

DEUS Computer Evaluation Model

Volume 2: Program User's Manual

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ABSTRACT

The DEUS (Dual Energy Use Systems) Analysis of Cogeneration Systems was undertaken by EPRI to evaluate industrial cogeneration from the utility perspective and to determine the extent to which potential benefits would accrue to a utility in representative site specific industrial applications.

A computer program was developed that compares a cogeneration system to a nocogeneration system in an industry with specified heat and power requirements. The economic comparison is based on user specified utility rate data, which includes industrial rates and rates for purchases of electricity from cogenerators under Section 210 of the Public Utility Regulatory Policies Act (PURPA rates). The industrial heat and power requirements as well as the utility rate data can be specified in a time varying profile for up to 36 periods in a year.

For use as a screening tool, a data base of performance and cost for a nocogeneration and several cogeneration systems is built into the program. System part load performance and applicable fuel characteristics are included. For application studies, the user must determine and specify the performance and cost characteristics for particular systems. Based on system capital and operating costs, the economics are determined for industrial, utility, and third-party ownership.

The computer program methodology is described in the Program Descriptive Manual for Computer Evaluation of Dual Energy Use Systems, RP 1276-4. This report is the computer program users manual.



EPRI PERSPECTIVE

PROJECT DESCRIPTION

This is the two-volume final report for RP1276-4, Evaluation of Alternative Technologies for Dual Energy Use Systems (DEUS)--System Analysis. The report, entitled DEUS Computer Evaluation Model, presents the descriptive and user's manuals for the computer model that was developed by General Electric Company for evaluation of cogeneration systems. The two volumes are:

- Volume 1: Program Descriptive Manual
- Volume 2: Program User's Manual

RP1276-4 is one project in the RP1276 series, which is conducted to investigate cogeneration and district heating. For details about the series, the interested reader is referred to EPRI Interim Report EM-2695, Evaluation of Dual Energy-Use Systems, Volumes 1 and 2, for RP1276-8.

PROJECT OBJECTIVE

The objective of this project is to develop a methodology which is intended for use by utilities as well as cogenerators in evaluating their cogeneration applications and which considers both the industry and utility perspectives. A computer simulation model, DEUS, was thus developed to serve this purpose.

PROJECT RESULTS

DEUS is a sophisticated simulation model that is written in standard FORTRAN. A cogeneration technology data base is also provided in the model for the industrial-sized cogeneration system (usually larger than 3 MW). Because of the current data base, the current version of the model is most suitable for cogeneration systems that are larger than 3 MW. For cogeneration systems that are smaller than 3 MW, the user will have to modify the technology data base.

When evaluating cogeneration applications, DEUS takes into account factors such as characteristics of cogeneration systems, process steam and electricity load

profiles, power sales agreements, ownership arrangements, and economic and rate assumptions. It computes information such as cogeneration costs, rates of return, payback periods, cash flows, utility revenue loss, utility system cost savings, and PURPA payments.

The program descriptive manual presents the structure, applications, methodology, validation, and data base for the DEUS model. The program user's manual discusses how to get access to the model, prepare data bases for cogeneration technologies, and interpret the results.

Currently, EPRI member utilities can obtain a computer tape and assistance regarding its use free of charge from the EPRI Patents and Licensing Department. The program is also available to non-EPRI members from the EPRI Patents and Licensing Department with payment of a license fee.

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TABLE OF CONTENTS

<u>Section</u>		<u>Page</u>
1	SUMMARY OF PROGRAM CAPABILITIES	1-1
1.1	Background	1-1
1.2	The Program	1-1
1.3	Industrial Process Model	1-8
1.4	Energy Conversion System Model	1-10
1.5	System Sizing	1-14
1.6	Ownership Options	1-18
1.7	System Dispatch	1-18
1.8	Economic Evaluation	1-20
1.9	Utility Impacts Evaluation	1-21
2	INPUT DATA DESCRIPTION	2-1
2.1	Introduction	2-1
2.2	Utility Rate Data	2-2
2.3	Process Data	2-3
2.4	Fuel Data	2-7
2.5	Energy Conversion Systems Data	2-8
2.6	Generalized Program Inputs	2-13
2.7	Special Functions	2-16
2.8	Economic Data	2-18
2.9	Input Data Worksheets	2-26
2.10	Alphabetical List of Input Data	2-53
3	COMPUTER DATA ENTRY & PROGRAM OPERATION--AN EXAMPLE	3-1
3.1	General	3-1
3.2	System Login	3-1
3.3	Data File Creation	3-4
3.4	Running the Program	3-11
3.5	File Management	3-12
4	PROGRAM OUTPUT	4-1
4.1	Introduction	4-1
4.2	Description of Output Data Files	4-1
4.3	Sample Output	4-16

TABLE OF CONTENTS (Cont'd)

<u>Section</u>		<u>Page</u>
5	INPUT DATA DEVELOPMENT FOR SAMPLE CASES	5-1
5.1	Introduction	5-1
5.2	Case C Example	5-1
5.3	Case G Example	5-4
6	PROGRAM DIAGNOSTICS	6-1

LIST OF ILLUSTRATIONS

<u>Figure</u>		<u>Page</u>
1.2-1	DEUS Evaluation Methodology - Comparison of Nocogeneration and Cogeneration	1-2
1.2-2	DEUS Computer Program	1-3
1.2-3	Summary Flow Chart for Computer Evaluation of Dual Energy Use Systems	1-4
1.3-1	Modelling of Dual Energy Use Systems	1-9
1.4-1	Energy Conversion System Model	1-10
1.4-2	Steam Turbine Cogeneration Design Point System Performance Model	1-12
1.4-3	Part Load System Performance Model	1-12
1.4-4	Total Installed Cost Model	1-13
1.5-1	Design Point Performance	1-15
1.5-2	Sizing for Example Industrial Process Energy Loads	1-17
2.8-1	Annual Cash Flow for Industrial Owned Cogeneration Compared to Nocogeneration	2-19
4.2-1	Optional Program Output	4-2
5.2-1	Hourly Heat and Power Demand Profiles for Validation Cases	5-2
5.3-1	Definition of Time-of-Day Periods	5-8



LIST OF TABLES

<u>Table</u>		<u>Page</u>
5.2-1	Program Input for Case C	5-3
5.3-1	Utility Billing Periods	5-6
5.3-2	Days Per Billing Season by Day Type Calendar Year 1984	5-7
5.3-3	Definition of Time-of-Day Periods	5-10
5.3-4	Equipment Operating Hours per Time Period	5-11
5.3-5	PURPA Avoided Energy Costs by Time Period	5-12
5.3-6	Modified PURPA Avoided Energy Costs Off-Peak Costs Changed to 1.5 ¢/kWh	5-13
5.3-7	Process Electric and Heat Demand Profiles	5-14
5.3-8	Program Input for Case G	5-16

EXECUTIVE SUMMARY

BACKGROUND

Recent changes in tax laws and fuel uses have provided new incentives for installing cogeneration systems. Prior cogeneration studies primarily consider the effects on industry. The objectives of this project (Task 4 of EPRI project RP1276-4 - DEUS (Dual Energy Use Systems) Analysis of Cogeneration) are to develop a methodology and to translate it into a computer program for analysis of cogeneration systems from a utility perspective. The analysis considers the utility Public Utility Regulatory Policies Act (PURPA) and industrial rates, avoided capacity and energy costs, steam and power profiles, fuel uses and other factors that require time varying data for a more realistic performance and economic evaluation.

OVERALL PROGRAM STRUCTURE

The program is designed to handle up to 12 energy conversion systems including a nocogeneration base case system, industrial requirements for heat and power, fuel types, utility rate schedules including industrial and rates determined by PURPA, economic data, operational groundrules, and various ownership types. The computer program contains a data base of default values that are used if not superseded by user input.

The DEUS methodology evaluates the performance and economics of cogeneration for third-party ownership and compares the cogeneration system with a nocogeneration base case system for industrial and utility ownership. In the nocogeneration system all electricity to the industry is supplied by the utility. Process steam is supplied by a process boiler supplemented by a waste heat boiler that utilizes any waste heat available from the plant. In the cogeneration system the steam from both the waste heat boiler and the energy conversion system is used for process heat and electricity. An auxiliary boiler can also be added to generate process steam. The utility can supply electricity to the industry or buy electricity from the cogeneration system owner or own the cogeneration system and sell steam to the industry.

In many industrial processes the actual process thermal and power demands vary with time-of-day and/or season. To be compatible with anticipated PURPA rate schedules, the program has the capability to represent up to 36 time periods per year. The time periods are used to define utility rates, including industrial rates, PURPA rates, and utility-avoided costs. These same time periods can then be used to define the industrial power and steam demand profiles.

Based on the industrial requirements, the system performance and cost, and other specifications on system sizing, dispatch, ownership and economic assumptions, the program determines the economic performance, the utility impacts, and the system benefits in terms of fuel savings and efficiency.

INDUSTRIAL PROCESS MODEL

The process heat may consist of up to a maximum of three streams of steam at different conditions. In many industrial processes, the actual process energy demands vary throughout the year. In this model, the yearly energy demand profile is represented by a demand in each of the time periods. The duration of each time period is specified. If the local electric utility has variable time of day electricity rates, it is essential to represent the industrial process energy demand profiles in the same time periods that represent the local utility rates.

The energy conversion systems supplying both process steam and electricity, together with waste energy utilization systems, are modelled to supply all industrial process heat demand. Electric demand is met by electricity produced by the energy conversion system, the waste energy utilization system, and, if required or economic, electricity produced by the local electric utility.

ENERGY CONVERSION SYSTEM MODEL

The Energy Conversion System (ECS) functional characteristics (performance and cost), along with fuel costs and utility rates, are the principal determinants of the economic feasibility of a cogeneration project. The process heat boiler is used both as a base case for comparison with other ECS's, and as an auxiliary process heat boiler to supply heat alone or in combination with other ECS's in the most economical manner. The computer program sizes systems in two ways. The first, called "Thermal Matched Size," sizes the system to serve process thermal needs at best overall efficiency. The second, called "User Specified MW Size," matches both total system desired electrical output and process thermal needs.

The waste utilization equipment is assumed to always supply a constant level of thermal energy to the process, based on the average value of waste energy converted to heat. For the Thermal Matched Size, the energy conversion system, together with an auxiliary boiler (if specified), is then sized to supply the remaining process thermal demand either at the average level, or at the maximum level, whichever is greater.

The relative incremental cost of electricity produced by an energy conversion system may be cheaper than the incremental cost of electricity produced by the local electric utility. In such cases it may be most economical to size a system (User Specified MW Size) to produce more electricity than that produced by the Thermal Matched Size.

SYSTEM DISPATCH

Thermal Matched Size DEUS plants are dispatched to follow process steam load requirements at minimum fuel flow in each of the 36 time periods. Similarly, the User Specified MW Size DEUS plants are dispatched for most economical operation while satisfying the thermal load requirement in each time period. A single year economic dispatch is performed for each cogeneration system using cost data for the first study year. Operating expenses and revenues, which vary through time, are then calculated using the economic dispatch for the first year.

In the case of industrial-owned cogeneration facilities, the program user has the option to specify either one of two power sales agreements between utility and cogenerator: (1) Buy All/Sell All (also called Simultaneous Buy/Sell) and (2) Sell Excess/Buy Shortage.

The power sales agreement specified by the user will influence the economic dispatch calculated by the DEUS program for industrial-owned cogeneration facilities.

OWNERSHIP OPTIONS AND ECONOMIC EVALUATION

Economic evaluations are performed in the DEUS computer program for three types of cogeneration ownership: industrial, third-party, and utility.

For industrial ownership cases, the Internal Rate of Return (IRR) on incremental investment (compared to a nocogeneration case) is calculated. The cash flows considered include those generated by fuel costs, operating and maintenance costs, income taxes, power revenues, and purchased power savings.

For third-party ownership, the IRR on total cogeneration investment is calculated. The third-party analysis considers the economics of independent ownership of the cogeneration plant including revenues associates with steam sales to the industrial customer and power sales to the local electric utility.

For utility ownership, the revenue requirements method is used to evaluate the economic performance. Incremental revenue requirement impacts are calculated by comparing a cogeneration case to a nocogeneration case. The reduction in revenue requirements is the measure of economic performance for utility-owned cogeneration.

UTILITY IMPACT EVALUATION

One of the principal objectives of the DEUS computer model is to evaluate economic impacts and potential benefits of cogeneration from a utility perspective. Several utility impacts are evaluated for industrial and third-party ownership. These include production costs and capital costs, electricity revenues, and purchase power payments under PURPA. Using utility rate and avoided cost data, utility impacts are calculated for each time period and summed for the year.

Section 1

SUMMARY OF PROGRAM CAPABILITIES

1.1 BACKGROUND

Recent changes in tax laws and fuel uses have provided new incentives for installing cogeneration systems. Prior cogeneration studies primarily consider the effects on industry. EPRI, therefore, undertook the DEUS (Dual Energy Use Systems) Analysis of Cogeneration Systems project to evaluate industrial cogeneration from the utility perspective and to determine the extent to which potential benefits would accrue to a utility in representative site specific industrial applications.

The objective of this project (Task 4 of the overall EPRI project) was to develop the methodology and translate that methodology into a computer program for analysis of cogeneration systems from a utility perspective. The program has the capability to evaluate alternate cogeneration systems in a wide variety of industries. While the program was developed for use as a screening tool based on general system characteristics, it can be used for more detailed application studies when modified with the proper input data for specific systems.

1.2 THE PROGRAM

The program is designed to handle up to twelve systems including a nocogeneration base case system, industrial requirements for heat and power, fuel types, utility rate schedules including industrial and PURPA rates, economic data, operational groundrules, and various ownership types. The computer program contains a data base with sufficient data for a complete run without user input. Any values in the data base can be superseded by other values specified via program input. The values in the data base become default values if they are not superseded by user input.

The cogeneration evaluation methodology is based on a comparison of two alternatives, nocogeneration and cogeneration, as illustrated in Figure 1.2-1. In the nocogeneration system all electricity to the industry is supplied by the utility. Process steam is supplied by a process boiler supplemented by a waste heat boiler that utilizes any waste heat available from the plant. In the cogeneration system, the steam from both the waste heat boiler and the energy conversion system is used for

process heat and electricity. An auxiliary boiler can also be added to generate process steam. The utility can supply electricity to the industry or buy electricity from the cogeneration system owner or own the cogeneration system and sell steam to the industry.

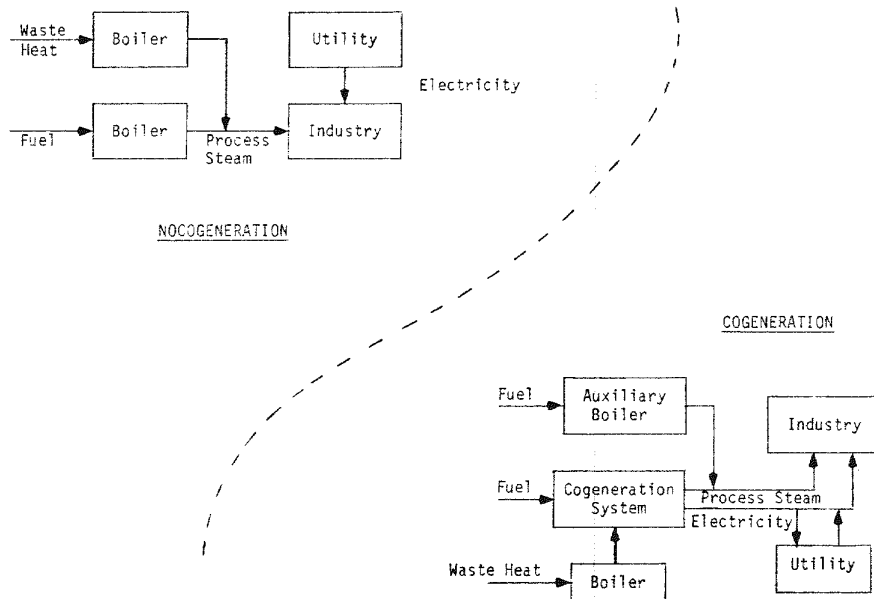


Figure 1.2-1. DEUS Evaluation Methodology - Comparison of Nocogeneration and Cogeneration

The overall structure of the DEUS program is illustrated in Figure 1.2-2. As indicated, the computer program includes a data base of generic cogeneration systems performance and cost, useful for screening analyses. The data base can be supplemented or altered by user input. As part of the output, the input data that was used in the analysis is listed along with the results from the analysis.

The overall computer model structure is illustrated in the flow chart, Figure 1.2-3. The model was designed utilizing a modular format. Thus each program component in itself is a separate module, that with the correct input, can be executed separately.

The computer model can be subdivided into four basic phases of operation. The first phase recreates the industrial process requirements, such as process energy load and waste utilization. The second phase determines the design point thermal and user specified megawatt sized plants for the nocogen (thermal only) and the selected cogen systems. The third phase matches the steam and energy load profiles

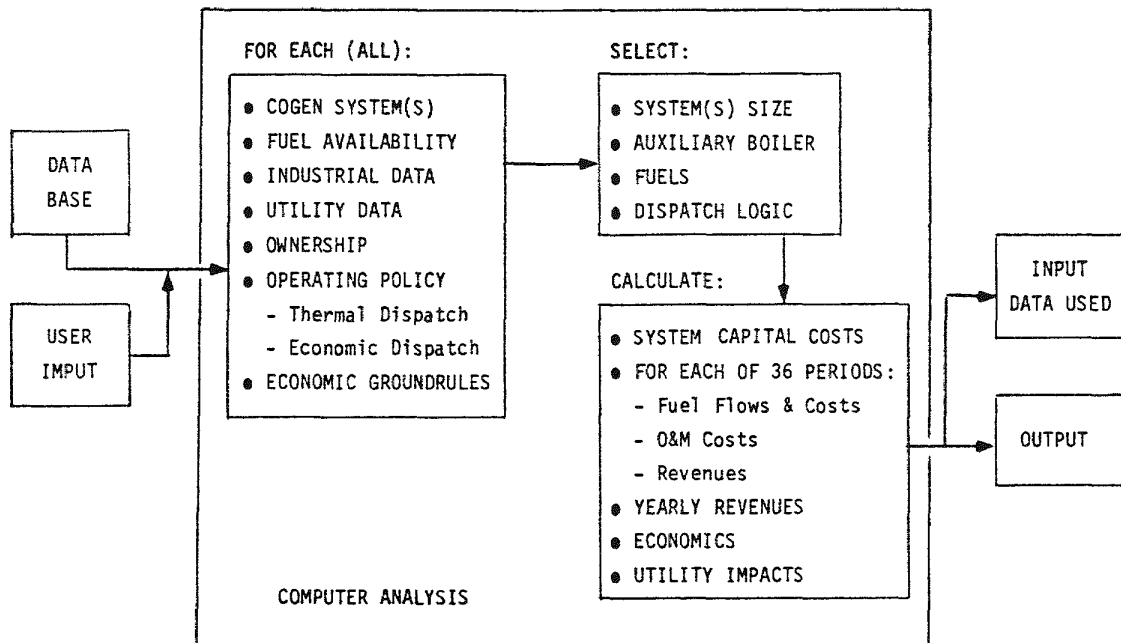


Figure 1.2-2. DEUS Computer Program

by dispatching the required DEUS units for both a thermal matched dispatch and an economic dispatch. For thermal dispatch the industrial thermal load is matched by the DEUS units and the electrical power out is determined by the characteristics of the units. The economic dispatch determines which type of unit and power level should be dispatched to obtain the most economical and feasible system performance. The fourth phase derives the economic benefits and utility impacts based on the performance data calculated in phases two and three.

The basic components of the computer model, shown in Figure 1.2-3, are outlined below.

1. Main Body & Integration Section

- Gross Process Energy Load Profiles
- Process Waste Fuel/Energy Utilization
- Auxiliary Process Boiler
- Selection of Candidate DEUS Systems
- DEUS Unit Sizing
- Nocogeneration Base Case

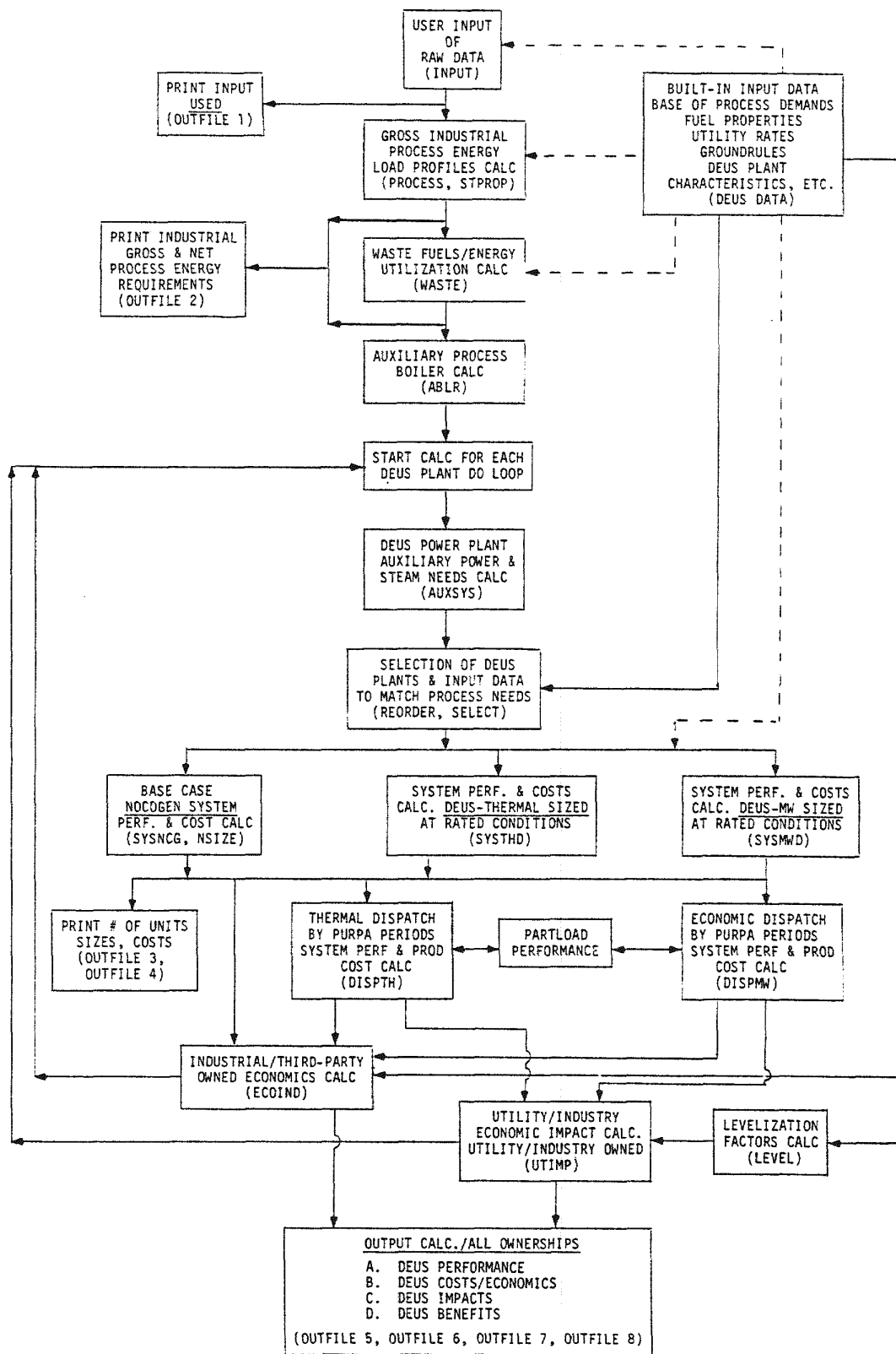


Figure 1.2-3. Summary Flow Chart for Computer Evaluation of Dual Energy Use Systems

2. DEUS-Performance/Economic/Utility Calculation Section

- Auxiliary Power & Steam Requirements
- Thermal Matched Size Plant
- User Specified MW Size Plant
- Thermal Dispatch
- Economic Dispatch
- Part Load
- Economic Benefits; Industrial and Third-party Ownership
- Utility Economics and Impacts
- System Benefits

In many industrial processes the actual process thermal and power demands vary with time-of-day and/or season. To be compatible with anticipated PURPA rate schedules, the program has the capability to represent 36 time periods per year. For example, the 36 time periods might be used to cover four seasons, three day types per week, and three time periods per day (on-peak, near-peak, and off-peak). The program user can specify any number of times periods, up to 36, to model his specific process energy demands and utility rate schedule. The user also specifies the duration of each time period. The 36 time periods are used to define utility rates, including industrial rates, PURPA rates, and utility system avoided costs.

These same 36 time periods can then be used to define the industrial power and steam demand profiles. Steam loads can be defined for up to three distinct pressure levels. The industrial steam and power demands are assumed constant in each time period. The program does have the capability, however, to calculate demand charges and PURPA capacity payments based on peak power demands and contract capacities specified by the user.

The program has the capability to evaluate DEUS configurations incorporating up to four fuel streams, each fueling a given type energy conversion system (ECS) sized to the availability limit of the fuel stream, the site steam requirements or a user specified power rating. Capital costs and operating and maintenance costs are calculated for each fuel/ECS combination using the data base characteristics or user values specified via program input.

The program considers two sizing options for all DEUS plants, a Thermal Matched Size and a User Specified MW Size. The Thermal Matched Size DEUS's are dispatched to follow process steam load requirements in each of the 36 time periods. Similarly, in each period, the User Specified MW Size DEUS's are dispatched for most economical operation while satisfying the thermal load. The economic dispatch mode also includes consideration of an auxiliary process steam boiler which can be dispatched based on thermal demand and economics.

The program evaluates the performance and economics of cogeneration systems under several ownership options: industrial, utility, and third-party ownership but with emphasis on the utility point of view. For both industrial and third-party ownership, a standard discounted cash flow (DCF) rate of return methodology is used, with due consideration to any available tax credits, to calculate internal rate of return for each cogeneration alternative. The analysis of an industry-owned cogeneration system has two options for electricity sales, (a) the industry either sells excess electricity to the utility or buys needed electricity if deficient, or (b) the industry sells all generated power to the utility and buys back all site power ("Buy All/Sell All"). For industrial ownership, the internal rate of return is calculated for the incremental investment for cogeneration as compared to nocogeneration. For third-party ownership, annual cash flows reflect revenues from electricity sales to the utility and steam sales to the industry. The internal rate of return for this case is calculated for the entire plant investment. Utility cost impacts are determined for both non-utility and utility ownership.

The DEUS program output includes the following:

- Process Demands
 - Heat
 - Power
- Cogeneration Plant Characteristics
 - Thermal sized plant
 - User specified size plant
- System Performance Summary
 - Power generation (MWh/year)
 - Capacity factor
 - Fuels used

- Economic Evaluation Results
 - Total installed costs
 - Operation and maintenance costs
 - Fuel costs
 - Purchased electricity costs
 - PURPA electric revenues
- Cogeneration Economic Performance
 - Discounted internal rate of return
 - Revenue requirements savings (utility owned cogeneration)
- Utility System Economic Impacts
 - Production costs (fuel and O&M)
 - Capital costs
 - Electricity revenues
 - PURPA payments

The data base includes performance and cost for nine generic systems useful for screening analyses. For more detailed application studies, specific system performance and cost data must be specified. When used as a screening tool the data base provides the performance and cost of a nocogeneration system used as a base case, and for each of the following cogeneration systems:

- Boiler-steam turbines (three types)
- Integrated coal gasifier-combined cycle
- Phosphoric acid fuel cell with a supplementally-fired heat recovery steam generator (HRSG)
- Simple cycle gas turbine with HRSG
- Combined cycle with clean fuel
- Medium speed diesel with HRSG and open cycle heat pump.

The steam turbines are both low and medium pressure and non-condensing and condensing multi-auto extraction. When using coal, both pulverized coal-fired boilers with flue gas treatment and atmospheric fluidized bed boilers are considered. For all systems the system performance includes both design point and part load performance for three steam pressures and a range of available heat-to-power ratios.

In addition to the systems performance and cost, the data base contains data on auxiliary boiler performance and cost, eight fuel types, a set of utility rate data for a utility with high oil use, including PURPA rates, industrial power energy and demand rates, marginal production costs and capacity values, industrial steam and power demand, economic data and general data on ownership and dispatch.

1.3 INDUSTRIAL PROCESS MODEL

The computer program models any industrial process as a black box which requires both electricity and process heat (primarily steam) as its process energy demands. Figure 1.3-1 shows how an industrial process is modelled to interface with the energy conversion systems, the local electric utility and the waste energy utilization systems. The process heat may consist of up to a maximum of three streams of steam at different conditions.

The energy conversion systems (e.g., Steam Turbine Cogeneration System supplying both process steam and electricity) together with waste energy utilization systems are modelled to supply all industrial process heat demand. Industrial process electric demand is met by electricity produced by the energy conversion system, the waste energy utilization system and, if required, electricity produced by the local electric utility. The specific amounts of electricity supplied by each source are a function of system design, fuel costs and utility rates. In the case of industrial owned cogeneration, on-site electricity production will depend on the sale/purchase agreement with the local utility. For a Simultaneous Buy/Sell agreement, electricity required to meet all the industrial process electric demand is purchased from the local utility and all electricity produced is sold to the utility. This sale/purchase agreement is frequently called "Buy All/Sell All." For a Sell Excess/Buy Shortage agreement, all the electricity produced is used first in the industrial process and any excess is sold to the utility or, if insufficient electricity is produced, the shortage is bought from the local utility.

In many industrial processes, the actual process energy demands vary throughout the year. In this model, the yearly energy demand profile can be represented by up to 36 discrete values with the duration of each time period specified. If the local electric utility has variable time-of-day electricity rates, it is essential to represent the industrial process energy demand profiles in the same time periods that represent the local utility rates or submultiple of those, up to a maximum of 36.

It is anticipated that the most common form of process heat requirement will be steam. Therefore, the industrial process is modelled such that it can use built-in steam properties to calculate the process heat requirement of each stream from steam flow, thermodynamic conditions, reject and return stream conditions and makeup water requirements.

The other important feature of the industrial process model is inclusion of a waste energy utilization systems model. Energy from process waste streams could be utilized in reducing total process energy requirements. The model can use a maximum of

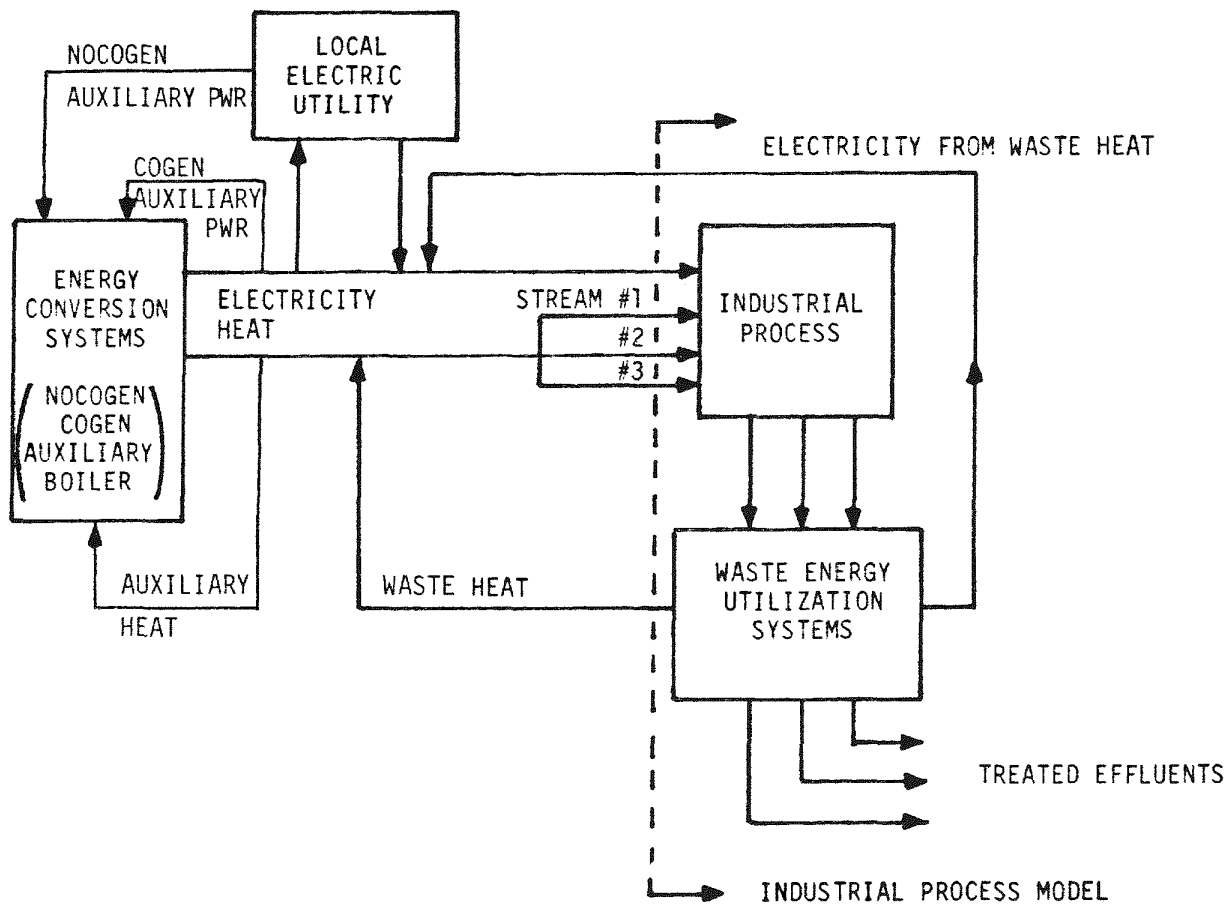


Figure 1.3-1. Modelling of Dual Energy Use Systems

three waste streams, one of which can be modelled as fuel. The model first calculates the available energy in each waste stream and then deducts it from process energy requirements normally as process heat or, if feasible, utilizes the available energy for cogeneration as a combination of process heat and electricity.

1.4 ENERGY CONVERSION SYSTEM MODEL

The Energy Conversion System (ECS) model is the heart of the DEUS computer program. Its functional characteristics (performance and cost) along with fuel costs and utility rates, are the principal determinants of the economic feasibility of a cogeneration project. Except for a process heat boiler, all ECS's modelled in this computer program generate both process heat and electricity. The process heat boiler is used both as a base case for comparison with other ECS's, and as an auxiliary process heat boiler to supply heat alone or in combination with other ECS's in the most economical manner.

A generalized ECS model is shown in Figure 1.4-1. It consists of four components, (a) furnace or combustor, (b) heat generator, (c) prime mover with electric generator, and (d) cleanup system. The costs and performance are determined from this model. Fuel is assumed to be the sole source of input energy to the ECS. The furnace or combustor converts it into thermal energy, part of which is further converted to electricity in a prime mover with an electric generator and heat energy in the heat generator. The effluents are treated in the cleanup system at or below EPA recommended levels. Auxiliary power and heat requirements for the ECS are obtained from the generating components, leaving only the net electricity and heat to be delivered.

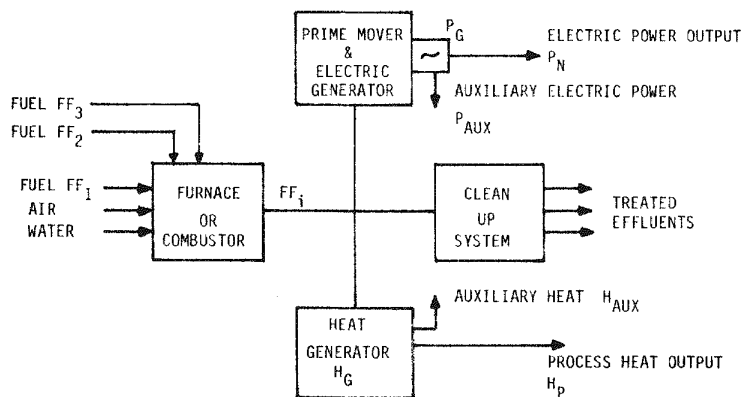


Figure 1.4-1. Energy Conversion System Model

Design Point Performance Model

The internal variables are constant at design conditions for each ECS and available fuel. Thus, apart from each component performance and efficiency, the only external variables considered at the design point are fuel flow as input and electricity and heat as output. Therefore, the entire design range of any ECS can be characterized by (P/FF_i) and (H/FF_i) or (P/FF_i) and (H/P) . The characteristics are unique for each particular thermodynamic condition of the process heat stream. Figure 1.4-2 shows an example of a steam turbine performance model in its complete design range. The lowest curve represents performance of this system when process steam is extracted at 15 psia. Similarly, other curves show its performance when extraction pressures are 150 and 450 psia, respectively. The dashed line on the right represents the minimum condenser flow for which a turbine would probably be designed. The solid curve connecting the end points on the right represents the performance of a back pressure turbine with no condensing. The point on the left where all the lines meet represents full condensing; however, a cogeneration plant would never be designed for full condensing. The dotted line on the left represents the H/P ratio that is a minimum to qualify for FUA exemptions as a cogenerator.

Part Load Performance Model

Dispatch of an ECS requires modelling of the part load performance which is dependent on heat energy and electricity output, as well as on the off-design performance of the system components. In the present model it is assumed that the part load performance can be modelled by first accounting for the ideal fuel requirements at part load conditions which would be a function of (H/H_m) and (P/P_m) . H_m is the maximum value of heat energy that can be converted by the ECS at design conditions. Similarly, P_m is the maximum value of electricity that can be converted by the ECS at design conditions. Part load data, both at maximum heat and at maximum power from the ECS, is represented as shown in Figure 1.4-3. Performance is shown for one representative steam pressure. It is assumed that the characteristics will be similar to these for other steam pressures. The $W_f/W_{fm} = 1.0$ line at the top represents the design point performance shown in Figure 1.4-2 for the representative pressure. W_f and W_{fm} represent the fuel flow and maximum fuel flow, respectively. The maximum power and maximum heat lines are extensions of the design point performance at reduced fuel flows. In a steam turbine ECS, for example, this is obtained by reducing the boiler fuel flow and steam output. The $W_f/W_{fm} = 1.0$ line and the maximum power and maximum heat lines represent an envelope of the ECS operating range.

