TECHNICAL AND ECONOMIC EVALUATIONS OF COGENERATION SYSTEMS USING COMPUTER SIMULATIONS

A Thesis

by

STEVEN RUSH FENNELL

Submitted to the Office of Graduate Studies of
Texas A&M University
in partial fulfillment of the requirements for the degree of

MASTER OF SCIENCE

MAY 1993

Major Subject: Mechanical Engineering

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Approved as to style and content by:

Jerald Caton
(Chair of Committee)

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ABSTRACT

Technical and Economic Evaluations of Cogeneration Systems Using Computer Simulations. (May 1993)

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Chair of Advisory Committee: Dr. Jerald Caton

Cogeneration is defined as the simultaneous production of electrical (or mechanical) power and useful recovered thermal energy. Computer simulation of cogeneration is necessary and beneficial because of the large amount of data involved, and the speed at which the computer can calculate hourly and monthly energy usage and generation is advantageous. A type of program that simulates a "first cut" cogeneration system has been completed. This program allows rapid evaluations of several engineering and economic alternatives for different types of cogeneration systems. The programs combine the technical and economic models in a simple and effective interface with the user.

This thesis discusses the attributes of the programs, and their usage at various agencies throughout Texas to test the feasibility of cogeneration at these locations. These sites were chosen not only because of the need for cogeneration, but because they represent sites which are robust enough to effectively test the flexibility of the technical and economic models. The technical evaluation program was written in FORTRAN on an IBM PC compatible computer. The data-entry program was written in BASIC, and the economic evaluation program was written in macro-language for a spreadsheet program.

The results from the tests give a good confidence to the accuracy of the programs' ability to model not only specific pieces of equipment, such as gas turbines, but also the varying electric rate schedules utilized throughout the state. In both the Austin State

Hospital and Southwest Texas State University (SWTSU) studies, the gas turbine modeling was shown to be within good tolerance of accepted models utilized previously. Also for the SWTSU study, the diesel engine modeling matched very closely to the accepted model that had been used for the 1985 study. Some differences occurred in the modeling of the diesel engine's fuel usage for SWTSU compared to the earlier study, due to the method of calculation used by the different modeling programs. However, the current model seems to be more accurate given the flexibility of the model to handle the non-linear part load conditions of diesel engines.

Studies were also conducted for the University of Houston, and Texas A&M University. For the University of Houston, an 8 to 12 megawatt gas turbine utilizing absorption chillers was recommended, with paybacks of less than 6 years, and a net present value of greater than $18 million. These results were obtained using Houston Lighting & Power's gas and electric price increases over the next 25 years, which are more punitive than a constant escalation of 5% per year. For Texas A&M University, several sizes of gas turbines were modeled. However, none seemed feasible for meeting the current electric and steam loads utilizing electrical load following procedures. The best results were with a 21 megawatt gas turbine, with a payback of 7.5 years, and a net present value of $15 million. It was therefore recommended that Texas A&M utilize a third-party contractor and operator to build and maintain a new power plant to meet the electrical and steam needs for the next 20 years, while selling excess power to pay for the power plant.

ACKNOWLEDGMENTS

Financial support of this research from the Governor's Energy Management Center, Texas, is greatly appreciated. I would first like to thank my committee, especially Dr. Jerry Caton, for their support of this research, as well as their undivided attention. I would also like to thank Mr. Al Baxter of the Texas A&M University Utilities for his assistance on details of the TAMU physical plant, as well as Mr. Jerry Smith and Mr. Jeff Bolander of Lockwood Andrews & Newnam for their technical assistance.

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NOMENCLATURE

A = first constant of gas turbine exponential curve fit
B = second constant of gas turbine exponential curve fit
bd = percent blowdown in heat recovery boiler
CF = correction factor for condensing or non-condensing steam turbines
C_p = specific heat of any substance, Btu/lb°R
C_{pair} = specific heat of air, Btu/lb°R
C_{pblr} = specific heat of gas in heat recovery boiler, Btu/lb°R
C_{pcom} = specific heat of gas in combustion chamber, Btu/lb°R
C_{pcpr} = specific heat of gas in compressor section, Btu/lb°R
C_{ptbn} = specific heat of gas in turbine section, Btu/lb°R
dev = % difference in heat transfer of gas and steam sides of heat recovery boiler
E = electrical power, kW
E_a = steam turbine electrical power at idle, kW
E_b = steam turbine electrical power at maximum exhaust and no extraction, kW
E_d = electrical power produced at full load, kW
E_{frc} = electrical power produced at fractional load, kW
E_{lcd} = steam turbine electrical power at power factor of 1.0, kW
E_{min} = steam turbine electrical power at max. extraction and min. exhaust, kW
E_p = electrical power produced at part load, kW
E_u = steam turbine electrical power at any point on performance map, kW
EF = extraction factor for steam turbines
FV_n = future value of present worth or annuity at year "n", $
H = enthalpy, Btu
h_{blr} = enthalpy of steam entering economizer of heat recovery boiler, Btu/lb
h_{evp} = enthalpy of steam entering evaporator of heat recovery boiler, Btu/lb
h_{exh} = enthalpy of steam at turbine exhaust, Btu/lb
h'_{exh} = isentropic enthalpy of steam at turbine exhaust, Btu/lb
h_{ext} = enthalpy of steam at turbine extraction point, Btu/lb
h'_{ext} = isentropic enthalpy of steam at turbine extraction point, Btu/lb
h_{fw} = enthalpy of feedwater to heat recovery boiler for gas turbine, Btu/lb
h_{steam} = enthalpy of steam leaving heat recovery boiler for diesel engine, Btu/lb
h_{stm} = enthalpy of steam leaving heat recovery boiler for gas turbine, Btu/lb
h_{thr} = enthalpy of steam entering the turbine throttle, Btu/lb
h_{water} = enthalpy of feedwater to heat recovery boiler for diesel engine, Btu/lb
i = annual interest or discount rate
m = mass flow of any substance, lb/hr
m_a = mass flow of steam at turbine idle through low-pressure section, lb/hr
m_{air} = mass flow of air through compressor, lb/hr
m_{aird} = mass flow of air through compressor at design conditions, lb/hr

m_b = mass flow of steam at maximum exhaust and no extraction, lb/hr
m_{exh} = mass flow of steam through exhaust section of turbine, lb/hr
m_{exhmax} = maximum steam flow through exhaust section of turbine, lb/hr
m_{exhmin} = minimum steam flow through exhaust section of turbine, lb/hr
m_{exp} = mass flow of steam exported from the plant, lb/hr
m_{ext} = mass flow of steam through extraction port of turbine, lb/hr
m_{extmax} = maximum steam flow through extraction port of turbine, lb/hr
m_{frc} = fractional steam flow, lb/hr
m_{gas} = mass flow of air/fuel mixture through turbine, lb/hr
m_{hfld} = half-load steam flow, lb/hr
m_{plnt} = mass flow of steam for plant use, lb/hr
m_{stm} = mass flow of steam exiting the heat recovery boiler, lb/hr
m_{thr} = mass flow of steam entering the turbine throttle, lb/hr
m_{thrmax} = maximum steam flow through turbine throttle, lb/hr
m_u = mass flow of steam at any point on performance map, lb/hr
m_{xmax} = maximum extraction of steam at power factor of 1.0, lb/hr
m_{xmin} = minimum extraction of steam at power factor of 1.0, lb/hr
p_{amb} = ambient pressure, psig
p_{ambd} = ambient pressure at design conditions, psig
PV = present value of a future value or annuity, $
${}_1Q_2$ = heat transfer from state 1 to state 2, Btu/hr
Q_{blr} = heat transfer of gas or steam side of heat exchanger, Btu/hr
Q_{fd} = fuel rate of gas turbine at design conditions, Btu/hr
Q_{fo} = fuel rate of gas turbine at idle, Btu/hr
Q_{gas} = heat transfer of gas side of heat recovery boiler, Btu/hr
Q_{steam} = heat transfer of steam side of heat recovery boiler for diesel engines, Btu/hr
Q_{stm} = heat transfer of steam side of heat recovery boiler for gas turbines, Btu/hr
S_d = water rate of steam turbine at full load, lb/kWh
S_{frc} = water rate of steam turbine at fractional load, lb/kWh
S_p = water rate of steam turbine at part load, lb/kWh
T = any temperature, R
T_1 = temperature of air at compressor entrance, R
T_2 = temperature of air at combustion chamber entrance, R
T_3 = temperature of air/fuel mixture at turbine entrance, R
t_{amb} = ambient temperature, R
t_{ambd} = ambient temperature at design conditions, R
T_{c1} = inlet temperature of "cold" side of heat recovery boiler, R
T_{c2} = exit temperature of "cold" side of heat recovery boiler, R
T_{evp} = temperature of steam in evaporator, R
T_{exh} = temperature of gas turbine exhaust, R
T_{exhd} = temperature of gas turbine exhaust at design conditions, R
T_{h1} = inlet temperature of "hot" side of heat recovery boiler, R
T_{h2} = exit temperature of "hot" side of heat recovery boiler, R
T_{LM} = log-mean temperature difference, R

T_{pinch} = "pinch-point" temperature of gas exiting evaporator, R
T_{stack} = temperature of gas leaving economizer, R
T_{stm} = temperature of steam leaving evaporator or superheater, R
TSR_1 = theoretical steam rate from throttle to exhaust, Btu/kWh
TSR_2 = theoretical steam rate from throttle to extraction, Btu/kWh
${}_1W_2$ = work from state 1 to state 2, Btu/hr
W_{cd} = work necessary to operate the compressor at design conditions, Btu/hr
W_{td} = work produced by the turbine at design conditions, Btu/hr
ε = effectiveness of the heat recovery boiler
η_{blr} = efficiency of the heat recovery boiler for gas turbines
η_{de} = efficiency of the heat recovery boiler for diesel engines
η_E = full-load non-extraction efficiency of extraction steam turbines
η_{gen} = generator efficiency
η_t = generalized steam turbine efficiency

CHAPTER I
INTRODUCTION

Energy conservation programs have become more prevalent over the last twenty years, largely due to the increase in the price of fossil fuels. In the United States, and in many parts of the world, people have become more conscience of the amount of energy that is being wasted through poor energy management and use of less-efficient systems, which produce and utilize energy for everyday needs. It may be fairly said that energy is the foundation upon which our technological civilization rests. In this age of rising prices and reduced availability of fuel, conservation of resources including efficient management of energy use must be employed for future benefit. One such method of efficient production and utilization of energy is through *cogeneration*.

Cogeneration is defined as the simultaneous or coincident production of useful thermal and electrical (or mechanical) energy. It may take many forms, and is not restricted to just one type of technology or available fuel. Cogeneration is an efficient utilization of resources because it renders a greater portion of the available energy in the fuel usable. A typical system may utilize a prime mover, such as a gas turbine, to generate electricity and use the energy from the turbine exhaust for a thermal need. The thermal requirements are typically in the form of heating, cooling, or drying. Cogeneration is most widely used where both large amounts of electricity and heating/cooling are required. These applications typically include certain manufacturing industries, and large public institutions such as universities. Cogeneration can be used elsewhere, such as laundries, gyms, hotels, or restaurants in smaller packaged systems, but unless the recovered thermal energy is utilized heat recovery is usually not practical or cost efficient.

This thesis follows the format of the ASME Journal of Engineering for Gas Turbines and Power.

Cogeneration is certainly not a new technology. The simultaneous use of generated electricity and thermal energy began in the early days of power production, at the end of the 19th century and beginning in the 20th century. The most common form of cogeneration appeared in two forms, that used by industry for some process need, and those public utility systems that also produced waste heat for district heating.

Two types of cogeneration systems have been defined: the topping and bottoming

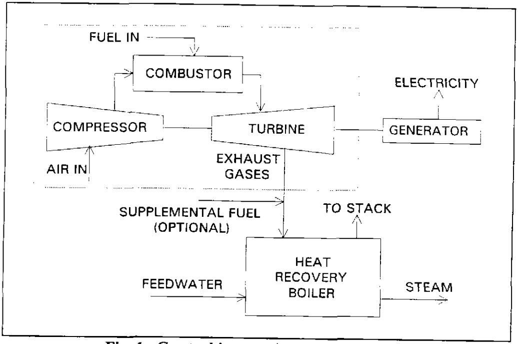

Fig. 1 Gas turbine topping cycle schematic

systems. In a topping cycle, the primary energy source is used to produce useful electrical or mechanical power, while rejected heat from the power production is then used to provide useful thermal energy. Topping systems have the widest application in industrial processes [1]. Figure 1 shows a schematic of a topping gas turbine system which uses a waste heat recovery boiler to produce steam. In a bottoming cycle, the primary energy source is applied to a useful heating process, and the ejected heat from the process is then used for power production. Bottoming systems are of limited application because of higher costs and lower efficiencies [1]. Figure 2 shows a schematic of a bottoming cogeneration cycle.

Combined cycles are a special form of the topping cycle, in that a gas turbine generates electricity, producing steam in a waste heat recovery boiler, and the high pressure steam is then utilized in a steam turbine to produce more power. Combined

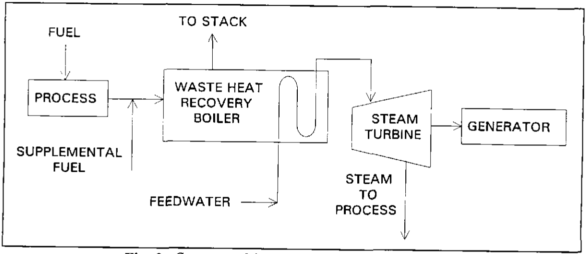

Fig. 2 Steam turbine bottoming cycle schematic

cycles are typically more efficient than their simple cycle counterparts. The intended usage is usually what drives the choice between the two, i.e., if more steam is required of the system, then a simple cycle is used. Likewise, the prime mover can be a diesel engine, which can produce equivalent power, but only approximately half the steam of a gas turbine due to its higher cycle efficiencies. This would not be a good choice when high steam rates are necessary.

The Public Utility Regulatory Policies Act (PURPA) of 1978 has defined the role of cogeneration systems in society, so that independent power producers can coexist with the larger utility companies. The cogenerator, in order to produce and sell power, must be classified as a Qualifying Facility (QF). The minimum efficiency requirement of a QF is 42.5% to 45%, depending on the percentage of thermal energy produced. Since cogeneration can achieve efficiencies of 70% or higher, this is not a difficult requirement to meet. However, not all cogenerators will want or need to sell power. Typically, a company or institution will want a cogeneration system in order to meet certain demands. Some want to provide a *base load* to their facilities. This means that the minimum power required is produced by the cogeneration system, to satisfy all power demands throughout the year. Likewise, the amount of steam produced by a base loaded system is mostly constant, and therefore a use for this steam is necessary in order to become a QF. On the other hand, *peak load* availability is the only requirement to some facilities. In this case, a gas or steam turbine is usually required in order to meet certain peak electrical or steam loads of the system during the year. This results in less efficiency because the system must run at part load, and not at its designed full load capacity.

Calculations involving cogeneration system simulation are tedious at best, because the system output must be found using hundreds of hours of steam and electrical load data. Unless the system will be run continuously at full load, or design conditions, whereby simple calculations performed by hand are only necessary, a computer must be used in order to process the many data points that make up the profile of the simulation. This is also true for systems that might be used in a part load situation, such as peaking systems. In this case, the equipment used to generate steam and electricity do not perform in a linear manner, e.g. fuel used does not vary directly with power output. Therefore, utilizing part load specifications from the manufacturer, the equipment may be simulated during off-design conditions.

For this research, a computer-based engineering and economic evaluation program was developed to allow simulation of cogeneration systems. These programs are not detailed enough for designing purposes, but simply allow a "first-cut" or general evaluation analysis of cogeneration. This type of program is used extensively to test the feasibility of cogeneration, not only for technical reasons, but for economic ones as well. Many people will want to investigate the economical feasibility of cogeneration for their systems before going into a detailed analysis and design of a system, and this program gives a robust engineering analysis of the system along with an economic evaluation in a quick streamlined format. A small amount of preparation by the user is required to run the program. This includes mostly gathering the necessary data, such as hourly electric and steam load profiles, equipment specifications, and economic parameters such as escalation and discount rates, inflation, and capital cost.

The following chapters describe the research in detail. Chapter II discusses previous literature on the subject, including studies performed on various Texas state agencies that used CELCAP as the model for engineering and economic calculations. Chapter III describes the technical, economic, and data-entry programs that are used to perform cogeneration analyses, and the fundamental theory behind the models.

The tests performed on certain Texas state agencies are discussed in Chapter IV, along with the technical and economic results of these tests. Analysis of each test and its results, with tables and graphs to highlight performance, follow. Finally, Chapter V summarizes and concludes the research and its implications on further feasibility studies.

The appendix contains the program listings for all three programs, and selected data and results from the tests performed in Chapter IV.

CHAPTER II

PREVIOUS RESEARCH

General research into computer analysis of cogeneration has been accomplished by several individuals and companies over the past ten to fifteen years. Many programs have been written to analyze cogeneration in general and in detail. Some programs developed have been used to design a *first cut system*. This is a program that can be used to quickly analyze several different combinations and size of systems, especially so that the economics of purchasing the system can be judged. Other programs can design much more detailed systems, including size, configuration, location, and smaller details such as electrical connections and steam piping.

Several programs have been developed in the past which perform cogeneration cycle simulation. They vary widely in application, detail, and robustness. Four general types of program classifications are identified. These are 1) first-cut evaluation models; 2) detailed engineering design; 3) financial evaluations; and 4) forecasting. Not all programs will contain every classification, and those with multiple applications will typically not be as robust as a program that only performs detailed engineering design or only performs financial assessments.

The DEUS model was developed by General Electric Company for the Electric Power Research Institute (EPRI) in 1982 [2]. This is a sophisticated program, in that it includes nine examples of steam and gas turbines, and can perform full and part load operation [3]. The COGEN3 model was developed by Mathtech, Inc. for EPRI in 1983. COGEN3 utilizes optimization routines to obtain cogeneration system designs. Its major flaw is that since cogeneration is so site specific, the program must include all possible combinations of cogeneration systems, which makes the program too complex [2].

Another optimization program that was utilized by the Texas A&M University physical plant is EOP by Sega, Inc. The program is capable of modeling 32 different types of equipment for use in a power plant, and optimizes along either the most efficient or most economical mode [3].

A first-cut analysis program that has been in use at Texas A&M is the Civil Engineering Lab Cogeneration Analysis Program (CELCAP). This was originally developed by Dr. T.Y. Richard Lee at the Naval Civil Engineering Laboratory in 1981. A later version was updated in 1985, although the manual that accompanies the program is somewhat hard to follow [4]. CELCAP allows the user to combine different types of equipment for power generation, and performs the engineering analysis to determine the electricity and steam generated, based on the user inputs of equipment performance, and steam and electrical loads. While this program is flexible in use, it does have its limitations. First, the economic analysis performed is too simple in that it doesn't consider complex utility rate schedules, variable electricity and fuel price escalations throughout the lifetime of the system, or capital costs in order to find such parameters as net-present value, payback, or rate-of-return. The program also does not allow combined cycle operations. Instead, each piece of equipment acts as a stand-alone, and does not affect the performance of the other equipment, which is not a typical situation in power production. Another problem with CELCAP is that entering data can be difficult to the novice user. The program requires the user to know the format of the data used by the program to calculate engineering and economic results. A user-friendly interface to enter and save the data to a file would be an excellent enhancement.

Several studies were performed at Texas A&M by the Energy Systems Lab (formerly the Energy Management Group) utilizing CELCAP as an engineering program to model the engines and boilers associated with cogeneration. These studies were limited to analyzing the feasibility of cogeneration at Texas state public institutions. These included Southwest Texas State University [5], the Austin State Hospital [6,7], Texas Women's University [8], Texas Tech University [9], the University of Houston [10], Prairie View A&M University [11], and Texas A&M University [12].

An explanation of cogeneration engineering and economic analysis using computer programs was done by Propp in 1986 [13]. This study explained some detailed aspects of computer simulation utilizing CELCAP. Specifically, the study described the use of CELCAP for Texas state agencies to determine if cogeneration was feasible or not. Types of equipment models used, data required to run the program, control modes to operate the cogeneration system, and economic factors and assumptions are all explained, as well as a general discussion of cogeneration and its applications.

One study by Muraya [14] looked at the benefits of using cogeneration simulation programs, and some of their drawbacks as well. Specifically, CELCAP was examined to see how it performed when analyzing several test cases of Texas public institutions. Muraya found that although CELCAP performed well under certain conditions, it was liable to give misleading answers unless the user understood well how the program worked to obtain those answers, and could correctly judge the accuracy. Including the restraints listed above for CELCAP, Muraya also suggested modifications in the hourly load profiles, and steam turbine analysis. Some other modifications were made to CELCAP to account for such things as a change in load, so that the user did not have to re-enter several hundred data points; implementation of the Texas holiday schedule to accurately reflect the loads during the holidays and off-days such as weekends; an option to reduce CELCAP's output, which is very lengthy; and use of a separate economic program to analyze the feasibility of cogeneration better than CELCAP. Muraya performed studies using CELCAP on Prairie View A&M University, and the University of Houston at University Park.

Another study by Muraya [15], concluded in 1989, investigated the possibility of cogeneration at the University of Houston using CELCAP. This study recommended that the university hold off for a while because cogeneration was not feasible at the time, with paybacks in the seven to ten year region. This was due to several factors, including low electrical rates and relatively high gas prices. However, a follow-up study in 1992 by Fennell [16] concluded that gas prices had dropped and electrical rates in the Houston Lighting and Power (HL&P) region had risen enough to warrant a further detailed investigation. Paybacks were from five to six years, and depended upon the escalation rates used. HL&P suggested gas and electrical escalation rates for the next 25 years.

Another study done by the Energy Systems Lab at Texas A&M in 1987 analyzed Texas A&M University's physical plant to determine if the cogeneration system presently installed needed to be upgraded [12]. This was supplemented by a second study by Athar [17] that used CELCAP and an optimization code developed by SEGA, Inc., to analyze the Texas A&M physical plant system. These studies were performed because the aging systems used by Texas A&M to generate power will need to be upgraded and retrofitted in the next few years to keep up with demand. Both studies found that a 37.4 MW General Electric Frame 6 gas turbine was needed in order to expand the system to handle 1988 electric and steam loads. Projected loads for 1992 were also studied, and a three to four year payback was found in both studies.

A third study performed on the Texas A&M system was by the consulting firm Lockwood Andrews & Newnam (LAN) in 1989 [18]. This study was mostly devoted to investigating and solving the electrical tie-in problem between the main and west campuses. The study recommended a three-stage design, tying the two campuses together. LAN also investigated the possibility of added more generated power to the main campus power plant. As before, the same 37.4 MW gas turbine was shown to be the optimal engine for the next decade, with a payback of around six years. As of the fall of 1992, the first stage of the electrical tie-in installation was completed. Although the current operation of the plant is not to supply on-site generated power to the west campus from the main campus, this is the intended mode of operation in the future once all stages of the installation are complete. In all cases to date, the studies have consistently used a base case that does not utilize the current electrical tie-in, which improves the viability of added cogeneration due to more incremental purchased electricity without the tie-in.

The objectives of this research are twofold. First, a computer program is needed to operate on an IBM PC compatible computer, allowing the user to model and simulate a cogeneration system for first-cut evaluations. This includes programs that: A) perform a technical analysis of the equipment to be modeled using electric and steam load profiles and manufacturer's engine performance data; B) perform an economic analysis to test for feasibility, utilizing complex electric rate schedules and life-cycle cost analyses; and C) input data for both programs in a user-friendly interface. Second, the programs must be tested on actual sites to check for flaws in the models, as well as analyze the feasibility of new or additional cogeneration systems at the specified sites. The next two chapters describe this process in detail.

CHAPTER III

EXPLANATION OF THE PROGRAM CODE

This chapter explains the three programs developed for cogeneration simulation. Each section will cover the aspects of the engineering, economic, and data-entry programs including a description of the program and any underlying theoretical equations from which the program is derived. The descriptions follow each of the programs' computer code, which is located in Appendix B for reference.

DESCRIPTION OF THE ENGINEERING PROGRAM

The main part of this research was to develop and implement a cogeneration simulation program, written in FORTRAN for the MS-DOS environment. This has been accomplished, and the prototype model is suitably named COGENeration SIMulation, or COGENSIM for short. The program is loosely based upon the CELCAP framework, in which a data file contains the site electrical and thermal load information, ambient and boiler data, along with specific data for the type and number of engines being used. Performance calculations are done to find the full load fuel use, electricity generated, and steam produced, if any. Some aspects of the code, mainly the gas turbine analysis, are similar to the CELCAP code because of its robust design calculations. Part load performance is calculated using three modes: full electrical output, electrical matching, and thermal matching. Under the matching modes, the output of either electricity or steam is matched to the electrical or steam load of the site. This may or may not result in part loading of the engines, which lowers efficiency. Finally, the output is written to two separate data files. The first is the performance numbers, given in hourly data for one year. The second is condensed into monthly totals, for use in the economic spreadsheet to be mentioned in detail later.

The engineering program may be started from the MS-DOS command line, or from the data entry program described later. In either case, the user is first prompted for the data files for the steam and electric loads, as well as the engine data. Note that the fully qualified DOS path should be included, unless the data files are contained within the same directory as the program itself. Next, the output file names are requested. If not given, then no output will be written to a file.

The program now begins to read in data from the files. This includes site information, such as the maximum and minimum monthly temperatures, the ambient pressure, and auxiliary boiler information such as temperature of the boiler feedwater and steam, heating value of the fuel used, and the boiler efficiency. Next, the engine data file is read, which contains the number of engines of each type. These include gas turbines, diesel or internal-combustion engines, automatic extraction steam turbines, and back pressure (non-condensing) steam turbines. For the gas turbine and diesel engine, points describing an exponential curve to determine performance are loaded into a subroutine for calculation of exponential curve functions. Figure 3 shows an example of the exponential relationship between fuel rate and generated electricity for a gas turbine. Note that a finite fuel rate (about 43 MMBtu/hr) is needed for zero kW output (idle).

The steam and electric load profiles are based on two 24 hour profiles for each month that extends for one year of operation. The days are either working (week days) or non-working (week-end) days. Working days are taken from a typical Wednesday of the month, and non-working days from a typical Saturday of the same month. Two profiles are chosen for simplicity, which results in a small amount of data to process. As it is, this gives the user 2 days x 24 hours x 12 months of data, or 576 numbers for the steam load, and 576 numbers for the electrical load. Therefore it is beneficial to be frugal when profiling the site loads. Monthly profiles are then calculated based upon the total for that particular day in the month, times the number of like days per month. For example, if there are 22 working days per month, then simply add up the 24 hours of one day's data,

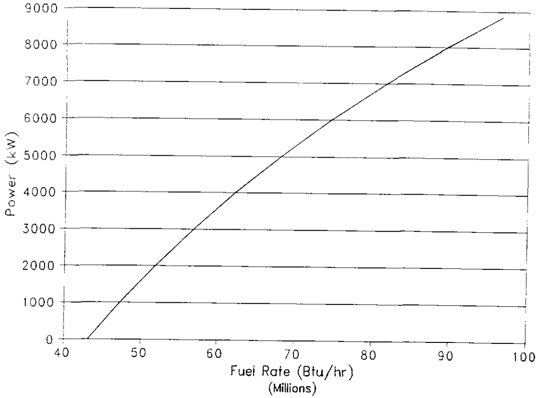

Fig. 3 Power vs. fuel exponential relationship

and multiply by 22. For all purposes, this gives a fairly accurate assessment of actual load profile without having to process 365 days worth of data.

For the combined cycle modes, specific data are referenced that show how each steam turbine, if any, receives steam from a steam producing heat recovery device. A major advantage of this program is that as many steam turbines can be set to one gas turbine as necessary to receive steam. Any additional steam required, which is usually the case, is provided through auxiliary boiler calculations. An array called *stcount* is used to keep track of the number of steam turbines requiring steam from any other heat recovery source. Thus, the program is extremely versatile for many different types of systems.

The next sections describe the specific theory and numerical method used to model a simple cycle gas turbine with waste heat recovery boiler, a diesel engine with waste heat recovery boiler, an automatic extraction steam turbine, and a back-pressure steam turbine. A description of the different modes of operation of cogeneration systems follows.

Gas Turbine

Analysis of the design output of the gas turbines starts by defining some of the operating constants and assumptions. These are the constant pressure specific heats at the five stages of the gas turbine: ambient inlet air, compressor stage, combustion of fuel and air, turbine stage, and finally the waste heat boiler (heat exchanger). For each gas turbine, it is assumed that a waste heat boiler is attached to the turbine exhaust ducting to recover the heat of the gas for steam generation. Common simplifying assumptions utilized for Brayton cycle calculations include adiabatic compression in the compressor, constant pressure heating in the combustion chamber, adiabatic expansion in the turbine section, ideal gas laws for air, and incompressibility of air. These assumptions are usually used in deriving the energy equations of each section of the gas turbine. They are not necessary for this analysis, however, because manufacturer's engine specifications are used which already reflect all efficiencies and losses incurred in the gas turbine.

First, the fuel input at idle conditions is calculated. When the gas turbine is at idle, there is no electricity being generated, but some fuel is consumed. This is found from the exponential curve fit equation calculated previously, which is:

$$Q_{fo} = A \cdot e^{B \cdot E_d} \tag{1}$$

Since E_d is zero, Q_{fo}, the fuel input, is easily defined. The work of the compressor is defined as:

$$W_{cd} = \frac{C_{ptbn}}{C_{pcom}} \cdot Q_{fo} \tag{2}$$

or the ratio of the specific heat of the turbine divided by the specific heat of combustion, multiplied by the idling fuel input [4]. The accompanying analysis is based upon the first law of thermodynamics for steady-state, steady-flow cycles [19]. The quantities of the gas turbine operation must be determined from this equation:

$${}_1Q_2 + {}_1W_2 = H_2 - H_1 \tag{3}$$

which is the energy balance equation for a steady flow process, assuming potential and kinetic energies are negligible. First, since the entrance temperature of the compressor air flow is known, the temperature exiting the compressor is calculated. The work is equal to the change in enthalpy, which is in this case:

$$\Delta\dot{H} = \dot{m} C_p \Delta T \tag{4}$$

Combining eq. (3) and (4), the energy equation reduces to

$$\dot{W}_{cd} = \dot{m} C_{pcpr} (T_2 - T_1) \tag{5}$$

From eq. (5) the compressor exit temperature, T_2, is calculated, which is also the combustion entrance temperature of the air-fuel mixture. This general equation for work will also be used for the turbine section.

