

**Evaluating Cogeneration Options for a
Campus Heating and Cooling Plant
A Case Study for the UW-Madison Campus**

by

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Abstract

In this study the feasibility of modifications to the heating and cooling system of the University of Wisconsin-Madison campus is investigated. The objective of these modifications is to cogenerate heat and electricity more efficiently and cost effectively than is presently done.

The study is conducted with the help of the simulation program TRNSYS which was developed at the Solar Energy Laboratory of the University of Wisconsin-Madison. In order to implement a generic capability to model steam operated power and cogeneration plants, several component models, such as a steam generator model and a turbine model, are developed and validated in the course of this study.

The general simulation approach is verified by modelling the steam cycle of the central plant of the campus heating and cooling system with hourly load data for an entire year.

Several alternative configurations, half of which include the option of cogeneration at and supply of steam from a power plant of the local utility (MG&E), are analyzed. The simulations yield detailed results for fuel consumption, electricity generation and steam mass flow rates within each system.

Finally, a preliminary economic analysis is conducted, using first estimates for the required capital investment and for auxiliary operational costs. An evaluation of the results of these analyses shows that for all investigated alternative configurations, which involve cogeneration at and steam supply from MG&E, the savings in

operational costs cannot offset the required high capital investment associated with the construction of a steam pipe line between the utility plant and the university campus. The only alternative, which appears to be competitive with the present system configuration on economic grounds, is the upgrading of the present turbine/generator at the central campus plant.

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First of all I would like to thank my four advisors: Professor Kenneth Ragland, Professor Sanford Klein, Professor John Mitchell and Professor William Beckman. Ken initiated this interesting and challenging study and kept it in motion. Sandy invited me to come to the Solar Energy Lab and was my main - and a great - academic advisor. John, returning from a sabbatical in France and Belgium, jumped right into the project when it was the roughest, and he supported me with his knowledge and well-timed "pep talks". Bill, the new head of the Solar Lab, contributed substantially to the progress of this study by asking critical questions and sharing his vast experience with me.

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Nomenclature

English Letter Symbols

Symbol	Definition
A	area
$A_{\text{subscript}}$	availability
bhp	brake horse power
c_f	friction factor for flow in a pipe
c_p	specific heat at constant pressure
d,D	diameter
h	enthalpy
h_{ht}	heat transfer coefficient
L	length
LHV	lower heating value of a fuel
M	molecular weight
m	mass
Nu	Nußelt number
P	power
Pr	Prandtl number
Re	Reynolds number

English Letter Symbols (contd.)	
Symbol	Definition
p	pressure
Q	heat energy
T	temperature
U	overall heat transfer coefficient
v	velocity
W	work energy
x	molar fraction, quality of steam

Greek Letter Symbols

Symbol	Definition
ε	emissivity
η_1	efficiency according to the first law of thermodynamics
η_2	efficiency according to the second law of thermodynamics
ρ	density
σ	Stefan-Boltzmann constant
ξ	fraction of inlet mass flow rate

Acronyms

Symbol	Definition
CSC	Clinical Science Center
CSP	Charter Street Plant
MG&E	Madison Gas and Electric
PRV	Pressure Reducing Valve
PURPA	Public Utility Regulatory Policies Act
ROR	Rate of Return
UW	University of Wisconsin
WSP	Walnut Street Plant

Subscripts	
Symbol	Definition
amb	ambient
bd	blowdown
c	combustion, condensate
con	convective
db	dry bulb
ex	exhaust gas, extraction
fw	feedwater
l	low
h	high
rad	radiation
s	surface
st	steam
tw	treated water
w	wall
wb	wet bulb

Unit Conversion Table

Multiply	by	to obtain
Btu	1.055	kJ
°F (32°F = 0°C)	5/9	°C
ft	0.3048	m
gallon (US)	0.00379	m ³
inch	2.54	cm
lb (mass)	0.454	kg
mile	1610	m
psi	6.89	kPa
ton, refrigeration	3.52	kW
ton, short (2000 lb)	0.907	Mg

Chapter 1

Introduction

In the first part of this introductory chapter a few general remarks are made about the technical environment of this study with special regard to the scenario that this study concentrates on. The second part provides some background information on the investigated heating and cooling system and on considerations which led to this project. Its twofold objective is then laid out in sections 1.3 and 1.4..

1.1 Cogeneration

Cogeneration is a relatively new name for an old and proven technology in power production. Cogeneration systems are, depending on the market sectors, also known as total-energy, dual-energy-use or waste-heat-utilization systems. Their main characteristic is that they produce sequentially two forms of useful energy from the same fuel source. These two energy forms are typically electricity and heat for industrial processes or for space heating. Possible sources of energy are conventional fuels, like coal, gas, oil and refuse, or nuclear fuels, as well as geothermal or solar energy (Fraas, 1982; Payne, 1985)

Two examples of possible system configurations are shown in Fig. 1.1: in the topping cycle (Fig. 1.1a) steam is first expanded through a back-pressure turbine, which is driving an electricity generator. The exhaust steam from the turbine can then

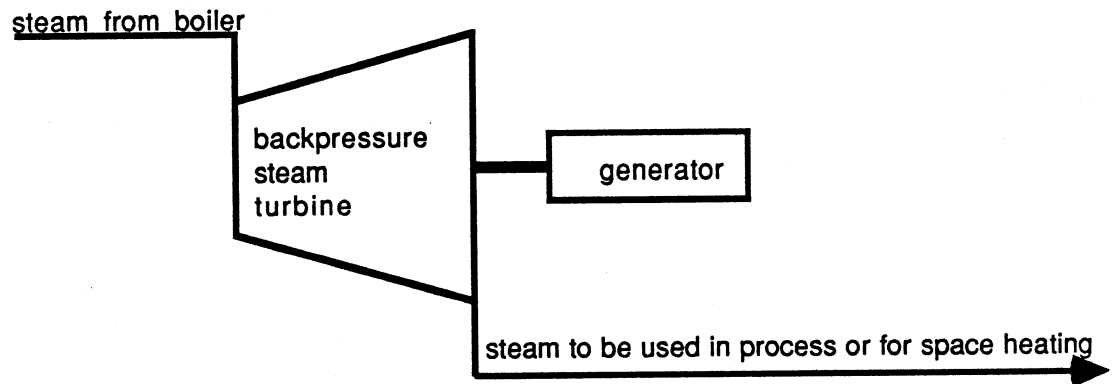


Figure 1.1a Characteristic part of a topping cycle

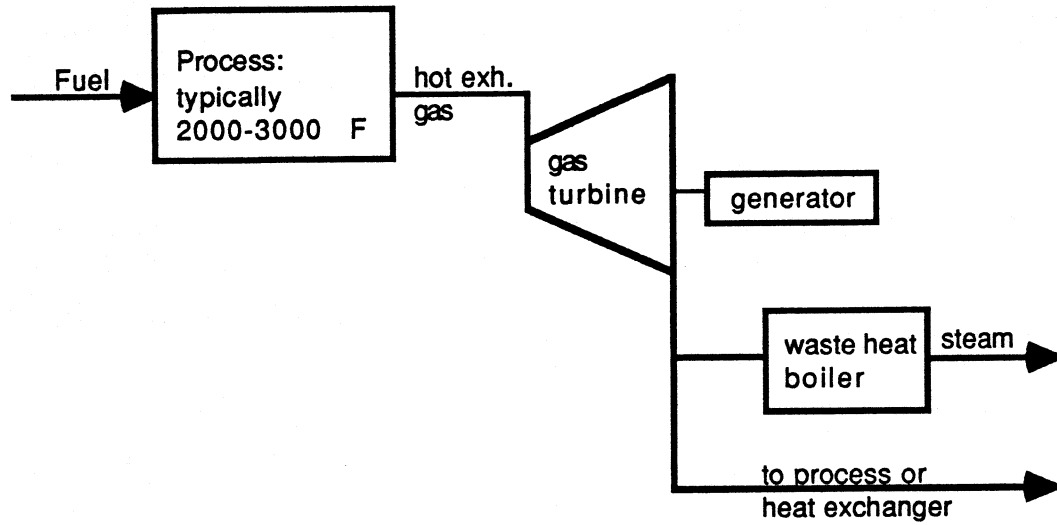


Figure 1.1b Example of a bottoming cycle

be used for low temperature processes (e.g. in the paper or food industry) or for space heating. Power production is the second step in a bottoming cycle (Fig. 1.1b), as the name indicates. In this configuration, process heat is needed at a very high temperature (typically above 1500°F) so that the working fluid, which is gas in the shown example, is still capable of driving a turbine afterwards. Heat rejected from the turbine could then in turn be utilized for various purposes.

These have been just two out of many possible configurations. The chosen system always depends on the characteristics of the heat requiring process and the size of the application. For small scale commercial purposes the reliable Diesel engine might be appropriate to produce power and provide heat from the exhaust gas and the jacket cooling. As power requirements increase in industrial applications, a gas turbine topping cycle becomes more and more competitive. In large facilities, especially for electricity generation in combination with district heating, the steam turbine cycle with either a back-pressure turbine or with steam extraction from a condensing turbine is the most frequently encountered case. This study focuses on an example of this scenario, i.e. the heating and cooling of a university campus from a centralized facility.

District heating has found widespread use to serve institutional users, like college campuses, medical or commercial complexes, military bases and industrial parks. Steam or hot water for space heating and chilled water for cooling is distributed via a network of pipes and ducts (see section 1.2). By replacing individual boilers with one central heating and cooling source, district heating can increase effective building space, reduce building construction and operating costs, and facilitate pollution control, which is easier to accomplish on a centralized plant. Above all the efficiency of fuel usage can be increased by utilizing large, efficient boilers and especially by cogenerating electricity together with heat. Despite these advantages, the use of district heating for

non-institutional areas like, residential housing and business districts, has declined in the U.S. over the years (Committee on district heating and cooling, 1985).

In the United States cogeneration regained attractiveness for private investors by enactment of the Public Utility Regulatory Policy Act (PURPA) which required utilities to set reasonable rates for buying power from and selling power to private cogenerators if their system met certain standards (FERC, 1978). Before 1978 the on-site industrial cogeneration had steadily declined from about 15% of total U.S. electrical generation to about 5% in 1974. In parts of Europe on the other hand, where a greater sense for fuel economy has always been dictated by lacking resources and consequently higher prices, industrial cogeneration accounts for a substantially bigger fraction of total power production. Due to intensive cogeneration for industrial processes and also for district heating of numerous communities planned and built after World War II, this figure is 25% for West Germany, for instance (Cogeneration Technology, 1987).

From an energy standpoint, cogeneration is always a desirable solution if there is a demand for both power and heat. Compared to a cogeneration system, the fuel consumption to provide a certain amount of electricity and heat from two separate sites is significantly higher, as can be seen from an examination of the systems shown in Fig. 1.2: the goal for both systems is to provide a certain amount of electricity (10 MW) and steam (200,000 lb/hr at 200 psi and 550°F). In the first system this is accomplished by operation of two separate plants. A conventional power plant generates electricity with an efficiency of 27% and a steam boiler provides the required steam. In the second case both demands are satisfied from the same fuel source, using a common cogeneration configuration with a back-pressure turbine. The total fuel usage to provide 10 MW electricity and 200,000 lb/hr of steam at the specified conditions from the separated systems is about 26% bigger than the fuel consumption

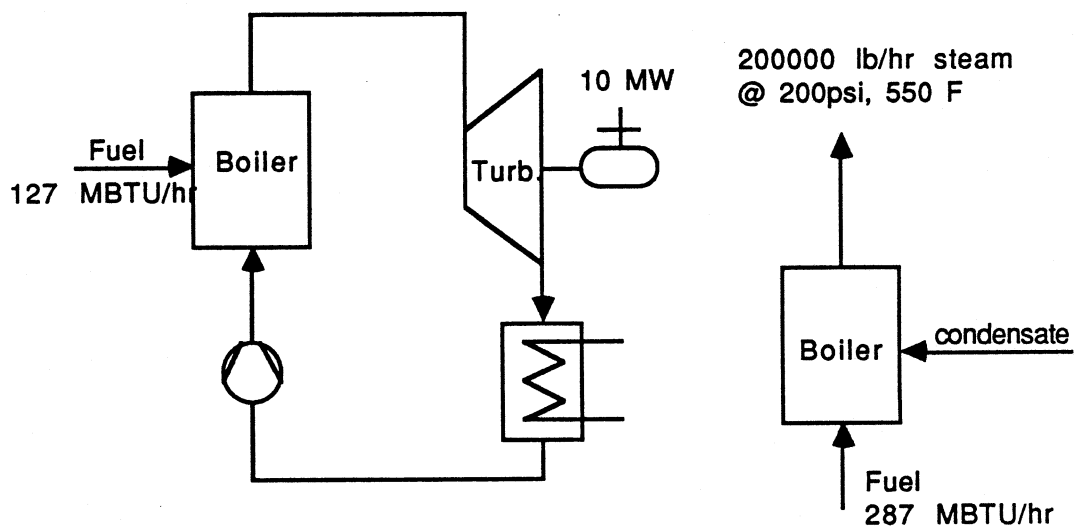


Figure 1.2a Heat and power delivered by separate systems

Total fuel consumption: 414 MBTU

Overall efficiency: $\eta_1 = 64\%$, $\eta_2 = 27.5\%$

Efficiency of power cycle ($\eta_1 = \eta_2$): 27 %

Efficiency of steam production: $\eta_1 = 84\%$, $\eta_2 = 28.3\%$

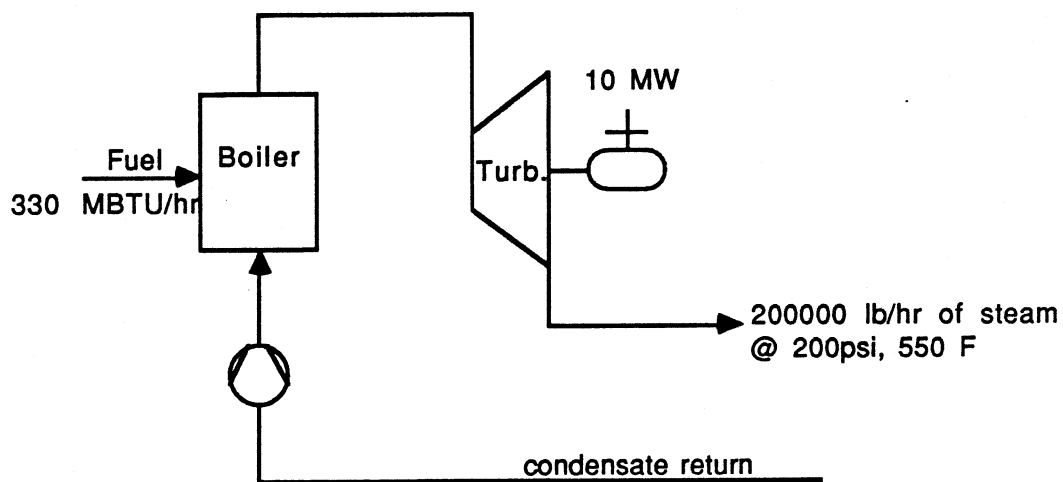


Figure 1.2b Heat and power delivered by cogeneration system

Total fuel consumption: 330 MBTU

First law efficiency: $\eta_1 = 80\%$

Second law efficiency: $\eta_2 = 32.4\%$

to provide the same power and heat from a combined system (414 MBTU/hr vs 330 MBTU/hr). It should be mentioned, however, that the typical efficiency of electricity generation by utilities is about 34% vs only 27% in the shown power cycle, so that the actual fuel savings are somewhat lower than in the idealized comparison made above.

In this context it has to be pointed out that there are different bases on which to evaluate efficiencies for cogeneration systems, where the production of power and heat poses the task to assign comparable values and eventually costs to these two forms of energy (Horlock, 1987; Gaggioli, 1988). Whereas an evaluation on an energy basis does not account for the degraded quality of thermal versus mechanical energy, thus conveying a distorted picture of relative values, an analysis based on availability, which results in the second law efficiency, offers a more appropriate way for costing and rating cogeneration products, as has been demonstrated in numerous textbooks and articles over the years (e.g. Gaggioli, 1988; van Wylen/Sonntag, 1986).

The second law efficiency η_2 for a total energy plant is defined as

$$\eta_2 = \frac{A_{\text{elec}} + A_{\text{heat}}}{A_{\text{fuel}}} \quad (1.1)$$

where A_i denotes the availabilities of the respective energy forms. This can be approximated as

$$\eta_2 = \frac{W_{\text{elec}} + A_{\text{heat}}}{\text{LHV}_{\text{fuel}}} \quad (1.2)$$

The derivation of this performance indicator and a comparison of the two mentioned analysis techniques can be found in Appendix A.

In the following an attempt is made to use and emphasize the adequacy of this efficiency, while the first law efficiency for a system, which delivers heat and electricity is given by

$$\eta_1 = \frac{W_{\text{elec}} + Q_{\text{heat}}}{\text{LHV}_{\text{fuel}}} \quad (1.3)$$

and will only be employed for comparative purposes.

Several other ways of comparing the thermodynamic performance of combined heat and power plants have been suggested in the literature (Horlock, 1987). An efficiency, called 'Fuel Energy Savings Ratio', which is based on the train of thought laid out with help of Fig. 1.2 involves comparison between the fuel required to meet the given loads of electricity and heat in the cogeneration plant with that required in separate conventional plants. Others try to incorporate the monetary value of fuel, power and heat energy to assess the performance of a system (e.g. 'Value Weighted Energy Utilization Factor' in Horlock, 1987).

The variety of efficiencies which finds use in the evaluation of cogeneration systems shows that discussion about the appropriate measure of performance for these systems has not been settled yet. From a thermodynamic viewpoint the second law efficiency seems to be the most basic and universal and will be used in this study. Eventually the decision on whether or not a system design is viable has to be made on economic grounds, where factors become important which can not be assessed from an efficiency viewpoint alone.

There are several difficulties opposing the improved fuel efficiency which have to be solved in every specific case to make cogeneration an economically viable

alternative. One major factor is the required additional capital investment, especially if retrofitting an existing system is under consideration. Other disincentives, which have been partially relieved by PURPA, are due to legal and institutional aspects.

A problem which has to be carefully addressed in the design stage of a cogeneration plant is the question of load management. There are basically two major options in sizing a cogeneration system for a certain application: it can be sized to meet both the total power and heat demand at any point in time or just one of these. In the second case, which is the more common one, it is typically the heat demand which is tracked. The electricity balance can usually be established in cooperation with a utility, meaning that excess power can be sold to and additional power can be purchased from the utility, which allows for a high flexibility of system operation.

Since this study is investigating an example of this latter type (district heating with steam in cooperation with a local utility) a few remarks regarding possible prime movers for these systems shall conclude this introductory section on cogeneration. As already mentioned above, the power generating unit can either be a back-pressure or a condensing steam turbine. For a back-pressure turbine the power generation is always proportional to the heat demand, since all steam required for the heating application is expanded through the turbine. This yields a high overall efficiency at the design point. However, if the steam load varies over time and if the turbine has to be operated at low part load, its efficiency is far below its optimum and the overall system performance decreases. Here a usually more expensive condensing steam turbine with variable extraction at the desired pressure offers greater flexibility, because the system can be operated at the design point for boiler and prime mover by condensing an increased amount of steam, even if the heat demand goes down. On the other hand, steam which is condensed does not serve for cogeneration purposes and in the limit of no steam

demand the efficiency of such a system approaches that of a conventional power plant.

1.2 UW Heating and Cooling System

Most of the buildings on the campus of the University of Wisconsin-Madison are heated and cooled by a centralized (district heating and cooling) system. Two plants provide steam and chilled water to the campus and also to the Clinical Science Center (CSC) at the west side of the campus.

An overview of the system is given in Fig. 1.3. Steam at high (175 psig) and low (10 psig) pressure for heating in the winter, reheating of cooled air during the summer, for hot water and for several absorption chillers is distributed via a complex tunnel and duct system from one plant at Charter Street (CSP) and from a second one at Walnut Street (WSP). The steam distribution network for the university and the CSC are interconnected, so that, in times of low demand, the steam load for both facilities can be met by operation of either plant.

There are basically two means by which to distribute heat from a centralized facility: steam or high temperature water (HTW). Nowadays HTW systems are usually preferred for space heating applications, since they feature several advantages over steam systems with respect to pipe construction, safety and maintenance (Committee on District Heating and Cooling, 1985). The construction of the steam distribution system of the studied facility dates back to the beginning of this century, when steam was the commonly used medium for such applications. A second reason for a steam system is that there is a direct demand for steam in several research facilities throughout the campus.

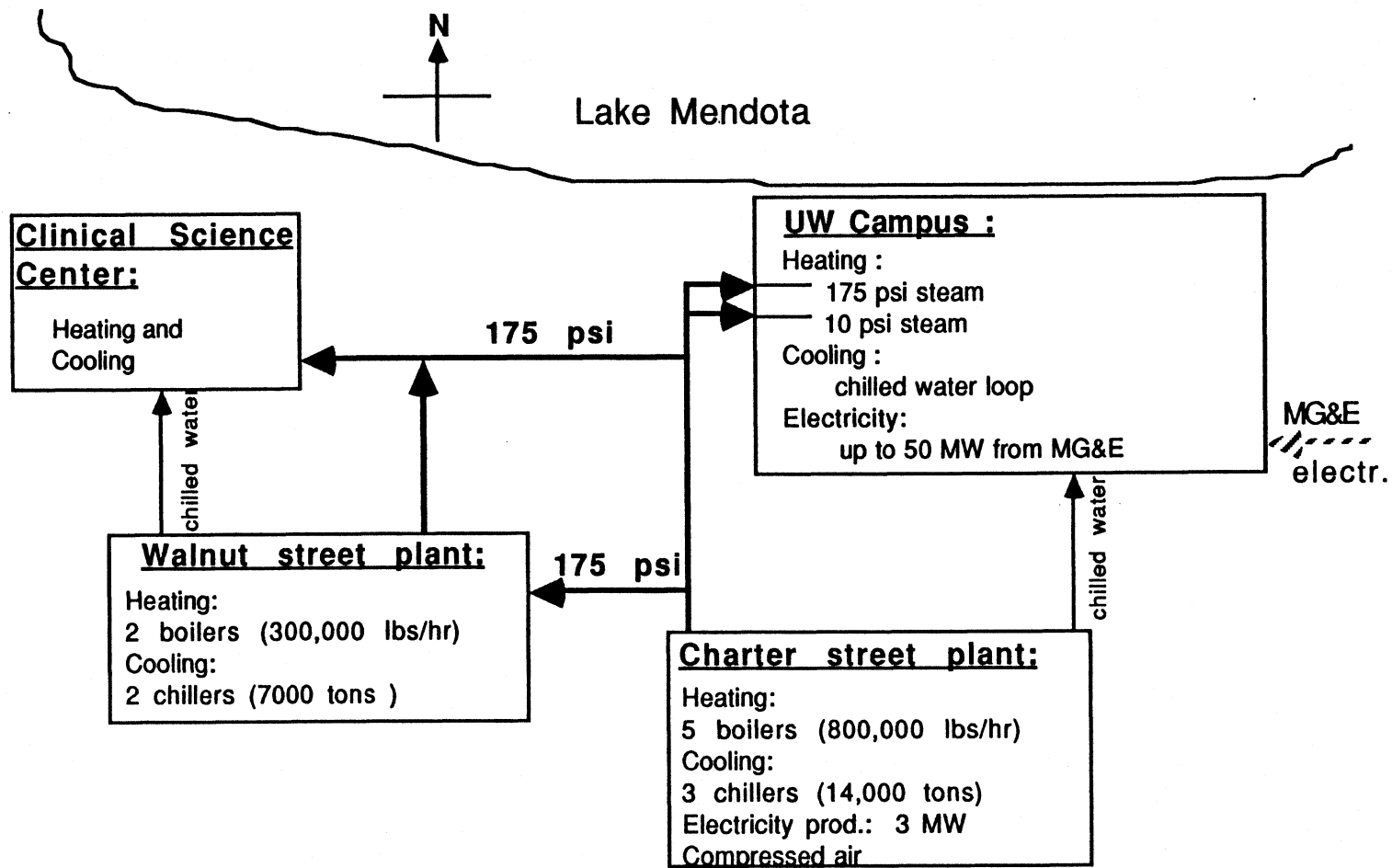


Figure 1.3 Schematic of the UW heating and cooling system

The two chilled water loops are not interconnected. Three chillers with a total capacity of 14,000 tons and with steam driven compressors (600 psi-condensing) at Charter Street supply chilled water for the UW and two 3500 ton chillers at Walnut Street provide cooling for the Clinical Science Center. The chiller compressors at WSP are driven by 175 psi-condensing turbines which means that they can be operated with high pressure steam from CSP if necessary. Table 1.1 gives some characteristic load and performance values for the system.

Steam and motor driven compressors at Charter Street supply compressed air and a 3 MW back-pressure turbine/generator unit produces electricity, which is sold to Madison Gas and Electric, the local utility for the Madison area. MG&E in turn supplies electricity to the UW with a total connected campus load of about 48 MW (1985).

Charter Street plant has been the central part of the campus heating and cooling system for about 30 years now. A detailed description of the plant is given in Ch. 3.1. Several components, including three of the five boilers and the turbine/generator unit, were purchased from the American Motors company in 1958. The four coal and one gas fired boilers have a total maximum steam output of 800,000 lb/hr at superheated conditions (615 psi and 725°F). The specification for this original system have governed all additions which were made afterwards, and there has been discussion whether a different choice regarding operating temperatures and pressures would have been made if the plant had been customized for the campus requirements.

The diagram in Fig. 1.4 shows a simplified schematic of the steam/water cycle for the plant. The major portion of the produced steam is sent out to the system at 175psig, 440°F or at 10 psig, 330°F and returns to the water treatment section as condensate.

Table 1.1 Characteristic data for the UW heating and cooling system (87/88)

Characteristic	Unit	CSP	WSP	TOTAL
max. boiler capacity	[10 ³ lb/hr]	800	300	1,100
WINTER:				
steam out (cold winter day)	[10 ³ lb/hr]	400	100	500
steam produced (")	[10 ³ lb/hr]	500	120	620
steam out (mild winter day)	[10 ³ lb/hr]	150	0	150
steam produced (")	[10 ³ lb/hr]	180	0	180
SUMMER:				
max. cooling capacity	[tons]	14,000	7000	21,000
max. chiller compr. power	[kW]	10,200	4900	15,100
cooling load (hot summer day)	[tons]	13,000	4500	17,500
chiller steam demand (")	[10 ³ lb/hr]	110	55	165
max. steam production (")	[10 ³ lb/hr]	400	0	400
ELECTRICITY:				
connected campus load	[MW]	--	--	48 (1985)
max. electricity generation	[MW]	3	--	3
max. steam through turbine	[10 ³ lb/hr]	110	--	--
ANNUAL TOTALS:				
steam produced	[10 ⁶ lb]	2000	200	2200
coal consumption	[tons]	53,000	--	53,000
natural gas consumption	[10 ⁶ scf]	1380	310	1690
electricity generation	[MWh]	13,800	--	13,800
electricity consumption	[MWh]	12,000	5000	17,000

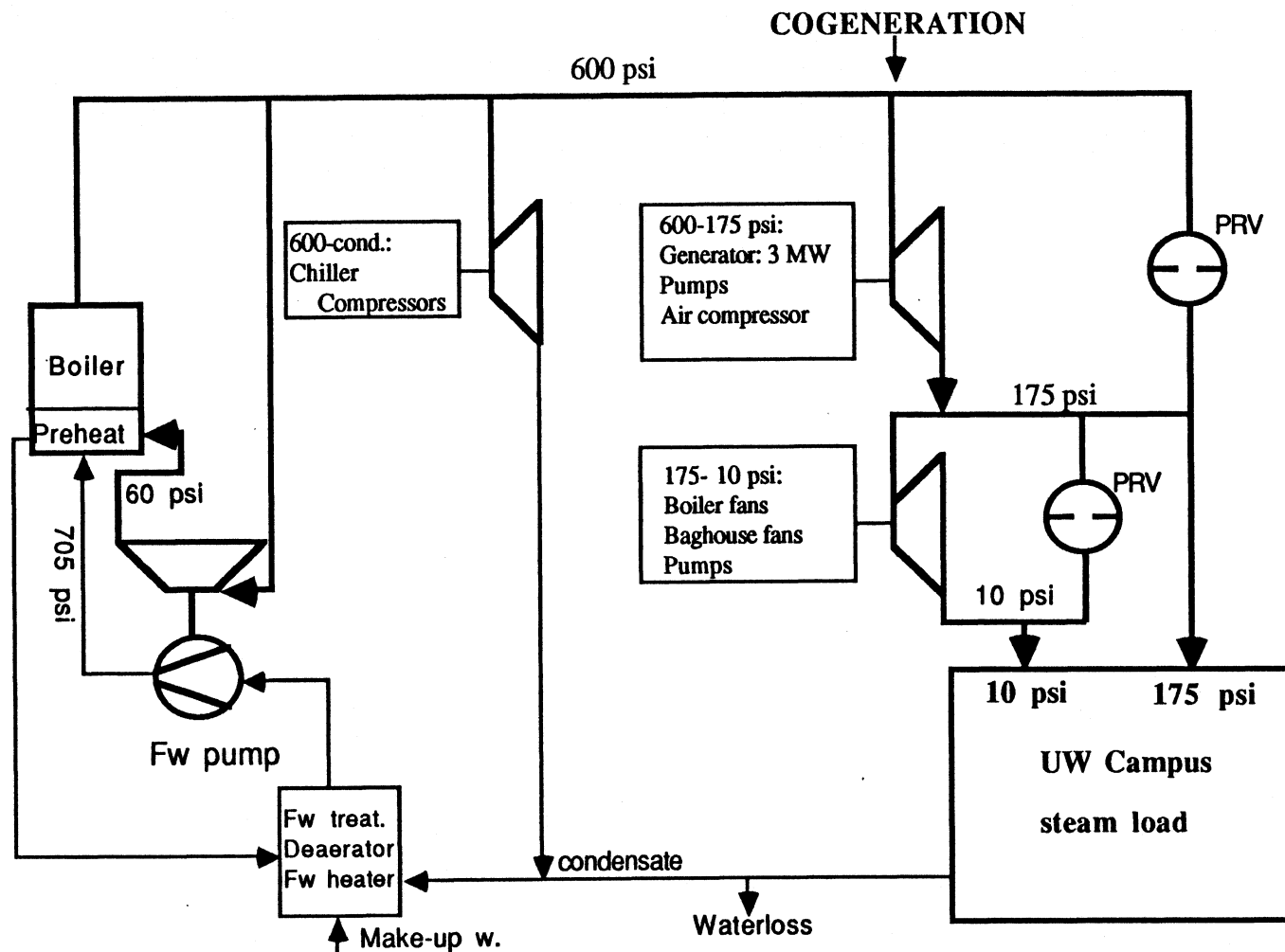


Figure 1.4 Simplified steam/water cycle for Carter Street heating and cooling plant

Before leaving the plant the steam is expanded through several turbines to generate electricity and power for pumps, fans and compressors (this part is labelled 'Cogeneration' in the diagram). If the campus steam demand is higher than the maximum capacity of this steam driven machinery, which is the case during most of the heating season, steam is throttled from 600 psi to 175 psi and from 175 psi to 10 psi in pressure reducing valves (PRV's). Thus a potential for power production is wasted.