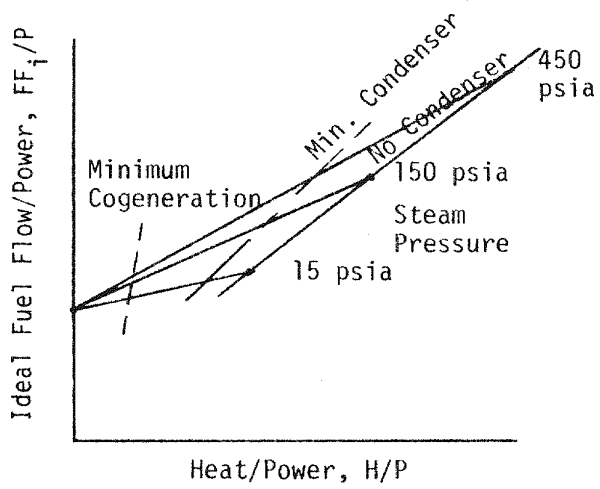


Figure 1.4-2. Steam Turbine Cogeneration Design Point System Performance Model

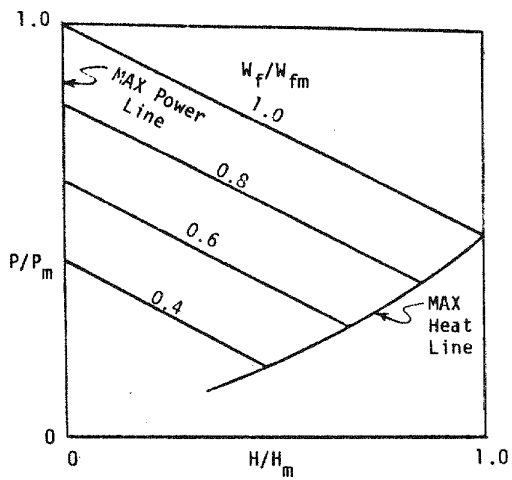


Figure 1.4-3. Part Load System Performance Model

Cost Estimation Model

The total installed cost (TIC) of each ECS unit is based on four design point conditions as shown in Figure 1.4-4. The cost is shown for the maximum power design and for the maximum heat design, each at a minimum size represented by the minimum fuel flow and at a maximum size represented by the maximum fuel flow. The TIC is assumed to be proportional to fuel flow raised to an exponential power that is defined by the two end values. On a log-log plot, the TIC function is a straight line as shown by Figure 1.4-4.

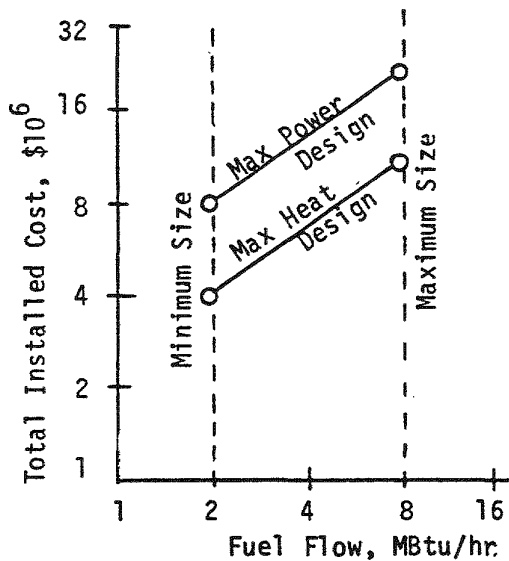


Figure 1.4-4. Total Installed Cost Model

Fuel flow of the normally used fuel is used to represent system size for estimating cost. Cost correction factors are applied to the costs for the alternate fuels. In most systems the lower curve is for the maximum heat design. The maximum power design usually costs more because of the addition of a condensing turbine and cooling towers. For the diesel system, however, the maximum heat design is more expensive since it includes a heat pump that adds to the cost of the system.

Operation and Maintenance (O&M) Model

The operation and maintenance (O&M) costs are assumed to consist of three parts - fixed, variable and consumables. Consumables, as defined here, do not include the fuel or its related items, but other consumed items such as chemicals for water treatment, etc. Consumables directly related to the fuel and the system, such as limestone, can be included in the fuel costs.

The fixed O&M costs are assumed to be directly proportional to the TIC and are given as a fraction of the TIC. The variable O&M costs are assumed to be proportional to the rated fuel flow raised to an exponent which is assumed to be the same for all fuels. The consumable O&M costs are assumed to be proportional to the rated fuel flow times the operating hours. When more than one fuel is used, the consumable component is equal to a constant times the sum of all the fuel flows each times the operating hours.

Auxiliary Requirements Model

Provisions are made for specifying auxiliary heat and power requirements that may be required by the ECS. Auxiliary heat and auxiliary power factors define these requirements as a fraction of the ECS gross heat and power output. Heat and power factors are not necessarily equal. Net heat and power available for process needs, or in the case of power for sale to the utility, are equal to the gross output less the respective auxiliary requirements. The auxiliary requirements can be specified differently for each fuel.

1.5 SYSTEM SIZING

The sizing of an energy conversion system is a very important step in the determination of its economic attractiveness in a given industrial process application. In this program, system sizing is made very flexible to accommodate various user external input options and yet supply all industrial process energy demands. Thus the user has the ability to force system sizes based on his experience, economics, and his ownership needs. Three major input options are (1) an auxiliary process heat generator, (2) minimum permissible number of units, and (3) design margin.

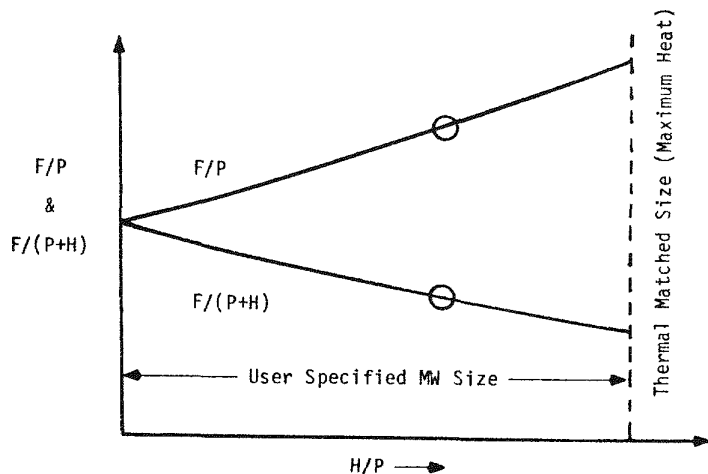


Figure 1.5-1. Design Point Performance

The design point performance is represented in Figure 1.5-1 for a range of heat to power ratios representative of a typical ECS. The upper curve is the same as shown in Figure 1.4-2 for one steam condition. The maximum heat to power ratio represents performance for the minimum size unit that can supply all process heat. All other values to the left represent lower heat to power ratios or higher values of power for a given heat output. The upper line is the ratio of ideal fuel heat input to power output and, except for unit conversion, is comparable to the conventional power plant heat rate. The lower curve is the ratio of ideal fuel heat input to total power plus heat output and is the inverse of overall thermal efficiency. At zero heat output on the left values for the two curves are equal. For a steam turbine system this represents full condensing and is not a valid cogeneration condition.

The computer program sizes systems two ways. The first, called "Thermal Matched Size," sizes the system to serve process thermal needs at best overall efficiency. The second, called "User Specified MW Size," matches both total system desired electrical output and process thermal needs.

Thermal Matched Sizing Model

The basic method of obtaining a "Thermal Matched Size" system is as follows. The waste utilization equipment is assumed to supply a constant level of thermal energy to the process based on the average value of waste energy converted to heat. The energy conversion system together with an auxiliary process heat generator (if specified in input) is then sized to supply the remaining process thermal demand,

either at the average level, or at the maximum level, whichever is greater. The size is based on the configuration giving maximum heat to power ratio (see Figure 1.5-1) and then increased to reflect design margin and other input options. The system is further subdivided into units whose sizes are determined by specified size limits, the burnable site fuels and their cost, fuel combustion efficiency and availability. The lowest energy cost fuel, based on dollars per million Btu corrected for efficiency, is used first with units of maximum permissible size. When this fuel is exhausted the next least expensive fuel is used, and so on, until the thermal demand is met. It is assumed that there is no limit on the most expensive fuel. If the total number of units desired is more, the largest units are split to satisfy this option. This sizing model represents thermodynamically the most efficient (minimum value of $F/P+H$) and the smallest size system. However, in this model the electrical output is slave to process thermal needs and may not represent the most economical choice.

User Specified MW Sizing Model

It is quite possible that the relative incremental cost of electricity produced by an energy conversion system is cheaper than the incremental cost of electricity produced by the local electric utility. This may be either due to availability of cheaper fuel to the energy conversion system or other institutional factors (such as PURPA). In such cases it may be most economical to size a system larger than the thermal matched size. In this computer program the user has the option to input a different size by specifying the system total electrical output.

The following describes the basic model to determine system size for this option. The electrical and thermal outputs from waste utilization equipment are subtracted respectively from total desired electrical output and total process thermal demand. The energy conversion system is therefore sized to meet both net electrical output and the net process thermal demand (maximum value less contribution due to an auxiliary process heat generator, if specified in the input). The circles on Figure 1.5-1 show an example of selecting a "User Specified MW Size" on the design point performance curve of an energy conversion system. Clearly the system has lower overall thermal efficiency and a bigger size when compared to the thermally matched system, yet its higher electrical output may make it the more economical choice. The modelling to calculate the number of units and their sizes is exactly the same as the thermally matched case.

It is important to note that size of an energy conversion system is directly affected by the size of an auxiliary process heat generator. The choice of adding the latter as an external input option is largely governed by the process thermal energy profile. It may be added to reduce oversizing of a more expensive energy conversion system if the thermal energy profile has a peak demand for only a small percentage of total operating time. This is illustrated in Figure 1.5-2 for an industrial process which has peak thermal demand for only four hours each operating day. The final size of an auxiliary process boiler need not be the same in the "Thermal Matched Size" ECS and the "User Specified MW Size" ECS, since modelling for system dispatch is different for the two sizes.

As will be explained, "Thermal Matched Size" ECS's are dispatched strictly following thermal load, while a "User Specified MW Size" ECS is dispatched in each time period according to the most favorable economics in that period. This means that if, in a particular situation, the local utility's incremental production cost of electricity is low (PURPA rate for purchased power), the energy conversion system would not dispatch at all in that period and the auxiliary process heat generator together with heat from waste utilization equipment (if any) would supply all process thermal demand in that period. In this case (User Specified MW Size) the model increases the auxiliary boiler size and cost to provide the added heat load.

On the other hand, an ECS of smaller MW rating than is obtained by the Thermal Matched Size can be obtained by adding an appropriately sized auxiliary boiler to a Thermal Matched Size system. In this case the ECS will operate at the maximum heat design and have a design MW rating less than that for the Thermal Matched Size without an auxiliary boiler.

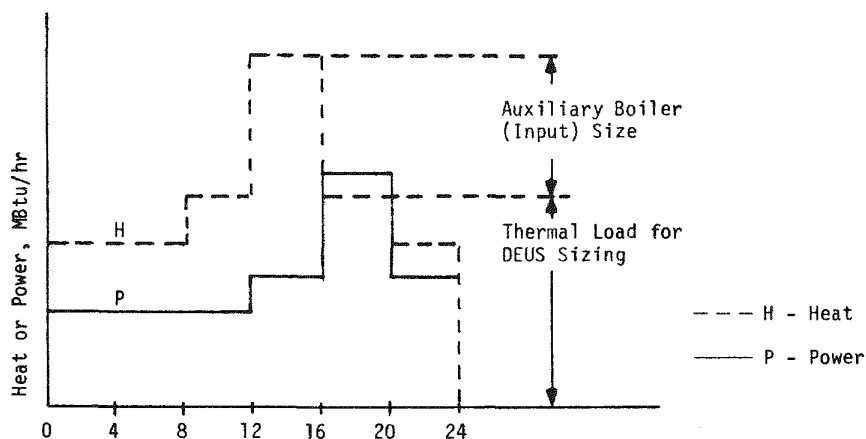


Figure 1.5-2. Sizing for Example Industrial Process Energy Loads

1.6 OWNERSHIP OPTIONS

The economic performance of cogeneration considers any one or all of the following ownership options:

- Industrial ownership
- Utility ownership
- Third-party ownership

In the industrial and utility ownership cases the economics are based on a comparison of the cogeneration system with a nocogeneration system. The nocogeneration investment is the installed cost of a process boiler. The nocogeneration operating costs are principally boiler fuel and O&M costs and purchased power costs.

In the third-party ownership case the economics are based on total investment and not on incremental investment over a nocogeneration case. Third-party ownership assumes steam sales to the industrial customer and power sales to the local electric utility.

1.7 SYSTEM DISPATCH

The DEUS program determines system dispatches for both Thermal Matched Size and User Specified MW Size cogeneration plants. A thermal dispatch is performed for Thermal Matched Size plants and an economic dispatch for User Specified MW Size cogeneration plants. Thermal Matched Size DEUS plants are dispatched to follow process steam load requirements in each of the 36 time periods. Similarly, in each time period the User Specified MW Size DEUS plants are dispatched for most economical operation while satisfying the thermal load.

A single year economic dispatch is performed for each cogeneration system using cost data for the first year of plant operation. This economic dispatch for the first year is assumed to remain the same for each year of operation. Operating expenses and revenues, however, are not assumed constant. Operating expenses and revenues, which vary through time, are calculated using the first year dispatch results and yearly cost data (fuel costs, utility electric rates, etc.) specified as program input.

During dispatch, the size of the cogeneration units are always held the same as the size that is determined under system sizing. The only exception is that during economic dispatch an auxiliary boiler can be added or increased in size if it is determined that its operation is more economical in any of the time periods.

Thermal Dispatch

The thermal dispatch is constant in each of the 36 time periods. Average steam loads and power loads determine the dispatch in each time period. Cogeneration units are sequentially dispatched, least expensive unit first, until the thermal load is met. If all units are dispatched and the thermal load is not satisfied, an auxiliary boiler is dispatched. If necessary during low thermal load periods, the last unit dispatched will be dispatched at part load.

Economic Dispatch

Whereas a single thermal dispatch is performed for each cogeneration plant regardless of ownership, two economic dispatches are performed. The first dispatch is for industrial and third-party ownership; the second economic dispatch is for utility ownership. In the case of industrial owned cogeneration facilities, the program user has the option to specify either one of the two power sales agreements between utility and cogenerator:

- Buy All/Sell All (also called "Simultaneous Buy/Sell")
- Sell Excess/Buy Shortage

The power sales agreement specified by the user will influence the economic dispatch calculated by the DEUS program for industrial owned cogeneration facilities.

With a Buy All/Sell All power sales agreement the economic dispatch methodology is the same for both industrial or third-party owned cogeneration and utility owned cogeneration. A two step approach is used to determine the economic dispatch. One step is to compare the thermal dispatch with an auxiliary boiler dispatch to determine which yields the lowest operating costs. If fuel chargeable to power plus incremental O&M costs exceed the PURPA energy rate ($\text{\$/kWh}$), the auxiliary boiler is dispatched for the time period under consideration. If in the first step the thermal dispatch yields lower operating costs than an auxiliary boiler, then the second step is taken.

The second step in the determination of the economic dispatch for industrial owned cogeneration (Buy All/Sell All power sales agreement) and utility owned cogeneration is the calculation of incremental production costs (fuel plus O&M costs) for an incremental dispatch from thermal load following to maximum rated power. If this incremental production cost ($\text{\$/kWh}$) is less than the PURPA energy rate, the industrial owned cogeneration plant is dispatched at rated power output. In the case of utility owned cogeneration plants, the incremental production cost for the plant is compared to utility avoided energy costs specified as input by the user. The

economic dispatch is performed for each of a maximum of 36 time periods for a year.

In the case of industrial owned cogeneration facilities, the program user has the option to specify a Sell Excess/Buy Shortage power sales agreement as an alternative to the Buy All/Sell All agreement discussed previously. The economic dispatch performed with a Sell Excess/Buy Shortage power sales agreement considers the following four possible operating levels: meet thermal load at minimum rated power, meet thermal load at maximum rated power, meet electric load, and zero power (auxiliary boiler dispatch). The minimum operating cost level is determined by considering fuel costs, O&M costs, purchased power costs (including demand and energy charges) and revenues from the sale of excess power to the utility at PURPA rates. The economic dispatch is performed for each of a maximum of 36 time periods.

The economic dispatch results consist of the following data for each fuel type and time period. Total performance results are calculated by adding the fuel specific results and including the contribution by the auxiliary process boiler:

- Dispatched power (MW)
- Heat output (MBtu/hr)
- Fuel flow (MBtu/hr)

These economic dispatch results are used subsequently in the program for economic evaluation of alternate ownership options.

1.8 ECONOMIC EVALUATION

Economic evaluations are performed in the DEUS computer program for three types of cogeneration ownership: industrial, third-party, and utility.

Industrial and third-party economics are evaluated using the discounted cash flow analysis method. The method is based on the simple idea that a capital investment by a firm is a cash outlay for the purpose of producing further cash revenues (or expense savings) sufficient to recover or repay the investment with some rate of return. This return, the Discounted Cash Flow Rate of Return (DCFRR), is the measure of economic performance and criterion for decision.

The discounted cash flow rate of return is frequently calculated without regard to project financing and when this is done the rate of return is referred to as the internal rate of return (IRR). In this instance the costs of investment (interest payments) are not included in the calculation of net cash flows from which the rate

of return is calculated. The IRR is thus a measure of the economic worth of a project without consideration for the method of financing the project.

For industrial ownership cases, the internal rate of return on incremental investment (compared to a nocogeneration case) is calculated. The cash flows considered include those generated by fuel costs, operating and maintenance costs, income taxes, power revenues, and purchased power savings.

For third-party ownership the internal rate of return on total cogeneration investment is calculated. The third-party analysis considers the economics of independent ownership of the cogeneration plant including revenues associated with steam sales to the industrial customer and power sales to the local electric utility.

For utility ownership the revenue requirements method is used to evaluate the economic performance. Incremental revenue requirements impacts are calculated by comparing a cogeneration case to a nocogeneration case. The reduction in revenue requirements (sometimes described as a net saving in total costs) is the measure of economic performance for utility owned cogeneration.

The economic evaluation in the DEUS program includes calculation of levelized costs for all three ownership options. Levelized costs and revenues are based on levelized fixed charge rates and escalation and discount rates specified in the program input. In the economic evaluation, cogeneration annual expenses and revenues are based on the first year dispatch as described earlier, either thermal or economic, using cost data for the first year of plant operation. Yearly expenses and revenues are subsequently calculated using the first year dispatch results and yearly cost data. These yearly cash flows are used in the discounted cash flow analysis to calculate an appropriate rate of return.

1.9 UTILITY IMPACTS EVALUATION

One of the principal objectives of the DEUS computer model is to evaluate economic impacts and potential benefits of cogeneration from a utility perspective. Several utility impacts are evaluated for industrial and third-party ownership. These include production costs and capital costs, electricity revenues, and purchase power payments under PURPA. Utilizing utility rate and avoided cost data, utility impacts are calculated for each time period and summed for the year.

Under Section 210 of the Public Utility Regulatory Policies Act (PURPA), the rates utilities will pay for purchase power from cogenerators and small power producers are to be based on "avoided costs". The PURPA regulations define avoided costs as "the incremental costs to an electric utility or electric energy or capacity or both, which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source". DEUS program input data includes both PURPA rates and utility system avoided costs. In the ideal situation, the PURPA rates and avoided costs should be equal; however, this may not always be the case. The DEUS model has the capability to handle both cases since both PURPA rates and utility system avoided costs are specified by the user. In most cases, however, the two will be identical.

PURPA rates, industrial rates and utility system avoided (or marginal) costs are specified by the user in terms of up to 36 time periods. The specific time periods are defined by the user and must represent a full year of plant operation. A representative set of 36 time periods is indicated below:

- Three periods for time of day
 - Peak
 - Partial peak
 - Off peak
- Three periods for day of week
 - Peak day
 - Average day
 - Weekend day
- Four periods for season of year

Utility system production costs are fuel costs and operation and maintenance (O&M) costs which result from the operation of utility power generating equipment. Production costs do not include equipment capital costs since these are sunk costs which do not influence equipment dispatch. Production cost savings are calculated for "Thermal Matched Size" systems that follow thermal load as well as "User Specified MW Size" systems with economically dispatched cogeneration described earlier.

In addition to avoided energy cost data (incremental production costs or system λ), the DEUS model user can specify avoided capacity cost data. This data represents capacity cost savings which are realized if the utility can avoid or defer the need to construct a generating unit, install a smaller, less expensive plant, or reduce firm power purchases from another utility.

Utility system plant cost savings which result from the cogeneration installation and operation are calculated as the product of a contract capacity and avoided capacity cost data specified by the user. The contract capacity depends on the reliability and availability of the cogeneration capacity. Avoided capacity costs specified by the user are expressed in \$/kW/time period where the time period is one or more of the 36 time periods. Capacity cost savings are not a function of the actual operation (dispatch) of the cogeneration plant.

Revenue losses resulting from reduced sales are calculated relative to a nocogeneration reference case. The revenue losses depend on the purchased power agreement - either Simultaneous Buy/Sell or Sell Excess/Buy Shortage, as previously described. In the case of utility owned cogeneration facilities, there is no change in electric revenues relative to the nocogeneration case. PURPA payments to the cogenerator by the utility will be calculated for both a Simultaneous Buy/Sell agreement and a Sell Excess/Buy Shortage agreement. The PURPA capacity payment is based on the contract capacity for both purchase power agreements.

Annual steam revenues are calculated as part of the utility impacts evaluation for utility owned cogeneration facilities. The steam revenues are calculated based on steam price information, \$/MBtu, specified by the user at two pressure levels. A linear interpolation is used to calculate steam rates at intermediate pressures levels. The DEUS program also has the capability to calculate a steam price for third-party ownership which yields a desired rate of return on a process boiler (nocogeneration) investment.

Section 2

INPUT DATA DESCRIPTION

2.1 INTRODUCTION

The primary purpose of this section is to present to the user a detailed description of the input required by the DEUS computer program. This section will be broken into three basic sections: to define and describe the variables; to illustrate how to add, change, or delete data for each program run; and worksheets to assist the user in defining the required input data. The generic DEUS computer program data base will also be presented in this section.

The DEUS computer program requires several characteristics to be input that define the system and process being screened. The required inputs (either from the built-in data base or user input) are summarized as follows:

- Utility Rates and Avoided Costs
- Industrial Power and Process Heat Loads
- On-Site Fuels
 - Characteristics
 - Availability
 - Costs
 - Waste fuels
- Power Plant Characteristics
 - Size
 - Full load output and efficiency
 - Part load efficiency
 - Capital and operating costs
- Economic factors
 - Inflation
 - Escalation
 - Taxes

2.2 UTILITY RATE DATA

Utility rate data required by the model are the industrial purchased power energy and demand rates, PURPA energy and capacity credit rates and utility marginal production and capacity cost. The utility rate data is specified for up to thirty-six time periods. For specific applications it is not necessary to specify all the periods. Instead, the time periods can be tailored to suit the needs of the user's process and application. However, if the user only specifies a specific number of periods, all other time varying arrays that are associated with that array must be specified in a format that is consistent. The utility rate data utilized in the DEUS screening program is made up of twelve characteristics which are defined by the Time Variation Data Arrays; TMDAT. The TMDAT variable is comprised of twelve array's each containing thirty-six values that represent the periods; i.e., costs, hours, rates, etc. The utility rate data utilized by the DEUS program is outlined below together with the corresponding variable name that is used. All cost or rate data are for the first full year of operation of the plant as specified in ECODAT (1,13). Inflation and escalations to these data are discussed in Section 2.8.

- The number of hours in each period - (TMDAT(1-36,6)).
- The name of brief description of the utility from which the rates are specified (UTITLE) (see Worksheet #9).
- The PURPA rates for the utility and region being analyzed. The PURPA rates are the negotiated rates which utilities will pay for output from cogenerators and small power producers and are to be based on "avoided costs". The PURPA regulations define avoided costs as "the incremental costs to an electric utility of electric energy or capacity or both, which, but for the purchase from qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source." There are two rates:
 - The PURPA energy cost or energy purchase price, specified in cents/kilowatt hour - (TMDAT(1-36,5)).
 - The PURPA capacity cost or capacity purchase price, specified in dollars/kilowatt within a time period - (TMDAT(1-36,7)).
- The PURPA fuel profile code number, which specifies the incremental fuel that is burned by the utility - (TMDAT(1-36,4)).
- The utility system avoided costs for the utility being analyzed (the PURPA rates and avoided costs may be equal; however, this may not always be the case):
 - The utility avoided energy costs, or sometimes called marginal production cost, specified in cents/kilowatt hour - (TMDAT(1-36,10)).
 - The utility avoided capacity costs, or sometimes called marginal capacity cost, specified in dollars/kilowatt within a time period - (TMDAT(1-36,11)).

- The industrial rates specified by the utility for the sale of power to the industry:
 - The industrial energy cost, specified in cents/kilowatt hour - (TMDAT(1-36,8)).
 - The industrial demand charge, specified in dollars/kilowatt within a time period - (TMDAT(1-36,9)).

2.3 PROCESS DATA

The DEUS program also requires data that is representative of the specific site and process that is being analyzed. The site is described by the following characteristics:

- The name of the site or application being studied can be specified by the user (optional input) in the variable (TITLE) (56 characters maximum).
 - The type of manufacturing involved (optional input) can be defined utilizing the industrial SIC code - (INDAT(1)).
 - The plant size or delivered product (INDAT(2)) specified in accordance with the units denoted (INDAT(3), see Worksheet #2).
 - The user also has the option of invoking a size limit on each ECS unit. The size limit is defined by fuel flow. An equipment size limit is imposed with a '1' in GNLDAT(14). The user also specifies the maximum and minimum fuel flow based on the higher heating value in INDAT(49) and (5) respectively.

The specific process data that defines the steam load profile and the electric power demand profile is specified for the same periods (up to thirty-six) used to define the utility rate data. The industrial process is described by the following characteristics:

- Electric power consumption
- Steam load for 1, 2 or 3 pressures
- Process return conditions
 - flow and temperature

and

- Waste fuel and/or heat streams.

The time varying process demands are also specified in the TMDAT array utilizing the thirty-six periods and are defined below. The annual hours of operation of the industry is specified by INDAT(9) which must equal to the total number of hours specified in the thirty-six time periods TNDAT(1-36,6).

Electrical Process Demand

The process electrical demand is specified by an overall average value and a profile corresponding to the time periods (TMDAT(1-36,6)).

The electrical process demand is defined by the following variables:

- Average electric demand during all time periods - INDAT(6).
- Electric demand factor (peak electric demand expressed as a percent of the average INDAT(7)).

The electric demand in each time period (TMDAT(1-36,6)) is defined as a percent of the average (INDAT(6)) and is assumed constant during each time period - TMDAT(1-36,1).

In addition to TMDAT(1-36,1) which defines the demand profile for the year, the peak to average demand factor for the process power in each of the time periods is specified in the array (TMDAT(1-36,12)). The peak to average demand factor is simply the ratio of the peak power to the average power in each period from which the demand charges and other pertinent calculations can be made. The factor is denoted by a ratio.

Process Steam Demand

The heat demand is defined by three streams corresponding to three steam pressures. The user has the option of defining only one or up to three (maximum) heat streams and corresponding steam pressures. If there are less than three streams, the remaining streams are set to zero, along with the extraction pressures and corresponding factors that will be defined below. The three heat streams however are limited to two profiles maximum, where the profile is denoted by the thirty-six periods (TMDAT(1-36,6)). Thus, the user can specify the same profile for all three heat streams or define one heat stream (one of the three steam pressures) by a separate heat stream profile.

The heat demand of the process is defined by the following input variables:

- The total number of heat streams that represent the process demand must be defined by the user. The number of heat streams is input as an integer number in the variable location INDAT(10) (max of three, min of one).
- The magnitudes of the average process heat demands of the three streams depends on the units chosen by the user (defined below). The magnitudes of the three streams are defined in the variable locations:

stream #1 - INDAT(11), stream #2 - INDAT(12), and stream #3 - INDAT(13).

- The code for the units of measure for the process heat demand are defined in the variable location (INDAT(14)). Codes for the different process heat units of measure are as follows:
 - 1 = MBtu/hr (million Btu's per hour)
 - 2 = thermal MW (megawatts)
 - 3 = K#/hr (thousand pounds per hour)
- The steam pressures and temperatures of the three streams are input as real numbers in the variable locations.
- The steam pressures of streams #1, 2 and 3 are specified in INDAT(38), INDAT(40), and INDAT(42), respectively.
- The steam temperatures of streams #1, 2, and 3 are specified in INDAT(37), INDAT(39), and INDAT(41), respectively.

The two heat stream profiles are defined as a percent of each average in the variable locations TMDAT(1-36,2) and TMDAT(1-36,3). If the user decides to specify a separate heat stream profile for a specific stream, that heat profile is specified first in TMDAT(1-36,2) and the other two streams are defined by TMDAT(1-36,3). The steam pressure that corresponds to the first specified heat stream is input in the variable location TMDAT(38) and the steam temperature in INDAT(37).

The program allows the user to specify a condensate return or, as called here, a reject stream. The reject stream is defined by three quantities; pressure, temperature and percent of the stream that is rejected. If the temperature of the reject stream is below steam saturation temperature, it is assumed to be condensed. If temperature is specified at saturation temperature or above, it is assumed to be steam. All makeup flow is assumed to be water at 80°F. The reject stream quantities (optional input) are inserted in the following locations:

- Reject stream (water or steam) pressure - INDAT(44)
- Reject stream temperature - INDAT(43)
- Reject stream flow returning to boiler for use as a percent of the total steam flow - INDAT(45).

The program also allows the user (optional) to specify the heat loss from the process piping to the power house extraction source. This loss is expressed as decimal percent of the total process steam flow and is input in the variable location INDAT(46).

For each of the three streams the user defines a demand size factor which is a percent of the average demand that is used to size and cost the system. The size factor should be sufficient to provide the peak demand plus any margin desired. The heat stream demand size factor for the three streams is input in the variable locations: stream #1 - INDAT(15), stream #2 - INDAT(16), and stream #3 - INDAT(17).

Waste Utilization in Process

The user also has the option of defining up to three waste streams if desired. One waste stream can be modelled as fuel and the other two as waste heat. The waste streams are defined by a constant or flat profile based on the average flow. Similar to the heat demand streams, the waste streams are defined by several program inputs. The variables and variable locations of the required inputs are listed below. (If the user does not desire any waste streams or less than three, the remaining streams must be specified as zero along with the corresponding data.)

- The number of waste systems desired by the user is an integer in the variable location INDAT(25).
- If the user desires the addition of a waste stream, several specific characteristics and variable locations are listed below.
 - The addition of the waste stream requires that the higher heating value of the first waste stream be specified. The higher heating value is input as an integer number in the variable location INDAT(31).
 - If the user specifies two or three waste streams, the user has the option to define the temperature drop (if water) or the enthalpy drop in ideal conditions for steam (or air or other fluids), expressed in Btu/lb for the process demands for the waste streams #2 and #3. The values are input in the variable locations: waste stream #2 - INDAT(35), and waste stream #3 - INDAT(36).
 - The user has the option of deciding how the waste stream #1 energy is to be utilized in the cogeneration mode. The user inputs an indicator code: 0 if no power is desired from the waste stream, an integer value 1 if the stream is used in the steam turbine mode (if the stream is used in the steam turbine mode the heat to power ratio must also be specified, variable location defined later), or a percent value that represents the amount of energy that is converted into electricity where the percent is in the range 1 to 100. The variable location is INDAT(47).
- The waste stream defined by a flat or constant profile based on the average flow for each of the three streams are input in the variable locations: waste stream #1 - INDAT(26), waste stream #2 - INDAT(27), and waste stream #3 - INDAT(28).
- The unit of measure for the waste stream is specified by the same codes as that for the heat streams. The code for the waste stream is input in the variable location INDAT(29).

- The user can specify the efficiency of utilization of the waste energy for the three streams. The efficiencies are input in the variable locations: waste stream #1 - INDAT(32), waste stream #2 - INDAT(33), and waste stream #3 - INDAT(34).

2.4 FUEL DATA

Some chemical properties of fuels and their costs are needed in the computer program and have significant impact on the economic evaluation of cogeneration systems. These are grouped in a two dimensional array variable FLDAT. The data base contains representative values for typical fuels (coal, distillate and residual oil, natural gas, wood, etc.) and estimated costs in 1984 dollars. Since the values in FLDAT could vary significantly, the user should normally input these values according to his site specific situation. A maximum of nine different types of fuels can be specified. The first five rows of data is reserved for coal, distillate, residual oil, natural gas and wood fuels in strict order. Only their values can be changed. Rows six through nine can accommodate other fuels or multiple variations of the above five fuels if they are to be considered. It is important to note that the fuels and energy systems considered must have compatible data. A description of variables FLDAT(X,N) for fuel 'N' follows:

- Higher heating value of the fuel in Btu's per pound - FLDAT(2,N)
- Weight fraction of sulfur per pound of fuel - FLDAT(6,N)
- Weight fraction of nitrogen per pound of fuel - FLDAT(7,N)
- Weight fraction of carbon per pound of fuel - FLDAT(8,N)
- First year purchase cost of fuel in dollars per million Btu's for short term industrial and third-party contracts - FLDAT(10,N)
- First year utility purchase cost of fuel in dollars per million Btu's for long term utility contracts for bulk purchases - FLDAT(11,N).

The nine fuels defined in the data base have corresponding titles or brief descriptions (FUELTL). The fuel titles (see Worksheet #9) are utilized in the output format of the program. Similar to the DEUS titles, the user has the option of changing the titles. The fuel title is denoted by the subscript 'N'; FUELTL(N), for N = 1 to 9 which corresponds to the fuel characteristics data; FLDAT(X,N). The user must maintain compatibility between the title and fuel characteristics.

2.5 ENERGY CONVERSION SYSTEMS DATA

The performance, cost and other functional characteristics of different types of energy conversion systems, which a user wishes to analyze, can be specified as "Energy Conversion Systems Input Data (PCODAT)". A maximum of eleven cogeneration systems PCODAT(2-12,Y) producing both electricity and process heat can be compared to a base nocogeneration energy conversion system PCODAT(1,Y) which produces only process heat. Each energy conversion system can have units burning different fuels (a maximum choice of three types of fuels). The base nocogeneration process heat generation system is always the first system in input data.

The data base consists of representative characteristics of the following nine 1980 state-of-the-art energy conversion systems which could be installed by 1984. All these systems are designed to meet EPA allowable source emission standards and the eight cogeneration systems have been configured to cogenerate process steam for industrial use (i.e., in the range of 15 psia to 450 psia).

1. Conventional Process Boiler.
2. Low Pressure Steam Turbine System (865 psia, 825⁰F) with conventional power steam boiler.
3. Medium Pressure Steam Turbine System (1465 psia, 950⁰F) with conventional power steam boiler.
4. Medium Pressure Steam Turbine System (as above) with atmospheric fluidized bed boiler.
5. Integrated Coal Gasification Combined Cycle System using Texaco O₂ blown gasifier.
6. Phosphoric Acid Fuel Cell Cogenerator with supplementary-fired process steam generator.
7. Gas Turbine with unfired heat recovery steam generator.
8. Combined Cycle Cogeneration System with dual pressure level (900 psia/160 psia) unfired heat recovery steam generator.
9. Medium Speed Diesel Engine with unfired heat recovery steam generator and open cycle heat pump.

The nine systems in the data base each have two brief title descriptions (different lengths) which are utilized in the format of the program output to distinguish the different systems (DTITLE & DEUSTL, see Worksheet #9). The complete title, DTITLE, is used in the output summary of all the inputs and data base, whereas the brief title DEUSTL is used for all the output tables. The user has the option of redefining the system titles (two for each system) if so desired (Worksheet #9). The

title subscripts, DTITLE(X) and DEUSTL(X) for X = 1 to 12, denote the system and must be compatible with the system characters also denoted by the same subscript; PCODAT(X,1-72) for X = 1 to 12, which will be discussed in the following paragraphs.

It is important to note that a user can use the data base values of any or all energy conversion systems and needs to update only those values in input which correctly describe different characteristics of his chosen systems. The variable PCODAT is a two dimensional array in which all functional specifications of any energy conversion system are specified as a single row. A maximum of eighty different characteristics can be specified to describe a single energy conversion system. These characteristics represent design point performance data at three specific steam pressure conditions with minimum and maximum design range of heat to power ratios, typical partload performance data, types of fuels burned, costs and size range of equipment, auxiliary electrical and heat requirements, operational and maintenance costs, etc. Usually most of this data can be obtained from equipment manufacturers and corrected to reflect previous engineering experience, site specific conditions and local regulatory requirements. The following paragraphs describe in detail the meaning of these variables for any one energy conversion system.

Design Point Data

- Fuel code for the primary fuel used by the energy conversion system for which detailed design point information is available (e.g., 1 = coal, 2 = distillate oil, 3 = residual oil) - PCODAT(X,1). A value of zero means that user is not interested in evaluating this system.
- Fuel conversion efficiency as a fraction of total fuel energy (HHV) converted into total heat and electrical energy - PCODAT(X,2).
- Minimum and maximum unit size of equipment as expressed by the fuel flow input energy in million Btu per hour - PCODAT(X,17) and PCODAT(X,18).
- Desired electrical output from User Specified MW Size cogeneration energy conversion system - PCODAT(X,72).
- System total installed cost at minimum and maximum unit sizes and minimum and maximum ranges of heat to electrical outputs - PCODAT(X,19-22).
- System annual operation and maintenance costs, as determined by fixed, variable and consumable cost coefficients. The fixed cost coefficient (A) (PCODAT(X,27)) is the ratio of fixed O&M cost to the total installed equipment cost. The variable cost coefficient (B) and exponent (C) (PCODAT(X,28 and 29)) represent the rated fuel flow (FF) dependent cost given by the equation $B(FF)^C$. The consumable cost coefficient (D) (PCODAT(X,20) represents costs of consumables, e.g.,

water, chemicals, etc. given by formula $D \cdot FF \cdot T$, where T is the annual operating hours.

- Plant design and construction time is total time from start of plant design to the time when plant is first ready for operation - PCODAT(X,70).
- Investment Tax Credit is fraction of total installed cost available for income tax write-off in the first year of plant operation - PCODAT(X,71).
- Design point performance data at three process steam pressure conditions (PCODAT(X,48-50) and minimum and maximum design range limit of cogeneration as determined by fractions of fuel energy converted into electricity (power/fuel) and heat (heat/fuel) - PCODAT(X,3-8) & (X,55-62).
- Maximum heat to fuel ratio (PCODAT(X,63)) is the maximum fractional amount of fuel that can be converted to heat by the ECS. This is used to normalize the heat in the partload performance data.
- Maximum cycle steam pressure and steam temperature (PCODAT(X,33 and 34)) are the maximum values at which steam can be delivered to a process. If these values are lower than the required stream #1 pressure and temperature (INDAT(38) and (37)) the selection routine will reject the ECS.
- Auxiliary power fraction is the fraction of gross electrical power output which is consumed internally by the cogeneration power plant. This power is normally not available for process use or export to a utility. Two values can be specified - one for the Thermal Matched Size system (PCODAT(X,31)) and one for the User Specified MW Size system (PCODAT(X,74)). For the nocogeneration system this auxiliary power is defined by a factor specified by the user in PCODAT(1,31) which when multiplied by the fuel energy input in MBtu/hr gives the auxiliary power required in MW.
- Auxiliary heat fraction is the fraction of gross heat output which is consumed internally by the cogeneration power plant for the two specified sizes - PCODAT(X,32 and 73).

The auxiliary requirements, which are expressed as percents of the gross heat or power, are the same for both the Thermal Matched Size and User Specified MW Size plants in the data base. The user can specify a different set of auxiliaries for the User Specified MW Size plant, but only for the normally burned fuel.