In combustion, the overall rate of heat released from a chemical reaction is the heating value of the fuel times the mass flow of the fuel. Heating values have been determined for a range of petroleum, coal, and natural gas fuels. The fueling rate of the gas turbine is given from the manufacturer's specifications for the particular turbine in question. Therefore, all that is needed is the mass flow of the fuel, which is mixed with the air before combustion begins. This is calculated, and added to the given design air flow from the manufacturer.

Next, the temperature exiting the combustion chamber to the turbine is calculated. From the general first law energy equation, this is:

$$\dot{Q}_{fd} = \dot{m} C_{pcom} (T_3 - T_2) \tag{6}$$

From eq. (6), the only unknown is T_3, which is the exit temperature needed. Finally, the work of the turbine is calculated at the design conditions. The turbine shaft work drives the compressor, and turns the generator to produce a magnetic field suitable for electrical generation. Simply put, the work of the turbine is divided amongst these two tasks, and therefore the energy balance is:

$$\dot{W}_{td} = \dot{W}_{cd} + \frac{\dot{E}_{ld}}{\eta_{gen}} \tag{7}$$

where E_{ld} is the design output of the turbine shaft work to the generator which is converted to electrical power, and η_{gen} is the generator efficiency.

At this point, the waste heat boiler calculations are performed, in order to ultimately find the amount of steam produced from the waste exhaust heat of the gas turbine. First, the exhaust temperature must be found. Once again, the first law energy equation will suffice to calculate the temperature:

$$\dot{W}_{td} = \dot{m}\, C_{ptbn}\, (T_3 - T_{exhd}) \tag{8}$$

T_{exhd} is the only unknown, so the temperature is easily calculated. Note that the inlet and exit temperatures have been switched, as compared to previous equations. This is due to sign conventions of work and heat, which are that positive work leaves a system, and positive heat enters a system. Therefore since the work of the expanding gas in the turbine acts on the turbine, causing rotational shaft work which is positive, the work of the gas is negative inside the turbine

The calculation of the pinch point temperature of the heat exchanger is next. Figure 4 shows the entrance and exit temperatures of the heat recovery boiler, where the pinch point is the hot gas exit temperature of the evaporator. Likewise, the gas turbine exhaust is the hot gas entrance temperature. On the steam, or cold side of the heat exchanger, the entrance to the evaporator is T_{evp}, and the exit is the final steam temperature, or T_{stm}. Both of these numbers are constant, and are site dependent. They are constant because typically a constant pressure saturated steam vapor is required in the process. In some cases, the steam may be superheated, but the temperatures are set. To find the pinch point temperature, the only unknown at this point, the effectiveness of the waste heat boiler is usually given by the manufacturer and is used in the calculation. Effectiveness is defined as:

$$\varepsilon = \frac{(T_{h1} - T_{h2})}{(T_{h1} - T_{c1})} = \frac{(T_{exh} - T_{pinch})}{(T_{exh} - T_{evap})} \tag{9}$$

where "h" represents the hot, or gas side, and "c" represents the cold, or steam side. The numbers "1" and "2" represent inlet and exit values, respectively [20]. Thus, the only unknown as before is T_{pinch}, and is calculated from equation (9).

The heat transferred through the waste heat boiler can be calculated on either side of the heat exchanger. In this case, the mass flow rate of the steam is not known, and is sought. Therefore, the calculation takes place on the gas side, in order that the heat transfer may be found. This is simply the first law equation again, assuming no work is

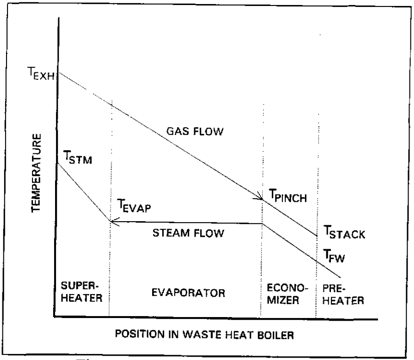

Fig. 4 Waste heat boiler pinch point

performed:

$$\dot{Q}_{blr} = \dot{m}_{gas} C_{pblr} (T_{exh} - T_{pinch}) \tag{10}$$

It is also useful to know the typical overall heat transfer coefficient (UA) of the boiler. This is a representative number used in heat exchanger heat transfer calculations to size the system. The UA number is the heat transfer of the boiler divided by the log-mean temperature difference, which is:

$$T_{LM} = \frac{(T_{exh} - T_{stm}) - (T_{pinch} - T_{evp})}{\ln\left(\dfrac{T_{exh} - T_{stm}}{T_{pinch} - T_{evp}}\right)} \tag{11}$$

The UA of the heat exchanger can be used to calculate the heat transfer area required, and subsequently the number of tubes or passes through the heat exchanger [20].

The steam flow through the cold side of the boiler is calculated from the energy balance on that side. Since Q_{blr} is known, as are the enthalpies of the steam at inlet and exit, the steam flow rate is then:

$$\dot{m}_{stm} = \dot{Q}_{blr} \cdot \frac{\eta_{blr}}{(h_{stm} - h_{evp})} \tag{12}$$

In some cases, the heat exchanger may require some blowdown, in which excess particulates are removed from the water, but also requires water to make-up what is lost in the blowdown. Also, the plant may require steam use of its own to preheat any incoming feedwater to the boiler in the economizer. Therefore, an equation is developed that will calculate the plant usage due to preheating and blowdown. This is

$$\dot{m}_{plnt} = \dot{m}_{stm} \cdot (1+bd) \cdot \frac{(h_{blr} - h_{fw})}{(h_{stm} - h_{fw})} \tag{13}$$

In eq. (13), if blowdown (bd) is zero, then the equation is not affected. If blowdown is greater, such as 5%, then the amount of steam needed by the plant to make it up is increased by 5%. If there is no preheating of the feedwater, the equation becomes zero, because there is no difference between the feedwater and boiler entrance enthalpies. If there were feedwater heating, then the boiler entrance enthalpy would be greater than the feedwater enthalpy by a certain amount given by the user, and therefore would increase the plant steam usage. Finally, the amount of exported steam is the generated steam minus the plant steam. This is the steam exported to any plant process headers, or to the steam turbine headers.

Gas turbine performance is a strong function of the inlet temperature to the compressor. Lower temperatures have the effect of producing more work output, and higher inlet temperatures less work output. Therefore, the ambient temperature of the air will affect turbine performance. Since ambient temperature is not constant during the day, nor during the year as well, a temperature profile is used to vary the performance of the turbine. This is obtained by simulating the rise and fall of air temperature due to the earth alternately being heated and cooled. A sine wave is used with the maximum and minimum temperatures based upon the given values for the particular month. The time for the maximum and minimum temperatures is given as 2 pm and 6 am respectively. Thus, the newly calculated ambient temperature is:

$$T_{amb} = \frac{(T_{max} + T_{min})}{2} + \frac{(T_{max} - T_{min})}{2}(xsin) \qquad (14)$$

where xsin is dependent upon the time of day set for maximum and minimum daily temperatures. This equation is readily observed in the program code in the appendix.

Once the new ambient temperatures are found, the gas turbine parameters are recalculated to show the effect of the new compressor inlet temperature. Only the turbine inlet temperature remains constant to keep the performance of the generator at a maximum during off-design conditions. The work of the compressor is the design work times the ratio of the actual inlet pressure to the ambient pressure. The air flow to the combustion chamber is calculated using the ideal gas law, assuming the volume is constant:

$$\dot{m}_{air} = \dot{m}_{aird} \cdot \frac{p_{amb}}{p_{ambd}} \cdot \frac{t_{ambd}}{t_{amb}} \qquad (15)$$

The compressor exit temperature is calculated as before using first law energy equations. The fueling rate of the gas turbine is also found using first law equations, assuming no work across the combustion chamber. Electricity generated is a function of the fuel rate, as given by the exponential equation calculated previously. Work of the turbine is found next, using the energy balance of work done by the turbine on the generator and compressor. Once again, the exhaust temperature of the turbine is calculated from first law equations.

To find the pinch point temperature, the program must now iterate using a Newton-Raphson iterative technique. The reason for this is that the pinch point cannot be calculated from the effectiveness of the waste heat boiler, because the effectiveness is not constant during off-design performance. However, since all temperatures except the pinch point are known, as well as the UA number of the boiler, T_{pinch} can be found assuming an initial value of T_{pinch} at the design point.

The remaining calculations involve finding the heat transfer of the boiler to find the mass flow rate of steam in the heat exchanger. With this, the plant steam usage can be found as shown previously, and the exported steam the steam header is calculated. Finally, the totals of the exported steam, fuel use, and electricity generated for all gas turbines are computed, and written to an output file.

Diesel Engine

Like the gas turbine, the performance of a diesel engine is largely governed by the performance curves relating fuel rate to exhaust temperature and electricity generated, and are typically exponential in nature. These equations, developed during the loading of the data at the beginning of the program, are used to calculate part load, or off-design performance of the prime mover. For the diesel engine design calculations, it is simply necessary to find the gas flow rate through the combustion cycle, the resulting heat transfer through a heat exchanger, and the export steam generated.

A diesel engine typically produces around half of the steam generated by a comparably sized gas turbine in the waste heat recovery boiler. Therefore, a diesel engine is usually not a good choice when large amounts of unfired steam are required. This is due to not only a higher efficiency of heat to work conversion in the diesel engine, but also because of the gas turbine's significantly higher mass flow of air through the turbine, which results in an higher overall heat transfer coefficient compared to the diesel engine.

The mass flow rate of the gas mixture, like the gas turbine, is simply the fueling rate divided by the heating value of the fuel (typically fuel oil or distillate) plus the design air flow rate. The transfer of heat to the steam is accomplished in reality by exchanging heat with the exhaust gases, which comprise approximately 33% of the total energy output, and also with the jacket water that cools the engine which is around 8-9%. For these calculations, assume that the heat exchanged is:

$$\dot{Q}_{steam} = \dot{m}_{gas} C_{pair} (T_{exh} - T_{stack}) \tag{16}$$

where T_{stack} is the exit gas temperature through the heat exchanger. Likewise, the steam created through heat transfer in the boiler is

$$\dot{m}_{\exp} = \dot{Q}_{steam} \cdot \frac{\eta_{de}}{(h_{steam} - h_{water})} \tag{17}$$

where η_{de} is the efficiency of the waste heat boiler, and the h's are the enthalpies of the steam and feedwater. Finally, the totals of exported steam, electricity generated, and fuel used for each diesel engine are computed.

Automatic Extraction Steam Turbine

The single automatic extraction steam turbine is very useful in situations where one or two different steam pressures are required. This type of steam turbine also gives the ability to control the amount of steam flow, keeping the power output constant, and vice versa. A performance map of the turbine, plotting throttle steam flow versus power output, shows the boundaries of the turbine's ability to perform within the map's range. It is therefore necessary, in order to calculate the performance of the turbine, to simulate the map on the computer.

Figure 5 shows an example of a typical performance map. In the figure, the line shown from point A to point B is the line of no extraction, from zero power, or idle, to maximum power. The parallel lines, which increase with increasing throttle flow, are the lines of constant extraction. Note that typically these lines are not completely linear, but do curve downward as the power drops off. For ease of calculation, however, these lines are assumed linear, which results in only slight discrepancies. The line from C to D is the

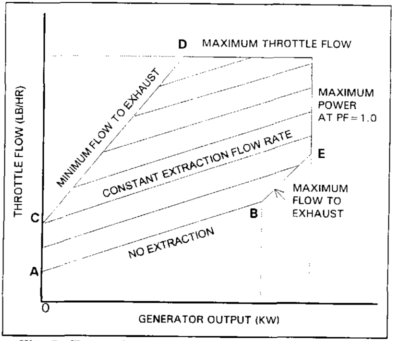

Fig. 5 Extraction steam turbine performance map

line of maximum extraction, also called the line of minimum flow to exhaust. Line B to E is known as the line of maximum flow to exhaust. By finding the slopes of these lines, the performance of the turbine can be calculated [21].

If the first law energy balance equation is applied to the steam turbine, assuming that the turbine is adiabatic, the following equation results:

$$\frac{\dot{E}}{\eta_{gen}} = \dot{m}_{thr}h_{thr} - \dot{m}_{ext}h_{ext} - \dot{m}_{exh}h_{exh} \tag{18}$$

The left side of eq. (18) is the power output to the generator set, divided by the generator efficiency. The single extraction turbine has three ports, the throttle entry steam port, the extraction exit steam port, and the exhaust exit steam port. Each has its own mass flow and enthalpy of steam. However, it can also be said that

$$\dot{m}_{thr} = \dot{m}_{ext} + \dot{m}_{exh} \tag{19}$$

With independent eqs. (18) and (19), or the energy balance and mass balance, it is possible to combine them to form a governing equation of steam turbine performance, and hence an equation that will help in calculating the performance map of the turbine.

If the throttle flow is substituted into the energy balance, the result is:

$$\frac{\dot{E}}{\eta_{gen}} = (\dot{m}_{ext} + \dot{m}_{exh})\cdot h_{thr} - \dot{m}_{ext}h_{ext} - \dot{m}_{exh}h_{exh} \tag{20a}$$

$$\frac{\dot{E}}{\eta_{gen}} = \dot{m}_{exh}\,(h_{thr} - h_{exh}) + \dot{m}_{ext}\,(h_{thr} - h_{ext}) \tag{20b}$$

$$\frac{\dot{E}}{\eta_{gen}} = \eta_t\dot{m}_{exh}\,(h_{thr} - h'_{exh}) + \eta_t\dot{m}_{ext}\,(h_{thr} - h'_{ext}) \tag{20c}$$

where η_t is the efficiency of the turbine. Using this efficiency, it is only necessary to know the isentropic drop in enthalpy from throttle to extraction, and throttle to exhaust. To simplify eq. (20c) more, a definition called the theoretical steam rate is used, which is

$$TSR = (h_1 - h_2')^{-1} \tag{21}$$

Combining eq. (21) into eq. (20c):

$$\frac{\dot{E}}{\eta_E} = \frac{\dot{m}_{exh}}{TSR_1} + \frac{\dot{m}_{ext}}{TSR_2} \tag{22}$$

where η_E is the full-load, non-extraction efficiency, a combination of the generator and turbine efficiency. TSR_1 is the theoretical steam rate from throttle to exhaust, and TSR_2 is the steam rate from throttle to extraction. Equation (22), coupled with its variations, forms the basis for the extraction steam turbine analysis. Some of the variations are given here:

$$\dot{m}_{ext} = \frac{\dot{m}_{thr} - \dfrac{\dot{E}}{\eta_E} \cdot TSR_1}{1 - CF \cdot \dfrac{TSR_1}{TSR_2}} \tag{23a}$$

$$\dot{m}_{ext} = \frac{\dfrac{\dot{E}}{\eta_E} \cdot TSR_1 - \dot{m}_{exh}}{CF \cdot \dfrac{TSR_1}{TSR_2}} \tag{23b}$$

The value CF is an empirical correction factor to correct the theoretical steam ratio for condensing and non-condensing turbines. For a condensing turbine this number is 0.857, and for non-condensing the number is 0.902 [4]. It is basically a compensation for the error introduced by assuming that the constant lines of extraction are linear and spaced evenly apart.

Typically the full-load non-extraction efficiency is given by the manufacturer. Likewise, another important number may be given, called the half-load flow factor. This is simply a number which is multiplied by the maximum exhaust flow, or throttle flow with no extraction. In other words, the flow factor is the percentage of full load mass flow at exactly half-power, assuming a linear relationship between non-extraction throttle flows and power output. In this program, either one or the other factor may be given. If not, the program then calculates an approximate number. This is accomplished by an exponential fit of three numbers, the full-load efficiency, throttle pressure, and power. For the half-load flow factor, just the factor and power output are fit exponentially. The equations are derived from a table of values given in the literature [4]. For simplicity, the equations are in the program so that the user does not have to look up the values. Also, the tables only go up to a certain range of values for power output, thus allowing the user more flexibility in the program. The resulting combination, when calculated, gives the efficiency and half-load factor that is used by the program to plot the performance map of the turbine

It is important to note at this point that, unfortunately, eqs. (22) and (23) can only apply at point B on the extraction map because the full-load non-extraction efficiency given is only applicable there. It is therefore necessary to compensate for this, by substituting an expression for the efficiency. At point B, the maximum exhaust is usually given by the manufacturer's specification. This may also be calculated using the above general equations, because extraction flow is zero. Thus,

$$\dot{m}_{exh} = \dot{m}_b = \dot{m}_{thr} = \frac{\dot{E}}{\eta_E} \cdot TSR_1 \tag{24}$$

Once again, eq. (24) is *only* correct at point B. However, if other points along the no extraction line were to be calculated, assuming that the line is linear, then only the slope needs to be found in order to calculate other exhaust flows and subsequently the electrical power generated. Once the full load non-extraction steam flow is calculated the half-load exhaust flow may be found by multiplying the half-load flow factor, given or calculated previously. With these two numbers, the slope of the line can be found. This slope is then constant for any point along the line; therefore, given either the exhaust flow or electrical output, the other can be calculated.

$$Slope = \frac{\dot{m}_b - \dot{m}_a}{\dot{E}_b - \dot{E}_a} \tag{25}$$

$$Slope = \frac{\dot{m}_b - \dot{m}_a}{\dot{E}_b / 2} \quad \text{if} \quad \dot{E}_a = \tfrac{1}{2}\dot{E}_b \tag{26}$$

The half-load flow is designated $\dot{m}_a$. For the unknown values, the slope is:

$$Slope = \frac{\dot{m}_u - \dot{m}_a}{\dot{E}_u - \dot{E}_a} \tag{27}$$

$$\dot{m}_u = \frac{\dot{E}_u - \frac{1}{2}\dot{E}_b}{\frac{1}{2}\dot{E}_b} \cdot (\dot{m}_b - \dot{m}_a) + \dot{m}_a \tag{28}$$

At the full-load, non-extraction point B, this unknown mass flow reduces to the mass flow at B. Therefore, it is possible to surmise that eq. (28) is equal to the general equation given earlier, or that

$$\dot{m}_u = \dot{m}_b = \frac{\dot{E}_b}{\eta_E} \cdot TSR_1 = \frac{\dot{E}_u}{\eta_u} TSR_1 \tag{29}$$

With this assumption, the efficiency at any point does not need to be found. Instead, since the slope of the line is already known given by the half-load flow factor, the other various forms of the general equation are combined with the eq. (29) as so:

$$\dot{m}_{ext} = \frac{\dot{m}_{thr} - \dfrac{\dot{E}}{\eta_E} TSR_1}{1 - CF \cdot \dfrac{TSR_1}{TSR_2}} \tag{30}$$

becomes

$$\dot{m}_{ext} = \frac{\dot{m}_{thr} - (\dot{E}_u - \frac{1}{2}\dot{E}_b)/\frac{1}{2}\dot{E}_b \cdot (\dot{m}_b - \dot{m}_a) - \dot{m}_a}{EF} \tag{31}$$

where EF is designated the extraction factor, or $1 - CF \cdot \frac{TSR_1}{TSR_2}$. Likewise,

$$\dot{m}_{ext} = \frac{\dfrac{\dot{E}}{\eta_E} \cdot TSR_1 - \dot{m}_{exh}}{CF \cdot \dfrac{TSR_1}{TSR_2}} \tag{32}$$

becomes

$$\dot{m}_{ext} = \frac{(\dot{E}_u - \frac{1}{2}\dot{E}_b)/\frac{1}{2}\dot{E}_b \cdot (\dot{m}_b - \dot{m}_a) + \dot{m}_a - \dot{m}_{exh}}{1 - EF} \tag{33}$$

With the new general equations (31) and (33), any point in the extraction turbine's performance map can be found by manipulating the equation accordingly.

Continuing on with the calculations, the minimum power at maximum extraction is found. This is labeled as point D, which is the junction point on the map between the minimum flow to exhaust line and the maximum throttle line. Using the second equation above, the only unknown is the power E_u. The extraction flow is given in the engine specifications as the maximum extraction at full-load, which is used here. The other flow is the minimum exhaust flow, also given in the engine's specifications. Manipulating the general equation, the minimum power is found:

$$\dot{E}_{min} = \tfrac{1}{2}\dot{E}_b \cdot \left(1 + \frac{\dot{m}_{extmax} \cdot (1 - EF) + \dot{m}_{exhmin} - \dot{m}_a}{\dot{m}_b - \dot{m}_a}\right) \tag{34}$$

Note that in the program listing, $\dot{m}_{exhmax} = \dot{m}_b$, and $\dot{m}_{hfld} = \dot{m}_a$. Next, if the maximum throttle flow rate is not given by the manufacturer, this flow rate may be calculated from one of the equations above as:

$$\dot{m}_{thrmax} = \dot{m}_{exhmax} + \dot{m}_{extmax} \cdot EF \tag{35}$$

Typically, however, most of these numbers are given in the manufacturer's specifications, and need not be calculated.

Finally, the last calculations involve finding the maximum and minimum extraction at a power factor of 1.0. Typically two electrical outputs are given, the first at a power factor of 0.80 (corresponding to point B on the map), and the second at a power factor of 1.0 (point E). Most of the specifications, including the maximum extraction and maximum exhaust, are given at full load power with pf = 0.80. However, notice from the performance map that it is possible to extend the power generated. The full load power can be generated with no extraction. To move into this higher region, some steam must be extracted, thus increasing the total throttle steam flow. The line of constant maximum flow to exhaust governs this behavior from point B to point E. At this point, the most electricity is being generated, and only the steam flow may increase up to the maximum throttle flow. In actual operation in this region, the exhaust nozzles are closed slightly. Likewise on the other side of the map, there is a minimum required exhaust flow, even at zero idling power, in order to keep the low pressure or exhaust section of the turbine cool. To calculate the maximum and minimum extractions at pf = 1.0, simply manipulate the general equations as before:

$$\dot{m}_{xmax} = \frac{\dot{m}_{thrmax} - (\dot{E}_{lcd} - \frac{1}{2}\dot{E}_b)/\frac{1}{2}\dot{E}_b \cdot (\dot{m}_{exhmax} - \dot{m}_{hfld}) - \dot{m}_{hfld}}{EF} \tag{36}$$

$$\dot{m}_{xmin} = \frac{(\dot{E}_{lcd} - \frac{1}{2}\dot{E}_b)/\frac{1}{2}\dot{E}_b \cdot (\dot{m}_{exhmax} - \dot{m}_{hfld}) + \dot{m}_{hfld} - \dot{m}_{exhmax}}{1 - EF} \tag{37}$$

The last calculations involve simply finding the boiler fuel used to create the throttle steam, the power generated, and total the electrical power, fuel use, and steam production of all extraction turbines.

Back-pressure Steam Turbine

The back-pressure, or non-condensing, steam turbine is used widely for cogeneration applications. This type of steam turbine provides small to very large power capacities, and is extremely useful in combined cycle systems. To simulate the performance of the back-pressure steam turbine, it is only necessary to know the relationship between the water rate and the power output. For this program, the full-load power and water rate, and the part load power and water rate must be given. Typically the part load is at 3/4 or 1/2 power. The slope of the linear relationship between the two is defined as

$$Slope = \frac{S_p - S_d}{E_d - E_p} \tag{38}$$

where the subscripts "p" and "d" stand for part and full load, respectively.

The throttle steam flow rate at full load through the steam turbine is simple to calculate. This is the full load power times the full load water rate, as

$$\dot{m}_{thr} = S_d \cdot E_d \tag{39}$$

Note that the term water rate is used, rather than steam rate, to differentiate between the units used. The steam rate has units of [Btu/kWh], whereas the water rate is in [lb/kWh]. The conversion between to the two is the enthalpy of the steam at that particular temperature and pressure.

The rest of the design calculations are simply the boiler fuel used to generate the steam at the turbine header temperature and pressure, the electricity generated which is given in the specifications, and the totals of electrical output, fuel used, and steam exported for all back-pressure turbines combined.

Combined Cycle Mode

As stated previously, an important feature that this program presents is the ability to perform combined cycle calculations on those engines that need them. Typically, combined cycles are gas turbines with heat recovery boilers whose steam production is sent to the header of one or more steam turbines. In the case of the Texas A&M University physical plant, for example, two extraction steam turbines receive 600 psig steam from three boilers plus the heat recovery boiler of the single gas turbine. In the program, three variable arrays are used to specify where the steam is going. The first is *stcount*, which is a count of the number of steam turbines that receive steam from any one engine. The second and third variables are *ref1* and *ref2* which are used solely by the steam turbines. *Ref1* is a number from 1 to 4 from which the steam turbine receives steam, where 1 is a gas turbine, 2 is a diesel engine, 3 is a different extraction turbine, and 4 a different back pressure turbine. Likewise, *ref2* is a number from 1 to 3 which represents the particular engine of that type being used, e.g. gas turbine 1, 2, or 3.

During steam turbine design calculations, a variable called *mcomb* is set to the particular engine which delivers steam to the steam turbine under analysis. Each steam turbine and its boiler produces a certain amount of steam to drive the turbine, and uses a certain amount of fuel. During a combined cycle operation, some of the steam produced will be displaced from the attached steam line. For example, if a steam turbine requires 190,000 lb/hr of steam, and is attached to a gas turbine in combined cycle which produces 66,000 lb/hr from its waste heat boiler, then only 124,000 lb/hr of steam is actually needed to be produced by the auxiliary boiler. Likewise, less fuel is needed in the boiler to make this smaller amount of steam. When the design calculations are finished, the amount of steam in *mcomb* is divided by *stcount*, the number of steam turbines receiving steam from *mcomb*'s source, and added together. Thus, if two extraction turbines utilize the steam from one gas turbine, the total combined cycle steam for the extraction turbines is equal to the amount of steam from the gas turbine, although each only receives half the amount. Similarly, the amount of gas displaced by the steam in combined cycle is calculated, and totaled for each engine.

At the end of all design calculations, the engine totals of steam production, electrical generation, and fuel use are added together to give the system totals. For normal operations this would be the end of the first part of the program. For combined cycle operations, the amount of steam and fuel displaced for both types of steam turbines is subtracted from the system totals. This is done so that the totals reflect actual steam production and fuel use.

It is important to note that each steam turbine has its own variable arrays to keep track of combined cycle steam and fuel. Also, in some cases, the engine delivering steam may produce more steam than the steam turbine receiving the steam actually requires. In this case, subtracting out the combined cycle steam would result in a negative number. Therefore, steps are taken in the program code to see if the totals drop below zero. If so, then the contribution from the steam turbine is considered to be zero, since all its steam needs are being provided by the combined cycle steam. If this were not done, then the totals would actually be reduced, and would not reflect the true conditions.

The modeling of the gas turbine, diesel engine, and extraction and back-pressure turbines are performed using fundamental equations of energy conservation, and numerical methods of computational analysis. The reader is referred to more comprehensive texts on theory of thermodynamic systems to understand more how these devices work, which is out of the scope of this thesis. A description of the typical modes of operation of cogeneration systems follows.

Modes of Operation

For the cogeneration analysis, the next step after the design system calculations is to specify one of three different phases of operation. The first is peak electrical power where the system runs at design capacity with no off-design conditions. The second is electrical matching where the system follows the electrical load of the site by modulating the steam and electrical output of the engines. The third mode is called thermal matching, and like electrical matching, follows the thermal or steam load of the site. This also modulates steam and electrical output of the engines. Typically, thermal matching is not used in actual operation because the varying steam load of a site would cause the engines to part load too much, and lose efficiency in the process. For some sites, the steam load is constant because steam is required in the winter months for heating, and in the summer months for cooling with absorption chillers. In this case, the thermal matching option is available.

Electrical matching is more popular when cogenerators cannot or do not want to sell their excess power. Plus the fact that wasting electrical power is considerably more expensive than steam, because fuel costs to produce energy in the form of steam are typically lower than those to produce electricity. However, to become a cogenerating qualifying facility, neither does a site wish to waste too much steam. Thermal and electrical matching is also helpful when sizing a system, because these modes will tell the user from the output data if the system is losing efficiency by running at low capacity.

Peak Electrical Capacity

This mode is used to simply to add up the design outputs of all engines. For many cases, this is the mode to use because many cogenerators want a system sized below their actual needs. This reduces any steam or electrical waste that may occur from larger systems, or loss of efficiency from part loading of the engines. The program first calculates the amount of fuel necessary to meet the steam load, which is used later as a comparison between using and not using cogeneration. Next, the amount of steam produced is compared to the steam load. If more steam is produced than needed, then it is simply wasted and nothing is done. If less, then an auxiliary boiler must be used to supply the necessary steam, and so therefore more fuel is consumed. The amount of electricity produced is also compared to the electrical load of the site. If generated electricity is more than the load, the difference is the amount that could be sold; if less, it is the amount that needs to be purchased from a utility or other power producer. Finally, the totals for the month are calculated based upon the number of working and non-working days in the month, and output to a data file.

Electrical Matching

Similar to the peak electrical mode, this matching mode first calculates the amount of fuel needed to produce the steam load of the site. Next, the design electrical production of the cogeneration system is compared to the electrical load. If it is less than the load, then the calculations proceed as they did in the peak electrical mode, i.e. comparing the steam needs to steam production. Should the generation of electricity be greater than the electrical needs, then the system must be modulated to reduce its output and match the electrical load.

The analysis from this point proceeds much like the design calculations shown previously for each engine. However, there are some differences, which shall be examined. The program decides at this point whether to part load the gas turbines or not, if any are available. This is an important feature of the program, especially when operating in combined cycle mode with a steam turbine, because a gas turbine's performance drops sharply when its load decreases. If it is possible for the gas turbine to operate at full output, then it will do so to save on efficiency. This is one reason why combined cycles are so attractive, due to the fact that a steam turbine, which has a lower efficiency anyway, can be modulated to meet the peaks and valleys of the electrical load and the gas turbine can then be base loaded. The program tests to see if the total combined output of all gas turbines can meet the electrical load. If so, then the gas turbines run at full load, and the part load factor calculated previously is re-calculated based upon this assumption. Therefore, all other engines will operate at a much more reduced load than before, to save on efficiency.