There are also internal loads. The steam which drives the feedwater pumps and the chiller compressors, and steam which is serving for space and feedwater heating purposes does not leave the plant and is eventually condensed within the plant. Due to chiller operation and the lower external load this internal consumption accounts for a fairly high fraction (about 50 %) of total steam production during the summer months.

The Walnut Street plant, shown schematically in Fig. 1.5, was constructed in 1973 as a backup system for CSP with two gas fired boilers (max. 150,000 lb/hr each), delivering saturated steam at 175 psig, 390°F. Steam at these conditions leaves the plant for heating of UW or CSC buildings or drives the compressors of the two chillers, which were installed in 1977. Similarly to CSP, part of the steam is expanded to low pressure or condensed in order to meet internal loads. WSP does not have any electricity generating unit.

The total system capacity for cooling is presently 21000 tons and the maximum steam production is 1,100,000 lb/hr, part of which is needed to satisfy internal loads, as delineated above.

In 1984 a committee for the long term assessment of space heating and cooling requirements for the Madison campus was appointed. One of its specific tasks has been to create a master plan for the UW plants to address such questions as load

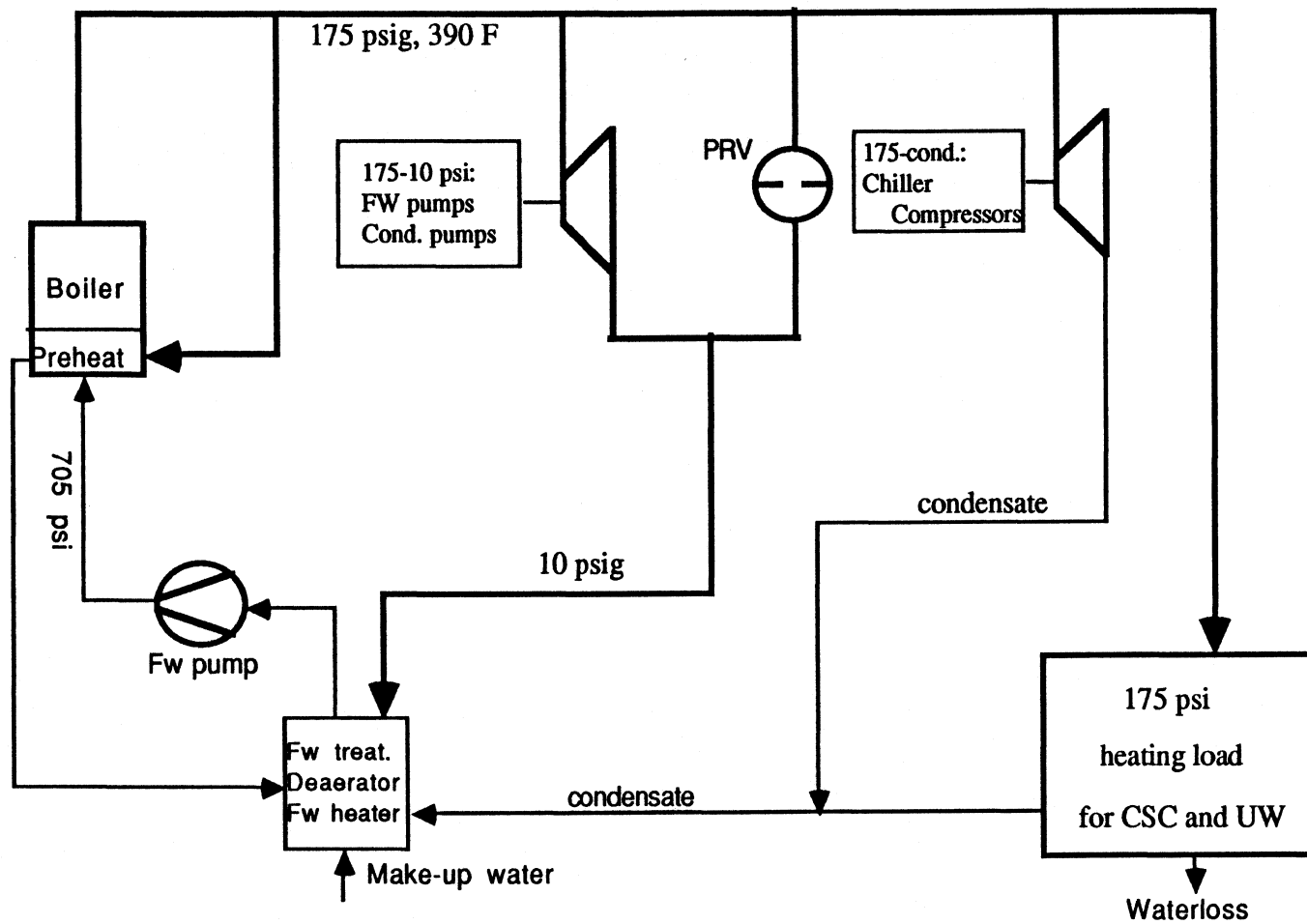


Figure 1.5 Simplified steam/water cycle for Walnut Street heating and cooling plant

projections, replacement of old components, additional equipment requirements and general guidelines for the future of the system.

A report which has been published in April 1986 gave a detailed evaluation of the present situation and made several recommendations for future projects and proceedings (*Campus Heating Master Plan*, 1986). The topics of steam generation, chilled water production and distribution systems for steam, condensate, compressed air and electricity were covered. Regarding the chilled water system, it has been recommended to install an additional 7000 tons of chilling capacity to meet an expected increase in load over the next years. One possible location for these chillers is Walnut Street, which would involve connecting the chilled water loops of the campus and the CSC, thus permitting a more flexible operation. With respect to the steam generation capacity, which will probably have to be stepped up only modestly over the 35-year planning horizon of that study, three major options have been suggested:

- 1) Addition of new boilers to the Charter Street site while keeping the old boilers for standby. Purchase of land contiguous to CSP site would be required.
- 2) Systematical replacement of the old coal-fired boilers at CSP with new coal-fired boilers with increased capacities if required.
- 3) Establishment of a connection with other sources of steam such as MG&E's Blount Street plant (or a municipal refuse-to-energy facility) for a base load of steam. CSP and WSP would be used as chilled water plants and as steam peaking and back-up plants.

It is of importance to note that the 30-40 year old power cycles at the Blount Street plant, which is separated from the central campus by about two miles of urbanized area, serve as peaking capacity for MG&E and are presently idling during

most of the year, with temporary full load operation during the summer.

In addition to options 1-3 it has also been proposed to consider possibilities for increased cogeneration of steam and electricity at CSP while making changes to the system. The feasibility of option 3 and of increased cogeneration at CSP are the issues that this study focuses on.

1.3 Objective

The objective of this project is twofold: one task is to conduct a preliminary feasibility study for several options by which cogeneration and the overall performance of the UW heating and cooling system could be increased. These options include the interconnection of the UW with the MG&E Blount street plant via a steam pipe (approximately 2.5 miles) and also modifications within the present campus plants.

The second objective focuses on the simulation program which is utilized to model the various possible configurations. This transient simulation program, well known as TRNSYS in the solar energy and building energy management field, was expanded to incorporate a capability to model conventional power producing plants and cogeneration systems with varying power and heating load profiles. The following brief introduction in section 1.4 is intended to delineate the main characteristics of this program (following a similar introduction provided by Kummer, 1986) and to point out the suitability of TRNSYS to analyze cogeneration problems.

1.4 The Simulation Program

TRNSYS has been developed at the University of Wisconsin Solar Energy Laboratory (Klein et al., 1983) and is a well documented program that has been proven to be extremely versatile in modelling and analyzing not only solar (Duffie and Beckman, 1980), but all kinds of energy systems. The program has a modular structure and consists of many individual subroutines, called "components", which each model the performance of an individual piece of equipment, such as a pipe, pump or storage tank. The user can connect any number of these components, in any fashion, in order to model a system. Each component must be supplied with a list of parameters to determine the component performance. A main program performs the simulation and handles information passing amongst the components. Information exchanged between components generally consists of mass flow rates, temperatures, pressures, energy transfer rates or control signals.

The system is defined in a "deck", which is a computer file containing a list of components, parameter specifications (e.g. pump size and speed), interconnection information to determine the data flux among components and other inputs to run a simulation. The simulation must be driven by forcing functions such as electric load profiles, ambient temperatures or other environmental data. The timestep at which this data is provided (minutes, hours, days etc.) can be determined by the user. For every timestep TRNSYS solves all of the equations defining the system performance by successive substitution. One complex example of a "deck" is provided in Appendix D and the description of components and system modelling procedures in subsequent chapters should gradually familiarize the reader with the specific features of TRNSYS.

Due to the size of the cogeneration market, available programs for the design,

sizing and analysis of such systems are abundant. These range from "look-up-table" data bases for the matching selection of cogeneration systems and industrial demand profiles to highly sophisticated mechanistic models for hydraulic and combustion machinery, often utilizing finite element or difference techniques (e.g. COGEN 3, 1987; ATHENA,1985).

The component subroutines for TRNSYS use either manufacturers performance data or employ basic principles such as mass and energy balances to establish a relationship between inputs and outputs. Consequently the effect of particular design changes within a piece of equipment, e.g. the blade angle of a centrifugal pump, can not be investigated, but results of changes in component size and overall system configuration can easily be set up and studied. For these purposes neither the "look-up-table" programs nor the complex mechanistic models appear to be adequate.

In contrast to base load power plants, which attempt to operate at a certain design point continuously, cogeneration systems pose specific load management problems (see section 1.1) due to simultaneous generation of electricity and heat. These can easily be accommodated by the flexible timestep simulation technique of TRNSYS.

Attempts to use this program for the analysis of cogeneration systems have already been successfully made (Guinn,1987). Guinn also pointed out that TRNSYS meets a wide array of indispensable requirements in such analyses, like the capability to consider ambient conditions and load profiles with a reasonable resolution, to analyze system performance at part load operation and to incorporate various control strategies. This is combined with sufficient simplicity to allow for easy system set up and short execution times.

Previous studies, however, made solely use of existing TRNSYS subroutines, which have not specifically been designed for cogeneration problems. Major plant

components were modelled in an interpolative fashion using manufacturers performance data. Here an attempt shall be made to develop specific thermodynamic models for plant equipment such as steam boiler and turbines, and to establish an expanded, generic capability for the modelling of cogeneration systems within TRNSYS.

Chapter 2

Component Development

As pointed out in the section 1.4, previous TRNSYS simulations of power, heating or chilling plants (Guinn, 1987; Nugent, 1986) made use of a general subroutine to model main components such as a steam turbine by interpolation of data provided by the manufacturer or obtained from measurements. If the goal of a study includes investigating the effect of equipment changes and modifications, however, it is convenient to have models available which are based on physical principles, so that a first assessment of consequences of variations in equipment size or operational parameters is possible without always having specific data at hand. Once a first scan of possible modifications has suggested ranges of potential optimums, specific manufacturers data can be employed to account for slight differences from the typical performance, that the model predicts.

In the following sections, the basic principles and equations of these newly developed or adapted components are laid out. Some pieces of equipment (e. g. pumps, chillers), have still been modelled with actual performance data, but for most of the components simple thermodynamic calculations and typical operational parameters have been used.

For every TRNSYS component two groups of data have to be specified: an array of 'Parameters' defines characteristics, which stay fixed throughout the simulation, such as size, maximum power output or inlet pressure for a specific steam turbine. For

'Inputs', which can vary over time, such as the electric load on a steam turbine, an initial value and the origin of the input has to be specified. This origin could be an external file (e.g. with load profiles) or an output from another component . In a detailed information flow diagram for a TRNSYS deck, every component is thus represented by user specified parameters, by the origin and type of the inputs and by a list of outputs that the component subroutine computes, using either the interpolative mode or the thermodynamic model, depending on what data is available.

In the following brief model descriptions, the main equations, inputs, parameters and outputs are stated. For more detailed information the reader is referred to the appendix with the program listings.

The components were verified individually before they were assembled to a TRNSYS deck to simulate an existing plant (i.e. CSP), so that the component interaction and the general approach could be validated (see Ch. 3).

It has to be mentioned at this point that a major part of the development for the steam turbine, the boiler and the deaerator model was done by Dr. W. Krumm, who also prepared subroutines to simulate the performance of a diesel engine and of a gas turbine, which are not described here, though. The author took these rudimentary models as a starting point and modified them to meet requirements of the project.

Finally it should be pointed out that all component models can be used in the English and the SI unit system and that for all steam property calculations a standard component of TRNSYS is used.

2.1 Steam boiler

This component simulates the performance of a common steam boiler, basically calculating the fuel and combustion air consumption as functions of the steam generation rate.

A steam boiler can be viewed as a heat exchanger in combination with a combustion chamber, as is schematically depicted in Fig. 2.1.

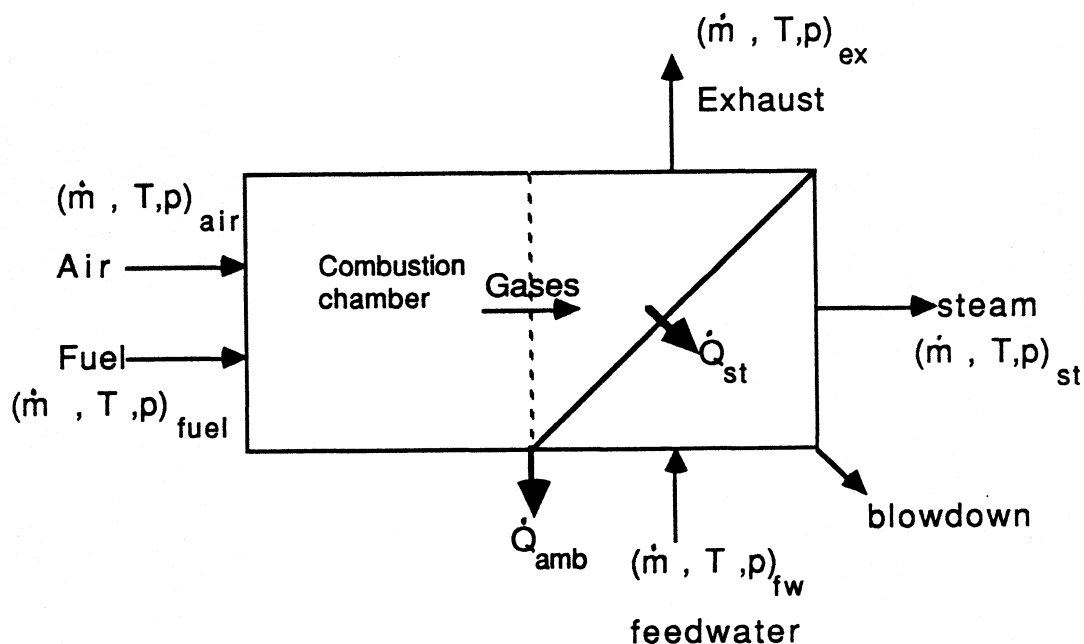


Figure 2.1 Simplified schematic of a steam boiler

Fuel which can be chosen to be coal, natural gas or oil for this model, is combusted with a certain amount of air in the combustion chamber. The hot

combustion gases transform the feedwater to saturated or superheated steam in several stages, typically including the economizer, which preheats the water, the evaporator and one or more steam superheaters.

The energy transfer to the working fluid is

$$\dot{Q}_{st} = \dot{m}_{st} (h_{st} - h_{fw}) \quad (2.1)$$

Besides generating steam, the total energy extracted from the gases has to compensate boiler blowdown and losses due to radiation and convection, before the gases are exhausted. Blowdown is the removal of a portion of saturated boiler water, which is often necessary to limit the accumulation of chemicals in the boiler drum. The associated energy loss is

$$\dot{Q}_{bd} = \dot{m}_{bd} (h_{bd} (p_{fw}, x=0) - h_{fw} (T_{fw}, p_{fw})) \quad (2.2)$$

The losses due to heat transfer from the boiler surface to the environment can be expressed as

$$\dot{Q}_{amb} = \dot{Q}_{conv} + \dot{Q}_{rad} = h_{ht} A (T_w - T_s) + \sigma \epsilon A (T_w^4 - T_s^4) \quad (2.3)$$

where T_s is the temperature of the surroundings and T_w is the wall temperature. This heat flow has to equal the heat which is transferred from the combustion gases to the boiler surface at an average temperature T_c

$$\dot{Q}_{amb} = U A (T_c - T_w) \quad (2.4)$$

With user specified T_s , T_c , and boiler surface area A , the subroutine calculates the boiler wall temperature and the heat loss to the surroundings.

The sum of the energy transfers to the working fluid, to the blowdown water and the environment is

$$\dot{Q}_c = \dot{Q}_{st} + \dot{Q}_{bd} + \dot{Q}_{amb} \quad (2.5)$$

and has to be supplied by the combustion gases. The losses with the flue gas are dependent on the composition and temperature of the gases and are accounted for in the subsequent computations.

To obtain the required fuel input

$$\dot{m}_{fuel} = \dot{Q}_c M_{fuel} / \Delta h_{R,Ex} \quad (2.6)$$

a combustion calculation for the determination of $\Delta h_{R,Ex}$ which is the difference between the energy content of the reactants (fuel and air) and the exhaust gases, has to be performed. Complete combustion is assumed and $\Delta h_{R,Ex}$ can be written on a molar basis as

$$\Delta h_{R,Ex} = \sum_i^{Ex} x_i (h_f^\circ + \Delta h)_i - \sum_i^R x_i (h_f^\circ + \Delta h)_i \quad (2.7)$$

where h_f° is the standard formation enthalpy and Δh_i is the enthalpy difference between a reference state and the actual temperature of species i . The standard formation

enthalpy of the individual components and the molecular weight M_{fuel} of the fuel are calculated in a subroutine. The temperature of the exhaust gases is assumed to vary linearly with part load operation over a user specified range.

For more details on the combustion calculation and for information on boilers the reader is referred to the standard literature (vanWylen/Sonntag, 1986, Ch.12 for combustion; Fraas, 1982 and Gill, 1984 on steam generators).

Detailed results from performance tests, conducted with natural gas and coal fired boilers at MG&E and at CSP, were used to check the accuracy of the model.

Table 2.1 comprises a list of the main specified parameters and inputs for the simulation of the coal fired steam generator #1 at Charter Street plant.

The lower heating value of the burned fuel was 12,400 BTU/lb and is one of the calculated outputs of the model. It has to be verified that the LHV, which is computed from the specified fuel mass fractions, corresponds to this value. For parameters marked by a star, estimates had to be made, since information was not included in the test documentation.

Table 2.2 gives the results for a comparison of some of the simulation outputs with the measured data and Fig. 2.2 shows the fuel consumption versus the steam production for the boiler and its model. Fig. 2.3 is a similar comparison for a natural gas fired boiler which is located at the MG&E Blount Street plant.

The overall performance of the model is satisfactory for the purpose of providing first estimates for the fuel consumption of a boiler without having specific data available. The observed discrepancies in the results are due to the simplicity of the model which does not account for special operational procedures taken at various part loads, such as for example the variation of the excess air ratio. The inclusion of a typical operational control should be part of further work to improve the model.

Table 2.1 Main parameters and inputs for a boiler model test

Parameter	units	used values
Fw inlet temperature	[°F]	300
Fw inlet pressure	[psi]	630
Steam outlet temp.	[°F]	720
Steam outlet pressure	[psi]	615
max. steam production	[lb/hr]	120,000
spec. min steam prod.	[lb/hr]	40,000
blowdown in % of inlet mass flow		5
T of exhaust gas at max. load	[°F]	420
T of exhaust gas at min. load	[°F]	350
heat loss surface	[ft ²]	4000*
temp. of comb. gases	[°F]	2000*
excess air in %		30
coal specifications: $x_C = 0.70$, $x_H = 0.05$, $x_{ash} = 0.07$		
steam generation rates: 50,000, 100,000 and 120,000 lb/hr		

Table 2.2 Comparison of main results for simulation of CSP boiler #1

Parameter	25% load	50% load	full load
Steam generation [lb/hr]	50,000	100,000	200,000
Actual coal rate [lb/hr]	5380	11,000	13,200
Simulated coal rate [lb/hr]	5990	10,950	12,980
Actual air intake [lb/hr]	61,000	132,500	158,000
Simulated air intake [lb/hr]	75,000	137,000	163,000

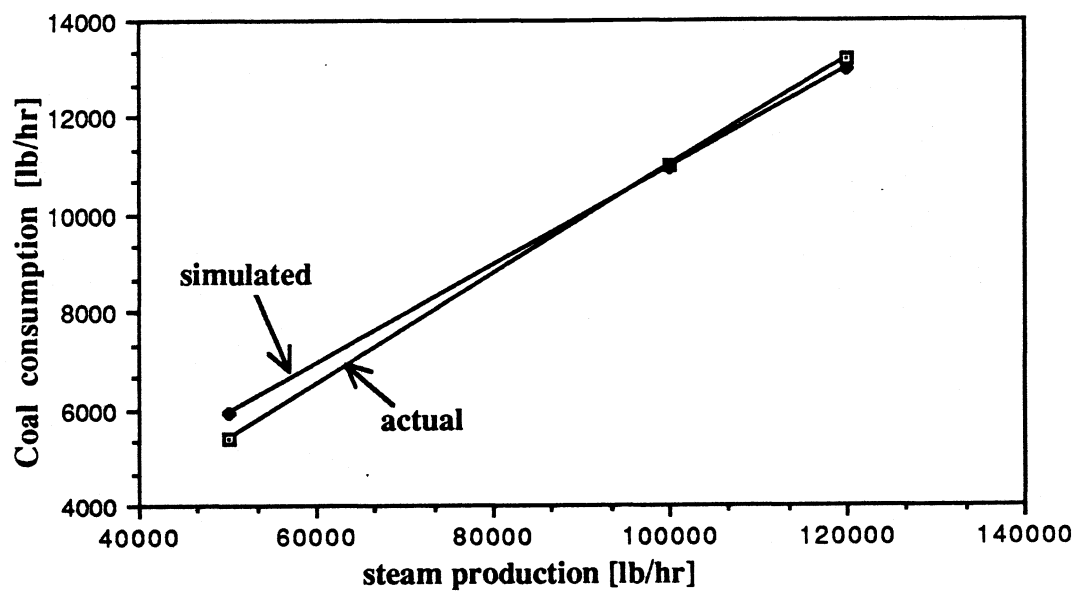


Figure 2.2 Measured and predicted coal consumption of boiler #1 at Charter street plant (steam at 615 psi, 725°F)

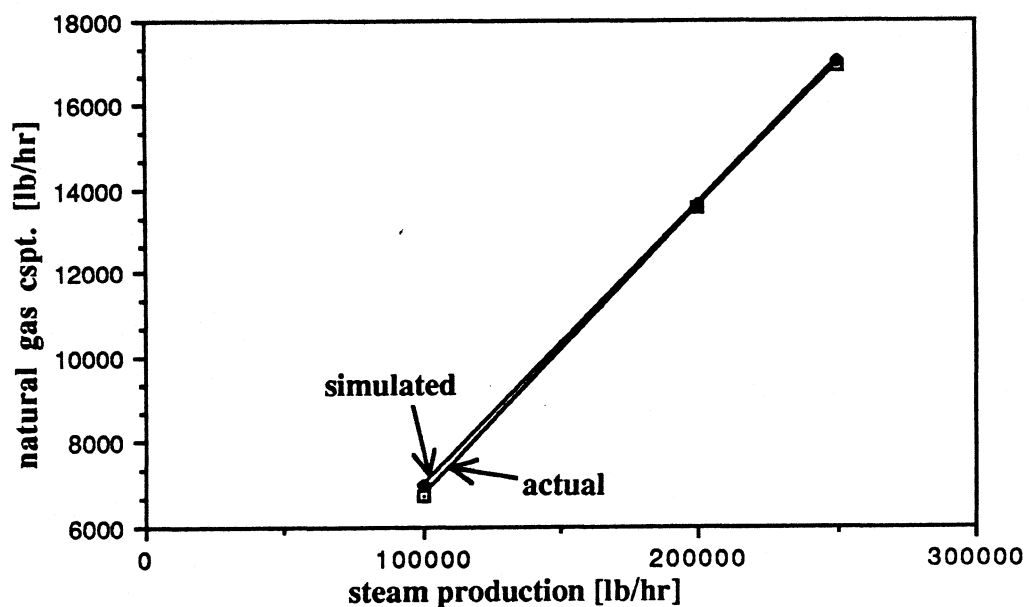


Figure 2.3 Measured and predicted natural gas consumption vs steam production of MG&E boiler #6 (1250 psi, 950°F steam)

2.2 Turbine Model

A standard thermodynamic analysis is also employed to simulate the performance of a back-pressure or of a condensing steam turbine, with or without an electricity generator. In a condensing turbine, the steam is expanded from the high inlet pressure to a very low pressure ($p_{\text{cond}} < 1 \text{ atm}$), which is maintained at the turbine outlet by a steam condenser. Extraction of a constant or variable fraction of the inlet mass flow at various pressures is often used to provide heat for feedwater preheating or cogeneration applications.

In a back-pressure turbine, on the other hand, the steam is not condensed, but leaves the turbine as superheated steam, so that it can be used for a second useful purpose like driving another low pressure turbine or heating.

In both turbine types two modes of calculation are possible: if the power output is given, the model calculates the required steam mass flow rate. In cogeneration systems, which are usually tracking the heat demand (see Ch.1), the available steam serves as the input to calculate the maximum possible power production.

2.2.1 Back-Pressure Turbine

Neglecting kinetic and potential energies, a first law analysis yields the required mass flow rate at the design point of the turbine

$$\dot{m}_{\text{st}} = \frac{P_t}{\eta_{\text{lt}} (h_1 - h_3)} \quad (2.8)$$

where h_1-h_3 is the isentropic enthalpy drop in the turbine, which can be calculated from the specified steam inlet and back-pressure conditions.

Taking part load and the operation of a generator into account, the required steam mass flow is determined by

$$\dot{m}_{st} = \frac{P_{el}}{\eta_t \eta_{gen} (h_1 - h_3)} D \quad (2.9)$$

where η_{gen} is the generator efficiency and D is a part load factor.

The turbine efficiency η_t at the design point is a function of turbine size and design and cannot be obtained analytically. Instead, typical turbine efficiencies are estimated from curve fits to extensive performance data which is compiled in the literature (Bartlett, 1958, Salisbury, 1974). In a similar fashion the part load operation factor D and the generator efficiency η_{gen} are treated.

A straightforward calculation to determine the potential power output from knowledge of the available steam mass flow rate is not possible and an iterative procedure, using the same equations (2.8, 2.9 and curve fits), is employed.

Results from the turbine model have been tested against performance measurements at the 3 MW back-pressure turbine/generator unit at CSP. Predicted and measured values for steam consumption are plotted versus power output in Fig.2.4. The actual performance is predicted with satisfactory accuracy. The discrepancy at 500 kW is due to a required minimum steam flow rate of 30,000 lb/hr for the turbine at CSP.