- The user size auxiliaries are specified as:
--auxiliary heat = PCODAT(N,73)
--auxiliary power = PCODAT(N,74)
- If the user doesn't desire alternate user size auxiliaries, the thermal auxiliary factors for the normally burned fuel must equal the user size factors:
--PCODAT(N,73) = PCODAT(N,32)
--PCODAT(N,74) = PCODAT(N,31)

The program has its own subroutine to calculate the auxiliary factors for each DEUS system. This allows the user to model a system including auxiliaries if the data is not known prior to execution. The subroutine calculates the auxiliaries based on the type of system and the fuel that is being burned. The heat auxiliaries are derived as some combination of the following components (DEUS and fuel dependent):

- air ejectors for condenser and D/A (Deaerator)
- soot blowers
- De-NO_x system
- fuel atomizing
- fuel heating
- exhaust cleanup system
- auxiliary steam drive equipment

Similarly, the auxiliary power requirements are based (also as a fraction of fuel and DEUS) on a combination of the following:

- boiler feed pump
- condenser and cooling tower
- coal-fired boiler
- oxygen plant

If the user does not know the auxiliaries for a particular system or the default values are not representative of the system being analyzed, the user can instruct the program to calculate the auxiliaries. The auxiliary system is initialized by inputting 1's into the normally burned fuels auxiliary factor variables:

- auxiliary heat = PCODAT(X,32) = 1
- auxiliary power = PCODAT(X,31) = 1

In order to utilize the auxiliary system routine, the DEUS system must be similar to one of the nine DEUS systems specified in the default data base. The DEUS must be specified in the memory location that denotes that type of DEUS system, i.e., low pressure steam turbine - DEUS #2 or diesel - DEUS #9. Secondly, the fuels that are specified for the DEUS must be burnable by that DEUS (e.g., diesel fuel cannot be nuclear or hydro).

- Performance and cost values can be modified for up to two (PCODAT(X,35)) alternate fuels - PCODAT(X,36 and 42), where the fuel codes are given by 1 to 9.
 - Different values of fuel conversion efficiency (PCODAT(X,37 and 43)) for alternate fuels. These values correspond to PCODAT(X,2) for the primary fuel PCODAT(X,1).

--Correction factors are applied to the total installed capital cost (PCODAT(X,38 and 44)) and to the variable portion of the O&M (PCODAT(X,39 and 45)). These factors are multiplied by the corresponding values PCODAT(X,19-22) and PCODAT(X,28) for the primary fuel.

--Alternate auxiliary power PCODAT(X,40 and 46) and auxiliary heat PCODAT(X,41 and 47) fractions for the alternate fuels replace these fractions PCODAT(X,31 and 32) for the primary fuel based on Thermal Matched Sizing. No alternate fractions can be specified for the User Specified MW Sizing.

- Cost factors to be used as multipliers on system installed costs are specified as PCODAT(X,24-26). These factors alter portions of the installed costs of each unit depending on fuel burned PCODAT(X,24-25) and alter the overall costs for all units for site specific or other considerations - PCODAT(X,26).
- Emission control efficiencies are system efficiencies for removing pollutants: SO_2 , NO_x , CO and particulates - PCODAT(X,51-54).

Part Load Performance

System part load performance data is expressed in the input data as a combination of performance changes due to thermodynamic conditions and efficiency changes due to components operating at part load conditions.

- System part load performance changes due to thermodynamic conditions are specified only for the intermediate steam pressure (PCODAT(X,49)). The characteristics are assumed to be similar for other steam pressures. Part load performance is expressed as fractions of design fuel required, e.g., PCODAT(X,10), for specified part load thermodynamic conditions expressed in the form of output heat and electricity. The output heat and output electricity are expressed as fractions of maximum heat and maximum electricity, respectively, to which the design point fuel flow energy can be converted - PCODAT(X,9-16).
- System part load performance changes due to component efficiencies at part load are determined from the component efficiencies at rated and at 20 percent of rated fuel flow conditions. Efficiencies are assumed to be zero at zero fuel flow and linear interpolation is used at all other fuel flows. The electric generator efficiency affects only the electric power output. The prime mover efficiency affects both the electric power output and fuel flow (such as heat losses in a turbine). The combustor efficiency affects only fuel flow. All values in the data base are 1.0 because these affects have been included in the remaining data. These factors are included to simplify changes in performance, if desired - PCODAT(X,64-69).

2.6 GENERALIZED PROGRAM INPUTS

The DEUS computer program requires several input characteristics of the total system that are general for each evaluation. As for all other values, no changes are required if the user is satisfied with the default values given. The user can change any, all, or none of default values if desired.

Several characteristics not discussed elsewhere that the user can specify for the evaluation are:

- Base Year for Capital Costs
- Megawatt Size Limit on Cogen Plants
- Maximum Limit on the Site Fuels A & B
- Minimum Number of DEUS Units
- Auxiliary Boiler Size
- Steam Revenues
- Contract Capacity Fraction
- Utility 'PURPA' Heat Rates
- Emission Limits

Base Year for Capital Cost

The capital cost base year (GNLDAT(1)) is the year for which the dollars are specified for the equipment costs.

Megawatt Size Limit

The user has the option of specifying the megawatt size of the plant desired, (User Specified MW Size) independent of the DEUS system (GNLDAT(8)). If the power generated by the thermal match design is greater than the required size, the program will neglect the size requirement. If, on the other hand, the power generated by a thermal match is less than that specified by the user (GNLDAT(8)), the program will size a unit to the specified MW size. The user can specify individual DEUS megawatt sized plants in the DEUS data (PCODAT(X,72), where X denotes the corresponding

number of the cogeneration system). If an individual plant size is specified (PCODAT(X,72)), the program will neglect the general size requirement (GNLDAT(8)) for that particular DEUS. An input of zero in PCODAT(X,72) will cause the computer to size to the general size requirement (GNLDAT(8)).

Fuel Limits

The program allows the user to specify up to three site fuels (INDAT(4)). The fuel types are specified by fuel codes in INDAT(5). The program requires the fuels to be input sequentially by cost; least expensive first (based on cost divided by efficiency). The program also needs a defined availability limit for the fuels (Fuel A - GNLDAT(9) and Fuel B - GNLDAT(10) where Fuel A is the least expensive of the fuels). The program assumes that there is no limit to the third site fuel since it is the most expensive. However, if a particular DEUS is unable to burn the third site fuel and the design requirements have not been satisfied, the program will print a warning message to inform the user the fuel limits have been exceeded.

Number of DEUS Units

The program user may wish to specify a minimum number of DEUS units for reliability reasons, and has the option with GNLDAT(17) to specify a minimum number. However, the program is limited to a maximum specification of five units.

Auxiliary Boiler

The user has the option to specify the addition of an auxiliary boiler to the DEUS system to displace peak steam loads (GNLDAT(15)). The auxiliary boiler will be sized to the percent of maximum thermal load specified and its cost will be based on this size. The auxiliary boiler will be used to satisfy the peak thermal demand. If the user specifies an auxiliary boiler, the user must define the fuel type to be burned by the boiler (GNLDAT(16)).

Steam Revenues

The revenues obtained from the steam produced by the DEUS system is a significant part of the DEUS economics for third-party and utility ownership. The user is required to input the steam revenue rates for the minimum steam pressure and the maximum steam pressure, GNLDAT(18) and GNLDAT(19)). Alternate steam revenue rates can be determined as those costs to an industrial if he had to install a nocogen boiler to produce his own steam. These values are obtained by setting a desired rate of return (DIRR) for third-party ownership (which assumes the

full cost) of a nocogen system and the program will determine the steam revenue rates that give the desired rate of return. The steam revenue rate calculation is initialized by a 1 in the variable KSTPR. Rates for both the minimum and maximum steam pressures (GNLDAT(18 & 19)) are still required in order to set the ratio for the rates at the two pressures. While the absolute values are not important, the relative values will be used to determine the ratio. While this desired rate of return is based on third-party ownership, the steam rates that are determined will be used in the economics for other ownerships.

Contract Capacity Fraction

In a contract with the utility, the PURPA rates for capacity are based on an agreed upon contract capacity. The ratio of this contract capacity to the system electrical capacity at the design point is given by GNLDAT(21).

PURPA Heat Rates

The program assumes that the utility can burn only coal, oil, and natural gas for marginal power production. The incremental fuel burned by the utility is defined for each period (TMDAT(1-36,4)) as discussed in Sect. 2.2. In order to determine the system benefits or the savings in fuel resulting from the addition of a cogenerator, the program requires as input the utility PURPA heat rates for each fuel. The PURPA heat rates for coal, oil and natural gas are given by GNLDAT(2), (3) & (4).

Emission Limits

The program also has the capability of checking the emission limits that may be present at the site in question. The emissions that are considered are (all in lb/MBtu at HHV):

--Stack SO ₂	- EMSDAT(1)
--Stack NO _x	- EMSDAT(2)
--Stack Particulates	- EMSDAT(3)
--Stack CO	- EMSDAT(4)

If the user opts to neglect any particular emission check, a zero is used for that variable. If the user opts to neglect the emissions altogether, the user indicates so by using zero in the variable GNLDAT(13).

2.7 SPECIAL FUNCTIONS

The DEUS program has several indicators or selection switches that allow the user to direct the program to execute specified functions. The user is not required to input any data if the default data are adequate for the evaluation. The selection switches available to the user are:

- Simultaneous Buy/Sell Switch
- User Size Thermal/MW Match Switch
- Emissions Limit Switch
- Equipment Size Limit Switch
- Suppression of Built-in Diagnostic Warning Message Switch
- Desired IRR Switch

The Simultaneous Buy/Sell Switch (GNLDAT(22)) allows the user two options for generating revenues from the cogeneration system. The first option is the sell excess or buy shortage. If the cogenerator generates more power than its own process requires, the excess power will be sold to the utility at the specified PURPA rates. However, if the process requires more power than the cogenerator is able to produce, the shortage will be purchased at industrial rates. The second option available to the user is to simultaneously buy and sell power. The cogenerator will sell all the power generated and purchase all the power requirements. One method may be more economical to the user than the other depending on the industrial purchased power and demand rates and the utility PURPA energy and capacity rates.

The program has the capability of calculating the steam revenue rates to yield a desired IRR as described in Section 2.6 Steam Revenues by setting KSTPP equal to 1.

The program allows the user several options for specifying the megawatt size. The user can size all the cogeneration systems to one specified size (denoted by GNLDAT(8)), specify an individual size for each DEUS (utilizing PCODAT(X,72) where 'X' denotes the DEUS), or a combination of both. As stated before, if PCODAT(72) > 0, that particular system will be sized to that value (regardless of GNLDAT(8)) or thermal, whichever is greater. (Reference Section 2.6 Megawatt Size Limit.)

If the User Specified MW Size requested by any of the options selected is larger than the maximum MW size that can be obtained with minimum heat to power ratio while matching the thermal load, the program can do one of two things. Under default conditions, the program will design the DEUS unit to meet both the thermal match and the megawatt match. If additional

fuel flow is required, however, to meet the megawatt demand, thereby producing excess heat, that excess heat will be wasted (any heat produced above the thermal match is excess heat). The second option which is available to the user, is to meet the thermal match and produce the maximum power possible by condensing. This option will prevent any wasted energy but will limit the generation capacity. The actual generation capacity is a function of the individual DEUS system performance. The selection of one or the other option is based on the User Specified MW Size Switch GNLDAT(7).

The program has a built-in DEUS selection routine (based on five characteristics) that determines if the DEUS is a candidate for evaluation. The evaluation is based on the following:

- suitable system for user application (subjective input)
- ability to meet process steam conditions
- availability of fuel(s)
- local emission rules
- available equipment size range.

The first three selection criteria are based on the process and DEUS characteristics (see Section 2.5). The last two criteria, local emissions and available equipment size, are subject to the user's discretion. The user has the option of neglecting these checks if so desired. With a zero in GNLDAT(13) the emissions from each unit that result from the equipment data PCODAT(51) to (54) and fuel data FLDAT(6) to (8) for the fuel used are not checked with the emission limits EMSDAT(1) to (4). The user can also, as stated before, select individual emission checks utilizing the variable EMSDAT(1) to (4). With a zero in GNLDAT(14), the fuel flow size limits on the equipment PCODAT(17) and (18) are not checked with the industrial site limits INDAT(49) and (50).

The program contains built-in diagnostic warning messages. Some of the warning messages indicate input errors, while others indicate special function execution (refer to Section 6 Program Diagnostics). If the user so desires, the warning messages can be suppressed by inserting a 1 in GNLDAT(6). This provides the user with the capability of printing output without warning messages that are only for the user's benefit.

The program also has an output print selector, IPRINT, which allows the user the selection of all, any, or just the economics printouts - IPRINT(1) to (8).

2.8 ECONOMIC DATA

General

The economic data used by the program has a significant impact on the overall economic results. It is usually desirable to perform a sensitivity analysis of a given situation by observing the variation of outputs of interest with respect to variations of inputs over their expected range of values.

The economic data inputs for the program are for the most part described on the Economic Groundrules Worksheet #4 and Economic Escalation Worksheet #5 given in Section 2.9. In addition, there are other parameters that pertain to economics but are described on other data worksheets because they fall into other descriptive categories as well. These are such parameters as fuel prices and electric power purchase and sales rates, plant capital costs, steam prices, etc.

The economic results over the life of the plant are based on the first year dispatch of the plant. The plant is dispatched thermally or economically based on first year economics and these results are escalated over the life of the plant according to the user escalation/inflation inputs.

Cash Flow Convention

Figure 2.8-1 shows the cash flows that go into computing the annual net cash flows used in the calculation of the internal rate of return on incremental investment for industrial ownership. The internal rate of return is calculated from a sequence of year end cash flows. The initial investment in the cogeneration project is assumed to occur at the end of year zero which is the same as at the beginning of year 1, the first year of operation of the plant.

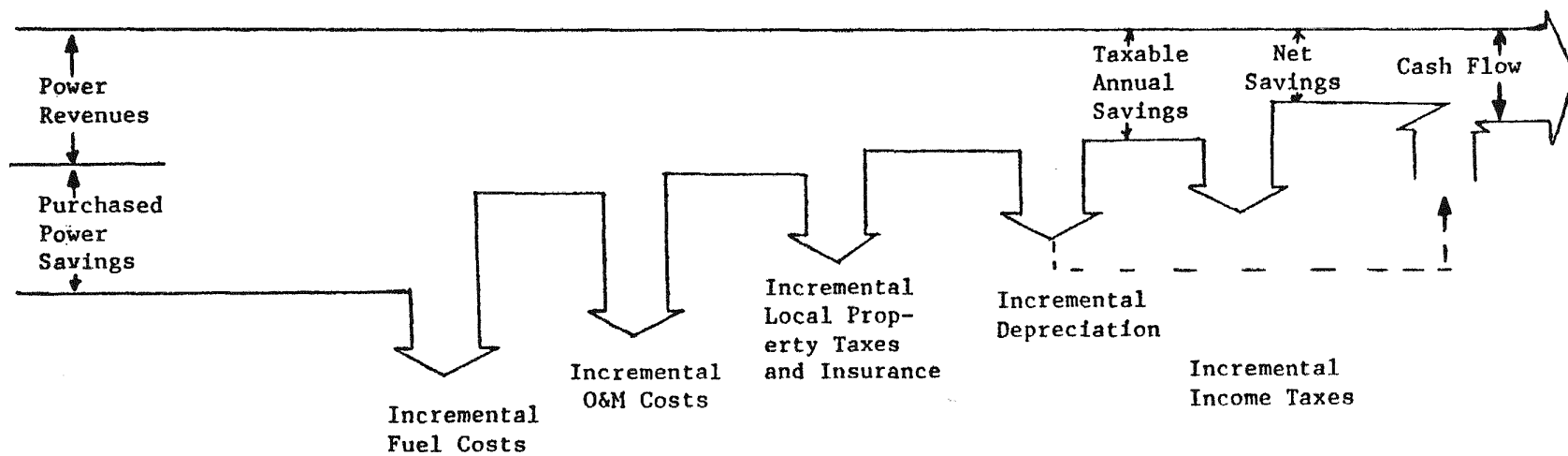


Figure 2.8-1. Annual Cash Flow for Industrial Owned Cogeneration Compared to Nocogeneration

Inflation

The program is designed to perform economic analysis with or without inflation. The inflation rate used is input in ECODAT(1,1) for industrial ownership calculations, ECODAT(2,1) for third-party ownership calculations, and ECODAT(3,1) for utility ownership calculations. It is not recommended to use a different rate of inflation for each ownership type as this probably wouldn't be realistic, but it is possible to do so. It is required, however, to input a value for each ownership type.

When performing analyses with inflation, it is important to have consistency in the various costs input into the program. It is required that all the plant capital costs be defined in terms of some base year dollars and that the base year (GNLDAT(1)) be specified. Plant capital costs for each plant type are defined by PCODAT(X,19-22) (see Section 2.5 for description of energy conversion system input). The program will automatically inflate the capital cost of the plant from the base year specified to the value for the beginning of the first full year of plant operation. Allowance for interest during construction will also be made if selected by the user through the proper program input (see the next subsection for a description of interest during construction).

All fuel costs, electric power purchase and sale prices, steam revenues, and O&M costs must be defined in dollars that are consistent with the first full year of plant operation defined by ECODAT(1,13). For instance, if the first year of plant operation is specified as 1986, then ECODAT(1,13) would be 1986., and all fuel costs, electric power rates, steam prices and O&M factors would be specified in terms of 1986 dollars for all ownerships. While ECODAT(1,13) defines the first full year of plant operation for industrial ownership, the program uses the same year for the other types of ownership.

If an analysis without inflation is desired, then all dollar values defined in the program must be in terms of the reference year dollars. It is the responsibility of the user to specify all economic parameters and dollar values on a consistent basis.

Interest During Construction

The program contains an algorithm for computing interest during construction which in reality is the project cost growth during construction. This algorithm accounts for charges for borrowed money during the construction period, cost escalation/inflation of labor, equipment and materials during construction and the fact that money is invested incrementally over the construction period. This algorithm requires definition of the following parameters:

• Base Year for Capital Costs	GNLDAT(1)
• Annual Rate of Inflation	ECODAT(X,1)
• Cost of Debt (Before Taxes & Above Inflation)	ECODAT(X,2)
• Fraction of Debt to Total Amount Borrowed	ECODAT(X,3)
• Cost of Preferred Equity	ECODAT(X,4)
• Fraction of Preferred Equity	ECODAT(X,5)
• Cost of Common Equity	ECODAT(X,6)
• Plant Design & Construction Times, Years	PCODAT(X,70)
• First Full Year of Plant Operation	ECODAT(1,13)
• Code for Calculation of Interest During Construction (-1 for calculation, 0 or 1 for no calculation)	ECODAT(X,15)
• Annual Capital Cost Escalation Above Inflation During Construction	ECODAT(X,14)

where X defines the ownership for the ECODAT data and the energy conversion system for the PCODAT data.

Plant Investment or Cost Used for Calculating Rate of Return

The cost of the plant, including interest during construction less the investment tax credit, is the investment used for calculating the rate of return.

The investment tax credit could vary for each energy conversion system. The input location for investment tax credit is PCODAT(1-12,71).

Internal Rate of Return

The internal rate of return (IRR) is an equivalent compound interest rate that the investment returns over the life of the project. Factors that effect the internal

rate of return are the initial investment, investment tax credit, the economic life of the project, the operating expenses, fixed expenses and revenues, tax rate, and tax depreciation life and method. The following economic inputs are important for calculating IRR.

- Federal & State Income Tax Rate ECODAT(X,7)
- Code for Tax Depreciation Method ECODAT(X,8)
 - 1 = Sum of Year Digits (SYD)
 - 2 = Double Declining Balance (DDB)
 - 3 = Straight Line (SL)
- Tax Life (Number of Years that Asset is Depreciated in) ECODAT(X,10)
- Annual Local Taxes & Insurance as Fraction of the Total Installed Cost ECODAT(X,11)
- Plant Economic Life ECODAT(X,12)

where

- X = 1 for industrial ownership
- X = 2 for third-party ownership
- X = 3 for utility ownership

Levelized Costs/Revenues, Utility Impacts

Levelized values of various cash flows are output from the program. For industrial owned cases, levelized values of fixed charges, fuel costs, O&M, purchased power and electric revenues are output. For third-party ownership, all of the above levelized costs/revenues are output as well as levelized steam revenue. Levelized utility impacts for industrial or third-party owned cogeneration plants and levelized revenue requirements for utility owned cogeneration plants are also output. Calculation of levelized values requires the specification of a discount rate. The program allows for specification of a different discount rate for each ownership type.

- Industrial Owned Discount Rate ECODAT(1,16)
- Third-Party Owned Discount Rate ECODAT(2,16)
- Utility Owned Discount Rate ECODAT(3,16)

Also, it is possible to input a different levelized fixed charge rate for each ownership type.

- Industrial Levelized Fixed Charge Rate ECODAT(1,17)
- Third-party Levelized Fixed Charge Rate ECODAT(2,17)
- Utility Levelized Fixed Charge Rate ECODAT(3,17)

Escalation Inputs

The program can accept escalation factors over and above inflation on the various parameters that effect yearly revenues and expenses of a proposed cogeneration project. It is also possible instead, to define the ratios of these costs to the costs specified for the first year of plant operation. The parameters that may be escalated or ratioed are:

<u>Parameter</u>	<u>Input Variable Name of Escalator/Ratio Array</u>	<u>Input Variable Name of Variable Escalated/ Ratioed</u>
Fuel Cost for Fuel 'N'	FULCST	FLDAT(10 or 11,N)
Utility Avoided Energy Cost	UPRCST	TMDAT(1-36,10)
Utility Avoided Capacity Cost	UMCCST	TMDAT(1-36,11)
Industrial Energy Cost	PWERGY	TMDAT(1-36,8)
Industrial Demand Charge	PWCAP	TMDAT(1-36,9)
PURPA Energy Cost	PUERGY	TMDAT(1-36,5)
PURPA Capacity Cost	PURCAP	TMDAT(1-36,7)
O&M Cost	OMESC	PCODAT(X,27-30)
Steam Revenue Rate	STPRIC	GNLDAT(18) & (19)

Only one cost escalation can be used for each fuel. This escalation is applied to both the short term cost (used for industrial or third party ownership) FLDAT(10,N) and the long term cost (used for utility ownership) FLDAT(11,N). Different fuels, however, can have different escalations or multipliers. The O&M Cost escalation is applied to the total O&M cost and is the same for all systems.

The ability to use escalators or multipliers is made possible through use of a linear interpolation scheme in the program. The user must input tabular values of year of plant operation and values of appropriate escalators or multipliers. Each escalator/ratio array in the program has a total of 20 input locations allotted for input of tabular information. Each escalator/multiplier data array is set up to handle ten values of operating years and ten values associated with description of the escalation/multiplication to be done. The first ten values are reserved for the year of plant operation and the next ten values are reserved for the escalation or ratio factors associated with the year of plant operation specified.

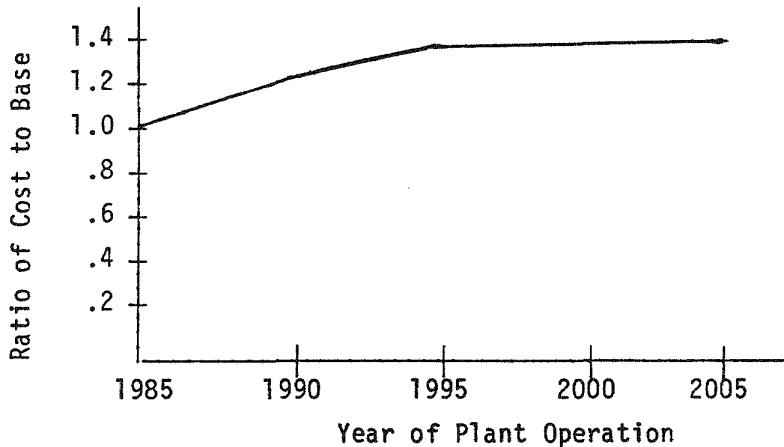
Rules for input of escalation factors or cost multipliers:

1. The first input value for year must be equal to the first full year of plant operation (ECODAT(1,13)). Up to ten values of years may be input (including the first year).

2. Also, the first value for the escalation factor or cost multiplier must be 1.
3. Linear interpolation is used to calculate tabular output of escalation/ratio tables. The magnitude of table values determines how the table output is used. If the value is greater than 0.25, then it is used as a multiplier on the base value input. If the value is equal to or less than 0.25 (including all negative values), then it is applied as an escalator. An escalator specified as negative will actually deflate the parameter. Up to 10 values of escalator/multiplier may be defined (including the first value of 1).
4. When some annual rate of inflation is defined (ECODAT(1-3,1)), then the inflation rate is applied over and above the escalators or multipliers. Separate inflation rates can be defined for each ownership, but only one value for each ownership can be defined for the full term of plant operation. Negative as well as positive values can be defined. Unlike escalators which can also be used as multipliers depending on their values, the inflation rate cannot be used as a multiplier.

Several examples will best illustrate use of the escalation/multiplier inputs.

Example 1, Purchased Power Energy Rate Multiplier Input



Assume for this example that the first year of plant operation is 1985 and the plant economic life is 15 years. Therefore, the above curve spans the economic life of the plant as required.

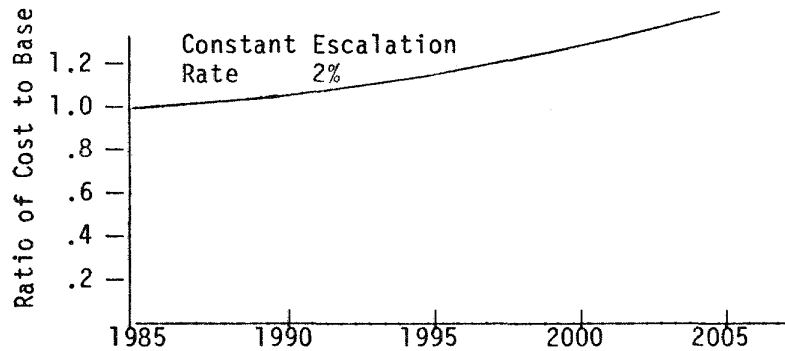
The input required to describe the multipliers on purchased power energy rate are:

```
PUERGY(1)=1985.,1990.,1995.,2005.,
PUERGY(11)=1.,1.2,1.3,1.3,
```

The resulting multipliers for each year of plant operation for the above input would be:

<u>Year</u>	<u>Multiplier Used</u>
1985	1.
1986	1.04
1987	1.08
1988	1.12
1989	1.16
1990	1.2
1991	1.22
1992	1.24
1993	1.26
1994	1.28
1995	1.30
1996	1.30
1997	1.30
1998	1.30
1999	1.30

Example 2, Purchased Power Energy Rate Escalator Input



Input Required:

PUERGY(1)=1985.,1986.,2005
 PUERGY(11)=1.,.02,.02,

<u>Year</u>	<u>Escalation Rate Used</u>
1985	0
1986	0.02
1987	0.02
1988	0.02
1989	0.02
1990	0.02
1991	0.02
1992	0.02
1993	0.02
1994	0.02
1995	0.02
1996	0.02
1997	0.02
1998	0.02
1999	0.02

Note that an input is required for 1986 in the above case. That is because cash flows are computed for year end of each plant operating year and the escalation factor is computed by the linear interpolation scheme for each year of plant operation. The input for year 1986 is required to force the output of the linear interpolation scheme to be 0.02 beginning in year 1986.

It is possible to model variable escalation rates as well. It just has to be remembered that linear interpolation is used for each year between the years specified. If the user wanted 10% escalation from 1985 through 1988, 7% escalation from 1989 through 1993 and 5% from 1994 on, the input would be:

```
PUERGY(1)=1985.,1986.,1988.,1989.,1993.,1994.,2005.,  
PUERGY(11)=1.,0.1,0.1,0.07,0.07,0.05,0.05,
```

2.9 INPUT DATA WORKSHEETS

This subsection contains all the input data forms or worksheets to fully utilize the DEUS computer program capabilities. Included on these worksheets are all the default values in the data base. These default values are included for two reasons - (1) they are convenient for determining whether they need to be changes, and (2) they are convenient for determining the magnitude and units of user values if they need to be used.

The worksheets are divided into the following nine categories:

1. General Program Input Data
2. Industrial Process Data
3. Time Varying Profile and Rate Data
4. Economic Groundrules
5. Economic Escalations
6. Fuel Properties
7. Cogeneration Systems
8. Special Input Indicators
9. Titles

Worksheet #1
General Program Input Data
(Sections 2.6, 2.7 and 2.8)

	Units	Input Variable	Default Value	User Value
Base Year for Capital Costs	Year	GNLDAT(1) =	1984	/____/
User Specified MW Size for Cogen Plants	MW	GNLDAT(8) =	100.0	/____/
Maximum Limit on Site Fuel A	MBtu/hr in HHV	GNLDAT(9) =	5,000	/____/
Maximum Limit on Site Fuel B	MBtu/hr in HHV	GNLDAT(10) =	10,000	/____/
Minimum Number of DEUS Units (Max. 5)	Number	GNLDAT(17) =	1.0	/____/
Auxiliary Boiler Size Percent (Peak Demand)	DCPT	GNLDAT(15) =	0.0	/____/
Code for Aux. Boiler Fuel Type (1 = Coal, 2 = Distillate Oil, 3 = Residual Oil, 4 = Natural Gas, 5 = Wood, 6 = Fossil, 7 = Nuclear, 8 = Hydrogen, 9 = Other)	Code	GNLDAT(16) =	4.0	/____/
Steam Revenue Rate for First Full Year of Operation (ECODAT(1,13) WS #4):				
at Minimum Extraction Pressure	\$/MBtu	GNLDAT(18) =	6.0	/____/
at Maximum Extraction Pressure	\$/MBtu	GNLDAT(19) =	8.0	/____/
or (See KSTPR Worksheet #8, Page 1)				
Contract Capacity Fraction	DCPT	GNLDAT(21) =	1.0	/____/
Desired Internal Rate of Return for Third- Party Ownership of Nocgoeneration to Determine Steam Revenue Rate	DCPT	DIRR =	0.15	/____/
Utility PURPA Heat Rate for:				
Coal	Btu/kWh	GNLDAT(2) =	10,000	/____/
Oil	Btu/kWh	GNLDAT(3) =	9,500	/____/
Natural Gas	Btu/kWh	GNLDAT(4) =	9,600	/____/
Emission Limits				
Stack SO ₂	lb/MBtu in HHV	EMSDAT(1) =	0.8	/____/
Stack NO _x	lb/MBtu in HHV	EMSDAT(2) =	0.2	/____/
Stack Particulates	lb/MBtu in HHV	EMSDAT(3) =	0.1	/____/
Stack CO	lb/MBtu in HHV	EMSDAT(4) =	0.01	/____/

Worksheet #2
Industrial Process Data
(Sections 2.2, 2.3 and 2.6)

	<u>Units</u>	<u>Input Variable</u>	<u>Default Value*</u>	<u>User Value*</u>
Industry SIC Code	Number	INDAT(1) =	26212	/_____/
Plant Size (Delivered Product)	Number	INDAT(2) =	1100	/_____/
Code for Unit of Measure (1 = TPD, 2 = BPD, 3 = K#/hr, 4 = GPM, 5 = CFM)	Code	INDAT(3) =	1	/_____/
Total Number of Available Site Fuels (Maximum of 3)	Number	INDAT(4) =	3	/_____/
Types of Site Fuels in Order of Availability (See GNLDAT(9) & (10) on WS #1) (1 = Coal, 2 = Distillate Oil, 3 = Residual Oil, 4 = Natural Gas, 5 = Wood, 6 = Fossil, 7 = Nuclear, 8 = Hydrogen, 9 = Other)	3 Digit Code	INDAT(5) =	142	/_____/
Average Electric Demand	kW	INDAT(6) =	11,000	/_____/
Electric Demand Sizing Factor (Peak/Avg.)	%	INDAT(7) =	100	/_____/
Annual Hours of Operation (see TMDAT(1-36,6) WS #3, page 2)	Hrs/Yr	INDAT(9) =	8280	/_____/
Total Number of Process Heat Streams (Maximum of 3)	Number	INDAT(10)=	1	/_____/
Average Process Heat Demand				
Stream #1	Number	INDAT(11)=	500	/_____/
Stream #2	Number	INDAT(12)=	100	/_____/
Stream #3	Number	INDAT(13)=	0	/_____/
Code for Unit of Measure of Heat Demand (1 = MBtu/hr, 2 = MW Thermal, 3 = K#/hr)	Code	INDAT(14)=	3	/_____/

*All INDAT values must be specified as integers.

Worksheet #2
Industrial Process Data
(Section 2.3)

	<u>Units</u>	<u>Input Variable</u>	<u>Default Value*</u>	<u>User Value*</u>
Heat Stream Demand Size Factor				
Stream #1	%	INDAT(15)=	100	/ <u> </u> /
Stream #2	%	INDAT(16)=	100	/ <u> </u> /
Stream #3	%	INDAT(17)=	100	/ <u> </u> /
Process Stream Temperature				
Stream #1	°F	INDAT(37)=	0	/ <u> </u> /
Stream #2	°F	INDAT(39)=	0	/ <u> </u> /
Stream #3	°F	INDAT(41)=	0	/ <u> </u> /
Reject Stream	°F	INDAT(43)=	200	/ <u> </u> /
Process Stream Pressures				
Stream #1	psia	INDAT(38)=	165	/ <u> </u> /
Stream #2	psia	INDAT(40)=	65	/ <u> </u> /
Stream #3	psia	INDAT(42)=	30	/ <u> </u> /
Reject Stream	psia	INDAT(44)=	15	/ <u> </u> /
Reject Stream Flow Returning to Boiler Use	%	INDAT(45)=	70	/ <u> </u> /
Fuel Flow Minimum Unit Size in HHV	MBtu/hr	INDAT(49)=	100	/ <u> </u> /
Fuel Flow Maximum Unit Size in HHV	MBtu/hr	INDAT(50)=	1600	/ <u> </u> /
Waste Fuel/Heat Streams Being Utilized (Maximum of 3)	Number	INDAT(25)=	0	/ <u> </u> /

* All INDAT values must be specified as integers.

Worksheet #2
Industrial Process Data
(Section 2.3)

	<u>Units</u>	<u>Input Variable</u>	<u>Default Value*</u>	<u>User Value*</u>
Average Flow of Waste Stream				
Waste Stream #1	Number	INDAT(26)=	0	/____/
Waste Stream #2	Number	INDAT(27)=	0	/____/
Waste Stream #3	Number	INDAT(28)=	0	/____/
Code for Unit of Measure of Waste Stream (Same codes as INDAT(14), page 1)	Code	INDAT(29)=	0	/____/
Higher Heating Value of Waste Fuel or Enthalpy Drop Available from Waste Heat				
Stream #1	Btu/lb	INDAT(31)=	0	/____/
Waste Energy Utilization Efficiency				
Waste Stream #1	%	INDAT(32)=	0	/____/
Waste Stream #2	%	INDAT(33)=	0	/____/
Waste Stream #3	%	INDAT(34)=	0	/____/
Waste Energy Stream #1 Cogeneration Indicator (0 if No Power is Produced or % Energy Converted to Electricity if >1 and <100)	Number	INDAT(47)=	20	/____/
Temperature Drop (if Water) or Enthalpy Drop in Ideal Conditions for Steam (or Air or Other Fluids) for Process Demands				
Waste Stream #2	°F or Btu/lb	INDAT(35)=	0	/____/
Waste Stream #3	°F or Btu/lb	INDAT(36)=	0	/____/

*All INDAT values must be specified as integers.

