual design for lime/limestone slurry FGD processes utilizing different absorber towers (e.g., spray tower, TCA, venturi scrubber-spray tower absorber), with and without chemical additives (e.g., magnesium oxide, adipic acid), with any of five sludge disposal options (untreated, forced oxidation, chemical fixation, on-site ponding, off-site landfill). The Shawnee Model estimates the capital investment (direct and indirect costs) for seven facility areas (i.e., raw material handling, raw material preparation, gas handling, SO_2 scrubbing, oxidation, reheat, and waste disposal) and annual and lifetime revenue requirements. A summary of the basic design parameters and economic conditions is presented in Table 4-6.

The Shawnee Model is accessible in several forms. The original version is a mainframe computer model that is suitable for loading onto an IBM-370 or compatible mainframe computer. The model is also available in a microcomputer version as part of IAPCS-II. The FGD module of IAPCS-II contains the complete version of the Shawnee model. As part of the enhancements of IAPCS

TABLE 4-6. SHAWNEE MODEL DESIGN PARAMETERS AND ECONOMIC CONDITIONS

DESIGN PARAMETERS

Plant application	New
Plant size, MW	100-1300
Coal sulfur, percent	1-5
SO_2 loading, ppmv/lb SO_2 per 10^6 Btu	600-4000/1.7-9.0
Scrubber gas velocity, ft/s	8-12.5
Number of absorbers	0-10
Number of spare absorbers	0-2
SO_2 removal, percent	1-100
Liquid-to-gas (L/G) ratio, gal/1000 acf	25-120
Slurry hold tank residence time, min	2-25
Recycle slurry solids, percent	5-15
Maximum reheat temperature, °F	225
Processing areas	Raw material handling Raw material preparation Gas handling SO_2 scrubbing Oxidation Reheat Waste disposal
Process options	Lime/limestone slurry
Process additive options	Adipic acid/magnesium oxide
Absorber options	Spray tower TCA tower Venturi-spray tower
Forced oxidation options	Within loop Slurry hold tank
Reheat options	Indirect steam Flue gas bypass Indirect steam/gas bypass combination
Solid waste treatment options	Untreated Chemical fixation Forced oxidation
Solid waste disposal options	Onsite/landfill Unlined/clay/synthetic Thickener/filter

(continued)

TABLE 4-6 (continued)

ECONOMIC CONDITIONS

Indirect Capital Investment, Percent of Total Direct Investment

Engineering design and supervision	6-8
A-E	1-3
Construction expense	14-18
Contractor fees	4-6
Contingency	10
Total	35-45
Royalties	0
Working capital	a
Interest during construction	15.6[b]
Allowance for startup/modifications	8
Land, $/acre	4700

Annual Revenue Requirements

Direct costs	Raw materials Conversion costs Operating labor and supervision Utilities Maintenance Analysis

Indirect Costs, percent

Overheads	60[c]
Marketing	10[d]

Levelized Capital Charges, Percent of Total Capital[e]

Weighted cost of capital	10
Depreciation (sinking fund factor)	3.15
Annual interim replacement	0.72
Levelized accelerated tax depreciation	(1.44)
Levelized investment tax credit	(2.39)
Levelized income tax	3.96
Insurance and property taxes	3.50
Total charge	16.5

---

[a] One month of raw materials, plus 1.5 months of conversion costs, plus 1.5 months overhead, plus 3 percent of total direct investment.

[b] Three-year construction schedule.

[c] Sixty percent of total conversion minus utilities.

[d] Ten percent of total by-product sales.

[e] Thirty-year plant life.

from Version I to Version II, the FGD module was upgraded to include the Shawnee Model. This procedure required the integration and downloading of two mainframe models--the Shawnee Model and IAPCS--the former being approximately four times the size of the latter into which it was incorporated. The Shawnee Model was integrated into IAPCS while retaining its mainframe version capabilities. Moreover, as part of IAPCS-II, the model now possesses a number of additional features. They include:

- Improved user friendliness provided by the microcomputer's simplified operating environment and IAPCS-II's operating protocol.
- Integrated modeling capability with the other IAPCS technology modules.
- The ability to cost FGD systems using TVA or EPRI economic premises.
- The ability to cost retrofit applications.

A summary of the basic design parameters and economic conditions of the FGD module as contained within IAPCS-II are presented in Table 4-7.

4.7 DRY SORBENT INJECTION[18-24]

The injection of sodium in dry powder form into the ductwork upstream of the PM collector exists as a technology module in IAPCS-II. The dry sorbent injection (DSI) module is contained in both versions of IAPCS. No revisions were made to the module's design and operating premises during the enhancement of IAPCS from Version I to Version II (excluding those enhancements to the model's overall accessibility and operation that expanded the

TABLE 4-7. DESIGN AND OPERATING PARAMETERS OF FGD MODULE OF IAPCS-II

Design Parameters[a]	
Plant application	New/retrofit
Plant size, MW	100-1300 MW
Coal sulfur, percent	Unlimited
SO_2 loading, ppmv/lb per 10^6 Btu	Unlimited
Absorber gas velocity, ft/s	8-12.5 (base case = 10)
Number of absorbers	0-10 (base case = 4)
Number of spare absorbers	0-2 (base case = 1)
SO_2 removal, percent	0-100 (base case 89)
L/G ratio, gal/1000 acf	25-120 (base case = 106)
Slurry hold tank residence time, min.	2-25 (base case = 18)
Recycle slurry solids, percent	5-15 (base case = 10)
Maximum reheat temperature	225 (base case - 175)
Processing Areas	
FGD	Raw material handling
	Raw material preparation
	SO_2 scrubbing
	Oxidation
	Reheat
System	Gas handling
	Waste disposal
Process Options	Limestone slurry (base case)
	Lime slurry
Process additive options	Adipic acid/magnesium oxide
Absorber options	Spray tower (base case)
	TCA
	Venturi-spray tower
Forced oxidation	Slurry hold tank
Reheat options	Indirect steam (base case)
	Flue gas bypass
	Combination
Solid waste treatment options	Chemical fixation
	Forced oxidation (base case)
Solid waste disposal options	Onsite/landfill (base case)
	Thickener/filter (base case)
Economic Conditions	
TVA premises	
EPRI premises	

[a] Base case values represent model-supplied defaults.

conditions under which DSI and all other technology modules can be evaluated).

Dry sorbent injection technology involves the introduction of a dry sorbent into the gas stream for chemical conversion of SO_2 to a waste salt that is subsequently removed in a downstream PM collection device. Based on this control technology concept, a number of process design configurations are possible that meet the following criteria:

- Additive: sodium alkali, calcium alkali, calcium-magnesium alkali, ammonia, fly ash
- Sorbent injection mode: continuous, intermittent, batch
- Particulate collection: ESP, FF
- Byproduct disposition: waste disposal, product recovery

Several other variations are possible within each grouping cited above; however, the overall number of specific design configurations that is feasible in IAPCS-II strategy are limited because of the maturity of the technology, inherent design limitations, resource constraints, and disposal considerations. Without going into undue detail and lengthy explanation, the process design configuration that meets the foregoing criteria is the continuous injection of a sodium-based alkali with the utilization of a FF as the downstream collector and the disposal of the collected reaction products in an environmentally acceptable manner.

A limited number of variations of the basic process design configuration warrant investigation for model strategies. These variations are based on the following information:

1. Five sodium-based alkalies are available for DSI: nahcolite, trona, commercial-grade sodium, bicarbonate, and commercial-grade soda ash. The major factors affecting additive selection include effectiveness of removing SO_2, cost, resource availability and access (in quantities suitable to support a commercial facility), auxiliary handling and disposal, and compatibility with other integrated operations. In accordance with these factors, nahcolite appears to represent the most practical additive for DSI.

2. The sorbent injection mode can be continuous, intermittent, or batch feed. Continuous feed involves sorbent injection into the gas stream (in the approach duct) to maintain a desired stoichiometric ratio. Continuous injection represents the most practical mode despite limitations in attainable SO_2 removal (due to "lead time" requirements to build up filter cake on the bags following a cleaning cycle).

3. The collected reaction products are disposed of. Recovery and reuse of the reaction products are economically prohibitive and technically questionable at the present time.

4.7.1 Design Basis

The nahcolite is prepared in a ball mill and injected continuously (pneumatically) into the approach duct to the downstream PM collector. The collected reaction products are insolubilized and hauled away to a landfill.

Design factors are as follows:

1. Nahcolite is the only additive considered for DSI for IAPCS strategies. Specified (typical) chemical characteristics are noted in Table 4-8.

TABLE 4-8. TYPICAL NAHCOLITE ORE COMPOSITION[a]

Component[b]	Weight, %
Sodium bicarbonate ($NaHCO_3$)	70
Magnesium carbonate	3
Calcium carbonate	7
Inerts	20

[a] Green River formation source.

[b] Chloride (NaCl) less than 0.05 percent (assume no presence).

2. The mined nahcolite is crushed to 0.25-in. rock for transport and ground to a 200- to 400-mesh particle size in a dry ball mill at the plant for injection into the gas stream.

3. The nahcolite mill product is injected pneumatically into the approach duct approximately 100 ft upstream of the PM collector.

4. Particulate matter dropout is ignored. All PM goes to the downstream collector. At normal gas velocities (approximately 6000 ft/min), no dropout should occur (with minor exceptions for bends and transitions). Dropout becomes a factor for velocities under 3000 ft/min, which represents a 50 percent turndown allowance.

5. The overall reaction between SO_2 and nahcolite proceeds as follows:

$$4NaHCO_3 + 2SO_2 + O_2 \rightarrow 2Na_2SO_4 + 4CO_2 \uparrow + 2H_2O$$

Two moles of $NaHCO_3$ are required for each mole of SO_2 absorbed. Normalized stoichiometric ratio (NSR) is defined as a measure of the amount of sodium injected relative to the sulfur present in the flue gas. An NSR of 1.0 implies 2 moles of sodium (or $NaHCO_3$) per mole of SO_2 absorbed. Therefore, at NSR of 1.5, 3 moles of $NaHCO_3$ per mole of SO_2 absorbed are required.

6. Nahcolite injection is fixed at an NSR of 1.5. Nahcolite additive feed rates (NFR) are calculated as follows:

$$NFR = \left(\frac{3\ \text{moles}\ NaHCO_3}{\text{mole}\ SO_2}\right)\left(\frac{84\ \text{lb}}{\text{mole}\ NaHCO_3}\right)\left(\frac{\text{mole}\ SO_2}{64\ \text{lb}}\right)$$

$$\frac{1.43 \text{ lb nahcolite}}{(1 \text{ lb } NaHCO_3)} = \frac{5.6 \text{ lb nahcolite}}{\text{lb } SO_2 \text{ absorbed}}$$

where NFR = nahcolite feed rate, lb/lb SO_2 absorbed

1.43 = 70 percent $NaHCO_3$ purity correction

7. Research on attainable SO_2 removal efficiencies for DSI technology has been limited to low-sulfur coal applications (less than 1000 ppm SO_2) and FF collection. Performance data reported for bench-scale testing and demonstration plant testing are somewhat contradictory with respect to the effect of operating parameters on attainable SO_2 removals. Figure 4-1 presents SO_2 performance curves for bench-scale testing. These results suggest a significant difference between steady-state and average SO_2 removals as a function of cleaning cycle time. This difference is attributed to no SO_2 removal during the first 10 to 15 minutes after the onset of injection following cleaning because of insufficient filter cake buildup on the bags ("induction"). The average SO_2 removals therefore represent integrated values for the period between cleaning cycles. Figure 4-2 presents an SO_2 performance curve for demonstration plant testing. These results represent steady-state values. Moreover, these results, although not shown graphically, demonstrated that the normal cleaning cycle (i.e., 3 hours for this demonstration) had very little effect on SO_2 removal efficiency. A decrease of 1 to 4 percent was observed throughout the test.

   In accordance with these test results, an SO_2 removal efficiency of 80 percent is provided for the DSI/FF configuration in IAPCS-II. This value represents a conservative estimate for an annual performance period for a commercially unproven technology based upon the assumed operating parameters (NSR = 1.5, particle size of 200 to 400 mesh, T_{inlet} = 300°F, coal sulfur $\leq$1.5 percent, SO_2 $\leq$1000 ppm).

8. Dry sorbent injection technology involves two types of SO_2 removal mechanisms: suspension capture (SO_2 capture by nahcolite particles in the gas stream) and filter cake capture (SO_2 capture by filter cake buildup on the bag surface). Suspension capture occurs in the approach duct between the sorbent injection point and the collector inlet. Suspension capture is a strong function of operating temperature and stoichiometric ratio and a weak function of residence time. For the model operating conditions (NSR = 1.5, T = 300°F,

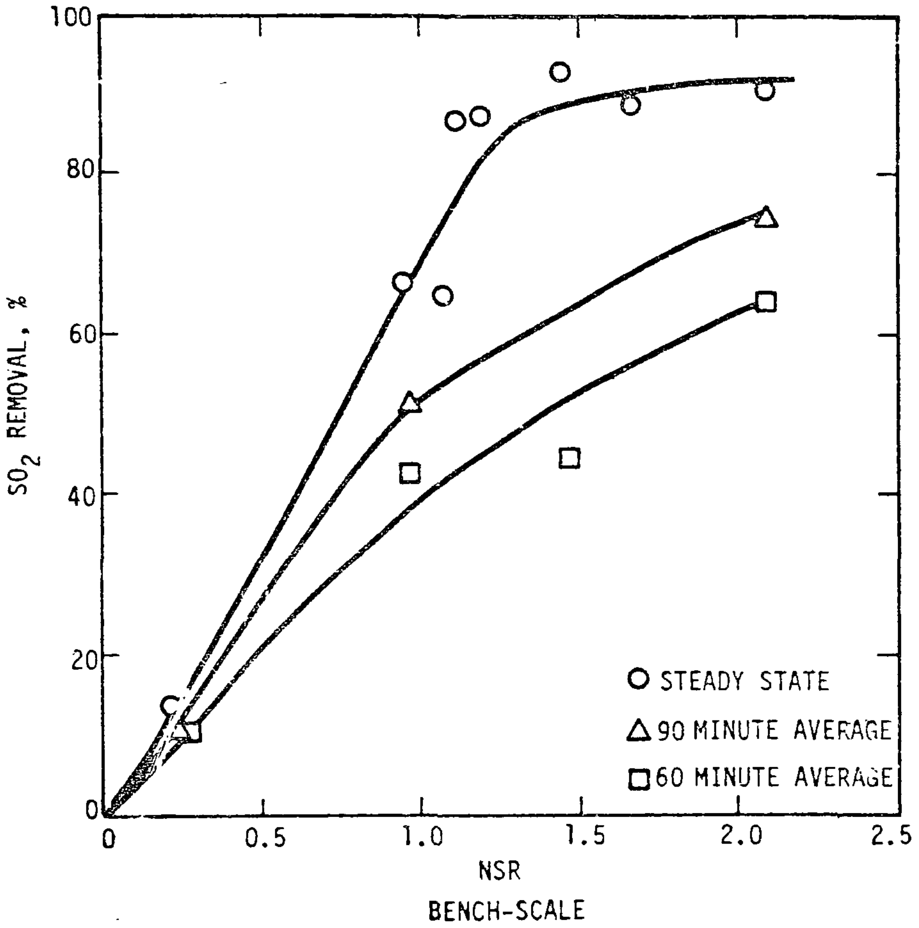

Figure 4-1. Bench-scale SO_2 removal performance curve[a].