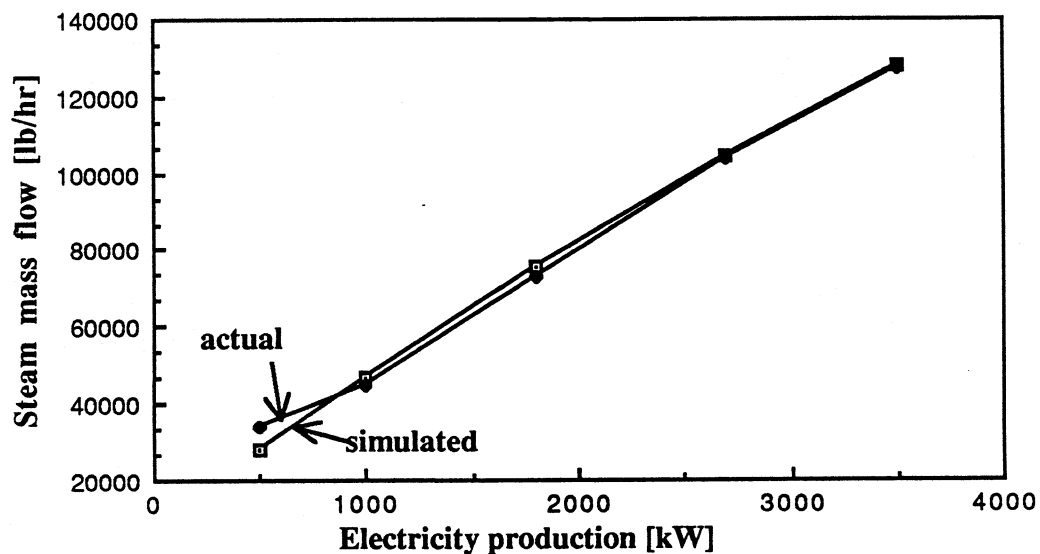


Figure 2.4 Measured and predicted steam mass flow through 3 MW backpressure turbine at Charter Street (inlet: 615psig, 700°F, backpressure: 175psig)

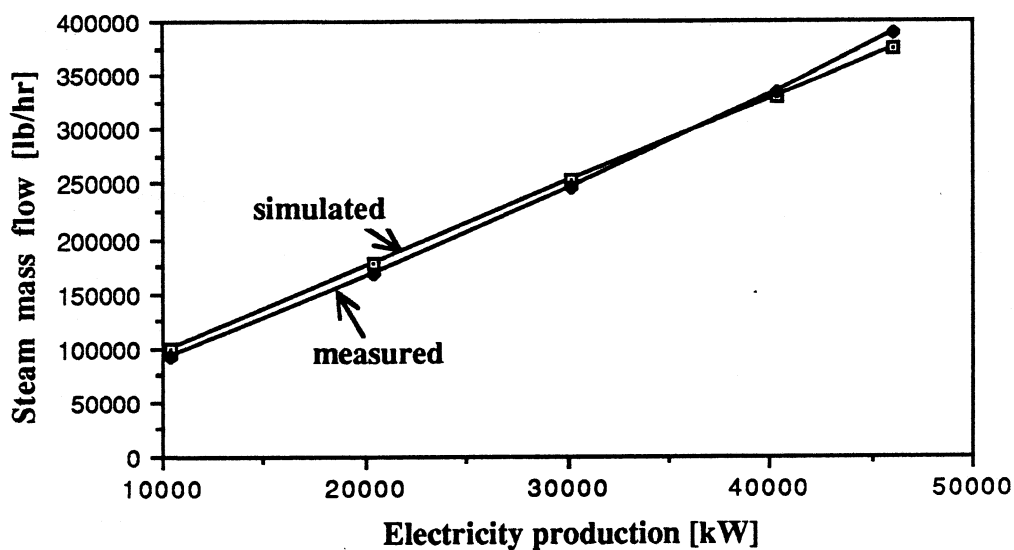


Figure 2.5 Measured and simulated steam mass flow vs electricity production for 44 MW condensing steam turbine at MG&E (inlet conditions: 1250psig, 950° F, five extraction points for feedwater heating)

2.2.2 Condensing Steam Turbine

The basic schematic for the thermodynamic analysis of a condensing steam turbine with one extraction point is shown in Fig. 2.6.

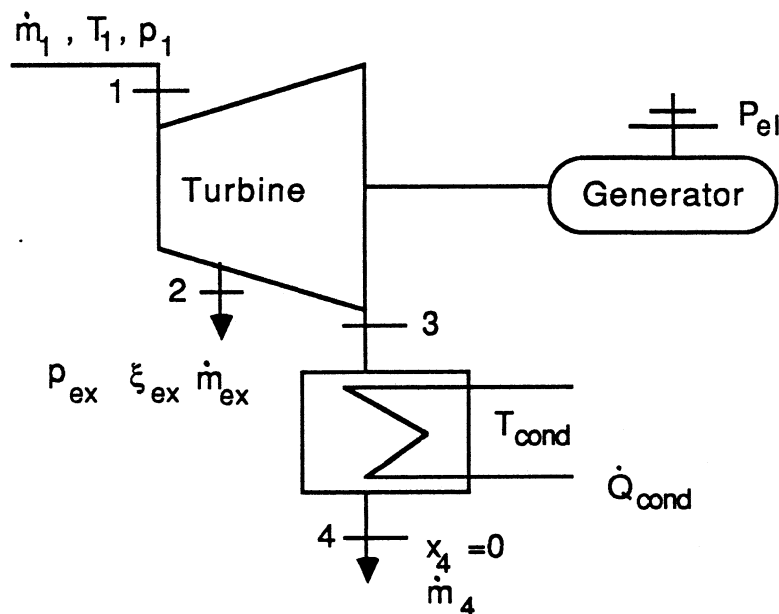


Figure 2.6 Schematic for a condensing steam turbine with extraction

The analysis is similar to that for the back-pressure turbine, except that steam extraction and the operation of the condenser have to be taken into account. Up to six extraction points at different pressures with variable extraction can be specified in the model. The corresponding equation to Eq. 2.9 is

$$\dot{m}_{st} = \frac{P_{el}}{\eta_t \eta_{gen} \left\{ (h_1 - h_3) - \sum_i^{Ex} \xi_i (h_i - h_3) \right\}} (1 + d) \quad (2.10)$$

where $h_1 - h_3$ and $h_i - h_3$ are isentropic enthalpy differences, $h_3 = h_3(T_{con}, s_{in})$ and $h_i = h_i(p_i, s_{in})$.

The 44 MW turbine at MG&E with five extraction points was simulated to test the condensing mode of the model. The entire cycle, including feedwater heater and deaerator steam demands was modelled to make an accurate comparison of the performance possible. Results are plotted in Fig. 2.5 and show good agreement.

It can be concluded that the model serves well in representing a typical example of this type of equipment. Once actual performance data is available, however, the model output should be verified to check for possible deviations from typical efficiencies or the manufacturers data should be used directly for the simulation.

2.3 Centrifugal Pump

For all pumps used in the simulations, actual performance data for the specific operating conditions of the form presented in Fig. 2.7 was used.

For given fluid properties and impeller rotational speed n , the required brake horse power (bhp) is a function of the pumping head and the volume flow rate:

$$bhp = bhp(\dot{Q}, H)_{n, fluid} \quad (2.11)$$

If the pump is motor driven, the electric power is $P_{el} = bhp / \eta_{el}$. In case of a steam driven pump, the curve fit model can be combined with the steam turbine model presented in Ch.2.2.

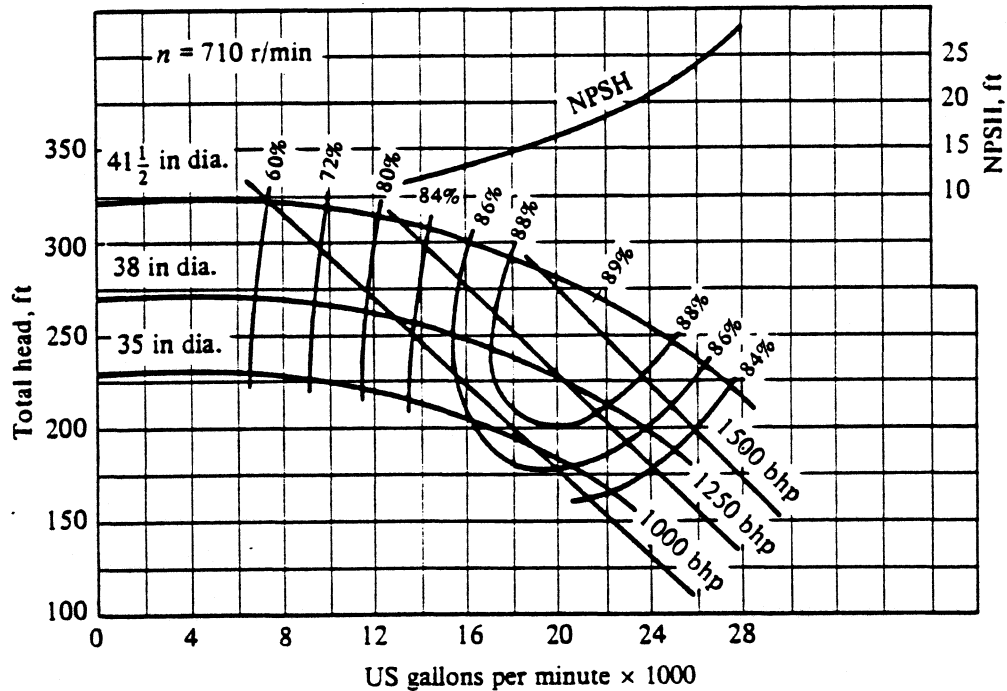


Figure 2.7 Example of the performance curves for a centrifugal pump.

(From White, 1986)

2.4 Deaerator/Desuperheater

Two devices, which are used in most steam cycles, can be modelled with this component: in the first mode, it represents a combination of deaerator and water treatment plant, as depicted in Fig. 2.8. A deaerator is a container, in which boiler feedwater is mixed with steam, usually extracted from the turbine, to preheat the water and to remove air and other gases before it enters the boiler.

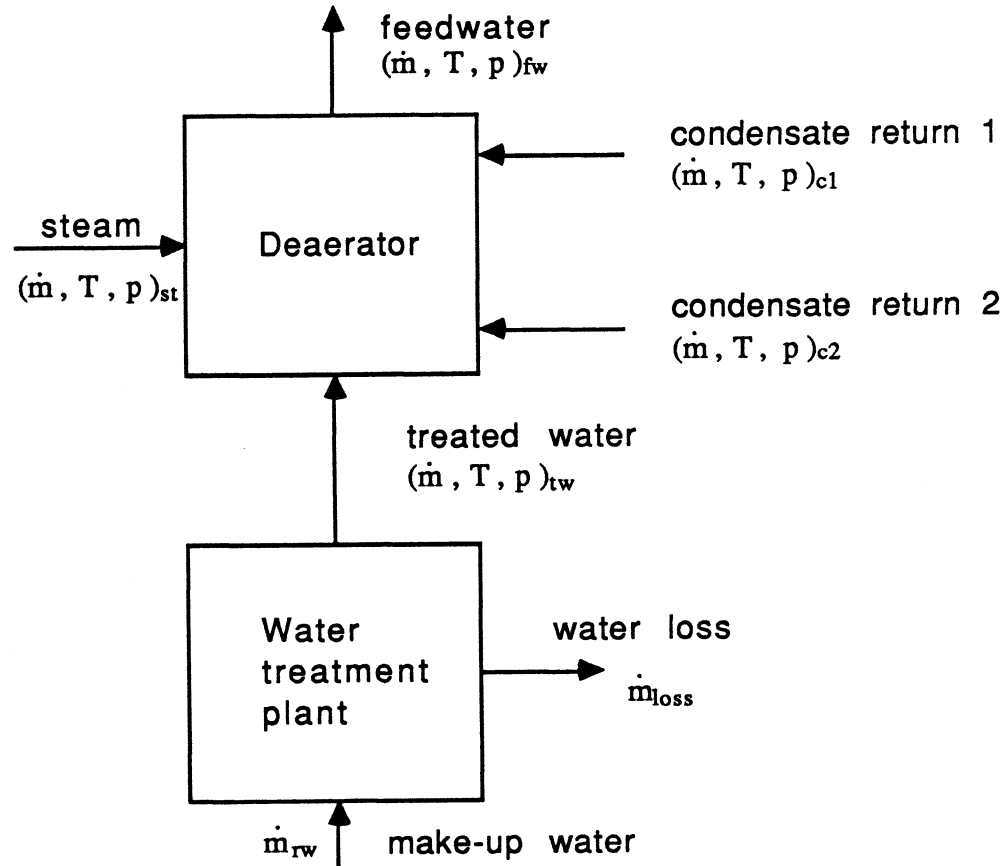


Figure 2.8 Schematic of a deaerator combined with a water treatment plant

In the second mode, the desuperheating process of mixing water and superheated steam for temperature control is simulated.

For both cases the governing equations are mass and energy balances. From Fig.2.8 it is obvious that for given temperatures, pressures, condensate and feedwater mass flow rates the mass balance is

$$\dot{m}_{fw} = \dot{m}_{st} + \dot{m}_{c1} + \dot{m}_{c2} + \dot{m}_{tw} \quad (2.12)$$

and the energy balance is

$$\dot{m}_{fw} h_{fw} = \dot{m}_{st} h_{st} + \dot{m}_{c1} h_{c1} + \dot{m}_{c2} h_{c2} + \dot{m}_{tw} h_{tw} \quad (2.13)$$

These equations can be solved to give the steam and the treated water mass flow rates. In case of high condensate return, $\dot{m}_{tw}$ could be negative, meaning that water has to be discarded in order to allow for sufficient steam injection to raise the temperature to T_{fw} .

The balances for the water treatment plant and the desuperheater mode follow directly from Fig. 2.8.

2.5 Heat Exchanger

An energy balance combined with steam property calculations serves to determine the flow rate of a fluid 1 to achieve a desired cooling or heating effect on a second fluid. Fluid 1 can be water with or without phase change (condensation or evaporation) or any other fluid without phase change. The properties of fluid 2 can also be user specified. The mass flow rate of fluid 1 is calculated by

$$\dot{m}_1 = \dot{Q} / (h_{1,in} - h_{1,out}) \quad (2.14)$$

with

$$\dot{Q} = \dot{m}_2 (h_{2,out} - h_{2,in}) \quad (2.15)$$

All inlet and outlet states and the mass flow rate of fluid 2 have to be specified.

Within the plant model this component is used to represent air heaters and the second stage heater for the feedwater (see Ch.3).

2.6 Steam Pipe

This component models the steady state operational behavior of steam flow in a long straight pipe, similar to the proposed one for the interconnection of MG&E and the UW. It uses basic equations for the determination of heat and pressure loss, and it is possible to determine the outlet steam conditions from given inlet conditions and vice versa.

Fig.2.9 illustrates the energy balance for a differential pipe volume, which is the starting point for the calculation of the heat losses (Incropera,1985).

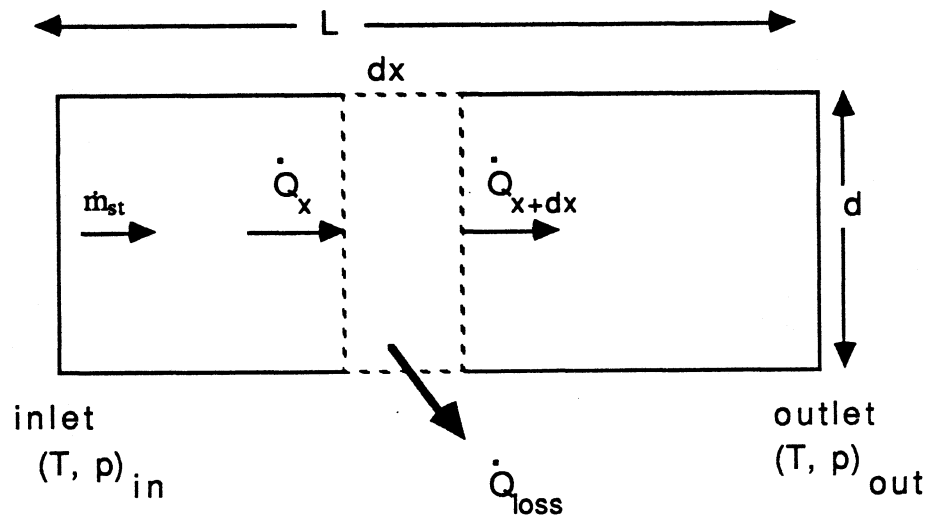


Figure 2.9 Energy balance for a differential pipe element

The result for the pipe outlet temperature is

$$T_{out} = T_a + (T_{in} - T_a) \exp\left(-\frac{UA}{\dot{m}c_p}\right) \quad (2.16)$$

The overall loss conductance can be calculated from $UA = 1/R_{tot}$, where R_{tot} is the sum of the individual heat transfer resistances between the steam and the surroundings. The heat transfer coefficient on the outside of the pipe and the conductances of the pipe and the insulation have to be specified by the user. In order to estimate values for the average internal heat transfer coefficient $h = Nu k / L$, the appropriate equations for the Nusselt number Nu are evaluated by the model: Dubbel (1983) suggests the following empirical equations for laminar and turbulent flow of steam in a pipe:

$$\text{for laminar flow: } Nu = \left[3.65 + \frac{0.0668 Re Pr d_i / L}{1 + 0.045 (Re Pr d_i / L)^{2/3}} \right] \quad (2.17)$$

$$\text{for turbulent flow: } Nu = 0.024 Re^{0.786} Pr^{0.45} \left[1 + (d_i / L)^{2/3} \right] \quad (2.18)$$

In both equations, the steam properties are to be evaluated at mean temperatures and pressures with the help of the TRNSYS 'steam' subroutine.

The analysis yields the pipe outlet temperature and the heat loss, which is

$$\dot{Q}_{loss} = \dot{m} c_p (T_{in} - T_{out}) \quad (2.19)$$

For isothermal, compressible flow, the pressure drop can be estimated by

$$\Delta p = p_i \left[1 - \sqrt{1 - 4 c_f \frac{L v_{in} \rho_{in}}{d_i p_{in}}} \right] \quad (\text{Dubbel, 1983}) \quad (2.20)$$

The friction factor c_f depends on the type of flow and on the pipe roughness and is evaluated with appropriate empirical equations taken from Dubbel (1983).

2.7 Chiller Model

All chillers at CSP and WSP are of the vapor compression type and have steam turbine driven compressors. In order to obtain relationships between the cooling load and the required compressor power, measurements of the chiller performance from hourly log sheets were correlated. Fig. 2.10, which is a plot of chiller power vs cooling load for a 3500 ton chiller at Walnut Street at various ambient and operating conditions, suggests an almost linear relationship for a wide range of cooling loads.

A linear regression analysis gives

$$\text{Power} = 22 + 0.000054 \text{ Load} \quad (2.21)$$

with power in kW, load in Btu and a standard deviation of 140 kW. This estimate for the chiller compressor power, which is considered to be satisfactory for the intended application, is then put into the steam turbine model (Ch. 2.1) to compute the required steam flow.

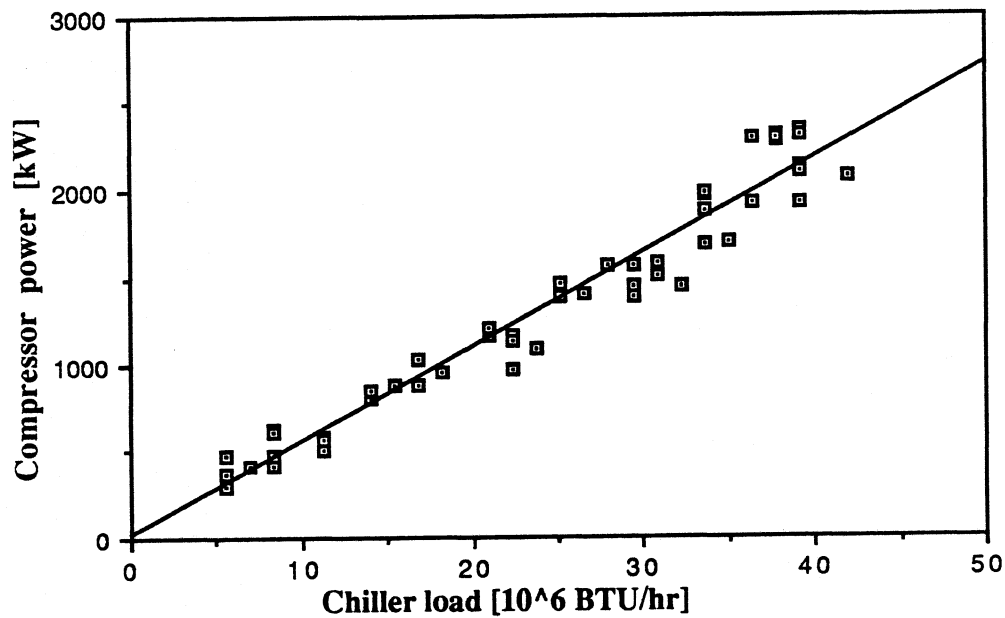


Figure 2.10 Power vs load for chiller #1 at Walnut Street plant (3500 ton)

2.8 Efficiency Calculator

In order to have a common basis on which to compare the thermal performance of various cogeneration systems, a subroutine has been written to compute the first law, second law and the PURPA efficiencies of the entire system. The equations for η_1 and η_2 are given in Appendix A. The PURPA efficiency η_p is a measure of performance

that is used to determine if a private business qualifies as a cogenerator under the PURPA act. It is defined as

$$\eta_P = \frac{W_{\text{elec}} + \frac{1}{2} Q_{\text{heat}}}{Q_{\text{fuel}}} \quad (2.22)$$

The calculations can account for various fuels, for heat supplied at different conditions and for all power producers in a plant.

Chapter 3

Plant Simulation and Validation of Method

The Charter Street plant (CSP), which is the central part of the UW heating and cooling system, was chosen for a first simulation. A general overview of the plant has been given in Ch. 1.2. Now the loads, equipment configuration and control of CSP are described in more detail, and the modelling methods and procedures are laid out afterwards. The verification of the obtained simulation results by comparison to actual plant numbers and an assessment of the accuracy of the model comprises the second part of this chapter.

3.1 Description of the Modelled Plant

The primary task of the Charter Street plant is to provide heating and cooling to the UW campus. Depending on the amount of steam, which is available to drive a turbine/generator unit, it also cogenerates up to 3 MW electricity.

The main goal of the simulation is to calculate this potential electricity generation and the amount of fuel which is required to meet the heating and cooling loads throughout a year. A summary of the main inputs and outputs of the model, which will be discussed in the following, is given in Fig. 3.1.

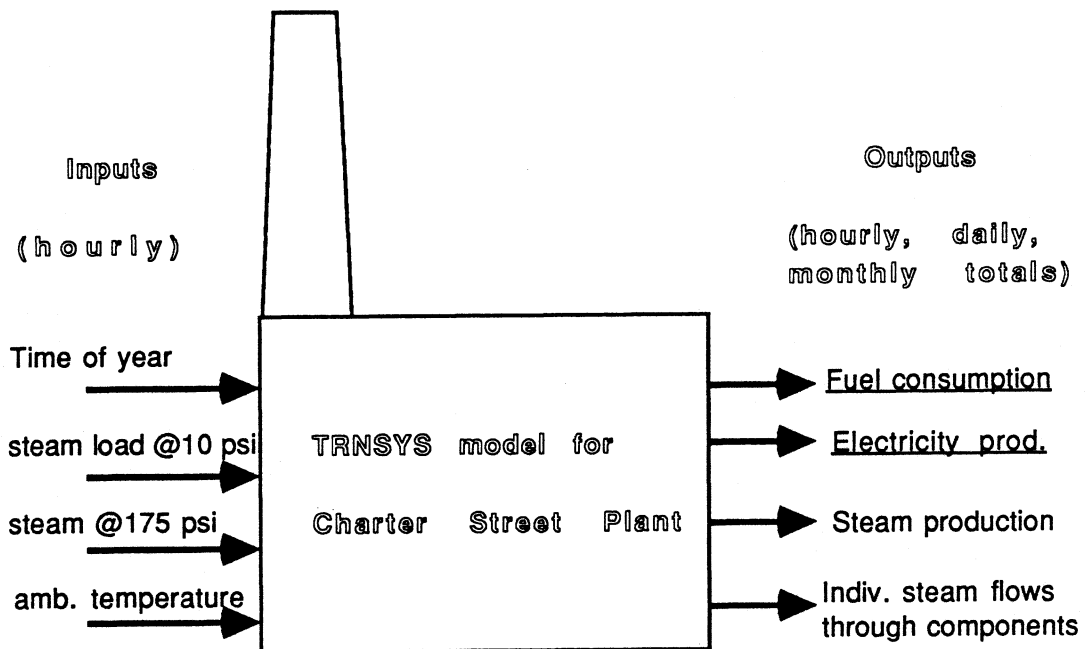


Figure 3.1 Main inputs and outputs of the simulation

3.1.1 Loads on CSP

Heating for university buildings is supplied by steam which leaves the plant at high (175 psig) and low (10 psig) pressures. The heating season in Madison typically lasts from the beginning of October until the middle of May. During the rest of the year, while the chillers are operating, steam serves mainly to reheat cooled air, to provide hot water and to drive several absorption chillers throughout the campus.

The plant operators keep track of main production figures on daily log sheets. The reported data on the steam cycle include 8-hour values of the steam leaving the plant at the different pressures, 2-hour measurements of individual boiler steam

production and daily totals of exiting steam, produced steam and consumed fuel.

In order to simulate with reasonable resolution, hourly values of the campus steam demand are needed as a forcing function for the model. Although attempts were made to correlate the steam output to ambient conditions and other influence factors, a decision was finally made to use recorded daily totals of 175 psig and 10 psig steam directly as a basis to generate hourly inputs. Data from March 87 to February 88 were chosen for this purpose, since it was the most recent and complete. From a statistical analysis of steam supply and production data, typical daily profiles were obtained that served to generate hourly inputs in combination with the daily figures. Different profiles were used to represent weekdays and weekends. They are shown in Fig. 3.2. Except for a sharp increase in steam demand in the morning, which is less pronounced on weekends, since classrooms do not have to be tempered, the steam flow appears to be relatively constant over the day.

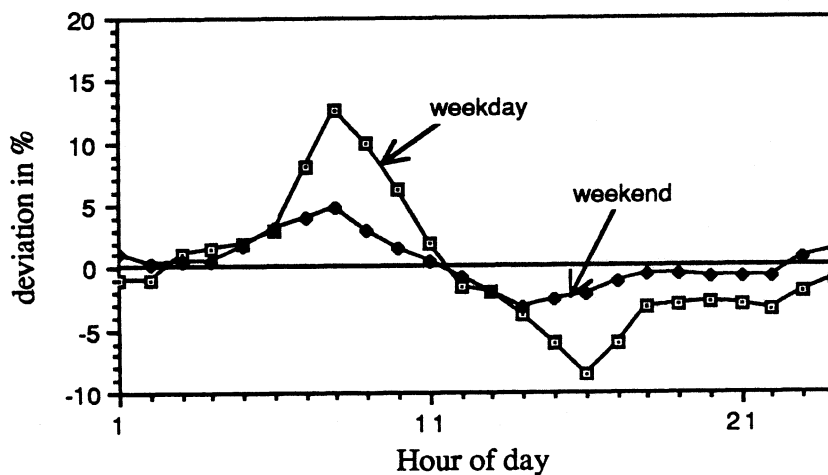


Figure 3.2 Deviation of hourly campus steam demand from daily average in %

The first simulation tests resulted in steam generation totals which were several percent below the measured ones. Further investigations revealed that a considerable amount of steam bypasses the flow meters for exiting steam and that the meters themselves tend to indicate a slightly lower steam mass flow than actually passes through them. Correction for these findings were built into the simulation (see program listing for 'Load Profile Generator' in Appendix B).

The external hourly steam load during the summer months, which is considerably lower than in the winter, was generated in a similar manner.

In contrast to steam load figures, only hourly measurements existed for the cooling loads on the chillers. It proved to be convenient and sufficiently accurate to correlate these loads from ambient conditions. Although load calculation guidelines show that internal building loads and insolation contribute substantially to the load (ASHRAE, 1985), the cooling load could be predicted solely from dry and wet bulb temperatures and the hour of day. A seasonal dependence has also been observed, so that three correlations were established to predict the hourly campus cooling load in 10^3 BTU/hr from ambient conditions for the period 1987-88:

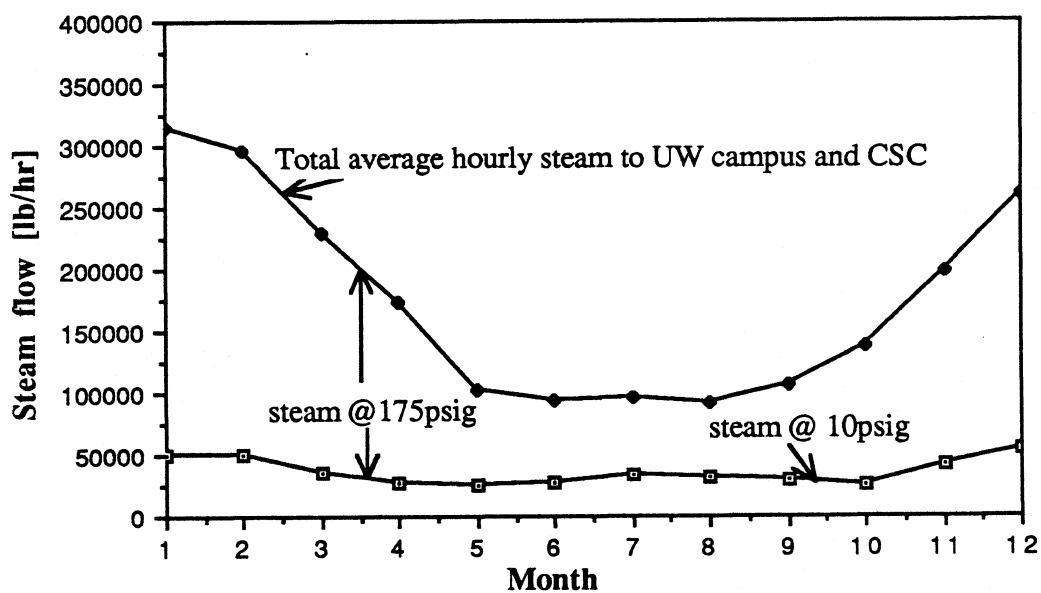
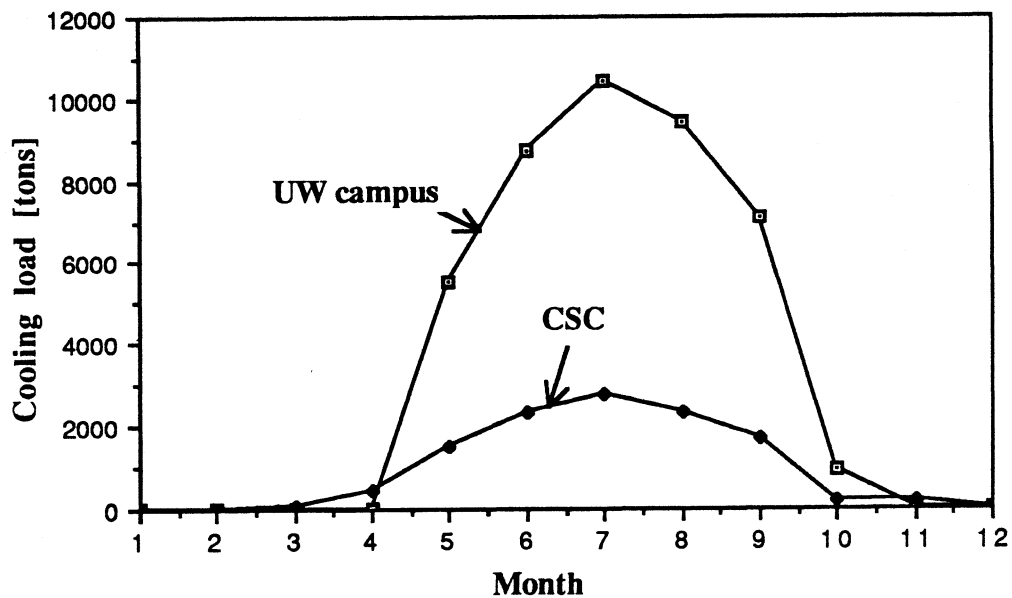
$$\text{Load} = -68428 + 674\text{HOD} - 736T_{\text{db}} + 3471T_{\text{wb}} \quad (\text{weekdays summer}) \quad (3.1a)$$

$$\text{Load} = -172000 + 16\text{HOD} - 2160T_{\text{db}} + 6730T_{\text{wb}} \quad (\text{weekends summer}) \quad (3.1b)$$

$$\text{Load} = -40700 + 605\text{HOD} - 2190T_{\text{db}} + 4420T_{\text{wb}} \quad (\text{spring and fall}) \quad (3.1c)$$

The file with hourly ambient temperatures for March 1987 until February 1988 also served as input for other components within the model.