The order of engines to be analyzed is the same, beginning with the gas turbine. Note that the analysis starts with the prime movers first, then continues on with the steam turbines because this is the optimum way to calculate steam loads for the combined cycle. In any case, the gas turbine part load calculations begin at this point. Simply put, an attempt is made to find the amount of steam generated by the heat exchanger at this reduced load. First, the part load electrical output is found by multiplying the previous design output by the part load factor, which in some cases might be a factor of one (for full load). Assuming that compressor work is a constant, the work output of the turbine is found from first law principles given that no heat is released or absorbed during the process. Using the exponential function relating fuel rate to electrical output, the part load fueling rate is then calculated. Likewise, the turbine entrance temperature, designated T_3, is found using first law equations assuming no work, as well as the exit temperature, T_{exh}, assuming adiabatic expansion in the turbine. The pinch point temperature must be determined by iteration using a Newton-Raphson technique, but a test is made first to see if the exhaust temperature is greater than the required steam temperature of the waste heat boiler. If not, the program indicates a failure and exits. Finally, the heat transfer in the boiler is calculated on the gas side, and used to find the mass flow rate of steam on the steam side. Totals are once again calculated to sum the steam production of all gas turbines.

The diesel engine analysis becomes slightly more complex at this point than it was during design calculations. Like the gas turbine, the performance of a diesel engine is exponential in nature, if electrical output is related to either fueling rate or exhaust temperature. For the gas turbine, only one exponential fit was necessary, although either one could have been used with equal clarity. For the diesel engine, it is simpler to utilize both curve fits to establish the performance of the engine under part load conditions.

First, the part load electrical output is calculated. This is applied to both curve fit equations to give the temperature of the exhaust gas and the fuel use of the engine. Since the stack temperature of the gas remains constant, the gas side heat transfer in the waste heat boiler is found. From this, the steam flow rate in the boiler is calculated, and the steam production of all diesel engines combined are summed.

The extraction steam turbine analysis is handled somewhat differently than other analyses, because the rigidness of its performance map must be met. After computing the part load electrical output, the combined cycle steam is found which has changed due to part loading in either of the prime movers. It should be noted here that the performance map is separated into three distinct regions: output below the minimum power at maximum extraction (point D), output between point D and the maximum output at no extraction (point B), and the higher output regions in the maximum exhaust domain. Because of this, the requirement of the extraction turbine differ depending upon where the electrical load on the turbine is situated. In all cases, the maximum steam extraction should be found first, because of the modulation routines that come later. First, the output is tested to see if it is below the minimum power at point D. If so, then a new extraction steam flow is calculated, assuming that the flow occurs along the line of maximum extraction and minimum flow to exhaust (line CD). From this a new throttle steam flow rate is found. Note that the program still uses the revised general equations for steam extraction turbines discussed previously.

If the output should be in the second region in the middle of the map, then extraction is assumed to be its maximum value given in the performance specifications. A new throttle steam flow rate is calculated based on this assumption. However, should the electrical part load output occur in the upper region above point B, the throttle steam flow rate is assumed to be its maximum design value, and from this the new extraction steam flow is calculated. Once again, the exhaust steam flow rate is minimized in all regions to maximize the extraction steam, which is the exported steam needed for the process. Finally, all totals are calculated, and the combined cycle steam and fuel displacement is found.

The back pressure steam turbine calculations are fairly simple in this mode, unlike the thermal matching mode shown later. In this case, after finding the combined cycle delivered steam flow and the part load electrical output, the part load water rate is calculated from the slope of the linear relationship between water rate and electrical output calculated earlier. Thus,

$$S_{frc} = S_d + (E_d - E_{frc}) \cdot Slope \tag{40}$$

From this, the steam flow rate is simply the new water rate times the part load electrical output.

Due to the extraction steam turbine's nature, if suitable controls are installed on the turbine the steam and electrical output can vary while keeping the other constant. Therefore, it is advantageous to do this simply because it allows the steam turbine control so that resources and energy are not wasted. This is important at sites where not as much steam is required as the steam turbine could output at a certain pressure.

First, the total steam export is compared to the steam load for the site. Should the load be greater, there is no need to try to increase the steam output of the turbine, since the maximum was just previously calculated. If the load is less, then the turbine is modulated to meet the steam load. The difference between the load and output is found, and divided by the number of extraction turbines into equal segments. This is the amount of steam that each turbine should produce less than it did previously. Thus, the amount is applied to the steam output to reduce it equally for each turbine. The analysis is tested to see if the electrical output falls into two areas, above or below the maximum output at no extraction (point B). If below then the throttle steam flow rate is found, constrained to be no less than the line AB, the non-extraction line. If the output is above point B, then at this point extraction is inevitable because the maximum exhaust flow point has been reached. Therefore, the minimum extraction is found. If the new extraction calculated before falls below the minimum, then the minimum is used. Then the throttle steam flow is found, which is simply the maximum exhaust flow plus the new extraction flow.

The new system totals are then recalculated to reflect this drop in steam production, and the program proceeds to find the auxiliary boiler fuel, if any, and the monthly totals and outputs the information to the data files.

Thermal Matching

This mode is much like its counterpart in that the steam load is tested against the steam output of the system to see if the system needs to be reduced in output to match the steam load. This situation is usually unrealistic, because most cogenerators are more willing to save electrical energy rather than thermal energy to save costs since electricity is much more valuable. However, the PURPA requirements must still be met in order for the cogenerator to be a qualifying facility, so that steam cannot be wasted. Rather than match the thermal requirements to the load, many designers simply size the system so that little or no steam is wasted, which may include installing devices which utilize the process steam more effectively.

The program begins by testing to see if the steam load is greater than the design output capacity of the system. If so, then no part loading is necessary, and the program continues on to find the electrical output difference and so forth. If not, then the engines must be modulated to reduce their steam output. As will be shown, this is a more difficult problem than matching electrical load due to some complex calculations involved with the gas turbine analysis.

First, the part load factor is used in order than the gas turbines will not be part loaded if they can meet the steam load, as shown previously. The fractional steam export of the waste heat boiler is calculated, given the constraints on plant steam use and blowdown. Also, the heat transfer of the boiler is found from calculations on the steam side. At this point it is advantageous to see if the gas turbine can provide the minimum steam requirements at idling conditions. The idle fuel rate is found, along with the turbine entrance temperature, turbine work, and exhaust temperature which is compared to the required steam exit temperature of the boiler. If it is less, then a Newton-Raphson iteration procedure is called in order to find the minimum electrical generation, and hence steam output and fuel use, to keep the exhaust temperature above the required steam temperature. Otherwise, the pinch point temperature is found through the iteration procedure as before. The heat transfer on the gas side of the heat exchanger is found, and if it is greater than the steam side heat transfer, the system is assumed capable of meeting part load steam output at idle conditions.

Should this not be the case, then the actual electrical generation needs to be found. This is somewhat more difficult because electrical output cannot be calculated directly, but must instead be found iteratively. First, all the previous quantities are found including fuel rate, temperatures, and turbine work. Likewise, the exhaust steam is once again compared to the steam exit temperature, and the electrical output is increased to facilitate the higher exhaust temperature that must exist for the heat exchanger to work properly. In either case, once all quantities are found, the gas side heat transfer is calculated and compared to the steam side heat transfer found earlier. The fractional deviation between the two,

$$dev = (Q_{stm} - Q_{gas})/Q_{gas} \tag{41}$$

is tested to see if it falls below 1%, i.e. that the two heat transfer values are within one percent of each other. If not, the electrical output is recalculated by,

$$E_{frc} = E_{frc} \cdot (1 + dev) \tag{42}$$

If *dev* is positive then Q_{stm} is greater than Q_{gas}. Therefore, the electrical generation should increase in order to increase the gas side heat transfer. Otherwise, electrical output should decrease and the previous equation facilitates this. The iteration proceeds until the correct value of E_{frc} is found to match the heat transfer in the waste heat boiler.

The diesel engine analysis follows the gas turbine analysis in much the same manner. The steam side requirements of the heat exchanger are found based on the fractional steam export, and the electrical generation needed to match the gas side heat transfer is iterated. If the exhaust temperature of the gas is found to be less than the required stack temperature, the minimum electrical output to meet the stack temperature is found, and the calculation stops.

For the extraction steam turbine, the fractional steam output is calculated, and tested to see if it falls below the minimum extraction. If so, a new electrical output is found along with a corresponding throttle steam flow. If not, the electrical output is assumed to be maximum, which will later be modulated in the automatic control process. Finally, the throttle flow is found for the new electric output and steam extraction.

The needs of the back pressure turbine are such that the electrical output must be found from a quadratic equation relating steam output to the water rate and electrical generation. This equation is found from the expressions for water rate and steam generation,

$$\dot{m}_{frc} = S_{frc} \cdot E_{frc} \tag{43}$$

$$S_{frc} = S_d + (E_d - E_{frc}) \cdot Slope \tag{44}$$

Therefore, the fractional power generated must be,

$$Slope \cdot E_{frc}^2 - (S_d + Slope \cdot E_d) \cdot E_{frc} + \dot{m}_{frc} = 0 \tag{45}$$

which can be solved using the quadratic equation. There are two possible answers to the electrical output, of which only one is necessary. Each answer is tested under the constraints of the system, i.e. maximum and minimum power available to be generated, and one is selected that meets this criteria.

Finally, the automatic extraction steam turbines are modulated to meet the electrical load. This is done in a similar manner to the electrical match mode. The difference between the greater generated power and the lesser required power is found, and divided by the number of steam turbines into equal parts. Each part is subtracted from the previously calculated electrical output to reduce the engines by an amount equal to the electrical load of the system. Two constraints guide this analysis, however. The first is the minimum possible power generated given the amount of extracted steam, which is already set. Either the newly calculated power must not fall below this minimum, or it must not fall below zero power, whichever is higher. From this point, the new throttle steam is calculated to reflect the change in output, and the system totals are recalculated as well to include the change in output and the combined cycle steam, if any is present.

This concludes the description of the engineering technical analysis program, and the modes of operation used in cogeneration system simulation. An explanation of the economic spreadsheet macro follows:

DESCRIPTION OF THE ECONOMIC PROGRAM

The feasibility of a cogeneration project is governed not only by the technical design, but also by the economics of the project. As such, it is necessary in any study of cogeneration feasibility to include an economic analysis of the technical parameters. The second part of the computer simulation is to take as input the information given by the engineering program to see if the project is economically viable. Such inputs are given in monthly totals for one year, and include the steam and electric loads of the site, the generated electrical output and steam production of the system, any excess steam produced and electricity purchased from the utility (i.e., output lacking from the system to meet the load), and the gas consumption of the prime movers and boilers. These inputs can be used to find the costs associated with their use, and the total cost of the system operation is derived from this data.

Two approaches for the economic calculation can be pursued to find the total cost of the system. One approach is to use a compiled program that can calculate the necessary monthly and yearly figures, much like the technical program. The second approach is the use of a commercial program known as a spreadsheet. Both have their advantages; however, the spreadsheet is by far the most flexible of the two, and was elected to use for this analysis. A spreadsheet is a program in which the user can enter either data or formulas into rows and columns of "cells". These cells are referenced by absolute or relative coordinates, where typically the columns are letters and the rows are numbers. Data can be entered and manipulated in each of these cells, as well as formulas that use this data.

A spreadsheet is chosen to perform the economic calculations because of the ease of use and manipulation of the data. A "macro" language is used to load data, enter inputs, and load other spreadsheet templates for use in the calculation. Therefore, the calculation is handled almost automatically, much like any other computer program. It should be noted here that the spreadsheet used was Quattro Pro (version 2.0) by Borland International. A spreadsheet allows not only ease of printing the data, but also graphing capabilities to show certain trends in the data. Also, the spreadsheet allows flexibility for the many different electric utility rate schedules that exist, which are far more difficult to code in a program. The problems associated with the spreadsheet are that (1) the user must have the program available, and (2) the user must know certain basic functions to use the program. These requirements are not difficult to overcome, but are a setback compared to using a compiled program that can be run on any personal computer. The benefits far outweigh the disadvantages, because most computer users have and can run a spreadsheet program. Calculation is also made simpler with the macro language, because the process is practically automated, except for the required prompted user inputs. A description of the macro language program follows, with remarks about the calculation of economic parameters and the rate schedules used.

The macro begins by prompting the user for information regarding the economic parameters. These include: the gas cost and electrical cost escalation rates, the operation and maintenance cost per kWh, the inflation and discount rates, the starting year and project life, the current year's gas price per thousand cubic feet (MCF), the standby charge (if any), the conversion rate between million Btu and MCF, the capital cost of the project, and electrical rate schedule. An explanation of each follows. The escalations rates are the percentage increase per year of their respective costs. It is typical to include some increase in cost due to rising costs in other areas that affect gas and electrical production. The operation and maintenance cost is the average cost per kWh to operate and maintain the generating equipment, and is generally less than one cent per kWh. Inflation and discount rates are economic parameters outside the realm of the project, and are affected by the macroeconomics of the country. The starting year and project life are determined as the beginning of full load operation of the plant and its "life" of operation. This life is typically over ten years. Current gas price is wellhead price plus the transportation cost of the fuel used in the current year. Standby charge is the rate set by the electric utility for electricity sold to the site as standby, or backup power per year. The conversion number is 1030 Btu per standard cubic foot of natural gas, but can vary and is determined from the gas utility bills. Finally, the capital cost is the total current cost of the project.

Once these values are entered, the macro continues by asking the user for the path and file name of the data file generated by the engineering program. This file is a standard monthly output described earlier, which the macro can read into the spreadsheet and use in economic calculations. After entering the appropriate file name, the rest of the process is automatic. The macro enters the data file into the spreadsheet, and sums the data to create a one year total. Next, the appropriate rate schedule template specified earlier is loaded into the worksheet (the current working spreadsheet shown on the screen). This rate schedule template contains all the labels and formulas necessary to calculate the yearly cost of electrical production with and without cogeneration, and the savings that result from utilizing a cogeneration system. The macro takes monthly and yearly values retrieved previously, and puts them into the appropriate spaces in the rate schedule so that the figures are calculated correctly. A note should be made here about the demand portion of the rate schedule. Demand charges are usually based upon the peak 15 minute demand of the month in question. When using the utility data in a two day per month profile as this analysis does, sometimes the peaks are not always represented in the data. The spreadsheet calculates demand from the total kWh for the month, divided by the number of hours per month and a nominal power factor if applicable. However, this demand number may not match the peak demand given in the data. Therefore, whichever number is higher should be used, and is up to the discretion of the user to determine which is applicable.

Also contained in the template is a separate template for calculating the life cycle cost analysis. This is the cost of operating the system beginning at the specified starting year and ending at the life of the cogeneration system. Life cycle cost analysis is a comparison between the costs associated without a cogeneration system, and those with cogeneration, including electrical, standby, operation and maintenance, and gas costs. The resulting savings from the cogeneration utilization are tabulated year by year. From this information, certain necessary economic indicators are found that tell the user whether the system configuration is feasible or not. The first is the net-present value (NPV). This is the present value of the savings created each year by using the system over the life of the project, minus the capital cost. NPV is calculated from the general formula:

$$PV = FV_1 \cdot (1+i)^{-1} + FV_2 \cdot (1+i)^{-2} + \ldots + FV_n \cdot (1+i)^{-n} \tag{46}$$

where FV_n is the value of the savings each year, i is the interest or discount rate, and n is the number of years of the project life. Note that payment of the resulting savings is assumed to paid at the end of the year, not the beginning. The capital cost is then subtracted from the present value to give the net-present value. Typically, the NPV should be greater than zero for feasibility. The second indicator is the rate-of-return (ROR) of the project. This is also calculated over the life of the project, and is the interest rate "i" given above if the present value of the project is considered to be zero. Most institutions set a minimum attractive rate-of-return (MARR), and therefore the ROR calculated should be higher than the MARR. In some cases there may be two or more ROR's if there are sign changes in the savings per year. However for most cogeneration studies, this usually does not happen unless the system has not been sized correctly. Finally, the simple payback is the third indicator used to judge the feasibility of the project. This is the time it takes to pay back the capital cost of the system using the accumulated yearly savings. For many state agencies, this should be less than or equal to around six years for a project of 20 years or more life. This number should be used with caution, however, for two reasons. First, payback does not take into account the time value of money (interest), and second, it does not consider the savings accrued after the payback year. Therefore, simple payback can sometimes conflict with the other indicators.

The real value of using the spreadsheet to accomplish these calculations is that once performed, the values entered by the user or other values in the spreadsheet may be altered by the user to fit special needs. Thus, only one study can be run, and several options calculated just by changing certain values such as gas escalation, gas price, or standby charges. Of course, each system alternative must be calculated at least once. But the ease of the spreadsheet allows simple manipulation of the data to give several options to examine. Another advantage is that data elements, such as those entered by the user, are named with easy to remember alphabetic characters instead of cell coordinates. Thus the user can easily read the formulas contained within the spreadsheet to understand their purpose.

DESCRIPTION OF THE DATA ENTRY PROGRAM

To supplement the engineering program, it is necessary to create the data files that the program uses for its calculations. This is accomplished with a third program that allows the user to enter engine and load data with a simple menu-driven interface. This program allows not only ease of use in handling the data, but also constructs the data files in an orderly manner, which is much more difficult if done by hand. The program provides a structured environment for a user to begin their cogeneration analysis. The program is also capable of launching the engineering program from its menu so that immediate results may be obtained by the user with the newly entered data.

The program provides four options to the user: create or edit an engine data file, create or edit a loads data file, run a simulation, or exit the program. For the first two options, a prompt requests the path and file name of the file to be edited. If the file does not exist, it is created and new data may be entered. If the file does exist, then the program allows the user to edit the previously created data.

The engine file data, if any, is read into memory and the subsequent number of each type of engine is displayed on the screen. The user is given the option to edit one of the engine's data file, save the file, or return to the top level menu. If an engine selection is made, the user is then prompted whether they wish to edit or delete a specific engine. Only existing engines may be deleted, although new engines may be created by selection of the appropriate number. A maximum of three of each type of engine has been chosen as the optimum for the set of programs. If the edit function is selected, the editing screen is then displayed. The user may move the solid cursor up and down the choices given on the screen, which represent the values necessary to successfully operate the engineering program. Also, the specific engine number is displayed at the bottom of the screen along with the engine type. Typing the escape key return the user to the sub-menu seen previously, at which time the file may be saved, or more editing may be performed.

Likewise, the site load and ambient information may be entered into a separate file. Once the file has been selected, the user is present with several menu choices. These are editing the average monthly temperatures, the ambient and auxiliary boiler constants, electric and steam loads, saving the file, and returning to the top-level menu. Each selection operates in a similar manner, in that the specific information is displayed along with its current value, which may be zero for a new data file. Typing "Enter" will keep the current value, or a new value may be entered. The program returns to the sub-menu when all data has been entered or paged through. The exception to this is when editing steam and electric loads. Because the total number of values is extensive and paging through all the data would take time, the user may type "quit" at any point to return to the sub menu. This method of data entry is the simplest to accomplish with the number of data points required. Alternatively, the user may wish to edit their own steam and electric loads from other computer data. These may be incorporated along with the other information by combining the files together. Care must be taken to insure the format of the data is the same as if it were entered from the keyboard. The option to enter the data manually is provided because most steam and electric site load data is usually on paper and not on easily accessed computer files. Although this method is tedious, it is the simplest to implement.

A simulation can be run from the top-level menu if the user desires to do so. This simply exits the data entry program and runs the engineering program, which operates in the same manner described earlier. Once run, however, the program is not called back and must be re-run from the MS-DOS prompt. A separate program from the engineering code is used for two important reasons. First, the data-entry requires a more complex input interface than what FORTRAN can provide, and is therefore written in BASIC which is much simpler to use and has more powerful screen functions. The second reason is that a combination program might be too unwieldy to compile because of certain maximum limits placed on code segments in the computer architecture and the operating system. Therefore, a separate program was developed, which does not take away from the compactness of the code.

CHAPTER IV

FEASIBILITY STUDIES USING THE COMPUTER PROGRAMS

During the course of the development of the programs, studies were conducted to test the program for flaws relating to the analysis of the four different types of engines. Most studies had been previously completed using CELCAP in the past few years, and as such the output of the new program was tested against that of CELCAP's to check for flaws. Four such original studies were redone not only to test the program, but also to study the feasibility of applying cogeneration to the site of study. The first two were performed simply to test the model against the findings of these studies. These sites included the Austin State Hospital in Austin, Texas [6,7], and Southwest Texas State University (SWTSU) in San Marcos [5]. Both studies included findings from utilizing simple cycle gas turbines, and the SWTSU study also included an analysis of using diesel engines for cogeneration. The two other sites were studied to test the program and also to find the feasibility of cogeneration at these sites. One site was the University of Houston, located in Houston, Texas, which has no cogeneration at this time. The other site was Texas A&M University in College Station, Texas, which has an aging cogeneration system to produce electricity and steam. Each site differed from the other in electrical and steam requirements, size of the load, existing equipment, and the electrical rate schedule used by their respective utilities.

AUSTIN STATE HOSPITAL

Several past studies have been completed to determine the feasibility of cogeneration at the Austin State Hospital. The final recommendation was made in 1990 to install a one megawatt simple cycle gas turbine with a waste heat steam generator on the premises. The installation was completed in the beginning of 1992 and is now cogenerating steam and electricity for the hospital.

To test the program model written for this research, the previous studies were redone using the original data and parameters. Since there were several studies performed over the years, the final study is used as the basis for testing, which was done by Muraya [7] in late 1990 using CELCAP. The steam and electrical hourly load data was reformatted for use by the new program, and included data for the auxiliary boilers. The gas turbine data was also formatted into a separate file, unlike CELCAP which uses only one file for all data. After running the engineering program to get the monthly data, the economic spreadsheet program was utilized. Several assumptions were made from the original data. These included the demand cost of $11.52/kW•mo in the winter and $11.85/kW•mo in the summer, energy cost of $0.01/kWh and fuel cost of $0.0165/kWh, standby charge of $2.52/kW•mo, gas cost of $2.33/MMBtu, electrical and gas price escalation of 5% per year, and operation and maintenance cost of the gas turbine at $4/MWh, of the auxiliary boiler at $1.1/klb-steam, and of the heat recovery boiler at $1.00/klb-steam. The capital cost was assumed to be $1.92 million.

After calculating the electrical cost, gas cost, and cost of O&M for the first year with and without cogeneration, the lifetime costs over twenty years were approximated using the given price escalations, including inflation at 2% per year. Using a discount rate of 8% per year, the net present value of the installation was approximately $2.8 million. The simple payback was 8.4 years, with a first savings of $185,000. The previous study mentioned calculated a simple payback of 8.6 years and a net present value of $2.7 million, with a first year savings of $197,000. This is a 2% difference in the simple payback and in the net present value, which is well within tolerable limits. Therefore, the gas turbine model used in the new engineering program, as well as the economic analysis program, have successfully repeated the previous figures from the Austin State Hospital study.

SOUTHWEST TEXAS STATE UNIVERSITY

Southwest Texas State currently operates a cogeneration facility on site, which utilizes a 6 megawatt diesel engine to generate electrical power and produce steam in a waste heat boiler. The original study was performed by Energy Management Group at Texas A&M University in 1985 [5]. This study recommended a 4.5 megawatt simple cycle gas turbine as the prime mover for cogeneration, but alternatively studied several diesel engine sizes as well. Both types of systems were tested with the new engineering program model to check for any errors in the gas turbine and diesel engine analyses.

To test the program models written for this research, the previous study was redone using the original data and parameters that were used in the CELCAP model. In the diesel engine case, much of the data was not available in the original report, unlike the gas turbine case. Therefore, a case study using assumed data values was run using a diesel engine model on CELCAP. These same values were used for the new program's inputs, for consistency. The unknowns included the stack gas temperature, the full load fuel consumption, the full load exhaust temperature, and the design intake air flow. Steam temperatures and enthalpies were assumed to be the same as in the gas turbine case, as were boiler efficiencies.

The steam and electrical hourly load data was reformatted for use by the new program, and included data for the auxiliary boilers. The gas turbine and diesel engine data were also formatted into separate files, unlike CELCAP which uses only one file for all data. After running the engineering program to get the monthly data, the economic spreadsheet program was utilized. Several assumptions were made from the original data.

These included the average energy cost of \$0.0467/kWh, gas cost of \$4.25/MMBtu, and electrical and gas price escalation of 4% and 2% per year, respectively. Operation and maintenance costs of the gas turbine, diesel engine, auxiliary boiler steam, and heat recovery steam were \$4/MWh, \$13/MWh, \$1.1/klb-steam, and \$1.00/klb-steam, respectively. The capital cost was assumed to be \$3.6 million for both the 4500 kW gas turbine, and \$4.8 million for the 6000 kW diesel engine.

After calculating the electrical cost, gas cost, and cost of O&M for the first year with and without cogeneration, the lifetime costs over twenty years were approximated using the given price escalations, including inflation at 5% per year. First, the findings for the gas turbine were tested. Using a discount rate of 8% per year, the net present value of the installation was approximately \$8.97 million, with a simple payback of 4.0 years and savings of slightly more than \$825,000 the first year. This matches very closely with the study, which reported a net present value of \$9.0 million, a simple payback of 4.3 years, and savings of about \$820,000 the first year. Like the Austin State Hospital study, the gas turbine model is very close to the results previous obtained with CELCAP, although the payback calculated was slightly higher given the fact that more was saved the first year. However, because of slight differences in escalation over the twenty year period, this is not a serious difference between the models. Therefore, the gas turbine model is accurate within the tolerances obtained from these tests.

For the diesel engine test, the same discount rate of 8% was used to calculate the NPV. After running the engineering program model and obtaining the monthly values of fuel used, electricity generated and so forth, a net present value of \$1.44 million was found, with a simple payback of 10.4 years and a first year savings of \$221,000. The results given in the study indicate that a 6 MW diesel engine would have an NPV of \$4 million and a payback of 10.8 years. However, since assumptions were used to calculate the new model, a comparison was run with the same assumptions on CELCAP. In this case, NPV was $727,200, payback was 11.4 years, and first year savings were $158,800. When examining the calculations, the only major differences between the two studies are in the amount of fuel used by the diesel engine and the auxiliary boiler. For the new program's model, the total fuel was 1,050,000 MMBtu/yr; likewise, for the CELCAP model, the total fuel was 1,065,000 MMBtu/yr. The incremental difference in fuel cost, at $4.25/MMBtu, is approximately $63,000/yr. If this value is added to the CELCAP first year savings of $158,000/yr, the total is $221,000/yr, which is the value given by the new program's model. Although there is a discrepancy between the two models in the amount of fuel utilized, which makes the new model less conservative than the CELCAP model, the difference is not great and is within acceptable tolerances.

UNIVERSITY OF HOUSTON

Description of the Campus Facilities

The University of Houston currently operates three steam boilers. The first, installed in 1956, has a capacity of 27,500 lb/hr. The second and third boilers, installed in 1986, have capacities of 66,000 lb/hr. This gives a total capacity of 159,500 lb/hr and a firm capacity of 93,500 lb/hr. Total installed capacity of chilled water is 17,000 tons, with a firm capacity of 12,500 tons. Although the current systems are adequate for the present loads, the 1991 load data received from the university indicates that the firm capacities of boilers, chillers, and pumps has been reached during the last year at peak times. The University is currently planning on expansion projects which will increase the electrical, steam, and cooling loads of the campus over the next five years. The study attempted to estimate the effect of new construction on the current loads, which includes an analysis of new chilled water equipment. This necessitates a review of the purchase of new equipment, which is why the cogeneration study was so timely.

Steam is provided to the campus at 235 psig saturated from natural gas-fired boilers. Electricity is provided completely by Houston Lighting and Power (HL&P) at 13.8 kV under the State Owned Educational Institution (SEI) rate schedule (a combination of the LOS-A and LGS rate schedules). The University used approximately 460,000 MMBtu/year of natural gas, and 160,000 MWh/year of electricity in 1991, based on the steam data provided by the University and electrical usage data provided by HL&P.

Method of Analysis

Using the cogeneration simulation program described above, and using the 1991 steam and electrical load information, a feasibility study was performed. Once the program calculates the monthly values of electric and steam generated and fuel used by both the engines and the auxiliary boilers, an economic analysis is performed. This was done using a commercial spreadsheet program described earlier. First, two rate calculations are required: one for the electric loads with no cogeneration system, and one with loads that include a cogeneration system. The total yearly bill for each is calculated, and a subsequent savings is derived based on the amount of electricity the cogeneration system displaces. Once this is known, a life cycle analysis is performed, using the electricity savings, boiler fuel cost savings, and the cost of using a cogeneration system. The total savings that results on a yearly basis is related to the payback for using cogeneration. Thus, the capital cost is paid back when the total savings becomes greater than the capital used to build the system. Escalation of the electrical and gas rates define the increasing costs per year, and are based on best guess assumptions. Fuel escalations are typically determined by gas companies and the Public Utility Commission (PUC) of

Texas, whereas electric rate increases are determined by the utility companies and the PUC.

The HL&P electricity bill for the University of Houston was recalculated using the provided electric data, and agreed with the actual bill within 3%. This was done to see if the steam and electric profiles closely matched the actual loads. The differences are derived from the fact the university changed rate schedules on May 16, 1991, and that the Power Cost Recovery Factor changed three times in the past year. Also, fuel refunds were credited to the university twice last year. In spite of these difficulties, good agreement was demonstrated.

Assumptions

Several assumptions were made in order to calculate the technical and economic data. First, the systems used in the analysis are based on actual equipment specifications. For the gas turbines, design load information such as power generated, fuel flow rates, air flow rates, and inlet air temperatures and pressures are utilized. Average maximum and minimum ambient temperatures are also required, because they can affect the efficiency of a gas turbine. Data on the heat recovery steam generators, which are basically heat exchangers that transfer heat from the exhaust gas of the turbine to make steam, and the auxiliary boilers include the boiler efficiencies, required temperatures and pressures, and the subsequent enthalpies of the steam.

Second, electrical and steam loads are given in two monthly profiles: one that represents the working or weekdays of the month, and one that represents the non-working or weekend days of the month. From this information, the actual loads over an entire year can be closely matched.