Worksheet #3
Time Varying Profile & Rate Data
(Section 2.3)

2-31

	<u>Units</u>	<u>Input Variable</u>	<u>Default Values</u>	
Process Electric Demand in Each Time Period	% of Avg.	TMDAT(1-36,1)	36*100.	/ / , / / , / / , / / , / / , / / / / , / / , / / , / / , / / , / / / / , / / , / / , / / , / / , / / , / / / / , / / , / / , / / , / / , / / , / / / / , / / , / / , / / , / / , / / , / / / / , / / , / / , / / , / / , / / , / /
Peak to Average Demand Factor for Process Electric Power in Each Time Period	Number	TMDAT(1-36,12)	0.,1.,0.,1.8,15*0 1.,0.,1.8,14*0	/ / , / / , / / , / / , / / , / / / / , / / , / / , / / , / / , / / / / , / / , / / , / / , / / , / / , / / / / , / / , / / , / / , / / , / / , / / / / , / / , / / , / / , / / , / / , / / / / , / / , / / , / / , / / , / / , / /
Process Heat Stream #1 Demand in Each Time Period	% of Avg.	TMDAT(1-36,2)	36*100.	/ / , / / , / / , / / , / / , / / / / , / / , / / , / / , / / , / / / / , / / , / / , / / , / / , / / , / / / / , / / , / / , / / , / / , / / , / / / / , / / , / / , / / , / / , / / , / / / / , / / , / / , / / , / / , / / , / /
Process Heat Stream #2 Demand in Each Time Period	% of Avg.	TMDAT(1-36,3)	36*100.	/ / , / / , / / , / / , / / , / / / / , / / , / / , / / , / / , / / / / , / / , / / , / / , / / , / / , / / / / , / / , / / , / / , / / , / / , / / / / , / / , / / , / / , / / , / / , / / / / , / / , / / , / / , / / , / / , / /

Worksheet #3
Time Varying Profile & Rate Data
(Section 2.3)

	<u>Units</u>	<u>Input Variable</u>	<u>Default Values</u>	
Code for 'PURPA' Fuel Profile (Same Code as INDAT(8), WS #2, page 1)	Code	TMDAT(1-36,4)	36*3.0	/ / , / / , / / , / / , / / , / / / / , / / , / / , / / , / / , / / / / , / / , / / , / / , / / , / / / / , / / , / / , / / , / / , / / / / , / / , / / , / / , / / , / / / / , / / , / / , / / , / / , / /
'PURPA' Energy Cost During First Full Year of Operation*	c/kWh	TMDAT(1-36,5)	8.66,10.1,10.5,10.5,10.1,10.1 8.66,10.1,10.1,10.1,10.1,10.1 8.66,8.66,8.66,8.66,8.66,8.66 8.5,9.5,9.5,10.0,10.0,9.5 8.5,9.5,9.5,9.5,9.5,9.5 8.5,8.5,8.5,8.5,8.5,8.5	/ / , / / , / / , / / , / / , / / / / , / / , / / , / / , / / , / / / / , / / , / / , / / , / / , / / / / , / / , / / , / / , / / , / / / / , / / , / / , / / , / / , / / / / , / / , / / , / / , / / , / /
'PURPA' Hours Per Period (Must total to INDAT(9) WS #2, page 1)	Hrs	TMDAT(1-36,6)	1010 404 404 202 202 202 210 84 84 42 42 42 240 96 96 48 48 48 1390 556 556 278 278 278 280 112 112 56 56 56 320 128 128 64 64 64	/ / , / / , / / , / / , / / , / / / / , / / , / / , / / , / / , / / / / , / / , / / , / / , / / , / / / / , / / , / / , / / , / / , / / / / , / / , / / , / / , / / , / / / / , / / , / / , / / , / / , / /
'PURPA' Capacity Cost During First Full Year of Operation*	\$/kW	TMDAT(1-36,7)	0,0,48.8,18*0 34.2,14*0	/ / , / / , / / , / / , / / , / / / / , / / , / / , / / , / / , / / / / , / / , / / , / / , / / , / / / / , / / , / / , / / , / / , / / / / , / / , / / , / / , / / , / /

* ECODAT(1,13) WS #4)

Worksheet #3
Time Varying Profile & Rate Data
(Section 2.3)

	Units	Input Variable	Default Values	
Industrial Energy Cost During First Full Year of Operation *	¢/kWh	TMDAT(1-36,8)	6.2,6.5,6.8,6.8,6.5,6.5	/ / , / / , / / , / / , / / , / /
			6.3,6.5,6.5,6.5,6.5,6.5	/ / , / / , / / , / / , / / , / /
			6.3,6.3,6.3,6.3,6.3,6.3	/ / , / / , / / , / / , / / , / /
			6.3,6.5,6.5,6.8,6.8,6.5	/ / , / / , / / , / / , / / , / /
			6.3,6.5,6.5,6.5,6.5,6.5	/ / , / / , / / , / / , / / , / /
			6.3,6.3,6.3,6.3,6.3,6.3	/ / , / / , / / , / / , / / , / /
Industrial Demand Charge During First Full Year of Operation *	\$/kW	TMDAT(1-36,9)	0.2,9.0,25.1,15*0	/ / , / / , / / , / / , / / , / /
			4.1,0.24.2,14*0	/ / , / / , / / , / / , / / , / /
				/ / , / / , / / , / / , / / , / /
				/ / , / / , / / , / / , / / , / /
				/ / , / / , / / , / / , / / , / /
				/ / , / / , / / , / / , / / , / /
Utility Avoided Energy Cost During First Full Year of Operation *	¢/kWh	TMDAT(1-36,10)	8.66,10.1,10.5,10.5,10.1,10.1	/ / , / / , / / , / / , / / , / /
			8.7,10.1,10.1,10.1,10.1,10.1	/ / , / / , / / , / / , / / , / /
			8.66,8.66,8.66,8.66,8.66,8.66	/ / , / / , / / , / / , / / , / /
			8.5,9.5,9.5,10.0,10.0,9.5	/ / , / / , / / , / / , / / , / /
			8.5,9.5,9.5,9.5,9.5,9.5	/ / , / / , / / , / / , / / , / /
			8.5,8.5,8.5,8.5,8.5,8.5	/ / , / / , / / , / / , / / , / /
Utility Avoided Capacity Cost During First Full Year of Operation *	\$/kW	TMDAT(1-36,11)	0.,0.48.8,18*0.0	/ / , / / , / / , / / , / / , / /
			34.2,14*0	/ / , / / , / / , / / , / / , / /
				/ / , / / , / / , / / , / / , / /
				/ / , / / , / / , / / , / / , / /
				/ / , / / , / / , / / , / / , / /
				/ / , / / , / / , / / , / / , / /

* ECODAT(1,13) WS #4)

Worksheet #4
Economic Groundrules
(Section 2.8)

	Units	"Y"	ECODAT(1,Y) Industrial Owned Default/User	ECODAT(2,Y) Third Party Default/User	ECODAT(3,Y) Utility Owned Default/User
Annual Rate of Inflation	DCPT	1	0.09 /_____/	0.09 /_____/	0.09 /_____/
Cost of Debt (Before Taxes & Above Inflation)	DCPT	2	0.03 /_____/	0.03 /_____/	0.03 /_____/
Fraction of Debt	DCPT	3	0.3 /_____/	0.3 /_____/	0.5 /_____/
Cost of Preferred Equity	DCPT	4	0.0 /_____/	0.0 /_____/	0.04 /_____/
Fraction of Preferred Equity	DCPT	5	0.0 /_____/	0.0 /_____/	0.15 /_____/
Cost of Common Equity	DCPT	6	0.07 /_____/	0.07 /_____/	0.07 /_____/
Federal & State Income Tax Rate	DCPT	7	0.5 /_____/	0.5 /_____/	0.5 /_____/
Code for Tax Depreciation Method (1 = SYD; 2 = DDB; 3 = SL)	Code	8	1.0 /_____/	1.0 /_____/	1.0 /_____/
Tax Life	Yrs	10	10 /_____/	10 /_____/	15 /_____/
Local Taxes & Insurance as Fraction of Total Installed Cost	DCPT	11	0.03 /_____/	0.03 /_____/	0.03 /_____/
Plant Economic Life	Yrs	12	28 /_____/	28 /_____/	28 /_____/
First Full Year of Operation	Year	13	1984 /_____/	(Program Uses ECODAT(1,13))	
Capital Cost Escalation Above Inflation, During Construction	DCPT	14	0.0 /_____/	0.0 /_____/	0.0 /_____/
Code for Calculation of Interest (-1 for calculation, 0 or 1 for no calculation)	Code	15	0.0 /_____/	0.0 /_____/	0.0 /_____/
Discount Rate for Levelization	DCPT	16	0.13 /_____/	0.13 /_____/	0.11 /_____/
Levelized Fixed Charge Rate	DCPT	17	0.30 /_____/	0.20 /_____/	0.18 /_____/

Worksheet #5
Economic Escalations
(Section 2.8)
(See Note Below)

	Units	Input Variable	Default Values	User Values (Up to 10 data points: Year + Escalator, Max.)
Fuel Cost Escalation for Both Short Term (Industry and Third Party) and Long Term (Utility) Fuel A* Cost	Yr	FULCST(1-10,A)	1984,2025	/____/ , /____/ , /____/ , /____/ , /____/ /____/ , /____/ , /____/ , /____/ , /____/
	DCPT	FULCST(11-20,A)	1.,1.	/____/ , /____/ , /____/ , /____/ , /____/ /____/ , /____/ , /____/ , /____/ , /____/
Fuel Cost Escalation for Both Short Term (Industry and Third Party) and Long Term (Utility) Fuel B* Cost	Yr	FULCST(1-10,B)	1984,2505	/____/ , /____/ , /____/ , /____/ , /____/ /____/ , /____/ , /____/ , /____/ , /____/
	DCPT	FULCST(1-10,B)	1.,1.	/____/ , /____/ , /____/ , /____/ , /____/ /____/ , /____/ , /____/ , /____/ , /____/
Fuel Cost Escalation for Both Short Term (Industry and Third Party) and Long Term (Utility) Fuel C* Cost	Yr	FULCST(1-10,C)	1984,2505	/____/ , /____/ , /____/ , /____/ , /____/ /____/ , /____/ , /____/ , /____/ , /____/
	DCPT	FULCST(1-10,C)	1.,1.	/____/ , /____/ , /____/ , /____/ , /____/ /____/ , /____/ , /____/ , /____/ , /____/

* A maximum of three fuel types are permitted. A, B, and C denote fuel types 1 to 9, see INDAT(5) WS #2, page 1 and WS #6.

Note: For all escalations the first year must be the same as the First Full Year of Operation ECODAT(1,13) WS #4 and the first Escalation for that year must equal 1.

Worksheet #5
Economic Escalations
(Section 2.8)
(See Note Below)

	Units	Input Variable	Default Values	User Values (Up to 10 data points: Year + Escalator, Max.)
Utility Avoided Energy Cost Escalation	Yr	UPRCST(1-10)	1984,2025	/____/ , /____/ , /____/ , /____/ , /____/ /____/ , /____/ , /____/ , /____/ , /____/
	DCPT	UPRCST(11-20)	1.,1.	/____/ , /____/ , /____/ , /____/ , /____/ /____/ , /____/ , /____/ , /____/ , /____/
Utility Avoided Capacity Cost Escalation	Yr	UMCCST(1-10)	1984,2025	/____/ , /____/ , /____/ , /____/ , /____/ /____/ , /____/ , /____/ , /____/ , /____/
	DCPT	UMCCST(11-20)	1.,1.	/____/ , /____/ , /____/ , /____/ , /____/ /____/ , /____/ , /____/ , /____/ , /____/
Industrial Energy Cost Escalation	Yr	PWERGY(1-10)	1984,2025	/____/ , /____/ , /____/ , /____/ , /____/ /____/ , /____/ , /____/ , /____/ , /____/
	DCPT	PWERGY(11-20)	1.,1.	/____/ , /____/ , /____/ , /____/ , /____/ /____/ , /____/ , /____/ , /____/ , /____/
Industrial Demand Charge Escalation	Yr	PWCAP(1-10)	1984,2025	/____/ , /____/ , /____/ , /____/ , /____/ /____/ , /____/ , /____/ , /____/ , /____/
	DCPT	PWCAP(11-20)	1.,1.	/____/ , /____/ , /____/ , /____/ , /____/ /____/ , /____/ , /____/ , /____/ , /____/

Note: For all escalations the first year must be the same as the First Full Year of Operation ECODAT(1,13) WS #4 and the first Escalation for that year must equal 1.

Worksheet #5
Economic Escalations
(Section 2.8)
(See Note Below)

	Units	Input Variable	Default Values	User Values (Up to 10 data points: Year + Escalator, Max.)
'PURPA' Energy Cost Escalation	Yr	PUERGY(1-10)	1984,2025	/____/ , /____/ , /____/ , /____/ , /____/
				/____/ , /____/ , /____/ , /____/ , /____/
	DCPT	PUERGY(11-20)	1.,1.	/____/ , /____/ , /____/ , /____/ , /____/
				/____/ , /____/ , /____/ , /____/ , /____/
'PURPA' Capacity Cost Escalation	Yr	PURCAP(1-10)	1984,2025	/____/ , /____/ , /____/ , /____/ , /____/
				/____/ , /____/ , /____/ , /____/ , /____/
	DCPT	PURCAP(11-20)	1.,1.	/____/ , /____/ , /____/ , /____/ , /____/
				/____/ , /____/ , /____/ , /____/ , /____/
O&M Cost Escalation	Yr	OMESC(1-10)	1984,2025	/____/ , /____/ , /____/ , /____/ , /____/
				/____/ , /____/ , /____/ , /____/ , /____/
	DCPT	OMESC(11-20)	1.,1.	/____/ , /____/ , /____/ , /____/ , /____/
				/____/ , /____/ , /____/ , /____/ , /____/
Steam Revenue Rate Escalation	Yr	STPRIC(1-10)	1984,2025	/____/ , /____/ , /____/ , /____/ , /____/
				/____/ , /____/ , /____/ , /____/ , /____/
	DCPT	STPRIC(11-20)	1.,1.	/____/ , /____/ , /____/ , /____/ , /____/
				/____/ , /____/ , /____/ , /____/ , /____/

Note: For all escalations the first year must be the same as the First Full Year of Operation ECODAT(1,13) WS #4 and the first Escalation for that year must equal 1.

Worksheet #6
Fuel Properties
(Section 2.4)

		FLDAT(X,1) Coal	FLDAT(X,2) Dist. Oil	FLDAT(X,3) Resid. Oil	FLDAT(X,4) Nat. Gas	FLDAT(X,5) Wood
	"X"	Default/User	Default/User	Default/User	Default/User	Default/User
Higher Heating Value (Btu/lb)	2	12000 /_____/	19400 /_____/	18500 /_____/	23860 /_____/	8750 /_____/
Sulfur Content (DCPT by wt)	6	0.02 /_____/	0.001 /_____/	0.01 /_____/	0.0 /_____/	0.001/_____/
Nitrogen Content (DCPT by wt)	7	0.02 /_____/	0.001 /_____/	0.003 /_____/	0.0 /_____/	0.001/_____/
Carbon Content (DCPT by wt)	8	0.83 /_____/	0.84 /_____/	0.85 /_____/	0.75 /_____/	0.41 /_____/
<u>Fuel Cost</u>						
Short Term (\$/MBtu)	10	2.91 /_____/	6.66 /_____/	6.6 /_____/	5.31 /_____/	2.5 /_____/
Long Term (\$/MBtu)	11	2.91 /_____/	6.66 /_____/	6.6 /_____/	5.31 /_____/	2.5 /_____/

		FLDAT(X,6) Fossil	FLDAT(X,7) Nuclear	FLDAT(X,8) Hydrogen	FLDAT(X,9) Other
	"X"	Default/User	Default/User	Default/User	User
Higher Heating Value (Btu/lb)	2	4347 /_____/	251x10 ⁶ /_____/	61110 /_____/	/_____/
Sulfur Content (DCPT by wt)	6	0.0 /_____/	0.0 /_____/	0.0 /_____/	/_____/
Nitrogen Content (DCPT by wt)	7	0.0 /_____/	0.0 /_____/	0.0 /_____/	/_____/
Carbon Content (DCPT by wt)	8	0.43 /_____/	0.0 /_____/	0.0 /_____/	/_____/
<u>Fuel Cost</u>					
Short Term (\$/MBtu)	10	0.8 /_____/	0.45 /_____/	6.0 /_____/	/_____/
Long Term (\$/MBtu)	11	0.8 /_____/	0.45 /_____/	6.0 /_____/	/_____/

Worksheet #7
Nocogeneration - Process Boiler PCODAT(1,Y)
Sections 2.5, 2.7 and 2.8)

SYSTEM IDENTIFICATION: NOCOG

DESIGN POINT DATA	UNITS	"Y"	DEFAULT VALUE	USER VALUE
Code for Primary Fuel	Code	1	1.0	/
Fuel Conversion Efficiency	DCPT	2	0.85	/
Fuel Flow } Minimum Size	MBtu/hr	17	100.0	/
Sizing Limits } Maximum Size	MBtu/hr	18	1600.0	/
Optional User Specified MW Size	0 or MW	72	0.0	/
Total Installed } Min. } Min. Heat	M\$	19	14.957	/
Cost (TIC)* } Size } Max. Heat	M\$	20	14.957	/
For Fuel Flow } Max. } Min. Heat	M\$	21	90.022	/
Sizing Limits } Size } Max. Heat	M\$	22	90.022	/
Operation and } Fixed	DCPT	27	0.025	/
Maintenance } Variable	Number	28	1252.0	/
(O&M) Cost } Variable Exponent	DCPT	29	0.32	/
Coefficients } Consumables	Number	30	0.094	/
Construction Time	Years	70	2.5	/
Investment Tax Credit	DCPT	71	0.1	/
Low Steam Pressure	psia	48	15.0	/
Min. Heat/Power, H/P=Min.				
Power/Fuel	DCPT	55	0.0	/
Heat/Fuel	DCPT	56	1.0	/
Max. Heat/Power, H/P=Max.				
Power/Fuel	DCPT	57	0.0	/
Heat/Fuel	DCPT	58	1.0	/
Intermediate Steam Pressure	psia	49	150.0	/
Min. Heat/Power, H/P=Min.				
Power/Fuel	DCPT	3	0.0	/
Heat/Fuel	DCPT	4	1.0	/
Intermediate Heat/Pwr, H/P=Mid.				
Power/Fuel	DCPT	5	0.0	/
Heat/Fuel	DCPT	6	1.0	/
Max. Heat/Power, H/P=Max.				
Power/Fuel	DCPT	7	0.0	/
Heat/Fuel	DCPT	8	1.0	/
High Steam Pressure	psia	50	450.0	/
Min. Heat/Power, H/P=Min.				
Power/Fuel	DCPT	59	0.0	/
Heat/Fuel	DCPT	60	1.0	/
Max. Heat/Power, H/P=Max.				
Power/Fuel	DCPT	61	0.0	/
Heat/Fuel	DCPT	62	1.0	/
Maximum Heat/Fuel at Min. Power	DCPT	63	1.0	/
Maximum Cycle Steam Pressure	psia	33	500.0	/
Maximum Cycle Steam Temperature	F	34	470.0	/

* For Base Year GNLDAT(1) WS #1.

	UNITS	"Y"	DEFAULT VALUE	USER VALUE
Auxiliary Power Fraction (Thermal)	DCPT	31	0.0016	/
Auxiliary Heat Fraction (Thermal)	DCPT	32	0.1133	/
Auxiliary Power Fraction (User S)	DCPT	74	0.0016	/
Auxiliary Heat Fraction (User S)	DCPT	73	0.1133	/
Number of Alternate Fuels	Number	35	2.0	/
Code for Alternate Fuel A	Code	36	5.0	/
Fuel Conversion Efficiency	DCPT	37	0.65	/
Correction } TIC	Number	38	1.0	/
Multipliers } Variable O&M	Number	39	1.0	/
Auxiliary Power Fraction	DCPT	40	0.0005	/
Auxiliary Heat Fraction	DCPT	41	0.0260	/
Code for Alternate Fuel B	Code	42	4.0	/
Fuel Conversion Efficiency	DCPT	43	0.79	/
Correction } TIC	Number	44	0.40	/
Multipliers } Variable O&M	Number	45	0.50	/
Auxiliary Power Fraction	DCPT	46	0.0001	/
Auxiliary Heat Fraction	DCPT	47	0.02633	/
Environmental } Sulfur	DCPT	51	0.9	/
Removal } NOx	DCPT	52	0.5	/
Efficiencies } CO	DCPT	53	0.5	/
	DCPT	54	0.9	/
PART LOAD PERFORMANCE				
@ Intermediate Steam Pressure				
@ H/H max. } P/P max	DCPT	9	0.0	/
= 0.2 } F/F max	DCPT	10	0.25	/
@ H/H max. } P/P max	DCPT	11	0.0	/
= 0.5 } F/F max	DCPT	12	0.55	/
@ H/H max. } P/P max	DCPT	13	0.0	/
= 0.8 } F/F max	DCPT	14	0.8	/
@ P/P max. } H/H max	DCPT	15	0.0	/
= 0.2 } F/F max	DCPT	16	0.0	/
Efficiencies } Electric } @ 20%FF	DCPT	64	0.0	/
for Part Load } Generator } @ Rated	DCPT	65	0.0	/
Operation } Prime } @ 20%FF	DCPT	66	0.0	/
(Based on } Mover } @ Rated	DCPT	67	0.0	/
Rated Fuel } } @ 20%FF	DCPT	68	1.0	/
Flow, FF) } Combustor } @ Rated	DCPT	69	1.0	/
COST FACTORS				
Waste Cleanup Cost Factor	DCPT	24	1.0	/
Fuel Processing Cost Factor	DCPT	25	1.0	/
Area Labor Cost Factor	DCPT	26	1.0	/

Worksheet #7
Steam Turbine 865 psia 825 F FGD System PCODAT(2,Y)
Sections 2.5, 2.7 and 2.8)

SYSTEM IDENTIFICATION: LPSTF

DESIGN POINT DATA	UNITS	"Y"	DEFAULT VALUE	USER VALUE
Code for Primary Fuel	Code	1	1.0	/
Fuel Conversion Efficiency	DCPT	2	0.85	/
Fuel Flow	MBtu/hr	17	100.0	/
Sizing Limits } Minimum Size	MBtu/hr	18	1600.0	/
Sizing Limits } Maximum Size	0 or MW	72	0.0	/
Optional User Specified MW Size				/
Total Installed } Min. } Min. Heat	M\$	19	21.024	/
Cost (TIC)* } Size } Max. Heat	M\$	20	17.496	/
For Fuel Flow } Max. } Min. Heat	M\$	21	118.947	/
Sizing Limits } Size } Max. Heat	M\$	22	100.181	/
Operation and } Fixed	DCPT	27	0.025	/
Maintenance } Variable	Number	23	2189.0	/
(O&M) Cost } Variable Exponent	DCPT	29	0.30	/
Coefficients } Consumables	Number	30	0.103	/
Construction Time	Years	70	3.0	/
Investment Tax Credit	DCPT	71	0.1	/
Low Steam Pressure	psia	48	15.0	/
Min. Heat/Power, H/P=Min.				/
Power/Fuel	DCPT	55	0.312	/
Heat/Fuel	DCPT	56	0.0	/
Max. Heat/Power, H/P=Max.				/
Power/Fuel	DCPT	57	0.231	/
Heat/Fuel	DCPT	58	0.704	/
Intermediate Steam Pressure	psia	49	150.0	/
Min. Heat/Power, H/P=Min.				/
Power/Fuel	DCPT	3	0.312	/
Heat/Fuel	DCPT	4	0.0	/
Intermediate Heat/Pwr, H/P=Mid.				/
Power/Fuel	DCPT	5	0.222	/
Heat/Fuel	DCPT	6	0.404	/
Max. Heat/Power, H/P=Max.				/
Power/Fuel	DCPT	7	0.132	/
Heat/Fuel	DCPT	8	0.809	/
High Steam Pressure	psia	50	450.0	/
Min. Heat/Power, H/P=Min.				/
Power/Fuel	DCPT	59	0.312	/
Heat/Fuel	DCPT	60	0.0	/
Max. Heat/Power, H/P=Max.				/
Power/Fuel	DCPT	61	0.070	/
Heat/Fuel	DCPT	62	0.860	/
Maximum Heat/Fuel at Min. Power	DCPT	63	0.860	/
Maximum Cycle Steam Pressure	psia	33	865.0	/
Maximum Cycle Steam Temperature	F	34	825.0	/

* For Base Year GNLDAT(1) WS #1.

	UNITS	"Y"	DEFAULT VALUE	USER VALUE
Auxiliary Power Fraction (Thermal)	DCPT	31	0.0338	/
Auxiliary Heat Fraction (Thermal)	DCPT	32	0.1225	/
Auxiliary Power Fraction (User S)	DCPT	74	0.0338	/
Auxiliary Heat Fraction (User S)	DCPT	73	0.1225	/
Number of Alternate Fuels	Number	35	2.0	/
Code for Alternate Fuel A	Code	36	5.0	/
Fuel Conversion Efficiency	DCPT	37	0.65	/
Correction } TIC	Number	38	1.0	/
Multipliers } Variable O&M	Number	39	1.0	/
Auxiliary Power Fraction	DCPT	40	0.0258	/
Auxiliary Heat Fraction	DCPT	41	0.0318	/
Code for Alternate Fuel B	Code	42	3.0	/
Fuel Conversion Efficiency	DCPT	43	0.86	/
Correction } TIC	Number	44	0.45	/
Multipliers } Variable O&M	Number	45	0.67	/
Auxiliary Power Fraction	DCPT	46	0.0190	/
Auxiliary Heat Fraction	DCPT	47	0.0409	/
Environmental } Sulfur	DCPT	51	0.9	/
Removal } NOx	DCPT	52	0.5	/
Efficiencies } CO	DCPT	53	0.9	/
Particulates	DCPT	54	0.5	/

PART LOAD PERFORMANCE

@ Intermediate Steam Pressure				
@ H/H max. } P/P max	DCPT	9	0.0467	/
= 0.2 } F/F max	DCPT	10	0.25	/
@ H/H max. } P/P max	DCPT	11	0.1166	/
= 0.5 } F/F max	DCPT	12	0.55	/
@ H/H max. } P/P max	DCPT	13	0.1866	/
= 0.8 } F/F max	DCPT	14	0.80	/
@ p/p max. } H/H max	DCPT	15	0.0	/
= 0.2 } F/F max	DCPT	16	0.25	/
Efficiencies } Electric } @ 20%FF	DCPT	64	1.0	/
for Part Load } Generator } @ Rated	DCPT	65	1.0	/
Operation } Prime } @ 20%FF	DCPT	66	1.0	/
(Based on } Mover } @ Rated	DCPT	67	1.0	/
Rated Fuel } @ 20%FF	DCPT	68	1.0	/
Flow, FF) } Combustor } @ Rated	DCPT	69	1.0	/

COST FACTORS

Waste Cleanup Cost Factor	DCPT	24	1.0	/
Fuel Processing Cost Factor	DCPT	25	1.0	/
Area Labor Cost Factor	DCPT	26	1.0	/

Worksheet #7
Steam Turbine 1465 psia 950F FGD System PCODAT(3,Y)
Sections 2.5, 2.7 and 2.8)

SYSTEM IDENTIFICATION: MPSTF

DESIGN POINT DATA	UNITS	"Y"	DEFAULT VALUE	USER VALUE
Code for Primary Fuel	Code	1	1.0	/
Fuel Conversion Efficiency	DCPT	2	0.85	/
Fuel Flow	MBtu/hr	17	100.0	/
Sizing Limits } Minimum Size	MBtu/hr	18	1600.0	/
Optional User Specified MW Size	0 or MW	72	0.0	/
Total Installed } Min. } Min. Heat	M\$	19	21.024	/
Cost (TIC)* } Size } Max. Heat	M\$	20	17.920	/
For Fuel Flow } Max. } Min. Heat	M\$	21	119.935	/
Sizing Limits } Size } Max. Heat	M\$	22	102.439	/
Operation and } Fixed	DCPT	27	0.025	/
Maintenance } Variable	Number	28	2189.0	/
(O&M) Cost } Variable Exponent	DCPT	29	0.30	/
Coefficients } Consumables	Number	30	0.094	/
Construction Time	Years	70	3.0	/
Investment Tax Credit	DCPT	71	0.1	/
Low Steam Pressure	psia	48	15.0	/
Min. Heat/Power, H/P=Min.				
Power/Fuel	DCPT	55	0.343	/
Heat/Fuel	DCPT	56	0.0	/
Max. Heat/Power, H/P=Max.				
Power/Fuel	DCPT	57	0.266	/
Heat/Fuel	DCPT	58	0.669	/
Intermediate Steam Pressure	psia	49	150.0	/
Min. Heat/Power, H/P=Min.				
Power/Fuel	DCPT	3	0.343	/
Heat/Fuel	DCPT	4	0.0	/
Intermediate Heat/Pwr, H/P=Mid.				
Power/Fuel	DCPT	5	0.259	/
Heat/Fuel	DCPT	6	0.384	/
Max. Heat/Power, H/P=Max.				
Power/Fuel	DCPT	7	0.174	/
Heat/Fuel	DCPT	8	0.767	/
High Steam Pressure	psia	50	450.0	/
Min. Heat/Power, H/P=Min.				
Power/Fuel	DCPT	59	0.343	/
Heat/Fuel	DCPT	60	0.0	/
Max. Heat/Power, H/P=Max.				
Power/Fuel	DCPT	61	0.115	/
Heat/Fuel	DCPT	62	0.829	/
Maximum Heat/Fuel at Min. Power	DCPT	63	0.830	/
Maximum Cycle Steam Pressure	psia	33	1465.0	/
Maximum Cycle Steam Temperature	F	34	950.0	/

* For Base Year GNLDAT(1) WS #1.

	UNITS	"Y"	DEFAULT VALUE	USER VALUE
Auxiliary Power Fraction (Thermal)	DCPT	31	0.0366	/
Auxiliary Heat Fraction (Thermal)	DCPT	32	0.1225	/
Auxiliary Power Fraction (User S)	DCPT	74	0.0366	/
Auxiliary Heat Fraction (User S)	DCPT	73	0.1225	/
Number of Alternate Fuels	Number	35	2.0	/
Code for Alternate Fuel A	Code	36	5.0	/
Fuel Conversion Efficiency	DCPT	37	0.65	/
Correction } TIC	Number	38	1.0	/
Multipliers } Variable O&M	Number	39	1.0	/
Auxiliary Power Fraction	DCPT	40	0.0275	/
Auxiliary Heat Fraction	DCPT	41	0.0318	/
Code for Alternate Fuel B	Code	42	4.0	/
Fuel Conversion Efficiency	DCPT	43	0.79	/
Correction } TIC	Number	44	0.40	/
Multipliers } Variable O&M	Number	45	0.50	/
Auxiliary Power Fraction	DCPT	46	0.0195	/
Auxiliary Heat Fraction	DCPT	47	0.0345	/
Environmental } Sulfur	DCPT	51	0.90	/
Removal } NO _x	DCPT	52	0.90	/
Efficiencies } CO	DCPT	53	0.90	/
	DCPT	54	0.90	/

PART LOAD PERFORMANCE

@ Intermediate Steam Pressure				
@ H/H max. } P/P max	DCPT	9	0.0706	/
= 0.2 } F/F max	DCPT	10	0.25	/
@ H/H max. } P/P max	DCPT	11	0.1765	/
= 0.5 } F/F max	DCPT	12	0.55	/
@ H/H max. } P/P max	DCPT	13	0.2823	/
= 0.8 } F/F max	DCPT	14	0.80	/
@ P/P max. } H/H max	DCPT	15	0.0	/
= 0.2 } F/F max	DCPT	16	0.25	/
Efficiencies } Electric } @ 20% FF	DCPT	64	1.0	/
for Part Load } Generator } @ Rated	DCPT	65	1.0	/
Operation } Prime } @ 20% FF	DCPT	66	1.0	/
(Based on } Mover } @ Rated	DCPT	67	1.0	/
Rated Fuel } Combustor } @ 20% FF	DCPT	68	1.0	/
Flow, FF) } } @ Rated	DCPT	69	1.0	/

COST FACTORS

Waste Cleanup Cost Factor	DCPT	24	1.0	/
Fuel Processing Cost Factor	DCPT	25	1.0	/
Area Labor Cost Factor	DCPT	26	1.0	/

Worksheet #7
Steam Turbine 1465 psia, 950F AFB System PCODAT(4,Y)
(Sections 2.4, 2.7 and 2.8)

SYSTEM IDENTIFICATION : MPSTA

DESIGN POINT DATA	UNITS	"Y"	DEFAULT VALUE	USER VALUE
Code for Primary Fuel	Code	1	1.0	/
Fuel Conversion Efficiency	DCPT	2	0.85	/
Fuel Flow	MBtu/hr	17	100.0	/
Sizing Limits } Minimum Size	MBtu/hr	18	640.0	/
Sizing Limits } Maximum Size	MBtu/hr	18	640.0	/
Optional User Specified MW Size	0 or MW	72	0.0	/
Total Installed	MS	19	16.368	/
Cost (TIC)*	MS	20	13.122	/
For Fuel Flow	MS	21	51.219	/
Sizing Limits } Size / Max. Heat	MS	22	41.201	/
Sizing Limits } Max. / Min. Heat	MS	22	41.201	/
Operation and	DCPT	27	0.025	/
Maintenance	Number	28	1829.0	/
(O&M) Cost	DCPT	29	0.30	/
Coefficients	Number	30	0.149	/
Consumables	Number	30	0.149	/
Construction Time	Years	70	2.5	/
Investment Tax Credit	DCPT	71	0.1	/
Low Steam Pressure	psia	48	15.0	/
Min. Heat/Power, H/P=Min.	DCPT	55	0.343	/
Power/Fuel	DCPT	56	0.0	/
Heat/Fuel	DCPT	56	0.0	/
Max. Heat/Power, H/P=Max.	DCPT	57	0.266	/
Power/Fuel	DCPT	58	0.669	/
Heat/Fuel	DCPT	58	0.669	/
Intermediate Steam Pressure	psia	49	150.0	/
Min. Heat/Power, H/P=Min.	DCPT	3	0.343	/
Power/Fuel	DCPT	4	0.0	/
Heat/Fuel	DCPT	4	0.0	/
Intermediate Heat/Pwr, H/P=Mid.	DCPT	5	0.259	/
Power/Fuel	DCPT	6	0.384	/
Heat/Fuel	DCPT	6	0.384	/
Max. Heat/Power, H/P=Max.	DCPT	7	0.174	/
Power/Fuel	DCPT	8	0.767	/
Heat/Fuel	DCPT	8	0.767	/
High Steam Pressure	psia	50	450.0	/
Min. Heat/Power, H/P=Min.	DCPT	59	0.343	/
Power/Fuel	DCPT	60	0.0	/
Heat/Fuel	DCPT	60	0.0	/
Max. Heat/Power, H/P=Max.	DCPT	61	0.115	/
Power/Fuel	DCPT	62	0.829	/
Heat/Fuel	DCPT	62	0.829	/
Maximum Heat/Fuel at Min. Power	DCPT	63	0.830	/
Maximum Cycle Steam Pressure	psia	33	1465.0	/
Maximum Cycle Steam Temperature	F	34	950.0	/

* For Base Year GNLDT(1) WS #1.

	UNITS	"Y"	DEFAULT VALUE	USER VALUE
Auxiliary Power Fraction (Thermal)	DCPT	31	0.0360	/
Auxiliary Heat Fraction (Thermal)	DCPT	32	0.0403	/
Auxiliary Power Fraction (User S)	DCPT	74	0.0360	/
Auxiliary Heat Fraction (User S)	DCPT	73	0.0403	/
Number of Alternate Fuels	Number	35	2.0	/
Code for Alternate Fuel A	Code	36	5.0	/
Fuel Conversion Efficiency	DCPT	37	0.71	/
Correction	Number	38	1.05	/
Multipliers	Number	39	1.0	/
Auxiliary Power Fraction	DCPT	40	0.0300	/
Auxiliary Heat Fraction	DCPT	41	0.0352	/
Code for Alternate Fuel B	Code	42	0.0	/
Fuel Conversion Efficiency	DCPT	43	0.0	/
Correction	Number	44	0.0	/
Multipliers	Number	45	0.0	/
Auxiliary Power Fraction	DCPT	46	0.0	/
Auxiliary Heat Fraction	DCPT	47	0.0	/
Environmental	DCPT	51	0.9	/
Removal	DCPT	52	0.9	/
Efficiencies	DCPT	53	0.9	/
	DCPT	54	0.9	/

PART LOAD PERFORMANCE

@ Intermediate Steam Pressure

@ H/H max.	P/P max	DCPT	9	0.0706	/
= 0.2	F/F max	DCPT	10	0.25	/
@ H/H max.	P/P max	DCPT	11	0.1765	/
= 0.5	F/F max	DCPT	12	0.55	/
@ H/H max.	P/P max	DCPT	13	0.2823	/
= 0.8	F/F max	DCPT	14	0.80	/
@ P/P max.	H/H max	DCPT	15	0.0	/
= 0.2	F/F max	DCPT	16	0.25	/
Efficiencies	Electric	DCPT	64	1.0	/
for Part Load	Generator	DCPT	65	1.0	/
Operation	Prime	DCPT	66	1.0	/
(Based on	Mover	DCPT	67	1.0	/
Rated Fuel	Combustor	DCPT	68	1.0	/
Flow, FF)	@ Rated	DCPT	69	1.0	/

COST FACTORS

Waste Cleanup Cost Factor	DCPT	24	1.0	/
Fuel Processing Cost Factor	DCPT	25	1.0	/
Area Labor Cost Factor	DCPT	26	1.0	/

Worksheet #7
Coal Gasification Combined Cycle O₂ Blown PCODAT(5,Y)
(Sections 2.4, 2.7 and 2.8)

SYSTEM IDENTIFICATION: CGCCO

DESIGN POINT DATA	UNITS	"Y"	DEFAULT VALUE	USER VALUE
Code for Primary Fuel	Code	1	1.0	/
Fuel Conversion Efficiency	DCPT	2	0.91	/
Fuel Flow	MBtu/hr	17	200.0	/
Sizing Limits } Minimum Size	MBtu/hr	18	2040.0	/
Sizing Limits } Maximum Size	0 or MW	72	0.0	/
Optional User Specified MW Size				/
Total Installed	M\$	19	49.526	/
Cost (TIC)*	M\$	20	45.152	/
For Fuel Flow	M\$	21	219.128	/
Sizing Limits	M\$	22	198.951	/
Operation and	DCPT	27	0.025	/
Maintenance	Number	28	2176.0	/
(O&M) Cost	DCPT	29	0.3	/
Coefficients	Number	30	0.02	/
Construction Time	Years	70	4.5	/
Investment Tax Credit	DCPT	71	0.1	/
Low Steam Pressure	psia	48	15.0	/
Min. Heat/Power, H/P=Min.				/
Power/Fuel	DCPT	55	0.366	/
Heat/Fuel	DCPT	56	0.0	/
Max. Heat/Power, H/P=Max.				/
Power/Fuel	DCPT	57	0.316	/
Heat/Fuel	DCPT	58	0.428	/
Intermediate Steam Pressure	psia	49	150.0	/
Min. Heat/Power, H/P=Min.				/
Power/Fuel	DCPT	3	0.366	/
Heat/Fuel	DCPT	4	0.0	/
Intermediate Heat/Pwr, H/P=Mid.				/
Power/Fuel	DCPT	5	0.318	/
Heat/Fuel	DCPT	6	0.276	/
Max. Heat/Power, H/P=Max.				/
Power/Fuel	DCPT	7	0.261	/
Heat/Fuel	DCPT	8	0.492	/
High Steam Pressure	psia	50	450.0	/
Min. Heat/Power, H/P=Min.				/
Power/Fuel	DCPT	59	0.366	/
Heat/Fuel	DCPT	60	0.0	/
Max. Heat/Power, H/P=Max.				/
Power/Fuel	DCPT	61	0.223	/
Heat/Fuel	DCPT	62	0.534	/
Maximum Heat/Fuel at Min. Power	DCPT	63	0.534	/
Maximum Cycle Steam Pressure	psia	33	1450.0	/
Maximum Cycle Steam Temperature	°F	34	950.0	/

* For Base Year GNLDAT(1) WS #1.