In order to convey a picture of the magnitude and annual fluctuations of the campus loads, plots of monthly average steam supply to the campus and of the cooling

Figure 3.3 Hourly average steam flow to UW campus and Clinical Science**Figure 3.4** Average monthly cooling load for UW campus and Clinical Science

load are presented in Figs. 3.3 and 3.4. Note that Fig. 3.3 shows the total steam supply to the campus and to the Clinical Science Center and that steam, which is sent from CSP to Walnut street in order to drive the 175-condensing chiller compressors, has been subtracted from the total steam flow to WSP/CSC in order to present only the steam flow which serves for heating purposes.

3.1.2 Equipment Configuration and Control at CSP

A more detailed diagram of CSP's steam/water cycle than that depicted in section 1.2 is shown in Fig. 3.5. Most of the information contained in this figure has been taken out of a plant description included in the Campus Heating Master Plan (1986). Several additions and changes to this figure resulted from inspection of the plant and frequent discussions with the plant personnel.

Figure 3.5 is still a simplified representation of the configuration. In reality, Charter Street plant consists of two almost separate steam generation facilities: one part, located in the northern section of CSP, comprises the #4 coal fired (200,000 lb/hr max. capacity) and the #5 natural gas fired boiler with a steam generation capacity of 300,000 lb/hr. The 'South end' has three coal fired boilers, each having a capacity of 100,000 lb/hr. Both parts are individually equipped with a deaerator, a feedwater treatment plant, second stage heater, several boiler fans and feedwater pumps.

Steam from both sides of the plant is fed into the same central 600 psig main system. In the cooling season, most of the steam is used to drive the chiller compressors and the condensate is returned to the boilers internally. Steam which leaves the plant is expanded to the required pressures through various turbines, to

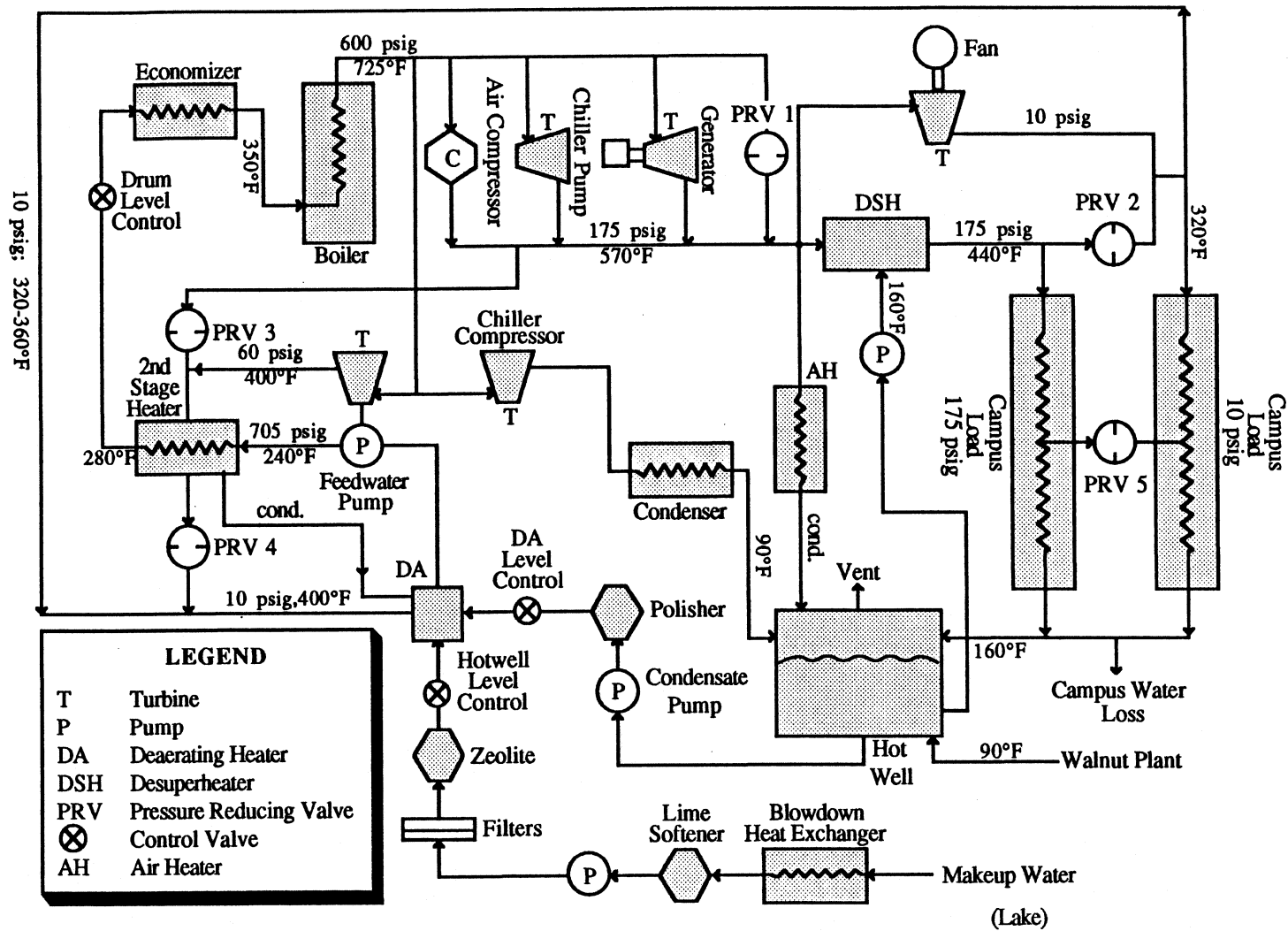


Figure 3.5 Simplified Steam / Water Cycle of Charter Street Plant

cogenerate shaft power and electricity. In the winter about half of the outgoing steam has to be throttled from 600 psig to 175 psig in up to three pressure reducing valves (combined as PRV1 in the diagram), because the maximum capacity of the 600-175 psig turbines, including the 3 MW turbine/generator unit, is only about 140,000 lb/hr. During most of the summer months, on the other hand, when the steam demand is fairly low and a 600-175 psig steam driven chilled water pump has to be run in parallel, the generator can only operate at low part load.

In order to meet the heating demand at low pressure, steam is further expanded, driving boiler fans, minor plant auxiliaries and also the fans for a recently installed stack emission control system (baghouse). If this steam flow is not sufficient, PRV2 which throttles steam from 175 psig to 10 psig, has to be opened. Additional 175-10 psig pressure reducing station are located throughout the campus to make up for pressure losses in the 10 psig system (PRV5 in diagram).

Low pressure steam is also needed for deaerating and space heating purposes within the plant. Tracing the 10 psig lines in the diagram, one sees that additional steam can be provided in several ways if there is not sufficient excess low pressure steam from the fan or feedwater pump turbines.

As already mentioned above, the main inputs for the simulation are the campus steam demand and the cooling load which is converted to an additional 600 psig steam load by the chiller/turbine combination described in Ch. 2.7. The required overall steam production is calculated and fed into the boiler models which in turn compute the fuel consumption rate, which is the single most important output of the model. Another important result is the potential electricity generation of the turbine/generator unit (see Fig. 3.1).

All steam driven components of Fig. 3.5 are included in the simulation, which is designed to be a complete representation of the steam/water cycle, with all five boilers, three chillers etc. Auxiliary equipment and electrically driven machinery, however, is not included in order to limit the complexity of the simulation.

A central control program is necessary to determine the number of operating boilers and chillers, to compute the available steam mass flow for the turbine/generator and to make decisions regarding the operation of several flow diverters and pressure reducing valves. The order in which the chillers and steam generators are usually switched on to meet an increasing load are a part of this program, as well as the operation of the deaerator/feedwater treatment component (see Ch. 2.4), which includes an average 17% water make-up due to losses on the campus. The programmed control strategy tries to imitate the 'typical' plant operation employed by the plant personnel, which is not that typical after all, because special procedures have often to be taken to respond to maintenance and other problems.

Before going into the verification of simulation results, a brief summary of major features of the simulation method with the TRNSYS program is given (see also Ch. 1.4): the simulation timestep is one hour. The simulation period is one year from March 1987 to February 1988. Hourly load and ambient data of the form, which has been described above, is supplied to the model, which computes the desired outputs (see Fig. 3.1) in an iterative fashion, i.e. for every timestep with new inputs the program calls the interconnected individual component models until the inputs of all components (which are outputs of other components) have converged within a specified tolerance. A special CPU-time saving feature of TRNSYS is that only components, whose inputs have not converged yet, are called.

3.2 Validation of the Model

Although all steam mass flows (through turbines, PRVs, etc.) within the plant at any hour of the year can be theoretically obtained from the simulation, these results have to be treated cautiously. As was stated above, the modelled configuration is still simplified. The temperature and pressures specified in the diagram are average numbers which are subject to variations throughout the year. Several simplifications and assumptions with respect to the operational control, for example, have also been made. Additional minor discrepancies might result from the error margin of the component models (see Chapter 2).

Since measurements of individual mass flow rates are not conducted at Charter Street, the basis for a validation of the simulation are daily, monthly and annual numbers for steam production, fuel consumption and electricity generation. Figure 3.6 shows the fluctuation of the predicted and the measured daily total steam production in August of 1987. The same plot for a winter month is given in Fig. 3.7. In both plots, the steam loads on the system at high and low pressure are also included. It is actually the difference between the steam production and the total exiting steam flow that the model predicts, i.e. the internal steam load, which is necessary to maintain the provision of heating and cooling to the campus.

The computed total required steam demand is then distributed among the operating boilers. The boiler model has been verified as described in Ch. 2.1 and a comparison of total daily fuel consumptions confirms the usefulness of the model.

Annual totals for measured and actual steam production, fuel consumption and electricity generation are summarized in Table 3.1. The numbers for the steam

Figure 3.6 Comparison of predicted and measured daily steam production for August 87

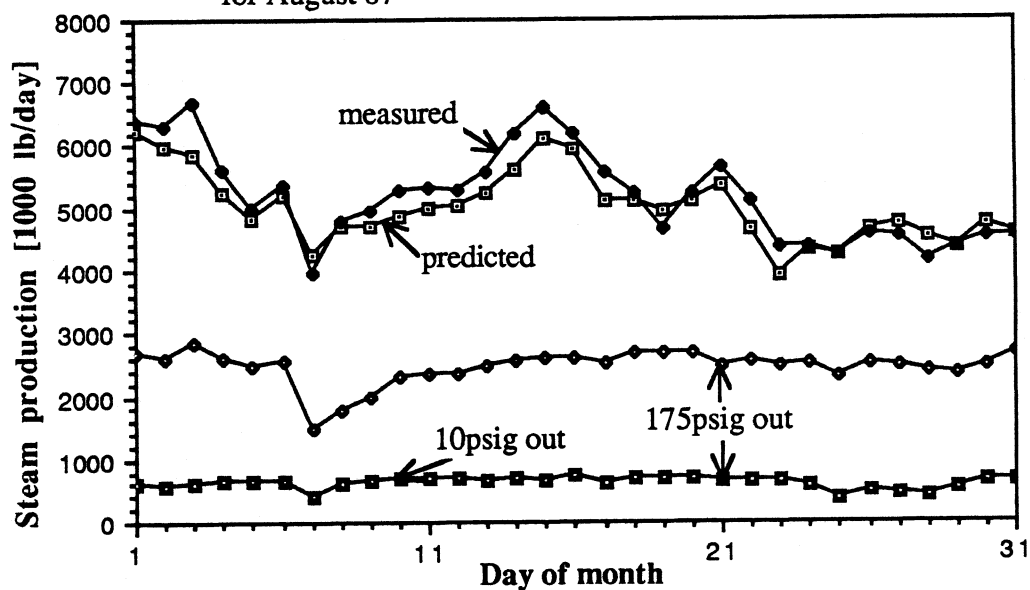
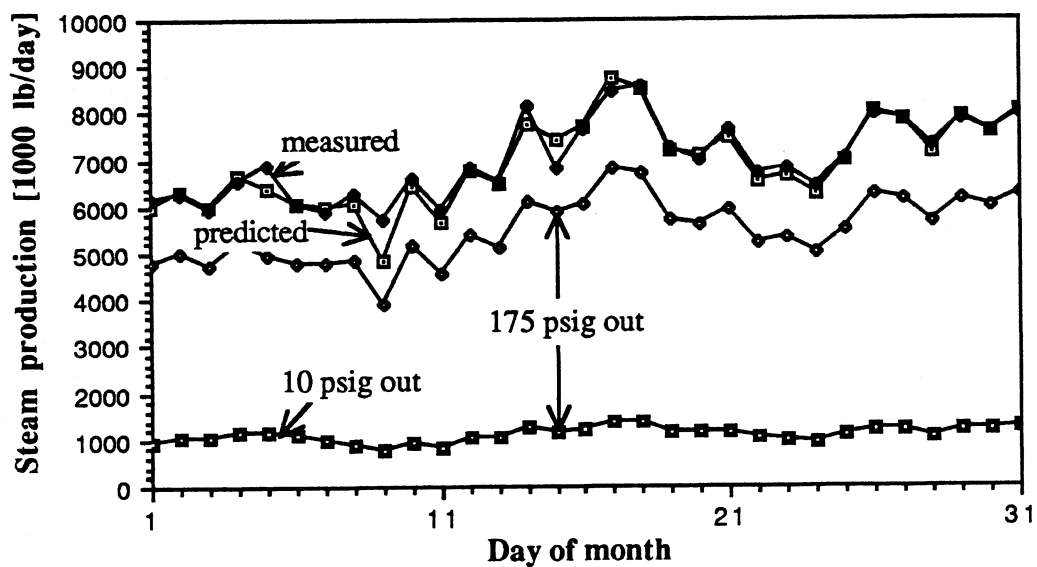


Figure 3.7 Comparison of daily steam production for December 87



production and the total fuel use in terms of energy show a good agreement. Results for the individual fuel consumption do not exactly coincide, however, because the boiler control could only be approximated (see Chapter 3.1.2).

Table 3.1 Comparison of annual simulation results to actual data at Charter Street plant for 3/87 to 2/88

Parameter		simulated	actual
steam production	[10 ⁶ lb]	2007	1990
coal consumption	[tons]	51,833	53,715
nat. gas cons.	[10 ⁶ scf]	1,479	1,380
total fuel energy	[10 ⁶ BTU]	2,799,110	2,739,823
electricity generation	[MWh]	18,002	13,887
(electricity consmpt. [MWh]		12,000	12,000) ¹

It is apparent that the model is considerably overpredicting the electricity generation of the plant. Several checks showed that this discrepancy results from the assumption that the maximum possible electricity is generated. In reality, the operation of the turbine is subject to a manual control, which cannot track the available steam flow on a continuous basis. Thus more than the required minimum amount of steam is throttled through PRV1, even if the turbine/generator is not fully utilized. In other

¹Both values for electricity consumption are taken from log sheets, because most electricity consumers have not been included in simulation

words, the model calculates the electricity which could be generated under optimal control conditions without maintenance or outage times.

3.3 Conclusions

The above comparison shows that the results obtained from the plant simulation are quite close to the measured values. For the prediction of the electricity generation the model gives the potential maximum generation, since it can not consider special, manually imposed, operating conditions. The results have been compared on a daily, monthly (Table 3.2) and annual basis. Unfortunately the data from CSP has not been as detailed as would have been desirable. Most individual steam flows within the plant are not measured and several measured quantities are recorded on a daily basis only. Together with the complexity of the plant with its numerous pieces of equipment and its branched piping network, a thorough validation of every simulation result has been impossible.

Once a diagram of the configuration at CSP was established the set-up of the simulation was easily conducted. The computational time for an annual simulation was below one hour on a mainframe computer (MicroVAX II).

Overall it can be concluded that the demonstrated performance of the model is sufficiently accurate on a daily to yearly basis to investigate and predict performance trends for different configurations and major equipment changes. Alternative configurations with the objective to cogenerate more electricity and to increase the efficiency of the entire system are described and evaluated in the next chapter.

Table 3.2 Comparison of actual and predicted monthly values for fuel consumption and electricity generation at Charter Street plant for the period 3/87 to 2/88

Month	Fuel _{act} [10 ⁶ BTU]	Fuel _{pred} [10 ⁶ BTU]	relative Error	Elec. _{act} [MWh]	Elec. _{pr} [MWh]	relative Error
March	251,980	267,200	+6%	1,724	2,130	+17%
April	82,240	93,120	+13%	461	792	+72%
May	178,535	185,633	+4%	348	1,049	+200%
June	213,150	207,205	-3%	435	971	+123%
July	252,024	244,154	-3%	759	1,237	+63%
August	223,089	222,000	-0.5%	676	1,005	+48%
September	200,514	207,705	+3.5%	1,046	1,250	+20%
October	137,321	131,186	-4%	1,113	1,134	+2%
November	200,105	209,979	+4.5%	1,645	1,999	+21%
December	289,791	311,070	+7%	1,726	2,145	+24%
January	366,583	381,413	+4%	2,006	2,145	+7%
February	344,491	338,445	-2%	1,948	2,145	+10%
YEAR	2,739,823	2,799,110	+2%	13,887	18,002	+30%

Chapter 4

Alternatives for Increased Cogeneration

In the first part of this chapter the potential and possibilities for more cogeneration for the UW heating and cooling system are assessed. Possible configurations at the MG&E Blount Street plant to supply steam to the UW campus besides generating electricity are discussed in section 4.2. The configurations chosen for a detailed examination and the results obtained from the simulations with the TRNSYS program are then presented in 4.3. In section 4.4 the results are discussed on a thermodynamic basis, before monetary aspects are taken into account in Ch. 5.

4.1 Cogeneration Potential for UW Plants

The primary goal of the studied system is to satisfy the heating and cooling needs of the UW. The two main areas to consider extended cogeneration at CSP are the minimization of use of pressure reducing valves (PRV) in the winter and the increased operation of the turbine/generator in the summer. A substantial amount of steam is throttled in various pressure reducing valves throughout the plant (see Fig. 3.5). The steam flow through most of these PRVs is very irregular and subject to great swings, so that these valves cannot be considered for replacement by power generating

machinery. In the heating season, however, the average steam flow through the 600-175 psig PRV (PRV 1 in Fig. 3.5) is about 100,000 lb/hr as can be deduced from Fig. 4.1, which shows the daily total steam flow through PRV 1 and PRV 2. Although large fluctuations are prominent due to the daily and seasonal load profile, the base steam flow is sufficient to drive a bigger or an additional turbine/generator unit from the beginning of November until the end of March.

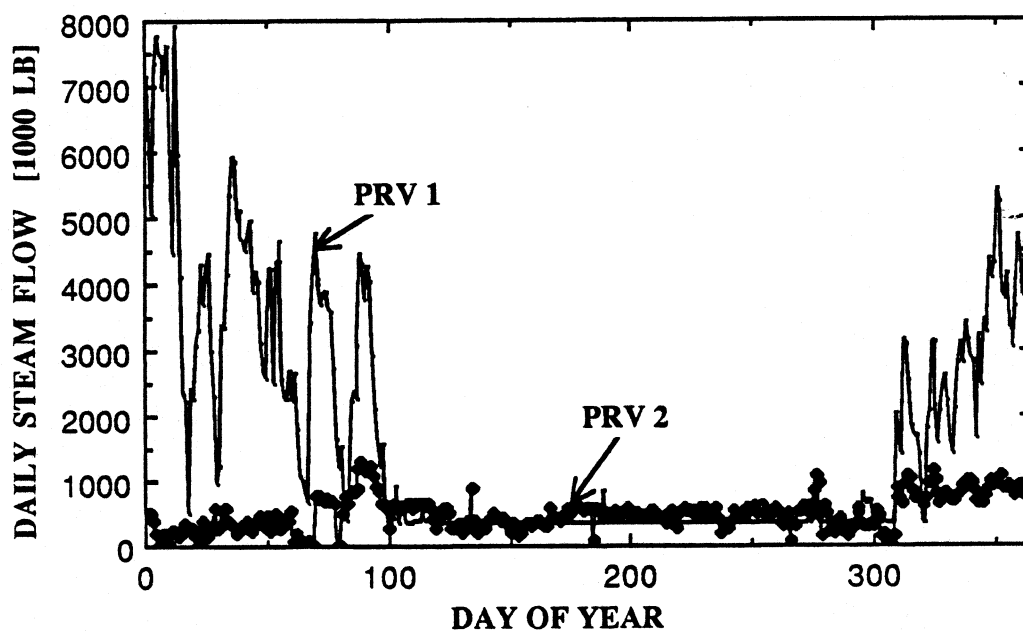


Figure 4.1 Daily steam flow through pressure reducing valves 1, 2 (see Fig. 3.5)

Secondly the present turbine/generator unit is only operating at part load during most of the spring, summer and fall, because of a low campus steam demand. In order to run the turbine at a higher part load, which would also increase its efficiency, ways have to be found to raise the steam demand at low and medium pressures. There are

several possibilities to accomplish this task: presently a primary chilled water (PCW) pump and an air compressor are operated in parallel to the turbine/generator unit, requiring between 20,000 and 40,000 lb/hr (see Fig. 3.5). If this steam were available for the turbine/generator, power could be produced at a higher efficiency than in the smaller compressor and pump turbines, which are fairly old and inefficient. One argument to keep the steam driven pumps and compressors is to maintain operational independence from the electric utility. If new motor driven units could satisfy the demand for compressed air and chilled water pumping, the steam driven components would still have to be maintained as back-up units.

The campus steam demand is estimated to increase at a rate of about 2%/year over a planning horizon of 30 years, which would increase the electricity generation at CSP even with the present system. One possibility to raise the 175 psig steam load considerably consists in operating more chiller compressor turbines at this pressure. This could be realized by replacing the present 600 psig-condensing units with 175 psig units. Another alternative is to install additional chilling capacity with 175 psig-condensing compressors and to decrease chilled water production with the present units at CSP in favor of the new chiller(s). In the process of the required expansion of cooling capacity (see Ch. 1.2), this should be taken into consideration. On the other hand the decreased efficiency of condensing turbines due to a lower inlet pressure is a disadvantage. A computer simulation will be helpful to assess the benefits of various scenarios.

If the mass flow of required steam is fixed, the electricity production and overall cycle efficiency can still be increased by raising the inlet pressure and temperatures to the power producers. The ratio of work output over required heat input of a power cycle increases by raising the pressure during heat addition in the boiler and by further

superheating of the steam (van Wylen/Sonntag, 1986). Rather than considering the use of higher pressure steam at CSP, this study considers a steam line connection with the MG&E Blount Street plant where steam is generated at 850 psig and 1250 psig. Steam generated at Blount Street and expanded in back pressure or condensing steam turbines to approximately 180 psig could be supplied to the UW campus, thus cogenerating electricity at a higher efficiency than CSP. This concept of providing steam to the UW by cogeneration at MG&E could also be employed to produce additional electricity in the winter, instead of installing more electricity generating capacity at Charter Street.

4.2 Possible Configurations at the Blount Street plant

Madison Gas and Electric serves the Madison area with electricity that is now mainly produced at a large coal fired and a nuclear powered plant, which MG&E has shares in. These shares amount to a base load capacity of 316 MW. The Blount Street plant with a total capacity of about 180 MW, which used to be the central part of the utility until the early 1970s, is now operated to satisfy intermediate and peaking loads.

At Blount Street there are two header systems which generate steam at a higher pressure and temperature than CSP: two boilers, producing steam at 1250 psig and 950°F have a total capacity of 850,000 lb/hr and a 850 psig, 900°F system with five boilers can produce up to 900,000 lb/hr of steam.

The two 1250 psig power cycles were constructed in 1956/57 with a total capacity of 90 MW. They are operational during most of the year at varying part load. The coal, gas and oil fired boilers of the 850 psig header system feed into one main pipe and

drive condensing steam turbines with a total capacity of about 80 MW to meet peaking loads on hot summer days.

There are several options to retrofit part of the Blount Street plant for cogeneration. Considering the still relatively low (compared to large facilities) header pressures (1250 psig and 850 psig), the campus demand and other factors such as the steam pipe, 175 psig appears to be the only supply feasible pressure, although 600 psig and 10 psig have also been considered. The steam could be extracted from condensing or from back-pressure turbines in either the 1250 psig or the 850 psig cycles.

The feedwater treatment capacity at Blount Street is not sufficient to handle the condensate return from the campus and associated losses. There are basically two possibilities to solve this problem: one is to expand the feedwater treatment capacity at Blount Street, the other one involves the separation of the cycle loop from the campus loop by insertion of a heat exchanger, which condenses steam on one and evaporates water on the other side. An example for such a system configuration is shown in Fig. 4.2. The lay-out of this figure is exemplary for all systems schematics presented in Appendix C. The cogeneration cycle at Blount Street is shown on the left hand side. For a more detailed representation of CSP and WSP the reader is referred to sections 1.2 and 3.1. The chilled water system is not shown in order to limit the complexity of the graph. The heat exchanger that would be needed for the scenario with separate loops is labeled HX.

A summary of all possible combinations at MG&E to cogenerate electricity and steam is given in Fig. 4.3.

Three of these options have been chosen for analysis:

- 1) condensing turbine with variable steam extraction in present 1250 psig cycle
- 2) back pressure turbine in 850 psig cycle

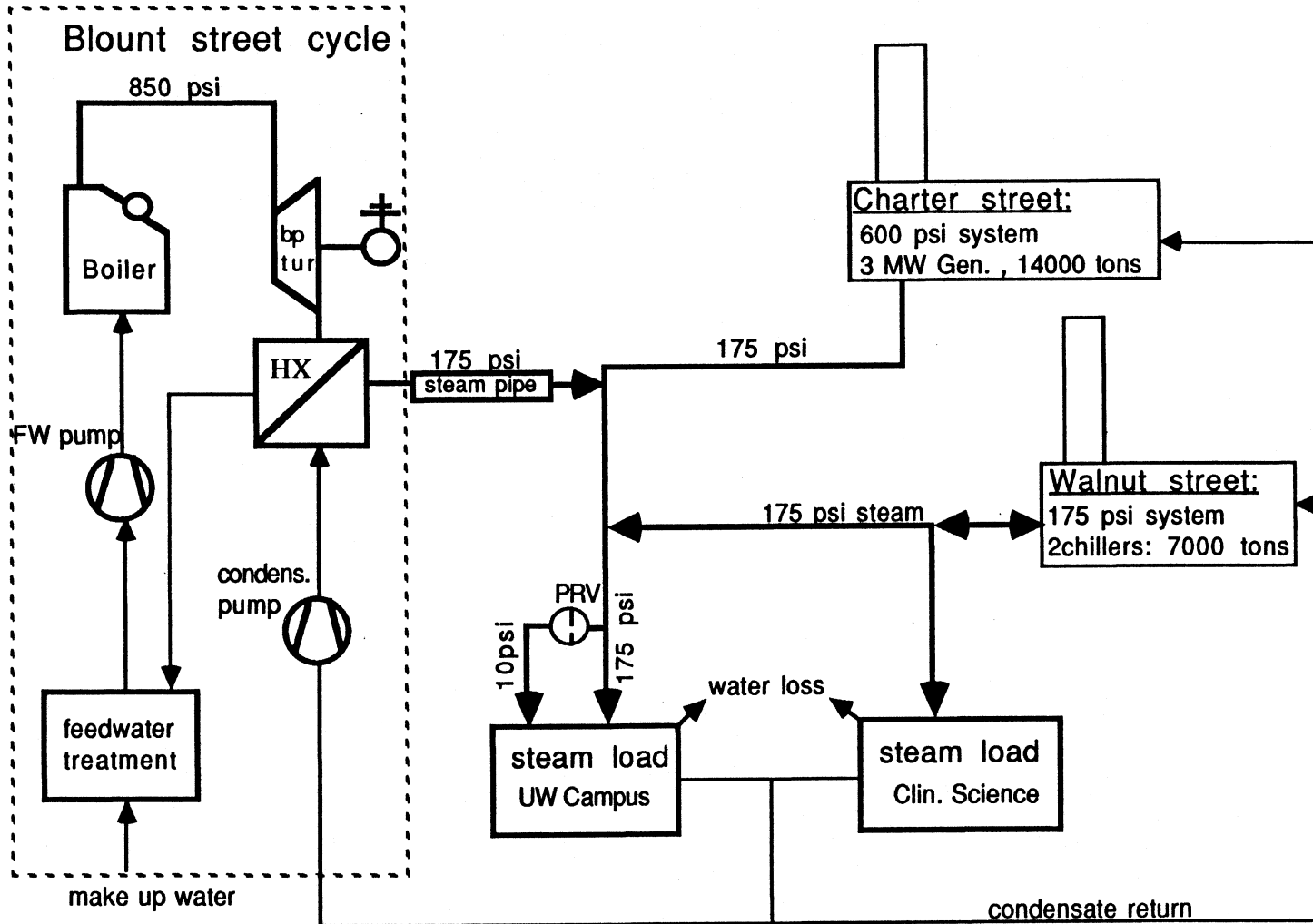


Figure 4.2 Example for a system with separate loops for MG&E and campus

- 3) back-pressure turbine in parallel to the present condensing unit in the 1250 psig cycle

An option including the installation of the described heat exchanger has not been included for the simulations, because this heat exchanger does not influence the thermodynamic performance of the system, but would only have to be considered in an economic analysis.