[a] A/C = 2.3, T = 265°F, and particle size = 200 mesh.

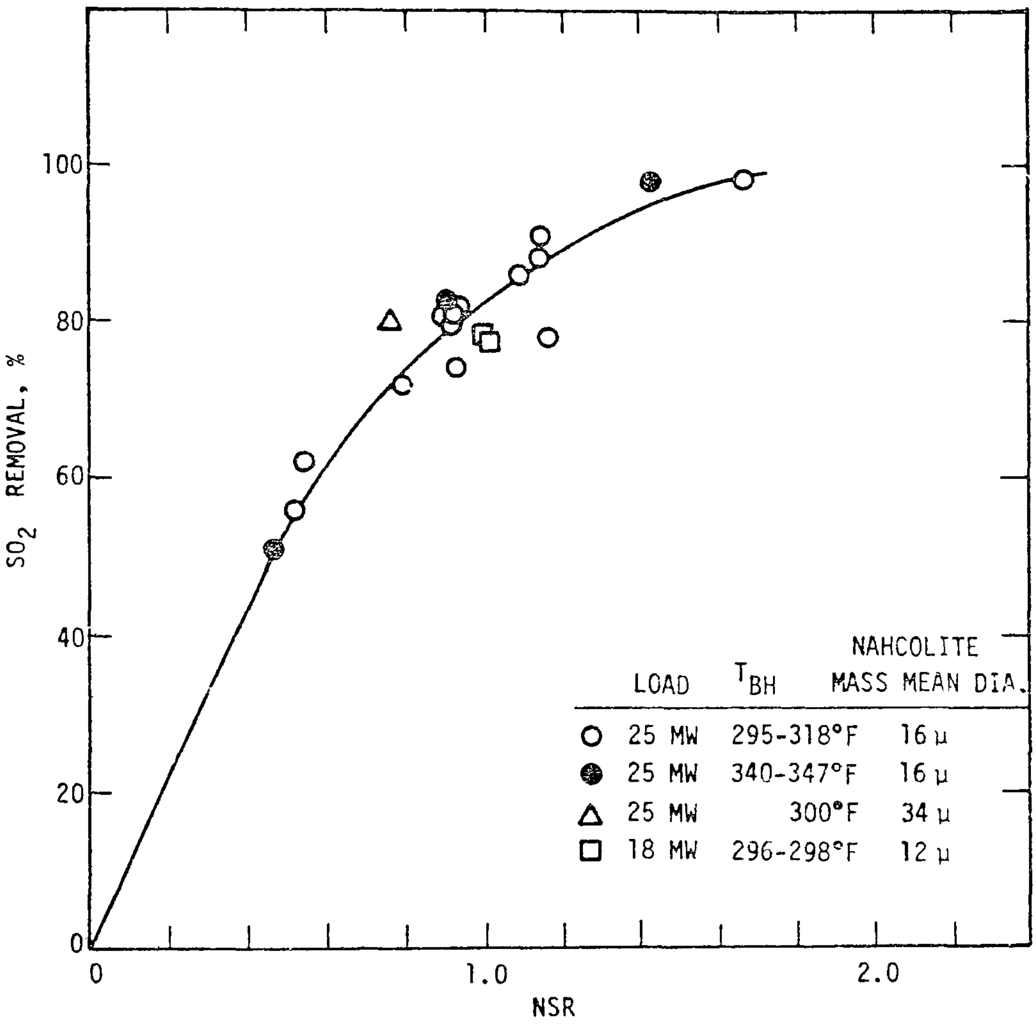

Figure 4-2. Demonstration plant SO_2 performance curve[a].

[a] A/C = 1.5 - 1.9 and T = 260°F - 350°F.

injection point 100-ft upstream of collector), experimental test results indicate very little SO_2 removal via suspension capture in the approach duct. Thus, DSI/ESP configuration represents an inappropriate selection in IAPCS-II (i.e., no SO_2 removal).

9. Injecting sorbent into the flue gas stream results in an increased PM loading to the FF and, subsequently, the amount of PM collected in the FF; however, experimental results indicate only slight effects on the FF's pressure drop/time characteristic. Furthermore, no increases have been observed in outlet loadings. The increased levels of PM loading and collection are estimated per the following:

   - 5.6 lb nahcolite/lb SO_2 absorbed
   - η_{SO_2} = 80 percent (see Item No. 5)
   - Increased loading = 4.5 lb nahcolite/lb inlet SO_2
   - Increased collection = (4.5 lb nahcolite/lb inlet SO_2) x fabric filter η_{part}.

10. Experimental test programs have shown varied results with respect to the effect of nahcolite injection on NO_x emission reduction. Recent results indicate that the nitric oxide (NO) component of NO_x is removed to a limited degree. Removal of NO is a strong function of NSR. At an NSR of 1.0, approximately 15 percent of the NO is removed. At an NSR of 1.75, approximately 25 percent of the NO is removed. Assuming linearity for this range, an NSR of 1.5 interpolates an NO removal of approximately 22 percent.

11. The contribution of fly ash alkalinity to SO_2 removal in DSI has been the subject of limited research. Major conclusions indicate that there is no significant removal of SO_2 by suspension capture in the approach ductwork (e.g., actual results were less than 3 percent) and that the SO_2 removal by filter cake capture is a function of fly ash concentration and SO_2 loading. This latter conclusion suggests that a high A/C ratio and SO_2 concentration are needed to effect significant removals. (Pilot plant results verify this conclusion in that SO_2 removals of 8 to 33 percent were measured for SO_2 levels of 400 and 4000 ppm at an air-to-cloth (A/C) ratio of 3:1.) These conclusions are further verified by dry lime sorbent injection testing that demonstrated low SO_2 capture for calcium oxide (the major alkali component of fly ash). Therefore, for the IAPCS-II model, credit was not be taken for alkalinity contributed by the captured fly ash.

12. The waste products associated with nahcolite DSI technology exhibit the following characteristics:

   ° They contain approximately 40 percent spent nahcolite and 60 percent fly ash.

   ° They are extremely soluble, on the order of 100 times more soluble in water than are calcium-based wastes.

   ° They are low in moisture, density, compressive strength, and structural integrity.

   These characteristics indicate that sodium-based wastes cannot be simply disposed of in a landfill. They will require special processing prior to final disposal. To this end, two broad techniques (or combinations thereof) are available: waste treatment (insolubilization via fixation or stabilization) and site treatment (dry impoundments, mine-fill). For IAPCS-II, waste treatment in the form of "conventional" fixation appears universally acceptable and applicable. Conversely, site treatment techniques appear to be unwieldy, expensive, and site-specific.

   Conventional chemical fixation involves the addition of lime and fly ash (as well as water) to the sodium wastes to generate an inert material environmentally suitable for landfill. Because no calcium compounds are present in the spent nahcolite, more lime may be needed to drive the pozzolanic reaction, especially for nonalkaline ashes associated with Eastern U.S. coals.

13. Nahcolite reactivity is a function of inlet flue gas temperature; the optimum temperature is 550°F. Below typical cold-side temperatures (275° to 325°F), SO_2 capture falls off dramatically. Minimum inlet gas temperature is 275°F. Therefore, DSI downstream of spray humidification represents an illegal combination.

4.7.2 Material Balance Considerations

The only change that occurs in the gas stream across the injection point is an increase in PM loading (3.9 lb of nahcolite per lb of inlet SO_2). No SO_2 or NO absorption occurs (no suspension removal). No PM dropout occurs in the approach duct to the downstream collection device. No significant changes occur in gas temperature and pressure.

4.8 ELECTROSTATIC PRECIPITATOR

The enhancement of IAPCS from Version I to Version II involved extensive modifications and refinements to the ESP module. The most significant refinement involved the incorporation of aspects of a model developed for EPA by Research Triangle Institute[25] and the incorporation of the resistivity prediction method developed for EPA by Southern Research Institute.[26] Based on the ESP module contained in Version I of IAPCS, three temperature-resistivity relationships were incorporated: volume resistivity, surface resistivity influenced by adsorbed water, and surface resistivity influenced by adsorbed acid. These temperature-resistivity relationships were used to adjust the specific collection area (SCA) predicted by the ESP module. The ESP module in IAPCS-II is now sensitive to fly ash alkalinity, moisture content, and sulfuric acid vapor with regard to resistivity; however, a parameter file value is always used for resistivity when LIMB is present in the system.

The module's cost equations estimate costs for the ESP, ductwork, and ash handling system. A fan is not included in this module (i.e., fan requirements are accounted for on a system basis). The ESP cost equations are for cold-side ESP's. The equipment installation costs are estimated as a percentage of the total equipment costs and added to the equipment cost to calculate the total direct cost of an ESP system. Operating and maintenance (O&M) costs are estimated by equations that calculate O&M labor, supervision, maintenance materials, and electricity and water requirements. Cost equations for ESP and ductwork are based on information prepared by PEI.

A new option in IAPCS-II allows for calculation of upgrade cost (additional plate area) for the ESP due to performance degradation of an existing ESP in the presence of LIMB. Calculation of upgrade-only costs will occur only if the following three conditions are true:

1. LIMB is present.
2. The system is a retrofit.
3. The appropriate parameter file value is set to 1 (the default).

If any of the above are false, costs for a new ESP will be calculated. The ESP performance will be reflected in any case.

The ESP is a cold-side insulated unit with a maximum possible PM removal efficiency of 99.9 percent. The cost estimated by the module depends on the flue gas flow rate and the SCA measured in square feet of plate area per 1000 acfm. The calculated SCA depends on the ash resistivity and the required PM removal efficiency. The matrix used to estimate the SCA requirements is based on data presented by EPA as having been derived from the EPA/SRI ESP computer model.[27]

This matrix is used in the module to predict the SCA; required removals and resistivities other than those in the matrix are interpolated by the program.

The basis of the ductwork cost is the same as that described for a FF (see Subsection 4.9). Estimates of duct layout and cost are based on typical ESP parameters: gas velocity, plate spacing, length-to-height ratio, flow rate, and SCA.

The ash handling system is based on design and costs developed for use in a U.S. Department of Energy study of coal conversion of 15 Florida powerplants.[28] These costs are in mid-1982 dollars and reflect an ash storage silo configuration rather than direct sluicing to an assumed onsite pond.

The ash system included for the ESP and FF modules consists of the following components:

- Under-device collection hoppers
- Pneumatic piping
- Vacuum producer
- Dust collector(s) for the ash silo(s)
- Three-day ash storage silos

This system has a number of advantages. Silo storage permits access to the fly ash in the case of concomitant use of an ESP or FF with lime spray drying. With this method of SO_2 control, large portions of the collected fly ash are used in the recycle slurry. Further, soluble wastes (e.g., from the dry sorbent injection module) may be safely stored prior to disposal. Costs for this dry storage system are higher than for an equivalent wet disposal system, unless the cost of a lined pond is included in the sluicing system. Capital cost validations were confirmed with vendors for use in the preparation of the cost algorithms.

Annual operating labor costs are based on the gas flow rate to the ESP, and an estimated 15 percent of these costs are for supervision. Maintenance materials are also estimated as a function of gas flow rate and are assumed to be equal to the maintenance labor cost.

The cost of electricity for operation of the ESP is based on a power density of 2.0 watts per square foot of ESP plate area and the number of operating hours per year. Electricity and water costs for the ash handling system also depend on the plant capacity factor and the quantity of ash that is collected and transported.

4.9 FABRIC FILTER

The module's cost equations estimate costs for an FF, ductwork, and ash handling equipment. An incremental fan cost based on the increased pressure drop in the FF is calculated as a system cost, not part of the FF cost. Installation costs are estimated as a percentage of the total equipment cost and are then added to this cost to determine the total direct cost of the FF system. The O&M costs are estimated by use of equations that calculate O&M labor, supervision, maintenance materials, rebagging expenses, electricity usage, and water requirements. Fabric filter and ductwork cost equations are based on information published by EPA.[26]

The FF is a reverse-air unit with a maximum removal efficiency of 99.7 percent. The estimated cost is dependent upon the flow rate and the air-to-cloth (A/C) ratio. The module assumes a default value of 2.0 acfm/ft^2. When combined with the LIMB module in an integrated system, the A/C ratio is assumed to be 1.5.

The ductwork is sized to provide a flue gas velocity of 3500 feet per minute. Although large utility systems generally use rectangular ducts for ease of fabrication, circular ductwork is assumed in this module to simplify calculations. Circular ducts are structurally stronger and have more flow rate for a given perimeter than rectangular ducts. The ductwork is insulated to prevent condensation. The ductwork cost model considers two different layouts: one for boilers with a capacity less than 650 MW and one for boilers in the 650- to 1300-MW range. The basic difference between the two layouts is the length of the ductwork.