	UNITS	"Y"	DEFAULT VALUE	USER VALUE
Auxiliary Power Fraction (Thermal)	DCPT	31	0.1385	/
Auxiliary Heat Fraction (Thermal)	DCPT	32	0.1618	/
Auxiliary Power Fraction (User S)	DCPT	74	0.1385	/
Auxiliary Heat Fraction (User S)	DCPT	73	0.1618	/
Number of Alternate Fuels	Number	35	0.0	/
Code for Alternate Fuel A	Code	36	0.0	/
Fuel Conversion Efficiency	DCPT	37	0.0	/
Correction	Number	38	0.0	/
Multipliers	Number	39	0.0	/
Auxiliary Power Fraction	DCPT	40	0.0	/
Auxiliary Heat Fraction	DCPT	41	0.0	/
Code for Alternate Fuel B	Code	42	0.0	/
Fuel Conversion Efficiency	DCPT	43	0.0	/
Correction	Number	44	0.0	/
Multipliers	Number	45	0.0	/
Auxiliary Power Fraction	DCPT	46	0.0	/
Auxiliary Heat Fraction	DCPT	47	0.0	/
Environmental	DCPT	51	0.9	/
Removal	DCPT	52	0.9	/
Efficiencies	DCPT	53	0.9	/
	DCPT	54	0.9	/

PART LOAD PERFORMANCE

@ Intermediate Steam Pressure				
@ H/H max.	P/P max	DCPT	9	0.1189
= 0.2	F/F max	DCPT	10	0.28
@ H/H max.	P/P max	DCPT	11	0.2973
= 0.5	F/F max	DCPT	12	0.6
@ H/H max.	P/P max	DCPT	13	0.4757
= 0.8	F/F max	DCPT	14	0.85
@ P/P max.	H/H max	DCPT	15	0.0
= 0.2	F/F max	DCPT	16	0.28
Efficiencies	Electric	DCPT	64	1.0
for Part Load	Generator	DCPT	65	1.0
Operation	Prime	DCPT	66	1.0
(Based on	Mover	DCPT	67	1.0
Rated Fuel	Combustor	DCPT	68	1.0
Flow, FF)	@ 20%FF	DCPT	69	1.0

COST FACTORS

Waste Cleanup Cost Factor	DCPT	24	1.0	/
Fuel Processing Cost Factor	DCPT	25	1.0	/
Area Labor Cost Factor	DCPT	26	1.0	/

Worksheet #7
Fuel Cell Phosphoric Acid PCODAT(6,Y)
(Sections 2.4, 2.7 and 2.8)

SYSTEM IDENTIFICATION: FCPA

DESIGN POINT DATA	UNITS	"Y"	DEFAULT VALUE	USER VALUE
Code for Primary Fuel	Code	1	2.0	/
Fuel Conversion Efficiency	DCPT	2	0.94	/
Fuel Flow	MBtu/hr	17	3.0	/
Sizing Limits } Minimum Size	MBtu/hr	18	100.0	/
Sizing Limits } Maximum Size	MBtu/hr	18	100.0	/
Optional User Specified MW Size	0 or MW	72	0.0	/
Total Installed } Min. } Min. Heat	M\$	19	0.373	/
Cost (TIC)* } Size } Max. Heat	M\$	20	0.339	/
For Fuel Flow } Max. } Min. Heat	M\$	21	9.821	/
Sizing Limits } Size } Max. Heat	M\$	22	7.676	/
Operation and } Fixed	DCPT	27	0.025	/
Maintenance } Variable	Number	28	171.0	/
(O&M) Cost } Variable Exponent	DCPT	29	0.36	/
Coefficients } Consumables	Number	30	1.545	/
Construction Time	Years	70	1.0	/
Investment Tax Credit	DCPT	71	0.1	/
Low Steam Pressure	psia	48	15.0	/
Min. Heat/Power, H/P=Min.				
Power/Fuel	DCPT	55	0.417	/
Heat/Fuel	DCPT	56	0.215	/
Max. Heat/Power, H/P=Max.				
Power/Fuel	DCPT	57	0.263	/
Heat/Fuel	DCPT	58	0.526	/
Intermediate Steam Pressure	psia	49	50.0	/
Min. Heat/Power, H/P=Min.				
Power/Fuel	DCPT	3	0.417	/
Heat/Fuel	DCPT	4	0.262	/
Intermediate Heat/Pwr, H/P=Mid.				
Power/Fuel	DCPT	5	0.307	/
Heat/Fuel	DCPT	6	0.384	/
Max. Heat/Power, H/P=Max.				
Power/Fuel	DCPT	7	0.263	/
Heat/Fuel	DCPT	8	0.552	/
High Steam Pressure	psia	50	100.0	/
Min. Heat/Power, H/P=Min.				
Power/Fuel	DCPT	59	0.417	/
Heat/Fuel	DCPT	60	0.215	/
Max. Heat/Power, H/P=Max.				
Power/Fuel	DCPT	61	0.263	/
Heat/Fuel	DCPT	62	0.526	/
Maximum Heat/Fuel at Min. Power	DCPT	63	0.580	/
Maximum Cycle Steam Pressure	psia	33	100.0	/
Maximum Cycle Steam Temperature	°F	34	320.0	/

* For Base Year GNLDAT(1) WS #1.

	UNITS	"Y"	DEFAULT VALUE	USER VALUE
Auxiliary Power Fraction (Thermal)	DCPT	31	0.0004	/
Auxiliary Heat Fraction (Thermal)	DCPT	32	0.0	/
Auxiliary Power Fraction (User S)	DCPT	74	0.0004	/
Auxiliary Heat Fraction (User S)	DCPT	73	0.0	/
Number of Alternate Fuels	Number	35	1.0	/
Code for Alternate Fuel A	Code	36	4.0	/
Fuel Conversion Efficiency	DCPT	37	0.88	/
Correction } TIC	Number	38	1.0	/
Multipliers } Variable O&M	Number	39	1.0	/
Auxiliary Power Fraction	DCPT	40	0.0004	/
Auxiliary Heat Fraction	DCPT	41	0.0	/
Code for Alternate Fuel B	Code	42	0.0	/
Fuel Conversion Efficiency	DCPT	43	0.0	/
Correction } TIC	Number	44	0.0	/
Multipliers } Variable O&M	Number	45	0.0	/
Auxiliary Power Fraction	DCPT	46	0.0	/
Auxiliary Heat Fraction	DCPT	47	0.0	/
Environmental } Sulfur	DCPT	51	0.95	/
Removal } NO _x	DCPT	52	0.95	/
Efficiencies } CO	DCPT	53	0.95	/
Particulates	DCPT	54	0.95	/

PART LOAD PERFORMANCE

@ Intermediate Steam Pressure				
@ H/H max. } P/P max	DCPT	9	0.126	/
= 0.2 } F/F max	DCPT	10	0.22	/
@ H/H max. } P/P max	DCPT	11	0.315	/
= 0.5 } F/F max	DCPT	12	0.50	/
@ H/H max. } P/P max	DCPT	13	0.504	/
= 0.8 } F/F max	DCPT	14	0.80	/
@ P/P max. } H/H max	DCPT	15	0.074	/
= 0.2 } F/F max	DCPT	16	0.22	/
Efficiencies } Electric } @ 20°F	DCPT	64	1.0	/
for Part Load } Generator } @ Rated	DCPT	65	1.0	/
Operation } Prime } @ 20°F	DCPT	66	1.0	/
(Based on } Mover } @ Rated	DCPT	67	1.0	/
Rated Fuel } Combustor } @ 20°F	DCPT	68	1.0	/
Flow, FF) } @ Rated	DCPT	69	1.0	/

COST FACTORS

Waste Cleanup Cost Factor	DCPT	24	1.0	/
Fuel Processing Cost Factor	DCPT	25	1.0	/
Area Labor Cost Factor	DCPT	26	1.0	/

Worksheet #7
Gas Turbine & Heat Recovery Process Boiler PCODAT(7,Y)
(Sections 2.4, 2.7 & 2.8)

SYSTEM IDENTIFICATION: GT-HR

DESIGN POINT DATA	UNITS	"Y"	DEFAULT VALUE	USER VALUE
Code for Primary Fuel	Code	1	2.0	/
Fuel Conversion Efficiency	DCPT	2	0.92	/
Fuel Flow } Minimum Size	MBtu/hr	17	100.0	/
Sizing Limits } Maximum Size	MBtu/hr	18	800.0	/
Optional User Specified MW Size	0 or MW	72	0.0	/
Total Installed } Min. } Min. Heat	MS	19	9.284	/
Cost (TIC)* } Size } Max. Heat	MS	20	6.212	/
For Fuel Flow } Max. } Min. Heat	MS	21	33.370	/
Sizing Limits } Size } Max. Heat	MS	22	29.49	/
Operation and } Fixed	DCPT	27	0.025	/
Maintenance } Variable	Number	28	337.0	/
(O&M) Cost } Variable Exponent	DCPT	29	0.36	/
Coefficients } Consumables	Number	30	0.0	/
Construction Time	Years	70	2.0	/
Investment Tax Credit	DCPT	71	0.1	/
Low Steam Pressure	psia	48	30.0	/
Min. Heat/Power, H/P=Min.				
Power/Fuel	DCPT	55	0.395	/
Heat/Fuel	DCPT	56	0.370	/
Max. Heat/Power, H/P=Max.				
Power/Fuel	DCPT	57	0.232	/
Heat/Fuel	DCPT	58	0.557	/
Intermediate Steam Pressure	psia	49	150.0	/
Min. Heat/Power, H/P=Min.				
Power/Fuel	DCPT	3	0.395	/
Heat/Fuel	DCPT	4	0.320	/
Intermediate Heat/Pwr, H/P=Mid.				
Power/Fuel	DCPT	5	0.313	/
Heat/Fuel	DCPT	6	0.425	/
Max. Heat/Power, H/P=Max.				
Power/Fuel	DCPT	7	0.232	/
Heat/Fuel	DCPT	8	0.520	/
High Steam Pressure	psia	50	465.0	/
Min. Heat/Power, H/P=Min.				
Power/Fuel	DCPT	59	0.395	/
Heat/Fuel	DCPT	60	0.299	/
Max. Heat/Power, H/P=Max.				
Power/Fuel	DCPT	61	0.232	/
Heat/Fuel	DCPT	62	0.522	/
Maximum Heat/Fuel at Min. Power	DCPT	63	0.564	/
Maximum Cycle Steam Pressure	psia	33	500.0	/
Maximum Cycle Steam Temperature	°F	34	470.0	/

* For Base Year GNLDAT(1) WS #1.

	UNITS	"Y"	DEFAULT VALUE	USER VALUE
Auxiliary Power Fraction (Thermal)	DCPT	31	0.0182	/
Auxiliary Heat Fraction (Thermal)	DCPT	32	0.0399	/
Auxiliary Power Fraction (User S)	DCPT	74	0.0182	/
Auxiliary Heat Fraction (User S)	DCPT	73	0.0399	/
Number of Alternate Fuels	Number	35	2.0	/
Code for Alternate Fuel A	Code	36	3.0	/
Fuel Conversion Efficiency	DCPT	37	0.90	/
Correction } TIC	Number	38	1.03	/
Multipliers } Variable O&M	Number	39	1.1	/
Auxiliary Power Fraction	DCPT	40	0.0178	/
Auxiliary Heat Fraction	DCPT	41	0.0390	/
Code for Alternate Fuel B	Code	42	4.0	/
Fuel Conversion Efficiency	DCPT	43	0.88	/
Correction } TIC	Number	44	0.91	/
Multipliers } Variable O&M	Number	45	0.85	/
Auxiliary Power Fraction	DCPT	46	0.0174	/
Auxiliary Heat Fraction	DCPT	47	0.0293	/
Environmental } Sulfur	DCPT	51	0.90	/
Removal } NO _x	DCPT	52	0.90	/
Efficiencies } CO	DCPT	53	0.90	/
	DCPT	54	0.90	/
PART LOAD PERFORMANCE				
@ Intermediate Steam Pressure				
@ H/H max. } P/P max	DCPT	9	0.116	/
= 0.2 } F/F max	DCPT	10	0.25	/
@ H/H max. } P/P max	DCPT	11	0.2875	/
= 0.5 } F/F max	DCPT	12	0.55	/
@ H/H max. } P/P max	DCPT	13	0.466	/
= 0.8 } F/F max	DCPT	14	0.82	/
@ P/P max. } H/H max	DCPT	15	0.107	/
= 0.2 } F/F max	DCPT	16	0.25	/
Efficiencies } Electric } @ 20%FF	DCPT	64	1.0	/
for Part Load } Generator } @ Rated	DCPT	65	1.0	/
Operation } Prime } @ 20%FF	DCPT	66	1.0	/
(Based on } Mover } @ Rated	DCPT	67	1.0	/
Rated Fuel } Combustor } @ 20%FF	DCPT	68	1.0	/
Flow, FF) } } @ Rated	DCPT	69	1.0	/
COST FACTORS				
Waste Cleanup Cost Factor	DCPT	24	1.0	/
Fuel Processing Cost Factor	DCPT	25	1.0	/
Area Labor Cost Factor	DCPT	26	1.0	/

Worksheet #7
Combined Cycle Process Steam Extraction PCODAT(8,Y)
(Sections 2.4, 2.7 and 2.8)

SYSTEM IDENTIFICATION: CC

DESIGN POINT DATA	UNITS	"Y"	DEFAULT VALUE	USER VALUE
Code for Primary Fuel	Code	1	2.0	/
Fuel Conversion Efficiency	DCPT	2	0.92	/
Fuel Flow	MBtu/hr	17	100.0	/
Sizing Limits } Minimum Size	MBtu/hr	18	800.0	/
Optional User Specified MW Size	0 or MW	72	0.0	/
Total Installed		19	12.7	/
Cost (TIC)*	\$	20	9.567	/
For Fuel Flow	\$	21	43.882	/
Sizing Limits } Max. } Min. Heat	\$	22	34.57	/
Operation and	DCPT	27	0.025	/
Maintenance	Number	28	1467.0	/
(O&M) Cost	DCPT	29	0.30	/
Coefficients	Number	30	0.004	/
Construction Time	Years	70	3.0	/
Investment Tax Credit	DCPT	71	0.1	/
Low Steam Pressure	psia	48	15.0	/
Min. Heat/Power, H/P=Min.				
Power/Fuel	DCPT	55	0.526	/
Heat/Fuel	DCPT	56	0.0	/
Max. Heat/Power, H/P=Max.				
Power/Fuel	DCPT	57	0.391	/
Heat/Fuel	DCPT	58	0.400	/
Intermediate Steam Pressure	psia	49	150.0	/
Min. Heat/Power, H/P=Min.				
Power/Fuel	DCPT	3	0.526	/
Heat/Fuel	DCPT	4	0.0	/
Intermediate Heat/Pwr, H/P=Mid.				
Power/Fuel	DCPT	5	0.430	/
Heat/Fuel	DCPT	6	0.410	/
Max. Heat/Power, H/P=Max.				
Power/Fuel	DCPT	7	0.333	/
Heat/Fuel	DCPT	8	0.464	/
High Steam Pressure	psia	50	450.0	/
Min. Heat/Power, H/P=Min.				
Power/Fuel	DCPT	59	0.526	/
Heat/Fuel	DCPT	60	0.0	/
Max. Heat/Power, H/P=Max.				
Power/Fuel	DCPT	61	0.310	/
Heat/Fuel	DCPT	62	0.456	/
Maximum Heat/Fuel at Min. Power	DCPT	63	0.480	/
Maximum Cycle Steam Pressure	psia	33	865.0	/
Maximum Cycle Steam Temperature	°F	34	825.0	/

* For Base Year GNLDAT(1) WS #1.

	UNITS	"Y"	DEFAULT VALUE	USER VALUE
Auxiliary Power Fraction (Thermal)	DCPT	31	0.0197	/
Auxiliary Heat Fraction (Thermal)	DCPT	32	0.0471	/
Auxiliary Power Fraction (User S)	DCPT	74	0.0197	/
Auxiliary Heat Fraction (User S)	DCPT	73	0.0471	/
Number of Alternate Fuels	Number	35	2.0	/
Code for Alternate Fuel A	Code	36	3.0	/
Fuel Conversion Efficiency	DCPT	37	0.9	/
Correction } TIC	Number	38	1.1	/
Multipliers } Variable O&M	Number	39	1.1	/
Auxiliary Power Fraction	DCPT	40	0.0193	/
Auxiliary Heat Fraction	DCPT	41	0.0430	/
Code for Alternate Fuel B	Code	42	4.0	/
Fuel Conversion Efficiency	DCPT	43	0.88	/
Correction } TIC	Number	44	0.90	/
Multipliers } Variable O&M	Number	45	0.85	/
Auxiliary Power Fraction	DCPT	46	0.0188	/
Auxiliary Heat Fraction	DCPT	47	0.0390	/
Environmental } Sulfur	DCPT	51	0.9	/
Removal } NOx	DCPT	52	0.9	/
Efficiencies } CO	DCPT	53	0.9	/
	DCPT	54	0.9	/

PART LOAD PERFORMANCE

@ Intermediate Steam Pressure				
@ H/H max. } P/P max	DCPT	9	0.1170	/
= 0.2 } F/F max	DCPT	10	0.25	/
@ H/H max. } P/P max	DCPT	11	0.2924	/
= 0.5 } F/F max	DCPT	12	0.52	/
@ H/H max. } P/P max	DCPT	13	0.4679	/
= 0.8 } F/F max	DCPT	14	0.82	/
@ P/P max. } H/H max	DCPT	15	0.0	/
= 0.2 } F/F max	DCPT	16	0.25	/
Efficiencies } Electric } @ 20%FF	DCPT	64	1.0	/
for Part Load } Generator } @ Rated	DCPT	65	1.0	/
Operation } Prime } @ 20%FF	DCPT	66	1.0	/
(Based on } Mover } @ Rated	DCPT	67	1.0	/
Rated Fuel } @ 20%FF	DCPT	68	1.0	/
Flow, FF) } Combustor } @ Rated	DCPT	69	1.0	/

COST FACTORS

Waste Cleanup Cost Factor	DCPT	24	1.0	/
Fuel Processing Cost Factor	DCPT	25	1.0	/
Area Labor Cost Factor	DCPT	26	1.0	/

Worksheet #7
Diesel Engine with HRSG & Heat Pump PCODAT(9,Y)
(Sections 2.4, 2.7 and 2.8)

SYSTEM IDENTIFICATION : DSHP

DESIGN POINT DATA	UNITS	"Y"	DEFAULT VALUE	USER VALUE
Code for Primary Fuel	Code	1	2.0	/
Fuel Conversion Efficiency	DCPT	2	1.0	/
Fuel Flow	MBtu/hr	17	5.0	/
Sizing Limits } Minimum Size	MBtu/hr	18	150.0	/
Sizing Limits } Maximum Size				/
Optional User Specified MW Size	0 or MW	72	0.0	/
Total Installed	M\$	19	2.328	/
Cost (TIC)*	M\$	20	2.65	/
For Fuel Flow	M\$	21	17.92	/
Sizing Limits } Size	M\$	22	22.462	/
Operation and } Fixed	DCPT	27	0.025	/
Maintenance } Variable	Number	28	472.0	/
(O&M) Cost	DCPT	29	0.36	/
Coefficients } Consumables	Number	30	0.0	/
Construction Time	Years	70	2.0	/
Investment Tax Credit	DCPT	71	0.1	/
Low Steam Pressure	psia	48	15.0	/
Min. Heat/Power, H/P=Min.				/
Power/Fuel	DCPT	55	0.361	/
Heat/Fuel	DCPT	56	0.250	/
Max. Heat/Power, H/P=Max.				/
Power/Fuel	DCPT	57	0.321	/
Heat/Fuel	DCPT	58	0.509	/
Intermediate Steam Pressure	psia	49	150.0	/
Min. Heat/Power, H/P=Min.				/
Power/Fuel	DCPT	3	0.361	/
Heat/Fuel	DCPT	4	0.213	/
Intermediate Heat/Pwr, H/P=Mid.				/
Power/Fuel	DCPT	5	0.300	/
Heat/Fuel	DCPT	6	0.382	/
Max. Heat/Power, H/P=Max.				/
Power/Fuel	DCPT	7	0.239	/
Heat/Fuel	DCPT	8	0.552	/
High Steam Pressure	psia	50	450.0	/
Min. Heat/Power, H/P=Min.				/
Power/Fuel	DCPT	59	0.361	/
Heat/Fuel	DCPT	60	0.181	/
Max. Heat/Power, H/P=Max.				/
Power/Fuel	DCPT	61	0.185	/
Heat/Fuel	DCPT	62	0.573	/
Maximum Heat/Fuel at Min. Power	DCPT	63	0.573	/
Maximum Cycle Steam Pressure	psia	33	450.0	/
Maximum Cycle Steam Temperature	°F	34	550.0	/

* For Base Year GNLDAT(1) WS #1.

	UNITS	"Y"	DEFAULT VALUE	USER VALUE
Auxiliary Power Fraction (Thermal)	DCPT	31	0.0196	/
Auxiliary Heat Fraction (Thermal)	DCPT	32	0.1333	/
Auxiliary Power Fraction (User S)	DCPT	74	0.0196	/
Auxiliary Heat Fraction (User S)	DCPT	73	0.1333	/
Number of Alternate Fuels	Number	35	2.0	/
Code for Alternate Fuel A	Code	36	3.0	/
Fuel Conversion Efficiency	DCPT	37	1.0	/
Correction } TIC	Number	38	1.05	/
Multipliers } Variable O&M	Number	39	1.05	/
Auxiliary Power Fraction	DCPT	40	0.0196	/
Auxiliary Heat Fraction	DCPT	41	0.1333	/
Code for Alternate Fuel B	Code	42	4.0	/
Fuel Conversion Efficiency	DCPT	43	0.94	/
Correction } TIC	Number	44	1.05	/
Multipliers } Variable O&M	Number	45	0.90	/
Auxiliary Power Fraction	DCPT	46	0.0184	/
Auxiliary Heat Fraction	DCPT	47	0.0313	/
Environmental } Sulfur	DCPT	51	0.9	/
Removal } NOx	DCPT	52	0.9	/
Efficiencies } CO	DCPT	53	0.9	/
	DCPT	54	0.9	/

PART LOAD PERFORMANCE

@ Intermediate Steam Pressure				
@ H/H max. } P/P max	DCPT	9	0.130	/
= 0.2 } F/F max	DCPT	10	0.35	/
@ H/H max. } P/P max	DCPT	11	0.270	/
= 0.5 } F/F max	DCPT	12	0.54	/
@ H/H max. } P/P max	DCPT	13	0.520	/
= 0.8 } F/F max	DCPT	14	0.83	/
@ P/P max. } H/H max	DCPT	15	0.050	/
= 0.2 } F/F max	DCPT	16	0.35	/
Efficiencies } Electric } @ 20%FF	DCPT	64	1.0	/
for Part Load } Generator } @ Rated	DCPT	65	1.0	/
Operation } Prime } @ 20%FF	DCPT	66	1.0	/
(Based on } Mover } @ Rated	DCPT	67	1.0	/
Rated Fuel } Combustor } @ 20%FF	DCPT	68	1.0	/
Flow, FF) } } @ Rated	DCPT	69	1.0	/

COST FACTORS

Waste Cleanup Cost Factor	DCPT	24	1.0	/
Fuel Processing Cost Factor	DCPT	25	1.0	/
Area Labor Cost Factor	DCPT	26	1.0	/

Worksheet #7
User's Cogeneration System PCODAT(X,Y) (X=10, 11, or 12)
(Sections 2.4, 2.7 and 2.8)

SYSTEM IDENTIFICATION

DESIGN POINT DATA	UNITS	"Y"	USER VALUE	USER VALUE
Code for Primary Fuel	Code	1		
Fuel Conversion Efficiency	DCPT	2		
Fuel Flow } Minimum Size	MBtu/hr	17		
Sizing Limits } Maximum Size	MBtu/hr	18		
Optional User Specified MW Size	0 or MW	72		
Total Installed } Min. } Min. Heat	MS	19		
Cost (TIC)* } Size } Max. Heat	MS	20		
For Fuel Flow } Max. } Min. Heat	MS	21		
Sizing Limits } Size } Max. Heat	MS	22		
Operation and } Fixed	DCPT	27		
Maintenance } Variable	Number	28		
(O&M) Cost } Variable Exponent	DCPT	29		
Coefficients } Consumables	Number	30		
Construction Time	Years	70		
Investment Tax Credit	DCPT	71		
Low Steam Pressure	psia	48		
Min. Heat/Power, H/P=Min.				
Power/Fuel	DCPT	55		
Heat/Fuel	DCPT	56		
Max. Heat/Power, H/P=Max.				
Power/Fuel	DCPT	57		
Heat/Fuel	DCPT	58		
Intermediate Steam Pressure	psia	49		
Min. Heat/Power, H/P=Min.				
Power/Fuel	DCPT	3		
Heat/Fuel	DCPT	4		
Intermediate Heat/Pwr, H/P=Mid.				
Power/Fuel	DCPT	5		
Heat/Fuel	DCPT	6		
Max. Heat/Power, H/P=Max.				
Power/Fuel	DCPT	7		
Heat/Fuel	DCPT	8		
High Steam Pressure	psia	50		
Min. Heat/Power, H/P=Min.				
Power/Fuel	DCPT	59		
Heat/Fuel	DCPT	60		
Max. Heat/Power, H/P=Max.				
Power/Fuel	DCPT	61		
Heat/Fuel	DCPT	62		
Maximum Heat/Fuel at Min. Power	DCPT	63		
Maximum Cycle Steam Pressure	psia	33		
Maximum Cycle Steam Temperature	F	34		

* For Base Year GNLDAT(1) WS #1.

Auxiliary Power Fraction (Thermal)	
Auxiliary Heat Fraction (Thermal)	
Auxiliary Power Fraction (User S)	
Auxiliary Heat Fraction (User S)	
Number of Alternate Fuels	
Code for Alternate Fuel A	
Fuel Conversion Efficiency	
Correction } TIC	
Multipliers } Variable O&M	
Auxiliary Power Fraction	
Auxiliary Heat Fraction	
Code for Alternate Fuel B	
Fuel Conversion Efficiency	
Correction } TIC	
Multipliers } Variable O&M	
Auxiliary Power Fraction	
Auxiliary Heat Fraction	
Environmental } Sulfur	
Removal } NOx	
Efficiencies } CO	
	Particulates

PART LOAD PERFORMANCE

@ Intermediate Steam Pressure

@ H/H max. }	P/P max	
= 0.2 }	F/F max	
@ H/H max. }	P/P max	
= 0.5 }	F/F max	
@ H/H max. }	P/P max	
= 0.8 }	F/F max	
@ P/P max. }	H/H max	
= 0.2 }	F/F max	
Efficiencies }	Electric } @ 20%FF	
for Part Load }	Generator } @ Rated	
Operation }	Prime } @ 20%FF	
(Based on }	Mover } @ Rated	
Rated Fuel }	Combustor } @ 20%FF	
Flow, FF) }		@ Rated

COST FACTORS

Waste Cleanup Cost Factor	
Fuel Processing Cost Factor	
Area Labor Cost Factor	

UNITS	"Y"	USER VALUE	USER VALUE
DCPT	31		
DCPT	32		
DCPT	74		
DCPT	73		
Number	35		
Code	36		
DCPT	37		
Number	38		
Number	39		
DCPT	40		
DCPT	41		
Code	42		
DCPT	43		
Number	44		
Number	45		
DCPT	46		
DCPT	47		
DCPT	51		
DCPT	52		
DCPT	53		
DCPT	54		

DCPT	9		
DCPT	10		
DCPT	11		
DCPT	12		
DCPT	13		
DCPT	14		
DCPT	15		
DCPT	16		
DCPT	64		
DCPT	65		
DCPT	66		
DCPT	67		
DCPT	68		
DCPT	69		

DCPT	24		
DCPT	25		
DCPT	26		

Worksheet #8
Special Input Indicators
(Sections 2.6, 2.7 and 6)

<u>Code & Switch Functions</u>	<u>Input Variable</u>	<u>Default Value</u>	<u>User Value</u>
Buy/Sell Switch (0 = Sell Excess/Buy Shortage) 1 = Buy All/Sell All)	GNLDAT(22)=	1	/____/
User Specified MW Size Switch (0 = Max. MW - without Exceeding Thermal Demand; 1 = Specified - discard Excess Thermal if Necessary - Additional Fuel Flow Added to Meet MW Specified)	GNLDAT(7) =	0	/____/
Emissions Limits Switch (0 = None, 1 = Yes)	GNLDAT(13)=	0	/____/
Equipment Size Limits Switch (0 = None, 1 = Yes)	GNLDAT(14)=	0	/____/
Suppress Built-in Diagnostic Warning Messages (0 = No 1 = Suppress Messages)	GNLDAT(6) =	0	/____/
Calculate Steam Price for Third-Party Ownership Based on a Desired IRR (See Worksheet #1) (0 = Data Base or Input Steam Prices 1 = Calculate Based on Desired IRR)	KSTPR =	0	/____/

2-49

Worksheet #8
Special Input Indicators
(Section 2.7)

<u>Code & Switch Functions</u>	<u>Input Variable</u>	<u>Default Value</u>	<u>User Value</u>
Output Print Selector Switch (0 = No, 1 = Yes)			
All Input Data Used	IPRINT(1) =	1	/____/
Industrial Gross & Net Process Energy Requirements	IPRINT(2) =	1	/____/
DEUS Systems Thermal Sized Design Information	IPRINT(3) =	1	/____/
DEUS Systems MW Sized Design Information	IPRINT(4) =	1	/____/
DEUS Systems Dispatched Performance (Industry/Utility)	IPRINT(5) =	1	/____/
DEUS Systems Costs and Economics (0 = No Third Party 1 = All Ownerships)	IPRINT(6) =	1	/____/
DEUS Systems Utility/Industry Economic Impacts	IPRINT(7) =	1	/____/
DEUS Systems Benefits	IPRINT(8) =	1	/____/

2-50

Worksheet #9
Titles
(Sections 2.2, 2.3 and 2.5)

Industry Name, Process &/or Site
(56 Characters maximum allowed)

TITLE = / _____ /

Utility Used in the Evaluation
(32 Characters maximum allowed)

UTITLE = / _____ /

DEUS Titles; Name/Description of Cogeneration System:

The number of each DEUS title is associated with that DEUS and is consistent with the process data required.
Maintain agreement with the numbers that define the DEUS.
(40 characters per title - 12 titles allowed)

DTITLE(1) = 'NOCOGEN PROCESS BOILER	'	/ _____ /
DTITLE(2) = 'STEAM TURBINE 865PSI 825F FGD SYSTEM	'	/ _____ /
DTITLE(3) = 'STEAM TURBINE 1465PSI 950F FGD SYSTEM	'	/ _____ /
DTITLE(4) = 'STEAM TURBINE 1465PSI 950F AFB SYSTEM	'	/ _____ /
DTITLE(5) = 'COAL GASIFICATION COMBINED CYCLE O2BLOWN'	'	/ _____ /
DTITLE(6) = 'FUEL CELL PHOSPHORIC ACID	'	/ _____ /
DTITLE(7) = 'GAS TURBINE+HEAT RECOVERY PROCESS BOILER'	'	/ _____ /
DTITLE(8) = 'COMBINED CYCLE+PROCESS STEAM EXTRACTION	'	/ _____ /
DTITLE(9) = 'DIESEL ENGINE WITH HRSG & HEAT PUMP	'	/ _____ /
DTITLE(10)= '_____	'	/ _____ /
DTITLE(11)= '_____	'	/ _____ /
DTITLE(12)= '_____	'	/ _____ /

2-51

Worksheet #9
Titles
(Sections 2.4 and 2.5)

DEUS Titles; Abbreviated Form:

(11 characters per title - 12 titles allows)

DEUSTL(1)= 'NOCOGEN ' /_____
DEUSTL(2)= 'STB 865 FGD ' /_____
DEUSTL(3)= 'STB 1465 FGD' /_____
DEUSTL(4)= 'STB 1465 AFB' /_____
DEUSTL(5)= 'CGCC ' /_____
DEUSTL(6)= 'FUEL CELL ' /_____

DEUSTL(7) = 'GTB HRSG ' /_____
DEUSTL(8) = 'COMB. CYCLE' /_____
DEUSTL(9) = 'DIESEL ' /_____
DEUSTL(10)= ' ' /_____
DEUSTL(11)= ' ' /_____
DEUSTL(12)= ' ' /_____

Fuel Titles:

(12 characters per title - up to 9 fuels allowed)

FUELTL(1)= 'COAL ' /_____
FUELTL(2)= 'DIST. OIL' /_____
FUELTL(3)= 'RESID OIL' /_____
FUELTL(4)= 'NAT. GAS ' /_____
FUELTL(5)= 'WOOD ' /_____
FUELTL(6)= 'FOSSIL ' /_____
FUELTL(7)= 'NUCLEAR ' /_____
FUELTL(8)= 'HYDRO ' /_____
FUELTL(9)= 'OTHER ' /_____

Note: It is only necessary to input the smallest number of characters required per title, the remaining characters will default to blanks. The user has to center the title if both left and right hand justification is desired.

2.10 ALPHABETICAL LIST OF INPUT DATA

This subsection is a cross reference to the worksheets and contains all of the inputs required in alphabetical order and reference to their location in the worksheets. These sheets do not contain the default values and are not designed for determining user values. This information is contained on five pages and provides a brief description of the data and a reference to the worksheets when more detailed information is desired. Four columns are used: (1) Input Variable Name and Number, (2) Brief Description, (3) Worksheet #, and (4) Worksheet Page.

ALPHABETICAL LIST OF INPUT DATA (DEUSTL to ECODAT)

<u>Input Variable</u>	<u>Brief Description</u>	<u>Worksheet</u>	
		<u>#</u>	<u>Page</u>
DEUSTL(1-12)	Abbreviated Title of DEUS	9	2
DIRR	Desired IRR	1	-
DTITLE(1-2)	Title of DEUS System	9	1
ECODAT(X,1)	Annual Rate of Inflation	4	-
ECODAT(X,2)	Cost of Debt	4	-
ECODAT(X,3)	Fraction of Debt	4	-
ECODAT(X,4)	Cost of Preferred Equity	4	-
ECODAT(X,5)	Fraction of Preferred Equity	4	-
ECODAT(X,6)	Cost of Common Equity	4	-
ECODAT(X,7)	Federal and State Tax Rate	4	-
ECODAT(X,8)	Code for Tax Depreciation	4	-
ECODAT(X,10)	Tax Life	4	-
ECODAT(X,11)	Local Taxes and Insurance	4	-
ECODAT(X,12)	Plant Economic Life	4	-
ECODAT(X,13)	First Full Year of Operation	4	-
ECODAT(X,14)	Capital Cost Escalation	4	-
ECODAT(X,15)	Code for Interest Calculation	4	-
ECODAT(X,16)	Discount Rate	4	-
ECODAT(X,17)	Levelized Fixed Charge Rate	4	-

where X = 1 for Industrial Ownership

X = 2 for Third Party Ownership

X = 3 for Utility Ownership

ALPHABETICAL LIST OF INPUT DATA
(EMSDAT to GNLDAT)

Input Variable	Brief Description	Worksheet	
		#	Page
EMSDAT(1-4)	Emission Limits	1	-
FLDAT(2,Y)	Fuel Higher Heating Value	6	-
FLDAT(6-8,Y)	Environmental Constituents	6	-
FLDAT(10-11,Y)	Fuel Costs	6	-
where Y = 1 to 9 for fuel types			
FUELTL(1-9)	Fuel Titles	9	2
FULCST(1-20, A,B,C)	Fuel Cost Escalation	5	1
GNLDAT(1)	Base Year for Capital Cost	1	-
GNLDAT(2-4)	Utility Heat Rates	1	-
GNLDAT(6)	Suppress Warning Messages	8	1
GNLDAT(7)	MW Size Switch	8	1
GNLDAT(8)	User Specified MW Size	1	-
GNLDAT(9-10)	Site Fuel Limits	1	-
GNLDAT(13)	Emissions Switch	8	1
GNLDAT(14)	Equipment Size Limit Switch	8	1
GNLDAT(15)	Auxiliary Boiler Size	1	-
GNLDAT(16)	Code for Auxiliary Boiler Fuel	1	-
GNLDAT(17)	Minimum No. of Units	1	-
GNLDAT(18,19)	Steam Revenue Rate	1	-
GNLDAT(22)	Buy/Sell Switch	8	1

ALPHABETICAL LIST OF INPUT DATA
(INDAT)

<u>Input Variable</u>	<u>Brief Description</u>	<u>Worksheet</u>	
		<u>#</u>	<u>Page</u>
INDAT(1)	Industry SIC Code	2	1
INDAT(2)	Plant Size	2	1
INDAT(3)	Code for Unit of Measure	2	1
INDAT(4)	Number of Site Fuels	2	1
INDAT(5)	Order of Fuel Availability	2	1
INDAT(6)	Average Electric Demand	2	1
INDAT(7)	Electric Sizing Factor	2	1
INDAT(9)	Annual Hours of Operation	2	1
INDAT(10)	Number of Heat Streams	2	1
INDAT(11-13)	Streams Heat Demand	2	1
INDAT(14)	Code for Unit of Measure	2	1
INDAT(15-17)	Heat Sizing Factors	2	2
INDAT(25)	Number of Waste Streams	2	2
INDAT(26-28)	Waste Stream Flows	2	3
INDAT(29)	Code for Unit of Measure	2	3
INDAT(31)	Waste Fuel Higher Heating Value	2	3
INDAT(32-34)	Waste Energy Efficiencies	2	3
INDAT(35-36)	Waste Streams Enthalpy Drop	2	3
INDAT(37-42)	Heat Streams Conditions	2	2
INDAT(43-44)	Reject Stream Conditions	2	2
INDAT(45)	Reject Stream Flow	2	2
INDAT(47)	Waste Stream Indicator	2	3
INDAT(49-50)	Fuel Flow Size Limits	2	2

ALPHABETICAL LIST OF INPUT DATA
(IPRINT to PCODAT)

Input Variable	Brief Description	Worksheet	
		#	Page
IPRINT(1-8)	Output Print Switches	8	2
KSTPR	Steam Price Switch	8	1
OMESC(1-20)	O&M Cost Escalation	5	3
PCODAT(X,1)	Code for Primary Fuel	7	1-9
PCODAT(X,2)	Fuel Conversion Efficiency	7	1-9
PCODAT(X,3-8)	Design Point Performance (A)	7	1-9
PCODAT(X,9-16)	Part Load Performance	7	1-9
PCODAT(X,17,18)	Size Limits	7	1-9
PCODAT(X,19-22)	Total Installed Costs	7	1-9
PCODAT(X,24-26)	Cost Factors	7	1-9
PCODAT(X,27-30)	O&M Cost Coefficients	7	1-9
PCODAT(X,31,32)	Aux. Power and Heat (Thermal)	7	1-9
PCODAT(X,33-34)	Maximum Pressure and Temperature	7	1-9
PCODAT(X,35-47)	Characteristics with Alternate Fuels	7	1-9
PCODAT(X,48-50)	Steam Pressures	7	1-9
PCODAT(X,51-54)	Environmental Efficiencies	7	1-9
PCODAT(X,55-62)	Design Point Performance (B)	7	1-9
PCODAT(X,63)	Maximum Heat/Fuel	7	1-9
PCODAT(X,64-69)	Part Load Efficiencies	7	1-9
PCODAT(X,70)	Construction Time	7	1-9
PCODAT(X,71)	Investment Tax Credit	7	1-9
PCODAT(X,72)	Optional Specified MW Size	7	1-9
PCODAT(X,73-74)	Aux. Heat and Power (User S)	7	1-9

where X = 1 to 12 for DEUS type.

ALPHABETICAL LIST OF INPUT DATA
(PUERGY to UTITLE)

Input Variable	Brief Description	Worksheet	
		#	Page
PUERGY(1-20)	"PURPA" Energy Escalation	5	3
PURCAP(1-20)	"PURPA" Capacity Escalation	5	3
PWCAP(1-20)	Industrial Demand Escalation	5	2
PWERGY(1-20)	Industrial Energy Escalation	5	2
STPRIC(1-20)	Steam Revenue Escalation	5	3
TITLE	Industry Name	9	1
TMDAT(X,1)	Electric Demand Profile	3	1
TMDAT(X,2)	Heat Stream #1 Profile	3	1
TMDAT(X,3)	Heat Stream #2 Profile	3	1
TMDAT(X,4)	"PURPA" Fuel Code Profile	3	2
TMDAT(X,5)	"PURPA" Energy Cost Profile	3	2
TMDAT(X,6)	"PURPA" Hours per Period	3	2
TMDAT(X,7)	"PURPA" Capacity Cost Profile	3	2
TMDAT(X,8)	Industrial Energy Cost Profile	3	3
TMDAT(X,9)	Industrial Demand Charge Profile	3	3
TMDAT(X,10)	Utility Avoided Energy Cost Profile	3	3
TMDAT(X,11)	Utility Avoided Capacity Cost Profile	3	3
TMDAT(X,12)	Electric Demand Profile	3	1

where X = 1-36 periods

UMCCST(1-20)	Avoided Capacity Escalation	5	2
UPRCST(1-20)	Avoided Energy Escalation	5	2
UTITLE	Utility Title	9	1

Section 3

COMPUTER DATA ENTRY & PROGRAM OPERATION--AN EXAMPLE

3.1 GENERAL

The computer data entry and program operation for the DEUS computer program is system-specific. In general, the DEUS program can be installed on any IBM computer systems. However, it requires modifications for installation on the CDC and other brand computers.