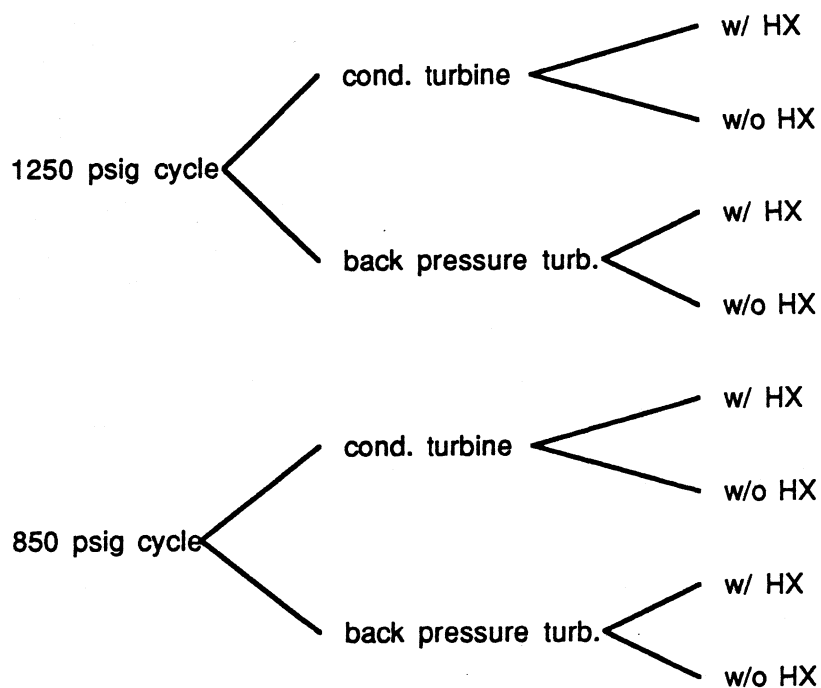


Figure 4.3 Possible combinations for cogeneration at MG&E

4.3 Description of Alternative Configurations

Out of numerous combinations which could be assembled with the various possible configurations at CSP, WSP and MG&E, about a dozen systems have been selected for the analysis. These systems cover a wide range of configurations and include options with and without steam supply from MG&E. A brief outline of the configuration, control, assumptions and main simulation results is given in the following sections. Systems with common characteristics are grouped under the same category number. Individual systems within each category are denoted by an additional letter, e.g. 'System 4b'. A diagram and a detailed description for every configuration is provided in Appendix C. Annual thermodynamic simulation results, which are discussed in section 4.4, and a summary of numbers useful for an economic analysis can also be found in the appendix.

The first task was to establish the base case, to which alternatives could be compared. The format of the presentation of simulation results is illustrated by means of this scenario.

4.3.1 Base Case

The equipment configuration at CSP and WSP for the base case is the same one as presented in chapters 1 and 3, including the CSP baghouse turbines, which became operational in early 1988 (see Ch. 3). Although one TRNSYS deck has also been set up to simulate the entire system (CSP and WSP) with the exact same load profiles and a

similar control as that in 1987/88 (**System 0**), details of the system control have been slightly altered for the base case (**System 1**) in order to have a common simple control guideline for all simulations:

a) the gas fired boilers at WSP only run if the capacity of the CSP boilers is exceeded, i.e. the steam load for WSP, which is generated for the simulation in an analogous fashion to that described in Ch. 3.1, is imposed on CSP.

b) gas is only used as a fuel if all four coal fired boilers at CSP are operating at full load. This is not an unrealistic assumption, since coal is the less expensive fuel and can be solely used if pollution control suffices (baghouses).

c) optimal control for the steam flow through the turbine/generator at CSP is assumed. This means that the maximum potential for electricity production is employed. Care has to be exercised if options, where the expected electricity output is equal to the predicted one, are compared to this case, where the actual electricity output might be considerably lower than the simulation predicts (see section 3.4).

The thermodynamic results for each configurations modelled are presented in a form similar to Table 4.1, which presents the results for the base case. Only annual totals are provided in this summary. In the first section of the table, the main variable outputs, i.e. fuel consumption, electricity production and additional electricity consumption, are listed. The second part contains the power and heat demands which have to be satisfied by the system. Additional useful results are provided in the third section. Finally the first and second law efficiencies for the individual plants and the total system, which have been evaluated by the routine presented in Ch. 2.8, are presented as indicators for the thermodynamic performance. It should be noted that these efficiencies can also be determined from data provided in the summary. All results are given in two different units: the first one serves for illustrative purposes.

The conversion to Joules facilitates efficiency calculations and comparative studies by presenting all outputs on a common basis.

In order to justify the choice of the presented parameters and to point out made assumptions, comments on every parameter follow:

Fuel consumption:

The total annual fuel consumption is given in tons of coal and in Joules. The LHV of the coal is taken to be 12,800 BTU/lb. If steam has been generated by natural gas fired boilers, the gas consumption is converted to equivalent tons of coal based on the heating values of the two fuels.

Electricity generation:

The gross electricity production of the turbine/generator units is presented.

Additional electricity consumption:

As has been stated earlier on (section 3.1.2), electrically driven equipment has not been included in the simulation. The electricity consumption of individual components at CSP and WSP and total numbers for the simulation period are known from recorded data. These values are presented and discussed in chapter 5. It is assumed that there is no electricity consumption in the base case, thus specifying a reference scenario for other systems. Additional or eliminated electrically driven equipment as part of an alternative has been included in the simulations. The annual electricity consumption due to these modifications is given here.

It is apparent that the total consumption of auxiliary machinery in the steam/power cycle at CSP and WSP will vary with the load on these plants. The difference to the

Table 4.1 Annual summary of thermodynamic simulation results for **System 1**

Parameter	Units	Total
Fuel consumption	[tons coal]	119,840
	[J*10 ¹²]	3,238
Electr. generation	[MWh]	21,000
	[J*10 ¹²]	75.6
Add. electr. consumption	[MWh]	0
	[J*10 ¹²]	0
Chiller power	[MWh]	28,500
	[J*10 ¹²]	102.6
other useful power	[MWh]	2,700
	[J*10 ¹²]	9.8
Steam for space heating	[lbs*10 ⁶]	1,524
	[J*10 ¹² energy]	1,841
	[J*10 ¹² availab.]	475
Steam produced	[lbs*10 ⁶]	2,210
	[J*10 ¹² energy]	2,541
	[J*10 ¹² availab.]	969
Steam for CSP chiller compr.	[lbs*10 ⁶]	254
Steam for WSP chiller compr.	[lbs*10 ⁶]	80
η_1	[%]	62.6
η_2	[%]	20.5

base case will be particularly high if steam is provided from MG&E. These swings of the total electricity consumption are also considered in Ch. 5.

Chiller power:

In order to provide the cooling for the reference year 1987/88 with the present or similar chillers, about 28,500 MWh of shaft power are required to drive the chiller compressors. All chiller compressors in the base case are driven by steam turbines. In some scenarios the drive has been changed to electric motors. In these cases the total shaft power stays the same, but part of it is provided from the electric grid. As explained above, this electricity has been included under the category 'Additional electricity consumption'.

Other useful power:

In the base case, the shaft power delivered by the steam cycle at CSP to one air compressor and to the primary chilled water pump (see Ch. 3.1.2) is considered as a useful and required output of every system. In cases where these components are switched to electric drives, the annual electricity consumption (approximately 1,300 MWh for the compressor and 1,400 MWh for the pump) has again been accounted for under 'Additional electricity consumption'.

Steam for space heating:

The main requirement for every system is that the space heating load of the campus and the Clinical Science Center for the reference year is met. This demand is presented in three forms. The first one is the total amount of steam delivered to the UW

for heating purposes. No distinction is made between high and low pressure steam. This is accounted for in the second value. From the 1987/88 data it is deduced that about 80% of the steam leaves the plants at 175 psig and the rest at 10 psig. The enthalpies of the steam flows with respect to a reference state of 100°F are 1,145 BTU/lb and 1,110 BTU/lb, respectively. In order to conduct an analysis based on the second law of thermodynamics (see Ch. 1.1), the total availability of the annual steam flow ($475 \text{ J} \cdot 10^{12}$) is provided as a third value. The specific availabilities of the steam at medium and low pressure with respect to the same reference state are 321 BTU/lb and 194 BTU/lb.

Steam produced:

The total steam production and its energy and availability content are presented as supplementary outputs. The average overall boiler efficiency based on the first or second law can easily be computed by division through the energy or exergy of the total annual fuel consumption.

Steam for chillers:

The total amount of steam, which is required to drive the chiller compressors at CSP (600 psig-condensing turbines) and at WSP (175 psig-condensing turbines) is given for the base case.

First law efficiency η_1 :

An efficiency which is based on the first law of thermodynamics is calculated in the following fashion (compare to section 1.1 and Appendix A):

$$[(\text{electr. gen.}) - (\text{add. elec. cons.}) + (\text{chiller power}) + (\text{other power}) + (\text{energy of steam for space heating})] / (\text{energy of consumed fuel})$$

Second law efficiency η_2 :

The second law efficiency is calculated using the same formula as for η_1 , except that the availability of the steam for space heating purposes is taken instead of the energy content. As explained in Ch. 1.1 and in Appendix A, it is this efficiency which is the most meaningful if different systems are to be compared on grounds of a common thermodynamic basis. This indicator has a value of 20.5% for the base case, which is slightly higher than that for System 0 ($\eta_2 = 20.2\%$). This increase is primarily due to the avoidance of generating steam with the less efficient WSP boilers.

4.3.2 Options without Steam Supply from MG&E

The effects of various modifications within the existing system have been investigated in the following simulations. In order to follow the comments made on the performance of every system, the reader should consult the simulation summaries which are provided in Appendix C.

Option 2: additional steam driven 3500 ton chiller vs motor driven chiller

Systems 2a and 2b feature basically the same configuration as the base case, except for the addition of a 3500 ton chiller which is operated whenever possible and which serves the UW campus, thus relieving the load on the three chillers at CSP. In System 2a the compressor of this new chiller is 175 psig-condensing steam driven, so

that there is an increased demand for 175 psig steam from CSP in the summer (see section 4.1). The total steam demand of this configuration is higher than in the base case, since the required steam mass flow to drive the new 175 psig-condensing turbine is higher than for the original 600 psig-condensing one. The resulting increased fuel consumption is compensated, however, by the improved utilization of the 600 psig-175 psig turbine/generator during the cooling season, so that the overall second law efficiency is slightly increased by 0.1 %.

The compressor of the new chiller in System 2b is motor driven. This reduces the fuel consumption on the one hand, but requires an additional electricity purchase. The overall second law efficiency remains unchanged compared to the base case. The efficiency according to the first law of thermodynamics is considerably higher than in System 2a or in the base case (64.5% compared to 62.6%). This results from the fact that this efficiency is maximized when there is no electricity generation, but only heat production. With respect to energy quality and also economic criteria, this is a misleading indicator. In the study of cogeneration systems η_1 can only be used if the heat and power outputs are the same for all systems investigated, so that the first law efficiency is an indicator of how much fuel is required to satisfy these demands (see also Appendix A).

In the following section there are several options which feature the addition of such a 3500 ton chiller. Since the increasing campus cooling load requires the installation of this capacity and since substantial costs are associated with this project, System 2a instead of System 1 is taken to be the base case for all systems with this additional chiller in the economic analysis (see Ch. 5). The chilled water load for the simulation of these systems, however, has been taken to be the same as in System 1.

Option 3: increased electricity generation capacity at Charter Street

The existing 3 MW turbine/generator unit is upgraded to a maximum capacity of 6 MW, a transformation which has already been under consideration in recent times. **System 3a** assumes that the 600 psig-175 psig steam driven air compressor and the PCW pump are replaced by electrically driven units. A considerable amount of steam which had to be throttled in pressure reducing valves in the base case is now expanded in the turbine/generator unit, producing about 75% more electricity over an entire year. The temperature of the steam at the exit of the turbine is lower than at the exit of the PRV, so that more steam at 175 psig has to be provided to satisfy the same heating load on the campus. Thus the steam generation and fuel consumption is slightly higher than in the base case. The overall second law efficiency is still substantially increased to 21.6%.

System 3b assumes that the chilled water capacity is expanded by installation of an additional 3500 ton chiller similar to that in System 2a. Part of the cooling load is again shifted from the present 600 psig-condensing chillers to the new one, which increases the average steam flow through the upgraded turbine in the summer by about 10,000 lb/hr, so that this unit can operate at a higher part load throughout most of the year. This scenario yields an 0.3% higher efficiency than System 3a.

Cases in which a second turbine is installed parallel to the existing 3 MW turbine/generator unit have also been investigated. They are not included here, since differences in the thermodynamic performance of these systems compared to system 3a and 3b are marginal. Furthermore this option would probably involve a substantially higher capital investment than modifications of the existing unit.

4.3.3 Options with MG&E

The main idea behind cogenerating electricity and steam at Blount Street is that the overall efficiency of the MG&E cycles with their elevated steam temperatures and pressures is higher than that of the Charter Street plant. Other considerations involve increased flexibility, reliability and extended life time for the UW heating and cooling system.

In order to use the turbine at MG&E, the steam flow to the UW campus should be as high as possible. A relatively constant steam supply is also desirable to run the turbine at Blount Street close to design conditions. Since the campus steam demand varies considerably on a daily as well as on a seasonal basis, load management and the choice of an optimal turbine size and control strategy for the entire system is of importance.

Most alternatives presented in the following involve the supply of a base load of steam from MG&E. This steam flow is usually between 100,000 lb/hr and 200,000 lb/hr, which is in the range of the average annual system steam demand. Steam generated at CSP or WSP serves as backup and takes some of the swings. One alternative in which it is assumed that all steam can be provided by MG&E is also considered (System 4e).

Different control strategies, which in some cases require equipment changes at CSP and WSP, are combined with suitable configurations at Blount Street (see section 4.3.2). All options involve the supply of steam at a pressure of about 190 psig and a temperature of 450°F. These steam conditions are slightly elevated compared to the

campus requirements (175 psig, 440°F), because the pressure and heat loss in the pipe has to be accounted for. The exiting steam from the back pressure or condensing turbine has to be desuperheated in order to reach these conditions. A desuperheater and a deaerator for condensate treatment and preheating is part of every system configuration.

The systems investigated fall under two categories: in the first one (System 4a-e) the configuration at CSP and WSP remains essentially unchanged. Some modifications serve to increase the steam demand at 175 psig, which is satisfied primarily by MG&E. Cogeneration cycles of various types and turbine sizes are tested at MG&E.

The second category (Option 5) involves the transformation of the CSP header system from 600 psig to 175 psig, so that CSP becomes a pure heating and cooling plant without electricity generation capabilities. Due to lower operating pressures and the elimination of the 600 psig-175 psig equipment and the desuperheaters, the operation and maintenance of CSP is facilitated. With respect to the overall efficiency it is advantageous to supply as much steam as possible from MG&E. This steam could also drive the chillers at CSP, which would have to be equipped with 175 psig-condensing turbines similar to those at Walnut Street. Hence this option is characterized by a high operational flexibility and reliability.

The format of the simulation summaries for the scenarios, which involve a steam supply from and cogeneration at MG&E, is essentially the same as that for the other systems (see base case). Special assumptions and a few minor differences are illustrated by an example of the simulation summary sheet for System 4a. Summaries for all systems, which are discussed in the following, can be found in Appendix C.

Option 4: CSP with present 600 psig header system

System 4a: From October until April MG&E provides a maximum steam flow of 160,000 lb/hr from a 7 MW back pressure turbine/generator in the 850 psig cycle. During the summer, when the steam campus demand is much lower, MG&E does not cogenerate and the steam demand has to be satisfied entirely by Charter Street plant. In order to increase the electricity generation at CSP by making more steam available to the turbine/generator unit, the 600-175 psig steam driven air compressor and PCW pump have been replaced by motor driven units (see 4.1).

Results: A summary of the annual results is given in Table 4.2 . In three columns the results for the combined UW facilities (CSP+WSP), for the cogeneration cycle at MG&E and for the entire system are listed. The explanation of the parameters has been provided in the description of the base case. A few special features should be noted about the following parameters:

Additional electricity consumption:

The total electricity consumption of the main auxiliary equipment for the steam cycle at Blount Street (feedwater pumps, condensate pumps etc.) has been assumed to be about 10% of the electricity generation.

Chiller power, Steam for space heating:

It is assumed that all steam for the 175 psig-condensing chiller compressor turbines is provided from Charter Street. The steam coming from MG&E is solely used for heating purposes. Although the steam from MG&E is supplied at the medium pressure conditions, it is assumed that only 80% are used at this pressure and that the

Table 4.2 Annual summary of thermodynamic simulation results for System 4a
(see Appendix C for similar summaries for all other systems)

Parameter	Units	CSP+WSP	MG&E	TOTAL
Fuel consumption	[tons coal]	74,645	49,520	124,165
	[J*10 ¹²]	2,015	1,337	3,352
Electr. generation	[MWh]	18,200	32,180	50,380
	[J*10 ¹²]	65.5	116	181.5
Add. electr. cons.	[MWh]	2,700	3,000	5,700
	[J*10 ¹²]	9.8	10.8	20.6
Chiller power	[MWh]	28,500	0	28,500
	[J*10 ¹²]	102.6	0	102.6
other useful power	[MWh]	2,700	0	2,700
	[J*10 ¹²]	9.8	0	9.8
Steam for space heating	[lbs*10 ⁶]	751	773	1,524
	[J*10 ¹² energy]	957	934	1,841
	[J*10 ¹² availab.]	234	241	475
Steam produced	[lbs*10 ⁶]	1,373	930	2,303
	[J*10 ¹² energy]	1,578	1,160	2,738
	[J*10 ¹² availab.]	602	482	1,084
η_1	[%]	55.8	77.7	63.1
η_2	[%]	20.0	25.9	22.3

rest is throttled to 10 psig (see base case). By making this assumptions, the total steam supply for space heating is the same as in the base case and calculations, especially efficiency calculations, are facilitated.

Steam produced:

The energy and availability contents of the steam generated with boilers at Blount Street are calculated with respect to a reference state, which is chosen to be the inlet state of the feed water to the economizers:

1183 BTU/lb enthalpy and 491 BTU/lb availability for the 850 psig, 900°F cycle

1198 BTU/lb enthalpy and 523 BTU/lb availab. for the 1250 psig, 950°F cycle

The efficiencies are computed in the manner described above (base case). The overall second law efficiency of System 4a is 22.3 %, which is higher than for any configuration analyzed so far. The slight increase in fuel consumption, which is due to the elevated steam generation conditions at MG&E and to the lower overall efficiency at CSP, is counterbalanced by the high electricity production at MG&E during the winter months.

System 4b: The only difference compared to System 4a is that in the winter steam is extracted from the existing 54 MW condensing steam turbine in the 1250 psig cycle at MG&E.

Results: The results for this scenario are profoundly different from all other systems investigated, since a major fraction of the generated steam is not used for

heating purposes, but is condensed in the turbine at Blount Street. During the heating season only about one third of the steam is extracted and during the summer all steam is condensed. It is assumed that the unit is block loaded at 40 MW while it is cogenerating, which is approximately the maximum electricity rate it can provide with steam extraction of 160,000 lb/hr at 190 psig. The simulation yields one of the highest second law efficiencies (27.6%) of all systems investigated, which is due to use of a large turbine/generator unit and operation close to the design point. The first law efficiency, however, is by far the lowest, since a major portion of the steam is condensed and not used for heating purposes.

Since this configuration is not a pure cogeneration plant, financial aspects have to be considered before it can be compared to other alternatives (see Ch. 5).

System 4c: This option is similar to System 4a with the following modifications: a 10 MW back pressure turbine as part of the 850 psig cycle provides as much steam as possible throughout the year, with an upper limit of 200,000 lb/hr.

Results: Compared to System 4a, the overall efficiency is again increased, because a bigger, more efficient turbine is installed at MG&E and because 50% more steam is provided from the cogeneration cycle at MG&E. Due to the highly irregular and low part load operation, the efficiency of Charter Street plant, on the other hand, is further decreased ($\eta_2 = 14\%$). One would probably have to make major changes of the equipment configuration at Charter Street in order to adapt the plant to these operating conditions. Studies with this intent have not been conducted at this point, though.

System 4d is similar to System 4c. In order to increase the turbine steam flow

in the summer, so that the 10 MW back pressure turbine can be operated at the design point more continuously, an additional 3500 ton chiller with a 175 psig-condensing steam driven compressor serves as a primary chilled water producer on the campus.

Results: As in System 2a and System 3b the overall efficiency is again improved by this chiller compressor modification.

System 4e: the steam cycle at Charter Street is idle. A maximum steam flow of 400,000 lb/hr can be supplied from the 1250 psig cycle with a 22 MW back pressure turbine parallel to the existing condensing steam turbine at MG&E. WSP serves as the back-up system in case of additional demand. Similar to System 4d a chiller with a 3500 ton chilling capacity has been added to increase the steam demand in the summer. All chiller compressors at CSP are driven by electric motors.

Results: By cogeneration of heat and electricity from one 22 MW cycle, the efficiency (28.0%) is substantially higher than in all other investigated systems, except for System 4b. It has to be pointed out, however, that this scenario could hardly be realized. The campus steam demand is subject to large swings which could not be tracked by the back pressure turbine. Outage and maintenance times for the turbine have not been accounted for. CSP and WSP would have to come on line in this case. Other obstacles involve the substantially decreased capacity of MG&E, by operating a 22 MW back pressure turbine, instead of the 54 MW condensing one. In order to meet peaking electricity loads in the summer with this latter unit, the supply of steam from Blount Street would probably have to be limited. These issues are further discussed in the next chapter.

Option 5: Charter Street with 175 psig header system

System 5: MG&E issues a maximum of 150,000 lb/hr of steam flow with a 850-180 psig back pressure turbine, similar to System 4b. The boilers at CSP generate 175 psig steam only in a back-up mode. Steam driven feed water pumps at CSP operate between 175 psig and 10 psig, and the primary chilled water pump is switched to 175 psig- condensing. All air compressors are driven by electric motors.

Results: The annual results of this option should be compared to System 4c, which features a similar operational strategy and equipment configuration at MG&E. The total steam production is higher than in 4c, because the 175 psig-condensing chiller turbines require more steam than the previous 600 psig-condensing ones, in order to produce the same shaft power for the compressors. The overall result is a decrease of the second law efficiency to 21.9% for System 5a compared to 23.0% for System 4c.

4.4 Discussion of Thermodynamic Simulation Results

The summary tables which have been introduced and exemplified in the previous section are set up in a form that all systems satisfy the same heating load and the same power requirements for chillers and some auxiliary equipment. The variable parameters are the fuel consumption, the electricity generation by the turbine/generator unit(s) and additional electricity requirements if necessary.

The total annual fuel consumption ranges from 105,000 tons of coal to 125,000 tons. The electricity production spans from 18,000 MWh to 39,000 MWh for systems without cogeneration at MG&E, and from 50,000 MWh to 85,000 MWh for

configurations which include MG&E. In System 4b, in which a steam turbine at MG&E generates electricity in the condensing mode, besides providing steam, the fuel consumption and the electricity production is considerably higher than in all other systems.

One main goal for all alternatives to the base case has been to maximize the use of steam, which is used in a cogenerative mode in the winter, i.e. to minimize the throttling of steam pressure by means of pressure reducing valves and to expand it through turbine/generators instead (see section 4.1). A second objective has been to increase the steam demand at 175 psig during the summer months in order to generate more electricity. The highest second law efficiency which has been obtained for systems without connection of MG&E is 21.9% for System 3b, which has an upgraded turbine/generator to handle high steam flows in the heating season and in which an additional 175-condensing steam turbine driven chiller has been installed to realize the second objective.

All systems with cogeneration at MG&E yield an equal or higher overall second law efficiency than System 3b, with values ranging from 21.9% for System 5 to 28.0% for System 4e. System 4b with an overall efficiency of 27.6% has to be discussed separately, as explained above.

It can generally be concluded that the more steam is provided from MG&E the higher is the overall efficiency. This is due to the bigger turbines and to the elevated pressures and temperatures at the turbine inlet compared to CSP, which makes the cycle at MG&E more efficient. The only systems, however, which yield a substantially increased second law efficiency are Systems 4b (extraction from existing condensing steam turbine at Blount Street; $\eta_2=27.6\%$) and 4e (supply of all steam from one large back-pressure turbine; $\eta_2=28.0\%$). The efficiencies of all other configurations are

lower than 24 %, which is only a marginal improvement compared to the two base cases with second law efficiencies of about 20.5 %.

This has several reasons. Under the given circumstances and requirements as far as the campus steam load is concerned, the potential for efficiency improvements for the UW facilities is relatively small. The main improvement in performance is achieved by using more of the generated steam for electricity generation during the winter months. This has been realized in all alternative configurations by installing additional electricity production capacity at CSP or MG&E. The campus steam load, which varies constantly on a diurnal and especially on a seasonal basis governs the possible electricity generation and does not permit a continuous operation of the turbine/generator(s) at an optimum design point. If part of the steam mass flow is supplied by MG&E, the efficiency of CSP decreases because it has to be operated at a low part load with substantial swings in demand. Although the efficiency of the cogeneration cycle at Blount Street is in the range of 28 % for all such configurations, the overall efficiency does not improve as long as CSP has to be operated.

Another reason for the generally low efficiencies is the use of relatively small turbines, since the turbine efficiency decreases considerably with its size. System 4e is the only configuration in which one large turbine is used to supply all the steam for the campus and for the Clinical Science Center, which results in the highest first and second law efficiencies of all alternatives ($\eta_1=76.3\%$; $\eta_2=28.0\%$). For all other configurations involving cogeneration at MG&E, it can be said that the distribution of the load on several plants is not optimal. If other aspects such as auxiliary operational costs associated with labor and maintenance are taken into account, the viability of operating several plants in order to meet the load is even more doubtful (see Ch. 5).

With regard to the load requirements it can be generally stated that by using

superheated steam at 175 psig for heating purposes, a large potential for additional electricity generation is wasted. A simulation showed that if the heating load could be satisfied with steam at 10 psig, about twice as much electricity could be generated in a 600-10 psig back-pressure turbine. This is attractive from a financial viewpoint, since the costs of the required additional steam flow and fuel consumption could be more than compensated by a sale of this electricity at the present conditions (3¢/ kWh). This scenario requires substantial changes of equipment and distribution system, however, and is presently not feasible.

The simulation results have to be interpreted with care. As a comparison of the actual system performance in 1987/88 with the base case demonstrates, the potential and realized electricity production are quite different, which is due to a non-optimal control (see Ch. 3.4). Maintenance and down times of components or an entire plant also lead to a substantial decrease in the annual operating efficiency.

Although the simulation results may not accurately predict the actual performance of an individual system, they serve well in predicting trends when comparing several alternatives to the same base case. Recommendations cannot be based on the discussed thermodynamic performance alone, however. Several other aspects, such as system reliability, flexibility and safety are important factors in the decision making process. Ultimately a decision has to be based on economic analyses, which do sometimes reflect the thermodynamic trend, but in which required capital investments to realize a highly efficient option often offset the savings in fuel and other operational costs. Estimates of operational costs, of expenses for new equipment or equipment changes and a first life-cycle analysis for each studied system configuration are presented in the next chapter.

Chapter 5

Economic Considerations and Analysis

At the end of the last chapter, which dealt with the thermodynamic aspects of the present and alternative configurations of the UW heating and cooling system, it was stated that the thermal efficiency is only one of many factors which have to be considered in order to give recommendations with respect to system modifications. In this chapter an attempt is made to assess the required capital investment to realize the various suggested system changes, to evaluate fuel, electricity and other operational costs and to conduct a preliminary economic analysis based on these estimates. For this purpose an economic analysis program has been written which is presented in section 5.4.1. Results of the economic analysis are finally summarized and discussed as to the economic viability of the different systems.

5.1 General Procedure for Economic Analysis

All investigated alternative configurations yielded a higher thermal efficiency than the base case, which suggests potential savings in terms of fuel and electricity expenses. The magnitude of these savings in monetary terms is dependent on the specific costs of these two forms of energy.

Other operational costs which have to be accounted for are expenses for labor, maintenance and for supplies and services. The last item includes peripheral costs such as chemicals for feed water treatment, office supplies etc. Estimates of the annual operational costs for every system are given in Appendix C. A discussion and comments are provided in section 5.3.1. Necessary major equipment modifications and associated capital investments for each system are also listed in the appendix with an explanatory evaluation in section 5.2.

For systems without cogeneration at MG&E (options 2 and 3) the analysis is straightforward since estimates of total operational costs can be obtained from simulation results and from data and typical numbers from previous years. By inclusion of MG&E the subject matter becomes more complicated. In this case financial aspects for two parties, one of which is a utility, have to be considered. The operation of a cogenerative cycle at the MG&E Blount Street plant would have implications for the entire utility system, which cannot be assessed as easily as for the independent university campus facilities. In the winter time, when most of the machinery at Blount Street is usually idle, the electricity generation at MG&E's base load plants would have to be reduced to incorporate a constant additional electricity production. During the peak weeks in the cooling season, on the other hand, the total electrical capacity of MG&E would be derated by operation of a cogenerative cycle instead of production of electricity in the condensing mode. If seasonal and time-of-day dependencies of the electricity price and auxiliary operational costs are taken into account, a financial analysis for the entire system, consisting of UW and MG&E, becomes even more intricate without having access to and knowledge of pricing strategies of utilities.