Finally, economic assumptions are made to judge whether the system will be feasible or not. These include the current price of gas (\$2.00/MMBtu), the energy per volume of gas (1.05 MMBtu/MCF), operation and maintenance of the plant (\$4/MWh), installed cost of the system (\$1200/kW for a gas turbine generator, not including buildings), and the base, fuel charge, natural gas, and standby escalations over the next twenty years of life for the plant. A first cost of \$100,000 for the buildings to house the equipment was also included in all cases. The escalations used were based in part on data provided by HL&P that described each of these escalations for the next twenty-five years. A recent contract between Entex and the University assumes that the transportation costs of natural gas will remain constant at \$0.35/MMBtu (including tax) until the year 2001. Therefore, only the estimated cost of the gas (ship-channel price) without shipping is escalated every year. Inflation was assumed to be 5% per year, and was applied only to the operation and maintenance costs. Discount rates for all cases was assumed to be 7%.

Results and Discussions

Five simple cycle gas turbine systems were studied: a 6.4, an 8.8, a 12.5, a 17.6, and a 21.4 MW system. Each includes a base case study using current loads, and two chiller studies using different configurations for the increased future cooling loads (approximately 1500 tons). The first uses an electric chiller at 1.3 kW/ton or 2050 kW extra load, and the second a double-effect absorption chiller at 10 lbs. steam/ton and 0.4 kW/ton, or 15,000 lbs. steam/hour and 630 kW extra load. Capital costs using the electric chiller increased by \$300/ton, whereas for the absorption chiller the increase was \$400/ton. Also, a \$20,000 per year operation and maintenance of the absorption chiller was included [22]. The base case is included to show the effect on the economics, but since the campus loads will be increasing due to new construction, the cases with the new chillers are more relevant.

Figure 6 shows the electrical loads of the University for one year. The gas turbine provides a fairly constant base load over the entire year. Figure 7 shows the steam loads

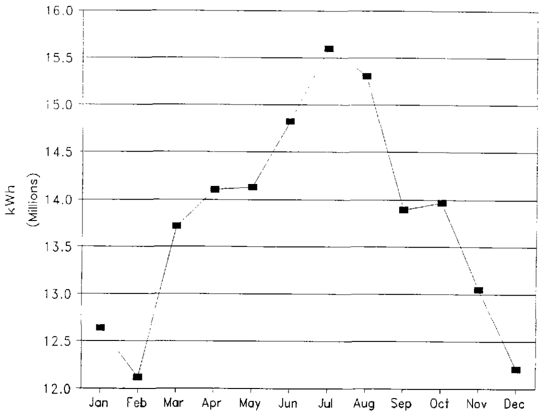

Fig. 6 University of Houston electrical loads for 1991-92

over the same period of time. Electricity savings that result from utilizing a cogeneration system over a twenty year period are based on the difference between electrical costs with and without cogeneration. The increased cost of natural gas over the same period of time is based on the fact that more gas is required to utilize a cogeneration system with a gas turbine than a conventional boiler system.

The preliminary economic results are shown in Tables 1-3. These tables show how the system size affects the net-present value (NPV) and simple payback (note that

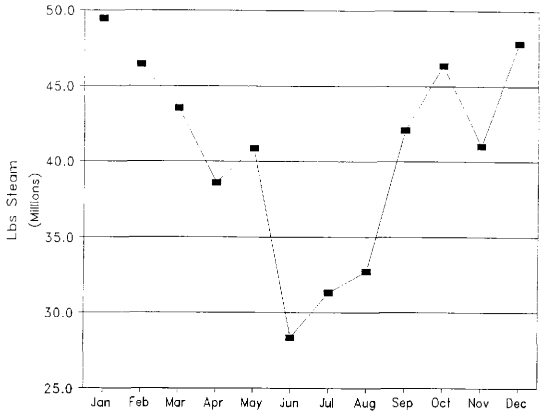

Fig. 7 University of Houston steam loads for 1991-92

size is in MW, NPV is in millions of dollars, and payback is in years). Three alternatives are considered: only the gas turbine, the gas turbine with an electrical chiller, or with an absorption chiller. Net-present value and simple payback for the two escalation schemes are shown, with the base case being the HL&P projected escalations. The NPV (less plant cost) and simple payback versus system size are plotted in Figures 8 and 9. For each plot, there is a peak in NPV based on system size, and the payback increases as size increases. Using the HL&P projected escalations, the optimal size for the cogeneration system is in the range of eight to twelve megawatts. This is due to the highest NPV with the lowest payback period. Because smaller systems have a higher installed cost per generated kilowatt and provide less displaced electricity and steam, they are not as economically attractive. Likewise, larger systems provide too much electricity and steam and must be run at part load, which decreases the efficiency of the system and increases the cost of operation. Therefore an optimal system is reached in which the capital cost is not too prohibitive, and the system runs at or near full load. Note that the HL&P escalation study is much more conservative than the 5% escalation study. If HL&P's projections are considered, and if a six year economic limit on the time to payback the system is set, then the best case is an 8 to 12 MW gas turbine, with a 1500 ton absorption chiller.

The only sensitivity analysis performed on the study at this time is the differences between escalation rates, using a constant 5% per year increase on all electrical and gas prices, and using HL&P's suggested escalation rates. It is felt that this is sufficient for the scope of this study, since other factors are not subject to much fluctuation. An example of this is the stand-by electrical rates from HL&P. According to the Public Utility Commission of Texas, no stand-by rate increase is expected for HL&P for several years, and no electrical rate increase will occur for the next few years as well.

Table 1 Simple cycle gas turbine option

Size (kW)	NPV (millions) 5% escalation	NPV (millions) HL&P escalation	Payback (years) 5% escalation	Payback (years) HL&P escalation
6,400	16.7	10.5	4.60	5.45
8,840	22.6	14.0	4.65	5.53
12,500	29.1	14.9	4.93	6.09
17,600	34.2	12.7	5.46	7.07
21,400	33.8	9.1	6.05	8.06

Table 2 Gas turbine with electric chiller option

Size (kW)	NPV (millions) 5% escalation	NPV (millions) HL&P escalation	Payback (years) 5% escalation	Payback (years) HL&P escalation
6,400	16.2	9.9	4.86	5.75
8,840	22.0	13.4	4.85	5.74
12,500	28.4	14.3	5.11	6.28
17,600	35.0	13.0	5.46	7.06
21,400	37.1	9.6	5.85	7.89

Table 3 Gas turbine with absorption chiller option

Size (kW)	NPV (millions) 5% escalation	NPV (millions) HL&P escalation	Payback (years) 5% escalation	Payback (years) HL&P escalation
6,400	15.2	9.6	5.08	5.95
8,840	21.4	13.6	4.96	5.81
12,500	30.6	18.7	4.89	5.78
17,600	37.5	18.9	5.26	6.46
21,400	40.1	16.2	5.61	7.14

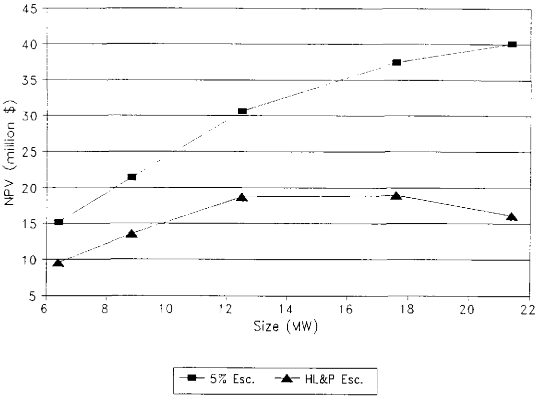

Fig. 8 NPV vs. system size for University of Houston

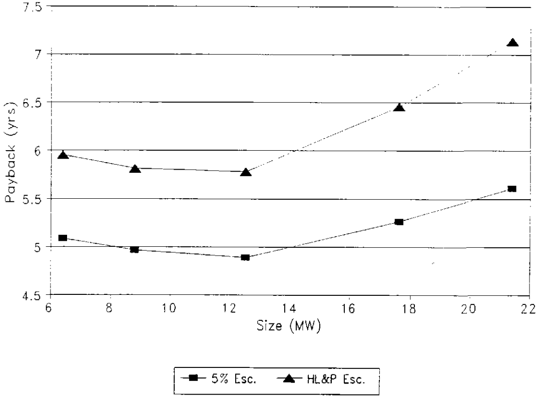

Fig. 9 Payback vs. system size for University of Houston

Summary and Conclusions of the University of Houston Study

A preliminary study was performed for the University of Houston to see if a cogeneration system could feasibly be installed in the next few years due to increasing electrical, steam, and cooling loads. A first-cut engineering assessment was done, analyzing five different sizes of gas turbines using a customized cogeneration simulation program. Next, an economic feasibility study was performed on a spreadsheet to compare the different alternatives based on net-present value, simple payback, and rate-of-return calculations.

Installing a cogeneration system on the campus to accommodate increased future loads is favorable, due to the low cost of natural gas, low present interest rates, and high electrical costs. A simple cycle gas turbine in the range of eight to twelve megawatts with a 1500 ton absorption chiller to handle future cooling loads is the recommended system for this site. The NPV utilizing HL&P forecasts is 18.7 million dollars (less plant cost), and the payback is approximately 5.8 years. Further detailed studies are required to size the system more accurately.

TEXAS A&M UNIVERSITY

Description of the Campus Facilities

Texas A&M University currently operates a cogeneration system in a combined cycle mode on its main campus. Its physical plant utilizes a 15 MW gas turbine with a supplementary fired waste heat boiler (no. 10) that supplies steam at 600 psig, and two automatic extraction steam turbines at 12.5 MW and 5 MW capacity to give a nominal 32 MW of generating capacity. Three gas-fired boilers are also available to produce steam at 600 psig and 750°F. All the steam at the 150 and 20 psig steam headers are supplied by extracting steam from the 600 psig header. The physical plant is currently under-capacity to generate all the electrical requirements of the main and west campuses, and must purchase power from Brazos Electric Power Cooperative. Figure 10 shows the electric loads for the campus over a twelve month period in 1991-92. Figure 11 shows a similar plot for the steam loads for the campus over the same period of time.

Two changes have recently come about that makes this study different from all previous studies. First, electrical an tie-in from the main campus to the west campus was installed in the summer and fall of 1992, so that the generating equipment can provide electrical power at the supply voltage of the west campus [18]. Previously, on-site generated power could only be supplied to the main campus because of the supply voltage differences between the main and west campuses. However, this is not the mode of

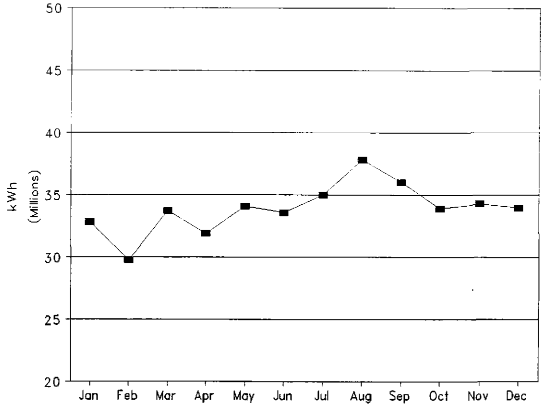

Fig. 10 Texas A&M electric loads for 1991-92

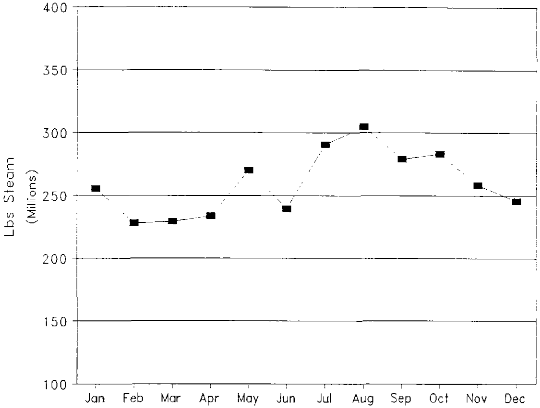

Fig. 11 Texas A&M steam loads for 1991-92

operation at the moment, since some of the equipment needs further testing and installation. Second, a new 4 MW back pressure steam turbine is being installed at the main campus physical plant to provide 150 psig steam to the four newly installed double-effect absorption chillers. This turbine replaces the older pressure-reducing valve which extracted steam from the 600 psig header, and can generate a nominal 3.3 MW of electrical power.

Method of Analysis

Using the cogeneration simulation program described above, and using the 1991-92 steam and electrical load information, a feasibility study was performed. Once the program calculates the monthly values of electric and steam generated and fuel used by the gas turbine and the auxiliary boilers, an economic analysis is performed. This was done using a commercial spreadsheet program described earlier. First, two rate calculations are required: one for the electric loads for the existing cogeneration system, and one with loads that include newly installed equipment. The total yearly bill for each is calculated, and a subsequent savings is derived based on the amount of electricity the new equipment displaces. Once this is known, a life cycle analysis is performed, using the electricity savings, boiler fuel cost savings, and the cost of using a newly installed system. The total savings that results on a yearly basis is the payback for using cogeneration. Thus, the capital cost is paid back when the total savings becomes greater than the capital used to build the system. Escalation of the electrical and gas rates define the increasing costs per year, and are based on best guess assumptions. Fuel escalations are typically determined by gas companies and the Public Utility Commission (PUC) of Texas, whereas electric rate increases are determined by the utility companies and the PUC.

The first study was performed to see if the programs could accurately calculate the electrical utility bill. Using bill data provided by the university physical plant, the yearly electrical cost was calculated from the electrical profiles and equipment specifications. The calculated bill was about 6% higher than the actual bill for the same period of time, which is in fairly good agreement. The study was performed such that the generators supplied electricity to only the main campus, since the electrical tie-ins have just recently been installed and no data is yet available. However, the base case for which all alternatives are compared against has the generators supplying electricity to both main and west campuses. This case also includes the new 4 MW steam turbine, whereas the bill calculation study does not for comparative purposes.

Note that, unlike the University of Houston study, this study compares the existing base cogeneration system with adding new equipment, and does not include a "no cogeneration" case since a cogeneration system already exists on campus.

Assumptions

Several assumptions were made in order to calculate the technical and economic data. First, the systems used in the analysis are based on actual equipment specifications. For the gas turbines, design load information such as power generated, fuel flow rates, air flow rates, and inlet air temperatures and pressures are utilized. Average maximum and minimum ambient temperatures are also required, because they can affect the efficiency of a gas turbine. Data on the heat recovery steam generators, which are basically heat exchangers that transfer heat from the exhaust gas of the turbine to make steam, and the auxiliary boilers include the boiler efficiencies, required temperatures and pressures, and the subsequent enthalpies of the steam.

Second, electrical and steam loads are given in two monthly profiles: one that represents the working or weekdays of the month, and one that represents the non-working or weekend days of the month. From this information, the actual loads over an entire year can be closely matched.

Finally, economic assumptions are made to judge whether the system will be feasible or not. These include the current price of gas ($1.75/MMBtu), the energy per volume of gas (1.061 MMBtu/MCF), operation and maintenance of the gas turbines ($4/MWh) and steam turbines ($2/MWh), installed cost of a gas turbine (varies between $1200/kW and $950/kW), installed cost for extraction steam turbines ($400/kW), natural gas price escalation (4%), and electrical rate schedule escalation (4%). The escalations used were based in part on historical data provided by the physical plant. Inflation was assumed to be 4% per year, and was applied only to the operation and maintenance costs. Discount rates for all cases was assumed to be 7%. The university currently purchases natural gas on the spot market, meaning that the price fluctuates every month. However, transportation of the fuel supplied by Loan Star Gas remains constant at 15.5 cents per MMBtu.

Results and Discussion

Several combinations of systems and alternatives were analyzed. New gas turbine installations ranging from 9 to 47 MW, and steam turbines from 5 to 25 MW were considered. The capital costs of the various sizes of turbines ranged from $950/kW to $1200/kW. The model for this escalation in price per unit of power with reduction in size is given by Payne [23]. In all cases, the system was matched to the electrical load since no excess power was expected to be sold. Two base cases were established to test the system. The first base case (new) included the current system plus the new 4 MW steam turbine. This case also includes the electrical tie-in between campuses, so that electricity generated on the main campus is delivered to the west campus. The second base case (old) is similar to the first, except that the tie-in is not included. This is the current operation of the plant, until all connections are completed and functional between the two campuses.

First, several cases were run with just one or two new gas turbines installed. For all, the new gas turbines were run at full load if possible, and the older gas turbine and steam turbines were used as peaking units to meet the load if necessary. Figures 12 and 13 shows the change in NPV and payback according to size, respectively. Second, more alternatives were tried using new gas turbines but removing the older gas turbine, because of its age and extremely inefficient waste heat boiler. Figures 14 and 15 shows how size affects NPV and payback for this scenario. These figures also show the difference between the new and old base cases. In all instances, the older base case scenarios have a higher NPV and lower payback than the new base case scenarios. This is due to the fact that less electricity is purchased for the west campus in the new base case, and subsequently less electrical power is displaced when a new gas turbine is installed for cogeneration. Finally, the best of both gas turbine scenarios were run including a new non-condensing steam turbine that extracted steam at 150 psig [24]. Utilizing a new steam turbine was deemed unnecessary, since it provided electricity at part load, requiring more fuel use for less electrical power generated. Also, the steam turbine increased the total capital cost of the system, which lowered the NPV and raised the payback.

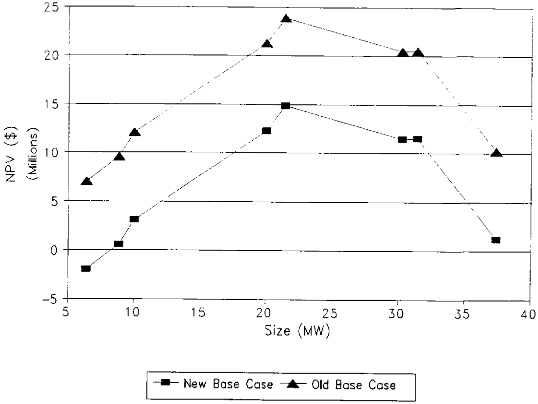

Fig. 12 NPV vs. system size for Texas A&M

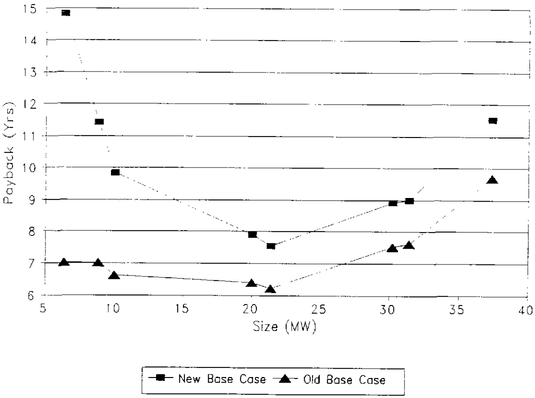

Fig. 13 Payback vs. system size for Texas A&M

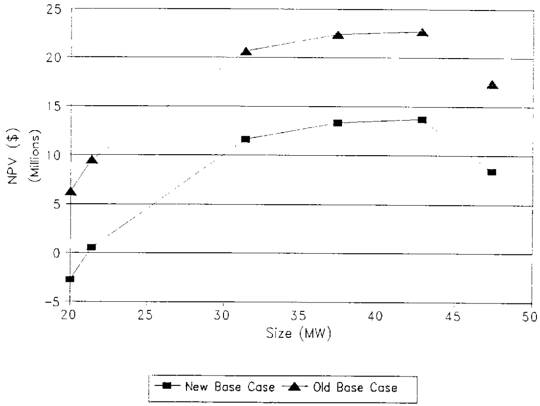

Fig. 14 NPV vs. system size without older gas turbine

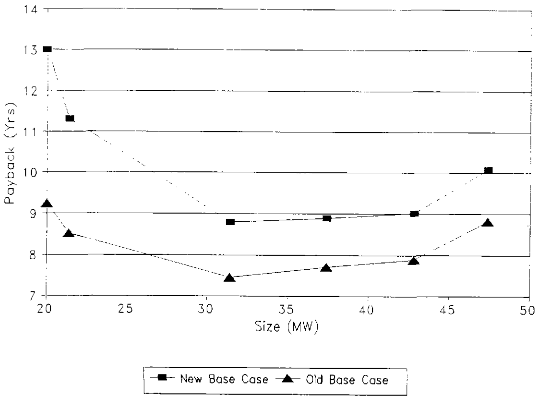

Fig. 15 Payback vs. system size without older gas turbine

For the first scenario utilizing the older gas turbine as a peaking unit, the best alternative was installing a 21 MW gas turbine. Using the new base case, this resulted in a net present value (NPV) of $14.9 million (less equipment cost) and a simple payback of

Table 4 New gas turbine options with older 15 MW gas turbine

Size (kW)	NPV (millions) New base case	NPV (millions) Old base case	Payback (years) New base case	Payback (years) Old base case
6,400	-2.0	7.0	14.84	7.04
8,840	0.6	9.6	11.43	7.02
10,000	3.1	12.1	9.84	6.63
20,000	12.3	21.3	7.90	6.39
21,400	14.9	23.9	7.54	6.23
30,240	11.5	20.5	8.93	7.53
31,400	11.5	20.5	9.00	7.62
37,400	1.2	10.2	11.53	9.69

Table 5 Gas turbine options without older 15 MW gas turbine

Size (kW)	NPV (millions) New base case	NPV (millions) Old base case	Payback (years) New base case	Payback (years) Old base case
20,000	-2.7	6.3	13.00	9.25
21,400	0.5	9.5	11.31	8.52
31,400	11.7	20.7	8.79	7.45
37,400	13.4	22.4	8.89	7.71
42,800	13.7	22.8	9.01	7.88
47,400	8.4	17.4	10.09	8.83

7.5 years. Using the old base case, the NPV was $23.9 million, and payback was 6.2 years. For the second scenario using the new base case, the best alternative was a 42.8 MW gas turbine, which resulted in a NPV of $13.7 million and a payback of 9.0 years.

Using the old base case, the NPV was $22.8 million and payback was 7.9 years. Tables 4 and 5 show how size affects the NPV and simple payback for both scenarios and both base cases. Adding a new steam turbine for either of these scenarios only increased the capital cost, resulting in higher paybacks and lower NPVs. The yearly electrical rate

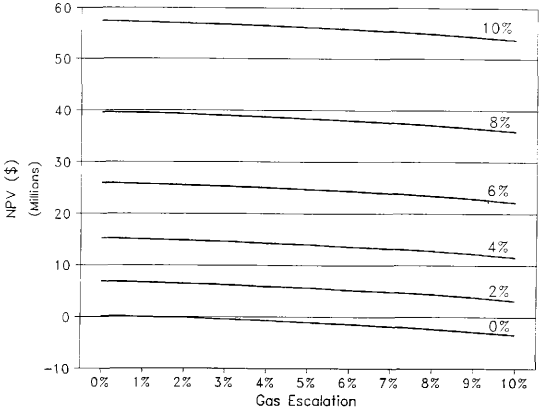

Fig. 16 NPV vs. gas price escalation with lines of constant electrical price escalation

calculations, as well as life cycle costs, can be found in the appendix for both cases and both scenarios.

Figure 16 shows the sensitivity of each case with respect to the gas and electricity price escalations. For both cases, an increase in the price escalation of electricity resulted in a substantially greater NPV. Because the 42.8 MW case uses less gas by not utilizing the older, less efficient gas turbine than the base case, gas price escalation increases the NPV slightly. However, for the 21 MW case which uses slightly more gas than the base case, the NPV drops as gas price increases. Figure 17 shows the sensitivity of NPV with respect to the percent change in operations and maintenance, as well as capital cost. Both are shown to fluctuate at ±20%. From the graph, it is easy to see that, although changes in O&M significantly change the NPV somewhat, the change in capital cost has more of an affect that does the O&M. This is due in part because NPV is figured directly from the present year value of the cogeneration system, which is the total capital cost.

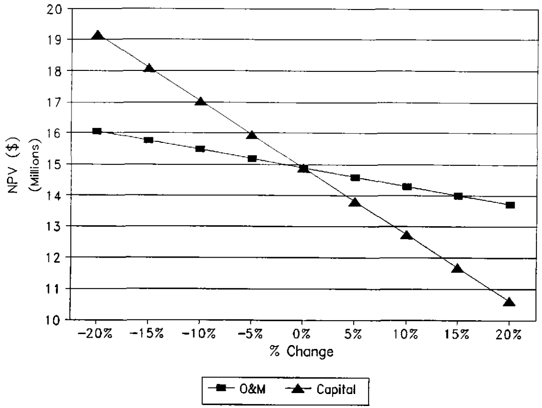

Fig. 17 NPV vs. % change in O&M and Capital expenses

Summary and Conclusions of the Texas A&M University Study

It is obvious from the results of this study that adding new generating equipment to the current system in order to meet the electrical load is not economically acceptable, unless the old base case is used for comparison. For smaller systems, the capital cost combined with low electrical rates makes this size unattractive, whereas for larger systems the capital cost plus under-utilization of the new equipment to meet the load also makes this size unfeasible. Gas turbine generating capacity around 42.8 MW (either with or without the older gas turbine) with the steam turbines used as peaking units is the best case, but is not truly feasible at a minimum payback of 8 years.

Since the University has plans for expansion in the next two decades, it is more likely that equipment should be purchased that can meet the load for the next several years. However, it should not be run at part load to match the electrical load, but should instead be run at or near full load, with the excess electrical power generated sold back to a utility. This produces better efficiency of the equipment, and revenue from the sale of excess electricity to be used to pay for the system. Two alternatives are open to the University: financing the project themselves, or utilizing a third-party to finance, build, and operate the plant, selling electricity and steam back to the university and the utility. An analysis of this is beyond the scope of this study which was directed at validating the simulation program.

Previous studies, mentioned earlier, which ran simulations of cogeneration systems for the University physical plant differ somewhat from this study. In most cases, the older studies did not take into account the new back-pressure steam turbine, which is a recent project. Also, this study used the electrical tie-in to the west campus as one of its base cases, such that less electrical power is purchased from the utility resulting is less displaced electricity. Previous studies used the older system of generating power only for the main campus as their base case, making the addition of new generating equipment more feasible. As shown in the tables and figures, using the older base case increases the NPV significantly by several million dollars, and reduces the simple payback by more than a year. This makes larger systems more economically attractive. Also, capital costs for new equipment, especially gas turbines, have increased significantly since these studies were performed, resulting in poorer economic results. Whereas the addition of a new 37.4 MW GE Frame 6 gas turbine was feasible in the studies mentioned, today the cost and amount of displaced electricity makes this option unfeasible in the short term. Increasing electrical loads might improve the study somewhat, however, since the most significant savings and costs are accrued in the first three to five years, the load will not have increased enough to make a difference.

CHAPTER V
SUMMARY AND CONCLUSIONS

The objective of this research has been obtained. Creation of a program to rapidly analyze the technical and economic feasibility of cogeneration systems was written, and tested using several scenarios from Texas public institutions. The engineering models used by the program are adequate enough for this "first cut" analysis, which is not a level of detailed design, but instead a simple way to judge several alternatives given the equipment manufacturer's specifications. The economic analysis is enhanced through the use of templates which allow accurate modeling of the specific electrical rate structure used at the site being analyzed. Finally, data entry is much more user friendly with a new interface which allows a user to easily input equipment and load data.

The programs were tested against previous studies of Texas public institutions, and performed very well. The results obtained using CELCAP were repeated, and were within tolerable limits, therefore showing the validity of the technical and economic models used in the programs. Also, the programs were used to assess the feasibility of new or additional cogeneration at the University of Houston, and Texas A&M University. For the University of Houston, cogeneration seems to be viable with paybacks under 6 years, using escalation rates obtained from Houston Lighting & Power, and utilizing new absorption chillers to enhance the usage of recovered thermal energy. For Texas A&M University, additional cogeneration does not seem to be viable unless the present campus electrical interconnection is fully functional. However, with increasing campus loads, plus new absorption chillers being installed at a new steam pressure header, additional cogeneration might be feasible under a selling contract or third-party alternative.