The fan cost is based on the flue gas flow rate and the horsepower of the fan motor. The motor horsepower depends on the pressure drop and the overall fan and motor efficiency.

The ash-handling system is a dry system. The pneumatic piping, vacuum producer, and silo costs are based on the tons of ash that are collected each hour by the FF.

The number of plant operating personnel required is based on flow rate. Supervision is calculated to be 15 percent of the operating labor cost. Maintenance labor is a function of the size of the and maintenance materials and replacement parts are assumed to be equal to the maintenance labor cost. Electricity costs are calculated as a function of the horsepower of the reverse-air fan and vacuum motors, the capacity factor of the plant (a measure of its operating time), and the cost of electricity. Water costs for the ash handling system also depend upon the plant capacity factor and the quantity of ash that is collected and transported.

SECTION 5

INTEGRATED CHARACTERISTICS OF THE SYSTEM

The IAPCS-II model has been developed in part to provide a unique view of the performance of an air emission control system made up of individual modules. To this end, the performance of the entire system is output, as well as the material balance associated with each module in a specified control system.

Solid waste quantities are summed by module, and the cost of disposal of both wet and dry waste components are presented. The ash storage and handling system of the PM collection device is special in that it has the built-in capability to recycle portions as required. A system that comprises storage silos and a conveyor network is more costly than one that calls for direct disposal to an ash pond, but the importance of recycle (especially of highly alkaline fly ash) cannot be overlooked.

Another integrated feature of the model involves the use of a system fan module. The individual pressure drops for any assembled control system are used to determine the overall horsepower and cost of the induced-draft fan(s). This is a less costly option for addressing the fan requirements than on a module-by-module basis.

The material balance is the single most important integrated characteristic of the program. The relative significance of application of a given technology on a system basis can be readily assessed.

Finally, the emission summary and the cost-effectiveness outputs permit easy comparison of integrated control configurations from an economic standpoint.

SECTION 6

COMPUTER PROGRAM STRUCTURE

6.1 PROGRAM ENVIRONMENT

IAPCS-II has been converted to Microsoft FORTRAN 77™ (Version 3.2) for use on the IBM PC AT™ or XT™ microcomputer.* The model cannot be used on a floppy-disk-based system. The system must include at least 512 kilobytes of random access memory and run under the DOS 2.1 (XT) or 3.1 (AT) (or higher) operating system. The user should have at least 1.5 megabytes available on the hard disk.

The executable program files and all supporting data files are provided on floppy disks in the PC DOS BACKUP format. Table 6-1 contains a description of these files.

The original version of IAPCS was designed as an interactive system; IAPCS-II allows input via a "batch" file created with a word processor or spreadsheet program. Section 6.3 provides details on input requirements. Output reports can be transmitted either to the console screen or the printer, or both at the user's option.

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* IBM PC AT and IBM PC XT are trademark names of the IBM Corporation.

TABLE 6-1. IAPCS-II DISK FILES[a]

File name	Description
MODULES.EXE	Program executable file to size and cost control modules.
INPUT.EXE	Program executable file to gather input data and perform initial gas stream and coal-cleaning calculations.
OUTPUT.EXE	Program executable file to site and cost system fans and waste disposal. Also makes economic calculations and prints output reports.
IAPCS.BAT	DOS batch command file to run executables sequentially.
PARMFILE.TVA	TVA default parameter file.
PARMFILE.EPR	EPRI default parameter file.
LOSTHELP.DOC	Help information for escalation.
OPTHELP.DAT	Help information for optimization.
PARMHELP.DAT	Help information for parameter editor.

[a] Other temporary files are created by the program.

6.2 PROGRAM STRUCTURE

6.2.1 Basic Structure

The program is designed to simulate numerically the effect of the emission control modules, selected and sequenced by the user, on the gas stream. Resources required by each module are allocated and stored when the module is encountered. This leads to a modular programming approach in that each module is generally represented by a subroutine. The control configuration therefore determines when and if each of these subroutines is called.

Figure 6-1 illustrates the IAPCS-II program flow control. Program flow is directed by the DRIVER, which initiates most subroutine calls. Provisions for the PCC control option are also made within DRIVER; there is no separate PCC subroutine. Subroutine INPUT solicits user input and reads a parameter file (see file descriptions) of "preliminary" design and cost parameters. INPUT also prints an input summary--the first output section. Subroutine UNCNTL calculates 1) initial gas stream characteristics, 2) the amount of bottom ash, 3) initial system performance, and 4) uncontrolled emissions.

Each of the control module routines selected is called by DRIVER in the order specified by the user. Both direct and indirect capital costs are calculated individually by each module subroutine. Annual resource quantities are calculated here; however, these are summed over the entire system and cost factors applied in the output routine. Material balance calculations are

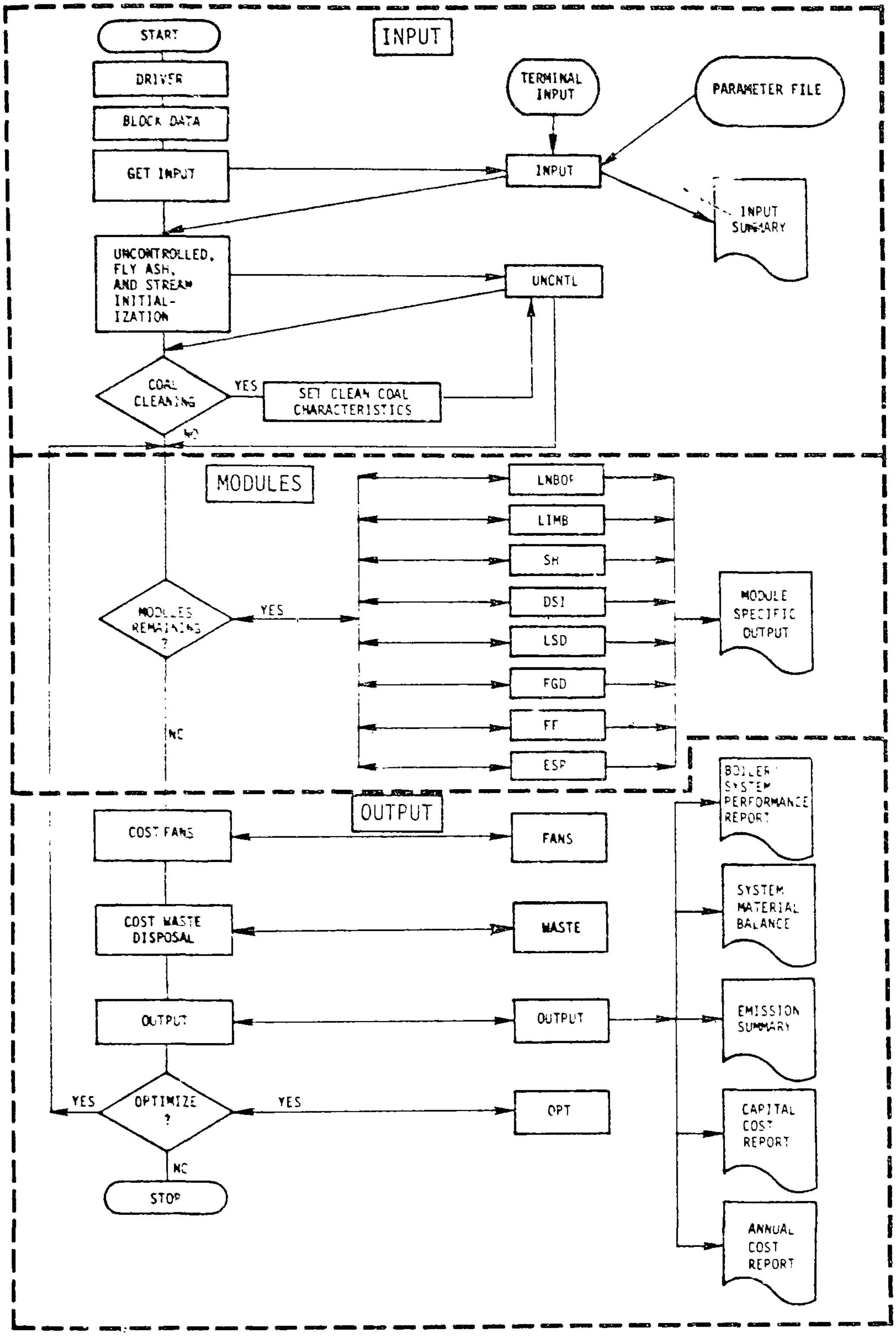

Figure 6-1. General flow diagram of the IAPCS program.

performed, and the gas stream characteristics (stored globally) are modified for use by subsequent module subroutines. Data pertinent to the design of certain modules are printed by the module subroutines; this forms the second output section.

Subroutine FANS is used to size and cost system fans. Subroutine OUTPUT makes final boiler/system performance calculations, totals capital costs, and calculates annual costs. The final six output sections are printed here. These are Boiler System Performance, System Material Balance, Emission Summary, Capital Costs, Annual Costs, and Cost-Effectiveness.

The user may optimize the cost for a particular emission rate through subroutine OPT. This option will calculate a removal efficiency for a control module chosen by the user and rerun the program. The user is required to input a target emission rate.

Further program documentation may be found in the source program listing (Appendix B).

6.2.2 IAPCS-II Modifications

Although the program is conceptually the same in IAPCS-II as in IAPCS-I, several structural changes were necessary because of the incorporation of the Shawnee Model into IAPCS-II. The Shawnee Model program alone is approximately four times the size of IAPCS-I. Because the new program is so large, it was divided into three smaller programs. The function of the first program (INPUT) is to collect input data and make the "uncontrolled" calculations. It then passes these data to the second program (MODULES) via a temporary disk file. MODULES contains a driver program that calls, in the proper sequence, all control modules selected by the user. It then writes all necessary calculated values in a disk file for use by the third program (OUTPUT). OUTPUT calculates costs and writes the final output report. Figure 6-1 shows the division of IAPCS-II operations among the three programs.

A batch file has been created to execute three IAPCS-II programs sequentially so that it appears to the user as if only one program is executed.

As stated previously, the Shawnee Model has replaced the original IAPCS-I FGD algorithms and subroutine. IAPCS-II still regards FGD as a single subroutine (refer to the subroutine tree diagram in Figure 6-2). Certain user options, and therefore subroutines, were not included, however. Also, the fan and waste disposal cost algorithms are included with subroutines in the OUTPUT program of IAPCS-II.

6.3 USER INFORMATION

IAPCS-II is provided on floppy disks and is loaded onto a hard disk by using the DOS RESTORE command.

IAPCS-II has two input methods: batch and interactive. The interactive method is the same as in the original version of IAPCS; the user is queried by the program for all pertinent information. All questions asked by the program must be answered; defaults, when shown, must be entered by the user.

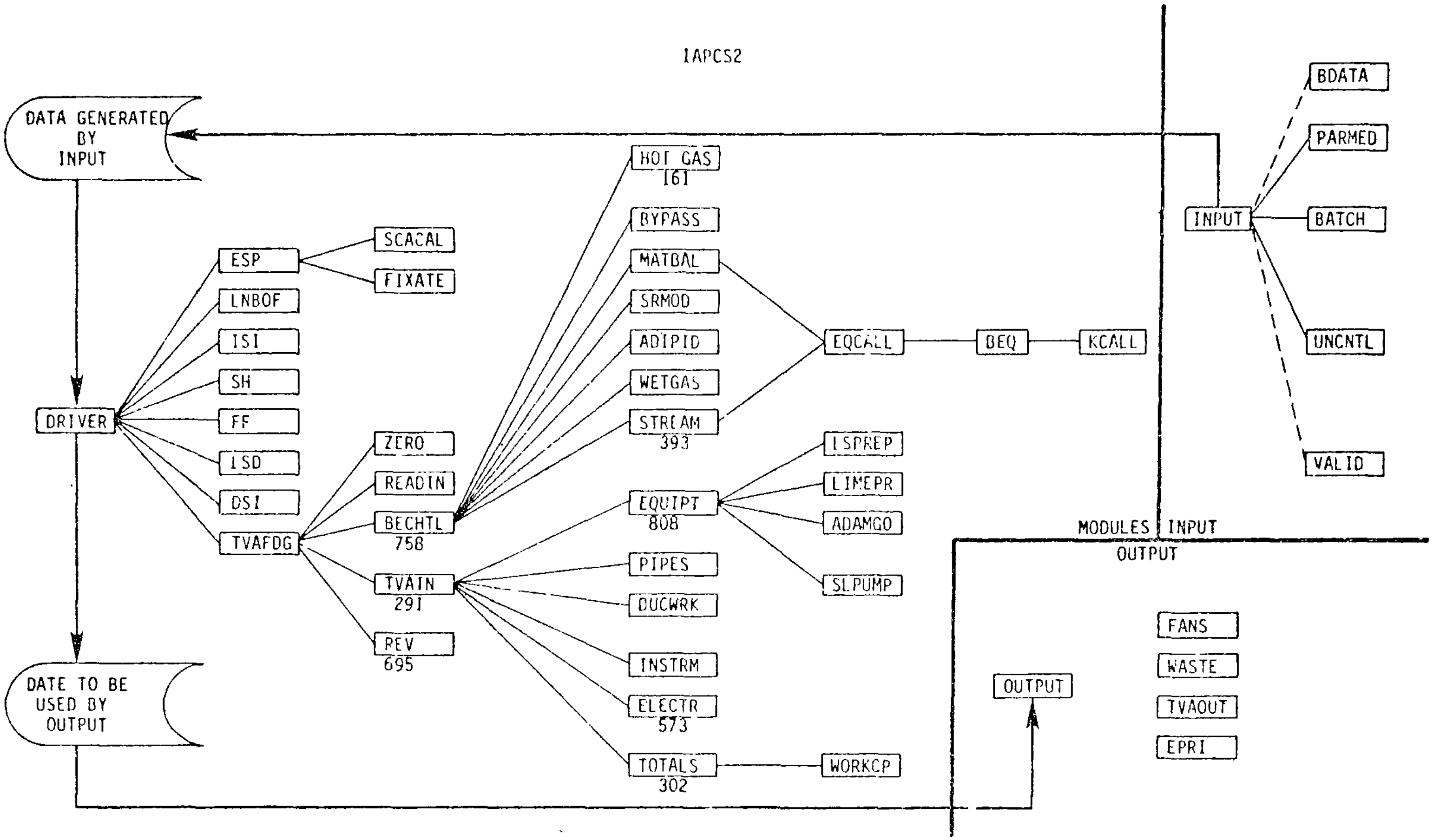

Figure 6-2. Subroutine tree diagram.