The solution to this dilemma has been to focus this study solely on the UW

system and include the purchase of steam from MG&E as an additional operational cost. In order to calculate the price of the supplied heat, the thermodynamic simulation results for various cogeneration scenarios at MG&E served as inputs to a utility economics program. This program calculated the cost and benefits of fuel consumption, electricity production and load management associated with the operation of a new cogenerative cycle. From these computations a first estimate for the price of the supplied steam has been obtained for three basic scenarios. These are presented and further discussed in section 5.3.2.

In Fig.5.1 the flows of all operational cost items for the UW are summarized. Together with estimates for the required capital investment and for economic parameters (such as analysis period, inflation etc.), the life cycle costs for each options are assessed and compared to the base cases (System 1 or System 2a if additional chiller) in section 5.4.

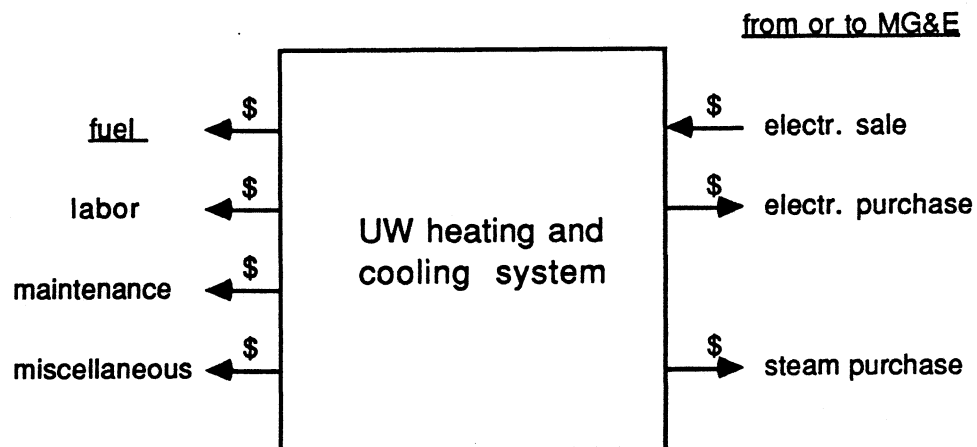


Figure 5.1 Flows of operational costs for the UW heating and cooling system

5.2 Capital investment

In order to obtain values for the necessary capital expenditures associated with the various configurations, a questionnaire was sent to contact persons at MG&E and UW. This questionnaire listed the main modifications which would have to be made to realize these systems and asked for approximate costs and comments.

The single most expensive item is the construction of a steam pipe from Blount to Charter Street, which is required in case of options 4 and 5. A first estimate for the cost of a pipe running in a railroad corridor between the two plants is \$ 6,500,000 based on a specific price of \$ 500 per linear foot and a total length of 13,000 ft.

Another main cost factor in most scenarios is the purchase of a new turbine/generator or the upgrading of the existing one at CSP (option 3).

All major changes and associated capital expenditures are listed for each system in Appendix C. It is assumed that all capital investments are due at the beginning of the analysis period. A second assumption is that there are no differences throughout the analysis period between the base case and the respective alternatives as far as other investments are concerned (replacement of equipment etc.). This simplifying assumption is made although the lifetime of equipment at CSP might be considerably extended by shifting part of the load to MG&E.

5.3 Operational costs

According to Fig. 5.1 the operational costs for the UW system comprise expenses for fuel, electricity (expenses and revenues), labor, maintenance, steam purchase (if

connected to MG&E) and miscellaneous costs. The calculation of the specific and total additional steam costs are treated separately in section 5.3.2.

5.3.1 Costs at UW plants

A summary of the actual operational costs in the different categories for CSP and WSP for the period 3/87 - 2/88 is presented in Table 5.1.

Table 5.1 Summary of operational costs for UW system in 1987/88 in \$

Item	CSP	WSP
Fuel	6,294,000	650,000
electr. generation	-416,500	0
electr. consumption	504,400	219,200
labor	1,100,000	250,000
maintenance	400,000	75,000
supplies and services	325,000	75,000
TOTAL	8,206,900	1,269,200

The total costs were \$9,476,100 for the entire heating and cooling system. In the following, the individual items are examined in more detail:

Fuel: By far the greatest cost factor is fuel consumption, which amounts to about 75% of the UW budget for the two plants. In the 87/88 analysis period, when the baghouse was not on line continuously (see Ch. 3), the fuel costs for the natural gas fired boilers at WSP and CSP (boiler #5) were approximately the same as for the coal fired steam generators. The average specific costs for these two fuels which are used in all calculations were:

natural gas with LHV of 1000 BTU/scf: \$ 2.50 /1000 scf

coal with LHV of 12,800 BTU/lb: \$ 24.0 / 1000 lb

In the base case as well as in all other system simulations, the guideline has been to use natural gas, which has a high specific cost per unit energy, as little as possible. Thus the total fuel costs for the base case are lower than for the actual case. In the life cycle cost calculations it is assumed that the heating and cooling load for the campus will stay at the present value. The estimate of the increase in fuel price over the analysis period of 20 years is 5.1% for coal and 7.8% for gas. These values have been taken from answers to the questionnaire mentioned in the previous section. All price increases include a general inflation rate of 5%.

Electricity generation: Cogenerated electricity is sold to MG&E at \$0.037/kWh in average during on-peak hours and at \$0.025/kWh during off-peak hours. An average \$0.03/kWh has been used. The values are inputs to a TRNSYS subroutine, which integrates the expenses for fuel, electricity and other items over the simulation period. The program listing can again be found in Appendix B.

Total sales, neglecting any surcharges, amounted to \$416,500 in the actual and \$629,000 in the base case (System 1). The price of electricity is supposed to increase with the rate of general inflation (5%).

Electricity consumption: The electricity purchase price for the UW is \$0.03/ kWh in average. There is also a monthly demand charge, which depends on the peak electricity usage rate. If this demand charge is included the average price per kWh of purchased electricity is \$0.042. The total electricity bill for CSP and WSP was \$723,600 in 1987/88. In terms of electricity this corresponds to a consumption of 17,230 MWh. A monthly summary for both plants is shown in Table 5.2.

Table 5.2 Monthly summary of electrical consumption at CSP and WSP in 1987/88 in MWh

Month	CSP steam cycle	CSP chiller plant	WSP
Jan	650	0	110
Feb	600	0	100
Mar	500	0	160
Apr	400	0	300
May	400	1000	650
Jun	350	1,100	700
Jul	350	1,500	800
Aug	350	1,400	750
Sep	350	900	600
Oct	400	700	600
Nov	500	0	300
Dec	550	0	150
TOTAL	5,400	6,600	5,220

Since most electrically driven machinery at CSP and WSP has not been included in the simulations, it is important to assess quantitatively how the annual electricity consumption varies with the different operational strategies used in the simulation. The electrical consumption of WSP, which is mostly due to the chilled water plant, and of the chiller plant at CSP is approximately the same for all scenarios. The fraction of the electricity consumption which is dependent on the steam generation at CSP is listed in column 1 of Table 5.2. It is assumed that two thirds of the load is directly proportional to the total annual steam generation at CSP and that the rest is a constant value. Hence, if CSP is idling throughout the year (System 4e), this value is $1/3 \times 5,400 \text{ MWh} = 1,800 \text{ MWh}$ and the electricity consumption of the WSP and the CSP chilled water plant amounts to 11,820 MWh. In the case of System 4e the chiller compressor at CSP, the PCW pump and the air compressor are driven by electric motors in contrast to the base case, where this equipment is steam turbine driven. This additional electricity consumption of 18,200 MWh, due to major equipment modifications, is an output of the simulations and has to be added to the values above which yields a total of 31,820 MWh.

Labor: Both plants together employ about 50 full time operating, maintenance and supervisory personnel. The annual salaries add up to about 1,350,000 for 87/88. This value is taken to be the same for all scenarios with an annual increase of 5%.

Maintenance: Similar to the calculation of the total electricity consumption, it is assumed that the annual expenses for maintenance are proportional to the steam generation. Of the total costs of \$475,000 for the actual system in 1987/88, \$200,000 are taken to be independent and the rest to be directly dependent of the steam load. This is an arbitrary choice, since concrete information has not been available.

Miscellaneous costs: Costs for supplies and services are assumed to be equal for all systems (\$400,000) and to rise at 5%/year.

5.3.2 Cost of Steam Supplied from MG&E

The pricing of heat from a cogeneration plant is a complex task (Horlock,1987). The cost of delivered steam from MG&E depends on several additional factors besides fuel consumption and electricity generation. Since Blount Street is a peaking plant, load management of the other power units of MG&E in case of continuous operation of an additional cogenerative cycle is important. Depending on which cycle (1250 psig or 850 psig) is used for cogeneration and what the electricity production is, the power output of other efficient base load units has to be reduced. Delivering steam at a certain back pressure instead of using its full potential for power production in one of the condensing steam turbines also reduces the maximum capacity of the system. This might have an effect in peaking demand times during the summer. In addition, variable and fixed operational and maintenance costs for the new cycle have to be included in a calculation of the price for the delivered heat.

First estimates for the price per unit of supplied steam were computed for three scenarios, which cover the range of alternatives for which simulations have been conducted:

- 1) Constant supply of 150,000 lb/hr by extraction from condensing turbine in 1250 psig cycle from November until March; unit is block loaded at 40 MW (similar to System 4b)
- 2) Supply of a maximum of 150,000 lb/hr throughout the year from 7 MW back-

pressure turbine in 850 psig cycle (similar to 4c,d and 5a)

- 3) Supply of 200,000 lb/hr from November until March from 12.5 MW back pressure turbine in 1250 cycle (similar to 4e)

In all scenarios the steam is delivered at 450°F and 190 psig.

Simplifications, such as the assumptions of block loading for the respective period cogeneration period had to be made, because the computer routine that was used at MG&E to simulate the operation of an additional cycle in their system could not accommodate a more sophisticated study at this point.

The inputs to the first scenario were the block loaded generation rate and the additional fuel consumption associated with cogeneration compared to the condensing mode. A value of 26% was obtained for the required increase in fuel input from a TRNSYS simulation of the present 1250 psig cycle at MG&E. The simulation included the regenerative feedwater heating used at Blount Street. It should be noted that of the eventually supplied 150,000 lb/hr of steam, about 140,000 lb/hr are extracted from the turbine and 10,000 lb/hr are added in a desuperheater in order to lower the temperature to the required value of 450°F. MG&E personnel determined that the cost to supply a steam flow rate of 150,000 lb/hr to the UW would be \$2.65 per 1000 lb of steam. This includes operational and maintenance costs for MG&E.

The required inputs to obtain cost estimates for scenarios 2 and 3, in which new back pressure turbines would have to be installed, are the electricity generation, the heat rate in BTU of fuel energy per kWh and the fuel energy required for steam production, which is an indicator for the boiler efficiency. These values were also computed by means of a TRNSYS simulation.

MG&E's cost estimate per 1000 lb of steam are \$2.12 for option 2 and \$2.34 for option 3. In contrast to the first scenario, where extraction from an already existing

unit has been assumed, fixed and variable operational and maintenance (O&M) costs for the new turbine/generator are not included in the estimated steam price in options 2 or 3 yet. MG&E suggested that about 5 % of its installed costs are annual O&M costs. These costs have to be passed on and distributed to the annual charges for electricity and steam. It has to be pointed out that none of these costs account for the capital investment of required system modifications.

On the basis of these three scenarios, the annual steam purchase from MG&E is estimated for the investigated systems of chapter 4. The specific and total annual costs summarized in Table 5.3. The listed O&M costs are the fractions which are assigned to the steam sale. It should be noted that all values are first estimates and subject to further negotiations.

Table 5.3 Estimated specific and total costs to purchase steam from MG&E
(steam conditions: 450°F, 190 psig)

System	\$/1000 lb	1000 lb/year	O+M costs	total costs [\$]
4a	2.12	773,000	70,000	1,710,000
4b	2.65	740,000	-	1,961,000
4c	2.12	1,360,000	100,000	2,983,000
4d	2.12	1,468,000	100,000	3,212,000
4e	2.34	1,744,000	265,000	4,346,000
5	2.12	1,218,000	100,000	2,682,000

5.4 Life Cycle Analysis for Investigated Systems

With the values listed in sections 5.2, 5.3 and in Appendix C, two economic analysis methods are employed to assess the monetary merits of each system described in Ch.4. These techniques and their implementation in a computer routine are described in the first part of this section. The results for the individual systems are then summarized and discussed in the second part.

5.4.1 Analysis Methods and Program

The first method determines the life cycle costs for the respective base case (System 1 or System 2a), for the alternatives and, most important, the difference between these two. The life cycle cost is the present worth of all owning and operating costs (Mitchell,1985). The present worth PW of a future cost FC is

$$PW(n,d) = \frac{FC}{(1+d)^n} \quad (5.1)$$

where d is the market discount rate and n is the number of interest periods.

Taking the respective annual operational cost (for fuel, electricity etc.) from Appendix C as a starting value, this cost n years in the future is calculated by including demand and price increases. A general inflation rate of 5.0 % is included in the discount rate d. Commonly used estimates of economic parameters have been provided by MG&E and the UW and are summarized in Table 5.4. It is assumed that all capital investments are made at the beginning of the analysis period.

The life cycle costs LCC are then computed as

$$LCC = CAPEX + \sum_{1}^m \sum_{1}^n \left(\frac{OPCOST * (1+j)^n}{(1+d)^n} \right) \quad (5.2)$$

where CAPEX is the capital expenditure at the beginning of the analysis period, m is the number of operational costs OPCOST and j is the annual price increase of the individual operational cost. By subtracting the LCC for the base case, it can be determined if savings are possible in the analysis period.

In order to facilitate the computations, a computer subroutine, customized for this application, has been written. The program listing can be found in Appendix B.

This program also performs the slightly more complicated calculation of the rate of return on an investment (see Newman, 1983). In this second analysis technique, the capital investment, the operational costs and the length of the analysis period is known. The objective is to obtain the interest rate which would yield the same benefits on the capital investment as those from the expenditure on the system improvements.

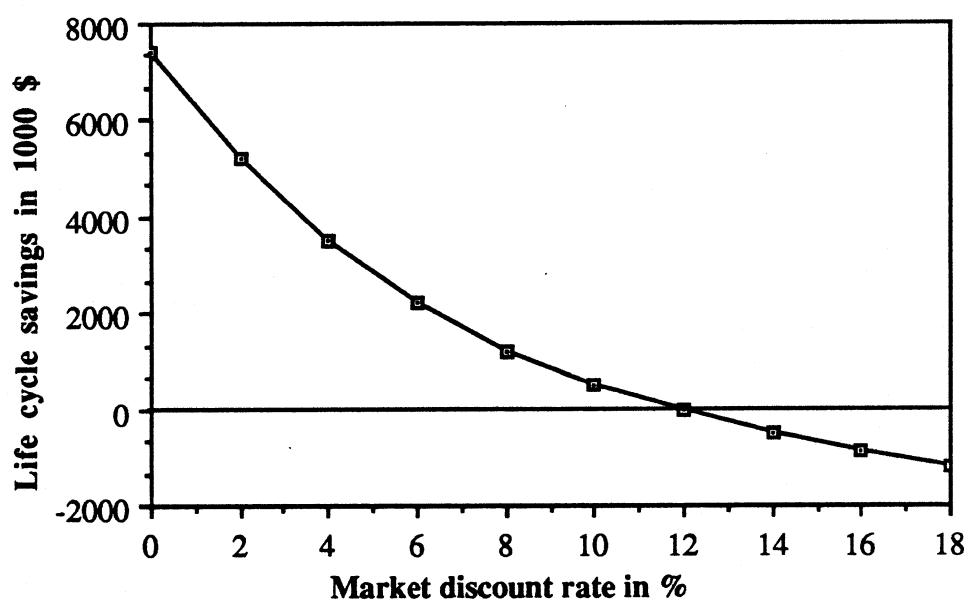
In these calculations every alternative has to be compared to a reference case, which is naturally the base case. The procedure is as follows: first the life cycle costs for the base case (System 1 or System 2a if additional chiller is part of alternative) and the alternative are calculated with a starting value for the discount rate d. The life cycle savings (see above) are a function of the discount rate, which is illustrated for a comparison of System 3a and the base case in Fig. 5.2. A Newton-Raphson algorithm is then used to determine the discount rate at which the present worth of the benefits due to the modifications are equal to the costs, i.e. the point at which the life cycle savings are zero.

Table 5.4 Parameters used in the economic analysis for the UW system

Parameter	Value
Number of years in analysis (Symbol: n)	15
Acceptable number of years for payback	15
Rate of general inflation	5.0% /year
Coal price	\$ 1.875 / 10^6 BTU
Natural gas price	\$ 2.50 / 10^6 BTU
Average electricity purchase price (price includes demand charges)	\$ 0.042/kWh
Average electricity sale price	\$ 0.03/kWh
note: all following rates include the general inflation	
Acceptable rate of return (Symbol: d)	9.2% /year
Increase in coal price	5.1% /year
Increase in natural gas price	7.8% /year
Increase in electricity price for UW	5.1% /year

Note that additional parameters such as taxes and depreciation, which usually have to be accounted for in economic studies, did not have to be included in this case, since the university is a state institution.

Figure 5.2 Life cycle savings as a function of the market discount rate



5.4.2 Summary and Discussion of Results

The life-cycle costs relative to the base case and the rate of return on the capital investment (ROR) were calculated using the parameters and assumptions listed in Table 5.4. The main results of the economic analysis are presented in Table 5.5 for all systems investigated. The most important conclusion is that none of the alternative configurations yield life-cycle savings in the specified analysis period of 15 years. In both categories the present worth of all capital and operational costs is the lowest for the base cases, i.e. System 1 and 2a, respectively. Annual savings in operational costs of the alternatives are not sufficient to compensate the high capital investment to realize the required modifications. Due to the particularly high capital costs for the construction of the steam pipe line, all systems involving steam supply from MG&E yield negative life-cycle 'savings' and a low rate of return. The best alternative to the present configuration is consequently Option 3 (upgraded turbine/generator at CSP) in both categories. The life-cycle costs for this option are about the same as for the base case and the rate of return on the investment is in the range of the desired value of 9.2 %.

A sensitivity analysis was conducted to determine the variation of the ROR with the capital expenditure and with the sale price for electricity generated at CSP. Fig. 5.3a shows that a ROR of 9.2% and consequently the same life-cycle costs as for the base case could be realized if the capital investment were only \$3.2 million instead of \$3.5 million. An average electricity sale price of 3.2¢/kWh instead of the current 3.0¢/kWh would yield the same result, as can be deduced from Fig.5.3b. Since in this scenario more electricity is generated during the demand peaking hours in the summer (especially after installation of a new 175-condensing steam turbine driven chiller),

Table 5.5 Summary of results of economic analysis**a) Systems without additional chiller (base case is System 1)**

Rank	System	Capital expenditure	Operational costs per year	Life-cycle savings	Rate of return
1	1 (base case)	0.0	8,071,100	0.0	--
2	3a	3,490,000	7,783,600	-270,000	8.0%
3	4a	9,190,000	7,646,800	-4,340,000	0.9%
4	4b	7,990,000	7,854,800	-5,430,000	-4.3%
5	4c	9,390,000	7,853,800	-6,750,000	-5.4%
6	5	10,980,000	7,916,000	-9,040,000	-9.5%

b) Systems with additional chiller (base case is System 2a: the cost for the additional chiller has been subtracted from all total capital investments)

Rank	System	Capital expenditure	Operational costs per year	Life-cycle savings	Rate of return
1	2a (base case)	0.0	8,023,000	0.0	--
2	3b	3,490,000	7,732,500	-270,000	8.1%
3	2b	-200,000	8,131,800	-1,102,000	--
4	4e	13,890,000	7,644,400	-9,360,000	-3.8%
5	4d	9,390,000	7,780,000	-6,460,000	-4.5%

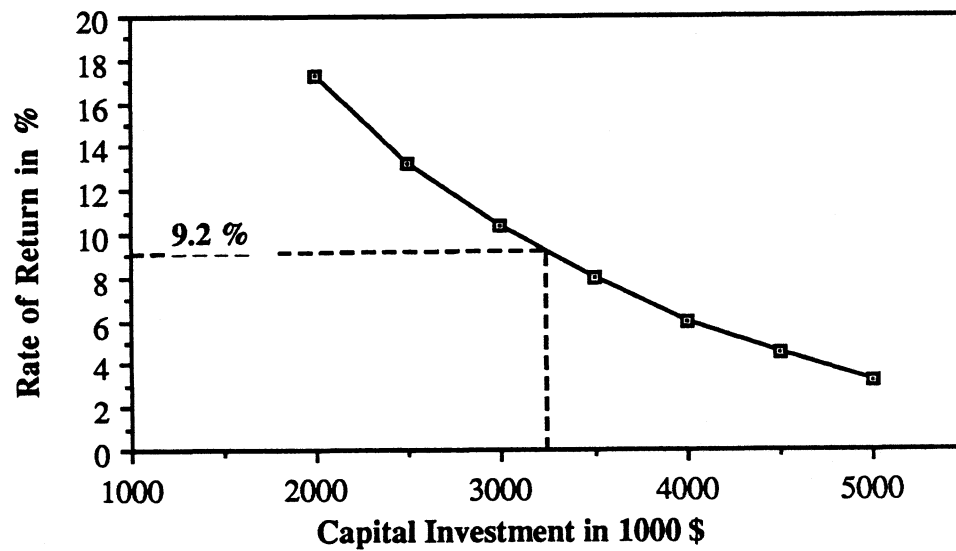


Figure 5.3a Variation of the ROR with the capital investment for System 3a

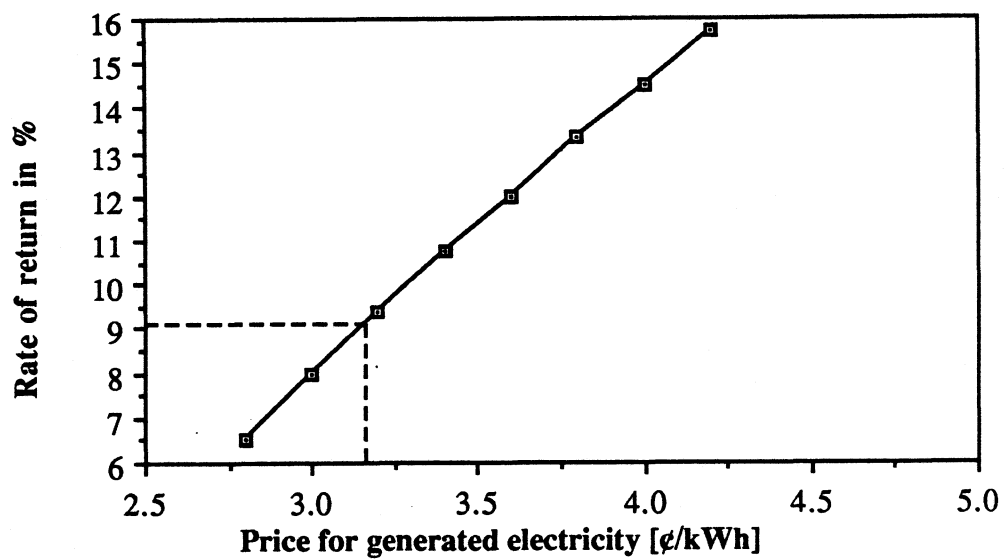


Figure 5.3b Variation of the ROR with the electricity sale price for System 3a

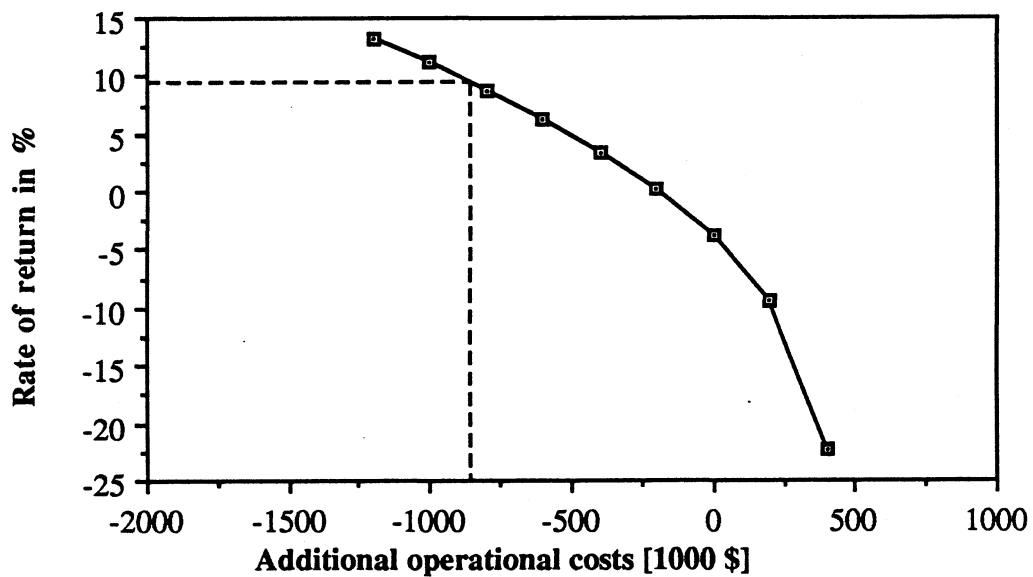


Figure 5.4a Variation of ROR with operational costs for System 4e

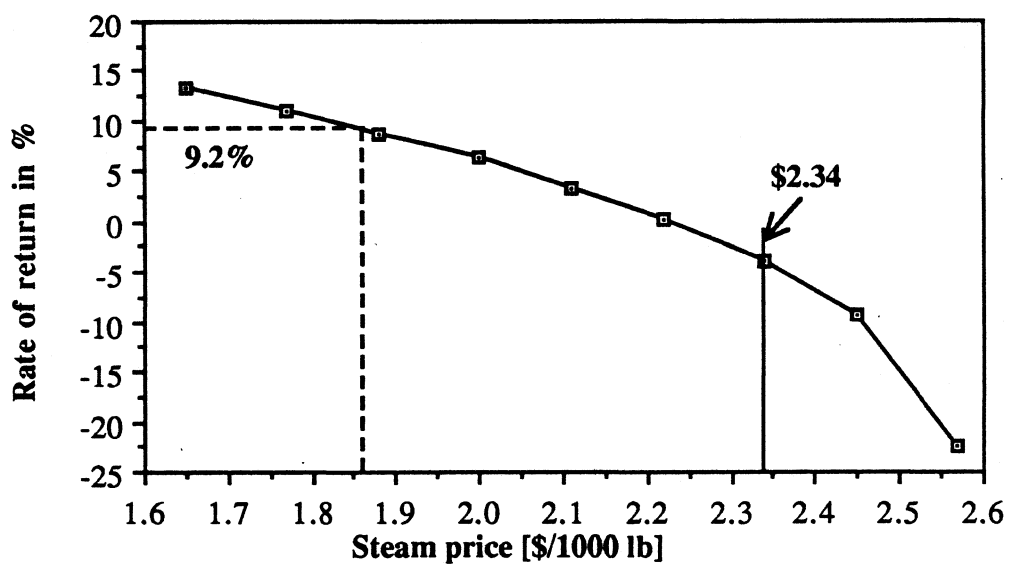


Figure 5.4b Variation of ROR with steam purchase price from MG&E for System 4e

which reduces the load on MG&E, an increased average price for sold electricity can be expected.

A sensitivity analysis has also been conducted for System 4e, which has the best thermodynamic performance and the lowest annual operational costs, but which also requires the highest capital expenditure. The variation of the ROR with auxiliary operational costs such as labor and maintenance has been investigated. So far it has been assumed that the total salaries at the UW plants are constant, even if only the chilled water plants are operated, as is the case in scenario 4e. Fig. 5.4a shows that the break-even point with the life-cycle costs for the base case is reached if additional \$850,000 in operational costs can be saved at CSP.

Since almost all steam is supplied from MG&E in case 4e, the operational costs are strongly dependent on the steam price. A second analysis (Fig. 5.4b) yields that a steam price of \$1.85 per 1000 lb of steam (instead of presently \$2.34) would also meet the minimum economic requirement of a rate of return of 9.2%.

The analyses for this system suggest that life-cycle savings cannot be realized in the analysis period at a market discount rate of 9.2%, unless assumptions regarding specific operational and capital costs are considerably altered. A similar conclusion can be drawn for all other systems which require the construction of a steam pipe from Blount Street to the UW campus.

In the course of expanding the chilled water capacity for the campus, it is of interest to know about consequences that the choice of the chiller compressor drive has on the overall system performance and costs. A comparison of System 2a (steam driven compressor) and 2b (electric motor) shows clearly that the use of steam at 175 psig to drive the chiller compressor yields an economic advantage over the electrically

driven one. Although the steam and fuel demand is higher in System 2a, the increased electricity generation (at \$0.03/kWh) and the avoidance of additional electricity purchase (\$0.042) during the summer, makes the steam driven chiller the preferable choice on an economic basis.

Chapter 6

Conclusions and Recommendations

There were two primary objectives of this thesis. The first objective was to improve TRNSYS' capability for modelling steam driven heating plants and power plants; special emphasis was placed on cogeneration facilities. New models representing the various components of such a plant were developed , validated and added to the TRNSYS program. The applicability of TRNSYS with its new components for modelling an entire system was investigated by modelling the cogeneration plant of the University of Wisconsin campus in Madison and comparing simulation data to real data from the plant. Once the general approach was validated, the second main goal of the study could be addressed. This consisted of evaluating various equipment and control modifications to the district heating and cooling system of the Madison campus. The thermodynamic and economic impact of these system changes was investigated. A detailed discussion of these findings is presented in chapters 4.4 and 5.4. In section 6.1 the main conclusions which can be drawn from the plant analysis are summarized. The final paragraphs of this chapter discuss the applicability of TRNSYS in the analysis of cogeneration systems and give suggestions for future research.