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APPENDIX A - RESULTS AND DATA

AUSTIN STATE HOSPITAL - 1 MW GAS TURBINE
LIFE-CYCLE ANALYSIS

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
DISPLACED UTILITIES										
Electricity Cost	356,633	374,464	393,187	412,847	433,489	455,164	477,922	501,818	526,909	553,254
Fuel	274,026	287,727	302,114	317,219	333,080	349,734	367,221	385,582	404,861	425,104
O&M Cost	79,928	81,526	83,157	84,820	86,516	88,246	90,011	91,812	93,648	95,521
Total Cost	710,586	743,718	778,458	814,886	853,086	893,144	935,154	979,212	1,025,418	1,073,879
COGENERATION COST										
Fuel Cost	379,303	398,269	418,182	439,091	461,046	484,098	508,303	533,718	560,404	588,424
Standby Cost	33,000	34,650	36,383	38,202	40,112	42,117	44,223	46,434	48,756	51,194
O&M Cost	113,196	115,460	117,769	120,124	122,527	124,977	127,477	130,027	132,627	135,280
Total Cost	525,499	548,378	572,334	597,417	623,684	651,193	680,003	710,179	741,787	774,897
Total Savings	185,087	195,339	206,124	217,469	229,401	241,952	255,151	269,033	283,631	298,982
Cumulative Savings	185,087	380,426	586,550	804,019	1,033,420	1,275,372	1,530,523	1,799,556	2,083,186	2,382,168
Capital Cost	1,920,000									
Simple Payback	8.42									
Int Rate of Return	12.4%									
Net Present Value	2,757,438									

AUSTIN STATE HOSPITAL - 1 MW GAS TURBINE
LIFE-CYCLE ANALYSIS

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
DISPLACED UTILITIES										
Electricity Cost	580,917	609,963	640,461	672,484	706,108	741,413	778,484	817,408	858,279	901,193
Fuel	446,359	468,677	492,111	516,717	542,553	569,680	598,164	628,073	659,476	692,450
O&M Cost	97,431	99,380	101,367	103,395	105,463	107,572	109,723	111,918	114,156	116,439
Total Cost	1,124,708	1,178,020	1,233,940	1,292,596	1,354,123	1,418,666	1,486,372	1,557,399	1,631,911	1,710,082
COGENERATION COST										
Fuel Cost	617,845	648,738	681,174	715,233	750,995	788,545	827,972	869,370	912,839	958,481
Standby Cost	53,754	56,441	59,263	62,226	65,338	68,605	72,035	75,637	79,418	83,389
O&M Cost	137,985	140,745	143,560	146,431	149,360	152,347	155,394	158,502	161,672	164,905
Total Cost	809,584	845,924	883,997	923,891	965,692	1,009,496	1,055,400	1,103,509	1,153,929	1,206,775
Total Savings	315,124	332,096	349,942	368,705	388,431	409,170	430,972	453,890	477,982	503,307
Cumulative Savings	2,697,292	3,029,388	3,379,330	3,748,035	4,136,466	4,545,636	4,976,607	5,430,498	5,908,480	6,411,787

SOUTHWEST TEXAS STATE UNIVERSITY - 4.5 MW GAS TURBINE
LIFE-CYCLE ANALYSIS

	1986	1987	1988	1989	1990
DISPLACED UTILITIES					
Electricity Cost	2,053,564	2,135,707	2,221,135	2,309,980	2,402,380
Fuel Cost	3,272,400	3,337,848	3,404,605	3,472,697	3,542,151
O&M Cost	571,593	583,025	594,685	606,579	618,711
Total Cost	5,897,557	6,056,580	6,220,425	6,389,257	6,563,241
COGENERATION COST					
Electricity Cost	368,191	382,918	398,235	414,164	430,731
Fuel Cost	3,999,922	4,079,921	4,161,519	4,244,749	4,329,644
Standby Cost	0	0	0	0	0
O&M Cost	703,556	717,627	731,980	746,619	761,552
Total Cost	5,071,669	5,180,466	5,291,734	5,405,533	5,521,927
Total Savings	825,888	876,114	928,692	983,724	1,041,314
Cumulative Savings	825,888	1,702,002	2,630,694	3,614,418	4,655,732

	1991	1992	1993	1994	1995
DISPLACED UTILITIES					
Electricity Cost	2,498,475	2,598,414	2,702,350	2,810,444	2,922,862
Fuel Cost	3,612,994	3,685,254	3,758,959	3,834,138	3,910,821
O&M Cost	631,085	643,707	656,581	669,712	683,107
Total Cost	6,742,554	6,927,374	7,117,890	7,314,295	7,516,790
COGENERATION COST					
Electricity Cost	447,960	465,878	484,514	503,894	524,050
Fuel Cost	4,416,237	4,504,562	4,594,653	4,686,546	4,780,277
Standby Cost	0	0	0	0	0
O&M Cost	776,783	792,318	808,165	824,328	840,815
Total Cost	5,640,980	5,762,759	5,887,332	6,014,769	6,145,142
Total Savings	1,101,574	1,164,615	1,230,558	1,299,526	1,371,648
Cumulative Savings	5,757,306	6,921,921	8,152,480	9,452,006	10,823,654

Capital Cost	3,600,000
Simple Payback	3.99
Int Rate of Return	28.3%
Net Present Value (less plant cost)	8,969,006

SOUTHWEST TEXAS STATE UNIVERSITY - 4.5 MW GAS TURBINE
LIFE-CYCLE ANALYSIS

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
DISPLACED UTILITIES										
Electricity Cost	3,039,777	3,161,368	3,287,822	3,419,335	3,556,109	3,698,353	3,846,287	4,000,139	4,160,144	4,326,550
Fuel	3,989,038	4,068,818	4,150,195	4,233,199	4,317,863	4,404,220	4,492,304	4,582,150	4,673,793	4,767,269
O&M Cost	696,769	710,704	724,918	739,416	754,205	769,289	784,675	800,368	816,376	832,703
Total Cost	7,725,583	7,940,890	8,162,935	8,391,950	8,628,176	8,871,862	9,123,266	9,382,657	9,650,313	9,926,522
COGENERATION COST										
Electricity Cost	545,012	566,812	589,485	613,064	637,587	663,090	689,614	717,198	745,886	775,722
Fuel Cost	4,875,883	4,973,400	5,072,868	5,174,326	5,277,812	5,383,369	5,491,036	5,600,857	5,712,874	5,827,131
Standby Cost	0	0	0	0	0	0	0	0	0	0
O&M Cost	857,631	874,784	892,279	910,125	928,327	946,894	965,832	985,148	1,004,851	1,024,948
Total Cost	6,278,526	6,414,996	6,554,633	6,697,515	6,843,727	6,993,353	7,146,482	7,303,204	7,463,612	7,627,802
Total Savings	1,447,057	1,525,894	1,608,303	1,694,435	1,784,449	1,878,509	1,976,784	2,079,453	2,186,701	2,298,720
Cumulative Savings	12,270,711	13,796,605	15,404,907	17,099,342	18,883,792	20,762,301	22,739,085	24,818,538	27,005,240	29,303,960

SOUTHWEST TEXAS STATE UNIVERSITY - 6 MW DIESEL ENGINE
LIFE-CYCLE ANALYSIS

	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
DISPLACED UTILITIES										
Electricity Cost	2,123,704	2,208,652	2,296,998	2,388,878	2,484,433	2,583,811	2,687,163	2,794,650	2,906,436	3,022,693
Fuel Cost	3,272,400	3,337,848	3,404,605	3,472,697	3,542,151	3,612,994	3,685,254	3,758,959	3,834,138	3,910,821
O&M Cost	571,593	583,025	594,685	606,579	618,711	631,085	643,707	656,581	669,712	683,107
Total Cost	5,967,697	6,129,525	6,296,289	6,468,154	6,645,295	6,827,890	7,016,124	7,210,189	7,410,286	7,616,620
COGENERATION COST										
Electricity Cost	157,766	164,077	170,640	177,465	184,564	191,946	199,624	207,609	215,914	224,550
Fuel Cost	4,526,402	4,616,930	4,709,269	4,803,454	4,899,523	4,997,514	5,097,464	5,199,413	5,303,401	5,409,469
Standby Cost	0	0	0	0	0	0	0	0	0	0
O&M Cost	1,124,698	1,147,192	1,170,136	1,193,539	1,217,409	1,241,757	1,266,593	1,291,924	1,317,763	1,344,118
Total Cost	5,808,866	5,928,199	6,050,044	6,174,458	6,301,496	6,431,217	6,563,681	6,698,947	6,837,078	6,978,138
Total Savings	158,831	201,326	246,244	293,696	343,799	396,672	452,443	511,242	573,208	638,483
Cumulative Savings	158,831	360,157	606,402	900,098	1,243,897	1,640,569	2,093,012	2,604,254	3,177,462	3,815,945
Capital Cost	4,800,000									
Simple Payback	11.36									
Int Rate of Return	9.3%									
Net Present Value (less plant cost)	727,221									

SOUTHWEST TEXAS STATE UNIVERSITY - 6 MW DIESEL ENGINE
LIFE-CYCLE ANALYSIS

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
DISPLACED UTILITIES										
Electricity Cost	3,143,601	3,269,345	3,400,119	3,536,123	3,677,568	3,824,671	3,977,658	4,136,764	4,302,235	4,474,324
Fuel	3,989,037	4,068,818	4,150,194	4,233,198	4,317,862	4,404,220	4,492,304	4,582,150	4,673,793	4,767,269
O&M Cost	696,769	710,704	724,918	739,416	754,205	769,289	784,675	800,368	816,376	832,703
Total Cost	7,829,407	8,048,867	8,275,231	8,508,738	8,749,635	8,998,179	9,254,636	9,519,282	9,792,403	10,074,296
COGENERATION COST										
Electricity Cost	233,532	242,874	252,588	262,692	273,200	284,128	295,493	307,312	319,605	332,389
Fuel Cost	5,517,659	5,628,012	5,740,572	5,855,384	5,972,491	6,091,941	6,213,780	6,338,056	6,464,817	6,594,113
Standby Cost	0	0	0	0	0	0	0	0	0	0
O&M Cost	1,371,001	1,398,421	1,426,389	1,454,917	1,484,015	1,513,695	1,543,969	1,574,849	1,606,346	1,638,473
Total Cost	7,122,192	7,269,306	7,419,550	7,572,992	7,729,706	7,889,764	8,053,242	8,220,217	8,390,767	8,564,975
Total Savings	707,215	779,561	855,681	935,746	1,019,929	1,108,415	1,201,394	1,299,066	1,401,636	1,509,321
Cumulative Savings	4,523,160	5,302,721	6,158,402	7,094,148	8,114,077	9,222,492	10,423,887	11,722,952	13,124,588	14,633,909

UNIVERSITY OF HOUSTON
12530 KW GAS TURBINE + ABSORPTION CHILLER

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
DISPLACED UTILITIES										
Base Savings	2,290,580	2,192,053	2,454,544	2,484,867	2,505,331	2,551,947	2,561,982	2,640,359	2,710,165	2,784,434
Fuel Charge Saving	2,253,225	2,392,140	2,724,182	2,947,902	3,163,090	3,429,056	3,706,677	3,960,470	4,210,516	4,507,283
Franchise Fee Savin	193,761	195,484	220,836	231,670	241,718	255,048	267,314	281,479	295,119	310,941
Gas Savings	1,262,479	1,476,768	1,710,991	1,860,495	2,014,983	2,194,388	2,388,743	2,558,181	2,754,545	2,967,272
Total	6,000,045	6,256,445	7,110,554	7,524,934	7,925,122	8,430,440	8,924,717	9,440,488	9,970,345	10,569,930
COGENERATION COST										
Fuel Cost	2,471,237	2,890,697	3,349,177	3,641,823	3,944,225	4,295,400	4,675,841	5,007,507	5,391,878	5,808,281
Standby Cost	522,841	522,841	549,258	556,119	560,579	570,871	573,273	590,769	606,207	623,018
O&M Cost	436,223	458,034	480,936	504,983	530,232	556,744	584,581	613,810	644,501	676,726
Total Cost	3,430,302	3,871,573	4,379,370	4,702,925	5,035,036	5,423,015	5,833,694	6,212,086	6,642,586	7,108,024
Total Savings	2,569,744	2,384,872	2,731,183	2,822,009	2,890,086	3,007,424	3,091,023	3,228,402	3,327,758	3,461,906
Cumulative Savings	2,569,744	4,954,616	7,685,799	10,507,808	13,397,895	16,405,319	19,496,342	22,724,744	26,052,502	29,514,408

Capital Cost	15,736,000
Simple Payback	5.78
Int Rate of Return	18.3%
Net Present Value (less plant cost)	18,748,707

UNIVERSITY OF HOUSTON

12530 KW GAS TURBINE + ABSORPTION CHILLER

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
DISPLACED UTILITIES										
Base Savings	2,812,977	3,127,368	3,201,772	3,434,107	3,581,656	3,711,213	3,873,946	4,035,057	4,207,040	4,360,456
Fuel Charge Saving	4,838,077	4,927,461	5,268,972	5,314,652	5,733,061	6,120,981	6,514,416	6,967,684	7,288,904	7,823,231
Franchise Fee Savin	326,264	343,482	361,218	373,073	397,207	419,274	442,991	469,190	490,222	519,549
Gas Savings	3,196,363	3,436,363	3,703,635	3,992,726	4,303,635	4,647,271	5,007,271	5,399,999	5,830,908	6,299,998
Total	11,173,680	11,834,673	12,535,597	13,114,559	14,015,560	14,898,740	15,838,625	16,871,929	17,817,073	19,003,234
COGENERATION COST										
Fuel Cost	6,256,714	6,726,502	7,249,674	7,815,555	8,424,143	9,096,793	9,801,474	10,570,217	11,413,699	12,331,920
Standby Cost	629,193	699,523	716,333	768,137	801,072	830,233	866,599	902,621	941,045	975,352
O&M Cost	710,562	746,090	783,394	822,564	863,692	906,877	952,221	999,832	1,049,823	1,102,315
Total Cost	7,596,469	8,172,115	8,749,402	9,406,256	10,088,907	10,833,903	11,620,294	12,472,670	13,404,568	14,409,587
Total Savings	3,577,211	3,662,558	3,786,195	3,708,304	3,926,653	4,064,837	4,218,331	4,399,259	4,412,506	4,593,647
Cumulative Savings	33,091,619	36,754,177	40,540,372	44,248,675	48,175,328	52,240,165	56,458,496	60,857,755	65,270,261	69,863,908

TEXAS A&M UNIVERSITY - 21.4 MW GAS TURBINE
LIFE-CYCLE ANALYSIS

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
DISPLACED UTILITIES										
Electricity Cost	3,826,787	3,979,858	4,139,053	4,304,615	4,476,799	4,655,871	4,842,106	5,035,790	5,237,222	5,446,711
Fuel Cost	11,114,616	11,342,097	11,578,677	11,824,721	12,080,606	12,346,727	12,623,492	12,911,328	13,210,678	13,522,001
O&M Cost	3,972,015	4,130,895	4,296,131	4,467,976	4,646,696	4,832,563	5,025,866	5,226,901	5,435,977	5,653,416
Total Cost	18,913,417	19,452,850	20,013,861	20,597,312	21,204,101	21,835,161	22,491,464	23,174,019	23,883,876	24,622,128
COGENERATION COST										
Electricity Cost	603,421	627,558	652,661	678,767	705,918	734,154	763,521	794,061	825,824	858,857
Fuel Cost	11,466,676	11,701,363	11,945,437	12,199,274	12,463,265	12,737,815	13,023,347	13,320,301	13,629,132	13,950,317
O&M Cost	4,379,681	4,554,869	4,737,063	4,926,546	5,123,608	5,328,552	5,541,694	5,763,362	5,993,896	6,233,652
Total Cost	16,449,779	16,883,790	17,335,161	17,804,587	18,292,790	18,800,521	19,328,562	19,877,724	20,448,853	21,042,826
Total Savings	2,463,638	2,569,061	2,678,700	2,792,725	2,911,311	3,034,640	3,162,902	3,296,295	3,435,024	3,579,302
Cumulative Savings	2,463,638	5,032,699	7,711,399	10,504,123	13,415,434	16,450,074	19,612,976	22,909,271	26,344,295	29,923,597
Capital Cost	21,400,000									
Simple Payback	7.54									
Int Rate of Return	13.7%									
Net Present Value (less plant cost)	14,886,407									

TEXAS A&M UNIVERSITY - 21.4 MW GAS TURBINE
LIFE-CYCLE ANALYSIS

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
DISPLACED UTILITIES										
Electricity Cost	5,664,579	5,891,163	6,126,809	6,371,881	6,626,757	6,891,827	7,167,500	7,454,200	7,752,368	8,062,463
Fuel	13,845,778	14,182,506	14,532,702	14,896,907	15,275,680	15,669,603	16,079,284	16,505,352	16,948,462	17,409,297
O&M Cost	5,879,552	6,114,734	6,359,324	6,613,697	6,878,244	7,153,374	7,439,509	7,737,090	8,046,573	8,368,436
Total Cost	25,389,910	26,188,402	27,018,835	27,882,485	28,780,681	29,714,804	30,686,293	31,696,641	32,747,403	33,840,196
COGENERATION COST										
Electricity Cost	893,211	928,939	966,097	1,004,741	1,044,931	1,086,728	1,130,197	1,175,405	1,222,421	1,271,318
Fuel Cost	14,284,349	14,631,743	14,993,032	15,368,773	15,759,544	16,165,945	16,588,603	17,028,166	17,485,313	17,960,745
O&M Cost	6,482,998	6,742,318	7,012,011	7,292,492	7,584,191	7,887,559	8,203,061	8,531,184	8,872,431	9,227,328
Total Cost	21,660,559	22,303,001	22,971,141	23,666,006	24,388,666	25,140,232	25,921,861	26,734,755	27,580,165	28,459,391
Total Savings	3,729,351	3,885,402	4,047,694	4,216,479	4,392,015	4,574,573	4,764,432	4,961,886	5,167,239	5,380,805
Cumulative Savings	33,652,948	37,538,349	41,586,044	45,802,523	50,194,538	54,769,110	59,533,543	64,495,429	69,662,668	75,043,473

TEXAS A&M UNIVERSITY - 42.8 MW GAS TURBINE
LIFE-CYCLE ANALYSIS

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
DISPLACED UTILITIES										
Electricity Cost	3,826,787	3,979,858	4,139,053	4,304,615	4,476,799	4,655,871	4,842,106	5,035,790	5,237,222	5,446,711
Fuel Cost	11,114,616	11,342,097	11,578,677	11,824,721	12,080,606	12,346,727	12,623,492	12,911,328	13,210,678	13,522,001
O&M Cost	3,972,015	4,130,895	4,296,131	4,467,976	4,646,696	4,832,563	5,025,866	5,226,901	5,435,977	5,653,416
Total Cost	18,913,417	19,452,850	20,013,861	20,597,312	21,204,101	21,835,161	22,491,464	23,174,019	23,883,876	24,622,128
COGENERATION COST										
Electricity Cost	90,893	94,528	98,309	102,242	106,332	110,585	115,008	119,608	124,393	129,369
Fuel Cost	10,736,305	10,956,043	11,184,571	11,422,240	11,669,415	11,926,478	12,193,823	12,471,862	12,761,023	13,061,750
O&M Cost	4,423,107	4,600,032	4,784,033	4,975,394	5,174,410	5,381,386	5,596,642	5,820,507	6,053,328	6,295,461
Total Cost	15,250,304	15,650,603	16,066,913	16,499,875	16,950,157	17,418,449	17,905,473	18,411,978	18,938,743	19,486,579
Total Savings	3,663,113	3,802,248	3,946,948	4,097,436	4,253,944	4,416,712	4,585,991	4,762,041	4,945,133	5,135,549
Cumulative Savings	3,663,113	7,465,361	11,412,309	15,509,745	19,763,690	24,180,402	28,766,393	33,528,435	38,473,568	43,609,117
Capital Cost	38,520,000									
Simple Payback	9.01									
Int Rate of Return	10.7%									
Net Present Value (less plant cost)	13,731,180									

TEXAS A&M UNIVERSITY - 42.8 MW GAS TURBINE
LIFE-CYCLE ANALYSIS

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
DISPLACED UTILITIES										
Electricity Cost	5,664,579	5,891,163	6,126,809	6,371,881	6,626,757	6,891,827	7,167,500	7,454,200	7,752,368	8,062,463
Fuel	13,845,778	14,182,506	14,532,702	14,896,907	15,275,680	15,669,603	16,079,284	16,505,352	16,948,462	17,409,297
O&M Cost	5,879,552	6,114,734	6,359,324	6,613,697	6,878,244	7,153,374	7,439,509	7,737,090	8,046,573	8,368,436
Total Cost	25,389,910	26,188,402	27,018,835	27,882,485	28,780,681	29,714,804	30,686,293	31,696,641	32,747,403	33,840,196
COGENERATION COST										
Electricity Cost	134,543	139,925	145,522	151,343	157,397	163,692	170,240	177,050	184,132	191,497
Fuel Cost	13,374,506	13,699,772	14,038,049	14,389,857	14,755,737	15,136,253	15,531,989	15,943,555	16,371,583	16,816,732
O&M Cost	6,547,279	6,809,170	7,081,537	7,364,799	7,659,391	7,965,766	8,284,397	8,615,773	8,960,404	9,318,820
Total Cost	20,056,328	20,648,867	21,265,108	21,905,998	22,572,524	23,265,711	23,986,626	24,736,377	25,516,118	26,327,049
Total Savings	5,333,582	5,539,535	5,753,727	5,976,486	6,208,156	6,449,093	6,699,667	6,960,264	7,231,285	7,513,147
Cumulative Savings	48,942,699	54,482,234	60,235,961	66,212,447	72,420,604	78,869,697	85,569,364	92,529,628	99,760,913	107,274,060