The batch method of input entails the use of batch files of input data created by a spreadsheet or word processor program. This method is not as straightforward as the interactive method and should be undertaken only by users with a working knowledge of a suitable spreadsheet of an ASCII word processor program. The advantage of this method over the interactive method is the ability to save input data so that multiple runs with similar data can be made without the need to reenter all the input. An internally documented template for a batch input file (Figure 6-3) is provided on the IAPCS-II program disks. To use this template, the user calls up the template file into a standard ASCII word processor, makes changes, and then saves the file under another name.

The line entries (records) in the template file correspond to the interactive input entries. The actual input data are contained at the beginning of each record up to the vertical bar. At least one blank space should follow the input data entry (immediately preceding the vertical bar). Text describing the input element follows the bar. This descriptive information can be deleted if desired.

Batch files may vary in length based the type of coal used (typical, ROM, or clean), the number of modules, and the number of modules to be optimized. If the user enters a typical coal type code, all ROM characteristics (all entries from coal type to cleaning level) must be deleted. If a clean, user-defined coal is desired, the characteristics for the clean coal should immediately follow the ROM characteristics.

```
EXAMPLE OF IAPCS2 BATCH FILE                   |---- COMMENT LINE 1
TEMPLATE.  .                                   |---- COMMENT LINE 2
1 |--- 1= TVA ECONOMIC FORMAT; 2= EPRI FORMAT
TVAPARMS |--- PARAMETER FILE NAME; MUST BE CONSISTENT WITH ECONOMIC FORMAT!
2 |--- 1- WALL FIRED; 2= TANGENTIAL
  500 |--- BOILER SIZE, MW
62.8 |--- CAPACITY FACTOR, %
1 |--- CONSTRUCTION STATUS, 1  NEW, 2= RETROFIT
 1986 |--- DATE OF COMMERCIAL OPERATION, YYYY
300 |--- INITIAL GAS TEMPERATURE, DEG.F
2 |--- 1= TYPICAL COAL TYPE; 2= USER-DEFINED COAL
1 |--- TYPICAL COAL TYPE (1-6) OR GENERAL COAL TYPE (1-3) FOR USER COAL
11700   |--- ROM HHV, BTU/# *** ALL ENTRIES HERE DOWN TO CLEANING OPTION OMITTED
 3.36   |--- ROM % SULFUR    *** FOR TYPICAL COAL
15.1    |--- ROM % ASH
0       |--- ROM COST, $/TON
0       |--- ROM % NA2O
0       |--- ROM % ALKALINITY
0.1     |--- ROM % CHLORINE
0       |--- ROM % FE2O3
4.00    |--- ROM % MOISTURE
40.45   |--- ROM % VOLATILE MATTER
40.45   |--- ROM % FIXED CARBON
N       |--- CLEAN COAL OPTION: Y OR N FOR USER COAL; 2(YES) OR 1 FOR TYPICAL
1       |--- 1= DRY BOTTOM; 2=WET *** INSERT CLEAN COAL SPECS ABOVE THIS LINE
1       |--- PRINTOUT OPTION: 1- PRINTER;2= DISPLAY;3= BOTH.
1       |--- NUMBER OF CONTROL MODULES.
8       |--- CONTROL MODULE NUMBERS. ONE LINE FOR EACH MODULE NUMBER!
N       |--- OPTIMIZATION OPTION: Y(ES) OR N(O);
END
```

Figure 6-3. Batch input file template.

Two further points should be noted regarding batch files. The two blank lines at the beginning of the file must always be present. Also, the user may configure the batch file so that a subsequent batch run is begun after the current run terminates. This "chaining" is done by entering the name of the next batch file on the final record of the current batch file.

Errors resulting in program termination frequently occur because an incorrect number of input records are in the batch file or because records are our of sequence. If an error occurs during a batch run, the user should check to make sure the number and order of records are consistent with regard to coal type and cleaning level, number of modules, and optimization.

Once the user has installed the program and decided on an input method, he/she is ready to run. The user logs into the IAPCS directory and types: IAPCS<cr> ("<cr>" is the command to press the carriage return). This command invokes the DOS command file that executes the three IAPCS-II programs.

Depending on the input options selected, output will be sent to the screen, to the printer, or to both. After the output is printed, the user is asked if he/she wishes to optimize. If so, a new emissions rate must be entered. All calculations and output are then repeated. The user may optimize as often as desired.

6.4 IAPCS-II PROGRAM LISTING

Appendix C represents the entire IAPCS-II program listing. A large amount of the program documentation is provided in the comment statements of the listing.

SECTION 7

SUMMARY OF INSTALLATION AND OPERATION PROCEDURES FOR IAPCS-II

1. Configure system files.

It is recommended that the CONFIG.SYS file (usually in the root directory of the boot drive) contain the command "BREAK=ON"; this will allow the user to stop a run at any time during execution.

If an IBM PC/AT (or compatible) is used with an 80287 math coprocessor, the following command must be in the AUTOEXEC.BAT file when the system is booted:

SET NO87 = FALSE

The user should refer to the DOS manual for information regarding CONFIG.SYS and AUTOEXEC.BAT.

2. Create a directory on a hard disk for the IAPCS files.

The user should log onto the root directory of the "C" drive (or other hard disk) of his/her computer and then enter the following DOS commands:

MD IAPCS <cr>

CD IAPCS <cr>

Once the directory has been created ("MD"), only the "CD" need be performed when the program is subsequently accessed.

3. Restore all files into the IAPCS directory.

The user should enter the following command:

RESTORE A: C: <cr>

He/she will be prompted to insert the program disks in sequence.

[The above three steps need only be performed once (except for the "CD" command in step 2 which must be entered each time the program is run).]

4. Run the program.

The user should enter the following command:

IAPCS <cr>

The program will then begin operation. During the course of a run, several extraneous messages may appear on the screen; these are normal and should be ignored. Examples of these messages are "FALSE" and File not found.

The input to the program is in five basic sections or "screens." These are discussed separately elsewhere in the manual, but are summarized below:

a) Input method option and economic format.

Entering an "I" followed by a carriage return in response to the initial question will cause the interactive input sequence to proceed. Otherwise, the IAPCS directory will be searched for the fully qualified batch input file named by the user and no further user prompts will be given. There will be a noticeable delay after this screen.

b) Parameter menus and submenus.

The user should enter menu option numbers or other information as prompted. In general, entering a zero for a submenu option will return the user to a higher menu level. Option 5 on the parameter menu will move the user to the next input section.

c) General design input.

Input questions will scroll past as the user responds to questions. The user should stay within stated ranges for numeric entries.

d) Control system configuration.

Option numbers for control modules are listed. Selected option numbers should be entered in order, on one line, separated by commas. Although any combination of modules may be entered, nonsensical configurations may result in an error termination of the program or untrustworthy output. It is advised that the user abide by the configuration rules displayed on the screen. After the system configuration has been entered, the user will be given an opportunity to edit his/her entries. The program will then run, and output will be printed and/or displayed.

e) Optimization.

If an optimizable module is in the control system, the user will be given an opportunity to optimize. The user must select one module to be optimized and select a target emission rate for the pollutant that this module removes. Please note that all modules except LIMB must be given an emission rate higher than the calculated value that is displayed on the screen. Also emission rates that would result in negative efficiencies may cause the program to abort or cause other unpredictable results.

5. Troubleshooting

The following are potential problems that may be encountered when running IAPCS-II:

° Parameter file does not exist

The user should check to make sure that the economic format used is consistent with the one used when the file was created. The DOS command "dir" should be used to verify the file's existence.

° Program continuously gives error messages (or terminates with a single error message)

The user should hold down the control key ("Ctrl") and press "Scroll Lock" (Break). This should be done repeatedly until the program stops. If the break set is not on (see number 1 above), the user may have to re-boot.

The program may get into this error loop (or, more likely, simply terminate with an error message) for several reasons. Some typical reasons are:

- An input item or parameter has an unreasonable value (possibly zero or negative).

- A nonsensical control system was specified.

- Batch file input records are missing or out of sequence.

- An invalid optimization was attempted.

- On an AT with a math coprocessor, N087 = FALSE was not specified (See 1. Above).

° The computer "just sits there" (no output, no hard disk activity)

Although this is sometimes natural (especially when wet FGD is present in the system), if it continues for longer than 5 minutes the user should attempt to "break"; however, rebooting will probably be necessary. (To perform a "warm-boot", user should hold down the "Ctrl", "Alt", and "Del" keys simultaneously and then release them.)

Any of the problems capable of causing an error termination or loop could also cause this problem.

SECTION 8

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APPENDIX A

PARAMETER FILE LISTING

EPRI DEFAULT PARAMETER FILE

PARMFILE.EPR

System Wide

VALUE		DESCRIPTION
.8846		BASE THERMAL EFFICIENCY
7914.	7924	GROSS HEAT RATE, BTU/KWH
.0000	9500	BOILER NET HEAT RATE (CALCULATED IF ZERO), BTU/KWH
100.0		BOILER LOAD, %
.5000		SOLID COMBUSTIBLE LOSS, %
.9950		COMBUSTIBLE LOSS CORRECTION FACTOR, FRACTION
.0000		FLOW RATE, ACFM (CALCULATED IF ZERO)
1.000		DEFAULT NA2O CONTENT OF ASH, %
7.500		SALES TAX AND FREIGHT, % PROCESS CAPITAL (WASTE)
10.00		ENGINEERING AND HOME OFFICE FEES, % PROCESS CAPITAL (WASTE)
10.00		GENERAL FACILITIES, % PROCESS CAPITAL(WASTE)
15.00		PROJECT CONTINGENCY, % PROCESS CAPITAL (WASTE)
10.00		PROCESS CONTINGENCY, % PROCESS CAPITAL (WASTE)
.0000		SALES TAX, % PROCESS CAPITAL (WASTE)
.0000		ROYALTY ALLOWANCE, % PROCESS CAPITAL (WASTE)
.0000		INVENTORY CAPITAL, % PROCESS CAPITAL (WASTE)
.0000		INITIAL CATALYST, % TOTAL PROCESS CAPITAL (WASTE)
3.000		MAINTENANCE LABOR AND MATERIAL, % TOTAL PROCESS CAPITAL (WASTE)
35.00		ANNUAL RAINFALL, IN/YEAR
.0000		SEEPAGE RATE, CM/SEC
32.00		ANNUAL EVAPORATION, IN/YEAR
5.000		SLUDGE DISPOSAL OPTION(4-THICKENER/FILTER/FIXATION,5-LANDFILL)
.0000		SLUDGE FIXATION OPTION (0-NO FIXATION,1-SLUDGE-FLY,ASH-LIME)
9999.		TOTAL AVAILABLE LAND FOR CONSTRUCTION OF WASTE FACILITY, ACRES
75.00		UNCOMPACTED WASTE BULK DENSITY, LB/CU FT
95.00		COMPACTED WASTE BULK DENSITY, LB/CU FT
5280.		DISTANCE FROM UTILITY AREA TO DISPOSAL SITE, FT
1.000		DISPOSAL SITE LINING (1-CLAY,2-SYNTHETIC,3-NO LINER)
12.00		CLAY DEPTH, IN
1.000		FRACTION ON-SITE DISPOSAL

PARMFILE.FPR

Unctrl Coal

VALUE	DESCRIPTION
.8000	DEFAULT PARTICULATE OVERHEAD RATIO, IF ZERO, AP 42 USED, FRACT
.0000	DEFAULT SO2 OVERHEAD RATIO, IF ZERO, AP 42 EMISSION FACTORS USED
.5000	PARTICULATE DRY-BOTTOM EMISSION FACTOR(AP42 SUPLMT.13 REV),FRACT
.3500	PARTICULATE WET-BOTTOM EMISSION FACTOR (IBID), FRACTION
.3150	PARTICULATE LIGNITE EMISSION FACTOR (IBID), FRACTION
.9750	SO2 BITUMINOUS EMISSION FACTOR (IBID), FRACTION
.8750	SO2 SUB-BITUMINOUS EMISSION FACTOR (IBID), FRACTION
.7500	SO2 LIGNITE EMISSION FACTOR (IBID), FRACTION
.5250	NOX WALL FIRED BITUMINOUS/SUB-BITUM DRY-BOTTOM (IBID), FRACTION
.3500	NOX WALL FIRED LIGNITE DRY-BOTTOM (IBID), FRACTION
.3750	NOX TANGEN. FIRED BITUMINOUS/SUB-BITUM. DRY BOTTOM (IBID), FRACT
.2000	NOX TANGENTIAL LIGNITE DRY-BOTTOM
.8500	NOX ALL WET-BOTTOM (AS ABOVE)
9820.	PC F-FACTOR (IBID, DSCF/MMBTU)
.2000	EXCESS AIR, FRACTION

PARMFILE.EPR

Fan

VALUE	DESCRIPTION
10.00	ENGINEERING AND HOME OFFICE FEES, % PROCESS CAPITAL (FANS)
10.00	GENERAL FACILITIES, % PROCESS CAPITAL (FANS)
15.00	PROJECT CONTINGENCY, % PROCESS CAPITAL (FANS)
10.00	PROCESS CONTINGENCY, % PROCESS CAPITAL (FANS)
.0000	SALES TAX, % PROCESS CAPITAL (FANS)
.0000	ROYALTY ALLOWANCE, % PROCESS CAPITAL (FANS)
4.000	MAINTENANCE LABOR AND MATERIAL, % TOTAL PROCESS CAPITAL (FANS)
.0000	INVENTORY CAPITAL, % PROCESS CAPITAL (FANS)
1.000	FAN RETROFIT FACTOR, DIMENSIONLESS