6.1 Conclusions for the UW Heating and Cooling Plant

The alternatives to the present (base) case can be grouped in two categories, i.e. systems with and without cogeneration at MG&E's Blount Street plant. The main result of this study is that the life-cycle costs for all alternatives in the first of these categories are substantially higher than those for the present configuration. Although these alternatives show improvements in the overall system efficiency, the savings in annual operational costs are not sufficient to compensate the required capital investment if the economic analysis is based on a period of 15 years and a market discount rate of 9.2%. Specifically the major capital expenses, which would be necessary for the construction of the steam pipe line from Blount Street to the campus via mostly urbanized area, cannot be offset.

Among the options without inclusion of MG&E, the upgrading of the existing turbine/generator at CSP yields the highest improvement in thermodynamic performance and a reduction of annual operating costs for the UW system by about 4%. The resulting life-cycle costs are about equal to those for the base case if a capital cost of about \$3,000,000 is assumed for the turbine modifications or replacement. This simulation scenario makes almost optimal use of the potential for cogeneration under the given circumstances and load requirements. This is further illustrated by the following remarks regarding the cogeneration potential for the UW system. In order to meet the demand of 175 psig and 10 psig steam and other loads, the required fuel consumption, which accounts for about 70 % of the total annual operating costs, is approximately constant. The only major possibility to reduce the operational costs is to generate electricity more efficiently than is presently done. In order to achieve this goal

several aspects have to be considered. A substantial steam mass flow during the winter months, which has presently to be throttled by pressure reducing valves, can be used for electricity generation with the realization of an upgraded turbine at Charter Street. During the summer months, on the other hand, the present turbine/generator is usually operated at a low part load because of the low back-pressure steam demand on the turbine. In this context it should be mentioned that an automatic control of the turbine/generator in order to better track the varying steam load might be beneficial. The simulations for the base case show that with the present manual control only about half of the potential for electricity generation is used during the spring, summer and fall. In addition the turbine/generator's steam flow and efficiency can be further increased if the 600-175 psig air compressor and chilled water pump, which are switched in parallel to the main turbine, are not operated. From a thermodynamic viewpoint the electric drive of the pump and the compressor and the use of the excess steam to generate electricity is advantageous. However, this advantage is offset if the average electricity rates for purchase (\$0.042/kWh) and sale (\$0.03/kWh) are taken into account.

Several of the analyzed systems include an additional chiller with a 175-condensing steam turbine driven compressor. On the basis of an economic analysis it has been demonstrated that the alternative option of an electrically driven chiller compressor is not competitive.

Overall it can be concluded that the potential for increased and more cost effective cogeneration for the heating and cooling system is too small to justify major equipment changes except for the upgrading of the turbine/generator at CSP from 3 MW to 6 MW.

6.2 Applicability of TRNSYS for the Analysis of Cogeneration Systems

In the following paragraphs, features of the simulation program are assessed with regard to its capability to model power, heating, cooling and, particularly, cogeneration plants.

Because of its modular structure and flexibility, TRNSYS permits the modelling of complex plants of any configuration and the analysis of the effects of changes in equipment and control. Once the base case was modelled and validated in the course of this project, various alternative configuration were easily compiled and investigated. Even if specific manufacturers data is not available for a component, the use of the developed models serves well to obtain a first estimate of the plant performance and parametric studies can be conducted in a simple fashion.

The feature of a user-specified time step of any desired length allows for simulations and for the use of load data on any level of resolution. For cogeneration and conventional power plants it is of particular importance to specify on-peak and off-peak operating times, which can be easily be accommodated by TRNSYS. Several loads of all kind (heating, cooling, electric) can be handled. Ambient conditions can also be taken into account.

Although an attempt was made in the beginning of this study to make use solely of standard TRNSYS components to realize the control of the various systems, the conclusion has been drawn that user-written control subroutines are indispensable and convenient for the simulation of a complex equipment configuration to govern the operation of chillers, steam generators, valves and so forth. Consequently some programming knowledge is necessary to facilitate a detailed study of such a plant with TRNSYS.

6.3 Suggestion for Further Research

Working experience with the newly developed component models for the simulation of cogeneration systems throughout this project has suggested several improvements of the performance and practicality of those models. Various modifications have already been implemented in the course of this study. Additional changes and further development work are proposed in the following paragraphs.

The boiler model requires the specification of parameters which are not easily obtainable, as mentioned in section 2.1. At that point it was also stated that the model performance varies over the range of part load operation. Additional work is required to improve this relatively complex component model, although the overall accuracy in the simulations has been satisfactory.

During the study of the Charter Street plant it was found that variations in pressures and temperatures within the plant are caused by manual control, changes in ambient conditions and part load operation. For several component models these properties are parameters which remain fixed throughout the simulation. A careful assessment of all relevant parameters must show which ones should be changed to variable inputs.

The model for the centrifugal pump (manufacturers performance data required) and the heat exchanger model (only one type of calculation possible) require further development work in order make them more flexible and powerful.

The Diesel engine and gas turbine, which are in widespread use for small and medium-sized cogeneration applications, have been modelled by Dr. W. Krumm. These models have been individually validated already, but have not been used in a study project yet. Future research work with TRNSYS in the area of cogeneration

should also attempt to make use of other TRNSYS component models, such as the chiller, cooling tower, air conditioner or building model, to compute heating and cooling loads for a cogeneration plant. Since TRNSYS was originally developed for the simulation of solar energy systems, the evaluation of a solar cogeneration application is also conceivable.

Appendix A
Discussion of Efficiencies
for the Evaluation of
Cogeneration Systems

As a supplement to remarks made in Ch. 1.1, the theory and application of two concepts for the evaluation of cogeneration systems are presented in the following paragraphs. One is based on an energy viewpoint and uses the first law efficiency as a measure of performance, the other concept takes the quality of energy into account, according to the second law of thermodynamics.

The first law efficiency η_1 expresses the ratio of useful output and required input in terms of energy. For a cogeneration plant, supplying electricity and heat in the form of a steam flow, this is

$$\eta_1 = \frac{W_{\text{elec}} + Q_{\text{heat}}}{Q_{\text{fuel}}} = \frac{W_{\text{elec}} + m(h - h_0)}{m_{\text{fuel}} \text{LHV}_{\text{fuel}}} \quad (\text{A.1})$$

where the lower heating value is taken in the calculation of Q_{fuel} .

The second law efficiency is based on the availability of the different forms of energy. The availability or exergy is that part of energy which can be converted into any other form of energy and which consequently represents the potential to do useful work. In contrast to energy, availability is not a conserved property and every known process leads to an irreversible decrease of total availability.

All mechanical and electrical energy is pure availability, whereas the maximum fraction of useful work that could be extracted from thermal energy is by operation of an ideal engine between two thermal reservoirs at T_h and T_l . The availability is given using the Carnot efficiency η_c

$$A_{\text{heat}} = Q \eta_c = Q \left(1 - \frac{T_l}{T_h} \right) \quad (\text{A.2})$$

Neglecting kinetic and potential energy terms, which are again pure exergy, the availability of a flow of a substance, e.g. steam, can be computed as

$$A_{fl} = m_{fl} [(h - h_0) - T_0 (s - s_0)] \quad (A.3)$$

where h_0 , s_0 and T_0 are reference properties of a designated dead state. The availability of a fluid is the maximum work it could do if it were brought to equilibrium with this dead state in an ideal, reversible process. In accordance with the second law of thermodynamics not all of the enthalpy is available for useful work.

The availability of a fuel is defined in an analogous fashion, but shall be taken as the lower heating value for hydrocarbon fuels, since for these fuels the difference between LHV and availability is small (van Wylen/Sonntag, 1986, p. 497).

From the above the second law efficiency is

$$\eta_2 = \frac{W_{elec} + A_{fl}}{A_{fuel}} = \frac{W_{elec} + m_{fl} [(h - h_0) - T_0 (s - s_0)]}{m_{fuel} LHV_{fuel}} \quad (A.4)$$

It is obvious that for a power plant without cogeneration η_2 equals η_1 , whereas η_1 could be substantially higher than η_2 for a dual purpose plant.

In this context it is of interest to look at the energy and availability transfers in a power plant. The flow diagrams and numbers in Fig. A.1 are taken from Mitchell (1985). The values are percent of the entering fuel energy or exergy, respectively. As mentioned before, the overall power generating efficiency is the same on either basis. If losses are considered, however, the picture is quite different depending on which viewpoint is adopted. On an energy basis (Fig. A.1a) the steam boiler appears to be a

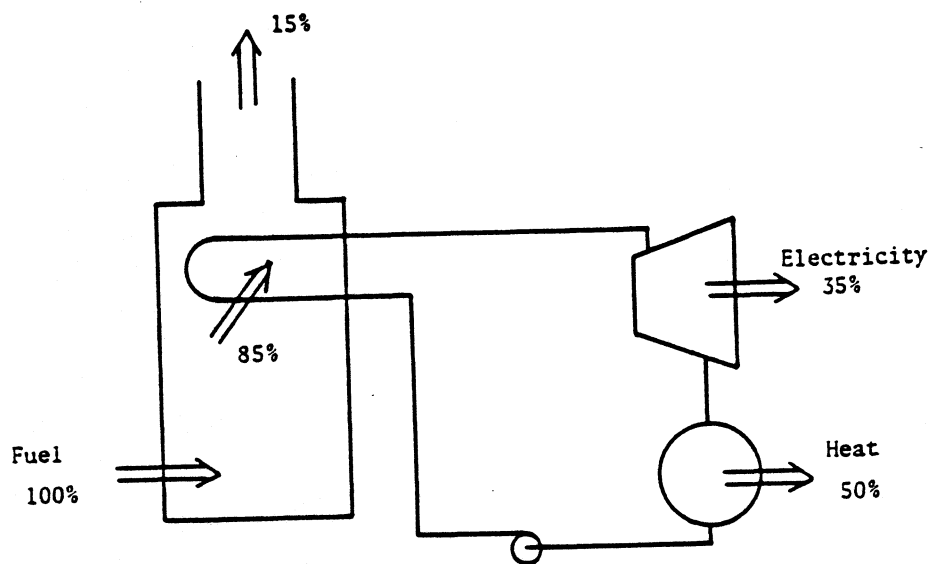


Figure A.1a Energy flows for a power plant

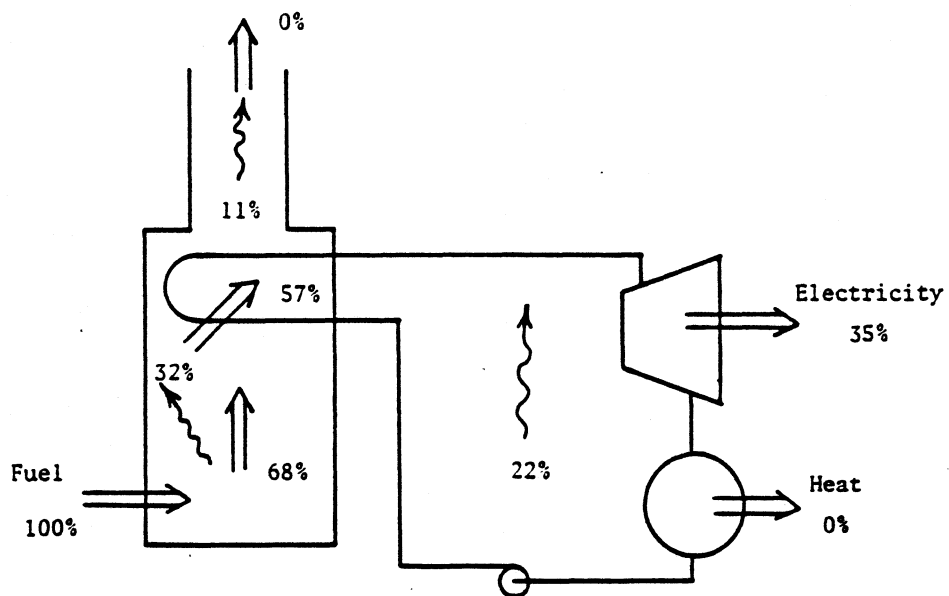


Figure A.1b Availability flows for a power plant

highly efficient device and the major energy losses to the environment occur in the condenser. If the quality of this energy (i.e. potential to produce useful work) is taken into account, it becomes apparent that the combustion process is an inherently irreversible process, which accounts for availability destruction in the order of 30-40 % (see Fig. A.1b). Availability losses to the environment, on the other hand, are almost negligible, since there is hardly any work potential left in the condensate.

For a cogeneration plant it follows that the availability which leaves the plant with the heat supplying fluid is much lower than its energy content. If a cogeneration plant has to satisfy a prescribed demand for heat and work, both efficiencies can be used to compare different configurations to meet these loads. Since the numerators in Eqs. A.1 and A.4 are constant in this case, the efficiencies are an indicator of the fuel consumption of the plant. If the outputs from a cogeneration plant are variable, however, the first law efficiency rises with the ratio of delivered heat energy to delivered work energy, reaches its maximum for the case of a pure heating plant and is equal to η_2 for a pure power plant. The first law efficiency does not account for the grade of the two forms of energy and attributes a misleadingly high value to heat energy. A performance comparison which is based on the first law of thermodynamics is therefore not adequate. It is the second law efficiency which should be taken as one performance indicator in the analysis of cogeneration systems.

Appendix B
Program Listings

Component	page
Steam Generator	116
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Control for Blount Street Cycle	221

Steam Generator

TYPE 50

C**** VERSION:10/28/88

SUBROUTINE TYPE50 (TIME,XIN,OUT,T,DTDT,PAR,INFO)

```

C*****
*
C
C   THIS ROUTINE SIMULATES THE THERMAL PERFORMANCE OF A STEAM BOILER
C   AND CALCULATES THE FUEL CONSUMPTION AS A FUNCTION OF PART LOAD
C   OPERATION (STEAM PRODUCTION). THE PERFORMANCE OF WASTE HEAT STEAM
C   GNENERATORS WITH AND WITHOUT SUPPLEMENTARY FIRING CAN ALSO BE
C   SIMULATED.
C
C*****
*
C*****
*
C   NOMENCLATURE: (IN ALPHABETICAL ORDER)
C
C   ALPHA  : CONVECTION HEAT TRANSFER COEFFICIENT
C   ARATE  : AIR RATE FOR COMBUSTION
C   BLOWDN : RATIO OF BLOWDOWN IN %
C   BOIL 1 : BOILER
C   BOIL 2 : WASTE HEAT BOILER
C   BOIL 3 : WASTE HEAT BOILER WITH SUPPL. FIRING
C   DHM    : SUBROUTINE FOR DETERMINATION OF STANDARD FORMATION
ENTHALPY
C   DNB    : INCREMENTAL FUEL ADDITION IN KMOL/SEC
C   DTB    : TEMP. DIFF. BETW. EXHAUST GAS INLET AND STEAM OUTLET IN C
OR F
C   EPS    : EMISSIVITY
C   ETABOI : BOILER EFFICIENCY IN %/100
C   FRBWDN : BLOWDOWN MASS FLOW RATE IN KG/S OR LB/HR
C   FRSUPP : STEAM MASS FLOW RATE TO PRODUCE BY SUPPL. FIRING IN KG/S
OR LB/HR
C   FUEL    : FUEL MASS FLOW RATE IN KG/S OR LB/HR
C   FWFR    : FEED WATER MASS FLOW RATE IN KG/S OR LB/HR
C   H       : STANDARD FORMATION ENTHALPY IN KJ/KMOL
C   Kwall   : HEAT TRANSFER COEFF. FOR INTERIOR
C            BOILER WALL IN W/M^2K OR BTU/HR/FT^2/F (INCL. CONV. AND
RAD.)
C   LHV     : LOWER HEATING VALUE IN KJ/KG OR BTU/LB
C   MC,M..  : MOL. WEIGHT
C   MCOAL   : MOL. WEIGHT OF COAL IN KG/KMOL
C   MNG     : MOL. WEIGHT OF NATURAL GAS IN KG/KMOL
C   MODE 1  : THERMODYNAMIC CALCULATION
C   MODE 2  : MANUFACTURERES PERFORMANCE CURVES
C   MODE 3  : REGRESSION FORMULAS
C   MOIL    : MOL. WEIGHT OF OIL IN KG/KMOL

```

```

C   NB      : FUEL CONSUMPTION IN KMOL/S
C   PIN     : FEED WATER PRESSURE IN MPA OR PSIA
C   POUT    : STEAM PRESSURE IN MPA OR PSIA
C   QFUEL   : FUEL ENERGY INPUT IN KW OR BTU/HR
C   QW      : CONVECTIVE AND RADIATION HEAT LOSS PER AREA OF BOILER IN
KW/M^2
C   QWLOSS  : CONVECTIVE AND RADIATION HEAT LOSS OF BOILER IN KW
C   QBD     : HEAT LOSS DUE TO BLOWDOWN IN KW
C   QGES    : HEAT SUPPLY BY COOLING OF HOT EXHAUST GAS IN KW
C   QOUT    : HEAT LOSS DUE TO HOT EXHAUST GAS IN KW
C   QST     : REQUIRED STEAM FOR STEAM PRODUCTION IN KW
C   SIG     : STEFAN-BOLTZMANN CONSTANT
C   ST      : STEAM PRODUCTION IN KG/S OR LB/HR
C   STMAX   : MAXIMUM STEAM PRODUCTION IN KG/S OR LB/HR
C   STMIN   : MINIMUM STEAM PRODUCTION IN KG/S OR LB/HR
C   SURF    : EXTERIOR BOILER SURFACE IN M^2 OR FT^2
C   TA      : AMBIENT TEMPERATURE IN C OR F
C   TB      : FUEL TEMPERATURE IN C OR F
C   TC      : COMBUSTION GAS TEMPERATURE IN C OR F
C   TEX     : EXHAUST GAS TEMPEARTURE IN C
C   TGIN    : COMBUSTION AIR OR EXHAUST GAS INLET TEMPERATURE IN C OR F
C   TGMAX   : EXHAUST GAS TEMPERATURE AT MAX. LOAD IN C OR F
C   TGMIN   : EXHAUST GAS TEMPERATURE AT MINIMUM LOAD IN C OR F
C   TIN     : FEED WATER TEMPERATURE IN C OR F
C   TOUT    : STEAM TEMPERATURE IN C OR F
C   TS      : TEMPERATURE OF SURROUNDINGS FOR BOILER IN C OR F
C   TW      : BOILER SURFACE TEMPERATURE IN C
C   UNITS   : 0: BRITISH; 1: SI UNITS
C   VGIN    : EXHAUST GAS MASS FLOW RATE IN KG/S OR LB/HR
C   XCH4    : MOLE FRACTION OF METHANE IN NATURAL GAS FOR Z=1
C   XC2H6   : MOLE FRACTION OF ETHANE IN NATURAL GAS FOR Z=1
C   XN2F    : MOLE FRACTION OF NITROGEN IN NATURAL GAS FOR Z=1
C   XC      : MOLE FRACTION OF CARBON IN COAL FOR Z=2
C   XH      : MOLE FRACTION OF HYDROGEN IN COAL FOR Z=2
C   XAS     : MOLE FRACTION OF ASHES IN COAL FOR Z=1
C   XCO2    : MOLE FRACTION OF CARBONDIOXID IN EXHAUST GAS
C   XH2     : MOLE FRACTION OF HYDROGEN IN EXHAUST GAS
C   XH2O    : MOLE FRACTION OF WATER IN EXHAUST GAS
C   XN2     : MOLE FRACTION OF NITROGEN IN EXHAUST GAS
C   XO2     : MOLE FRACTION OF OXYGEN IN EXHAUST GAS
C   Y...    : MASS FRACTIONS
C   Z       : 0=OIL OR 1=NATURAL GAS OR 2=COAL
C*****
*
```

```

REAL N2A,N2B,N2C,N2D,N2HM,KWALL,MAIR,NB,LHV,MOIL,MNG,NAIR,NO2
REAL NN2,N2EX,MCOAL,MC,MH2,MAS
DIMENSION FFUEL(10),STM(200),STMAC(10),STMACF(10),TSG(10)
DIMENSION XIN(6),PAR(221),OUT(8),INFO(10)
```

```

C***** COEFFICIENTS FOR COMBUSTION CALCULATION (STANDARD FORMATION ENTH.)
DATA C8A,C8B,C8C,C8D,C8HM /60.73,0.,0.,0.,-59.75/
DATA CH4A,CH4B,CH4C,CH4D,CH4HM /2.975,18.329,.346,-4.303,-17.88/
DATA C2H6A,C2H6B,C2H6C,C2H6D,C2H6HM /7.8,14.3,0.,0.,12.54/
DATA O2A,O2B,O2C,O2D,O2HM /7.16,1.0,.4,0.,0./
DATA N2A,N2B,N2C,N2D,N2HM /6.66,1.02,0.,0.,0./
DATA CO2A,CO2B,CO2C,CO2D,CO2HM /10.55,2.16,-2.04,0.,-94.05/
DATA H2OA,H2OB,H2OC,H2OD,H2OHM /7.17,2.56,.08,0.,-57.95/
DATA ALPHA,SIG,EPS,MAIR,MOIL /10.,5.669E-08,.9,28.85,114./
DATA MC,MH2,MH,MAS /12.,2.,1.,30./
DATA CCLA,CCLB,CCLC,CCLD /.026,9.307,.354,-4.155/
DATA HCLA,HCLB,HCLC,HCLD /6.52,.78,.12,0./

```

```

C***** FIRST CALL OF SIMULATION
IF (INFO(7).GE.0) GO TO 1
INFO(6)=9
INFO(9)=0

```

```

1  MODE=PAR(1)
   BOIL=PAR(2)
   UNITS=PAR(3)
   IF (MODE.GE.1.AND.MODE.LE.3.AND.BOIL.GE.1.AND.BOIL.LE.3
+ .AND.UNITS.GE.0..AND.UNITS.LE.1.) GO TO 2
   CALL TYPECK(4,INFO,0,0,0)
   RETURN

```

```

C***** SET PARAMETERS AND INPUTS
2  IF (MODE.EQ.2) GO TO 20
   IF (MODE.EQ.3) GO TO 30

```

```

C*****
C*****
C***** THERMODYNAMIC CALCULATION
C*****
C*****

```

```

TIN=PAR(4)
PIN=PAR(5)
TOUT=PAR(6)
POUT=PAR(7)
STMAX=PAR(8)
STMIN=PAR(9)
BLOWDN=PAR(10)
TGMAX=PAR(11)+273.15
TGMIN=PAR(12)+273.15
SURF=PAR(13)
KWALL=PAR(14)

```

```

IF (BOIL.EQ.1.) TC=PAR(15)+273.15

```

```

IF (BOIL.NE.1.) DTB=PAR(15)

Z=PAR(16)
ARATE=PAR(17)

C**** FUEL=OIL
IF (Z.EQ.0.) XC8H18=1.

C**** FUEL=NATURAL GAS, INPUT AS MOLE (=VOLUME) FRACTIONS
IF (Z.EQ.1.) THEN
  XCH4=PAR(18)
  XC2H6=PAR(19)
  XN2F=PAR(20)
END IF

C**** FUEL=COAL: INPUT AS MASS FRACTIONS, CONVERSION TO MOLE FRACTIONS
IF (Z.EQ.2.) THEN
  YC=PAR(18)
  YH=PAR(19)
  YAS=PAR(20)
  YREST=1-YC-YH2-YAS
  MCOAL=1/(YC/MC+YH/MH+YAS/MAS+YREST/16)
  XC=YC*MCOAL/MC
  XH=YH*MCOAL/MH
  XAS=YAS*MCOAL/MAS
END IF

C*****
C**** INPUTS FOR BOILER AND WASTE HEAT BOILER
C*****
ST=XIN(1)

C**** GOTO END IF NO STEAM LOAD
IF (ST.EQ.0.) GOTO 800

TA=XIN(2)+273.15
TS=XIN(3)+273.15
TB=XIN(4)+273.15
TGIN=XIN(5)+273.15
IF (BOIL.NE.1.) VGIN=XIN(6)

C**** UNIT CONVERSION
IF (UNITS.EQ.0.) THEN
  TIN=(TIN-32)/1.8
  PIN=PIN*0.00689
  TOUT=(TOUT-32)/1.8
  POUT=POUT*0.00689
  STMAX=STMAX/3600*0.454
  STMIN=STMIN/3600*0.454
  TGMAX=(PAR(11)-32)/1.8+273.15

```



```

TGMIN=(PAR(12)-32)/1.8+273.15
SURF=SURF*0.0929
KWALL=KWALL*5.68
IF (BOIL.EQ.1.) TC=(PAR(15)-32)/1.8+273.15
IF (BOIL.NE.1.) DTB=PAR(15)/1.8

```

```

ST=ST/3600*0.454
TA=(XIN(2)-32)/1.8+273.15
TS=(XIN(3)-32)/1.8+273.15
TB=(XIN(4)-32)/1.8+273.15
TGIN=(XIN(5)-32)/1.8+273.15
IF (BOIL.NE.1.) VGIN=VGIN/3600*0.454
END IF

```

```

C**** CHECK OF WORKING RANGE
      IF (BOIL.EQ.1..AND.ST.GT.STMAX.AND.ST.LT.STMIN) THEN
        WRITE(6,90) TIME, INFO(1), INFO(2)
90    FORMAT(T2,'***** WARNING *****',/,
+T2,' TIME : ',E12.5,' UNIT : ',I3,' TYPE : ',I3,/,
+ ' ! STEAM PRODUCTION OUT OF RANGE !',/)
        CALL TYPECK(2,INFO,0,0,0)
        RETURN
      END IF

```

```

C*****
C**** CALCULATON OF CONVECTIVE AND RADIATION LOSSES
C*****

```

```

C**** ITERATIVE CALCULATION OF BOILER SURFACE TEMPERATURE WITH ENERGY
BALANCE

```

```

C      AND NEWTON METHOD
      I=1
      TW=TS
      IF (BOIL.NE.1.) TC=TGIN
4    QW= ALPHA*(TW-TS) - KWALL*(TC-TW) + SIG*EPS*(TW**4.-TS**4.)
      QWS=4.*SIG*EPS*TW**3.+ALPHA+KWALL
      TWA=TW
      TW=(TW-QW)/QWS
      IF (ABS(TW-TWA).LE..01) GO TO 5
      I=I+1

      IF (I.GT.100) THEN
        WRITE(6,92) TIME, INFO(1), INFO(2)
92    FORMAT(T2,'***** WARNING *****',/,
+T2,' TIME : ',E12.5,' UNIT : ',I3,' TYPE : ',I3,/,
+ ' NO CONVERGENCE FOR BOILER SURFACE TEMPERATURE CALCULATION!',/)
        CALL TYPECK(4,INFO,0,0,0)
        RETURN
      END IF

```

```

GO TO 4
5 QWLOSS=KWALL*SURF*(TC-TW)/1000.

C*****
C**** CALCULATION OF TOTAL HEAT DEMAND
C*****

C**** HEAT DEMAND FOR STEAM PRODUCTION
CALL STEAM ('SI',TIN,PIN,HIN,SIN,QIN,VIN,UI,12)
CALL STEAM ('SI',TOUT,POUT,HOUT,SOUT,QOUT,VOUT,UOUT,12)
QST=ST*(HOUT-HIN)

C**** HEAT LOSS DUE TO BLOWDOWN
FWFR=ST/(1.-BLOWDN/100.)
FRBWDN=FWFR-ST
CALL STEAM ('SI',TBD,PIN,HBD,SBD,0.,VDB,UBD,25)
QBD=FRBWDN*(HBD-HIN)

C**** ESTIMATION OF EXHAUST GAS TEMPERATURE OF BOILER:
GRAD=(TGMAX-TGMIN)/(STMAX-STMIN)
B=TGMAX-GRAD*STMAX
TEX=GRAD*ST+B

C*****
C**** COMBUSTION CALCULATION
C*****

C**** FOR Z=0 : OIL
IF (Z.EQ.0.) THEN

C**** CARBONDIOXID AND WATER CONTENTS OF THE EXHAUST GAS IN CASE OF OIL
XCO2=8.
XH2O=9.
XC8H18=1.
XCH4=0.
XC2H6=0.
XN2F=0.
XC=0.
XH2=0.
XAS=0.

C**** LOWER HEATING VALUE OF OIL: ADJUSTED FOR AVERAGE FUEL OIL
LHV=0.85*(C8HM-XCO2*CO2HM-XH2O*H2OHM)*4186.8/MOIL
END IF

C*****

C**** FOR Z=1: NATURAL GAS
IF (Z.EQ.1.) THEN

```

```

C**** CARBONDIOXID AND WATER CONT. OF EXH. GAS IN CASE OF NATURAL GAS
XCO2=2.*XC2H6+XCH4
XH2O=2.*(XCH4+XC2H6)
XC8H18=0.
XC=0.
XH2=0.
XAS=0.
MNG=XCH4*16.+XC2H6*28.+XN2F*28.

```

```

C**** LOWER HEATING VALUE OF NATURAL GAS
LHV=(XCH4*CH4HM+XC2H6*C2H6HM-XCO2*CO2HM-XH2O*H2OHM)*4186.8/MNG
END IF

```

```

C*****

```

```

C**** IF Z=2: COAL
IF(Z.EQ.2.) THEN

```

```

C**** CARBONDIOXID AND WATER CONT. OF EXH. GAS IN CASE OF COAL
XCO2=XC
XH2O=0.5*XH
XC8H18=0.
XCH4=0.
XC2H6=0.
XN2F=0.