APPENDIX B - PROGRAM CODES

TECHNICAL EVALUATION PROGRAM

```
c ----------------------------------------
c -- Program COGENeration SIMulation --
c --  Written by Steven R. Fennell   --
c --   Texas A&M University  1993    --
c ----------------------------------------
      program cogensim
      implicit real(a-z)
c
c Gas turbine variables
c
      dimension qfgt(3,12,24),elgt(3,12,24),mexpgt(3,12,24),tamb(12,24)
      dimension texh(3,12,24),mair(3,12,24),t2(3,12,24),mgtfrc(3,12,24)
      dimension qgttot(12,24),egttot(12,24),mgttot(12,24)
      dimension eld(3),qfd(3),maird(3),tambd(3),pambd(3),hv(3)
      dimension tpinchd(3),tevp(3),hevp(3),hblr(3),bd(3),agt(3),bgt(3)
      dimension ua(3),wc(3),pstm(3),tstm(3),hstm(3),tfw(3),hfw(3)
      dimension nblr(3),effctv(3)

c
c Diesel (I.C.) engine variables
c
      dimension qfde(3,12,24),elde(3,12,24),mexpde(3,12,24)
      dimension mdefrc(3,12,24),qdetot(12,24),edetot(12,24)
      dimension mdetot(12,24),qff(3),elf(3),texhf(3),mairf(3)
      dimension tstack(3),psteam(3),tsteam(3),twater(3),hsteam(3)
      dimension hwater(3),effncy(3),hval(3),ade(3,2),bde(3,2)
c
c Backpressure steam turbine variables
c
      dimension qfbt(3,12,24),elbt(3,12,24),mexpbt(3,12,24)
      dimension mbtfrc(3,12,24)
      dimension qbttot(12,24),ebttot(12,24),mbttot(12,24)
      dimension eed(3),sfd(3),eep(3),sfp(3),beta(3),hfeed(3),hexst(3)
      dimension hinst(3),pinst(3),tinst(3),pexst(3),texst(3),nboil(3)
c
c Autoextraction steam turbine variables
c
      dimension qfst(3,12,24),elst(3,12,24),mexpst1(3,12,24)
      dimension mexpst2(3,12,24),mthrfrc(3,12,24),elstfrc(3,12,24)
      dimension mstfrc1(3,12,24),mstfrc2(3,12,24)
      dimension qsttot(12,24),esttot(12,24),msttot(12,24)
      dimension pthr(3),pext(3),pexh(3),tthr(3),hthr(3),elcd(3),ed(3)
      dimension cf(3),ef(3),hfwtr(3),nstblr(3),mthrmax(3),mextmax(3)
      dimension tsr1(3),tsr2(3),ff(3),fleff(3),mexhmax(3),mexhmin(3)
      dimension mhfld(3),emin(3),mexthfl(3),mxmax(3),mxmin(3)
c
c Misc. variables
c
      dimension qf(12,24),el(12,24),mexp(12,24)
      dimension mstcc(12,24),qstcc(12,24),mbtcc(12,24),qbtcc(12,24)
      dimension eload(12,24,2),sload(12,24,2)
      dimension qx(3),ex(3),tx(3),tmax(12),tmin(12)
      dimension wgt(3),wde(3),wst(3),wbt(3)
      dimension days(12,2),stcount(5,3)
      character month(12)*10,ldsinfile*12,enginfile*12,outfile*12
      character econfile*12,engf*4,outf*4,ecof*4
      integer hr,mo,i,j,k,L,n,numgt,numde,numbt,numst,ref1(2,3),
     & ref2(2,3),econ
c
c Log-mean temperature difference function
```

```
c
      tlogm(tx1,tx2,tx3,tx4)=(tx1-tx2-tx3+tx4)/alog((tx1-tx2)/(tx3-tx4))
c
      data days/10,20,16,20,21,20,22,21,21,23,18,14,21,8,15,10,10,10,
     &9,10,9,8,12,17/
      data month/'January   ','February  ','March     ','April     ',
     &'May       ','June      ','July      ','August    ','September ',
     &'October   ','November  ','December  '/
c
c Get input & output data file names
c
c      write(*,9020)
c      write(*,9000)
c      read(*,9005) ldsinfile
c      write(*,9001)
c      read(*,9005) enginfile
c      write(*,9010)
c      read(*,9005) outfile
c      if (outfile.eq.' ') then
c         outfile=enginfile
c         econfile=enginfile
c         engf='.dat'
c         outf='.out'
c         ecof='.eco'
c         econ=1
c         go to 2
c      endif
c      write(*,9015)
c      read(*,9005) econfile
c 9000 format(1x,'Enter loads data input file name: ',$)
c 9001 format(1x,'Enter engine data input file name: ',$)
c 9005 format(a12)
c 9010 format(1x,'Enter engr. data output file name: ',$)
c 9015 format(1x,'Enter econ. data output file name: ',$)
c 9020 format(1x,'COGENeration SIMulation'/
c     & 1x,'Written by Steven Fennell'/
c     & 1x,'Texas A&M University, 1992'//)
c
  2   open(unit=10,file=' ',status='old')
      open(unit=15,file=' ',status='old')
c
      open(unit=11,file=' ',status='new')
      open(unit=12,file=' ',status='new')
      econ=1
c
c Input max,min temp, ambient conditions
c
    5 read(10,*) (tmax(mo),mo=1,12)
      read(10,*) (tmin(mo),mo=1,12)
      read(10,*) pamb,tbstm,tbfdw,hlv,blreff
      read(15,*) numgt,numde,numst,numbt
      write(*,*) '# Gas Turbines               =',numgt
      write(*,*) '# Diesel Engines             =',numde
      write(*,*) '# Extraction Steam Turbines  =',numst
      write(*,*) '# Back Press. Steam Turbines =',numbt
      write(*,*) ' '
      write(*,*) 'Loading Data For...'
c
c Design point data for gas turbines
c
      if (numgt.eq.0) go to 22
      write(*,*) ' -- Gas Turbines'
      do L=1,numgt
         read(15,*) eld(L),qfd(L),maird(L),tambd(L)
```

```
         read(15,*) pambd(L),hv(L),tevp(L),hevp(L)
         read(15,*) hblr(L),bd(L),ex(1),qx(1)
         read(15,*) ex(2),qx(2),ex(3),qx(3)
         read(15,*) pstm(L),tstm(L),hstm(L),tfw(L)
         read(15,*) hfw(L),nblr(L),effctv(L)
c
c Fit gas turbine data with n points
c
         agt(L)=0.0
         bgt(L)=0.0
         call expfit (agt(L),bgt(L),ex,qx)
      end do
c
c Design point data for I.C. engines
c
   22 if (numde.eq.0) go to 25
      write(*,*) ' -- Diesel Engines'
      do L=1,numde
         read(15,*) qff(L),elf(L),texhf(L),mairf(L)
         read(15,*) tstack(L),psteam(L),tsteam(L),twater(L)
         read(15,*) hsteam(L),hwater(L),effncy(L),hval(L)
         read(15,*) ex(1),ex(2),ex(3),qx(1)
         read(15,*) qx(2),qx(3),tx(1),tx(2)
         read(15,*) tx(3)
c
         ade(L,1)=0.0
         bde(L,1)=0.0
         ade(L,2)=0.0
         bde(L,2)=0.0
         call expfit (ade(L,1),bde(L,1),ex,qx)
         call expfit (ade(L,2),bde(L,2),ex,tx)
      end do
c
c Design point data for autoextraction turbines
c
   25 if (numst.eq.0) go to 30
      write(*,*) ' -- Extraction Steam Turbines'
      do L=1,numst
         read(15,*) pthr(L),pext(L),pexh(L),tthr(L)
         read(15,*) hthr(L),elcd(L),ed(L),cf(L)
         read(15,*) hfwtr(L),nstblr(L),mthrmax(L),mextmax(L)
         read(15,*) tsr1(L),tsr2(L),fleff(L),ff(L)
         read(15,*) mexhmax(L),mexhmin(L),ref1(1,L),ref2(1,L)
      end do
c
c Design point data for steam turbines
c
   30 if (numbt.eq.0) go to 40
      write(*,*) ' -- Back Pressure Steam Turbines'
      do L=1,numbt
         read(15,*) eed(L),sfd(L),eep(L),sfp(L)
         read(15,*) ref1(2,L),ref2(2,L),hinst(L),pinst(L)
         read(15,*) tinst(L),pexst(L),texst(L),hexst(L)
         read(15,*) hfeed(L),nboil(L)
      end do
c
c Input electric and steam load data
c
   40 write(*,*) 'Loading Steam and Electric Load Data'
      do 10 j=1,2
      do 10 mo=1,12
   10 read(10,*) (eload(mo,hr,j),hr=1,24)
      do 20 j=1,2
      do 20 mo=1,12
```

```
   20 read(10,*) (sload(mo,hr,j),hr=1,24)
c
c Count the number of steam turbines that are combined cycle
c
      do 35 i=1,2
      do 35 j=1,3
         if (ref1(i,j).eq.0) then
            stcount(ref1(i,j),ref2(i,j))=99
         else
            stcount(ref1(i,j),ref2(i,j))=stcount(ref1(i,j),ref2(i,j))+1
         endif
   35 continue
c
c Get control mode
c
c      k=1
      write(*,9030)
c      write(*,9025) k
      read(*,9026) k
      write(*,*) ' '
 9025 format(1x,'Which control mode? (0,1,2,3) ',$)
 9026 format(i1)
 9030 format(/1x,'Choose a Control Mode of Operation:'/
     & 1x,' 0. Peak Electrical Output'/
     & 1x,' 1. Electrical Matching'/
     & 1x,' 2. Thermal Matching'/
     & 1x,' 3. All Three Modes'/)
c      if (numst.ne.0) then
c         write(*,*) 'Run Extraction-turbines on automatic (1/0)?'
c         read(*,*) n
c      endif
       n=1
c
c ---------------------------
c Gas turbine engine analysis
c ---------------------------
c
c Some gas, math constants
c
      cpair=.240
      cptbn=.265
      cpcom=.275
      cpcpr=.247
      cpblr=.260
      cph2o=1.0
      ngen=.95
      pi=3.141593
c
c Calculate design points for gas turbine
c
      if (numgt.eq.0) go to 42
      write(*,*) 'Calculating Design Points for Gas Turbine'
      do mo=1,12
         do hr=1,24
            do L=1,numgt
c
c Fuel input, idle conditions (Ed = 0)
c
               qfo=agt(L)
c
c Work of compressor at idle
c
               wcd=cptbn/cpcom*qfo
c
```

```
c Temp at compressor exit
c
              t2d=tambd(L)+wcd/maird(L)/cpcpr
c
c Fuel flow rate
c
              mfueld=qfd(L)/hv(L)
c
c Gas (fuel+air) flow rate
c
              mgasd=maird(L)+mfueld
c
c Turbine inlet temp
c
              t3d=t2d+qfd(L)/mgasd/cpcom
c
c Work of turbine
c
              wtd=3413./ngen*eld(L)+wcd
c
c WASTE HEAT BOILER CALCS
c Turbine exhaust temp
c
              texhd=t3d-wtd/mgasd/cptbn
c
c Pinch point temp
c
              tpinchd(L)=texhd-effctv(L)*(texhd-tevp(L))
              if (texhd.lt.tstm(L)) go to 9998
c
c Heat input to boiler
c
              qblrd=mgasd*cpblr*(texhd-tpinchd(L))
c
c Log-mean temp diff.
c
              tlmd=tlogm(texhd,tstm(L),tpinchd(L),tevp(L))
c
c UA boiler characteristic
c
              ua(L)=qblrd/tlmd
c
c Steam flow through boiler
c
              mstmd=qblrd*nblr(L)/(hstm(L)-hevp(L))
c
c Flow of steam for plant use, accounting for blowdown and
c  feedwater heating
c
              mplntd=(1+bd(L))*mstmd*(hblr(L)-hfw(L))/(hstm(L)-hfw(L))
c
c Amount of steam exported
c
              mexpd=mstmd-mplntd
c
c Based on ambient data, calculate monthly and hourly data
c
c Sine wave function for min and max temperatures
c
              if (hr.ge.1.and.hr.le.6) then
                 xsin=sin(((6.-hr)/16.)*pi-pi/2.)
              elseif (hr.gt.6.and.hr.le.14) then
                 xsin=sin(((hr-6.)/8.)*pi-pi/2.)
              else
```

```
                  xsin=sin(pi/2.-(hr-14.)/16.*pi)
               endif
               tamb(mo,hr)=(tmax(mo)+tmin(mo))/2.+(tmax(mo)-tmin(mo))
     &          /2.*xsin
c
c Based on new ambient temperatures, re-calculate GT design points
c
               wc(L)=wcd*pamb/pambd(L)
                mair(L,mo,hr)=maird(L)*pamb/pambd(L)*tambd(L)/tamb(mo,hr)
               t2(L,mo,hr)=tamb(mo,hr)+wc(L)/mair(L,mo,hr)/cpcpr
               t3=t3d
               mfuel=mair(L,mo,hr)/(hv(L)/cpcom/(t3-t2(L,mo,hr))-1.)
               qfgt(L,mo,hr)=mfuel*hv(L)
               elgt(L,mo,hr)=1./bgt(L)*alog(qfgt(L,mo,hr)/agt(L))
               wt=3413./ngen*elgt(L,mo,hr)+wc(L)
               mgas=mair(L,mo,hr)+mfuel
               texh(L,mo,hr)=t3-wt/mgas/cptbn
c
c Iterate to find pinch pt temp.
c
c               tpinch=tevp(L)+50.
               tpinch=tpinchd(L)
               if (texh(L,mo,hr).le.tstm(L)) then
                  write(*,*) '>>>>>> Failure <<<<<<'
                  go to 9999
               endif
               call iterate(texh(L,mo,hr),tstm(L),tpinch,tevp(L),mgas,
     &          cpblr,ua(L),nblr(L))

               qblr=ua(L)*tlogm(texh(L,mo,hr),tstm(L),tpinch,tevp(L))
               qblr0=mgas*cpblr*(texh(L,mo,hr)-tpinch)
c               print*, qblr/1.e6, qblr0/1.e6
               mstm=qblr*nblr(L)/(hstm(L)-hevp(L))
               mplnt=(1.+bd(L))*mstm*(hblr(L)-hfw(L))/(hstm(L)-hfw(L))
               mexpgt(L,mo,hr)=mstm-mplnt
               mgttot(mo,hr)=mgttot(mo,hr)+mexpgt(L,mo,hr)
               egttot(mo,hr)=egttot(mo,hr)+elgt(L,mo,hr)
               qgttot(mo,hr)=qgttot(mo,hr)+qfgt(L,mo,hr)
            end do
         end do
      end do
c
c --------------------------------------
c Calculate design point for I.C. Engine
c --------------------------------------
c
   42 if (numde.eq.0) go to 45
      write(*,*) 'Calculating Design Points for Diesel Engine'
      do mo=1,12
         do hr=1,24
            do L=1,numde
c
c Flow rate of air/fuel mixture
c
               mgas=qff(L)/hval(L)+mairf(L)
c
c Heat produced in heat exchanger from hot gases
c
               qsteam=mgas*cpair*(texhf(L)-tstack(L))
c
c Steam produced in heat exchanger
c
               mexpde(L,mo,hr)=qsteam*effncy(L)/(hsteam(L)-hwater(L))
c
```

```
               qfde(L,mo,hr)=qff(L)
               elde(L,mo,hr)=elf(L)
c
               mdetot(mo,hr)=mdetot(mo,hr)+mexpde(L,mo,hr)
               edetot(mo,hr)=edetot(mo,hr)+elde(L,mo,hr)
               qdetot(mo,hr)=qdetot(mo,hr)+qfde(L,mo,hr)
            end do
         end do
      end do
c
c ------------------------------
c Calculate design point for aest
c ------------------------------
c
   45 if (numst.eq.0) go to 50
      write(*,*) 'Calculating Design Points for Extract. Steam Turbine'
      do mo=1,12
         do hr=1,24
            do L=1,numst
c
c Get analytical full-load non-extraction efficiencies
c  and half-load flow factors
c
               if (fleff(L).eq.0.and.cf(L).eq.0.857) then
                  fleff(L)=.343964-3.06602e-4*pthr(L)+.0462787*
     &             alog(ed(L))+2.78533e-5*pthr(L)*alog(ed(L))
               elseif (fleff(L).eq.0.and.cf(L).eq.0.902) then
                  fleff(L)=.548093-7.06435e-4*pthr(L)+.0236672*
     &             alog(ed(L))+7.1851e-5*pthr(L)*alog(ed(L))
               endif
c
               if (ff(L).eq.0.and.cf(L).eq.0.857) then
                  ff(L)=-.00800454*alog(ed(L))+.640167
               elseif (ff(L).eq.0.and.cf(L).eq.0.902) then
                  ff(L)=-.00910131*alog(ed(L))+.699209
               endif
c
c Max exhaust flow
c
               if (mexhmax(L).eq.0) mexhmax(L)=ed(L)*tsr1(L)/fleff(L)
c
c Half load exhaust flow
c
               mhfld(L)=mexhmax(L)*ff(L)
c
c Extraction factor
c
               ef(L)=1.0-cf(L)*tsr1(L)/tsr2(L)
c
c Min power at max extraction
c
               emin(L)=ed(L)/2.0*(1.0+(mextmax(L)*(1.0-ef(L))+mexhmin(L)
     &          -mhfld(L))/(mexhmax(L)-mhfld(L)))
c
c Max extraction at min flow to exhaust, half load
c
               mexthfl(L)=(mhfld(L)-mexhmin(L))/(1.0-ef(L))
c
c Calculated max throttle
c
               if (mthrmax(L).eq.0.0) then
                  mthrmax(L)=mexhmax(L)+mextmax(L)*ef(L)
               endif
c
```

```
c Get combined cycle steam flow
c
               if (ref1(1,L).eq.0) mcomb=0.0
               if (ref1(1,L).eq.1) mcomb=mexpgt(ref2(1,L),mo,hr)
               if (ref1(1,L).eq.2) mcomb=mexpde(ref2(1,L),mo,hr)
               if (ref1(1,L).eq.3) mcomb=mexpst1(ref2(1,L),mo,hr)
               if (ref1(1,L).eq.4) mcomb=mexpst2(ref2(1,L),mo,hr)
               if (ref1(1,L).eq.5) mcomb=mexpbt(ref2(1,L),mo,hr)
c
c Max and min extraction flow based on max throttle
c
 47            mxmax(L)=(mthrmax(L)-(mexhmax(L)-mhfld(L))*(elcd(L)-
     &          ed(L)/2.0)/(ed(L)/2.0)-mhfld(L))/ef(L)
               mxmin(L)=(mhfld(L)+(mexhmax(L)-mhfld(L))*(elcd(L)-
     &          ed(L)/2.0)/(ed(L)/2.0)-mexhmax(L))/(1.0-ef(L))
c
c Set design points for throttle and export flow, electrical output
c
               mexpst1(L,mo,hr)=mxmax(L)
               mexpst2(L,mo,hr)=mthrmax(L)-mxmax(L)
               elst(L,mo,hr)=elcd(L)
               qfst(L,mo,hr)=mthrmax(L)*(hthr(L)-hfwtr(L))/
     &          nstblr(L)/.98
c
               esttot(mo,hr)=esttot(mo,hr)+elst(L,mo,hr)
               msttot(mo,hr)=msttot(mo,hr)+mexpst1(L,mo,hr)
               qsttot(mo,hr)=qsttot(mo,hr)+qfst(L,mo,hr)
               mstcc(mo,hr)=mstcc(mo,hr)+mcomb/
     &           stcount(ref1(1,L),ref2(1,L))
               qstcc(mo,hr)=qstcc(mo,hr)+mcomb/
     &           stcount(ref1(1,L),ref2(1,L))*(hthr(L)-hfwtr(L))/
     &           nstblr(L)/.98
            end do
         end do
      end do
c
c ---------------------------------------
c Calculate design point for steam turbine
c ---------------------------------------
c
 50   if (numbt.eq.0) go to 60
      write(*,*) 'Calculating Design Points for Backpres. Steam Turbine'
      do mo=1,12
         do hr=1,24
            do L=1,numbt
c
c Slope of power and steam rate using design and part load data
c
               beta(L)=(sfp(L)-sfd(L))/(eed(L)-eep(L))
c
c Get combined cycle flows if necessary
c
               if (ref1(2,L).eq.0) mcomb=0.0
               if (ref1(2,L).eq.1) mcomb=mexpgt(ref2(2,L),mo,hr)
               if (ref1(2,L).eq.2) mcomb=mexpde(ref2(2,L),mo,hr)
               if (ref1(2,L).eq.3) mcomb=mexpst1(ref2(2,L),mo,hr)
               if (ref1(2,L).eq.4) mcomb=mexpst2(ref2(2,L),mo,hr)
               if (ref1(2,L).eq.5) mcomb=mexpbt(ref2(2,L),mo,hr)
c
c Calculate design steam turbine flow
c
 70            mexpbt(L,mo,hr)=sfd(L)*eed(L)
c
c Fuel flow in boiler
```

```
c
               qfbt(L,mo,hr)=mexpbt(L,mo,hr)*(hinst(L)-hfeed(L))/
     &          nboil(L)/.98
               elbt(L,mo,hr)=eed(L)
               ebttot(mo,hr)=ebttot(mo,hr)+elbt(L,mo,hr)
               mbttot(mo,hr)=mbttot(mo,hr)+mexpbt(L,mo,hr)
               qbttot(mo,hr)=qbttot(mo,hr)+qfbt(L,mo,hr)
c
c Calculate steam contributed by combined cycle, if any
c  and fuel displace by comb. cycle steam
c
               mbtcc(mo,hr)=mbtcc(mo,hr)+mcomb/
     &           stcount(ref1(2,L),ref2(2,L))
               qbtcc(mo,hr)=qbtcc(mo,hr)+mcomb/
     &           stcount(ref1(2,L),ref2(2,L))*(hinst(L)-hfeed(L))/
     &           nboil(L)/.98
c
   55       end do
         end do
      end do
c
c ------------------------------------
c Output design points for ALL engines
c ------------------------------------
c
   60 write(11,*) 'Design Output of All Engines Combined'
      write(11,*) ' '
      do mo=1,12
         write(11,*) month(mo)
         write(11,5025)
         do hr=1,24
c
            el(mo,hr)=egttot(mo,hr)+edetot(mo,hr)+esttot(mo,hr)+
     &       ebttot(mo,hr)
            qf(mo,hr)=qgttot(mo,hr)+qdetot(mo,hr)+qsttot(mo,hr)+
     &       qbttot(mo,hr)-qstcc(mo,hr)-qbtcc(mo,hr)
            mexp(mo,hr)=mgttot(mo,hr)+mdetot(mo,hr)+msttot(mo,hr)+
     &       mbttot(mo,hr)-mstcc(mo,hr)-mbtcc(mo,hr)
c
            write(11,5020) hr,egttot(mo,hr),esttot(mo,hr)+ebttot(mo,hr),
     &       mgttot(mo,hr),msttot(mo,hr)+mbttot(mo,hr),mstcc(mo,hr)+
     &       mbtcc(mo,hr),mexp(mo,hr),qgttot(mo,hr),qsttot(mo,hr)+
     &       qbttot(mo,hr),qstcc(mo,hr)+qbtcc(mo,hr),qf(mo,hr)
         end do
      end do
c
 5010 format(//1x,a10/1x,'Hour',2x,'Electrical [kW]',5x,
     &'Steam [klbs]',5x,'Fuel [BtuX1000]')
 5020 format(4x,i2,6(2x,f8.0),4(2x,f11.0))
 5025 format(1x,'Hour   GT elec   ST elec   GT flow   ST flow   CC flow
     &  TL flow      GT gas      ST gas      CC gas      TL gas')
c
c =============================================================
c
c ---------------------
c Peak electrical output
c ---------------------
c
  100 if (k.ne.0.and.k.ne.3) go to 200
      write(*,*) '#0 - Peak Electrical Output'
      write(11,5032) 'Peak Electrical Output'
      do mo=1,12
      write(11,5030) month(mo)
c
```

```
c Set monthly variables to zero
c
      weload=0.0
      wsload=0.0
      wel=0.0
      wmexp=0.0
      wpurch=0.0
      wstm=0.0
      wqf=0.0
      wqfaux=0.0
      wqfnc=0.0
      peakcogen=0.0
      peaknocgn=0.0
c
      do j=1,2
      if (j.eq.1) write(11,5031) 'Working Days    '
      if (j.eq.2) write(11,5031) 'Non-working Days'
      do hr=1,24
         peakcogen=peakcogen+el(mo,hr)
         if (eload(mo,hr,j).gt.peaknocgn) peaknocgn=eload(mo,hr,j)
c
c Boiler fuel needed w/o cogeneration
c
         qfnc=sload(mo,hr,j)*(hlv+cph2o*(tbstm-tbfdw))/blreff/.98
c
c Amount of steam req'd or wasted
c
         stmdif=mexp(mo,hr)-sload(mo,hr,j)
         if (stmdif.lt.0.0) then
c
c Aux. boiler fuel necessary to make up steam reqs.
c
            qfaux=abs(stmdif)*(hlv+cph2o*(tbstm-tbfdw))/blreff/.98
            stmdif=abs(stmdif)
         else
            qfaux=0.0
            stmdif=0.0
         endif
c
c Calc elec. difference to determine purchase or sale of elec.
c
         eldif=el(mo,hr)-eload(mo,hr,j)
         if (eldif.ge.0.0) then
            sell=eldif
            purch=0.0
         else
            purch=abs(eldif)
            sell=0.0
         endif
c
c Efficiency calculations
c
c         npower=el(mo,hr)*3413./qf(mo,hr)
c         if (numbt.gt.0) then
c            hexit=hexst(L)
c            hf=hfeed(L)
c         else
c            hexit=hstm(L)
c            hf=hfw(L)
c         endif
c         qavail=mexp(mo,hr)*(hexit-hf)
c         ncogen=(el(mo,hr)*3413.+qavail)/qf(mo,hr)
c         write(20,*) npower,ncogen
c
```

```
c Sum monthly totals according to # days in month
c
         weload=weload+eload(mo,hr,j)*days(mo,j)
         wsload=wsload+sload(mo,hr,j)*days(mo,j)
         wel=wel+el(mo,hr)*days(mo,j)
         wmexp=wmexp+mexp(mo,hr)*days(mo,j)
         wpurch=wpurch+purch*days(mo,j)
         wstm=wstm+stmdif*days(mo,j)
         wqf=wqf+qf(mo,hr)/1.0e6*days(mo,j)
         wqfaux=wqfaux+qfaux/1.0e6*days(mo,j)
         wqfnc=wqfnc+qfnc/1.0e6*days(mo,j)
c
c Output to file
c
         write(11,5040) hr,sload(mo,hr,j)/1000.,mgttot(mo,hr)/1000.,
     &    (msttot(mo,hr)+mbttot(mo,hr)-mstcc(mo,hr)-mbtcc(mo,hr))/
     &    1000.,qgttot(mo,hr)/1.0e6,(qsttot(mo,hr)+qbttot(mo,hr)-
     &    qstcc(mo,hr)-qbtcc(mo,hr))/1.0e6,qfaux/1.0e6,eload(mo,hr,j),
     &    egttot(mo,hr),(esttot(mo,hr)+ebttot(mo,hr)),purch,
     &    tamb(mo,hr)-459.67,texh(1,mo,hr)-459.67
      end do
      end do
      write(11,5042) wsload/1000.,wmexp/1000.,wqf,wqfaux,weload,
     & wel,wpurch
      if (econ.eq.0) go to 195
      peakcogen=peakcogen/24.0/2.0
      write(12,5041) weload,wsload,wel,wmexp,wpurch,wstm,wqf,wqfaux,
     & wqfnc,peakcogen,peaknocgn
  195 end do
c
c -------------------
c Electrical Matching
c -------------------
c
  200 if (k.ne.1.and.k.ne.3) go to 300
      write(*,*) '#1 - Electrical Matching'
      write(11,5032) 'Electrical Matching    '
      do L=1,3
         wgt(L)=0.0
         wde(L)=0.0
         wst(L)=0.0
         wbt(L)=0.0
      end do
      do mo=1,12
      write(11,5030) month(mo)
c
      weload=0.0
      wsload=0.0
      wel=0.0
      wmexp=0.0
      wpurch=0.0
      wstm=0.0
      wqf=0.0
      wqfaux=0.0
      wqfnc=0.0
      peakcogen=0.0
      peaknocgn=0.0
c
      do j=1,2
      if (j.eq.1) write(11,5031) 'Working Days'
      if (j.eq.2) write(11,5031) 'Non-working Days'
      do hr=1,24
         qfelect=0.0
         qfnc=sload(mo,hr,j)*(hlv+cph2o*(tbstm-tbfdw))/blreff/.98
```

```
         eldif=el(mo,hr)-eload(mo,hr,j)
         if (eldif.le.0.0) then
c
c Check to see if elec. generated meets load; if not
c
            el1=el(mo,hr)
            mexp1=mexp(mo,hr)
            qf1=qf(mo,hr)
            purch=abs(eldif)
            sell=0.0
            qgttot1=qgttot(mo,hr)
            mgttot1=mgttot(mo,hr)
            egttot1=egttot(mo,hr)
            qdetot1=qdetot(mo,hr)
            mdetot1=mdetot(mo,hr)
            edetot1=edetot(mo,hr)
            qsttot1=qsttot(mo,hr)
            msttot1=msttot(mo,hr)
            esttot1=esttot(mo,hr)
            qbttot1=qbttot(mo,hr)
            mbttot1=mbttot(mo,hr)
            ebttot1=ebttot(mo,hr)
            qstcc1=qstcc(mo,hr)
            mstcc1=mstcc(mo,hr)
            qbtcc1=qbtcc(mo,hr)
            mbtcc1=mbtcc(mo,hr)
            mtop=mgttot1+mdetot1
            mbot1=msttot1-mstcc1
            mbot2=mbttot1-mbtcc1
            qtop=qgttot1+qdetot1
            qbot1=qsttot1-qstcc1
            qbot2=qbttot1-qbtcc1
            if (mbot1.lt.0.0) mbot1=0.0
            if (qbot1.lt.0.0) qbot1=0.0
            if (mbot2.lt.0.0) mbot2=0.0
            if (qbot2.lt.0.0) qbot2=0.0
            do L=1,3
               wgt(L)=wgt(L)+elgt(L,mo,hr)*days(mo,j)
               wde(L)=wde(L)+elde(L,mo,hr)*days(mo,j)
               wst(L)=wst(L)+elst(L,mo,hr)*days(mo,j)
               wbt(L)=wbt(L)+elbt(L,mo,hr)*days(mo,j)
               mstfrc1(L,mo,hr)=mexpst1(L,mo,hr)
            end do
            fac=1.
            go to 280
         endif
c
c If excess elec. generated, then modulate engines accordingly
c
c         el1=eload(mo,hr,j)
         fac=eload(mo,hr,j)/el(mo,hr)
         mexp1=0.0
         qf1=0.0
         purch=0.0
         sell=0.0
         mstcc1=0.0
         qstcc1=0.0
         mbtcc1=0.0
         qbtcc1=0.0
c
c -- Gas Turbine --
c
         if (numgt.eq.0) go to 220
  210    egttot1=0.0
```

```
         mgttotl=0.0
         qgttotl=0.0
         elgtfull=0.0
c
c See design calcs. for descriptions of each variable
c
         do L=1,numgt
c
c Check to see if GT can meet load.  If not, then part load
c
            facgt=fac
            elgtfull=elgtfull+elgt(L,mo,hr)
            if (elgtfull.lt.eload(mo,hr,j)) then
               fac=(eload(mo,hr,j)-elgtfull)/(el(mo,hr)-elgtfull)
               facgt=1.
            endif
c
            elfrc=facgt*elgt(L,mo,hr)
            wt=3413./ngen*elfrc+wc(L)
            qffrc=agt(L)*exp(bgt(L)*elfrc)
            mgas=mair(L,mo,hr)+qffrc/hv(L)
            t31=qffrc/mgas/cpcom+t2(L,mo,hr)
            texh1=t31-wt/mgas/cptbn
c            tpinch1=tevp(L)+50.
            tpinch1=tpinchd(L)
            if (texh1.le.tstm(L).or.texh1.le.tpinch1) then
               qblr1=0.0
               go to 215
            endif
            call iterate (texh1,tstm(L),tpinch1,tevp(L),mgas,cpblr,
     &       ua(L),nblr(L))
            qblr1=mgas*cpblr*(texh1-tpinch1)
  215       mstm1=qblr1*nblr(L)/(hstm(L)-hevp(L))
            mplnt1=(1+bd(L))*mstm1*(hblr(L)-hfw(L))/(hstm(L)-hfw(L))
            mgtfrc(L,mo,hr)=mstm1-mplnt1
            mgttotl=mgttotl+mgtfrc(L,mo,hr)
            qgttotl=qgttotl+qffrc
            egttotl=egttotl+elfrc
            wgt(L)=wgt(L)+elfrc*days(mo,j)
         end do
c
c -- I.C. engine ---
c
  220    if (numde.eq.0) go to 230
         edetotl=0.0
         mdetotl=0.0
         qdetotl=0.0
         do L=1,numde
            elfrc=fac*elde(L,mo,hr)
            qffrc=ade(L,1)*exp(elfrc*bde(L,1))
            mgas=qffrc/hval(L)+mairf(L)
            texhfrc=ade(L,2)*exp(elfrc*bde(L,2))
            qsteam=mgas*cpair*(texhfrc-tstack(L))
            if (qsteam.lt.0.0) qsteam=0.0
            mdefrc(L,mo,hr)=qsteam*effncy(L)/(hsteam(L)-hwater(L))
            mdetotl=mdetotl+mdefrc(L,mo,hr)
            qdetotl=qdetotl+qffrc
            edetotl=edetotl+elfrc
            wde(L)=wde(L)+elfrc*days(mo,j)
         end do
c
c -- Extraction Steam Turbine --
c
  230    if (numst.eq.0) go to 250
```

```
         esttot1=0.0
         msttot1=0.0
         qsttot1=0.0
         mstthr1=0.0
         do L=1,numst
            elfrc=fac*elst(L,mo,hr)
            if (ref1(1,L).eq.0) mcomb=0.0
            if (ref1(1,L).eq.1) mcomb=mgtfrc(ref2(1,L),mo,hr)
            if (ref1(1,L).eq.2) mcomb=mdefrc(ref2(1,L),mo,hr)
            if (ref1(1,L).eq.3) mcomb=mstfrc1(ref2(1,L),mo,hr)
            if (ref1(1,L).eq.4) mcomb=mstfrc2(ref2(1,L),mo,hr)
            if (ref1(1,L).eq.5) mcomb=mbtfrc(ref2(1,L),mo,hr)
c
c Check to see if part load elec is less than the min elec. generated
c  at maximum steam extraction
c
            if (elfrc.lt.emin(L)) then
               mstfrc1(L,mo,hr)=(mhfld(L)+(2.0*elfrc/ed(L)-1.0)
     &          *(mexhmax(L)-mhfld(L))-mexhmin(L))/(1.0-ef(L))
               mthrfrc(L,mo,hr)=mhfld(L)+(2.0*elfrc/ed(L)-1.0)
     &          *(mexhmax(L)-mhfld(L))+mstfrc1(L,mo,hr)*ef(L)
               go to 240
            endif
c
c Check to see if part load elec is less than or eq to max design elec.
c  at no extraction.
c
            if (elfrc.le.ed(L)) then
               mstfrc1(L,mo,hr)=mextmax(L)
               mthrfrc(L,mo,hr)=mhfld(L)+(2.0*elfrc/ed(L)-1.0)
     &          *(mexhmax(L)-mhfld(L))+mstfrc1(L,mo,hr)*ef(L)
               go to 240
            else
               mthrfrc(L,mo,hr)=mthrmax(L)
               mstfrc1(L,mo,hr)=(mthrfrc(L,mo,hr)-(2.0*elfrc/ed(L)-1.0)
     &          *(mexhmax(L)-mhfld(L))-mhfld(L))/ef(L)
            endif
c
  240       msttot1=msttot1+mstfrc1(L,mo,hr)
            mstthr1=mstthr1+mthrfrc(L,mo,hr)
            qsttot1=qsttot1+mthrfrc(L,mo,hr)*(hthr(L)-hfwtr(L))/
     &        nstblr(L)/.98
            esttot1=esttot1+elfrc
            wst(L)=wst(L)+elfrc*days(mo,j)
            mstfrc2(L,mo,hr)=mthrfrc(L,mo,hr)-mstfrc1(L,mo,hr)
            mstcc1=mstcc1+mcomb/stcount(ref1(1,L),ref2(1,L))
            qstcc1=qstcc1+mcomb/stcount(ref1(1,L),ref2(1,L))*
     &        (hthr(L)-hfwtr(L))/nstblr(L)/.98
         end do
c
c -- Back-Pressure Steam Turbine --
c
  250    if (numbt.eq.0) go to 270
         ebttot1=0.0
         mbttot1=0.0
         qbttot1=0.0
         do L=1,numbt
            if (ref1(2,L).eq.0) mcomb=0.0
            if (ref1(2,L).eq.1) mcomb=mgtfrc(ref2(2,L),mo,hr)
            if (ref1(2,L).eq.2) mcomb=mdefrc(ref2(2,L),mo,hr)
            if (ref1(2,L).eq.3) mcomb=mstfrc1(ref2(2,L),mo,hr)
            if (ref1(2,L).eq.4) mcomb=mstfrc2(ref2(2,L),mo,hr)
            if (ref1(2,L).eq.5) mcomb=mbtfrc(ref2(2,L),mo,hr)
  255       elfrc=fac*elbt(L,mo,hr)
```

```
            sfrc=sfd(L)+(eed(L)-elfrc)*beta(L)
            mbtfrc(L,mo,hr)=sfrc*elfrc
            mbttotl=mbttotl+mbtfrc(L,mo,hr)
            qbttotl=qbttotl+mbtfrc(L,mo,hr)*(hinst(L)-hfeed(L))/
     &       nboil(L)/.98
            ebttotl=ebttotl+elfrc
            wbt(L)=wbt(L)+elfrc*days(mo,j)
            mbtccl=mbtccl+mcomb/stcount(ref1(2,L),ref2(2,L))
            qbtccl=qbtccl+mcomb/stcount(ref1(2,L),ref2(2,L))*
     &        (hinst(L)-hfeed(L))/nboil(L)/.98
  260    end do
c
  270    mtop=mgttotl+mdetotl
         mbot1=msttotl-mstccl
         mbot2=mbttotl-mbtccl
         qtop=qgttotl+qdetotl
         qbot1=qsttotl-qstccl
         qbot2=qbttotl-qbtccl
         if (mbot1.lt.0.0) mbot1=0.0
         if (qbot1.lt.0.0) qbot1=0.0
         if (mbot2.lt.0.0) mbot2=0.0
         if (qbot2.lt.0.0) qbot2=0.0
         mexpl=mtop+mbot1+mbot2
         qfl=qtop+qbot1+qbot2
         el1=egttotl+edetotl+esttotl+ebttotl
c         print*, el1, el2
c
c Modulate extraction steam turbine to meet the steam load if possible
c
  280    if (n.eq.0) go to 290
c         if (sload(mo,hr,j).ge.mexpl) go to 290
         if (numst.eq.0) go to 290
c
c Calculate steam necessary to reduce exported steam to steam load
c
         difstm=mexpl-sload(mo,hr,j)
         modstm=difstm/numst
         msttotl=0.0
         qsttotl=0.0
         mstthrl=0.0
         do L=1,numst
            elfrc=fac*elst(L,mo,hr)
c
c Subtract component steam from total to reduce output, and re-calc
c  elec generated
c
            mstfrcl(L,mo,hr)=mstfrcl(L,mo,hr)-modstm
            if (elfrc.le.ed(L)) then
               if (mstfrcl(L,mo,hr).lt.0.0) mstfrcl(L,mo,hr)=0.0
               mthrfrc(L,mo,hr)=(2.*elfrc/ed(L)-1.)*(mexhmax(L)-
     &          mhfld(L))+mhfld(L)+mstfrcl(L,mo,hr)*ef(L)
            else
               mextfrc=(elfrc-ed(L))*(mexhmax(L)-mhfld(L))/
     &          (ed(L)/2.)/(1.-ef(L))
               if (mstfrcl(L,mo,hr).lt.mextfrc) then
                  mstfrcl(L,mo,hr)=mextfrc
               endif
               mthrfrc(L,mo,hr)=mstfrcl(L,mo,hr)+mexhmax(L)
               if (mthrfrc(L,mo,hr).gt.mthrmax(L)) then
                  mthrfrc(L,mo,hr)=mthrmax(L)
               endif
            endif
            msttotl=msttotl+mstfrcl(L,mo,hr)
            mstthrl=mstthrl+mthrfrc(L,mo,hr)
```

```
            qsttotl=qsttotl+mthrfrc(L,mo,hr)*(hthr(L)-hfwtr(L))/
     &        nstblr(L)/.98
         end do
         mbotl=msttotl-mstccl
         qbotl=qsttotl-qstccl
         if (mbotl.lt.0.0) mbotl=0.0
         if (qbotl.lt.0.0) qbotl=0.0
         mexpl=mtop+mbotl+mbot2
         qfl=qtop+qbotl+qbot2
c
  290    stmdif=mexpl-sload(mo,hr,j)
         if (stmdif.lt.0.0) then
            qfaux=abs(stmdif)*(hlv+cph2o*(tbstm-tbfdw))/blreff/.98
            stmdif=abs(stmdif)
         else
            qfaux=0.0
            stmdif=0.0
         endif
c
         peakeng=eload(mo,hr,j)-ell
         if (peakeng.gt.peakcogen) peakcogen=peakeng
         if (eload(mo,hr,j).gt.peaknocgn) peaknocgn=eload(mo,hr,j)
c
c Efficiency calcs
c
c         qfelect=qfelect+qfaux
c
c         L=1
c         npower=ell*3413./qfelect
c         if (numbt.gt.0) then
c            hexit=hexst(L)
c            hf=hfeed(L)
c         else
c            hexit=hstm(L)
c            hf=hfw(L)
c         endif
c         qavail=mexpl*(hexit-hf)
c         ncogen=(ell*3413.+qavail)/qfelect
c         write(20,*) npower,ncogen
c
c Calculate monthly totals
c
         weload=weload+eload(mo,hr,j)*days(mo,j)
         wsload=wsload+sload(mo,hr,j)*days(mo,j)
         wel=wel+ell*days(mo,j)
         wmexp=wmexp+mexpl*days(mo,j)
         wpurch=wpurch+purch*days(mo,j)
         wstm=wstm+stmdif*days(mo,j)
         wqf=wqf+qfl/1.0e6*days(mo,j)
         wqfaux=wqfaux+qfaux/1.0e6*days(mo,j)
         wqfnc=wqfnc+qfnc/1.0e6*days(mo,j)
c
c output to file
c
         write(11,5040) hr,sload(mo,hr,j)/1000.,mgttotl/1000.,(mbotl+
     &    mbot2)/1000.,qgttotl/1.0e6,(qbotl+qbot2)/1.0e6,qfaux/1.0e6,
     &    eload(mo,hr,j),egttotl,esttotl+ebttotl,purch,tamb(mo,hr)-
     &    459.67,texh(1,mo,hr)-459.67
      end do
      end do
      write(11,5042) wsload/1000.,wmexp/1000.,wqf,wqfaux,weload,
     & wel,wpurch
      if (econ.eq.0) go to 295
      write(12,5041) weload,wsload,wel,wmexp,wpurch,wstm,wqf,wqfaux,
```

```
     & wqfnc,peaknocgn,peakcogen,0.0
  295 end do
      write(12,5041) (wgt(L),L=1,3),(wde(L),L=1,3),(wst(L),L=1,3),
     & (wbt(L),L=1,3)
c
c ----------------
c Thermal matching
c ----------------
c
  300 if (k.ne.2.and.k.ne.3) go to 9999
      write(*,*) '#2 - Thermal Matching'
      write(11,5032) 'Thermal Matching        '
      do mo=1,12
      write(11,5030) month(mo)
c
      weload=0.0
      wsload=0.0
      wel=0.0
      wmexp=0.0
      wpurch=0.0
      wstm=0.0
      wqf=0.0
      wqfaux=0.0
      wqfnc=0.0
      peakcogen=0.0
      peaknocgn=0.0
c
      do j=1,2
      if (j.eq.1) write(11,5031) 'Working Days'
      if (j.eq.2) write(11,5031) 'Non-working Days'
      do hr=1,24
         qftherm=0.0
         qfnc=sload(mo,hr,j)*(hlv+cph2o*(tbstm-tbfdw))/blreff/.98
         stmdif=mexp(mo,hr)-sload(mo,hr,j)
c
c Check to see if export steam meets steam load needs; if not
c
         if (stmdif.le.0.0) then
            mexp1=mexp(mo,hr)
            el1=el(mo,hr)
            qf1=qf(mo,hr)
            qfaux=abs(stmdif)*(hlv+cph2o*(tbstm-tbfdw))/blreff/.98
            stmdif=abs(stmdif)
            qgttot1=qgttot(mo,hr)
            mgttot1=mgttot(mo,hr)
            egttot1=egttot(mo,hr)
            qdetot1=qdetot(mo,hr)
            mdetot1=mdetot(mo,hr)
            edetot1=edetot(mo,hr)
            qsttot1=qsttot(mo,hr)
            msttot1=msttot(mo,hr)
            esttot1=esttot(mo,hr)
            qbttot1=qbttot(mo,hr)
            mbttot1=mbttot(mo,hr)
            ebttot1=ebttot(mo,hr)
            qstcc1=qstcc(mo,hr)
            mstcc1=mstcc(mo,hr)
            qbtcc1=qbtcc(mo,hr)
            mbtcc1=mbtcc(mo,hr)
            mtop=mgttot1+mdetot1
            mbot1=msttot1-mstcc1
            mbot2=mbttot1-mbtcc1
            qtop=qgttot1+qdetot1
            qbot1=qsttot1-qstcc1
```

```
            qbot2=qbttot1-qbtcc1
            if (mbot1.lt.0.0) mbot1=0.0
            if (qbot1.lt.0.0) qbot1=0.0
            if (mbot2.lt.0.0) mbot2=0.0
            if (qbot2.lt.0.0) qbot2=0.0
            go to 390
         endif
c
c Export steam is greater than steam load, so modulate engines
c
         mexp1=sload(mo,hr,j)
         fac=mexp1/mexp(mo,hr)
         facgt=fac
         el1=0.0
         qf1=0.0
         stmdif=0.0
         qfaux=0.0
         qstcc1=0.0
         mstcc1=0.0
         qbtcc1=0.0
         mbtcc1=0.0
c
c --- Gas Turbine ---
c
         if (numgt.eq.0) go to 335
c
c Check to see if GT meets steam load reqs, otherwise part load
c
c         if (mgttot(mo,hr).le.sload(mo,hr,j)) then
c            fac=(sload(mo,hr,j)-mgttot(mo,hr))/(mexp(mo,hr)-
c     &        mgttot(mo,hr))
c            facgt=1.
c         endif
  310    qgttot1=0.0
         egttot1=0.0
         mgttot1=0.0
         do L=1,numgt
            elfrc=0.0
            mgtfrc(L,mo,hr)=facgt*mexpgt(L,mo,hr)
            mstm1=mgtfrc(L,mo,hr)/(1.-(1.+bd(L))*(hblr(L)-hfw(L))/
     &       (hstm(L)-hfw(L)))
            qblr1=mstm1*(hstm(L)-hevp(L))/nblr(L)
c
c Test engines at idle
c
            qffrc=agt(L)
            mgas=qffrc/hv(L)+mair(L,mo,hr)
            t31=qffrc/mgas/cpcom+t2(L,mo,hr)
            wt=3413./ngen*elfrc+wc(L)
            texh1=t31-wt/mgas/cptbn
c            tpinch1=tpinchd(L)
            tpinch1=tevp(L)+10.
c
c If Texhaust < Tsteam, then recalculate Texhaust and elec generated
c  in order to minimum temperature requirements
c
            if (texh1.le.tstm(L)) then
               elfrc=elgt(L,mo,hr)*facgt
               call newton (elfrc,elgt(L,mo,hr),agt(L),bgt(L),cpcom,
     &          hv(L),t2(L,mo,hr),tstm(L),mair(L,mo,hr),cptbn,ngen,
     &          wc(L))
               go to 320
            endif
c            write(*,6000) '0a',texh1,tstm(L),tpinch1,tevp(L)
```

```
            call iterate (texh1,tstm(L),tpinch1,tevp(L),mgas,cpblr,
     &       ua(L),nblr(L))
c            write(*,6000) '0b',texh1,tstm(L),tpinch1,tevp(L)
 6000       format(1x,a2,4(3x,f8.2))
            qblr2=mgas*cpblr*(texh1-tpinch1)
c
c If steam load is met at idling conditions, then finish
c
            if (qblr2.ge.qblr1) go to 330
c
c Now test at part load
c
            elfrc=facgt*elgt(L,mo,hr)
  320       qffrc=agt(L)*exp(bgt(L)*elfrc)
            mgas=qffrc/hv(L)+mair(L,mo,hr)
            t31=qffrc/mgas/cpcom+t2(L,mo,hr)
            wt=3413./ngen*elfrc+wc(L)
            texh1=t31-wt/mgas/cptbn
c            tpinch1=tpinchd(L)
            tpinch1=tevp(L)+10.
c
c Once again, check to make sure exhaust temp is greater than steam temp
c
            if (texh1.le.tstm(L)) then
               call newton (elfrc,elgt(L,mo,hr),agt(L),bgt(L),cpcom,
     &          hv(L),t2(L,mo,hr),tstm(L),mair(L,mo,hr),cptbn,ngen,
     &          wc(L))
               go to 320
            endif
c            write(*,6000) '1a',texh1,tstm(L),tpinch1,tevp(L)
            call iterate (texh1,tstm(L),tpinch1,tevp(L),mgas,cpblr,
     &       ua(L),nblr(L))
c            write(*,6000) '1b',texh1,tstm(L),tpinch1,tevp(L)
            qblr2=mgas*cpblr*(texh1-tpinch1)
c
c Must iterate to find part load elec generated.  Match Qblr on gas side
c  of H.E. with Qblr on steam side of H.E.
c
            dev=(qblr1-qblr2)/qblr2
            if (abs(dev).le.0.01) go to 330
            elfrc=elfrc*(1.+dev)
            go to 320
c
  330       mgttot1=mgttot1+mgtfrc(L,mo,hr)
            egttot1=egttot1+elfrc
            qgttot1=qgttot1+qffrc
         end do
c
c --- I.C. Engines ---
c
  335    if (numde.eq.0) go to 340
         qdetot1=0.0
         edetot1=0.0
         mdetot1=0.0
         do L=1,numde
            mdefrc(L,mo,hr)=fac*mexpde(L,mo,hr)
            qsteam1=mdefrc(L,mo,hr)*(hsteam(L)-hwater(L))/effncy(L)
            elfrc=fac*elde(L,mo,hr)
c
  337       qffrc=ade(L,1)*exp(bde(L,1)*elfrc)
            texhfrc=ade(L,2)*exp(bde(L,2)*elfrc)
            qsteam2=(qffrc/hval(L)+mairf(L))*(texhfrc-tstack(L))*cpair
            dev=(qsteam1-qsteam2)/qsteam2
            if (abs(dev).le.0.01) go to 338
```

```
            elfrc=elfrc*(1.0+dev)
            if (texhfrc.lt.tstack(L)) then
               elfrc=1.0/bde(L,2)*alog(tstack(L)/ade(L,2))
               go to 338
            endif
            go to 337
c
  338       mdetot1=mdetot1+mdefrc(L,mo,hr)
            edetot1=edetot1+elfrc
            qdetot1=qdetot1+qffrc
         end do
c
c --- Extraction Steam Turbine ---
c
  340    if (numst.eq.0) go to 360
         qsttot1=0.0
         esttot1=0.0
         msttot1=0.0
         do L=1,numst
            if (ref1(1,L).eq.0) mcomb=0.0
            if (ref1(1,L).eq.1) mcomb=mgtfrc(ref2(1,L),mo,hr)
            if (ref1(1,L).eq.2) mcomb=mdefrc(ref2(1,L),mo,hr)
            if (ref1(1,L).eq.3) mcomb=mstfrc1(ref2(1,L),mo,hr)
            if (ref1(1,L).eq.4) mcomb=mstfrc2(ref2(1,L),mo,hr)
            if (ref1(1,L).eq.5) mcomb=mbtfrc(ref2(1,L),mo,hr)
c
            mstfrc1(L,mo,hr)=fac*mexpst1(L,mo,hr)+(1.-fac)*
     &       mcomb/stcount(ref1(1,L),ref2(1,L))
c
c Check to see if extract. steam is less than minimum extraction steam
c  at pf=1.0
c
            if (mstfrc1(L,mo,hr).lt.mxmin(L)) then
               elfrc=ed(L)/2.0*(1.0+(mstfrc1(L,mo,hr)*(1.0-ef(L))+
     &          mexhmax(L)-mhfld(L))/(mexhmax(L)-mhfld(L)))
               mthrfrc(L,mo,hr)=mstfrc1(L,mo,hr)+mexhmax(L)
               go to 350
            endif
c
            elfrc=elcd(L)
            mthrfrc(L,mo,hr)=mhfld(L)+(2.0*elfrc/ed(L)-1.0)*
     &       (mexhmax(L)-mhfld(L))+mstfrc1(L,mo,hr)*ef(L)
c
  350       elstfrc(L,mo,hr)=elfrc
            esttot1=esttot1+elfrc
            qsttot1=qsttot1+mthrfrc(L,mo,hr)*(hthr(L)-hfwtr(L))/
     &       nstblr(L)/.98
            msttot1=msttot1+mstfrc1(L,mo,hr)
            mstfrc2(L,mo,hr)=mthrfrc(L,mo,hr)-mstfrc1(L,mo,hr)
            mstcc1=mstcc1+mcomb/stcount(ref1(1,L),ref2(1,L))
            qstcc1=qstcc1+mcomb/stcount(ref1(1,L),ref2(1,L))*
     &        (hthr(L)-hfwtr(L))/nstblr(L)/.98
         end do
c
c --- Back-Pressure Steam Turbine ---
c
  360    if (numbt.eq.0) go to 380
         mbttot1=0.0
         qbttot1=0.0
         ebttot1=0.0
         do L=1,numbt
            if (ref1(2,L).eq.0) mcomb=0.0
            if (ref1(2,L).eq.1) mcomb=mgtfrc(ref2(2,L),mo,hr)
            if (ref1(2,L).eq.2) mcomb=mdefrc(ref2(2,L),mo,hr)
```

```
           if (ref1(2,L).eq.3) mcomb=mstfrc1(ref2(2,L),mo,hr)
           if (ref1(2,L).eq.4) mcomb=mstfrc2(ref2(2,L),mo,hr)
           if (ref1(2,L).eq.5) mcomb=mbtfrc(ref2(2,L),mo,hr)
c
           mbtfrc(L,mo,hr)=fac*mexpbt(L,mo,hr)+(1.-fac)*
     &      mcomb/stcount(ref1(2,L),ref2(2,L))
c
c To find elec generated, must use polynomial equation to solve for
c  two answers.  Only one answer can be acceptable, therefore we
c  must test.
c
 370       a2=beta(L)
           b2=-(sfd(L)+eed(L)*beta(L))
           c2=mbtfrc(L,mo,hr)
           d2=sqrt(b2**2-4.*a2*c2)
           eefrc1=(-b2+d2)/a2/2.
           eefrc2=(-b2-d2)/a2/2.
           if (eefrc1.gt.eed(L).and.eefrc2.le.eed(L).and.
     &      eefrc2.gt.0.0) then
              ebttot1=ebttot1+eefrc2
           else
              ebttot1=ebttot1+eefrc1
           endif
           qbttot1=qbttot1+mbtfrc(L,mo,hr)*(hinst(L)-hfeed(L))/
     &       nboil(L)/.98
           mbttot1=mbttot1+mbtfrc(L,mo,hr)
           mbtcc1=mbtcc1+mcomb/stcount(ref1(2,L),ref2(2,L))
           qbtcc1=qbtcc1+mcomb/stcount(ref1(2,L),ref2(2,L))*
     &       (hinst(L)-hfeed(L))/nboil(L)/.98
        end do
c
 380    mtop=mgttot1+mdetot1
        mbot1=msttot1-mstcc1
        mbot2=mbttot1-mbtcc1
        qtop=qgttot1+qdetot1
        qbot1=qsttot1-qstcc1
        qbot2=qbttot1-qbtcc1
        if (mbot1.lt.0.0) mbot1=0.0
        if (qbot1.lt.0.0) qbot1=0.0
        if (mbot2.lt.0.0) mbot2=0.0
        if (qbot2.lt.0.0) qbot2=0.0
        mexp2=mtop+mbot1+mbot2
        qf1=qtop+qbot1+qbot2
        el1=egttot1+edetot1+esttot1+ebttot1
c
c Modulate extraction steam turbine to meet the elec load if possible
c
        if (n.eq.0) go to 390
c        if (eload(mo,hr,j).ge.el1) go to 390
        if (numst.eq.0) go to 390
c
c Calculate electricity needed to reduce engines to elec. load
c
        difelc=el1-eload(mo,hr,j)
        modelc=difelc/numst
        esttot1=0.0
        qsttot1=0.0
        do L=1,numst
c
c Reduce elec generated by a calculated amount, then recalc. throttle
c  steam.  Make sure that elec does not go below minimum req'd.
c
           elstfrc(L,mo,hr)=elstfrc(L,mo,hr)-modelc
           eltst=ed(L)/2.*(1.+(mstfrc1(L,mo,hr)*(1.-ef(L))+mexhmin(L)
```

```
     &        -mhfld(L))/(mexhmax(L)-mhfld(L)))
            if (eltst.lt.0.0) eltst=0.0
            if (elstfrc(L,mo,hr).lt.eltst) elstfrc(L,mo,hr)=eltst
            mthrfrc(L,mo,hr)=(2.*elstfrc(L,mo,hr)/ed(L)-1.)*(mexhmax(L)
     &        -mhfld(L))+mhfld(L)+mstfrcl(L,mo,hr)*ef(L)
            qsttotl=qsttotl+mthrfrc(L,mo,hr)*(hthr(L)-hfwtr(L))/
     &        nstblr(L)/.98
            esttotl=esttotl+elstfrc(L,mo,hr)
         end do
         ell=egttotl+edetotl+esttotl+ebttotl
         qbotl=qsttotl-qstccl
         if (qbotl.lt.0.0) qbotl=0.0
         qfl=qtop+qbotl+qbot2
c
  390    eldif=ell-eload(mo,hr,j)
         if (eldif.ge.0.0) then
            sell=eldif
            purch=0.0
         else
            purch=abs(eldif)
            sell=0.0
         endif
c
         peakcogen=peakcogen+ell
         if (eload(mo,hr,j).gt.peaknocgn) peaknocgn=eload(mo,hr,j)
c
         weload=weload+eload(mo,hr,j)*days(mo,j)
         wsload=wsload+sload(mo,hr,j)*days(mo,j)
         wel=wel+ell*days(mo,j)
         wmexp=wmexp+mexpl*days(mo,j)
         wpurch=wpurch+purch*days(mo,j)
         wstm=wstm+stmdif*days(mo,j)
         wqf=wqf+qfl/1.0e6*days(mo,j)
         wqfaux=wqfaux+qfaux/1.0e6*days(mo,j)
         wqfnc=wqfnc+qfnc/1.0e6*days(mo,j)
c
         write(11,5040) hr,sload(mo,hr,j)/1000.,mgttotl/1000.,(mbotl+
     &    mbot2)/1000.,qgttotl/1.0e6,(qbotl+qbot2)/1.0e6,qfaux/1.0e6,
     &    eload(mo,hr,j),egttotl,esttotl+ebttotl,purch,tamb(mo,hr)-
     &    459.67,texh(1,mo,hr)-459.67
      end do
      end do
      write(11,5042) wsload/1000.,wmexp/1000.,wqf,wqfaux,weload,
     & wel,wpurch
      if (econ.eq.0) go to 395
      peakcogen=peakcogen/24.0/2.0
      write(12,5041) weload,wsload,wel,wmexp,wpurch,wstm,wqf,wqfaux,
     & wqfnc,peakcogen,peaknocgn
  395 end do
      stop
c
 5030 format(//1x,a10)
 5031 format(/1x,a16//2x,'Hour',3x,'Stm Load',3x,'HRSG Stm',5x,'ST Stm',
     & 4x,'GT Fuel',3x,'Blr Fuel',3x,'Aux Fuel',2x,'Elec Load',4x,
     & 'GT Elec',4x,'ST Elec',2x,'Util Elec',2x,'Amb Tmp',2x,'Exh Tmp'/
     & 6x,3(3x,'[klb/hr]'),3(1x,'[MMBtu/hr]'),4(7x,'[kW]'),2(5x,'[øF]'),
     & /1x,133('-'))
 5032 format(//1x,a22)
 5040 format(4x,i2,6(f11.2),4(f11.0),2(f9.0))
 5041 format(1x,12(f15.2))
 5042 format(/1x,100('-')/1x,'Total',3x,'Stm Load',4x,'Exp Stm',
     & 3x,'Prm Fuel',3x,'Aux Fuel',2x,'Elec Load',3x,'Gen Elec',
     & 2x,'Util Elec'/1x,'Month',5x,'[kLbs]',5x,'[kLbs]',4x,'[MMBtu]',
     & 4x,'[MMBtu]',6x,'[kWh]',6x,'[kWh]',6x,'[kWh]'/2x,'Data',
```

```
     & 4(f11.2),3(f11.0)/1x,100('-'))
c
 5050 format(/1x,'The gas turbine exhaust temperature is less than the r
     &equired'/1x,'heat exchanger exit steam temperature.  Either use a
     &different'/1x,'gas turbine with higher exhaust temp., or lower the
     & required'/1x,'h.e. steam temp.')
c
 9998 write(*,5050)
 9999 stop
      end
c
c=================================================================
c------------------------END OF PROGRAM---------------------------
c=================================================================
      subroutine expfit (afit,bfit,ax,bx)
      dimension ax(3),bx(3)
c
c This subroutine will take two inputs, of three sets each, and calc
c  an exponential curve to fit the points.
c
      r1=0
      r2=0
      r3=0
      r4=0
      do i=1,3
         r1=r1+ax(i)*alog(bx(i))
         r2=r2+ax(i)
         r3=r3+alog(bx(i))
         r4=r4+ax(i)**2
      end do
      bfit=(r1-r2*r3/3)/(r4-r2**2/3)
      afit=exp(r3/3-bfit*r2/3)
      return
      end
c
c ================================================================
c
      subroutine iterate (texh,tstm,tpinch,tevp,mgas,cpblr,ua,nblr)
      implicit real(a-z)
      tlogm(tx1,tx2,tx3,tx4)=(tx1-tx2-tx3+tx4)/alog((tx1-tx2)/(tx3-tx4))
c
c This subroutine uses Newton-Raphson iterative technique to find
c  the pinch point temperature
c
      tsav=tpinch
      dev=tpinch
      tol=0.5
      const=ua/nblr/cpblr/mgas
   10 f=exp(const*((tstm-tevp)/(texh-tpinch)-1.))-(tpinch-tevp)/
     & (texh-tstm)
      df=const*(tstm-tevp)/((texh-tpinch)**2)*exp(const*((tstm-tevp)/
     & (texh-tpinch)-1.))-1./(texh-tstm)
      tpinch=tpinch-f/df
      devp=dev
      dev=abs(f/df)
c      write (*,*) dev
      if (dev.le.tol) return
      if (dev.gt.devp) then
         tpinch=tsav
         return
      endif
      go to 10
      end
c ----------------------------------
```

```
c      tol=1.
c      const=ua/nblr/cpblr/mgas
c      tmin=tevp+1.
c      inc=(tpinch-tmin)/2.
c      tpgs=tmin+39
c   10 tp1=texh-const*tlogm(texh,tstm,tpgs,tevp)
c      value=tp1-tpgs
c      write(*,*) value
c      if (abs(value).lt.tol) then
c         tpinch=tpgs
c         return
c      elseif (value.gt.0.0) then
c         tpgs=tpgs+inc
c         go to 10
c      else
c         tpgs=tpgs-inc
c         inc=inc/2.
c         go to 10
c      endif
c      end
c
c ==================================================================
c
c Use Newton-Raphson method if Texh < Tstm
c
      subroutine newton (eltst,dev,agt,bgt,cpcom,hv,t2,tstm,mair,
     & cptbn,ngen,wc)
      implicit real(a-z)
c
      tol=0.01
      elsav=eltst
   10 f=agt*exp(bgt*eltst)*(1./cpcom+1./hv*(t2-tstm))+mair
     & *(t2-tstm)-1./cptbn*(3413.*eltst/ngen+wc)
      df=agt*bgt*exp(bgt*eltst)*(1./cpcom+1./hv*(t2-tstm))
     & -3413./cptbn/ngen
      eltst=eltst-f/df
      devp=dev
      dev=abs(f/df)
      if (dev.le.tol) then
         eltst=eltst+25.
         return
      endif
      if (dev.gt.devp) then
         eltst=elsav
         return
      endif
      go to 10
      end
```