PARMFILE.EPR

Economic

VALUE	DESCRIPTION
.0000	O & M LEVELIZATION FACTOR (CALCULATED IF ZERO), DIMENSIONLESS
.0000	CAPITAL LEVELIZATION FACTOR (CALCULATED IF ZERO), DIMENSIONLESS
10.00	ITC INVESTMENT TAX CREDIT, %
30.00	B1 BOOK LIFE, YEARS
15.00	P1 TAX LIFE, YEARS
11.00	CD COST OF DEBT, %
50.00	DR DEBT RATIO, %
11.50	CP COST PREFERRED STOCK, %
15.00	PR PREFERRED RATIO, %
15.30	CE COST OF COMMON STOCK, % (COMMON RATIO= 100%-PR-DR)
50.00	TX FEDERAL AND STATE INCOME TAX, %
8.500	EI INFLATION RATE, %
2.000	PTI PROPERTY TAX AND INSURANCE, %
.8000	ER REAL ANNUAL ESCALATION RATE, %
3.000	TDM: 1=ACC.DEPR.;2=STRT.LN.OVER B1;3=STRT.LN.ON ACRS SCHED.
.0000	DISCOUNT RATE, % CALCULATED FROM ABOVE IF 0
30.00	ADMINISTRATIVE AND SUPPORT LABOR FACTOR (% OF O&M LABOR)
.0000	YEAR OF CAP COSTS(YYMM), IF 0., JUNE, 1982 (BASE YEAR) USED
.0000	YEAR OF O&M COSTS(YYMM), IF 0., JUNE, 1982 (BASE YEAR) USED
8507.	DATE OF CE AND O&M INDICES, YYMM
325.0	CE PLANT INDEX FOR CORRESPONDING YEAR AND MONTH OF COST
340.7	CE MATERIAL INDEX FOR CORRESPONDING YEAR AND MONTH OF COST
264.9	CE LABOR INDEX FOR CORRESPONDING YEAR AND MONTH OF COST
113.0	O&M INDEX FOR CORRESPONDING YEAR AND MONTH OF COST (6/82=100)

PARMFILE.EPR

LSD

VALUE	DESCRIPTION
1.530	STOICHIOMETRIC RATIO (LSD)
80.00	UTILIZATION OF FLY ASH ALKALINITY, % (LSD)
53.00	AVERAGE MOLECULAR WEIGHT OF ALKALINITY IN FLY ASH
.7250	FRESH LIME COMPONENT OF SLURRY, FRACTION (LSD)
85.00	MAXIMUM EFFICIENCY OF LSD, % (LSD)
35.00	MAXIMUM SOLIDS IN SLURRY BY WEIGHT, %
4.636	MAXIMUM REACTIVE ALKALINITY/MEGAWATT (LSD)
10.00	MAXIMUM EFFICIENCY OF FLY ASH ALKALINITY, % (LSD)
1.560	MODIFIED PARTICULATE LOADING EXITING SPRAY DRYER, FRACT. (LSD)
160.0	SPRAY DOWN TEMPERATURE, DEG.F (LSD)
6.000	PRESSURE DROP ACROSS DRYER, IN. H2O (LSD)
2.000	INSTALLATION FACTOR, DIMENSIONLESS (LSD)
10.00	GENERAL FACILITIES, % PROCESS CAPITAL (LSD)
10.00	ENGINEERING AND HOME OFFICE FEES, % PROCESS CAPITAL (LSD)
15.00	PROJECT CONTINGENCY, % PROCESS CAPITAL (LSD)
15.00	PROCESS CONTINGENCY, % PROCESS CAPITAL (LSD)
.0000	SALES TAX,% PROCESS CAPITAL (LSD)
.0000	ROYALTY ALLOWANCE FACTOR, % PROCESS CAPITAL (LSD)
.0000	REACTIVE ALKALINITY FACTOR FOR BITUMINOUS COAL, FRACTION (LSD)
.2500	REACTIVE ALKALINITY FACTOR FOR SUB-BITUMINOUS COAL, FRACTION (LS
.2000	REACTIVE ALKALINITY FACTOR FOR LIGNITE COAL, FRACTION (LSD)
.4300E+05	OPERATING AND SUPERVISION LABOR, MANHOURS/YEAR (LSD)
.4300	LSD ELECTRIC USEAGE, % GROSS KILOWATTS (LSD)
1.500	LSD REPLACEMENT PARTS COST FACTOR, % TOTAL EQP COST (LSD)
6.000	MAINTENANCE LABOR AND MATERIAL, % OF TOT.PROCESS CAP. (LSD)
.0000	INVENTORY CAPITAL, % PROCESS CAPITAL (LSD)
1.000	LSD RETROFIT FACTOR, DIMENSIONLESS

PARMFILE.EPR

Low Nox/Over

VALUE	DESCRIPTION
10.00	ENGINEERING AND HOME OFFICE FEES, % PROCESS CAPITAL (LNBOF)
10.00	GENERAL FACILITIES, % PROCESS CAPITAL (LNBOF)
15.00	PROJECT CONTINGENCY, % PROCESS CAPITAL (LNBOF)
10.00	PROCESS CONTINGENCY, % PROCESS CAPITAL (LNBOF)
.0000	ROYALTY ALLOWANCE COST FACTOR, % PROCESS CAPITAL(LNBOF)
.0000	SALES TAX, % PROCESS CAPITAL (LNBOF)
2.000	MAINTENANCE LABOR AND MATERIAL, % OF TOT.PROCESS CAP.(LNBOF)
.0000	INVENTORY CAPITAL, % PROCESS CAPITAL (LNBOF)

PARMFILE.EPR

Fabr. Filter

VALUE	DESCRIPTION
.000	AIR-TO-CLOTH RATIO, CFM/SQUARE FOOT (FF)
9.70	FABRIC FILTER EFFICIENCY, % (FF)
0.00	MINIMUM BYPASS, % (FF)
.020	INSTALLATION AND FREIGHT COST FACTOR, DIMENSIONLESS (FF)
0.00	ENGINEERING AND HOME OFFICE FEES, % PROCESS CAPITAL (FF)
0.00	GENERAL FACILITIES, % PROCESS CAPITAL (FF)
5.00	PROJECT CONTINGENCY, % PROCESS CAPITAL (FF)
0.00	PROCESS CONTINGENCY, % PROCESS CAPITAL (FF)
0000	SALES TAX, % PROCESS CAPITAL (FF)
0000	ROYALTY ALLOWANCE, % PROCESS CAPITAL (FF)
0000	INITIAL CATALYST, % TOTAL PROCESS CAPITAL (FF)
15.00	PERCENT SUPERVISION TO OPERATING LABOR, % (FF)
20.00	WATER TO ASH BY WEIGHT, % (FF)
3.000	PRESURE DROP ACCROSS FABRIC FILTER, IN. H2O (FF)
20.00	SO2 EFFICIENCY OF FF PRECEEDED BY LIMB, % REMOVAL (FF)
.0000	SO2 EFFICIENCY OF FF PRECEEDED BY SPRAY HUMID., % REMOVAL (FF)
20.00	SO2 EFFICIENCY OF FF PREDEEDED BY LSD, % REMOVAL (FF)
30.00	SO2 EFFICIENCY OF FF PRECEEDED BY DSI, % REMOVAL (FF)
1.000	MAINTENANCE LABOR AND MATERIAL, % TOT. PROCESS CAPITAL (FF)
.0000	INVENTORY CAPITAL, % PROCESS CAPITAL (FF)
1.000	FABRIC FILTER RETROFIT FACTOR, DIMENSIONLESS

PARMFILE.EPR

ESP

VALUE	DESCRIPTION
99.90	MAXIMUM REMOVAL EFFICIENCY, % (ESP)
2.170	INSTALLATION AND FREIGHT COST FACTOR, DIMENSIONLESS (ESP)
2.000	DUCT COST FACTOR FOR LARGE(>=500MW) UNITS, DIMENSIONLESS (ESP)
100.0	SIZING FACTOR FOR ASH SILOS, TONS/HOUR/SILO (ESP)
10.00	ENGINEERING AND HOME OFFICE FEES, % OF PROCESS CAPITAL (ESP)
10.00	GENERAL FACILITIES, % OF PROCESS CAPITAL (ESP)
15.00	PROJECT CONTINGENCY, % OF PROCESS CAPITAL (ESP)
10.00	PROCESS CONTINGENCY, % OF PROCESS CAPITAL (ESP)
.0000	SALES TAX, % OF PROCESS CAPITAL (ESP)
.0000	ROYALTY ALLOWANCE, % OF PROCESS CAPITAL (ESP)
15.00	PERCENT SUPERVISION TO OPERATING LABOR, % (ESP)
20.00	WATER TO ASH BY WEIGHT, % (ESP)
1.000	PRESSURE DROP ACROSS ESP, IN. H2O
.0000	SO2 EFFICIENCY OF ESP PRECEEDED BY LIMB, % (ESP)
.0000	SO2 EFFICIENCY OF ESP PRECEEDED BY SPRAY HUMIDIFICATION,%(ESP)
.0000	SO2 EFFICIENCY OF ESP PRECEEDED BY LSD, % (ESP)
.0000	SO2 EFFICIENCY OF ESP PRECEEDED BY DSI, % (ESP)
4.000	MAINTENANCE LABOR AND MATERIAL, % TOT.PROCESS CAPITAL(ESP)
.0000	ASH RESISTIVITY, 10**9 OHM-CM (CALCULATED FROM COAL SULFUR IF 0)
1500.	ASH RESISTIVITY IN PRESENCE OF LIMB, 10**9 OHM-CM
.0000	INVENTORY CAPITAL, % PROCESS CAPITAL (ESP)
1.000	ESP RETROFIT FACTOR, DIMENSIONLESS

PARMFILE.EPR

LIMB

VALUE	DESCRIPTION
2.000	STOICHIOMETRIC RATIO (LIMB)
7.000	1-CALC.LMST 2-DOL.LMST 3-CALC.HYD 4-DOL.HYD 5-CPH 6-DPH7-LS8-L
95.00	SORBENT PURITY, % (LIMB)
5.000	NUMBER OF JOBS (LIMB)
10.00	ENGINEERING AND HOME OFFICE FEES, % PROCESS CAPITAL (LIMB)
10.00	GENERAL FACILITIES, % PROCESS CAPITAL (LIMB)
25.00	PROJECT CONTINGENCY, % PROCESS CAPITAL (LIMB)
20.00	PROCESS CONTINGENCY, % PROCESS CAPITAL (LIMB)
.0000	SALES TAX, % PROCESS CAPITAL (LIMB)
.0000	ROYALTY ALLOWANCE, % PROCESS CAPITAL COST (LIMB)
.5000	CAPTURE EFFICIENCY RANGE SPAN, FRACTION
15.00	SUPERVISION, % OPERATING MANHOURS (LIMB)
700.0	QUENCH RATE, DEG.F/SEC
4.000	MAINTENANCE LABOR AND MATERIAL, % OF PROCESS CAPITAL (LIMB)
1.000	ASSUME ESP COST IS UPGRADE FOR LIMB RETROFIT(1=TRUE,0=FALSE)
.8000	FRACTION FLYASH, REMAINDER IS BOTTOM ASH (LIMB)
15.00	ADDITIVE SO3 CONCENTRATION, PPM

PARMFILE.EPR

Spray Humid.

VALUE	DESCRIPTION
3500.	GAS VELOCITY IN S.H. CHAMBER, FT/MIN (SH)
1.250	EXTRA FABRICATION COST FACTOR (1.+25%) (SH)
3.000	WATER USEAGE FACTOR, DIMENSIONLESS (SH)
8.000	SURGE TANK RETENTION TIME, HOURS (SH)
.1473E+05	MAXIMUM TANK SIZE, CU. FT. (SH)
1.100	EXTRA PUMPAGE FACTOR, DIMENSIONLESS (SH)
70.00	PUMP EFFIECIENCY, % (SH)
100.0	PUMP HEAD ON FEED PUMPS, FT. (SH)
50.00	PUMP HEAD ON FRESH WATER PUMPS, FT. (SH)
1.850	TANK AND PUMP INSTALLATION FACTOR, DIMENSIONLESS (SH)
2.000	FEED PUMP REDUNDANCY, DIMENSIONLESS (SH)
2.000	FRESH WATER PUMP REDUNDANCY, DIMENSIONLESS (SH)
10.00	ENGINEERING AND HOME OFFICE FEES, % PROCESS CAPITAL (SH)
10.00	GENERAL FACILITIES, % PROCESS CAPITAL (SH)
20.00	PROJECT CONTINGENCY, % PROCESS CAPITAL (SH)
20.00	PROCESS CONTINGENCY, % PROCESS CAPITAL (SH)
.0000	SALES TAX, % PROCESS CAPITAL COST (SH)
.0000	ROYALTY ALLOWANCE, % PROCESS CAPITAL COST (SH)
600.0	OPERATING AND SUPERVISION MANHOURS/YEAR (SH)
2.000	MAINTENANCE LABOR AND MATERIAL, % TOT.PROCESS CAPITAL(SH)
2.000	INCREMENTAL PRESSURE DROP ACROSS SH, IN. H2O (SH)
.0000	INVENTORY CAPITAL, % PROCESS CAPITAL (SH)
1.000	SPRAY HUMIDIFICATION RETROFIT FACTOR, DIMENSIONLESS