The DEUS program was installed and tested satisfactorily on the National CSS under host name NCS1. This section describes the experience with the National CSS to demonstrate the computer data entry and program operation for the DEUS program. The readers are reminded that their own computer system may be significantly different from National CSS and they should be familiar with the computer system on which they are going to install the DEUS program.

3.2 SYSTEM LOGIN

The following description has been taken from pages 1.4 - 1.8 of the National CSS manual "Programmers Introduction to VP/CSS" and modified to suit this application.

1. Dial the NCSS-supplied telephone number.
2. When you hear a high pitched tone, place the telephone receiver in the coupler (or perform whatever action is necessary to activate your modem-terminal to the online - ready status). An indicator on your coupler and/or your terminal lights to verify that your telephone call was successfully completed.
3. Type in the speed identification code for your terminal, then press the carriage return (CR). In response, the system types CSS ONLINE at your terminal to signal that you have reached an NCSS monitor. On most terminals the system also types the character >. This

character is a prompt and appears whenever the system is ready to accept additional typing from your terminal.

Valid speed identification codes are:

<u>CHARACTERS PER SECOND (SPEED)</u>	<u>BAUD RATE</u>	<u>SPEED CODE</u>
10	110	S
15	150	Y
30	300	0 (alpha)
60	600	5
120	1200	↑ (or >)
14.5	236.4	(CR)

4. Type the line

link NCS1 (CR)

5. Type the line

login userid (CR)

The system responds

PASSWORD:
%%%%%%%%

thus providing a blocked-out area in which you may enter your password. Type your password on top of the blocked-out area and press the carriage return.

If your password is MYPSWD, you would type those letters in the blocked-out area.

The system responds

A/C INFO:
>

6. This is a request for accounting information, such as the name of the project on which you are working. This will be recorded as the accounting information for this particular session on the terminal. Since this facility provides information for your records, its use is optional. You may simply press carriage return (CR).

The system responds with a ready message, indicating that the system is ready for use; followed by a time response giving the time of day. An example of this is given below.

```
(Host)      (Time)      (Date)
NCS1 READY AT 11.01.01 on 27 JUNE 81.
```

```
(CSS Version) (Version Date)
CSS.303       01APR80
```

```
(Time)
11.01.04>
```

At the completion of this procedure, which is called login, communication has been established with the computer and you are ready to begin setting up your data files and executing the DEUS computer program.

When you have completed your work and would like to sign off the system, type

```
>logout (CR)
```

The system responds with accounting statistics pertaining to the work you have just completed and the message

```
(Time)      (Date)
LOGGED OFF AT 11:10.02 ON 27 JUNE 81.
```

Hang up your telephone receiver and turn off the power on your terminal equipment. You have just completed a terminal session. A terminal session begins when you log in and ends when you log out.

Character Delete and Line Delete

@ (Character Delete)

During a session on the terminal you may type in an incorrect character and recognize that it is not what you intended immediately after typing it. To correct this, simply type in an @ to delete the character and then type in the desired character. Multiple characters may be deleted by typing the same number of @'s followed by the correct characters.

[or ¢ (Line Delete)

If you have entered an entire line incorrectly and recognize it before you press carriage return, you may delete all that you have typed by typing the character [. If your terminal does not have a [key, then use ¢.

3.3 DATA FILE CREATION

Creation of the DEUS program input file requires use of the National CSS EDIT system. It is recommended that you read over sections 1, 2, and 3 of the National CSS publication "Programmers Introduction to VP/CSS". Enough information is provided here to allow creation and modification of a data file but may not be as complete as required if difficulty is encountered.

The DEUS program uses standard FORTRAN Namelist input and therefore data must be specified according to Namelist input requirements.

When typing data on a terminal using the National CSS EDIT system you will actually be creating card images. (This is a throwback to the days when punched cards were the only way of inputting data into the computer.) The important point is that each card or input line allows 80 characters of input. Each character is referred to as a column and there are certain rules about which columns that data may be input. The first character of input on a line or card is referred to as column 1 and the 80th character is referred to as column 80 and so forth. For Namelist input all data must be keyed in within columns 2 through 72.

The Namelist name in the DEUS program is INPUT. The first line of input in the Namelist input file must be &INPUTb with the ampersand (&) in column 2 and a blank space (b) following the T in column 8. The last line of input in the Namelist input file must be &END within ampersand in column 2.

The following constitutes a complete Namelist input file:

```
$INPUT
INDAT(7)=182,
INDAT(10)=2,
INDAT(15)=160.,150.,
ECODAT(1,1)=3*0.,
PCODAT(2,1)=0
PCODAT(4,1)=0.,0.,0.,
PCODAT(9,1)=0.,
KSTPR=1,
DIRR=.15,
TITLE='DEUS VALIDATION STUDY CASE C',
UTITLE='TYPICAL GAS/OIL BURNING UTILITY',
$
```

Viewing the Namelist data input file above will reveal some of the rules for Namelist data input.

Note that each data item must be followed by a comma.

The following causes invalid data to be used:

=, e.g. INDAT(7)=,
blank, e.g. INDAT(7)=182 ,
,, e.g. INDAT(15)=160.,150.,

Heading blanks are valid:

```
column 234
      ^^^
      INDAT(7)=182,
      INDAT(10)=2,
```

The form that data items may take is:

1. Constants

Integer INDAT(10)=2,

Real

GNLDAT(2)=100000, or GNLDAT(2)=100000.,
or GNLDAT(2)=1.0E5,
DIRR=.15, or DIRR=15.E-2,

where E5 means that the digits immediately preceding are multiplied by 10^5 .

2. Arrays or Lists

Singly Dimensioned Array

Note on the program data input work sheets that many of the input variables are arrays (dimensioned variables). Some shortcuts are possible when inputting arrayed data. For instance, in the example data file above the input variable INDAT is a dimensioned array. The shortcut that may be taken is that when sequential elements of the data array are to be input, the variable name need not be repeated for each index of the variable. In the input example above the line

```
INDAT(15)=160.,150.,
```

really means

```
INDAT(15)=160.,
INDAT(16)=150.,
```

The asterisk may be used to indicate repeated data. For example, the line

```
IPRINT=8*1,
```

really means

```
IPRINT(1)=1,  
IPRINT(2)=1,  
IPRINT(3)=1,
```

and so on.

Double Dimension Arrays

The variable PCODAT or the variable ECODAT in the input example are double dimensioned arrays. The same rules that apply to single dimension arrays also apply to double dimension arrays, but interpretation of which index of the double dimension is increasing must be understood by the user.

The first index of the array varies the fastest. For example, the input

```
ECODAT(1,1)=3*0.,ECODAT(1,2)=3*.03,
```

really implies

```
ECODAT(1,1)=0.,  
ECODAT(2,1)=0.,  
ECODAT(3,1)=0.,  
ECODAT(1,2)=.03,  
ECODAT(2,2)=.03,  
ECODAT(3,2)=.03,
```

The reason that the second index increases after the three inputs that increment the first index is because the array is dimensioned in the program (3,20), so after 3 automatic increments of the 1st index, the second index is incremented. The input data line above could have been input as

```
ECODAT=3*0.,3*.03,
```

3. Hollerith or Alphabetic

In the Namelist input file above the data input for the variable TITLE or the variable UTITLE is of the type Hollerith. There are two ways of inputting Hollerith data. One way to input the data is to precede it by XXH and end it by a comma. XX is the count of Hollerith characters supplied on each line. The variables TITLE and UTITLE are declared double precision in the program. TITLE is dimensioned 7 and UTITLE is dimensioned 4. Each word of TITLE and UTITLE in core storage is 8 characters long. This means that TITLE can be no more than 56 characters long and UTITLE no more than 32 characters long. TITLE also could have been input as

```
TITLE='DEUS VAL',  
TITLE(2)='IDATION',  
TITLE(3)='STUDY CA',  
TITLE(4)='SE C   ',
```

It is seen that Hollerith characters may be enclosed within ' marks rather than specifying a count.

The National CSS EDIT System

The National CSS EDIT system is invoked by typing

EDIT filename filetype

The file name is a name that the user specifies for his input file. The file type for data input files will always be of the type data. The file name may be from one to eight characters long with no embedded blanks. The file type must be data. For example, if you want to create a new data file named DDATA, you would type

edit ddata data

If there are no files of the name ddata and type data saved on your user catalog, the system responds

NEWFILE

INPUT:

>

The > is a prompt from the system indicating that it is ready for your input. Anything typed while in the input mode will constitute a card image (i.e., will constitute a line of data input). Assuming you are in the CSS mode (which is signified by a system printout of the time, followed by a >) entry of the data file proceeds as follows:

(The underlined type corresponds to what you would type and the characters not underlined correspond to system responses. Your typed input may be either upper or lower case.)

11.50.52 >EDIT DDATA DATA(CR)

NEWFILE

INPUT:

> <u>b&INPUT</u> b(CR)	Where b signifies a blank (space) and (CR)
> <u>bIPRINT=8*1</u> (CR)	signifies a carriage return and the underlined
> <u>bINDAT(7)=182</u> , (CR)	type is what the user types. Type not under-
> <u>bINDAT(10)=2</u> , (CR)	lined is printed by the computer.
> <u>bINDAT(15)=160.,150.</u> , (CR)	
> <u>bECODAT(1,1)=3*0.,3*.03</u> , (CR)	
> <u>bGNLDAT(2)=10000.</u> , (CR)	
> <u>bPCODAT(2,1)=0.,PCODAT(4,1)=0.,0.,0.</u> , (CR)	
> <u>bPCODAT(9,1)=0.</u> , (CR)	
> <u>bKSTPR=1,DIRR=.15</u> , (CR)	
> <u>bTITLE='DEUS VALIDATION STUDY CASE C'</u> , (CR)	

```

>bTITLE= 'TYPICAL GAS/OIL BURNING UTILITY',(CR)
>b&END(CR)
>(CR)
EDIT:
>FILE(CR)
>11.53.04

```

In the example given above it is seen that a null line transmission takes you from the EDIT-INPUT mode to the EDIT command mode where the EDIT command FILE is typed in to store your completed input file.

It is important to remember that while you are in the EDIT INPUT mode everything you type at your terminal becomes part of your file. If you had typed in the letters FILE(CR) while in the input mode, the word FILE would have become a line of data in your data file. The EDIT commands only work while in the EDIT command mode.

File Modification

If, for example, you had typed in the line FILE at the end of the data file while in the input mode and subsequently stored the file, and you discovered that you also had made a mistake in typing in a value, you would have to use the other features of the EDIT system to make the corrections.

To recall a previously stored file with the EDIT system, simply type in

```

11.55.03 EDIT DDATA DATA(CR)
EDIT:
>P *(CR)
&INPUT
INDAT(7)=182,
INDAT(10)=2,
INDAT(15)=1600.,150.,
ECODAT(1,1)=3*0.,
PCODAT(2,1)=0.,PCODAT(4,1)=0.,0.,0.,
PCODAT(9,1)=0.,
KSTPR=1,DIRR=.15,
TITLE='DEUS VALIDATION STUDY CASE C'
UTITLE='TYPICAL GAS/OIL BURNING UTILITY',
&END
FILE
EOF:
>

```

The command P means to print. The command P * means to print all lines to the end of the file.

Note that there are three errors in the above file as compared to what was desired. The value of 1600 should have been 160, there should be a comma at the end of the input line for TITLE, and the word FILE needs to be removed from the end of the file.

Correcting files or modifying files with EDIT requires understanding the concept of the "pointer". The pointer is positioned at the line of the file you are working on in the EDIT system. Changes are only made on the line in the file that the pointer is positioned to. To find out where the pointer is positioned, type in P(CR) or PRINT(CR).

The editor will respond by printing out on your terminal the current line of the data file. If you were to type in P 5(CR), the editor would print out five consecutive lines of the file beginning with the current line, and move the pointer along with the lines displayed (four lines toward the bottom of the file). Another means of moving the pointer is to use the DOWN command or the UP command. The pointer would be moved down four lines by typing in D 4 or DOWN 4. Similarly, the pointer could be moved up four lines by typing in U 4 or UP 4. The pointer is moved to the top of the file by the command TOP and similarly to the bottom of the file by the command BOTTOM.

Locating Lines

You may also position the pointer at the line specified according to its contents using the LOCATE or L command. To move the pointer from above to the line containing 1600, type in

L /1600/

or D /1600/

The search begins with the line below the one that the pointer is at.

To perform a search from the pointer in an upward manner, the command

U /1600/

would be used. In this instance the search begins in the first line above the current pointer position.

Changing or Correcting Files

Changes can be made to the line that the pointer is positioned at by the CHANGE command. If the pointer is currently positioned at the line with the 1600 in it,

1600 may be changed to 160 by typing
 >Cb/1600/160/(CR)

Another way of correcting would have been to replace the line. You could have typed

 >REPLACEbbINDAT(15)=160.,150.,(CR)

which would have replaced the entire line with what was specified one space beyond the command REPLACE. To verify what was inserted, use the PRINT command.

To delete a line from the file, such as the word FILE at the end, move the pointer to the line and type >DELETE(CR). The entire line is deleted and the pointer is positioned at the next line of the file. It is also possible to delete sequential lines by specifying a count with the delete command. If it was desired to delete 5 lines the command would have been >DELETE 5(CR).

To add a new line to the file, position the pointer to the line after which you want your new line to appear. Then type in the command

 >INSERTbbGNLDAT(3)=9500.,

To add several consecutive lines, use the INPUT command. Move the pointer to the line immediately above the place where the insertion is to occur. Then type

 >INPUT(CR)

The system responds

 >INPUT:

This indicates that you are in the input mode of the editor - the same mode that was used to create the file originally. The same rules apply here as before. To get out of the input mode into the edit mode, simply type a null line (carriage return with no other data on the line). The pointer is now positioned at the last new line you entered. If you are satisfied that your file is correct, you may type the command

 >FILE

which will save the revised file. If you would like to abort the entire edit session, type in the command

 >QUIT

which will not store any of the revised information. Your file would remain as it had been before your edit session.

A complete example of using EDIT to correct the erroneous data file is as follows:

```
11 58 09>EDIT DDATA DATA(CR)
EDIT:
>Lb/1600/(CR)
  INDAT(15)=1600.,150.,
>Cb/1600/160/(CR)
  INDAT(15)=160.,150.,
>Lb/C'/(CR)
  TITLE='DEUS VALIDATION STUDY CASE C'
>Cb/C'/C',/(CR)
  TITLE='DEUS VALIDATION STUDY CASE C',
>Lb/FILE/(CR)
  FILE
>DET@LETE(CR)
  EOF:
>TOP(CR)
>P *(CR)
  &INPUT
  INDAT(7)=182,
  INDAT(10)=2,
  INDAT(15)=160.,150.,
  ECODAT(1,1)=3*0.,3*.03,
  GNLDAT(2)=10000.,
  PCODAT(2,1)=0.,PCODAT(4,1)=0.,0.,0.,
  PCODAT(9,1)=0.,
  KSTPR=1,DIRR=.15,
  TITLE='DEUS VALIDATION STUDY CASE C',
  UTITLE='TYPICAL GAS/OIL BURNING UTILITY',
  &END
  EOF:
>FILE(CR)
>12.05.11
```

3.4 RUNNING THE PROGRAM

Once your data file has been completed, running the program requires two commands. The first command is to attach the EPRI proprietary disk that contains the DEUS Program text files and an executive file that loads and executes the program. The next command is the executive command that runs the executive file and passes the name of your data input file to the executive file.

The ATTACH command is simply

```
11.59.23>ATTACH DEUS(CR)
```

The system will then ask you for a password to enable the attachment of the disk file DEUS (which will be supplied by EPRI). If you are running the program from EPRI's account, it is not necessary to issue the ATTACH command.

The executive command is of the form

DEUS datafilename

To executive the DEUS program using the data file DDATA, simply enter the following

>DEUS DDATA(CR)

The program should begin execution immediately and the output should appear on your terminal.

3.5 FILE MANAGEMENT

Refer to the National CSS publication, "Programmer's Introduction to VP/CSS," Section 3 on File Management for more detail on file management. A summary of a few commands is provided here.

You will be creating data input files when using the DEUS program on National CSS. You need to know how to manage the data files to efficiently use computer storage resources and to conserve expenses.

To find out what files are saved on your account at NCSS, simply type in LIST while in the CSS mode during a terminal session. The system will respond with a list of names and types of all files saved on your user account.

If you want to get rid of any saved files, simply type in the command

ERASE filename filetype

while in the CSS mode.

To create a duplicate copy of a saved file, type in the command

COPY oldfilename oldfiletype as newfilename newfiletype

If, for example, you wanted to create a duplicate of the filename DDATA and call it DDATA1, you would type

COPY DDATA DATA AS DDATA1 DATA(CR)

Section 4

PROGRAM OUTPUT

4.1 INTRODUCTION

The output produced by the DEUS program consists of eight output reports identified below:

- Input Data Used
- Industrial Process Demands (Power and Heat)
- Plant Requirements - Thermal Matched Size Design
- Plant Requirements - User Specified MW Size Design
- System Performance Summary
- Economic Analysis Results
 - Industrial ownership
 - Third-party ownership
- Utility System Economic Impacts
 - Industrial ownership
 - Utility ownership
- System Benefits

The DEUS program user can selectively request desired output using output print selector switches described below and on Worksheet #8, page 2. Economic analysis results for industrial ownership are always printed. Economic analysis results for third-party owned cogeneration are an optional output.

4.2 DESCRIPTION OF OUTPUT DATA FILES

As illustrated in Figure 4.2-1, the output print selector, IPRINT, can be used to selectively request any combination or all of the output data files identified previously. The contents of each of the output files are identified below.

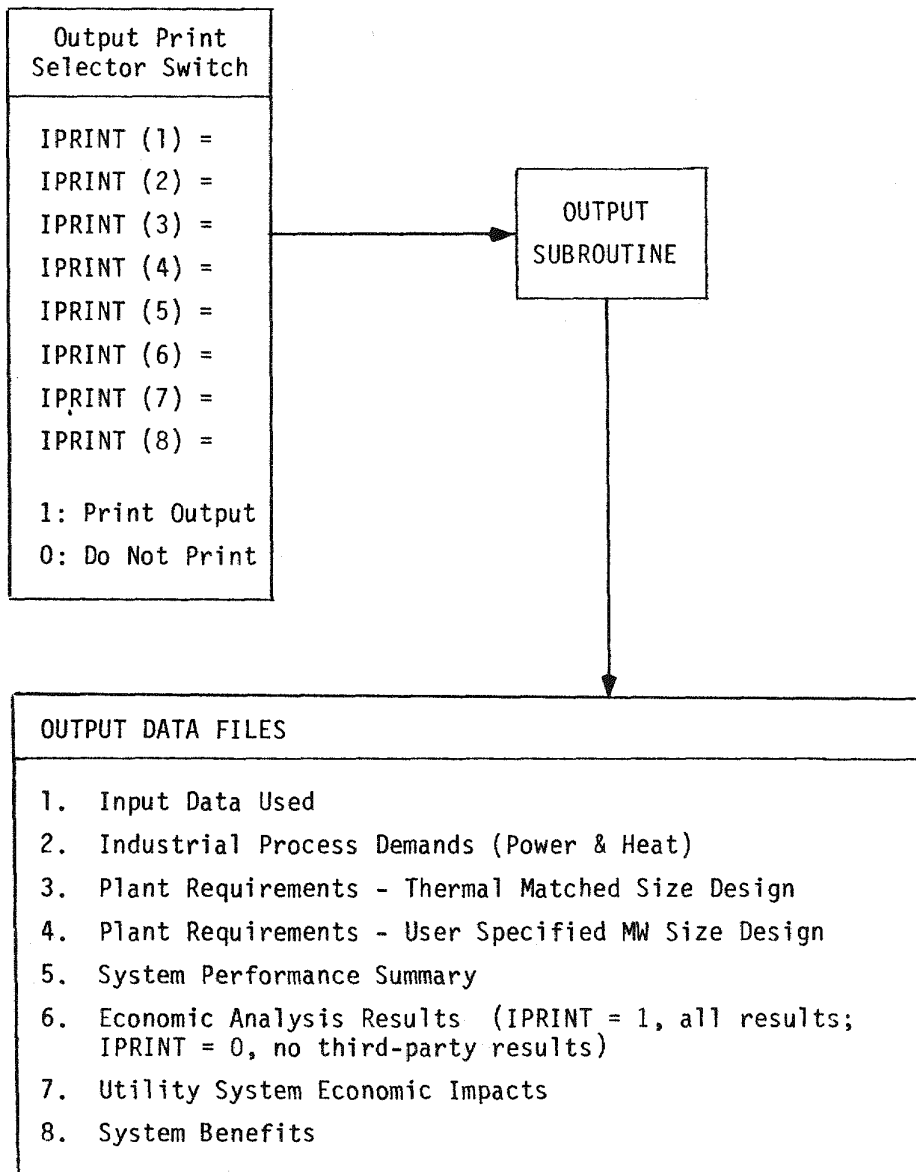


Figure 4.2-1. Optional Program Output

Input Data Used (Outfile 1)

The first set of data printed out is a record of the data used in the program, whether it came from input values or default values from the data base. This record avoids questions later as to what input data was used. The data is listed at the beginning of the output in the following order:

1. Site Specific Industrial Process Data INDAT(50)
2. Utility Related Data TMDAT(36,4-12)
3. Allowable Emission Limits Data EMSDAT(5)
4. General Data - Operational Codes & Groundrules GNLDAT(25)*
5. Economic & Financial Data ECODAT(3,20)*
6. DEUS Plants System Characteristics PCODAT(12,80)*

* Several variable locations are not presently utilized and contain zeros.

Industrial Process Demands (Outfile 2)

This data identifies the industry, its characteristics and summarizes the fuel availability and cost (including waste fuel used), average and maximum power and heat demands and the power and heat demand profiles. The data is given in the following format.

SUMMARY OF AVERAGE & MAXIMUM INDUSTRIAL PROCESS DEMANDS

SIC CODE		26212	
DAILY OUTPUT		1100	
UNITS OF MEASURE		TPD	
UTILITY			
SITE FUELS		LIMITS	
A		0.00 MBTU/HR	
B		0.00 MBTU/HR	
C		0.00 MBTU/HR	
COST			
A		\$/MBTU 00	
B		\$/MBTU 00	
C		\$/MBTU 00	

* PROCESS POWER *		* PROCESS HEAT *		* PROCESS TEMP *		* WASTE *		*	
* MW *		* MBTU/HR *		* DEG. F *		* USED *		*	
* AVG. : MAX. *		* AVG. : MAX. *		* MIN. : MAX. *		* MBTU/HR *		*	

* 1 *		* 1 *		* 1 *		* 1 *		*	
* 1 *		* 1 *		* 1 *		* 1 *		*	
* 1 *		* 1 *		* 1 *		* 1 *		*	

The time related industrial data TMDAT(36,1-3) is combined with the average industrial data INDAT(6 and 11-13) to give the power and heat demand profiles PWRTM(36) and HTTM(36) for the 36 periods.

PWRTM(36)
TIME VARIANT POWER PROFILE
(MW)

0.	0.	0.	0.	0.	0.
0.	0.	0.	0.	0.	0.
0.	0.	0.	0.	0.	0.
0.	0.	0.	0.	0.	0.
0.	0.	0.	0.	0.	0.
0.	0.	0.	0.	0.	0.

HTTM(36)
TIME VARIANT POWER PROFILE
(MBtu/hr)

0.	0.	0.	0.	0.	0.
0.	0.	0.	0.	0.	0.
0.	0.	0.	0.	0.	0.
0.	0.	0.	0.	0.	0.
0.	0.	0.	0.	0.	0.
0.	0.	0.	0.	0.	0.

Power Plant Requirements - Thermal Sizing Requirements (Outfile 3)

The data in this part summarizes the design characteristics for the Thermal Matched Size design for all systems (including nocogeneration) that can be used. In order to be used, a system must satisfy the emission limits (if checked) and fuel availability limits. These results are design point values and are given in the following form. If there are design margins or extra units for reliability, these design values may never be used even at peak loads.

POWER PLANT REQUIREMENTS

THERMAL: SIZING REQUIREMENTS

WASTE PROCESS STEAM = 0. MBTU/HR & POWER = 0. MW

```
*****
*          *          *          *          *          *
* NO COGEN * FUEL A   * FUEL B   * FUEL C   * TOTAL   *
*          *          *          *          *          *
*****
* POWER MW * 0.      * 0.      * 0.      * 0.      *
*          *          *          *          *          *
* HEAT MBTU/HR * 0.    * 0.    * 0.    * 0.    *
*          *          *          *          *          *
* FUEL MBTU/HR * 0.    * 0.    * 0.    * 0.    *
*          *          *          *          *          *
* INST COST M$ * 0.    * 0.    * 0.    * 0.    *
*          *          *          *          *          *
*EQV. MAX UNITS* 0.    * 0.    * 0.    * 0.    *
*          *          *          *          *          *
* # OF UNITS  * 0.    * 0.    * 0.    * 0.    *
*****
```

MAXIMUM PLANT UNIT SIZE 0. MBTU/HR
 MINIMUM PLANT UNIT SIZE 0. MBTU/HR

FUEL	AUX. POWER %	MW	AUX. HEAT %	MBTU
FUEL A	0.	0.	0.	0.
FUEL B	0.	0.	0.	0.
FUEL C	0.	0.	0.	0.

THERMAL: SIZING REQUIREMENTS

WASTE PROCESS STEAM = 0. MBTU/HR & POWER = 0. MW

```
*****
*          *          *          *          *          *
* COGEN A* * FUEL A   * FUEL B   * FUEL C   * TOTAL   *
*          *          *          *          *          *
*****
* POWER MW * 0.      * 0.      * 0.      * 0.      *
*          *          *          *          *          *
* HEAT MBTU/HR * 0.    * 0.    * 0.    * 0.    *
*          *          *          *          *          *
* FUEL MBTU/HR * 0.    * 0.    * 0.    * 0.    *
*          *          *          *          *          *
* INST COST M$ * 0.    * 0.    * 0.    * 0.    *
*          *          *          *          *          *
*EQV. MAX UNITS* 0.    * 0.    * 0.    * 0.    *
*          *          *          *          *          *
* # OF UNITS  * 0.    * 0.    * 0.    * 0.    *
*****
```

MAXIMUM PLANT UNIT SIZE 0. MBTU/HR
 MINIMUM PLANT UNIT SIZE 0. MBTU/HR

FUEL	AUX. POWER %	MW	AUX. HEAT %	MBTU
FUEL A	0.	0.	0.	0.
FUEL B	0.	0.	0.	0.
FUEL C	0.	0.	0.	0.

* Specific cogeneration systems and fuel names can be specified as input or generic names used.

The values for power and heat are net values after the auxiliary requirements have been subtracted. The fuel flows are the resulting values after accounting for all efficiencies. Installed cost is the total installed cost of the cogeneration system including an auxiliary boiler, if there is one, but not the waste heat boiler which is assumed to be available for both the nocogeneration and cogeneration if it exists (see Figure 1.2-1).

The equivalent maximum units is given by the fuel flow (for each fuel and the total) divided by the maximum fuel flow (as specified for each cogen system). The number of units identifies the number for each fuel and total number as determined by the sizing program or by the specification of a minimum number for reliability purposes. It is assumed that no unit can use more than one fuel type and every unit must have a size between the minimum and maximum.

Maximum and minimum unit sizes and the auxiliary power and heat requirements for each fuel type are given at the bottom for each system. In the case of nocogeneration where no power is generated, the auxiliary power in MW is defined as a percent of the fuel flow in MBtu/hr.

Power Plant Requirements - Megawatt Sizing Requirements (Outfile 4)

The data in this part is the same as that above except it is for the User Specified MW Size design.

MEGAWATT: SIZING REQUIREMENTS

WASTE PROCESS STEAM = 0. MBTU/HR & POWER = 0. MW						

* COGEN A	* FUEL A	* FUEL B	* FUEL C	* TOTAL		

* POWER MW	0.	0.	0.	0.		

* HEAT MBTU/HR	0.	0.	0.	0.		

* FUEL MBTU/HR	0.	0.	0.	0.		

* INST COST M\$	0.	0.	0.	0.		

* EQV. MAX UNITS	0.	0.	0.	0.		

* # OF UNITS	0.	0.	0.	0.		

MAXIMUM PLANT UNIT SIZE			0.	MBTU/HR		
MINIMUM PLANT UNIT SIZE			0.	MBTU/HR		
FUEL	AUX. POWER		AUX. HEAT			
	%		%			

FUEL A	0.	0.	0.	0.		
FUEL B	0.	0.	0.	0.		
FUEL C	0.	0.	0.	0.		

System Performance Summary (Outfile 5)

This data is a very brief summary of all systems in one table showing the total design MW ratings and fuel flow ratings taken from the previous design tables, plus a summary of the resulting operation showing the total megawatt hours output and capacity factor based on the rated capacity and 8760 hours per year.

The format of the table is shown below. The thermal load is the same for all cases at the level demanded by the industry. The megawatt hours are determined from the dispatch routines.

There are three tables - one for Thermal Matched Size and thermal dispatch which is independent of ownership and two for User Specified MW Size with economic dispatch, one for industry or third-party ownership and one for utility ownership.

SYSTEM PERFORMANCE

THERMAL SIZED/THERMAL DISPATCH

```
*****
* DEUS * * FUEL FLOW * MW HRS * CAPACITY *
* TECHNOLOGY * MW RATED * RATED MBTU/HR * ( X 10E-3 ) * FACTOR *
*****
* NO COGEN * * 0. * 0. * 0. * 0. *
*-----*
* COGEN A * * 1.00 * 0. * 0. * 0. *
*-----*
* COGEN B * * 1.00 * 0. * 0. * 0. *
*-----*
* COGEN C * * 1.00 * 0. * 0. * 0. *
*****
```

THIRD PARTY OR INDUSTRY OWNED ECONOMIC DISPATCH/INDUSTRIAL RATES

```
*****
* DEUS * * FUEL FLOW * MW HRS * CAPACITY *
* TECHNOLOGY * MW RATED * RATED MBTU/HR * ( X 10E-3 ) * FACTOR *
*****
* NO COGEN * * 0. * 0. * 0. * 0. *
*-----*
* COGEN A * * 1.00 * 0. * 0. * 0. *
*-----*
* COGEN B * * 1.00 * 0. * 0. * 0. *
*-----*
* COGEN C * * 1.00 * 0. * 0. * 0. *
*****
```

UTILITY OWNED
ECONOMIC DISPATCH/MARGINAL PRODUCTION COSTS
=====

```

*****
* DEUS * * FUEL FLOW * MW HRS * CAPACITY *
* TECHNOLOGY * MW RATED * RATED MBTU/HR * ( X 10E-3 ) * FACTOR *
*****
* NO COGEN * 0. * 0. * 0. * 0. *
*-----*
* COGEN A * 1.00 * 0. * 0. * 0. *
*-----*
* COGEN B * 1.00 * 0. * 0. * 0. *
*-----*
* COGEN C * 1.00 * 0. * 0. * 0. *
*****

```

Economic Analysis Results (Outfile 6)

In this part the economics for any one ownership or sizing is displayed in three tables as illustrated on the next page. The first table shows the economics for the first year of operation for all systems considered. Shown is the total installed cost of the system and the operating costs and revenues. The total installed cost is the same as shown under plant requirements. The second table shows the costs and revenues levelized over the life of the plant. In this table the investment costs are taken as the yearly costs using a fixed charge rate. The third table shows the internal rate of return and payback (i.e., years until cumulative net cash flow becomes positive).

These sets of three tables are shown for the following four conditions:

<u>Size</u>	<u>Dispatch</u>	<u>Ownership</u>
Thermal Matched	Thermal	Industrial
User Specified MW	Economic	Industrial
Thermal Matched	Thermal	Third-party
User Specified MW	Economic	Third-party

In addition, the value of steam (for both low and high pressure) is shown. When it is determined on the basis of a third-party nocogeneration system with a specified return on investment the desired IRR is shown, otherwise only the input values of steam price are shown.

ECONOMICS
 #####
 #####

PRESENT VALUE OF STEAM
 =====

DESIRED IRR = 0. %
 LOW PRESSURE VALUE = 00 \$/MBTU
 HIGH PRESSURE VALUE = 00 \$/MBTU

ECONOMICS
 INDUSTRY OWNED
 THERMAL SIZED/THERMAL DISPATCH
 =====

SYSTEM COSTS/REVENUES
 -M\$ PER YEAR-

DEUS	TECHNOLOGY	FIXED CHARGES	FUEL COST	O & M	PURCHASED ELECTRICITY	ELECTRIC REVENUES
A	NO COGEN	0.	0.	0.	0.	0.
A	COGEN A	0.	0.	0.	0.	0.
A	COGEN B	0.	0.	0.	0.	0.
A	COGEN C	0.	0.	0.	0.	0.

SYSTEM LEVELIZED COSTS/REVENUES
 -M\$ PER YEAR-

DEUS	TECHNOLOGY	FIXED CHARGES	FUEL COST	O & M	PURCHASED ELECTRICITY	ELECTRIC REVENUES
A	NO COGEN	0.	0.	0.	0.	0.
A	COGEN A	0.	0.	0.	0.	0.
A	COGEN B	0.	0.	0.	0.	0.
A	COGEN C	0.	0.	0.	0.	0.

SYSTEM ECONOMICS

DEUS	TECHNOLOGY	DISCOUNTED CF IRR	PAYBACK
A	NO COGEN	0.	0.
A	COGEN A	0.	0.
A	COGEN B	0.	0.
A	COGEN C	0.	0.

ECONOMICS
INDUSTRIAL OWNED BASE CASE
ECONOMIC DISPATCH/INDUSTRIAL RATES
=====

SYSTEM COSTS/REVENUES
-M\$ PER YEAR-

DEUS	* * *	* * *	* * *	* * *	* * *	* * *	* * *
TECHNOLOGY	* * *	* * *	* * *	* * *	* * *	* * *	* * *
NO COGEN	* * *	* * *	* * *	* * *	* * *	* * *	* * *
COGEN A	* * *	* * *	* * *	* * *	* * *	* * *	* * *
COGEN B	* * *	* * *	* * *	* * *	* * *	* * *	* * *
COGEN C	* * *	* * *	* * *	* * *	* * *	* * *	* * *

SYSTEM LEVELIZED COSTS/REVENUES
-M\$ PER YEAR-

DEUS	* * *	* * *	* * *	* * *	* * *	* * *	* * *
TECHNOLOGY	* * *	* * *	* * *	* * *	* * *	* * *	* * *
NO COGEN	* * *	* * *	* * *	* * *	* * *	* * *	* * *
COGEN A	* * *	* * *	* * *	* * *	* * *	* * *	* * *
COGEN B	* * *	* * *	* * *	* * *	* * *	* * *	* * *
COGEN C	* * *	* * *	* * *	* * *	* * *	* * *	* * *

SYSTEM ECONOMICS

DEUS	* * *	* * *	* * *	* * *
TECHNOLOGY	* * *	* * *	* * *	* * *
NO COGEN	* * *	* * *	* * *	* * *
COGEN A	* * *	* * *	* * *	* * *
COGEN B	* * *	* * *	* * *	* * *
COGEN C	* * *	* * *	* * *	* * *

Utility System Economic Impacts (Outfile 7)

Five tables in this part show the economic impact on utilities for both industrial and utility ownership. The first two tables are for industrial ownership: first, with Thermal Matched Size and thermal dispatch, and second, with User Specified MW Size and economic dispatch. The format of these tables is shown by the table below. They show both production and capacity cost savings as a result of the power furnished by the cogeneration unit, the revenue loss, PURPA payments and net cost savings. The revenue loss is the decrease in revenues when the cogeneration plant replaces a nocogeneration plant. For a "Simultaneous Buy/Sell" purchase agreement between the industrial and the utility, where the industry buys all his needed power and sells all that he generates, there is no utility loss of revenue. PURPA payments, however, must be made to the industry for all the power bought. Net utility cost savings are the production and capacity cost savings less revenue loss (if any) and the PURPA payments. When the PURPA rates are equal to the utility marginal costs the net cost savings are zero with a "Simultaneous Buy/Sell" purchase agreement.

UTILITY SYSTEM ECONOMIC IMPACTS ***** *****

INDUSTRIAL OWNED COGEN PLANT THERMAL SIZED/THERMAL LOAD FOLLOWING =====

(UTILITY SYSTEM COST IMPACTS) -M\$ PER YEAR-

```
*****
* DEUS * PRODUCTION* CAPACITY * REVENUE * PURPA *NET UTILITY*
* TECHNOLOGY* COSTSAVINGS* COSTSAVINGS* LOSS * PAYMENTS *COSTSAVINGS*
*****
* COGEN A * 0. * 0. * 0. * 0. * 0. *
*-----*
* COGEN B * 0. * 0. * 0. * 0. * 0. *
*-----*
* COGEN C * 0. * 0. * 0. * 0. * 0. *
*****
```

INDUSTRIAL OWNED COGEN PLANT
ECONOMIC DISPATCH/INDUSTRIAL RATES
=====

(UTILITY SYSTEM COST IMPACTS)
-M\$ PER YEAR-

*****	*****	*****	*****	*****	*****	*****	*****	*****
* DEUS	* PRODUCTION	* CAPACITY	* REVENUE	* PUKPA	* NET UTILITY			
* TECHNOLOGY	* COST SAVINGS	* COST SAVINGS	* LOSS	* PAYMENTS	* COST SAVINGS			
*****	*****	*****	*****	*****	*****	*****	*****	*****
* COGEN A	* 0.	* 0.	* 0.	* 0.	* 0.	* 0.	* 0.	*
*****	*****	*****	*****	*****	*****	*****	*****	*****
* COGEN B	* 0.	* 0.	* 0.	* 0.	* 0.	* 0.	* 0.	*
*****	*****	*****	*****	*****	*****	*****	*****	*****
* COGEN C	* 0.	* 0.	* 0.	* 0.	* 0.	* 0.	* 0.	*
*****	*****	*****	*****	*****	*****	*****	*****	*****

The last three tables are for utility ownership and have a different format as shown by the three tables below. Cost savings and fuel costs are first shown for thermal dispatch then the incremental savings and costs are shown for economic dispatch. The yearly capital costs are based on the total installed cost and a utility fixed charge rate. Other costs, cost savings and revenues are also shown and a net savings per year is given. The net savings per year are converted into a capitalized net saving by dividing by the utility fixed charge rate.