DATA-ENTRY PROGRAM

```
DECLARE SUB getinfo (curr() AS DOUBLE, a, vpos, hmin, num)
ON ERROR GOTO errhandler
DIM gtvar(1 TO 3, 1 TO 25) AS DOUBLE
DIM devar(1 TO 3, 1 TO 25) AS DOUBLE
DIM stvar(1 TO 3, 1 TO 25) AS DOUBLE
DIM btvar(1 TO 3, 1 TO 25) AS DOUBLE
DIM curr(1 TO 3, 1 TO 25) AS DOUBLE
DIM tmax(1 TO 12), tmin(1 TO 12), month$(1 TO 12)
DIM eload(1 TO 12, 1 TO 24, 1 TO 2)
DIM sload(1 TO 12, 1 TO 24, 1 TO 2)
CONST ESC = 27, DOWN = 80, UP = 72, LEFT = 75, RIGHT = 77
CONST HOME = 71, ENDKEY = 79, PGDN = 81, PGUP = 73

FOR i = 1 TO 12
   READ month$(i)
NEXT i
DATA
January,February,March,April,May,June,July,August,September,October,November,D
ecember

begin:
   CLOSE
   CLS
   LOCATE 1, 15
   PRINT "COGENERATION SIMULATION PROGRAM DATA ENTRY MODULE"
   LOCATE 6, 1
   PRINT "CHOOSE ONE OF THE FOLLOWING:"
   PRINT : PRINT "1) Create/Edit New Engine Data File"
   PRINT : PRINT "2) Create/Edit New Loads Data File"
   PRINT : PRINT "3) Run a Simulation"
   PRINT : PRINT "4) Exit the Program"
   PRINT : INPUT "Selection: ", a$
   a = VAL(a$)
   IF a < 1 AND a > 4 THEN GOTO begin
   ON a GOSUB enginedata, loaddata, simulation, quit
   GOTO begin

enginedata:

   CLS
   PRINT "Create/Edit New Engine Data"

100 LOCATE 3, 1
   INPUT "Enter <path> and <filename> for file: ", engfile$
   IF engfile$ = "" THEN RETURN
   OPEN engfile$ FOR INPUT AS #1
   IF e = 53 THEN
      e = 0
      PRINT : INPUT "Do you want to create a new file?", a$
      IF a$ = "Y" OR a$ = "y" THEN
         numgt = 0: numde = 0: numst = 0: numbt = 0
         FOR i = 1 TO 3: FOR j = 1 TO 25
            gtvar(i, j) = 0
            devar(i, j) = 0
            stvar(i, j) = 0
            btvar(i, j) = 0
         NEXT j, i
         GOTO 140
      ELSE
         RETURN
```

```
      END IF
   END IF
   PRINT : PRINT "Reading file information..."
   INPUT #1, numgt, numde, numst, numbt

105 IF numgt = 0 GOTO 110
   FOR i = 1 TO numgt
      FOR j = 1 TO 23
         INPUT #1, gtvar(i, j)
      NEXT j
      INPUT #1, a$
   NEXT i

110 IF numde = 0 GOTO 120
   FOR i = 1 TO numde
      FOR j = 1 TO 21
         INPUT #1, devar(i, j)
      NEXT j
      INPUT #1, a$
   NEXT i

120 IF numst = 0 GOTO 130
   FOR i = 1 TO numst
      FOR j = 1 TO 20
         INPUT #1, stvar(i, j)
      NEXT j
      INPUT #1, a$
   NEXT i

130 IF numbt = 0 GOTO 140
   FOR i = 1 TO numbt
      FOR j = 1 TO 14
         INPUT #1, btvar(i, j)
      NEXT j
      INPUT #1, a$
   NEXT i

140 CLOSE #1

145 CLS : PRINT "This file contains information on: "
   PRINT : PRINT "1) "; numgt; "gas turbine(s)"
   PRINT "2) "; numde; "diesel engine(s)"
   PRINT "3) "; numst; "extraction steam turbine(s)"
   PRINT "4) "; numbt; "condesing steam turbine(s)"
   PRINT : PRINT "5) Save File"
   PRINT "6) Go to main menu"
   PRINT : INPUT "Which?", a$
   a = VAL(a$)
   IF a < 1 OR a > 6 GOTO 145
   IF a = 6 THEN RETURN
   ON a GOSUB 150, 160, 170, 180, 200
   GOTO 145

'Gas Turbine

150 LOCATE 15, 1
   INPUT "(E)dit or (D)elete a gas turbine: ", a$
   IF a$ = "e" OR a$ = "E" GOTO 156
   IF a$ = "d" OR a$ = "D" GOTO 157
   RETURN

157 IF numgt = 0 THEN RETURN
   PRINT : INPUT "Delete which gas turbine (1-3): ", a$
   a = VAL(a$)
```

```
   IF a = 0 THEN RETURN
   IF a < 1 OR a > 3 OR a > numgt GOTO 157
   FOR i = 1 TO 23: gtvar(a, i) = 0: NEXT i
   IF a = numgt THEN
      numgt = numgt - 1
   ELSE
      FOR j = a TO numgt - 1
         FOR i = 1 TO 23
            gtvar(j, i) = gtvar(j + 1, i)
         NEXT i
      NEXT j
      numgt = numgt - 1
   END IF
   RETURN

156 PRINT : INPUT "Edit which gas turbine (1-3): ", a$
   a = VAL(a$)
   IF a = 0 THEN RETURN
   IF a < 1 OR a > 3 OR a > numgt + 1 GOTO 156
   IF a > numgt THEN
      PRINT : INPUT "Edit a new gas turbine? ", c$
      IF c$ <> "Y" AND c$ <> "y" THEN RETURN
      numgt = numgt + 1
   END IF

155 CLS
   PRINT "                  Design output, kW :"; gtvar(a, 1)
   PRINT "    Design fuel consumption, Btu/hr :"; gtvar(a, 2)
   PRINT "              Design air flow, lb/hr :"; gtvar(a, 3)
   PRINT "                   Ambient temp., R :"; gtvar(a, 4)
   PRINT "               Ambient press., psig :"; gtvar(a, 5)
   PRINT "         Fuel heating value, Btu/lb :"; gtvar(a, 6)
   PRINT "              Inlet temp to HRSG, R :"; gtvar(a, 7)
   PRINT "     Inlet enthalpy to HRSG, Btu/lb :"; gtvar(a, 8)
   PRINT "    HRSG Feedwater enthalpy, Btu/lb :"; gtvar(a, 9)
   PRINT "       Steam fraction blowdown loss :"; gtvar(a, 10)
   PRINT "                     Elec. output #1 :"; gtvar(a, 11)
   PRINT "                     Elec. output #2 :"; gtvar(a, 12)
   PRINT "                     Elec. output #3 :"; gtvar(a, 13)
   PRINT "                 Fuel consumption #1 :"; gtvar(a, 14)
   PRINT "                 Fuel consumption #2 :"; gtvar(a, 15)
   PRINT "                 Fuel consumption #3 :"; gtvar(a, 16)
   PRINT "     Exit steam press to HRSG, psig :"; gtvar(a, 17)
   PRINT "         Exit steam temp to HRSG, R :"; gtvar(a, 18)
   PRINT "Exit steam enthalpy to HRSG, Btu/lb :"; gtvar(a, 19)
   PRINT "                  Feedwater temp, R :"; gtvar(a, 20)
   PRINT "         Feedwater enthalpy, btu/lb :"; gtvar(a, 21)
   PRINT "                  Efficiency of HRSG :"; gtvar(a, 22)
   PRINT "               Effectiveness of HRSG :"; gtvar(a, 23)
   LOCATE 24, 50
   COLOR 0, 7: PRINT "Editing Gas Turbine #"; a; : COLOR 7, 0
   vpos = 1
   hmin = 39
   num = 23

153 CALL getinfo(gtvar(), a, vpos, hmin, num)
   RETURN

'Diesel Engine

160 LOCATE 15, 1
   INPUT "(E)dit or (D)elete a diesel engine: ", a$
   IF a$ = "e" OR a$ = "E" GOTO 166
   IF a$ = "d" OR a$ = "D" GOTO 167
```

```
   RETURN

167 IF numde = 0 THEN RETURN
   PRINT : INPUT "Delete which diesel engine (1-3): ", a$
   a = VAL(a$)
   IF a = 0 THEN RETURN
   IF a < 1 OR a > 3 OR a > numde GOTO 167
   FOR i = 1 TO 21: devar(a, i) = 0: NEXT i
   IF a = numde THEN
      numde = numde - 1
   ELSE
      FOR j = a TO numde - 1
         FOR i = 1 TO 21
            devar(j, i) = devar(j + 1, i)
         NEXT i
      NEXT j
      numde = numde - 1
   END IF
   RETURN

166 PRINT : INPUT "Edit which diesel engine (1-3): ", a$
   a = VAL(a$)
   IF a = 0 THEN RETURN
   IF a < 1 OR a > 3 OR a > numde + 1 GOTO 166
   IF a > numde THEN
      PRINT : INPUT "Edit a new diesel engine? ", c$
      IF c$ <> "Y" AND c$ <> "y" THEN RETURN
      numde = numde + 1
   END IF

165 CLS
   PRINT "    Design fuel consumption, Btu/hr :"; devar(a, 1)
   PRINT "                  Design output, kW :"; devar(a, 2)
   PRINT "            Design exhaust temp, R :"; devar(a, 3)
   PRINT "            Design air flow, lb/hr :"; devar(a, 4)
   PRINT "                 Stack gas temp., R :"; devar(a, 5)
   PRINT "         Steam press. to HRSG, psig :"; devar(a, 6)
   PRINT "                   Temp to HRSG, R :"; devar(a, 7)
   PRINT "                 Feedwater temp, R :"; devar(a, 8)
   PRINT "Exit steam enthalpy of HRSG, Btu/lb :"; devar(a, 9)
   PRINT "    HRSG Feedwater enthalpy, Btu/lb :"; devar(a, 10)
   PRINT "                   HRSG efficiency :"; devar(a, 11)
   PRINT "         Fuel heating value, Btu/lb :"; devar(a, 12)
   PRINT "                   Elec. output #1 :"; devar(a, 13)
   PRINT "                   Elec. output #2 :"; devar(a, 14)
   PRINT "                   Elec. output #3 :"; devar(a, 15)
   PRINT "               Fuel consumption #1 :"; devar(a, 16)
   PRINT "               Fuel consumption #2 :"; devar(a, 17)
   PRINT "               Fuel consumption #3 :"; devar(a, 18)
   PRINT "                  Exhaust temp. #1 :"; devar(a, 19)
   PRINT "                  Exhaust temp. #2 :"; devar(a, 20)
   PRINT "                  Exhaust temp. #3 :"; devar(a, 21)
   LOCATE 24, 50
   COLOR 0, 7: PRINT "Editing Diesel Engine #"; a; : COLOR 7, 0
   vpos = 1
   hmin = 39
   num = 21

163 CALL getinfo(devar(), a, vpos, hmin, num)
   RETURN

'Extraction Steam Turbine

170 LOCATE 15, 1
```

```
   INPUT "(E)dit or (D)elete a steam turbine: ", a$
   IF a$ = "e" OR a$ = "E" GOTO 176
   IF a$ = "d" OR a$ = "D" GOTO 177
   RETURN

177 IF numst = 0 THEN RETURN
   PRINT : INPUT "Delete which steam turbine (1-3): ", a$
   a = VAL(a$)
   IF a = 0 THEN RETURN
   IF a < 1 OR a > 3 OR a > numst GOTO 177
   FOR i = 1 TO 20: stvar(a, i) = 0: NEXT i
   IF a = numst THEN
      numst = numst - 1
   ELSE
      FOR j = a TO numst - 1
         FOR i = 1 TO 20
            stvar(j, i) = stvar(j + 1, i)
         NEXT i
      NEXT j
      numst = numst - 1
   END IF
   RETURN

176 PRINT : INPUT "Edit which steam turbine (1-3): ", a$
   a = VAL(a$)
   IF a = 0 THEN RETURN
   IF a < 1 OR a > 3 OR a > numst + 1 GOTO 176
   IF a > numst THEN
      PRINT : INPUT "Edit a new steam turbine? ", c$
      IF c$ <> "Y" AND c$ <> "y" THEN RETURN
      numst = numst + 1
   END IF

175 CLS
   PRINT "              Throttle pressure, psig :"; stvar(a, 1)
   PRINT "     Steam extraction pressure, psig :"; stvar(a, 2)
   PRINT "        Steam exhaust pressure, psig :"; stvar(a, 3)
   PRINT "             Throttle temperature, R :"; stvar(a, 4)
   PRINT "     Throttle steam enthalpy, Btu/lb :"; stvar(a, 5)
   PRINT "           Power output @ pf=1.0, kW :"; stvar(a, 6)
   PRINT "             Design power output, kW :"; stvar(a, 7)
   PRINT "       Correction factor for exhaust :"; stvar(a, 8)
   PRINT "          Feedwater enthalpy, Btu/lb :"; stvar(a, 9)
   PRINT "      Efficiency of gas-fired boiler :"; stvar(a, 10)
   PRINT "        Maximum throttle flow, lb/hr :"; stvar(a, 11)
   PRINT "      Maximum extraction flow, lb/hr :"; stvar(a, 12)
   PRINT " 1st Theoretical steam rate, lb/kWh :"; stvar(a, 13)
   PRINT " 2nd Theoretical steam rate, lb/kWh :"; stvar(a, 14)
   PRINT "        Full-load turbine efficiency :"; stvar(a, 15)
   PRINT "               Half-load flow factor :"; stvar(a, 16)
   PRINT "         Maximum exhaust flow, lb/hr :"; stvar(a, 17)
   PRINT "         Minimum exhaust flow, lb/hr :"; stvar(a, 18)
   PRINT "          Throttle flow reference #1 :"; stvar(a, 19)
   PRINT "          Throttle flow reference #2 :"; stvar(a, 20)
   LOCATE 24, 50
   COLOR 0, 7: PRINT "Editing Steam Turbine #"; a; : COLOR 7, 0
   vpos = 1
   hmin = 39
   num = 20

173 CALL getinfo(stvar(), a, vpos, hmin, num)
   RETURN

'Condensing Steam Turbine
```

```
180 LOCATE 15, 1
   INPUT "(E)dit or (D)elete a steam turbine: ", a$
   IF a$ = "e" OR a$ = "E" GOTO 186
   IF a$ = "d" OR a$ = "D" GOTO 187
   RETURN

187 IF numbt = 0 THEN RETURN
   PRINT : INPUT "Delete which steam turbine (1-3): ", a$
   a = VAL(a$)
   IF a = 0 THEN RETURN
   IF a < 1 OR a > 3 OR a > numbt GOTO 187
   FOR i = 1 TO 14: btvar(a, i) = 0: NEXT i
   IF a = numbt THEN
      numbt = numbt - 1
   ELSE
      FOR j = a TO numbt - 1
         FOR i = 1 TO 14
            btvar(j, i) = btvar(j + 1, i)
         NEXT i
      NEXT j
      numbt = numbt - 1
   END IF
   RETURN

186 PRINT : INPUT "Edit which steam turbine (1-3): ", a$
   a = VAL(a$)
   IF a = 0 THEN RETURN
   IF a < 1 OR a > 3 OR a > numbt + 1 GOTO 186
   IF a > numbt THEN
      PRINT : INPUT "Edit a new steam turbine? ", c$
      IF c$ <> "Y" AND c$ <> "y" THEN RETURN
      numbt = numbt + 1
   END IF

185 CLS
   PRINT "       Full power design output, kW :"; btvar(a, 1)
   PRINT "      Full power steam rate, lb/kWh :"; btvar(a, 2)
   PRINT "           Partial power output, kW :"; btvar(a, 3)
   PRINT "   Partial power steam rate, lb/kWh :"; btvar(a, 4)
   PRINT "         Throttle flow reference #1 :"; btvar(a, 5)
   PRINT "         Throttle flow reference #2 :"; btvar(a, 6)
   PRINT "    Throttle steam enthalpy, Btu/lb :"; btvar(a, 7)
   PRINT "      Throttle steam pressure, psig :"; btvar(a, 8)
   PRINT "      Throttle steam temperature, R :"; btvar(a, 9)
   PRINT "       Exhaust steam pressure, psig :"; btvar(a, 10)
   PRINT "       Exhaust steam temperature, R :"; btvar(a, 11)
   PRINT "     Exhaust steam enthalpy, Btu/lb :"; btvar(a, 12)
   PRINT "         Feedwater enthalpy, Btu/lb :"; btvar(a, 13)
   PRINT "     Efficiency of gas-fired boiler :"; btvar(a, 14)
   LOCATE 24, 50
   COLOR 0, 7: PRINT "Editing Steam Turbine #"; a; : COLOR 7, 0
   vpos = 1
   hmin = 39
   num = 14

183 CALL getinfo(btvar(), a, vpos, hmin, num)
   RETURN

'Saving file

200 CLS
   PRINT "Save as filename ["; engfile$; "] :";
   INPUT "", a$
```

```
   IF a$ = "" THEN a$ = engfile$
   PRINT : PRINT "Saving data..."
   OPEN a$ FOR OUTPUT AS #1
   PRINT #1, numgt; SPC(5); numde; SPC(5); numst; SPC(5); numbt

205 IF numgt = 0 GOTO 206
   FOR i = 1 TO numgt
      FOR j = 1 TO 23
         PRINT #1, USING "###########.##"; gtvar(i, j);
         IF (j MOD 4) = 0 THEN PRINT #1, " "
      NEXT j
      PRINT #1, " "
      PRINT #1, " "
   NEXT i

206 IF numde = 0 GOTO 207
   FOR i = 1 TO numde
      FOR j = 1 TO 21
         PRINT #1, USING "###########.##"; devar(i, j);
         IF (j MOD 4) = 0 THEN PRINT #1, " "
      NEXT j
      PRINT #1, " "
      PRINT #1, " "
   NEXT i

207 IF numst = 0 GOTO 208
   FOR i = 1 TO numst
      FOR j = 1 TO 20
         IF j = 19 OR j = 20 THEN
            PRINT #1, USING "##############"; stvar(i, j);
         ELSE
            PRINT #1, USING "###########.##"; stvar(i, j);
         END IF
         IF (j MOD 4) = 0 THEN PRINT #1, " "
      NEXT j
      PRINT #1, " "
   NEXT i

208 IF numbt = 0 GOTO 209
   FOR i = 1 TO numbt
      FOR j = 1 TO 14
         IF j = 5 OR j = 6 THEN
            PRINT #1, USING "##############"; btvar(i, j);
         ELSE
            PRINT #1, USING "###########.##"; btvar(i, j);
         END IF
         IF (j MOD 4) = 0 THEN PRINT #1, " "
      NEXT j
      PRINT #1, " "
      PRINT #1, " "
   NEXT i

209 CLOSE #1
   RETURN

loaddata:

500 CLS
   PRINT "Create/Edit New Load Data"
   LOCATE 3, 1
   INPUT "Enter <path> and <filename> for file: ", loadfile$
   IF loadfile$ = "" THEN RETURN
   OPEN loadfile$ FOR INPUT AS #1
   IF e = 53 THEN
```

```
      e = 0
      PRINT : INPUT "Do you want to create a new file?", a$
      IF a$ = "Y" OR a$ = "y" THEN
         FOR i = 1 TO 12
            tmax(i) = 0
            tmin(i) = 0
         NEXT i
         pamb = 0
         tstm = 0: tfdw = 0: hv = 0: blreff = 0
         FOR m = 1 TO 12
            FOR d = 1 TO 2
            FOR h = 1 TO 24
                eload(m, h, d) = 0
                sload(m, h, d) = 0
            NEXT h, d
         NEXT m
         GOTO 510
      ELSE
         RETURN
      END IF
   END IF
   PRINT : PRINT "Reading file information..."
   FOR i = 1 TO 12
      INPUT #1, tmax(i)
   NEXT i
   FOR i = 1 TO 12
      INPUT #1, tmin(i)
   NEXT i
   INPUT #1, pamb, tstm, tfdw, hv, blreff
   FOR d = 1 TO 2
      FOR m = 1 TO 12: FOR h = 1 TO 24
         INPUT #1, eload(m, h, d)
      NEXT h, m
   NEXT d
   FOR d = 1 TO 2
      FOR m = 1 TO 12: FOR h = 1 TO 24
         INPUT #1, sload(m, h, d)
      NEXT h, m
   NEXT d
   CLOSE #1

510 CLS
   PRINT "Choose a selection to edit:"
   PRINT : PRINT "1) Average monthly temperatures"
   PRINT : PRINT "2) Ambient and boiler constants"
   PRINT : PRINT "3) Electric loads"
   PRINT : PRINT "4) Steam loads"
   PRINT : PRINT "5) Save file"
   PRINT : PRINT "6) Return to main menu"
   PRINT : INPUT "Which? ", a$
   a = VAL(a$)
   IF a = 6 THEN RETURN
   IF a = 7 THEN GOSUB 850
   IF a = 8 THEN GOSUB 860
   IF a < 1 OR a > 6 THEN 510
   ON a GOSUB 600, 650, 700, 750, 800
   GOTO 510

'Avg monthly temps

600 CLS : PRINT "Edit Average Monthly Temperatures"
   FOR m = 1 TO 12
      PRINT : PRINT "Max temp for "; month$(m); ", R ["; tmax(m); "] :";
      INPUT "", t1
```

```
      PRINT "Min temp for "; month$(m); ", R ["; tmin(m); "] :";
      INPUT "", t2
      IF t1 <> 0 THEN tmax(m) = t1
      IF t2 <> 0 THEN tmin(m) = t2
   NEXT m
   RETURN

'Amb and boil contants

650 CLS : PRINT "Edit Ambient and Boiler Constants"
   PRINT : PRINT "Ambient Pressure, psig ["; pamb; "] :";
   INPUT "", p1: IF p1 <> 0 THEN pamb = p1
   PRINT : PRINT "Exit boiler steam temperature, R ["; tstm; "] :";
   INPUT "", t3: IF t3 <> 0 THEN tstm = t3
   PRINT : PRINT "Inlet boiler feedwater temperature, R ["; tfdw; "] :";
   INPUT "", t4: IF t4 <> 0 THEN tfdw = t4
   PRINT : PRINT "Heating value of boiler fuel, Btu/lb ["; hv; "] :";
   INPUT "", h1: IF h1 <> 0 THEN hv = h1
   PRINT : PRINT "Boiler efficiency ["; blreff; "] :";
   INPUT "", b1: IF b1 <> 0 THEN blreff = b1
   RETURN

'Electric loads

700 CLS : PRINT "Edit Electric Load Profile"
   PRINT : INPUT "Start with month (1-12)?", mon
   IF mon < 1 OR mon > 12 GOTO 700
   FOR m = mon TO 12
     FOR d = 1 TO 2
       IF d = 1 THEN dy$ = "Week Day"
       IF d = 2 THEN dy$ = "Weekend Day"
       PRINT : PRINT month$(m); SPC(5); dy$
       h = 1
710     PRINT SPC(3); "Hour"; SPC(h < 10); h; ",kW ["; eload(m, h, d); "] :";
        INPUT "", elec$
        IF elec$ = "q" OR elec$ = "quit" THEN RETURN
        IF elec$ = "b" AND h > 1 THEN
          h = h - 1
          GOTO 710
        END IF
        elec = VAL(elec$)
        IF elec <> 0 THEN eload(m, h, d) = elec
        h = h + 1
        IF h < 25 GOTO 710
     NEXT d
   NEXT m
   RETURN

'Steam loads

750 CLS : PRINT "Edit Steam Load Profile"
   PRINT : INPUT "Start with month (1-12)?", mon
   IF mon < 1 OR mon > 12 GOTO 750
   FOR m = mon TO 12
     FOR d = 1 TO 2
       IF d = 1 THEN dy$ = "Week Day"
       IF d = 2 THEN dy$ = "Weekend Day"
       PRINT : PRINT month$(m); SPC(5); dy$
       h = 1
760     PRINT SPC(3); "Hour"; SPC(h < 10); h; ",kW ["; sload(m, h, d); "] :";
        INPUT "", stm$
        IF stm$ = "q" OR stm$ = "quit" THEN RETURN
        IF stm$ = "b" AND h > 1 THEN
          h = h - 1
```

```
        GOTO 760
       END IF
       stm = VAL(stm$)
       IF stm <> 0 THEN sload(m, h, d) = stm
       h = h + 1
       IF h < 25 GOTO 760
    NEXT d
  NEXT m
  RETURN

'Save file

800 PRINT : PRINT "Save as filename ["; loadfile$; "] :";
   INPUT "", a$
   IF a$ = "" THEN a$ = loadfile$
   PRINT : PRINT "Saving file information..."
   OPEN a$ FOR OUTPUT AS #1
   FOR i = 1 TO 12
      PRINT #1, USING "######.##"; tmax(i);
      IF (i MOD 4) = 0 THEN PRINT #1, " "
   NEXT i
   FOR i = 1 TO 12
      PRINT #1, USING "######.##"; tmin(i);
      IF (i MOD 4) = 0 THEN PRINT #1, " "
   NEXT i
   PRINT #1, USING "######.##"; pamb; tstm; tfdw; hv; blreff
   FOR d = 1 TO 2
      FOR m = 1 TO 12: FOR h = 1 TO 24
         PRINT #1, USING "########.##"; eload(m, h, d);
         IF (h MOD 4) = 0 THEN PRINT #1, " "
      NEXT h, m
   NEXT d
   FOR d = 1 TO 2
      FOR m = 1 TO 12: FOR h = 1 TO 24
         PRINT #1, USING "########.##"; sload(m, h, d);
         IF (h MOD 4) = 0 THEN PRINT #1, " "
      NEXT h, m
   NEXT d
   CLOSE #1
   RETURN

850 CLS
   INPUT "Enter overall ELECTRICAL multiplier value:", mv
   IF mv = 0 THEN RETURN
   FOR m = 1 TO 12
   FOR h = 1 TO 24
   FOR d = 1 TO 2
   LOCATE 12, 1: PRINT m, h, d;
   eload(m, h, d) = eload(m, h, d) * mv
   NEXT d, h, m
   RETURN

860 CLS
   INPUT "Enter overall STEAM multiplier value:", mv
   IF mv = 0 THEN RETURN
   FOR m = 1 TO 12
   FOR h = 1 TO 24
   FOR d = 1 TO 2
   LOCATE 12, 1: PRINT m, h, d;
   sload(m, h, d) = sload(m, h, d) * mv
   NEXT d, h, m
   RETURN

simulation:
```

```
   RUN "c:\fortran\bin\cogensim.exe"

quit:
   END

presskey:
   PRINT : PRINT "Press any key to continue:"
   DO
      a$ = INKEY$
   LOOP WHILE a$ = ""
   RETURN

errhandler:
e = ERR
SELECT CASE ERR
     CASE 52  'Bad file name or number.
          PRINT : PRINT "Bad file name"
          GOSUB presskey
          GOTO begin
     CASE 53  'File not found.
          PRINT : PRINT "File not found on disk"
          RESUME NEXT
     CASE 57  'Device I/O error.
          PRINT : PRINT "You should probably format the diskette."
          GOSUB presskey
          GOTO begin
     CASE 62 'End-of-File
          RESUME NEXT
     CASE 64  'Bad File Name.
          PRINT : PRINT "The drive name you specified was not correct."
          GOSUB presskey
          GOTO begin
     CASE 68  'Device unavailable.
          PRINT : PRINT "The drive you named is unavailable."
          GOSUB presskey
          GOTO begin
     CASE 71  'Drive not ready.
          PRINT : PRINT "The drive was not ready. Check the drive."
          GOSUB presskey
          GOTO begin
     CASE ELSE
          PRINT : PRINT "An unexpected FATAL error has occurred."
          STOP
END SELECT

SUB getinfo (curr() AS DOUBLE, a, vpos, hmin, num)

900 cur$ = LTRIM$(RTRIM$(STR$(curr(a, vpos))))

910 hpos = hmin + LEN(cur$)
   LOCATE vpos, hmin
   PRINT cur$;
   COLOR 0, 7: PRINT " "; : COLOR 7, 0
   PRINT SPC(hmin - LEN(cur$));
   DO
      a$ = INKEY$
   LOOP WHILE a$ = ""
   b$ = RIGHT$(a$, 1)
   IF LEN(a$) > 1 THEN
      SELECT CASE b$
      CASE CHR$(DOWN)
         LOCATE vpos, hpos: PRINT " ";
         curr(a, vpos) = VAL(cur$)
         vpos = vpos + 1
```

```
         IF vpos > num THEN vpos = 1
      CASE CHR$(UP)
         LOCATE vpos, hpos: PRINT " ";
         curr(a, vpos) = VAL(cur$)
         vpos = vpos - 1
         IF vpos < 1 THEN vpos = num
      END SELECT
   ELSE
      IF b$ = CHR$(8) THEN
         LOCATE vpos, hpos: PRINT " ";
         hpos = hpos - 1
         IF hpos < hmin THEN hpos = hmin
         IF hpos = hmin THEN
            cur$ = ""
         ELSE
            cur$ = LEFT$(cur$, LEN(cur$) - 1)
         END IF
         GOTO 910
      END IF
      IF b$ = CHR$(27) THEN curr(a, vpos) = VAL(cur$): EXIT SUB
      IF b$ = CHR$(13) THEN
         LOCATE vpos, hpos: PRINT " ";
         curr(a, vpos) = VAL(cur$)
         vpos = vpos + 1
         IF vpos > num THEN vpos = 1
         GOTO 900
      END IF
      LOCATE vpos, hpos
      IF hpos > 77 GOTO 910
      PRINT b$;
      cur$ = cur$ + b$
      GOTO 910
   END IF
   GOTO 900

END SUB
```