PARMFILE.EPR

DSI

VALUE	DESCRIPTION
3.000	MOLAR STOICHIOMETRIC RATIO (DSI)
70.00	NAHCOLITE PURITY, % (DSI)
85.00	PERCENT SOLIDS IN FIXATION WASTE STREAM (DSI)
1.500	FIXATION COST FACTOR, DIMENSIONLESS (DSI)
80.00	DSI EFFICIENCY , % (DSI)
10.00	ENGINEERING AND HOME OFFICE FEES, % (DSI)
10.00	GENERAL FACILITIES, % PROCESS CAPITAL (DSI)
20.00	PROJECT CONTINGENCY, % PROCESS CAPITAL (DSI)
20.00	PROCESS CONTINGENCY, % PROCESS CAPITAL (DSI)
.0000	SALES TAX, % PROCESS CAPITAL (DSI)
.0000	ROYALTY ALLOWANCE, % PROCESS CAPITAL (DSI)
2400.	OPERATING AND SUPERVISION MANHOURS/YEAR (DSI)
4.000	MAINTENANCE LABOR AND MATERIAL, % TOTAL PROCESS CAPITAL (DSI)
1.500	NORMAL STOICHIOMETRIC RATIO (DSI)
.0000	INITIAL CATALYST, % TOTAL PROCESS CAPITAL (DSI)
.0000	INVENTORY CAPITAL, % PROCESS CAPITAL (DSI)
1.000	DSI RETROFIT FACTOR, DIMENSIONLESS

PARMFILE.EPR

FGD System

VALUE	DESCRIPTION
200	SRIN STOICHIOMETRIC RATIO (FGD)
.00	XSO2 MAXIMUM REMOVAL EFFICIENCY, % (FGD)
000	FGD RETROFIT FACTOR, DIMENSIONLESS
6.0	XLG L/G RATIO FOR SCRUBBER, GALLONS/1000 CU. FT.
000	ISR L/G, EFFICIENCY CONTROL VARIABLE (0,1,2)
000	XESP PARTICULATE COLLECTION OPTION (0,1,2)
000	XRH REHEAT OPTION (0,2)
5.0	TSK TEMPERATURE OF STACK GAS, DEG. F.
0.0	TSTEAM TEMPERATURE OF REHEATER STEAM, DEG. F.
1.9	HVS HEAT OF VAPORIZATION OF REHEATER STEAM, BTU/LB
000	IASH UNIT OF MEASURE OPTION FOR PARTICULATE REMOVAL(0,1,2,3)
000E-01	ASHUPS VALUE FOR PARTICULATE REMOVAL UPSTREAM FROM SCRUBBER
.00	VLG L/G RATIO IN VENTURI, GALLONS/1000 CU FT
000	VTR VENTURI/OXIDATION HOLD TANK RESIDENCE TIME, MIN
.00	V SCRUBBER GAS VELOCITY, FT/SEC
.00	VRH SUPERFICIAL GAS VELOCITY THROUGH REHEATER, FT/SEC
000	TR RECIRCULATION/OXIDATION HOLD TANK RESIDENCE TIME, MIN
000	IALK ALKALI ADDITION OPTION (1,2)
000	IADD CHEMICAL ADDITIVE OPTION (0,1,2)
000	WPMGO SOLUBLE MGO IN LIMESTONE OR LIME, WT % DRY BASIS
500	XMGOAD SOLUBLE MGO ADDED TO SYSTEM, LB/100 LB LIMESTONE
00.	AD ADIPIC ACID IN SCRUBBING LIQUID, PPMW
000	ADDC ADIPIC ACID DEGRADATION CONSTANT
850	WPI INSOLUBLES IN LIMESTONE-LIME ADDITIVE, WT % DRY BASIS
000	WPM MOISTURE IN LIMESTONE-LIME ADDITIVE, LB/100 LB DRY BASIS
000	WPS SOLIDS IN RECYCLE SURRY TO SCRUBBER, WT %
.00	PSD SOLIDS IN SLUDGE DISCHARGE, WT %
000	RS THICKENER SOLIDS SETTLING RATE, FT/HR
.00	PSC PERCENT SOLIDS IN THICKENER UNDERFLOW, WT %
000	IFOX FORCED OXIDATION OPTION (0,1,2,3)
.00	OX OXIDATION OF SULFITE IN SRUBBER LIQUID, MOLE %
500	SRAIR AIR STOICHIOMETRY VALUE, MOLES OXYGEN/MOLE SO2 ABSORBED
.00	PSF PERCENT SOLIDS IN FILTER CAKE, WT %
200	FILRAT FILTRATION RATE, TONS/SQ FT/DAY
200	PHLIME RECIRCULATION LIQUOR PH
000	IVPD VENTURI -P- OPTION (0,1)
000	VPD VALUE FOR EITHER -P- OR THROAT VELOCITY, IN H2O OR FT/SE
000	DELTAP OVERRIDE -P- FOR ENTIRE SYSTEM, IN H2O
.70	PRES SCRUBBER PRESSURE, PSIA
000	IFAN FAN OPTION (0,1)
000	ISCRUB SCRUBBING OPTION (1,2,3,4,5,6)
000	XNS NUMBER OF TCA STAGES
000	XNG NUMBER OF TCA GRIDS
000	HS HEIGHT OF SPHERES PER STAGE, IN
00	WINDEX LIMESTONE HARDNESS WORK INDEX FACTOR, DIMENSIONLESS
00	HPTONW FINENESS OF GRIND INDEX FACTOR, HP/TON
000	NOREDN NUMBER OF SPARE SCRUBBER TRAINS
000	PCNTRN ENTRAINMENT LEVEL OF WET GAS, WT %
000	NSPREP NUMBER OF SPARE PREPARATION UNITS
000	NOTRAN NUMBER OF OPERATING SCRUBBER TRAINS
00	EXSAIR EXCESS AIR, %

PARMFILE.EPR

FGD Econs

VALUE	DESCRIPTION
.0000	SALES TAX, % PROCESS CAPITAL (FGD)
.0000	INITIAL CATALYST, % TOTAL PROCESS CAPITAL (FGD)
12.20	GENERAL FACILITIES, % PROCESS CAPITAL(FGD)
18.80	ENGINEERING AND HOME OFFICE FEES, % PROCESS CAPITAL (FGD)
7.800	PROJECT CONTINGENCY, % PROCESS CAPITAL (FGD)
.0000	PROCESS CONTINGENCY, % PROCESS CAPITAL (FGD)
.0000	ROYALTY ALLOWANCE, % PROCESS CAPITAL (FGD)
.0000	MAINTENANCE LABOR AND MATERIALS, % PROCESS CAPITAL
4.000	TXRAT SALES TAX RATE, %
3.500	FRRAT FREIGHT RATE, %
6.000	SERVRT SERVICES, UTILITIES, AND MISCELLANEOUS, % TPC

PARMFILE.EPR
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Cost based JUNE, 1986

VALUE	DESCRIPTION
78.70	SULFUR COST ($/TON)
20.87	OPERATING AND SUPERVISION LABOR COST ($/HR)
25.05	ANALYSIS LABOR COST ($/HR)
.4819E-01	ELECTRICITY COST ($/KWH)
.6902	WATER COST ($/1000GAL)
6.672	STEAM REHEAT COST ($/MMBTU)
30.27	CALCITE ($/TON)
84.76	CALCITIC HYDRATE COST ($/TON)
109.0	NAHCOLITE COST ($/TON)
14.09	WASTE DISPOSAL, WET($/TON)
6.841	WASTE DISPOSAL, DRY ($/TON)
6893.	LAND COST ($/ACRE)
30.27	DOLOMITIC LIMESTONE COST, $/TON
90.81	DOLOMITIC HYDRATE COST, $/TON
102.9	CALCITIC PRESSURE HYDRATE COST, $/TON
109.0	DOLOMITIC PRESSURE HYDRATE COST, $/TON
16.42	LIMESTONE COST, $/TON
57.48	LIME COST, $/TON
3.771	DUCTWORK METAL FABRICATION AND INSTALLATION COST, $/LB(SH)
6.630	CLAY COST, $/CU YD
617.5	MGO UNIT COST, $/TON
1816.	ADIPIC ACID UNIT COST, $/TON
1.937	DIESEL FUEL COST, $/GAL
.0000	SYNTHETIC LINER MATERIAL UNIT COST, $/SQ YD
.0000	SYNTHETIC LINER LABOR UNIT COST, $/SQ YD

TVA DEFAULT PARAMETER FILE

PARMFILE.TVA

System Wide

VALUE	DESCRIPTION
.8846	BASE THERMAL EFFICIENCY
7924.	GROSS HEAT RATE, BTU/KWH
9500.	BOILER NET HEAT RATE (CALCULATED IF ZERO), BTU/KWH
100.0	BOILER LOAD, %
.5000	SOLID COMBUSTIBLE LOSS, %
.9950	COMBUSTIBLE LOSS CORRECTION FACTOR, FRACTION
.0000	FLOW RATE, ACFM (CALCULATED IF ZERO)
7.500	TAXES AND FREIGHT, % DIRECT COST (WASTE)
1.000	A-E CONTRACTOR, % DIRECT COST (WASTE)
2.000	ENGINEERING DESIGN AND SUPERVISION, % DIRECT COST (WASTE)
8.000	CONSTRUCTION EXPENSE COST FACTOR, % DIRECT COST (WASTE)
5.000	CONTRACTOR'S FEE COST FACTOR, % DIRECT COST (WASTE)
20.00	CONTINGENCY COST FACTOR, % D+I (WASTE)
.0000	ROYALTIES, % DIRECT COST (WASTE)
15.60	INTEREST DURING CONSTRUCTION, % D+I (WASTE)
.0000	ALLOWANCE FOR STARTUP AND MODIFICATION, % D+I (WASTE)
3.000	MAINTENANCE LABOR AND MATERIAL, % OF DIRECT COST (WASTE)
35.00	ANNUAL RAINFALL, IN./YEAR
.0000	SEEPAGE RATE, CM/SEC
32.00	ANNUAL EVAPORATION, IN./YEAR
5.000	SLUDGE DISPOSAL OPTION (4-THICKENER/FILTER/FIXATION, 5-LANDFILL)
.0000	SLUDGE FIXATION OPTION (0-NO FIXATION, 1-SLUDGE-FLY, ASH-LIME)
9999.	TOTAL AVAILABLE LAND FOR CONSTRUCTION OF WASTE FACILITY, ACRES
75.00	UNCOMPACTED WASTE BULK DENSITY, LB/CU FT
95.00	COMPACTED WASTE BULK DENSITY, LB/CU FT
5280.	DISTANCE FROM UTILITY AREA TO DISPOSAL SITE, FT
1.000	DISPOSAL SITE LINING (1-CLAY, 2-SYNTHETIC, 3-NO LINER)
12.00	CLAY DEPTH, IN
1.000	FRACTION ON-SITE DISPOSAL

PARMFILE.TVA

Unctrl Coal

VALUE	DESCRIPTION
.8000	DEFAULT PARTICULATE OVERHEAD RATIO, IF ZERO, AP 42 IS USED,FRAC.
.9500	DEFAULT SO2 OVERHEAD RATIO,IF ZERO,AP 42 EMISSION FACTORS USED
.5000	PARTICULATE DRY-BOTTOM EMISSION FACTOR(AP42 SUPLMT13 REV.), FRAC
.3500	PARTICULATE WET-BOTTOM EMISSION FACTOR (IBID), FRACTION
.3150	PARTICULATE LIGNITE EMISSION FACTOR (IBID), FRACTION
.9500	SO2 BITUMINOUS EMISSION FACTOR (IBID), FRACTION
.8750	SO2 SUBBITUMINOUS EMISSION FACTOR (IBID), FRACTION
.7500	SO2 LIGNITE EMISSION FACTOR (IBID), FRACTION
.5250	NOX WALL FIRED BITUMINOUS/SUB-BITUM DRY-BOTTOM (IBID), FRACTION
.3500	NOX WALL FIRED LIGNITE DRY-BOTTOM (IBID), FRACTION
.3750	NOX TANGEN. FIRED BITUMINOUS/SUB-BITUM. DRY BOTTOM (IBID), FRACT
.2000	NOX TANGENTIAL LIGNITE DRY-BOTTOM
.8500	NOX ALL WET-BOTTOM (AS ABOVE)
9820.	PC F-FACTOR (IBID, DSCF/MMBTU)
.3900	EXCESS AIR, FRACTION
940.0	# AIR/MMBTU FIRED (IBID)

PARMFILE.TVA

Fan

VALUE	DESCRIPTION
1.000	A-E CONTRACTOR, % DIRECT COST (FANS)
6.000	ENGINEERING DESIGN AND SUPERVISION, % DIRECT CAPITAL (FANS)
14.00	CONSTRUCTION EXPENSE COST FACTOR, % DIRECT CAPITAL (FANS)
4.000	CONTRACTOR'S FEE COST FACTOR, % D+I (FANS)
10.00	CONTINGENCY COST FACTOR, % D+I (FANS)
.0000	ROYALTIES, % D+I (FANS)
8.000	ALLOWANCE FOR STARTUP AND MODIFICATIONS, % D+I CAPITAL (FANS)
4.000	MAINTENANCE LABOR AND MATERIAL, % OF DIRECT COST (FANS)
15.60	INTEREST DURING CONSTRUCTION, % D+I COST (FANS)
1.000	FAN RETROFIT FACTOR, DIMENSIONLESS

PARMFILE.TVA

Economic

VALUE	DESCRIPTION
60.00	OVERHEAD CHARGE ON O&M LABOR (%)
14.70	LEVELIZED CAPITAL CHARGE RATE (CALCULATED IF ZERO), DIMENSIONLES
1.886	O&M LEVELIZATION FACTOR (CALCULATED IF ZERO), DIMENSIONLESS
15.00	CONTINGENCY (% OF D&I COST)
5.000	STARTUP & SPARES (% OF D&I COST)
15.60	INTEREST DURING CONSTRUCTION(% OF D&I COST)
10.00	WEIGHTED COST OF CAPITAL (CALCULATED IF ZERO), %
.5000	FRACTION OF LONG TERM DEBT
9.000	COST OF CAPITAL, %
.1500	FRACTION OF PREFERED STOCK
10.00	COST OF PREFERED STOCK, %
.3500	FRACTION OF COMMON STOCK
11.40	COST OF COMMON STOCK, %
30.00	ECONOMIC LIFE, YEARS
30.00	TAX LIFE, YEARS
30.00	BOOK LIFE, YEARS
.5000	INCOME TAX RATE
10.00	INVESTMENT TAX CREDIT RATE, %
.2500E-01	INSURANCE AND PROPERTY TAXES
.1000	DISCOUNT RATE
8506.	YEAR OF CAP COSTS(YYMM), IF 0., JUNE, 1982 (BASE YEAR) USED
8706.	YEAR OF O&M COSTS(YYMM), IF 0., JUNE, 1982 (BASE YEAR) USED
8508.	DATE OF CE INDICES (YYMM)
325.0	CE PLANT INDEX FOR CORRESPONDING YEAR AND MONTH OF COST
366.8	CE MATERIAL INDEX FOR CORRESPONDING YEAR AND MONTH OF COST
292.2	CE LABOR INDEX FOR CORRESPONDING YEAR AND MONTH OF COST
113.0	O&M INDEX FOR CORRESPONDING YEAR AND MONTH OF COST (6/82=100)