UTILITY OWNED COGEN PLANT
ECONOMIC DISPATCH/MARGINAL PRODUCTION COSTS
=====

UTILITY SYSTEM COST SAVINGS
-M\$ PER YEAR-

*****	*****	*****	*****	*****	*****	*****	*****	*****
* DEUS	* PRODUCTION	* INCREMENTAL	* STEAM	* DISPLACED				
* TECHNOLOGY	* COST SAVINGS	* PROD. COST	* REVENUES	* CAPACITY				
*****	*****	*****	*****	*****	*****	*****	*****	*****
* COGEN A	* 0.	* 0.	* 0.	* 0.	* 0.	* 0.	* 0.	*
*****	*****	*****	*****	*****	*****	*****	*****	*****
* COGEN B	* 0.	* 0.	* 0.	* 0.	* 0.	* 0.	* 0.	*
*****	*****	*****	*****	*****	*****	*****	*****	*****
* COGEN C	* 0.	* 0.	* 0.	* 0.	* 0.	* 0.	* 0.	*
*****	*****	*****	*****	*****	*****	*****	*****	*****

ADDITIONAL UTILITY SYSTEM COSTS
-MS PER YEAR-

* DEUS *	* COGEN *	* COGEN *	* INCREMENTAL *	* COGEN *	* AUX *		
* TECHNOLOGY *	* CAPITAL *	* FUEL COST *	* THERMAL LO. *	* FUEL COST *	* O & M *	* BOILER *	
	* COSTS *	* FOLLOWING *		* COSTS *	* FUEL COST *		

* COGEN A *	0.	* 0.	* 0.	* 0.	* 0.	* 0.	*

* COGEN B *	0.	* 0.	* 0.	* 0.	* 0.	* 0.	*

* COGEN C *	0.	* 0.	* 0.	* 0.	* 0.	* 0.	*

NET UTILITY SYSTEM COST IMPACT

* DEUS *	* NET SAVINGS *	* CAPITALIZED *	
* TECHNOLOGY *	* (MS PER YR) *	* NET SAVINGS-MS *	

* COGEN A *	0.	* 0.	*

* COGEN B *	0.	* 0.	*

* COGEN C *	0.	* 0.	*

This part shows system benefits in the format shown in the table below. The total fuel saved includes the marginal fuel use by the utility. Fuel saved values are relative to the nocogeneration fuel use. Increased fuel use is a negative fuel saving.

The results are shown in three tables for the following conditions:

<u>Size</u>	<u>Dispatch</u>	<u>Ownership</u>
Thermal Matched	Thermal	All
User Specified MW	Economic	Third-party or Industrial
User Specified MW	Economic	Utility

新 時 新 時 新 時 新 時 林 林 林 林 林 林 林 林 林 林 林 林 林 林 林 林
 新 時 新 時 新 時 新 時 新 時 林 林 林 林 林 林 林 林 林 林 林 林 林 林

2018年12月31日

* * * * *									
* FUEL SAVED MBTU/YEAR * ECS * SYSTEM * * * * *									
* * * * *									
* TECHNOLOGY * OIL * GAS * COAL * EFFICIENCY * EFFICIENCY * * * * *									
* * * * *									
* COGEN A	* O.	* O.	* O.	* O.	* O.	* O.	* O.	* O.	* * * * *
* * * * *									
* COGEN B	* O.	* O.	* O.	* O.	* O.	* O.	* O.	* O.	* * * * *
* * * * *									
* COGEN C	* O.	* O.	* O.	* O.	* O.	* O.	* O.	* O.	* * * * *
* * * * *									

$$\text{ECS Efficiency} = \frac{\text{ECS Output}}{\text{ECS Input}}$$

$$\text{System Efficiency} = \frac{\text{ECS Output} + \text{Auxiliary Boiler Output}}{\text{ECS Input} + \text{Aux. Blr. Fuel} + \text{Waste Heat Utilized}}$$

THIRD PARTY OR INDUSTRY OWNED
MEGAWATT DISPATCH

=====

```

*****
*          * FUEL SAVED MBTU/YEAR *          ECS * SYSTEM *
*-----*-----*-----*-----*-----*-----*
*TECHNOLOGY * OIL * GAS * COAL * EFFICIENCY * EFFICIENCY *
*****
* COGEN A * 0. * 0. * 0. * 0. * 0. *
*-----*-----*-----*-----*-----*
* COGEN B * 0. * 0. * 0. * 0. * 0. *
*-----*-----*-----*-----*-----*
* COGEN C * 0. * 0. * 0. * 0. * 0. *
*****

```

UTILITY OWNED
MEGAWATT DISPATCH

=====

```

*****
*          * FUEL SAVED MBTU/YEAR *          ECS * SYSTEM *
*-----*-----*-----*-----*-----*-----*
* COGEN C * 0. * 0. * 0. * 0. * 0. *
*****

```

4.3 SAMPLE OUTPUT

The sample output presented in this section is for Validation Case C which is described in Section 6 of the Program Descriptive Manual. Case C is considered representative of industries that have relatively flat demand profiles but located in an area where the utility has PURPA rates and industrial rates with seasonal and time-of-day variations. A "Simultaneous Buy/Sell" purchase agreement was assumed for Case C.

The nocogeneration system considered in Case C was a coal-fired boiler. In addition, the following three cogeneration systems were considered in Case C.

- Coal-Fired Steam Turbine
(Medium pressure coal-fired boiler with flue gas treatment and single automatic extraction back-pressure steam turbine.)
- Gas-Fired Gas Turbine with HRSG
- Gas-Fired Combined Cycle System

For Case C, the system was first thermally sized (Thermal Matched Size) to meet the industrial heat demand and then the size was specified (User Specified MW Size) to meet an electric load of 100 MW (GNLDAT(8)) or the same electric load as produced by the thermal sized plant if greater than 100 MW.

The program input for the Case C example is described in Section 5.2. The sample output for Case C follows.

 INPUT DATA USED

INDAT(50)
 INDUSTRIAL PROCESS DATA

26212	1100	1	3	142
11000	182	3	8280	2
500	100	0	3	160
150	100	3	3	3
0	0	0	0	0
0	0	0	0	0
0	0	0	0	0
0	0	165	0	65
0	30	200	15	70
0	20	5	100	1600

TMDAT(36,12)
 TIME VARIANT DATA

PURPA FUEL CODE PROFILE DATA

3.00	3.00	3.00	3.00	3.00	3.00
3.00	3.00	3.00	3.00	3.00	3.00
3.00	3.00	3.00	3.00	3.00	3.00
3.00	3.00	3.00	3.00	3.00	3.00
3.00	3.00	3.00	3.00	3.00	3.00
3.00	3.00	3.00	3.00	3.00	3.00

PURPA AVOIDED ENERGY COST DATA

8.66	10.10	10.50	10.50	10.10	10.10
8.66	10.10	10.10	10.10	10.10	10.10
8.66	8.66	8.66	8.66	8.66	8.66
8.50	9.50	9.50	10.00	10.00	9.50
8.50	9.50	9.50	9.50	9.50	9.50
8.50	8.50	8.50	8.50	8.50	8.50

PURPA HRS PER PERIOD DATA

1010.00	404.00	404.00	202.00	202.00	202.00
210.00	84.00	84.00	42.00	42.00	42.00
240.00	96.00	96.00	48.00	48.00	48.00
1390.00	556.00	556.00	278.00	278.00	278.00
280.00	112.00	112.00	56.00	56.00	56.00
320.00	128.00	128.00	64.00	64.00	64.00

PURPA AVOIDED CAPACITY COST

0.	0.	48.80	0.	0.	0.
0.	0.	0.	0.	0.	0.
0.	0.	0.	0.	0.	0.
0.	0.	0.	34.20	0.	0.
0.	0.	0.	0.	0.	0.
0.	0.	0.	0.	0.	0.

INDUSTRIAL RATE ENERGY COST DATA

6.30	6.50	6.80	6.80	6.50	6.50
6.30	6.50	6.50	6.50	6.50	6.50
6.30	6.30	6.30	6.30	6.30	6.30
6.30	6.50	6.50	6.80	6.80	6.50
6.30	6.50	6.50	6.50	6.50	6.50
6.30	6.30	6.30	6.30	6.30	6.30

INDUSTRIAL RATE DEMAND CHARGE

0.	2.90	0.	25.10	0.	0.
0.	0.	0.	0.	0.	0.
0.	0.	0.	0.	0.	0.
0.	4.10	0.	24.20	0.	0.
0.	0.	0.	0.	0.	0.
0.	0.	0.	0.	0.	0.

UTILITY MARGINAL PRODUCTION COST

8.66	10.10	10.50	10.50	10.10	10.10
8.70	10.10	10.10	10.10	10.10	10.10
8.66	8.66	8.66	8.66	8.66	8.66
8.50	9.50	9.50	10.00	10.00	9.50
8.50	9.50	9.50	9.50	9.50	9.50
8.50	8.50	8.50	8.50	8.50	8.50

UTILITY MARGINAL CAPACITY COST

0.	0.	48.80	0.	0.	0.
0.	0.	0.	0.	0.	0.
0.	0.	0.	0.	0.	0.
0.	0.	0.	34.20	0.	0.
0.	0.	0.	0.	0.	0.
0.	0.	0.	0.	0.	0.

PEAK TO AVG. DEMAND FACTOR FOR PROCESS ELECTRICAL POWER

0.	1.00	0.	1.80	0.	0.
0.	0.	0.	0.	0.	0.
0.	0.	0.	0.	0.	0.
0.	1.00	0.	1.80	0.	0.
0.	0.	0.	0.	0.	0.
0.	0.	0.	0.	0.	0.

EMSDAT(5)
EMISSION DATA

0.80	0.20	0.10	0.01	0.50
------	------	------	------	------

GNLDAT(24)
GENERAL GROUND RULES

1984.00	10000.00	9500.00	9600.00	0.	0.
0.	100.00	5000.00	10000.00	2.00	3.00
0.	0.	0.	4.00	1.00	6.00
8.00	1.00	1.00	1.00	1.00	1.00

ECODAT(3,20)
ECONOMIC & FINANCIAL DATA

INDUSTRIAL OWNED

0.	0.03	0.30	0.	0.
0.	0.	1.00	3.00	10.00
0.03	28.00	1984.00	0.	0.
0.13	0.20	0.	0.	0.

THIRD PARTY OWNED

0.	0.03	0.30	0.	0.
0.07	0.50	1.00	3.00	10.00
0.03	28.00	1984.00	0.	0.
0.13	0.20	0.	0.	0.

UTILITY OWNED

0.	0.03	0.50	0.04	0.15
0.07	0.50	1.00	3.00	15.00
0.03	28.00	1984.00	0.	0.
0.11	0.18	0.	0.	0.

PCODAT(12,80)
POWER PLANT DATA

*** NDEUS # 1 ***
NO COGEN PROCESS BOILER

1.00	0.85	0.	1.00	0.
1.00	0.	1.00	0.	0.25
0.	0.55	0.	0.80	0.
0.	100.00	1600.00	14.96	14.96
90.02	90.02	1.00	1.00	1.00
1.00	0.02	1252.00	0.32	0.09
0.00	0.11	500.00	470.00	2.00
5.00	0.65	1.00	1.00	0.00
0.03	4.00	0.79	0.40	0.50
0.00	0.03	15.00	150.00	450.00
0.90	0.50	0.50	0.90	0.
1.00	0.	1.00	0.	1.00
0.	1.00	1.00	1.00	0.
0.	0.	1.00	1.00	2.50
0.10	0.	0.11	0.00	1.00
1.00	1.00	1.00	1.00	1.00

*** NDEUS # 3 ***
STEAM TURBINE 1465PSI 950F FGD SYSTEM

1.00	0.85	0.34	0.	0.26
0.45	0.17	0.77	0.07	0.25
0.18	0.55	0.28	0.80	0.
0.25	100.00	1600.00	21.02	17.92
119.94	102.44	1.00	1.00	1.00
1.00	0.02	2189.00	0.30	0.09
0.04	0.12	1465.00	950.00	2.00
5.00	0.65	1.00	1.00	0.03
0.03	4.00	0.79	0.40	0.50
0.02	0.03	15.00	150.00	450.00
0.90	0.90	0.90	0.90	0.34
0.	0.27	0.69	0.34	0.
0.12	0.83	0.83	1.00	1.00
1.00	1.00	1.00	1.00	3.00
0.10	0.	0.12	0.04	1.00
1.00	1.00	1.00	1.00	1.00

*** NDEUS # 7 ***
GAS TURBINE+HEAT RECOVERY PROCESS BOILER

2.00	0.92	0.39	0.32	0.31
0.43	0.23	0.53	0.12	0.25
0.29	0.55	0.47	0.82	0.11
0.25	100.00	800.00	9.28	8.21
33.37	29.49	1.00	1.00	1.00
1.00	0.02	337.00	0.36	0.
0.02	0.04	500.00	470.00	2.00
3.00	0.90	1.03	1.10	0.02
0.04	4.00	0.88	0.91	0.85
0.02	0.03	30.00	150.00	465.00
0.90	0.90	0.90	0.90	0.39
0.37	0.23	0.56	0.39	0.30
0.23	0.52	0.56	1.00	1.00
1.00	1.00	1.00	1.00	2.00
0.10	0.	0.04	0.02	1.00
1.00	1.00	1.00	1.00	1.00

*** NDEUS # 8 ***
COMBINED CYCLE+PROCESS STEAM EXTRACTION

2.00	0.92	0.53	0.	0.43
0.41	0.33	0.48	0.12	0.25
0.29	0.52	0.47	0.82	0.
0.25	100.00	800.00	12.70	9.57
43.88	34.57	1.00	1.00	1.00
1.00	0.02	1467.00	0.30	0.00
0.02	0.05	865.00	825.00	2.00
3.00	0.90	1.10	1.10	0.02
0.04	4.00	0.88	0.90	0.85
0.02	0.04	15.00	150.00	450.00
0.90	0.90	0.90	0.90	0.53
0.	0.39	0.40	0.53	0.
0.31	0.46	0.48	1.00	1.00
1.00	1.00	1.00	1.00	3.00
0.10	0.	0.05	0.02	1.00
1.00	1.00	1.00	1.00	1.00

INDUSTRIAL PROCESS DEMANDS
 #####
 #####

SUMMARY OF AVERAGE & MAXIMUM INDUSTRIAL PROCESS DEMANDS

DEUS VALIDATION STUDY CASE C

SIC CODE 26212
 DAILY OUTPUT 1100
 UNITS OF MEASURE TPD

UTILITY TYPICAL GAS/OIL BURNING UTILITY

SITE FUELS	LIMITS	COST
COAL	5000.00 MBTU/HR	\$/MBTU 2.91
NAT. GAS	10000.00 MBTU/HR	\$/MBTU 5.31
DIST. OIL	20000.00 MBTU/HR	\$/MBTU 6.66

```

*****
* PROCESS POWER * PROCESS HEAT * PROCESS TEMP *
*-----*-----*-----*
* MW MBTU/HR DEG. F
*-----*-----*-----*
* AVG. : MAX. * AVG. : MAX. * MIN. : MAX. * MBTU/HR *
*-----*-----*-----*
* : * : * : *
* 11.00 : 20.02 * 636.50 : 1007.79 * 297. : 365. * 0. *
* : * : * : *
*****
  
```

PWRM(36)
 TIME VARIANT POWER PROFILE
 (MW)

11.00	11.00	11.00	11.00	11.00	11.00
11.00	11.00	11.00	11.00	11.00	11.00
11.00	11.00	11.00	11.00	11.00	11.00
11.00	11.00	11.00	11.00	11.00	11.00
11.00	11.00	11.00	11.00	11.00	11.00
11.00	11.00	11.00	11.00	11.00	11.00

HTTM(36)
 TIME VARIANT HEAT PROFILE
 (MBTU/HR)

636.50	636.50	636.50	636.50	636.50	636.50
636.50	636.50	636.50	636.50	636.50	636.50
636.50	636.50	636.50	636.50	636.50	636.50
636.50	636.50	636.50	636.50	636.50	636.50
636.50	636.50	636.50	636.50	636.50	636.50
636.50	636.50	636.50	636.50	636.50	636.50

POWER PLANT REQUIREMENTS
 #####
 #####

 THERMAL: SIZING REQUIREMENTS

WASTE PROCESS STEAM = 0. MBTU/HR & POWER = 0. MW

```

*****
*      NO COGEN      *      COAL      *      NAT. GAS      *      NONE      *      TOTAL      *
*      *      *      *      *      *      *      *      *
*****
*      POWER MW      *      0.      *      0.      *      0.      *      0.      *
*-----*-----*-----*-----*-----*-----*
*      HEAT MBTU/HR *      1007.79 *      0.      *      0.      *      1007.79 *
*-----*-----*-----*-----*-----*-----*
*      FUEL MBTU/HR *      1337.18 *      0.      *      0.      *      1337.18 *
*-----*-----*-----*-----*-----*-----*
*      INST COST M$ *      80.15 *      0.      *      0.      *      80.15 *
*-----*-----*-----*-----*-----*-----*
*      EQV. MAX UNITS*      0.84 *      0.      *      0.      *      0.84 *
*-----*-----*-----*-----*-----*-----*
*      # OF UNITS *      1.00 *      0.      *      0.      *      1.00 *
*****
  
```

MAXIMUM PLANT UNIT SIZE 1600.00 MBTU/HR
 MINIMUM PLANT UNIT SIZE 100.00 MBTU/HR

FUEL	AUX. POWER		AUX. HEAT	
	%	MW	%	MBTU
-----	-----	-----	-----	-----
COAL	0.160	2.14	11.333	128.82
NAT. GAS	0.010	0.	2.633	0.
DIST. OIL	0.	0.	0.	0.

THERMAL: SIZING REQUIREMENTS

WASTE PROCESS STEAM = 0. MBTU/HR & POWER = 0. MW

```

*****
*          *          *          *          *          *
*STB 1465FGD *    COAL *    NAT. GAS *    NONE *    TOTAL *
*          *          *          *          *          *
*****
* POWER MW *    74.74 *    0. *    0. *    74.74 *
*-----*
* HEAT MBTU/HR *    1007.79 *    0. *    0. *    1007.79 *
*-----*
* FUEL MBTU/HR *    1765.86 *    0. *    0. *    1765.86 *
*-----*
* INST COST M$ *    127.07 *    0. *    0. *    127.07 *
*-----*
*EQV. MAX UNITS*    1.10 *    0. *    0. *    1.10 *
*-----*
* # OF UNITS *    2.00 *    0. *    0. *    2.00 *
*****
  
```

MAXIMUM PLANT UNIT SIZE 1600.00 MBTU/HR
 MINIMUM PLANT UNIT SIZE 100.00 MBTU/HR

FUEL	AUX. POWER		AUX. HEAT	
	%	MW	%	MBTU
COAL	3.602	2.79	12.250	140.69
NAT. GAS	1.949	0.	3.450	0.
DIST. OIL	0.	0.	0.	0.

MEGAWATT: SIZING REQUIREMENTS

WASTE PROCESS STEAM = 0. MBTU/HR & POWER = 0. MW

```
*****
*          *          *          *          *          *
*STB 1465FGD *    COAL *    NAT. GAS *    NONE *    TOTAL *
*          *          *          *          *          *
*****
*  POWER MW *    100.00 *          0. *          0. *    100.00 *
*-----*-----*-----*-----*-----*
*  HEAT MBTU/HR *    1007.79 *          0. *          0. *    1007.79 *
*-----*-----*-----*-----*-----*
*  FUEL MBTU/HR *    2072.56 *          0. *          0. *    2072.56 *
*-----*-----*-----*-----*-----*
*  INST COST M$ *    155.06 *          0. *          0. *    155.06 *
*-----*-----*-----*-----*-----*
*EQV. MAX UNITS*          1.30 *          0. *          0. *          1.30 *
*-----*-----*-----*-----*-----*
*  # OF UNITS *          2.00 *          0. *          0. *          2.00 *
*****
```

MAXIMUM PLANT UNIT SIZE 1600.00 MBTU/HR
MINIMUM PLANT UNIT SIZE 100.00 MBTU/HR

FUEL	AUX. POWER		AUX. HEAT	
	%	MW	%	MBTU
COAL	3.602	3.74	12.250	140.69
NAT. GAS	1.949	0.	3.450	0.
DIST. OIL	0.	0.	0.	0.

THERMAL: SIZING REQUIREMENTS

WASTE PROCESS STEAM = 0. MBTU/HR & POWER = 0. MW

```
*****
*          *          *          *          *          *
* GTB HRSG *      NONE *    NAT. GAS *    DIST. OIL *    TOTAL   *
*          *          *          *          *          *
*****
* POWER MW *      0.   *    130.62 *      0.   *    130.62 *
*-----*-----*-----*-----*-----*
* HEAT MBTU/HR *      0.   *    1007.79 *      0.   *    1007.79 *
*-----*-----*-----*-----*
* FUEL MBTU/HR *      0.   *    2222.40 *      0.   *    2222.40 *
*-----*-----*-----*-----*
* INST COST M$ *      0.   *     76.67 *      0.   *     76.67 *
*-----*-----*-----*-----*
*EQV. MAX UNITS*      0.   *     2.78 *      0.   *     2.78 *
*-----*-----*-----*-----*
* # OF UNITS *      0.   *     3.00 *      0.   *     3.00 *
*****
```

MAXIMUM PLANT UNIT SIZE 800.00 MBTU/HR
MINIMUM PLANT UNIT SIZE 100.00 MBTU/HR

FUEL	AUX. POWER		AUX. HEAT	
	%	MW	%	MBTU
COAL	0.	0.	0.	0.
NAT. GAS	1.745	2.32	2.933	30.45
DIST. OIL	1.824	0.	3.987	0.

MEGAWATT: SIZING REQUIREMENTS

WASTE PROCESS STEAM = 0. MBTU/HR & POWER = 0. MW

```

*****
*      *      *      *      *      *
* GTB  HRSG  *      NONE  *      NAT. GAS  *      DIST. OIL  *      TOTAL      *
*      *      *      *      *      *
*****
* POWER MW   *      0.    *      130.62   *      0.    *      130.62   *
*-----*-----*-----*-----*-----*-----*
* HEAT MBTU/HR *      0.    *      1007.79  *      0.    *      1007.79  *
*-----*-----*-----*-----*-----*-----*
* FUEL MBTU/HR *      0.    *      2222.40  *      0.    *      2222.40  *
*-----*-----*-----*-----*-----*-----*
* INST COST M$ *      0.    *      76.67   *      0.    *      76.67   *
*-----*-----*-----*-----*-----*-----*
*EQV. MAX UNITS*      0.    *      2.78    *      0.    *      2.78    *
*-----*-----*-----*-----*-----*-----*
* # OF UNITS  *      0.    *      3.00    *      0.    *      3.00    *
*****

```

MAXIMUM PLANT UNIT SIZE 800.00 MBTU/HR
 MINIMUM PLANT UNIT SIZE 100.00 MBTU/HR

FUEL	AUX. POWER		AUX. HEAT	
	%	MW	%	MBTU
COAL	0.	0.	0.	0.
NAT. GAS	1.745	2.32	2.933	30.45
DIST. OIL	1.824	0.	3.987	0.

THERMAL: SIZING REQUIREMENTS

WASTE PROCESS STEAM = 0. MBTU/HR & POWER = 0. MW

```

*****
*          *          *          *          *
* COMB. CYCLE *      NONE      *    NAT. GAS    *    DIST. OIL    *    TOTAL      *
*          *          *          *          *
*****
* POWER MW *      0.      *    209.64    *      0.      *    209.64    *
*-----*-----*-----*-----*-----*
* HEAT MBTU/HR *      0.      *    1007.79    *      0.      *    1007.79    *
*-----*-----*-----*-----*-----*
* FUEL MBTU/HR *      0.      *    2476.74    *      0.      *    2476.74    *
*-----*-----*-----*-----*-----*
* INST COST M$ *      0.      *    101.95    *      0.      *    101.95    *
*-----*-----*-----*-----*-----*
* EQV. MAX UNITS *      0.      *      3.10    *      0.      *      3.10    *
*-----*-----*-----*-----*-----*
* # OF UNITS *      0.      *      4.00    *      0.      *      4.00    *
*****
  
```

MAXIMUM PLANT UNIT SIZE 800.00 MBTU/HR
 MINIMUM PLANT UNIT SIZE 100.00 MBTU/HR

FUEL	AUX. POWER		AUX. HEAT	
	%	MW	%	MBTU
COAL	0.	0.	0.	0.
NAT. GAS	1.883	4.02	3.900	40.90
DIST. OIL	1.968	0.	4.713	0.

MEGAWATT: SIZING REQUIREMENTS

WASTE PROCESS STEAM = 0. MBTU/HR & POWER = 0. MW

```

*****
*          *          *          *          *          *
*COMB. CYCLE *      NONE      *  NAT. GAS  *  DIST. OIL  *      TOTAL      *
*          *          *          *          *          *
*****
*  POWER MW  *      0.      *    209.64   *      0.      *    209.64   *
*-----*
*  HEAT MBTU/HR *      0.      *    1007.79  *      0.      *    1007.79  *
*-----*
*  FUEL MBTU/HR *      0.      *    2476.74  *      0.      *    2476.74  *
*-----*
*  INST COST M$ *      0.      *    101.95   *      0.      *    101.95   *
*-----*
*EQV. MAX UNITS*      0.      *      3.10   *      0.      *      3.10   *
*-----*
*  # OF UNITS  *      0.      *      4.00   *      0.      *      4.00   *
*****

```

MAXIMUM PLANT UNIT SIZE 800.00 MBTU/HR
 MINIMUM PLANT UNIT SIZE 100.00 MBTU/HR

FUEL	AUX. POWER		AUX. HEAT	
	%	MW	%	MBTU
COAL	0.	0.	0.	0.
NAT. GAS	1.883	4.02	3.900	40.90
DIST. OIL	1.968	0.	4.713	0.

SYSTEM PERFORMANCE
 #####
 #####

THERMAL SIZED/THERMAL DISPATCH

```
*****
*   DEUS      *   FUEL FLOW   *   MW HRS   *   CAPACITY  *
* TECHNOLOGY *   MW RATED *RATED MBTU/HR* ( X 10E-3 ) *   FACTOR   *
*****
*   NO COGEN  *      0.    *   1337.18 *      0.    *      0.    *
*-----*
*STB 1465FGD *      74.74 *   1765.86 *   350.40 *      0.54 *
*-----*
* GTB  HRSG   *     130.62 *   2222.40 *   679.51 *      0.59 *
*-----*
*COMB. CYCLE  *     209.64 *   2476.74 *   1083.87 *      0.59 *
*****
```

THIRD PARTY OR INDUSTRY OWNED
 ECONOMIC DISPATCH/INDUSTRIAL RATES

```
*****
*   DEUS      *   FUEL FLOW   *   MW HRS   *   CAPACITY  *
* TECHNOLOGY *   MW RATED *RATED MBTU/HR* ( X 10E-3 ) *   FACTOR   *
*****
*   NO COGEN  *      0.    *   1337.18 *      0.    *      0.    *
*-----*
*STB 1465FGD *     100.00 *   2072.56 *   469.80 *      0.54 *
*-----*
* GTB  HRSG   *     130.62 *   2222.40 *   679.51 *      0.59 *
*-----*
*COMB. CYCLE  *     209.64 *   2476.74 *   1083.87 *      0.59 *
*****
```

UTILITY OWNED
 ECONOMIC DISPATCH/MARGINAL PRODUCTION COSTS

```
*****
*   DEUS      *   FUEL FLOW   *   MW HRS   *   CAPACITY  *
* TECHNOLOGY *   MW RATED *RATED MBTU/HR* ( X 10E-3 ) *   FACTOR   *
*****
*   NO COGEN  *      0.    *   1337.18 *      0.    *      0.    *
*-----*
*STB 1465FGD *     100.00 *   2072.56 *   469.80 *      0.54 *
*-----*
* GTB  HRSG   *     130.62 *   2222.40 *   679.51 *      0.59 *
*-----*
*COMB. CYCLE  *     209.64 *   2476.74 *   1083.87 *      0.59 *
*****
```

ECONOMICS

#####

PRESENT VALUE OF STEAM

=====

DESIRED IRR =15.0 %
LOW PRESSURE VALUE = 6.91 \$/MBTU
HIGH PRESSURE VALUE = 9.22 \$/MBTU

ECONOMICS

INDUSTRY OWNED

THERMAL SIZED/THERMAL DISPATCH

=====

SYSTEM COSTS/REVENUES

-M\$ PER YEAR-

```
*****
* DEUS * * * * * PURCHASED * ELECTRIC *
* TECHNOLOGY* TIC M$ * FUEL COST * O & M *ELECTRICITY* REVENUES *
*****
* NO COGEN * 80.15 * 24.90 * 3.77 * 8.26 * 0. *
*-----*
*STB 1465FGD* 127.07 * 27.98 * 5.23 * 6.92 * 38.48 *
*-----*
* GTB HRSG * 76.67 * 60.54 * 2.48 * 6.92 * 73.42 *
*-----*
*COMB. CYCLE* 101.95 * 69.19 * 3.32 * 6.92 * 117.22 *
*****
```

SYSTEM LEVELIZED COSTS/REVENUES

-M\$ PER YEAR-

```
*****
* DEUS * FIXED * * * * * PURCHASED * ELECTRIC *
* TECHNOLOGY* CHARGES * FUEL COST * O & M *ELECTRICITY* REVENUES *
*****
* NO COGEN * 16.03 * 24.90 * 3.77 * 8.26 * 0. *
*-----*
*STB 1465FGD* 25.41 * 27.98 * 5.23 * 6.92 * 38.48 *
*-----*
* GTB HRSG * 15.33 * 60.54 * 2.48 * 6.92 * 73.42 *
*-----*
*COMB. CYCLE* 20.39 * 69.19 * 3.32 * 6.92 * 117.22 *
*****
```

SYSTEM ECONOMICS

```
*****
* DEUS * DISCOUNTED * *
* TECHNOLOGY * CF IRR * PAYBACK *
*****
* NO COGEN * 0. * 0. *
*-----*
*STB 1465FGD * 0.48 * 2.01 *
*-----*
* GTB HRSG * -1.00 * ***** *
*-----*
*COMB. CYCLE * 1.98 * 0.50 *
*****
```

ECONOMICS
INDUSTRIAL OWNED BASE CASE
ECONOMIC DISPATCH/INDUSTRIAL RATES
=====

SYSTEM COSTS/REVENUES
-M\$ PER YEAR-

```

*****
* DEUS      *      *      *      * PURCHASED * ELECTRIC *
* TECHNOLOGY* TIC M$ * FUEL COST * O & M *ELECTRICITY* REVENUES *
*****
* NO COGEN  * 80.15 * 24.90 * 3.77 * 8.26 * 0. *
*-----*
*STB 1465FGD* 155.06 * 35.18 * 6.24 * 6.92 * 51.57 *
*-----*
* GTB HRSG * 76.67 * 60.54 * 2.48 * 6.92 * 73.42 *
*-----*
*COMB. CYCLE* 101.95 * 69.19 * 3.32 * 6.92 * 117.22 *
*****

```

SYSTEM LEVELIZED COSTS/REVENUES
-M\$ PER YEAR-

```

*****
* DEUS      * FIXED *      *      * PURCHASED * ELECTRIC *
* TECHNOLOGY* CHARGES * FUEL COST * O & M *ELECTRICITY* REVENUES *
*****
* NO COGEN  * 16.03 * 24.90 * 3.77 * 8.26 * 0. *
*-----*
*STB 1465FGD* 31.01 * 35.18 * 6.24 * 6.92 * 51.57 *
*-----*
* GTB HRSG * 15.33 * 60.54 * 2.48 * 6.92 * 73.42 *
*-----*
*COMB. CYCLE* 20.39 * 69.19 * 3.32 * 6.92 * 117.22 *
*****

```

SYSTEM ECONOMICS

```

*****
* DEUS      * DISCOUNTED *      *
* TECHNOLOGY * IRR * PAYBACK *
*****
* NO COGEN  * 0. * 0. *
*-----*
*STB 1465FGD * 0.36 * 2.68 *
*-----*
* GTB HRSG * -1.00 * ***** *
*-----*
*COMB. CYCLE * 1.98 * 0.50 *
*****

```

ECONOMICS
THIRD PARTY OWNERSHIP
THERMAL SIZED/THERMAL DISPATCH
=====

SYSTEM COSTS/REVENUES
-M\$ PER YEAR-

```
*****
* DEUS * * * * * POWER * STEAM *
* TECHNOLOGY* TIC M$ * FUEL COST * O & M * REVENUES * REVENUES *
*****
* NO COGEN * 80.15 * 24.90 * 3.77 * 0. * 47.10 *
*-----*
*STB 1465FGD* 127.07 * 27.98 * 5.23 * 38.48 * 47.10 *
*-----*
* GTB HRSG * 76.67 * 60.54 * 2.48 * 73.42 * 47.10 *
*-----*
*COMB. CYCLE* 101.95 * 69.19 * 3.32 * 117.22 * 47.10 *
*****
```

SYSTEM LEVELIZED COSTS/REVENUES
-M\$ PER YEAR-

```
*****
* DEUS * * * * * POWER * STEAM *
* TECHNOLOGY* FIXED * FUEL COST * O & M * REVENUES * REVENUES *
*****
* NO COGEN * 16.03 * 24.90 * 3.77 * 0. * 47.10 *
*-----*
*STB 1465FGD* 25.41 * 27.98 * 5.23 * 38.48 * 47.10 *
*-----*
* GTB HRSG * 15.33 * 60.54 * 2.48 * 73.42 * 47.10 *
*-----*
*COMB. CYCLE* 20.39 * 69.19 * 3.32 * 117.22 * 47.10 *
*****
```

SYSTEM ECONOMICS

```
*****
* DEUS * * DISCOUNTED *
* TECHNOLOGY * CF IRR * PAYBACK *
*****
* NO COGEN * 0.15 * 5.57 *
*-----*
*STB 1465FGD * 0.28 * 3.32 *
*-----*
* GTB HRSG * 0.48 * 2.02 *
*-----*
*COMB. CYCLE * 0.57 * 1.72 *
*****
```

ECONOMICS
THIRD PARTY OWNERSHIP
ECONOMIC DISPATCH/INDUSTRIAL RATES
=====

SYSTEM COSTS/REVENUES
-M\$ PER YEAR-

```
*****
*   DEUS   *           *           *   POWER *   STEAM *
* TECHNOLOGY* TIC M$ * FUEL COST * O & M * REVENUES * REVENUES *
*****
* NO COGEN * 80.15 * 24.90 * 3.77 * 0. * 47.10 *
*-----*
*STB 1465FGD* 155.06 * 35.18 * 6.24 * 51.57 * 47.10 *
*-----*
* GTB HRSG * 76.67 * 60.54 * 2.48 * 73.42 * 47.10 *
*-----*
*COMB. CYCLE* 101.95 * 69.19 * 3.32 * 117.22 * 47.10 *
*****
```

SYSTEM LEVELIZED COSTS/REVENUES
-M\$ PER YEAR-

```
*****
*   DEUS   *   FIXED *           *   POWER *   STEAM *
* TECHNOLOGY* CHARGES * FUEL COST * O & M * REVENUES * REVENUES *
*****
* NO COGEN * 16.03 * 24.90 * 3.77 * 0. * 47.10 *
*-----*
*STB 1465FGD* 31.01 * 35.18 * 6.24 * 51.57 * 47.10 *
*-----*
* GTB HRSG * 15.33 * 60.54 * 2.48 * 73.42 * 47.10 *
*-----*
*COMB. CYCLE* 20.39 * 69.19 * 3.32 * 117.22 * 47.10 *
*****
```

SYSTEM ECONOMICS

```
*****
*   DEUS   * DISCOUNTED *
* TECHNOLOGY * IRR * PAYBACK *
*****
* NO COGEN * 0.15 * 5.57 *
*-----*
*STB 1465FGD * 0.25 * 3.62 *
*-----*
* GTB HRSG * 0.48 * 2.02 *
*-----*
*COMB. CYCLE * 0.57 * 1.72 *
*****
```

UTILITY SYSTEM ECONOMIC IMPACTS
 #####
 #####

INDUSTRIAL OWNED COGEN PLANT
 THERMAL SIZED/THERMAL LOAD FOLLOWING
 =====

(UTILITY SYSTEM COST IMPACTS)
 -M\$ PER YEAR-

```
*****
* DEUS      * PRODUCTION* CAPACITY * REVENUE * PURPA  *NET UTILITY*
* TECHNOLOGY* COSTSAVINGS* COSTSAVINGS* LOSS    * PAYMENTS * COSTSAVINGS*
*****
*STB 1465FGD* 32.28 * 6.20 * 0. * 38.48 * 0. *
*-----*
* GTB HRSG * 62.59 * 10.84 * 0. * 73.42 * 0. *
*-----*
*COMB. CYCLE* 99.84 * 17.40 * 0. * 117.22 * 0. *
*****
```

INDUSTRIAL OWNED COGEN PLANT
 ECONOMIC DISPATCH/INDUSTRIAL RATES
 =====

(UTILITY SYSTEM COST IMPACTS)
 -M\$ PER YEAR-

```
*****
* DEUS      * PRODUCTION* CAPACITY * REVENUE * PURPA  *NET UTILITY*
* TECHNOLOGY* COSTSAVINGS* COSTSAVINGS* LOSS    * PAYMENTS * COSTSAVINGS*
*****
*STB 1465FGD* 43.27 * 8.30 * 0. * 51.57 * 0. *
*-----*
* GTB HRSG * 62.59 * 10.84 * 0. * 73.42 * 0. *
*-----*
*COMB. CYCLE* 99.84 * 17.40 * 0. * 117.22 * 0. *
*****
```

UTILITY OWNED COGEN PLANT
ECONOMIC DISPATCH/MARGINAL PRODUCTION COSTS
=====

UTILITY SYSTEM COST SAVINGS
-M\$ PER YEAR-

```
*****
*      DEUS      * PRODUCTION * INCREMENTAL *      *
* TECHNOLOGY * COST SAVINGS * PROD. COST * STEAM * DISPLACED *
*              * THERMAL LOAD * SAVINGS WITH * REVENUES * CAPACITY *
*              * FOLLOWING * INCR. DISPT. *      * COST SAVINGS *
*****
*STB 1465FGD *      32.28 *      11.00 *      47.10 *      8.30 *
*-----*
* GTB  HRSG *      62.59 *      0. *      47.10 *      10.84 *
*-----*
*COMB. CYCLE *      99.84 *      0. *      47.10 *      17.40 *
*****
```

ADDITIONAL UTILITY SYSTEM COSTS
-M\$ PER YEAR-

```
*****
*      *      * COGEN * INCREMENTAL *      *
* DEUS * COGEN * FUEL COST * COGEN * COGEN * AUX *
* TECHNOLOGY * CAPITAL * THERMAL LD. * FUEL COST * O & M * BOILER *
*              * COSTS * FOLLOWING *      * COSTS * FUEL COST *
*****
*STB 1465FGD*      27.91 *      27.98 *      7.20 *      6.24 *      0. *
*-----*
* GTB  HRSG *      13.80 *      60.54 *      0. *      2.48 *      0. *
*-----*
*COMB. CYCLE*      18.35 *      69.19 *      0. *      3.32 *      0. *
*****
```

NET UTILITY SYSTEM COST IMPACT

```
*****
*      DEUS      * NET SAVINGS * CAPITALIZED *
* TECHNOLOGY * (M$ PER YR) * NET SAVINGS-M$ *
*****
*STB 1465FGD *      29.34 *      163.01 *
*-----*
* GTB  HRSG *      43.72 *      242.87 *
*-----*
*COMB. CYCLE *      73.47 *      408.17 *
*****
```

SYSTEM BENEFITS

#####

THERMAL DISPATCH

=====

```
*****
*          *      FUEL SAVED MBTU/YEAR      *      ECS      *      SYSTEM      *
*-----*-----*-----*-----*-----*-----*-----*
*TECHNOLOGY*  OIL      *      GAS      *      COAL      *  EFFICIENCY*  EFFICIENCY*
*****
*STB 1465FGD* 0.33E 07 *      0.      * -0.11E 07 * 0.67      * 0.67      *
*-----*-----*-----*-----*-----*-----*
* GTB HRSG * 0.65E 07 * -0.11E 08 * 0.86E 07 * 0.67      * 0.67      *
*-----*-----*-----*-----*-----*-----*
*COMB. CYCLE* 0.10E 08 * -0.13E 08 * 0.86E 07 * 0.69      * 0.69      *
*****
```

THIRD PARTY OR INDUSTRY OWNED MEGAWATT DISPATCH

=====

```
*****
*          *      FUEL SAVED MBTU/YEAR      *      ECS      *      SYSTEM      *
*-----*-----*-----*-----*-----*-----*-----*
*TECHNOLOGY*  OIL      *      GAS      *      COAL      *  EFFICIENCY*  EFFICIENCY*
*****
*STB 1465FGD* 0.45E 07 *      0.      * -0.35E 07 * 0.57      * 0.57      *
*-----*-----*-----*-----*-----*-----*
* GTB HRSG * 0.65E 07 * -0.11E 08 * 0.86E 07 * 0.67      * 0.67      *
*-----*-----*-----*-----*-----*-----*
*COMB. CYCLE* 0.10E 08 * -0.13E 08 * 0.86E 07 * 0.69      * 0.69      *
*****
```

UTILITY OWNED MEGAWATT DISPATCH

=====

```
*****
*          *      FUEL SAVED MBTU/YEAR      *      ECS      *      SYSTEM      *
*-----*-----*-----*-----*-----*-----*-----*
*TECHNOLOGY*  OIL      *      GAS      *      COAL      *  EFFICIENCY*  EFFICIENCY*
*****
*STB 1465FGD* 0.45E 07 *      0.      * -0.35E 07 * 0.57      * 0.57      *
*-----*-----*-----*-----*-----*-----*
* GTB HRSG * 0.65E 07 * -0.11E 08 * 0.86E 07 * 0.67      * 0.67      *
*-----*-----*-----*-----*-----*-----*
*COMB. CYCLE* 0.10E 08 * -0.13E 08 * 0.86E 07 * 0.69      * 0.69      *
*****
```

Section 5

INPUT DATA DEVELOPMENT FOR SAMPLE CASES

5.1 INTRODUCTION

The purpose of this section is to illustrate use of the DEUS program with two realistic sample cases. Input data files are presented for each sample case. It is assumed that the program user is interested in studying the cost-benefit impacts (with various ownership situations) of owning one of three alternative dual energy use systems which are suitable for the particular industrial application. In addition to the three DEUS plants, a nocogeneration base case was also selected from the data base for both sample case studies. Case C and G of the eight validation cases described in Section 6 of the Program Descriptive Manual were selected to illustrate input data development for these two sample cases. The two sample cases are briefly described below.