ECONOMIC SPREADSHEET MACRO

```
econ     {/ View;NewWindow}                  ; open new worksheet
         {GOTO}a1~
         "Gas Esc. Rate:~{DOWN}               ; get user inputs
         "Elec. Esc. Rate:~{DOWN}
         "Op. & Maint. Cost:~{DOWN}
         "Inflation:~{DOWN}
         "Discount Rate:~
         {GOTO}c1~
         "Starting Year:~{DOWN}
         "Project Life:~{DOWN}
         "Curr. Gas Price:~{DOWN}
         "Curr. Gas Trans:~{D}
         "Gas Trans. Esc.:~
         {GOTO}e1~
         "Standby Charge:~{DOWN}
         "MMBtu/MCF conv:~{D}
         "Captial Cost:~{D}
         "Worksheet Name:~{D}
         "Rate Schedule:~
         {GETNUMBER +[]A1,[]B1}
         {GETNUMBER +[]A2,[]B2}
         {GETNUMBER +[]A3,[]B3}
         {GETNUMBER +[]A4,[]B4}
         {GETNUMBER +[]A5,[]B5}
         {GETNUMBER +[]c1,[]d1}
         {GETNUMBER +[]c2,[]d2}
         {GETNUMBER +[]c3,[]d3}
         {GETNUMBER +[]c4,[]d4}
         {GETNUMBER +[]c5,[]d5}
         {GETNUMBER +[]e1,[]f1}
         {GETNUMBER +[]e2,[]f2}
         {GETNUMBER +[]e3,[]f3}
         {GETLABEL +[]e4,[]f4}
         {GETLABEL +[]e5,[]f5}
         {GOTO}a7~
         {/ File;ImportText}                 ; import econ text file
         {?}~
         {/ Parse;CreateLine}                ; parse labels into numeric
         {/ Parse;Input}a7..a19~             ; columns
         {/ Parse;Output}b8~
         {/ Parse;Go}
         {/ Block;Erase}a7..a19~
         {GOTO}a8~
         {/ Column;Width}22~                 ; set col widths, enter labels
         {/ Block;SetWidth}b1..u1~12~
         "Jan{D}"Feb{D}"Mar{D}"Apr{D}"May{D}"Jun{D}
         "Jul{D}"Aug{D}"Sep{D}"Oct{D}"Nov{D}"Dec{D 2}"Total~
         {GOTO}b7~
         "Load KWH{R}"Load LBS{R}"Gen KWH{R}"Gen LBS{R}
         "Purch Elec{R}"Excess Stm{R}"GT Fuel{R}"Boiler Fuel~
         {GOTO}b21~
         @sum(b8..b19)~                      ; create yearly sums
         {/ Block;Copy}b21~c21..j21~
         {/ Name;Create}gasesc~b1~           ; create named blocks for
         {/ Name;Create}elecesc~b2~          ; easy access
         {/ Name;Create}o&m~b3~
         {/ Name;Create}inflation~b4~
         {/ Name;Create}discount~b5~
         {/ Name;Create}start~d1~
         {/ Name;Create}life~d2~
```

```
          {/ Name;Create}gasprice~d3~
          {/ Name;Create}tranprice~d4~
          {/ Name;Create}tranesc~d5~
          {/ Name;Create}standby~f1~
          {/ Name;Create}convert~f2~
          {/ Name;Create}captial~f3~
          {/ Name;Create}wsname~f4~
          {/ Name;Create}rsched~f5~
          {/ Name;Create}gtfuel~h21~
          {/ Name;Create}boilerfuel~i21~
          {/ Name;Create}boileronly~j21~
          {GOTO}a1~
          {DISPATCH []rsched}            ; branch according to rate
                                         ; schedule

rate_sei  {/ File;CopyFile}              ; HL&P SEI rate schedule
          {CLEAR}rate_sei~
          {/ Block;Transpose}k8..k11~b31~
          {/ Block;Transpose}k12..k17~f30~
          {/ Block;Transpose}k18..k19~131~
          {/ Block;Transpose}18..111~b65~
          {/ Block;Transpose}112..117~f64~
          {/ Block;Transpose}118..119~165~
          {/ Block;Transpose}b8..b19~b35~
          {/ Block;Transpose}f8..f19~b69~
          {/ Name;RightCreate}a93~
          {GOTO}a93~
          {BRANCH lifecycl}


rate_bec  {/ File;CopyFile}              ; Brazos Coop rate schedule
          {CLEAR}rate_bec~
          {/ Block;Transpose}b8..b19~b33~
          {/ Block;Transpose}f8..f19~b62~
          {/ Name;RightCreate}a83~
          {GOTO}a83~
          {BRANCH lifecycl}


rate_lgs  {/ File;CopyFile}              ; HL&P LGS rate schedule
          {CLEAR}rate_lgs~
          {/ Block;Transpose}b8..b19~b35~
          {/ Block;Transpose}f8..f19~b65~
          {/ Name;RightCreate}a85~
          {GOTO}a85~
          {BRANCH lifecycl}


rate_lcr  {/ File;CopyFile}              ; Lower Col. River Authority
          {CLEAR}rate_lcr~
          {/ Block;Transpose}b8..b19~b33~
          {/ Block;Transpose}f8..f19~b62~
          {/ Name;RightCreate}a83~
          {GOTO}a83~
          {BRANCH lifecycl}


rate_aus  {/ File;CopyFile}              ; City of Austin
          {CLEAR}rate_aus~
          {/ Block;Transpose}b8..b19~b33~
          {/ Block;Transpose}f8..f19~b62~
          {/ Name;RightCreate}a83~
          {GOTO}a83~
          {BRANCH lifecycl}
```

```
lifecycl {R}{D 5}                    ; Enter values for life cycle
         +$start~                    ; analysis table
         {R}
         {/ Block;Copy}{D 25}~
         {R}.{RIGHT []life-3}~
         {L}{D 17}
         @min(
         {D 7}.{END}{R})~
         {D 2}
         @irr(@na,
         {LEFT}{D 6}.{END}{R})~
         {D 2}
         @npv($B$5,
         {LEFT}{D 4}.{END}{R},1)~
         {D 4}
         {/ Block;SetWidth}{END}{R}~12~
         {GOTO}a1~
         {QUIT}
```

VITA

Steven Rush Fennell was born on June 23, 1968 in Annapolis, Maryland. He is the second of two children by Chester and Patricia Fennell. Steven attended grade schools in Maryland, New York, and Arizona, and attended Chaparral High School in Phoenix, Arizona for two years. He moved to San Antonio, Texas in 1984 to complete secondary studies at Winston Churchill High School. Steven was active in soccer, marching band, and symphonic band while in school. After graduation, he began his collegiate career at Texas A&M University in the fall of 1986 in Mechanical Engineering. There he pursued a Bachelor of Science degree, which he received in December 1990. During this time, Steven worked as an intern at Timeplex, Inc., and also worked for Dr. David Jansson as an undergraduate researcher. He also specialized in thermal systems during his senior year in his technical electives. After completing his degree, Steven began pursing graduate studies, first under Dr. Jansson in January 1991, then under Dr. Jerald Caton in June 1991 as a graduate research assistant. He has continued studies in the thermal systems area, most recently involving research into cogeneration. Steven is an associate member of the American Society of Mechanical Engineers.

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The typist for this thesis was Steven Fennell. It was formatted using Microsoft Word for Windows version 2.0.