PARMFILE.TVA

LSD

VALUE	DESCRIPTION
1.530	STOICHIOMETRIC RATIO (LSD)
80.00	UTILIZATION OF FLY ASH ALKALINITY, % (LSD)
53.00	AVERAGE MOLECULAR WEIGHT OF ALKALINITY IN FLY ASH
.7250	FRESH LIME COMPONENT OF SLURRY, FRACTION (LSD)
85.00	MAXIMUM EFFICIENCY OF LSD, % (LSD)
35.00	MAXIMUM SOLIDS IN SLURRY BY WEIGHT, %
4.636	MAXIMUM REACTIVE ALKALINITY/MEGAWATT (LSD)
10.00	MAXIMUM EFFICIENCY OF FOR FLY ASH ALKALINITY, % (LSD)
1.560	MODIFIED PARTICULATE LOADING EXITING SPRAY DRYER, FRACT (LSD)
160.0	SPRAY DOWN TEMPERATURE, DEG.F (LSD)
6.000	PRESSURE DROP ACROSS DRYER, IN. H2O (LSD)
2.000	INSTALLATION FACTOR, DIMENSIONLESS (LSD)
7.000	ENGINEERING DESIGN AND SUPERVISION, % DIRECT CAPITAL (LSD)
2.000	A-E CONTRACTOR, % DIRECT COST (LSD)
16.00	CONSTRUCTION EXPENSE COST FACTOR, % DIRECT CAPITAL (LSD)
5.000	CONTRACTOR FEE COST FACTOR, % DIRECT CAPITAL (LSD)
20.00	CONTINGENCY COST FACTOR, %DIRECT&INDIRECT CAPITAL (LSD)
.0000	ROYALTIES, % DIRECT + INDIRECT (LSD)
.0000	REACTIVE ALKALINITY FACTOR FOR BITUMINOUS COAL, FRACTION (LSD)
.2500	REACTIVE ALKALINITY FACTOR FOR SUB-BITUMINOUS COAL, FRACTION (LS
.2000	REACTIVE ALKALINITY FACTOR FOR LIGNITE COAL, FRACTION (LSD)
10.00	ALLOWANCE FOR START-UP AND MODIFICATIONS , % D+I CAPITAL (LSD)
.4400E+05	OPERATING AND SUPERVISION LABOR, MANHOURS/YEAR (LSD)
.4300	LSD ELECTRIC USEAGE, % GROSS KILOWATTS (LSD)
1.500	LSD REPLACEMENT PARTS COST FACTOR, % TOTAL EQP COST (LSD)
6.000	MAINTENANCE LABOR AND MATERIALS, % OF DIRECT COST (LSD)
15.60	INTEREST DURING CONSTRUCTION FACTOR, % D&I CAPITAL (LSD)
1.000	LSD RETROFIT FACTOR, DIMENSIONLESS

PARMFILE.TVA

Low Nox/Over

VALUE	DESCRIPTION
1.000	A-E CONTRACTOR, % DIRECT COST (LNBOF)
6.000	ENGINEERING DESIGN AND SUPERVISION, % DIRECT CAPITAL (LNBOF)
14.00	CONSTRUCTION EXPENSE COST FACTOR, % DIRECT CAPITAL (LNBOF)
4.000	CONTRACTOR FEE COST FACTOR, % DIRECT CAPITAL (LNBOF)
10.00	ALLOWANCE FOR STARTUP AND MODIFICATION, % D&I CAPITAL (LNBOF)
.0000	ROYALTIES, % DIRECT + INDIRECT (LNBOF)
20.00	CONTINGENCY COST FACTOR, % D&I CAPITAL (LNBOF)
4.000	MAINTENANCE LABOR AND MATERIALS, % DIRECT (LNBOF)
4.840	INTEREST DURING CONSTRUCTION COST FACTOR, % D&I CAPITAL (LNBOF)

PARMFILE.TVA

Fabr. Filter

VALUE	DESCRIPTION
2.000	AIR-TO-CLOTH RATIO, CFM/SQUARE FOOT (FF)
99.70	FABRIC FILTER EFFICIENCY, % (FF)
10.00	MINIMUM BYPASS, % (FF)
2.020	INSTALLATION AND FREIGHT COST FACTOR, DIMENSIONLESS (FF)
1.000	A-E CONTRACTOR, % DIRECT (FF)
6.000	ENGINEERING DESIGN AND SUPERVISION FACTOR, % DIRECT CAPITAL (FF)
14.00	CONSTRUCTION EXPENSE COST FACTOR, % DIRECT CAPITAL (FF)
4.000	CONTRACTOR FEE COST FACTOR, % DIRECT CAPITAL (FF)
20.00	CONTINGENCY COST FACTOR, % DIRECT & INDIRECT CAPITAL (FF)
.0000	ROYALTIES, % DIRECT (FF)
10.00	ALLLOWANCE FOR STARTUP AND MODIFICATIONS, % D+I COST (FF)
15.00	PERCENT SUPERVISOION TO OPERATING LABOR, % (FF)
20.00	WATER TO ASH RATIO BY WEIGHT, % (FF)
3.000	PRESURE DROP ACCROSS FABRIC FILTER, IN. H2O (FF)
20.00	SO2 EFFICIENCY OF FF PRECEEDED BY LIMB, % REMOVAL (FF)
.0000	SO2 EFFICIENCY OF FF PRECEEDED BY SPRAY HUMID., % REMOVAL (FF)
20.00	SO2 EFFICIENCY OF FF PREDEEDED BY LSD, % REMOVAL (FF)
80.00	SO2 EFFICIENCY OF FF PRECEEDED BY DSI, % REMOVAL (FF)
4.000	MAINTENANCE LABOR AND MATERIALS, % DIRECT (FF)
15.60	INTEREST DURING CONSTRUCTION, % D+I COST (FF)
1.000	FABRIC FILTER RETROFIT FACTOR, DIMENSIONLESS

PARMFILE.TVA
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ESP

VALUE	DESCRIPTION
99.90	MAXIMUM REMOVAL EFFICIENCY, % (ESP)
.4000	DEFAULT NA2O CONTENT OF ASH, % (ESP)
2.170	INSTALLATION AND FREIGHT COST FACTOR (ESP)
2.000	DUCT COST FACTOR FOR LARGE (>=500MW) UNITS (ESP)
100.0	SIZING FACTOR FOR ASH SILOS, TONS/HOUR/SILO (ESP)
1.000	A-E CONTRACTOR, % DIRECT COST (ESP)
6.000	ENGINEERING DESIGN AND SUPERVISION FACTOR, % OF DIRECT COST (ESP
14.00	CONSTRUCTION EXPENSE COST FACTOR, % OF DIRECT COST (ESP)
4.000	CONTRACTOR'S FEE COST FACTOR, % OF DIRECT (ESP)
20.00	CONTINGENCY COST FACTOR, % OF DIRECT & INDIRECT COSTS (ESP)
.0000	ROYALTIES, % DIRECT + INDIRECT (ESP)
15.00	PERCENT SUPERVISION TO OPERATING LABOR, % (ESP)
20.00	WATER TO ASH RATIO BY WEIGHT, % (ESP)
1.000	PRESSURE DROP ACROSS ESP, IN. H2O
.0000	SO2 EFFICIENCY OF ESP PRECEEDED BY LIMB, % (ESP)
.0000	SO2 EFFICIENCY OF ESP PRECEEDED BY SPRAY HUMIDIFICATION,% (ESP)
.0000	SO2 EFFICIENCY OF ESP PRECEEDED BY LSD, % (ESP)
.0000	SO2 EFFICIENCY OF ESP PRECEEDED BY DSI, % (ESP)
4.000	MAINTENANCE LABOR AND MATERIALS, % DIRECT (ESP)
10.00	ALLOWANCE FOR STARTUP AND MODIFICATION, % OF D+I COSTS (ESP)
.0000	ASH RESISTIVITY, 10**9 OHM-CM (CALCULATED FROM COAL SULFUR IF 0)
1500.	ASH RESISTIVITY IN PRESENCE OF LIMB, 10**9 OHM-CM
15.60	INTEREST DURING CONSTRUCTION, % D+I COST (ESP)
1.000	ESP RETROFIT FACTOR, DIMENSIONLESS

PARMFILE.TVA

Spray Humid.

VALUE	DESCRIPTION
3500.	GAS VELOCITY IS S.H. CHAMBER, FT/MIN (SH)
1.250	EXTRA FABRICATION COST FACTOR (1.+25%) (SH)
3.000	WATER USEAGE FACTOR, DIMENSIONLESS (SH)
8.000	SURGE TANK RETENTION TIME, HOURS (SH)
.1473E+05	MAXIMUM TANK SIZE, CU. FT. (SH)
1.100	EXTRA PUMPAGE FACTOR (1. + 10%) (SH)
70.00	PUMP EFFIECIENCY, % (SH)
100.0	PUMP HEAD ON FEED PUMPS, FT. (SH)
50.00	PUMP HEAD ON FRESH WATER PUMPS, FT. (SH)
1.850	TANK AND PUMP INSTALLATION FACTOR, DIMENSIONLESS (SH)
2.000	FEED PUMP REDUNDANCY, DIMENSIONLESS (SH)
2.000	FRESH WATER PUMP REDUNDANCY, DIMENSIONLESS (SH)
1.000	A-E CONTRACTOR, % DIRECT COST (SH)
6.000	ENGINEERING DESIGN AND SUPERVISION FACTOR, % DIRECT COST (SH)
14.00	CONSTRUCTION EXPENSE COST FACTOR, % DIRECT COST (SH)
4.000	CONTRACTOR'S FEE COST FACTOR, % DIRECT COST (SH)
20.00	CONTINGENCY COST FACTOR, % D&I COST (SH)
.0000	ROYALTIES, % DIRECT COST (SH)
600.0	OPERATING AND SUPERVISION MANHOURS/YEAR (SH)
2.000	MAINTENANCE LABOR AND MATERIALS, % DIRECT (SH)
2.000	INCREMENTAL PRESSURE DROP, IN H2O (SH)
4.840	INTEREST DURING CONSTRUCTION, % D&I COST (SH)
10.00	ALLOWANCE FOR STARTUP AND MODIFICATION, % D&I COST (SH)
1.000	SPRAY HUMIDIFICATION RETROFIT FACTOR, DIMENSIONLESS

PARMFILE.TVA

DSI

VALUE	DESCRIPTION
3.000	MOLAR STOICHIOMETRIC RATIO (DSI)
70.00	NAHCOLITE PURITY, % (DSI)
85.00	PERCENT SOLIDS IN FIXATION WASTE STREAM (DSI)
1.500	FIXATION COST MULTIPLIER, DIMENSIONLESS (DSI)
80.00	DSI EFFICIENCY , % (DSI)
1.000	A-E CONTRACTOR, % DIRECT COST (DSI)
10.00	ENGINEERING DESIGN AND SUPERVISION FACTOR, % (DSI)
14.00	CONSTRUCTION EXPENSE COST FACTOR, % DIRECT (DSI)
4.000	CONTRACTOR'S FEE COST FACTOR, % D+I (DSI)
20.00	CONTINGENCY COST FACTOR, % D+I (DSI)
.0000	ROYALTIES, % DIRECT COST (DSI)
2400.	OPERATING AND SUPERVISION MANHOURS (DSI)
4.000	MAINTENANCE LABOR AND MATERIALS, % OPERATING (DSI)
1.500	NORMAL STOICHIOMETRIC RATIO (DSI)
10.00	ALLOWANCE FOR STARTUP AND MODIFICATION, % D+I (DSI)
4.840	INTEREST DURING CONSTRUCTION, % D+I (DSI)
1.000	DSI RETROFIT FACTOP, DIMENSIONLESS