Case C: Average Loads
Variable Utility Rates
Simultaneous Buy/Sell

Case G: Variable Loads
Variable Utility Rates with Low Off-Peak PURPA Rates

5.2 CASE C EXAMPLE

Hourly profiles for process heat and power demands are shown in Figure 5.2-1. The average and maximum process electric demands are 11 MW and 20 MW, respectively. The average and maximum process steam demands are, respectively, 500,000 and 800,000 lb/hr at 150 psig saturated and 100,000 and 150,000 lbs/hr at 50 psig saturated. The average energy demands are used to calculate total annual fuel used by each system and the maximum energy demands are used to size systems to meet energy demands at all times. The hourly profiles are the same for weekdays, Saturdays, Sundays and holidays throughout the year. Equipment maintenance outages are assumed to be three weeks per year (94% availability).

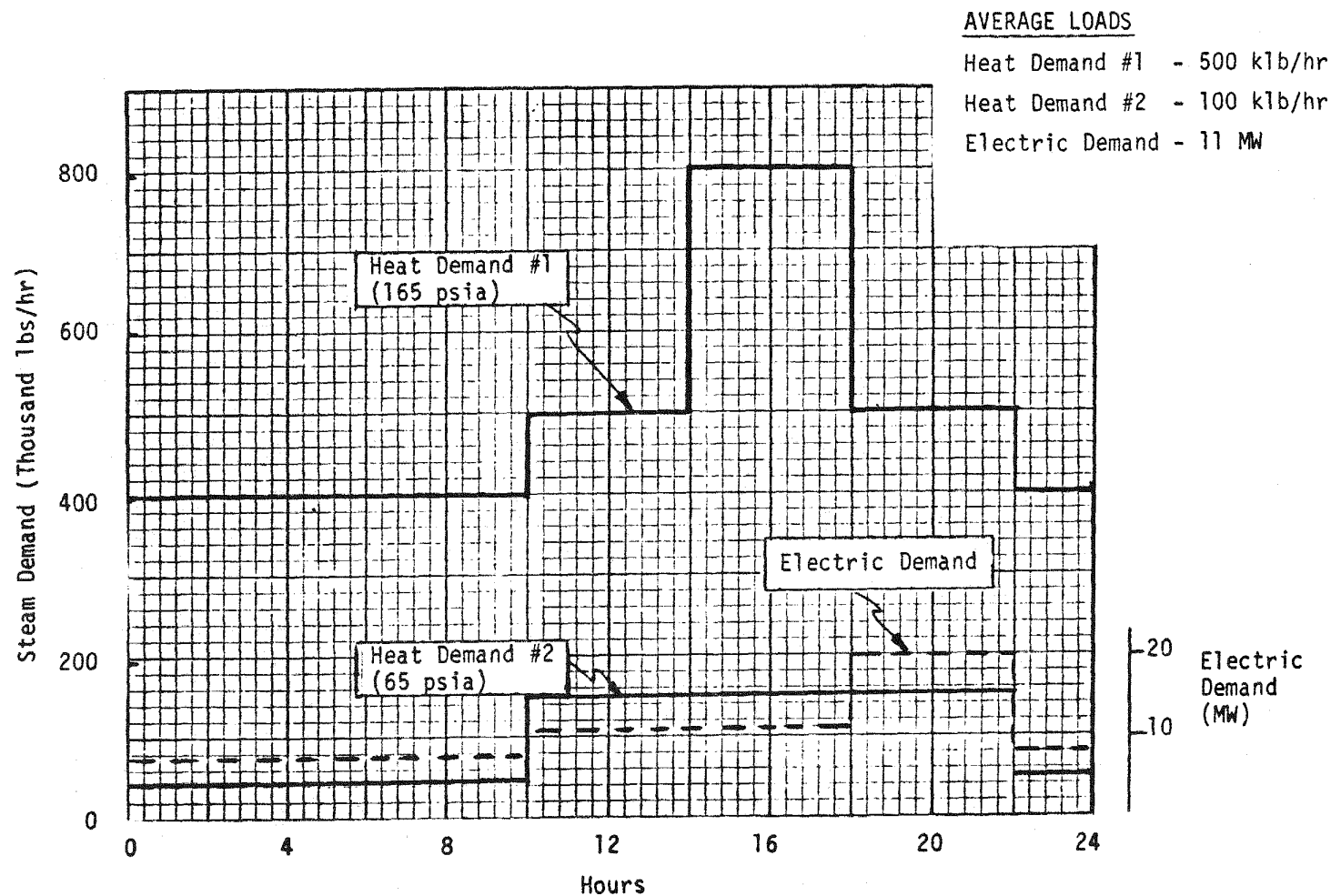


Figure 5.2-1. Hourly Heat and Power Demand Profiles for Validation Cases

On inspection it is determined that the input data requirements for the industrial process variables (INDAT) are the same as those in the computer program except for INDAT(7), (10), (15), and (16) which need to be changed from the data base values of 100, 1, 100 and 100 to new values of 182, 2, 160 and 150, respectively. Table 5.2-1 lists all input needed to make this run. INDAT(7), for example, represents maximum electric demand as a percentage ratio of average electric demand. In this example its value is $\frac{20}{11} * 100 = 182$. Similarly, INDAT(15) has a value of $\frac{800,000}{500,000} * 100 = 160$ and INDAT(16) has a value of $\frac{150,000}{100,000} * 100 = 150$. Since the number of process heat streams is 2 (i.e., one of 150 psig and the other of 50 psig), the data base value of 1 for INDAT(10) is changed to 2. It is to be noted that all the user has to do is to input only correctional values which supersede the data base values.

Table 5.2-1
PROGRAM INPUT FOR CASE C

```
LIST VALIDC
$INPUT/
INDAT(7)=182,
INDAT(10)=2,
INDAT(15)=160, 150,
ECODAT(1,1)=3*0.,
PCODAT(2,1)=0
PCODAT(4,1)=0.,0.,0.,
PCODAT(9,1)=0.,
KSTPR=1,
DIRR=.15,
TITLE='DEUS VALIDATION STUDY CASE C',
UTITLE='TYPICAL GAS/OIL BURNING UTILITY',
$
```

On further inspection, it is clear that there is no need to change the input variables (TMDAT) in the input sheets from those in the data base. For both the data base and this case study, industrial electric and heat demands are assumed constant for the full year. The default values for electric and heat demand profiles can, therefore, be used for this case study. Utility rates and other utility data required for this case study are also the same as data base values and no input data changes are necessary. Similarly, the input variables ECODAT, GNLDAT, EMSDAT and FLDAT are the same, except for ECODAT(1) which is made equal to zero and represents no inflation as compared to the data base inflation value of 9%.

For this case study, four types of DEUS systems from the data base were selected. These are the nocogen base case, the medium pressure steam turbine fired by coal with flue gas treatment and gas turbine and combined cycle systems fired by gas. The data base performance and cost information was retained for these DEUS systems. while PCODAT(2,1), (4,1), (5,1), (6,1) and (9,1) were set to zero thereby eliminating the remaining systems from further consideration in this case study.

In this case, the price of steam was calculated by the program so that the third-party or utility owners of DEUS systems would obtain a rate of return on the nocogen system of 15%. This was accomplished with the input by overriding the data base values of steam prices of \$6/MBtu for low pressure steam GNLDAT(18) and \$8/MBtu for high pressure steam GNLDAT(19) by using variables in the input sheet KSTPR=1 and desired internal rate of return as DIRR=0.15. In this case the values of 6 and 8 \$/MBtu are used and must be retained to set the ratio of the steam prices for the two pressures.

In order to study full computer output, the data base value of IPRINT=8*1.0 can be left with no need to change it in the input file. Finally, to identify this example, inputs for TITLE and UTITLE with character variables up to a maximum of 56 and 32 letters, respectively, inside parentheses (e.g., 'CASE XXX') are made. It is to be noted that all the variables in the input are separated by commas. Input starts with \$INPUT/ and ends with a \$ sign.

The complete output for this sample Case C is given in Section 4.3.

5.3 CASE G EXAMPLE

The Case G example assumes both variable electric and heat demand profiles, as illustrated in Figure 5.2-1. For the previously discussed Case C, both electric and heat demands were assumed constant at the average of the variable profiles shown in Figure 5.2-1. Variable utility rates (PURPA rates and industrial rates) and variable utility marginal production costs were assumed for both Case G and Case C. For Case G, the utility PURPA avoided energy costs and utility marginal production costs were changed to very low values (1.5¢/kWh) during off-peak utility billing periods. Validation Case G was designed to verify expected operation of the auxiliary boiler during the off-peak periods when it is more economic to dispatch an auxiliary boiler than to operate the power generating equipment.

The primary objective of the following discussion is to illustrate input data development for Case G with emphasis on the time varying profile and rate data. This data is specified by the program user via the TMDAT input array which is dimensioned 36 (36 maximum time periods) by 12 (12 input variables as described in Section 2).

Case G is an example of an industrial process where actual process demands (electricity and heat) vary during the day. The hourly process demands are shown in Figure 5.2-1. Hourly profiles are assumed to be the same for weekdays, Saturdays, Sundays and holidays throughout the year. Equipment maintenance outages are assumed to be three weeks per year. In the DEUS model, each energy demand profile is represented by average energy demands for each of up to 36 time periods. Peak demands in each time period can also be specified by the program user via peak to average demand factors. For example, peak electric demands are determined by input variable TMDAT(I,12) described in Section 2, where I denotes the 36 time periods; 1 to 36.

For Case G, the electric utility is assumed to have variable time-of-day electricity rates which vary according to billing periods identified in Table 5.3-1.

As indicated in Table 5.3-1, there are two seasonal period (Period A and Period B) and three time-of-day periods (On-Peak, Partial-Peak and Off-Peak). As described below, these billing periods must be recognized in the specification of TMDAT input data.

Days Per Billing Season

The first step in specifying time varying profile and rate data (TMDAT) is to determine the number of days of equipment operation for each seasonal period. This calculation is illustrated in Table 5.3-2 for the calendar year 1984, which is First Year of operation for Case G. As indicated at the bottom of Table 5.3-2, the number of days by day-type (weekday, Saturday, etc.) are calculated and adjusted for maintenance outages.

Definition of Time-of-Day Periods

The second step in specifying time varying data is to define time periods (maximum of 36 periods). The definition of time-of-day periods, for Case G, is illustrated in Figure 5.3-1. It is essential to represent industrial process demand

Table 5.3-1

UTILITY BILLING PERIODS

<u>Seasonal Period A</u> (May 1 to September 30)	<u>Mon. - Fri.*</u>	<u>Saturdays*</u>	<u>Sun. & Holidays</u>
On-Peak	12:30 p.m. to 6:30 p.m.		
Partial-Peak	8:30 a.m. to 12:30 p.m. 6:30 p.m. to 10:30 p.m.	8:30 a.m. to 10:30 p.m.	
Off-Peak	10:30 p.m. to 8:30 a.m.	10:30 p.m. to 8:30 a.m.	12:00 a.m. to 12:00 a.m.
<u>Seasonal Period B</u> (October 1 to April 30)			
On-Peak	4:30 p.m. to 8:30 p.m.		
Partial-Peak	8:30 p.m. to 10:30 p.m. 8:30 a.m. to 4:30 p.m.	8:30 a.m. to 10:30 p.m.	
Off-Peak	10:30 p.m. to 8:30 a.m.	10:30 p.m. to 8:30 a.m.	12:00 a.m. to 12:00 a.m.

*Except the following holidays: New Year's Day, Washington's Birthday, Memorial Day, Independence Day, Labor Day, Veteran's Day, Thanksgiving and Christmas Day, as said days are specified in Public Law 90-363 (U.S.C.A. Section 6103).

Table 5.3-2

DAYS PER BILLING SEASON BY DAY TYPE
CALENDAR YEAR 1984

<u>Month</u>	<u>Billing Season</u>	<u>Weekdays</u>	<u>Saturdays</u>	<u>Sundays & Holidays</u>	<u>Total</u>
Jan.	B	22	4	5	31
Feb.	B	20	4	5	29
Mar.	B	22	5	4	21
Apr.	B	21	4	5	20
May	A	22	4	5	21
June	A	21	5	4	20
July	A	21	4	6	21
Aug.	A	23	4	4	21
Sept.	A	19	5	6	20
Oct.	B	23	4	4	21
Nov.	B	21	4	5	20
Dec.	B	20	5	6	<u>21</u>
					366
<u>Season Totals</u>					
May-Sept.	A	106	22	22	153
Oct-April	B	149	30	34	<u>213</u>
					366
<u>Adjusted Season Totals</u> (Equipment maintenance days not included)					
May-Sept.	A	101	21	24	146
Oct-April	B	139	28	32	<u>199</u>
					345

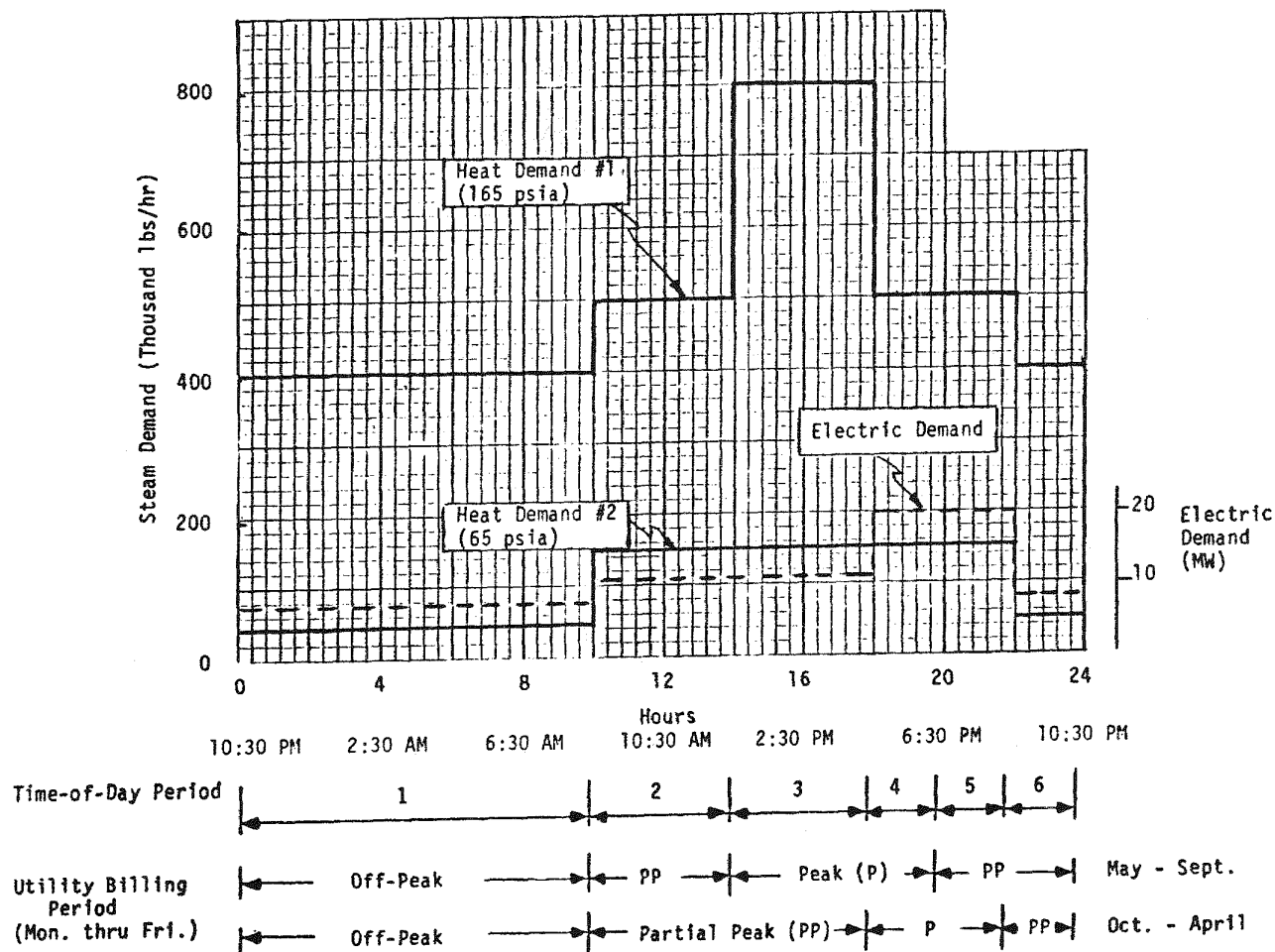


Figure 5.3-1. Definition of Time-of-Day Periods

profiles, in the same time periods that represent the local utility rates, or submultiples of those, up to a maximum of 36. The definition of time-of-day periods for Case G is presented in Table 5.3-3. As indicated, each of the 36 time periods represents a time interval on a specific day type. The duration of the 36 time intervals is also indicated in Table 5.3-3.

Equipment Operating Hours Per Time Period

One of the TMDAT input variables for the DEUS program is TMDAT(I,6) which is the total hours per period per year for each of the 36 time periods. The calculation of annual operating hours per period is illustrated in Table 5.3-4. As indicated, hours per period are calculated using data presented in Tables 5.3-2 and 5.3-3. The summation of hours per period for all 36 time periods is 8280 hours/year. This represents equipment availability of 94.3% ($8280/8784 = .943$, where 8784 = hours per year for calendar year 1984).

PURPA Avoided Energy Costs by Time Period

PURPA avoided energy cost data is input to the DEUS program using the TMDAT (I,5) input variable. For Case G, some utility PURPA avoided energy costs and utility marginal production costs in the data base must be changed. Specifically, data base values of 8.7 ¢/kWh must be reduced to 1.5 ¢/kWh during the off-peak utility periods identified in Table 5.3-1.

The data base values for PURPA avoided energy costs are summarized in Table 5.3-5. As defined in Table 5.3-1, the time periods are described as either off-peak (OP), partial-peak (PP), or on-peak (P). In Table 5.3-6, all the off-peak PURPA avoided energy costs have been changed to 1.5 ¢/kWh.

Process Electric and Heat Demand Profiles

Process electric and heat demand profiles are specified as DEUS program input with the TMDAT(I,1), TMDAT(I,2), and TMDAT(I,3) variables. As indicated in Section 2, demand profiles are all expressed as a percent of average annual demand. Process electric and heat demand profiles for Case G are presented in Table 5.3-7. The values in Table 5.3-7 were calculated using the hourly profiles and average demands shown in Figure 5.2-1.

Table 5.3-3
DEFINITION OF TIME-OF-DAY PERIODS

Season A				Season B			
Time Period ID	Day Type	Time Period	Hours/ Day	Time Period ID	Day Type	Time Period	Hours/ Day
1	W	10:30-8:30 AM	10	19	W	10:30-8:30 AM	10
2	W	8:30-12:30 PM	4	20	W	8:30-12:30 PM	4
3	W	12:30-4:30 PM	4	21	W	12:30-4:30 PM	4
4	W	4:30-6:30 PM	2	22	W	4:30-6:30 PM	2
5	W	6:30-8:30 PM	2	23	W	6:30-8:30 PM	2
6	W	8:30-10:30 PM	2	24	W	8:30-10:30 PM	2
7	Sat.	10:30-8:30 AM	10	25	Sat.	10:30-8:30 AM	10
8	Sat.	8:30-12:30 PM	4	26	Sat.	8:30-12:30 PM	4
9	Sat.	12:30-4:30 PM	4	27	Sat.	12:30-4:30 PM	4
10	Sat.	4:30-6:30 PM	2	28	Sat.	4:30-6:30 PM	2
11	Sat.	6:30-8:30 PM	2	29	Sat.	6:30-8:30 PM	2
12	Sat.	8:30-10:30 PM	2	30	Sat.	8:30-10:30 PM	2
13	S/H	10:30-8:30 AM	10	31	S/H	10:30-8:30 AM	10
14	S/H	8:30-12:30 PM	4	32	S/H	8:30-12:30 AM	4
15	S/H	12:30-4:30 PM	4	33	S/H	12:30-4:30 PM	4
16	S/H	4:30-6:30 PM	2	34	S/H	4:30-6:30 PM	2
17	S/H	6:30-8:30 PM	2	35	S/H	6:30-8:30 PM	2
18	S/H	8:30-10:30 PM	2	36	S/H	8:30-10:30 PM	2

Notes: W = Weekdays
Sat. = Saturdays
S/H = Sundays and Holidays

Table 5.3-4

EQUIPMENT OPERATING HOURS PER TIME PERIOD

Season A			Season B		
Time Period ID	Hours Per Day	Hours Per Period	Time Period ID	Hours Per Day	Hours Per Period
1	10	1010	19	10	1390
2	4	404	20	4	556
3	4	404	21	4	556
4	2	202	22	2	278
5	2	202	23	2	278
6	2	202	24	2	278
7	10	210	25	10	280
8	4	84	26	4	112
9	4	84	27	4	112
10	2	42	28	2	56
11	2	42	29	2	56
12	2	42	30	2	56
13	10	240	31	10	320
14	4	96	32	4	128
15	4	96	33	4	128
16	2	48	34	2	64
17	2	48	35	2	64
18	2	48	36	2	64

Total = 8280 hrs/yr

Example Calculation: Time Period 3

$$\frac{\text{Hours}}{\text{Period}} = 4 \left(\frac{\text{Hours}}{\text{Day}} \right) \times 101 \left(\frac{\text{Days}}{\text{Period}} \right) = 404 \left(\frac{\text{Hours}}{\text{Period}} \right)$$

(From Tables 5.3-2 and -3)

Table 5.3-5
PURPA AVOIDED ENERGY COSTS BY TIME PERIOD

Season A			Season B		
Time Period ID	Utility Billing Period	PURPA Avoided Energy Cost (¢/kWh)	Time Period ID	Utility Billing Period	PURPA Avoided Energy Cost (¢/kWh)
1	OP	8.7	19	OP	8.5
2	PP	10.1	20	PP	9.5
3	P	10.5	21	PP	9.5
4	P	10.5	22	P	10.0
5	PP	10.1	23	P	10.0
6	PP	10.1	24	PP	9.5
7	OP	8.7	25	OP	8.5
8	PP	10.1	26	PP	9.5
9	PP	10.1	27	PP	9.5
10	PP	10.1	28	PP	9.5
11	PP	10.1	29	PP	9.5
12	PP	10.1	30	PP	9.5
13	OP	8.7	31	OP	8.5
14	OP	8.7	32	OP	8.5
15	OP	8.7	33	OP	8.5
16	OP	8.7	34	OP	8.5
17	OP	8.7	35	OP	8.5
18	OP	8.7	36	OP	8.5

Note: OP = Off-Peak

P = Peak

PP = Partial Peak

Table 5.3-6

MODIFIED PURPA AVOIDED ENERGY COSTS
Off-Peak Costs Changed to 1.5 ¢/kWh

Season A			Season B		
Time Period ID	Utility Billing Period	PURPA Avoided Energy Cost (¢/kWh)	Time Period ID	Utility Billing Period	PURPA Avoided Energy Cost (¢/kWh)
1	OP	1.5	19	OP	1.5
2	PP	10.1	20	PP	9.5
3	P	10.5	21	PP	9.5
4	P	10.5	22	P	10.0
5	PP	10.1	23	P	10.0
6	PP	10.1	24	PP	9.5
7	OP	1.5	25	OP	1.5
8	PP	10.1	26	PP	9.5
9	PP	10.1	27	PP	9.5
10	PP	10.1	28	PP	9.5
11	PP	10.1	29	PP	9.5
12	PP	10.1	30	PP	9.5
13	OP	1.5	31	OP	1.5
14	OP	1.5	32	OP	1.5
15	OP	1.5	33	OP	1.5
16	OP	1.5	34	OP	1.5
17	OP	1.5	35	OP	1.5
18	OP	1.5	36	OP	1.5

Table 5.3-7

PROCESS ELECTRIC AND HEAT DEMAND PROFILES

<u>Time Period</u>	<u>Electric Demand (% of Avg.)</u>	<u>Heat Demand #1 (% of Avg.)</u>	<u>Heat Demand #2 (% of Avg.)</u>
1	72.7	80	50
2	100.0	100	150
3	100.0	160	150
4	181.8	100	150
5	181.8	100	150
6	72.7	80	50

7-12	}	Same as 1-6 above
13-18		
19-24		
25-30		
31-36		

Industrial Rate Data: Demand and Energy Charges

Industrial rate data are specified by the DEUS program user via the TMDAT(I,8) and TMDAT(I,9) input variables. As described in Section 2, energy charges for energy purchased by the industrial plant owner are specified by the TMDAT(I,8) variable. Energy charges for each of the 36 time periods are specified in much the same way as PURPA avoided energy costs, as described earlier in this section (see Table 5.3-5).

Demand charges are specified by the TMDAT(I,i) input variable. Whereas energy charges are incurred during all 36 time periods, demand charges are not. Typically, demand charges are made during utility peak load periods and, in some cases, during partial-peak periods. For Case G, the following demand charge rates were assumed:

Season A (May 1 - September 30)

On-Peak: \$5.02 per month per kW of maximum demand
Partial-Peak: \$0.58 per month per kW of maximum demand

Season B (October 1 - April 30)

On-Peak: \$3.46 per month per kW of maximum demand
Partial-Peak: \$0.59 per month per kW of maximum demand

Utility rate schedules frequently specify demand charges in \$/kW/month for one or more time periods. In the case above, monthly demand charges were specified for on-peak and partial-peak time periods. Before being input to the DEUS program, monthly demand charges must be distributed over the appropriate time periods. For example, on-peak demand charges for Season A are \$25.1/kW/season (\$5.02/kW month x 5 months = 25.1). Demand charges expressed in \$/kW/season are summarized below. For Case G, demand charges are specified only during Time Periods 2, 4, 20 and 22.

<u>Season A (May 1 - September 30)</u>	<u>Time Period</u>
On-Peak: \$25.1/kW/season	4
Partial-Peak: \$2.9/kW/season	2
<u>Season B (October 1 - April 30)</u>	
On-Peak: \$24.2/kW/season	22
Partial-Peak: \$4.1/kW/season	20

All of the input data required to make the DEUS computer run for Case G are shown in Table 5.3-8. For Case G, PURPA avoided energy costs, TMDAT(I,5), and utility marginal production costs, TMDAT(I,10) are assumed equal. In addition, PURPA avoided capacity costs, TMDAT(I,7), and utility marginal capital costs, TMDAT(I,11), are assumed equal.

Table 5.3-8

PROGRAM INPUT FOR CASE G

```

$INPUT/
INDAT(7)=182,
INDAT(10)=2,
INDAT(15)=160,150,
TMDAT(1,1)=72.727,2*100.,2*181.818,2*72.727,2*100.,2*181.818,2*72.727
TMDAT(14,1)=2*100.,2*181.818,2*72.727,2*100.,2*181.818,2*72.727,2*100
TMDAT(28,1)=2*181.818,2*72.727,2*100.,2*181.818,72.727,
TMDAT(1,2)=80.,100.,160.,2*100.,2*80.,100.,160.,2*100.,2*80.,100.,
TMDAT(15,2)=160.,2*100.,2*80.,100.,160.,2*100.,2*80.,100.,160.,2*100.
TMDAT(30,2)=2*80.,100.,160.,2*100.,80.,
TMDAT(1,3)=50.,4*150.,2*50.,4*150.,2*50.,4*150.,2*50.,4*150.,
TMDAT(24,3)=2*50.,4*150.,2*50.,4*150.,50.,
TMDAT(1,4)=36*3.0,
TMDAT(1,5)=1.5,10.1,2*10.5,2*10.1,1.5,5*10.1,
TMDAT(13,5)=6*1.5,1.5,2*9.5,2*10.0,9.5,
TMDAT(25,5)=1.5,5*9.5,6*1.5,
TMDAT(1,6)=1010.,2*404.,3*202.,210.,2*84.,3*42.,
TMDAT(13,6)=240.,2*96.,3*48.,1390.,2*556.,3*278.,
TMDAT(25,6)=280.,2*112.,3*56.,320.,2*128.,3*64.,
TMDAT(1,7)=2*0.,48.8,17*0.,0.0,34.2,14*0.,
TMDAT(1,8)=6.3,6.5,2*6.8,2*6.5,6.3,5*6.5,
TMDAT(13,8)=7*6.3,6.5,6.5,6.8,6.8,6.5,6.3,5*6.5,6*6.3,
TMDAT(1,9)=0.,2.9,0.,25.1,15*0.,4.1,0.,24.2,14*0.,
TMDAT(1,10)=1.5,10.1,2*10.5,2*10.1,1.5,5*10.1,
TMDAT(13,10)=6*1.5,1.5,2*9.5,2*10.0,9.5,
TMDAT(25,10)=1.5,5*9.5,6*1.5,
TMDAT(1,11)=2*0.,48.8,17*0.,0.0,34.2,14*0.,
ECODAT(1,1)=3*0.,
DIRR=.15,
KSTPR=1,
PCODAT(2,1)=0.,
PCODAT(4,1)=0.,0.,0.,
PCODAT(9,1)=0.,
IPRINT(1)=8*1,
TITLE='DEUS VALIDATION STUDY',
UTITLE='TYPICAL GAS/OIL BURNING UTILITY',
*
```

Section 6

PROGRAM DIAGNOSTICS

The DEUS computer program contains a set of built-in diagnostic warning messages. The warning message informs the user that there is an inconsistency resulting from the input and the general location of the inconsistency or the calculation in which the error resulted. The user has the capability of suppressing the warning messages by inserting a one into GNLDAT(6) (reference Section 2.7, Special Functions). The warning messages that are built into the program are described below.

The system design and performance plus the economic analysis of each of the DEUS systems require many variables to be determined from interpolation of tabular data. The various calculations that require data look-ups are cost, heat to fuel ratios, power to fuel ratios, partload parameters, auxiliary boiler and unit sizing and component efficiencies. If the data is inconsistent the program may encounter conditions in which the independent parameter of interpolation is outside the range of data specified. For example, if the auxiliary boiler required to meet some specified heat demand is larger than the size limits specified in the data, the program will print the following message:

```
ARGUMENT NOT IN THE TABLE  
VALUE >MAXIMUM: RE-EVALUATE PROCESS
```

In the case where the independent parameter is below the minimum value specified in the table, the program will automatically default to the minimum value and then inform the user with the following message:

```
ARGUMENT NOT IN THE TABLE  
VALUE <MINIMUM: (DEFAULT TO MIN. VALUE)
```

(In many cases, the user may desire the program to default to the minimum value. The warning message suppression switch allows the user to eliminate the message printing in these cases.)

The program not only informs the user about the value being interpolated (for whatever the calculation may be) but it also instructs the user as to which interpolation error it is and in what calculation the message occurred. The user must conduct the final diagnostic procedures to determine the cause of the message. The message usually results from inconsistent data. The possible error messages that the user may obtain are: (Note: the numbers indicated are those defined by the DEUS computer program.)

1. AUXILIARY BOILER FUEL FLOW
2. NOCOGEN BOILER COST
3. NOCOGEN PARTLOAD HEAT
4. NOCOGEN PARTLOAD EFFICIENCY
5. THERMAL DESIGN: P/F & H/F RATIOS
6. THERMAL DESIGN: TIC \$
7. MEGAWATT DESIGN: P/F & H/F RATIOS
8. MEGAWATT DESIGN: TIC \$
9. THERMAL DISPATCH: AUXILIARY BOILER
10. PARTLOAD CASE #1
11. PARTLOAD CASE #2
12. PARTLOAD CASE #4
13. PARTLOAD COMPONENT EFFICIENCIES

The program will also indicate to the user the dependent value that the program attempted to interpolate with and the data table in which it was interpolating. The additional message printed by the computer is:

INDEPENDENT VARIABLE = ##

INDEPENDENT
VARIABLE DATA

##

DEPENDENT
VARIABLE DATA

##

The total warning message that the DEUS computer program will print to inform the user is illustrated by the example shown below.

INTERPOLATION ERROR #4
NOCOGEN PARTLOAD EFFICIENCY

ARGUMENT NOT IN TABLE
VALUE > MAXIMUM: RE-EVALUATE PROCESS

INDEPENDENT VARIABLE = 1.12

INDEPENDENT VARIABLE DATA	DEPENDENT VARIABLE DATA
.2	.75
.5	.80
.8	.85
1.0	1.00

The program only informs the user of the possible problem or inconsistent data. It is up to the user to track down the specific cause of the warning message.

The program also has built-in warning messages to inform the user of sizing inconsistencies. In some cases, the size requirement of the DEUS system is larger than the size that can be obtained from the cheapest burnable fuel. The program will then size the remaining requirement (requirement that was not satisfied by the first fuel) utilizing the next, and even the third fuel if necessary to meet the heat requirement. However, it is possible that the third fuel (which does not have a limit) is not burnable by that particular DEUS. In this case the program will go back to the last burnable fuel (next expensive fuel) and remove the limits in order to satisfy the requirement. The program assumes that the user will be able to source the fuel from some location. However, the program is unable to account for the additional cost that may be incurred by having to obtain the fuel from another source. Thus, the program informs the user of the limit removal. The user can then decide if the size required should be decreased, the fuel price increased to reflect additional charges, or whatever the user feels will best represent the system being evaluated. The warning message printed by the computer is

AVAILABLE FUEL EXHAUSTED LIMITS REMOVED

The user may also run into a situation where there is no fuel available to meet the demands. This error indicates an input error somewhere in the costs, efficiencies or fuel data. The SELECTION routine will screen out those DEUS systems that can not burn any of the site fuels, hence the error is due to other inconsistent data (the user is responsible for tracking down these errors). The

program will inform the user by the warning message

ERROR NO AVAILABLE FUELS

Another message associated with the sizing of the DEUS unit can appear as a result of the size requested for the user sized plant. The program has a built-in warning message associated with the option of THERMAL MATCH/POWER MATCH. If the user specified a size requirement that was larger than the DEUS unit can supply, even at full condensing, the program automatically increases the fuel flow (by iteration) until the power requirement is met. The increased fuel flow will also result in excess steam that will not be utilized. The program will inform the user of the addition of heat besides the data associated with the increase. The warning message printed is

```
HEAT ADDED TO MEET POWER REQUIREMENT
HEAT AVAILABLE = ####
POWER AVAILABLE = ####
POWER REQUIRED = ####
HEAT THUS REQUIRED = ####
```

(The program will iterate until the power requirement is satisfied.)

The program also has a check in the economics section to insure the type of depreciation is consistent with the requirements that are associated with depreciation. The first warning message indicates that the user selected a depreciation method that is not defined. The user has three options for depreciation:

1. SUM OF THE YEARS DIGITS METHOD
2. DOUBLE DECLINING BALANCE METHOD
3. STRAIGHT LINE METHOD

If the user inputs a number greater than three for the required tax depreciation method (ECODAT(X,8), where X denotes the ownership option and is 1 to 3), the program will print a warning message. The message printed is:

CHECK CALLS TO DEPRTN - WRONG TYPE SELECTED

The other condition that must be satisfied for the depreciation logic is years the depreciation is desired for. The year must be a sequential value supplied from the calling routine (which is based on the tax life (ECODAT(X,10))). The sequence must start from 0 or 1 and can extend beyond the life. If the user accidentally inputs a negative value for the tax life (ECODAT(X,10)) the program

will print the message

ERROR IN CALL TO DEPRTN, JY < 0

If the program is instructed to calculate the auxiliary power and heat requirements, the type of system and the fuel being burned must be consistent (see Section 2.5). If these are inconsistent with the allowed combinations (which are too numerous to list) the program will print one of the following messages (depending whether the error only effects the auxiliary heat or power calculation or both).

AUXP MUST BE SPECIFIED FOR DEUS
INSUFFICIENT DATA OR INPUT ERROR-AUXH

(AUXP and AUXH denote auxiliary power and heat factors, respectively.)