PARMFILE.TVA

FGD System

VALUE	DESCRIPTION
1.400	SRIN STOICHIOMETRIC RATIO (FGD)
39.00	XSO2 REMOVAL EFFICIENCY (FGD)
1.000	FGD RETROFIT FACTOR, DIMENSIONLESS
106.0	XLG L/G RATIO FOR SCRUBBER, GALLONS/1000 CU. FT.
.0000	ISR L/G, EFFICIENCY CONTROL VARIABLE (0,1,2)
.0000	XESP PARTICULATE COLLECTION OPTION (0,1,2)
2.000	XRH REHEAT OPTION (0,2)
175.0	TSK TEMPERATURE OF STACK GAS, DEG. F.
170.0	TSTEAM TEMPERATURE OF REHEATER STEAM
751.9	HVS HEAT OF VAPORIZATION OF REHEATER STEAM
2.000	IASH UNIT OF MEASURE OPTION FOR PARTICULATE REMOVAL(0,1,2,3)
6000E-01	ASHUPS VALUE FOR PARTICULATE REMOVAL UPSTREAM FROM SCRUBBER
20.00	VLG L/G RATIO IN VENTURI, GALLONS/1000 CU FT
5.000	VTR VENTURI/OXIDATION HOLD TANK RESIDENCE TIME, MIN
10.00	V SCRUBBER GAS VELOCITY, FT/SEC
25.00	VRH SUPERFICIAL GAS VELOCITY THROUGH REHEATER, FT/SEC
3.000	TR RECIRCULATION/OXIDATION HOLD TANK RESIDENCE TIME, MIN
1.000	XIALK ALKALI ADDITION OPTION (1,2)
0000	IADD CHEMICAL ADDITIVE OPTION (0,1,2)
0000	WPMGO SOLUBLE MGO IN LIMESTONE OR LIME, WT % DRY BASIS
1500	XMGOAD SOLUBLE MGO ADDED TO SYSTEM, LB/100 LB LINESTONE
1500.	AD ADIPIC ACID IN SCRUBBING LIQUID, PPMW
3.000	ADDC ADIPIC ACID DEGRADATION CONSTANT
1.850	WPI INSOLUBLES IN LIMESTONE-LIME ADDITIVE, WT % DRY BASIS
5.000	WPM MOISTURE IN LIMESTONE-LIME ADDITIVE, LB/100 LB DRY BASIS
3.000	WPS SOLIDS IN RECYCLE SURRY TO SCRUBBER, WT %
15.00	PSD SOLIDS IN SLUDGE DISCHARGE, WT %
0200	RS THICKENER SOLIDS SETTLING RATE, FT/HR
10.00	PSC PERCENT SOLIDS IN THICKENER UNDERFLOW, WT %
2.000	IFOX FORCED OXIDATION OPTION (0,1,2,3)
15.00	OX OXIDATION OF SULFITE IN SRUBBER LIQUID, MOLE %
2.500	SRAIR AIR STOICHIOMETRY VALUE, MOLES OXYGEN/MOLE SO2 ABSORBED
15.00	PSF PERCENT SOLIDS IN FILTER CAKE, WT %
.200	FILRAT FILTRATION RATE, TONS/SQ FT/DAY
5.200	PHLIME RECIRCULATION LIQUOR PH
0000	IVPD VENTURI -P- OPTION (0,1)
3.000	VPD VALUE FOR EITHER -P- OR THROAT VELOCITY, IN H2O OR FT/SE
0000	DELTAP OVERRIDE -P- FOR ENTIRE SYSTEM, IN H2O
14.70	PRES SCRUBBER PRESSURE, PSIA
1.000	IFAN FAN OPTION (0,1)
.000	ISCRUB SCRUBBING OPTION (1,2,3,4,5,6)
3.000	XNS NUMBER OF TCA STAGES
1.000	XNG NUMBER OF TCA GRIDS
5.000	HS HEIGHT OF SPHERES PER STAGE, IN
10.00	WINDEX LIMESTONE HARDNESS WORK INDEX FACTOR, DIMENSIONLESS
5.700	HPTONW FINENESS OF GRIND INDEX FACTOR, HP/TON
.000	NOREDN NUMBER OF SPARE SCRUBBER TRAINS
1000	PCNTRN ENTRAINMENT LEVEL AS PERCENTAGE OF WET GAS, WT %
3.000	PCTMNT MAINTENANCE RATE, EXCLUDING DISPOSAL SITE COST, % TDI
1.000	NSPREP NUMBER OF SPARE PREPARATION UNITS
1.000	NOTRAN NUMBER OF OPERATING SCRUBBER TRAINS
19.00	EXSAIR EXCESS AIR, %

PARMFILE.TVA

FGD Econs

VALUE	DESCRIPTION
7.000	ENGINEERING DESIGN AND SUPERVISION, % TDI (FGD)
2.000	ARCHITECT AND ENGINEERING CONTRACTOR, % TDI (FGD)
16.00	CONSTRUCTION FIELD EXPENSES, % TDI (FGD)
5.000	CONTRACTOR FEES, % TDI (FGD)
10.00	CONTINGENCY, % TDI + PROCESS INDIRECT INVESTMENT(FGD)
8.000	ALLOWANCE FOR STARTUP AND MODIFICATIONS, % TFI (FGD)
15.60	INTEREST DURING CONSTRUCTION (FGD)
4.000	TXRAT SALES TAX RATE, %
3.500	FRRAT FREIGHT RATE, %
6.000	SERVRT SERVICES, UTILITIES, AND MISCELLANEOUS, % TPC
.0000	ROYALTIES, % TPC (FGD)

PARMFILE.TVA
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Cost based JUNE, 1986

VALUE	DESCRIPTION
76.75	SULFUR COST ($/TON)
17.92	OPERATING AND SUPERVISION LABOR COST ($/HR)
22.65	WASTE DISPOSAL FACILITY LABOR COST ($/HR)
24.52	ANALYSIS LABOR COST ($/HR)
.5189E-01	ELECTRICITY COST ($/KWH)
.1509	WATER COST ($/1000GAL)
5.000	STEAM REHEAT COST ($/K LB)
14.16	CALCITE COST ($/TON)
84.41	CALCITIC HYDRATE COST ($/TON)
106.3	NAHCOLITE COST ($/TON)
16.18	WASTE DISPOSAL, WET($/TON)
5.904	WASTE DISPOSAL, DRY ($/TON)
29.52	DOLOMITIC LIMESTONE COST, $/TON
88.55	DOLOMITIC LIME COST, $/TON
100.4	CALCITIC PRESSURE HYDRATE, $/TON
106.3	DOLOMITIC PRESSURE HYDRATE, $/TON
6286.	LAND COST ($/ACRE)
14.16	LIMESTONE COST, $/TON
84.41	LIME COST, $/TON
3.677	DUCTWORK METAL FABRICATION AND INSTALLATION COST, $/LB (SH)
5.988	CLAY COST, $/CU YD
481.1	MGO UNIT COST, $/TON
1416.	ADIPIC ACID UNIT COST, $/TON
1.509	DIESEL FUEL COST, $/GAL
.0000	SYNTHETIC LINER MATERIAL UNIT COST, $/SQ YD
.0000	SYNTHETIC LINER LABOR UNIT COST, $/SQ YD

APPENDIX B

EXAMPLE OUTPUT

INTEGRATED AIR POLLUTION CONTROL SYSTEM COSTING PROGRAM

TEST
CASE

USER INPUT SUMMARY

BOILER SIZE: 500. MW   WALL FIRED, DRY BOTTOM
CAPACITY FACTOR:65.0 %   310. DEG.F

DATE OF COMMERCIAL OPERATION OF BOILER: 1987
CONSTRUCTION STATUS OF CONTROL SYSTEM: NEW

COAL CLEANING LEVEL: RUN-OF-MINE SORTED AND SCREENED
COAL CHARACTERISTICS AT THIS CLEANING LEVEL:

HHV (BTU/#):	11952.0
SULFUR CONTENT (%):	2.23
ASH CONTENT (%):	15.90
COST ($/TON):	.00
CHLORINE CONTENT (%):	.00
MOISTURE CONTENT (%):	3.30
VOLATILE MATTER CONTENT (%):	33.80
FIXED CARBON CONTENT (%):	47.00

ASH CHARACTERISTICS AT THIS CLEANING LEVEL:

NA2O CONTENT (%):	.40
ALKALINITY (%):	6.50
FE2O3 CONTENT (%):	9.00

CONTROL SYSTEM CONFIGURATION:

1 - FABRIC FILTER (FF)
2 - LIMESTONE FGD (LFGD)

ECONOMIC PREMISES (TVA/EPRI): EPRI

INTEGRATED AIR POLLUTION CONTROL SYSTEM COSTING PROGRAM

USER INPUT SUMMARY (CONTINUED)

PARAMETER FILE USED: PARMFILE.EPR

NO CHANGES WERE MADE TO THIS PARAMETER FILE FOR THIS RUN.

FABRIC FILTER

THE FABRIC FILTER IS DESIGNED TO REMOVE 99.7% OF THE PARTICULATE LOADING WITH AN AIR-TO-CLOTH RATIO OF 2.0. .0% OF THE FLUE GAS IS BYPASSING THE FABRIC FILTER. THE FABRIC FILTER REFLECTS A REVERSE AIR CLEANING CONFIGURATION AND TEFLON-COATED FIBERGLASS BAGS.

LIMESTONE FGD

THE CONFIGURATION OF THIS SYSTEM INCLUDES SPRAY TOWER ABSORBERS. FORCED OXIDATION IS USED TO STABILIZE THE SLURRY. NO CHEMICAL ADDITIVE IS USED.
SPARE ABSORBER CAPACITY OF 25.% IS PROVIDED. THE L/G RATIO IS 106.0 AND DESIGN SO2 REMOVAL OF 89.0% OCCURS IN THE TREATED GAS STREAM.
0.% OF THE GAS STREAM IS BEING BYPASSED.
100.% OF THE WASTES ARE DISPOSED OF IN AN ONSITE FACILITY.

FANS

THE TOTAL SYSTEM PRESSURE DROP IS 15.8 IN. H2O.
THE SYSTEM REQUIRES 5 FAN(S) RATED AT 1299. HP EACH.

BOILER/SYSTEM PERFORMANCE
(100% CAPACITY CONDITION)

UNIT THERMAL EFFICIENCY..................	87.1%
BOILER NET HEAT RATE......................	9935.0 BTU/KWH
HEAT INPUT................................	4967.5 MMBTU/H
COAL USE..................................	207.8 TONS/H
ANNUAL COAL CONSUMPTION..................	1.1833E+06 TONS/YR
IAPCS ENERGY PENALTY.....................	72.6 BTU/KWH
SYSTEM NET GENERATION....................	496.4 MW

SYSTEM MATERIAL BALANCE
(100% CAPACITY CONDITION)

	UNCONT- ROLLED	AIR HEATER EXIT	FF	LFGD
FLUE GAS, 1000 LB/H :	5046.	5046.	4994.	5884.
FLUE GAS, 1000 ACFM :	1417.	1417.	1417.	1362.
TEMPERATURE, DEG. F :	310.	310.	310.	175.
MOISTURE, LB/H :	240650.	240650.	240650.	528467.
ALKALINITY, LB/H :	3436.	3436.	10.	10.
PARTICULATE, LB/H :	52867.	52867.	159.	159.
SO2, LB/H :	18073.	18073.	18073.	1986.
NO2, LB/H :	4364.	4364.	4364.	4364.

EMISSION SUMMARY

POLLUTANT	LB/HR	PERCENT REDUCTION	LB/MMBTU	PPM(V)
PARTICULATE	159.	99.7	.032	
SO2	1986.	89.0	.400	166.
NO2	4364.	.0	.879	780.

INSTALLED CAPITAL COSTS JUNE, 1982

FABRIC FILTER------------------------------$		13663700
FF&DUCTING-----------------$	11854900	
FF ASH DISPOSAL------------$	1808800	
LIMESTONE FGD------------------------------$		43770800
FGD MATERIAL HANDLING------$	1227400	
FGD FEED PREPARATION------$	3869800	
FGD GAS HANDLING----------$	6443900	
FGD SO2 SCRUBBING---------$	22405000	
FGD OXIDATION-------------$	2400000	
FGD REHEAT----------------$	4544800	
FGD SOLID SEPARATION------$	2880000	
WASTE DISPOSAL --------------------------$		4730000
FANS---------------------------------------$		16164400
TOTAL DIRECT CAPITAL COSTS>>>>>>>>>>>>>>>>>>>>>>$		78328900
INDIRECT COSTS----------------------------$		43000500
GENERAL FACILITIES........$	6386100	
ENGINEERING/HOME OFFICE...$	4197500	
PROJECT CONTINGENCY.......$	11986500	
PROCESS CONTINGENCY... ...$	5510600	
SALES TAX.................$	0	
TOTAL PLANT COST.................$	106409596	
TOTAL PLANT INVESTMENT...........$	106409600	
ROYALTY ALLOWANCE.........$	8876700	
PREPRODUCTION COSTS.......$	3148200	
INVENTORY CAPITAL.........$	2040000	
INITIAL CATALYST..........$	0	
LAND......................$	854900	

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TOTAL CAPITAL REQUIREMENT)>>>>>>>>>>>>>>>>>>>*$ 121329400*
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TOTAL SYSTEM COST)>>>>>>>>>>>>>>>>>>>>>>>>>>>>$  242.66/KW
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ANNUAL OPERATING COSTS JUNE, 1982

ITEM	QUANTITY		RATE		ANNUAL COST
OPERATING AND SUPERVISORY LABOR					
SYSTEM	.4817E+05	MANHRS	17.24	$	830500
WASTE DISPOSAL FACILITY	.3744E+05	MANHRS	20.69	$	774600
ANALYSIS	5087.	MANHRS	20.69	$	105200
MAINTENANCE LABOR	.5082E+07	$	.40	$	2032800
MAINTENANCE MATERIAL	.5082E+07	$	.60	$	3049100
ADMIN. & SUPPORT LABOR	.3743E+07	$	.30	$	1122900
FIXED COMPONENT	.7915E+07	$	.65	$	5144800
VARIABLE COMPONENT	.7915E+07	$	.35	$	2770300
CONSUMABLES					
CALCITIC LIMESTONE	.9015E+05	TONS	25.00	$	2253800
WATER	.2124E+06	K GAL	.57	$	121100
STEAM	.5470E+06	K LBS	5.51	$	3014200
ELECTRICITY	.5966E+08	KWH	.04	$	2374500
DIESEL FUEL	.1203E+06	GAL	1.60	$	192500
TOTAL FIRST YEAR O&M EXPENSE				$	15871200
LEVELIZED CARRYING CHARGES	121329400	$	16.3%	$	19827300
BUSBAR COST OF POWER				$	35698500
LEVELIZED FIRST YEAR O&M	15871200	$	2.559	$	40616500
LEVELIZED CARRYING CHARGES	121329400	$	16.3%	$	19827300
LEVELIZED ANNUAL REQUIREMENTS				$	60443800

FIRST YEAR BUSBAR COST OF POWER	12.54 MILLS/KWH
LEVELIZED ANNUAL BUSBAR COST OF POWER	21.23 MILLS/KWH

PARTICULATE COST EFFECTIVENESS	402.80 $/TON
SO2 COST EFFECTIVENESS	1319.74 $/TON
NOX COST EFFECTIVENESS	.00 $/TON

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