```

```

C**** LOWER HEATING VALUE OF COAL
LHV=-(XCO2*CO2HM+XH2O*H2OHM)*4186.8/MCOAL
END IF

```

```

C*****

```

```

C**** CONSISTENCE OF EXHAUST GAS AND AIR DEMAND
XO2ST=XCO2+.5*XH2O
XN2ST=.79/.21*XO2ST
XO2IN=ARATE*XO2ST
XN2IN=ARATE*XN2ST
IF(BOIL.EQ.2.) GO TO 10
XO2=(ARATE-1.)*XO2ST
XN2=ARATE*XN2ST+XN2F

```

```

C**** SPECIFIC HEAT OUTPUT OF COMBUSTION: QOUT IN kJ/kmol OF FUEL
A1=1000.
HCO2 = DHM(TA,TEX,CO2A,CO2B,CO2C,CO2D)/A1
HH2O = DHM(TA,TEX,H2OA,H2OB,H2OC,H2OD)/A1
HN2 = DHM(TA,TEX,N2A,N2B,N2C,N2D)/A1
HO2 = DHM(TA,TEX,O2A,O2B,O2C,O2D)/A1
HCH4 = DHM(TA,TB,CH4A,CH4B,CH4C,CH4D)/A1

```

```

HC2H6 = DHM(TA, TB, C2H6A, C2H6B, C2H6C, C2H6D) / A1
HC8H18 = DHM(TA, TB, C8A, C8B, C8C, C8D) / A1
HN2F = DHM(TA, TB, N2A, N2B, N2C, N2D) / A1
HO2A = DHM(TA, TGIN, O2A, O2B, O2C, O2D) / A1
HN2A = DHM(TA, TGIN, N2A, N2B, N2C, N2D) / A1
HC = DHM(TA, TB, CCLA, CCLB, CCLC, CCLD) / A1
HH = DHM(TA, TB, HCLA, HCLB, HCLC, HCLD) / A1

```

```

IF(BOIL.EQ.3.) GO TO 10

```

```

QOUT=(XCO2*(CO2HM+HCO2)+XH2O*(H2OHM+HH2O)+XN2*HN2+XO2*HO2
+      -(XCH4*(CH4HM+HCH4)+XC2H6*(C2H6HM+HC2H6)+XC8H18*(C8HM+HC8H18)
+      +XC*HC+XH*HH+XN2F*HN2F+XO2IN*HO2A+XN2IN*HN2A))*(-4186.8)

```

```

C*****
C**** FUEL COMSUMPTION OF BOILER
C*****

```

```

C**** FUEL CONSUMPTION IN KMOL/SEC
NB=(QST+QBD+QWLOSS)/QOUT

```

```

C**** FUEL CONSUMPTION IN KG/SEC, EFFICIENCY, COMB. AIR MASS FLOW RATE
IF(Z.EQ.0.) FUEL=NB*MOIL
IF(Z.EQ.1.) FUEL=NB*MNG
IF(Z.EQ.2.) FUEL=NB*MCOAL

```

```

QFUEL=LHV*FUEL
ETABOI=QST/QFUEL
VGIN=(XO2IN+XN2IN)*NB*MAIR
GO TO 50

```

```

C*****
C**** WASTE HEAT BOILER (HAS NOT BEEN USED OR VALIDATED YET!!!!)
C*****

```

```

10 IF(BOIL.EQ.2..AND.TOUT.GT.(TGIN-DTB-273.15)) THEN
  WRITE(6,93) TIME, INFO(1), INFO(2)
93 FORMAT(T2,'***** WARNING *****',/,
+T2,' TIME : ',E12.5,' UNIT : ',I3,' TYPE : ',I3,/,
+ ' STEAM OF DESIRED QUALITY CANNOT BE PRODUCED WITHOUT',/,
+ ' SUPPLEMENTARY FIRING!',//)
  CALL TYPECK(4,INFO,0,0,0)
  RETURN
END IF

```

```

C*****
C**** CALCULATION OF THEORETICAL ENERGY SUPPLY, ASSUMPTION: GAS = AIR
C*****

```

```

NAIR=VGIN/MAIR
NO2=.21*NAIR
NN2=.79*NAIR
HO2A=DHM(TA,TGIN,O2A,O2B,O2C,O2D)/1000.
HN2A=DHM(TA,TGIN,N2A,N2B,N2C,N2D)/1000.
QGES=(NO2*HO2A+NN2*HN2A)*4186.8

C*****
C**** ITERATIVE CALCULATION OF PRODUCABLE STEAM MASS FLOW RATE
C*****

K=0
STA=0.
400 TEX=GRAD*STA+B
STAA=STA
HO2=DHM(TEX,TGIN,O2A,O2B,O2C,O2D)/1000.
HN2=DHM(TEX,TGIN,N2A,N2B,N2C,N2D)/1000.
QVG=(NO2*HO2+NN2*HN2)*4186.8
STA=(QVG-QWLOSS)/(HOUT-HIN+(1./(1.-BLOWDN/100.)-1.)*(HBD-HIN))
IF (ABS(STA-STAA).LT..0001) GO TO 401
K=K+1
IF (K.GT.100) THEN
  WRITE(6,94) TIME, INFO(1), INFO(2)
94 FORMAT(T2,'***** WARNING *****',/,
+T2,' TIME : ',E12.5,' UNIT : ',I3,' TYPE : ',I3,/,
+ ' NO CONVERGENCE FOR STEAM MASS FLOW RATE CALCULATION IN ',/,
+ ' WASTE HEAT BOILER!',//)
  CALL TYPECK(2,INFO,0,0,0)
  RETURN
  END IF
  GO TO 400

C**** CHECK OF STEAM PRODUCTION FOR MODE 2
401 IF (STA.LT.ST.AND.BOIL.EQ.2.) THEN
  WRITE(6,95) TIME, INFO(1), INFO(2)
95 FORMAT(T2,'***** WARNING *****',/,
+T2,' TIME : ',E12.5,' UNIT : ',I3,' TYPE : ',I3,/,
+ ' WASTE HEAT NOT SUFFICIENT FOR DESIRED STEAM PRODUCTION!',/,
+ ' NEED FOR SUPPL. FIRING!',//)
  CALL TYPECK(2,INFO,0,0,0)
  RETURN
  END IF

IF (BOIL.EQ.2.) THEN
  ST=STA
  FUEL=0.
  QFUEL=0.
  ETABOI=ST*(HOUT-HIN)/QGES
  FWFR=ST/(1.-BLOWDN/100.)
  FRBWDN=FWFR-ST
  GO TO 50

```

END IF

```

C*****
C**** WASTE HEAT BOILER WITH SUPPLEMENTARY FIRING (HAS NOT BEEN USED
C**** OR VALIDATED YET !!!!!!!
C*****

C**** IN CASE OF WASTE STEAM
      IF (STA.GE.ST.AND.BOIL.EQ.3..AND.TOUT.LE.(TGIN-DTB-273.15)) THEN
        FUEL=0.
        QFUEL=0.
        ETABOI=ST*(HOUT-HIN)/QGES
        ST=STA
        FWFR=ST/(1.-BLOWDN/100.)
        FRBWDN=FWFR-ST
        GO TO 50
      END IF

C**** FUEL CONSUMPTION DUE TO SUPPLEMENTARY FIRING IF FLUE GAS NOT
C      SUFFICIENT FOR DESIRED STEAM PRODUCTION
      FRSUPP=(ST-STA)*(HOUT-HIN)/LHV

C**** TEMPERATURE CHECK
      IF (Z.EQ.0.) NB=FRSUPP/MOIL
      IF (Z.EQ.1.) NB=FRSUPP/MNG
      IF (Z.EQ.2.) NB=FRSUPP/MCOAL
      TG=TGIN
14  I=0
11  QIN=NB*(XCH4*(HCH4+CH4HM)+XC2H6*(HC2H6+C2H6HM)+XN2F*(HN2F+N2HM)
      +
      +XC8H18*(C8HM+HC8H18))+NO2*HO2A+NN2*HN2A
      HCO2 = DHM(TA,TG,CO2A,CO2B,CO2C,CO2D)/1000.
      HH2O = DHM(TA,TG,H2OA,H2OB,H2OC,H2OD)/1000.
      HO2   = DHM(TA,TG,O2A,O2B,O2C,O2D)/1000.
      HN2   = DHM(TA,TG,N2A,N2B,N2C,N2D)/1000.
      CO2=NB*XCO2
      H2O=NB*XH2O
      O2EX=NO2-NB*XO2ST
      N2EX=NN2
      QOUT=CO2*(HCO2+CO2HM)+H2O*(HH2O+H2OHM)+O2EX*HO2+N2EX*HN2
      IF (I.EQ.0) DNB=NB/100000.
      IF (QOUT.GT.QIN) GO TO 12
      I=I+1
      TG=TG+2.
      IF (I.GT.2000) THEN
        WRITE(6,96) TIME, INFO(1), INFO(2)
96  FORMAT(T2,'***** WARNING *****',/,
      +T2,' TIME : ',E12.5,' UNIT : ',I3,' TYPE : ',I3,/,
      +' NO CONVERGENCE FOR WASTE HEAT BOILER CALC.(WITH SUP. FIR.)',/)

```

```

CALL TYPECK(2,INFO,0,0,0)
RETURN
END IF
GO TO 11

```

C**** CHECK OF EXHAUST GAS INLET TEMPERATURE AND INCREASE OF SUPPLEMENTARY

```

C    FIRING IF TEMP. TOO LOW
12  IF ((TG-DTB-273.15).GT.TOUT) GO TO 13
    NB=NB+DNB
    GO TO 14
13  IF (Z.EQ.0.) FUEL=NB*MOIL
    IF (Z.EQ.1.) FUEL=NB*MNG
    IF (Z.EQ.2.) FUEL=NB*MCOAL
    QFUEL=FUEL*LHV
    ETABOI=ST*(HOUT-HIN)/(QFUEL+QGES)
    GO TO 50

```

```

C*****
C*****
C**** PERFORMANCE CALCULATION FROM MANUFACTURERS PERFORMANCE CURVES
C*****
C*****

```

C**** SET PARAMETERS AND INPUTS

```

20  BLOWDN=PAR(4)
    N=PAR(5)
    M=PAR(6)
    IF (M.LE.10.AND.N.LE.10) GO TO 300
    WRITE(6,97) TIME, INFO(1), INFO(2)
97  FORMAT(T2,'***** WARNING *****',/,
+T2,' TIME : ',E12.5,' UNIT : ',I3,' TYPE : ',I3,/,
+' TOO MANY PERFORMANCE VALUES !!!',//)
    CALL TYPECK(4,INFO,0,0,0)
    RETURN
300 IF (BOIL.NE.1.) GO TO 21

```

```

C*****
C**** BOILER
C*****

```

```

DO 22 I=1,N
    STM(I)=PAR(I+6)
    FFUEL(I)=PAR(I+6+N)
    IF (UNITS.EQ.0.) THEN
        STM(I)=STM(I)/3600*0.454
        FFUEL(I)=FFUEL(I)/3600*0.454
    END IF
22  CONTINUE

```

```

      ST=XIN(1)
      IF (ST.EQ.0.) GOTO 800
      IF (UNITS.EQ.0.) ST=ST/3600*0.454
      IF (ST.GE.STM(1).AND.ST.LE.STM(N)) GO TO 25
      WRITE(6,98) TIME, INFO(1), INFO(2)
98  FORMAT(T2,'***** WARNING *****',/,
+T2,' TIME : ',E12.5,' UNIT : ',I3,' TYPE : ',I3,/,
+' STEAM PRODUCTION OUT OF RANGE (MODE 2)!!!',/)
      CALL TYPECK(2,INFO,0,0,0)
      RETURN

C***** CALCULATION OF FUEL CONSUMP. OF THE BOILER BY LIN. INTERPOLATION
25  IF (ST.EQ.STM(1)) THEN
      FUEL=FFUEL(1)
      GO TO 61
      END IF
      I=1
24  IF (ST.GE.STM(I)) GO TO 23
      GRAD=(ST-STM(I-1))/(STM(I)-STM(I-1))
      FUEL=FFUEL(I-1)+GRAD*(FFUEL(I)-FFUEL(I-1))
      GO TO 61
23  I=I+1
      GO TO 24

C*****
C***** WASTE HEAT BOILER
C*****
21  ST=XIN(1)
      VG=XIN(2)
      TG=XIN(3)
      FUMAX=PAR(7)
      L=7
      ZK=PAR(8)
      IF (ZK.NE.1.) THEN
          TIN=PAR(9)
          PIN=PAR(10)
          TOUT=PAR(11)
          POUT=PAR(12)
          DTB=PAR(13)
          L=13
      END IF

C***** UNIT CONVERSION
      IF (UNITS.EQ.0.) THEN
          ST=ST/3600*0.454
          VG=VG/3600*0.454
          TG=(TG-32)/1.8
          FUMAX=FUMAX/3600*0.454
          IF (ZK.NE.1.) THEN
              TIN=(TIN-32)/1.8

```



```

PIN=PIN*0.00689
TOUT=(TOUT-32)/1.8
POUT=POUT*0.00689
DTB=DTB/1.8
END IF
END IF

DO 26 I=1,M
TSG(I)=PAR(L+I)
26 IF (UNITS.EQ.0.) TSG(I)=(TSG(I)-32)/1.8
N2=N*M
N1=N2
IF (BOIL.EQ.3.) N1=2*N2
DO 27 I=1,N
FFUEL(I)=PAR(L+M+I)
27 IF (UNITS.EQ.0.) FFUEL(I)=FFUEL(I)/3600*0.454
DO 28 I=1,N1
STM(I)=PAR(L+M+N+I)
IF (UNITS.EQ.0..AND.ZK.EQ.2.) STM(I)=STM(I)*0.0034123      !KW-
>BTU/HR
28 IF (UNITS.EQ.0..AND.ZK.EQ.1.) STM(I)=STM(I)/3600*0.454      !LB/HR-
>KG/SEC
IF (ZK.NE.1.) THEN
CALL STEAM ('SI',TIN,PIN,HIN,SIN,QIN,VIN,UIIN,12)
CALL STEAM ('SI',TOUT,POUT,HOUT,SOUT,QOUT,VOUT,UOUT,12)
DO 29 I=1,N1
29 STM(I)=STM(I)/(HOUT-HIN)
END IF

C**** CHECK OF DATA RANGE
IF (VG.LT.FFUEL(1).OR.VG.GT.FFUEL(N)) THEN
WRITE(6,99) TIME, INFO(1), INFO(2)
99 FORMAT(T2,'***** WARNING *****',/,
+T2,' TIME : ',E12.5,' UNIT : ',I3,' TYPE : ',I3,/,
+' EXHAUST MASS FLOW RATE GREATER OR LOWER',/,
+' THAN A VALID PERFORMANCE CURVE (MODE 3) !!!',//)
CALL TYPECK(4,INFO,0,0,0)
RETURN
END IF

IF (TG.LT.TSG(1).OR.TG.GT.TSG(M)) THEN
WRITE(6,190) TIME, INFO(1), INFO(2)
190 FORMAT(T2,'***** WARNING *****',/,
+T2,' TIME : ',E12.5,' UNIT : ',I3,' TYPE : ',I3,/,
+' EXHAUST GAS TEMPERATURE GREATER OR LOWER THAN ',/,
+' OR LOWER THAN A VALID PERFORMANCE CURVE (MODE 3) !!!',//)
CALL TYPECK(4,INFO,0,0,0)
RETURN
END IF

```

```

C***** INTERPOLATION BETWEEN PERFORMANCE CURVES
      IF (TG.EQ.TSG(1)) THEN
      IF (VG.EQ.FFUEL(1)) THEN
      STA=STM(1)
      STAF=STM(1+N2)
      GO TO 42
      END IF

      I=1
44  IF (VG.GT.FFUEL(I)) GO TO 43
      GRAD=(VG-FFUEL(I-1))/(FFUEL(I)-FFUEL(I-1))
      STA=STM(I-1)+GRAD*(STM(I)-STM(I-1))
      STAF=STM(I-1+N2)+GRAD*(STM(I+N2)-STM(I-1+N2))
      GO TO 42
43  I=I+1
      GO TO 44
      END IF

      J=1
48  IF (TG.GT.TSG(J)) GO TO 45
      GRAD=(TG-TSG(J-1))/(TSG(J)-TSG(J-1))
      DO 46 I=1,N
      STMAC(I)=(STM((J-1)*N+I)-STM((J-2)*N+I))*GRAD+STM((J-2)*N+I)
46  STMACF(I)=(STM((J-1)*N+N2+I)-STM((J-2)*N+N2+I))*GRAD
      1+STM((J-2)*N+N2+I)
      GO TO 47
45  J=J+1
      GO TO 48

47  IF (VG.EQ.FFUEL(1)) THEN
      STA=STMAC(1)
      STAF=STMACF(1)
      GO TO 42
      END IF

      I=1
60  IF (VG.GT.FFUEL(I)) GO TO 49
      GRAD=(VG-FFUEL(I-1))/(FFUEL(I)-FFUEL(I-1))
      STA=STMAC(I-1)+GRAD*(STMAC(I)-STMAC(I-1))
      STAF=STMACF(I-1)+GRAD*(STMACF(I)-STMACF(I-1))
      GO TO 42
49  I=I+1
      GO TO 60
42  FUEL=0.

      IF ((TOUT+DTB).GT.TG.AND.BOIL.EQ.2.) THEN
      WRITE(6,191) TIME, INFO(1), INFO(2)
191  FORMAT(T2,'***** WARNING *****',/,
      +T2,' TIME : ',E12.5,' UNIT : ',I3,' TYPE : ',I3,/,

```

```

+' STEAM OF THE DESIRED QUALITY CANNOT BE PRODUCED, ',/,
+' SINCE EXHAUST GAS TEMP. TOO LOW (MODE 2, BOIL=2)! ',//)
CALL TYPECK(4,INFO,0,0,0)
RETURN
END IF

IF (STA.LT.ST.AND.BOIL.EQ.2.) THEN
WRITE(6,193) TIME, INFO(1), INFO(2)
193 FORMAT(T2,'***** WARNING *****',/,
+T2,' TIME : ',E12.5,' UNIT : ',I3,' TYPE : ',I3,/,
+' WASTE HEAT NOT SUFFICIENT FOR DESIRED STEAM PRODUCTION',/,
+' USE SUPPLEMENTARY FIRING! (MODE 2, BOIL=2)',//)
CALL TYPECK(2,INFO,0,0,0)
RETURN
END IF

IF (STA.GE.ST) THEN
ST=STA
GO TO 61
END IF

C*****
C**** WASTE HEAT BOILER WITH SUPPLEMENTARY FIRING
C*****

IF (ST.GT.STAF) THEN
WRITE(6,194) TIME, INFO(1), INFO(2)
194 FORMAT(T2,'***** WARNING *****',/,
+T2,' TIME : ',E12.5,' UNIT : ',I3,' TYPE : ',I3,/,
+' EVEN AT MAXIMUM PRODUCTION RATE THE DESIRED',/,
+' STEAM FLOW RATE CANNOT BE PRODUCED (MODE 2, BOIL=3)!!!',//)
CALL TYPECK(4,INFO,0,0,0)
RETURN
END IF

GRAD=(ST-STA)/(STAF-STA)
FUEL=GRAD*FUMAX
61 FWFR=ST/(1.-BLOWDN/100.)
FRBWDN=FWFR-ST
ETABOI=0.
GO TO 50

C*****
C*****
C**** REGRESSION FORMULA FOR BOILER PERFORMANCE (HAS NOT BEEN USED
YET!!)
C*****
C*****

C**** SET PARAMETERS AND INPUTS

```

```

30 BLOWDN=PAR(3)
   STMAX=PAR(4)
   STMIN=PAR(5)
   A1=PAR(6)
   A2=PAR(7)
   A3=PAR(8)
   IF (BOIL.EQ.1.) THEN
     ST=XIN(1)
     IF (ST.EQ.0.) GOTO 800
     IF (ST.LE.STMAX.AND.ST.GE.STMIN) GO TO 31
     WRITE(6,195) TIME, INFO(1), INFO(2)
195  FORMAT(T2,'***** WARNING *****',/,
+T2,' TIME : ',E12.5,' UNIT : ',I3,' TYPE : ',I3,/,
+' STEAM PRODUCTION OUT OF RANGE (MODE 3,BOIL=1)!!!',//)
     CALL TYPECK(2,INFO,0,0,0)
     RETURN

31 FUEL=A1+A2*ST+A3*ST*ST
   GO TO 33
   END IF

C*****
C**** REGRESSION FORMULA FOR WASTE HEAT BOILER PERFORMANCE
C*****

   A4=PAR(9)
   A5=PAR(10)
   A6=PAR(11)
   A7=PAR(12)
   A8=PAR(13)
   ST=XIN(1)
   VG=XIN(2)
   TG=XIN(3)
   ETABOI=0.
   FUEL=0.
   IF (ST.LE.STMAX.AND.ST.GE.STMIN) GO TO 32
   WRITE(6,196) TIME, INFO(1), INFO(2)
196  FORMAT(T2,'***** WARNING *****',/,
+T2,' TIME : ',E12.5,' UNIT : ',I3,' TYPE : ',I3,/,
+' STEAM PRODUCTION OUT OF RANGE (MODE 3,BOIL=2)!!!',//)
   CALL TYPECK(2,INFO,0,0,0)
   RETURN

32 STP=A1+A2*VG+A3*VG*VG+A4*TG+A5*TG*TG+A6*TG*VG

   IF (BOIL.EQ.2.) THEN
     IF (ST.GT.STP) THEN
       WRITE(6,197) TIME, INFO(1), INFO(2)
197  FORMAT(T2,'***** WARNING *****',/,
+T2,' TIME : ',E12.5,' UNIT : ',I3,' TYPE : ',I3,/,
+' WASTE HEAT NOT SUFFICIENT FOR DESIRED STEAM PRODUCTION',/,

```

```

+' USE SUPPL. FIRING (MODE 3, BOIL=2)!!!',//)
CALL TYPECK(2,INFO,0,0,0)
RETURN
END IF

```

```

GO TO 33
END IF

```

```

C*****
C**** WASTE HEAT BOILER WITH SUPPLEMENTARY FIRNG
C*****
      IF (ST.LE.STP) THEN
        ST=STP
        GO TO 33
      END IF
C**** IF SUPPL. FIRING NECESSARY
      C=ST-STP
      FUEL=SQRT (C/A8+ (A7/2./A8)**2.)-A7/2./A8

C**** ALL BOILERS
33 FWFR=ST/ (1.-BLOWDN/100.)
   FRBWDN=FWFR-ST

```

```

C*****
C*****
C**** SET OUTPUTS
C*****
50 IF (UNITS.EQ.1..OR.MODE.EQ.3.) THEN
      OUT(1)=ST
      OUT(2)=FWFR
      OUT(3)=FRBWDN
      OUT(4)=FUEL
      OUT(5)=ETABOI
      OUT(6)=QFUEL
      OUT(7)=VGIN
      OUT(8)=TGIN-273.15
      IF (MODE.EQ.1..AND.BOIL.EQ.1.) OUT(9)=LHV
      IF (BOIL.NE.1..AND.MODE.NE.1) THEN
        OUT(7)=VG
        OUT(8)=TG
      END IF

      ELSE
        OUT(1)=ST*3600/0.454
        OUT(2)=FWFR*3600/0.454
        OUT(3)=FRBWDN*3600/0.454
        OUT(4)=FUEL*3600/0.454
        OUT(5)=ETABOI

```

```

      OUT(6)=QFUEL*1000/3.4123
      OUT(7)=VGIN*3600/0.454
      OUT(8)=(TGIN-273.15)*1.8+32
      IF(MODE.EQ.1..AND.BOIL.EQ.1.) OUT(9)=LHV/2.33
      IF(BOIL.NE.1..AND.MODE.NE.1) THEN
      OUT(7)=VG*3600/0.454
      OUT(8)=TG*1.8+32
      END IF
      END IF

800   IF(ST.EQ.0.) THEN
      DO 801 I=1,9
      OUT(I)=0
801   CONTINUE
      END IF

      RETURN
      END

```

```

      FUNCTION DHM (T1,T2,A,B,C,D)
C*****
C**** THIS ROUTINE CALCULATES THE ENTHALPY DROP DHM IN MCAL/KMOL
C*****
      HM2=A*T2+B*T2**2./2000.-C*100000./T2+D*T2**3./3000000.
      HM1=A*T1+B*T1**2./2000.-C*100000./T1+D*T1**3./3000000.
      DHM=HM2-HM1
      RETURN
      END

```

Steam Turbine**TYPE 48**

C**** VERSION:10/28/88

SUBROUTINE TYPE48 (TIME,XIN,OUT,T,DTDT,PAR,INFO)

```

C*****
*
C
C   THIS ROUTINE SIMULATES THE PERFORMANCE OF A BACKPRESSURE
C   OR A CONDENSING STEAM TURBINE AS A FUNCTION OF THE LOAD OR AS
C   A FUNCTION OF THE AVAILABLE STEAM MASS FLOW RATE
C
C*****
*
C*****
*
C   NOMENCLATURE: (IN ALPHABETICAL ORDER)
C
C   CALC   : 1 : STEAM CONSUMPTION IS CALCULATED FROM ELECTRICITY
PROD.
C           2 : ELECTRICITY PROD. IS CALCULATED FROM AVAIL. STEAM
FLOW
C   ELEC   : ELECTRICITY PRODUCTION IN KW
C   ENEX   : EXTRACTED SPECIFIC ENERGY FROM CONDENSING TURBINE
C   EX     : EXTRACTION FRACTION
C   ETAG   : GENERATOR EFFICIENCY
C   ETAI   : INTERNAL EFFICIENCY OF TURBINE
C   ETATUR : OVERALL EFFICIENCY
C   FREX   : EXTRACTION MASS FLOW RATE IN KG/S OR LB/HR
C   FROUT  : TURBINE OUTLET MASS FLOW RATE IN KG/S OR LB/HR
C   GEN    : IF GEN=0 : NO GENERATOR HOOKED UP TO TURBINE
C           IF GEN=1 : TURBINE/GENERATOR SYSTEM
C   GRAD   : GRADIENT FOR INTERPOLATION
C   H      : ENTHALPY IN KJ/KG
C   HOUTR  : TURBINE OUTLET ENTHALPY OF STEAM IN KJ/KG
C   IN     : INLET
C   K      : COUNTER FOR ERRORS
C   MODE   : 1: THERMODYNAMIC CALCULATION
C           : 2: MANUFACTURERES PERFORMANCE CURVES
C           : 3: REGRESSION FORMULAS
C   OUT    : OUTLET
C   PCOR   : CONVERSION FROM KW TO HORSE POWER
C   PELMAX : MAXIMUM ELECTRICITY PRODUCTION CAPACITY IN KW
C   PELMIN : MINIMUM ELECTRICITY PRODUCTION IN KW
C   PEX    : EXTRACTION PRESSURE IN MPA OR PSIA
C   PIN    : STEAM INLET PRESSURE IN MPA OR PSIA
C   PIPE   : IF PIPE=0 : POUT AS PARAMETER
C           IF PIPE=1 : POUT AS INPUT SINCE CALCULATED ELSEWHERE
C   POUT   : STEAM OUTLET PRESSURE IN MPA OR PSIA
C   QCOND  : HEAT TRANSFER IN CONDENSER IN KW OR BTU/HR

```



```

C    RATEX  : RATIO OF STEAM EXTRACTION TO TURBINE INLET STEAM MASS
FLOW
C    REL    : RATIO OF ELECTRICITY PRODUCTION TO MAX. ELEC. PROD.
C    S      : ENTROPY IN KJ/KGK
C    STA    : STARTING VALUE FOR ITERATIVE SOLUTION
C    STCSPT : STEAM CONSUMPTION IN KG/S OR LB/HR
C    STPL   : CORRECTION FACTOR FOR PART LOAD OPERATION
C    STSOLL : STEAM FLOW RATE AS INPUT IN CALC=2
C    TA     : AMBIENT TEMPERATURE IN C OR F
C    TCON   : TEMPERATURE DROP IN CONDENSER IN C OR F
C    TIN    : STEAM INLET TEMPERATURE IN C OR F
C    TURB 1 : BACKPRESSURE STEAM TURBINE
C    TURB 2 : CONDENSING STEAM TURBINE
C    UNITS  : IF UNITS=1 : IN/OUT IN SI UNITS
C            IF UNITS=0 : IN/OUT IN BRITISH UNITS AND CONVERTED FOR
CALC.
C*****
*

      DIMENSION A(9),B(9),D(6),PEL(50),STCON(10),EX(5),PELAC(10)
      DIMENSION HEX1(6),PEX1(6),FREX1(6),RATEX1(6)
      DIMENSION XIN(9),PAR(71),OUT(14),INFO(10)

C**** COEFFICIENTS FOR TURBINE EFFICIENCY CALCULATIONS
      DATA (A(I),I=1,9) /.68357,.021429,-.02357,.75,.003086,.10449,.831,
1      0.,0./
      DATA (B(I),I=1,9) /.85695,.023,-.005925,1.01477,-.0008385,-.26383,
1      .988,0.,0./

C**** COEFFICIENTS FOR PART LOAD OPERATION
      DATA (D(I),I=1,6) /.07,-.12,.05,.14,-.2,.06/
      IF (INFO(7).GE.0) GO TO 1

C**** FIRST CALL OF SIMULATION
      INFO(6)=15
      INFO(9)=0
1      MODE=PAR(1)
      TURB=PAR(2)
      UNITS=PAR(3)
      CALC = PAR(4)
      IF (MODE.LT.1.OR.MODE.GT.3.OR.TURB.LT.1.OR.TURB.GT.2) THEN
      CALL TYPECK(4,INFO,0,0,0)
      RETURN
      END IF

C*****
C**** SET INPUTS AND PARAMETERS
C*****
      IF (CALC.EQ.1.) THEN

```

```

      ELEC=XIN(1)
      IF (ELEC.LT.0.) THEN
        WRITE(6,885) TIME, INFO(1), INFO(2)
885  FORMAT(T2,'***** WARNING *****',/,
      +T2,' TIME : ',E12.5,' UNIT : ',I3,' TYPE : ',I3,/,
      +' DESIRED POWER PRODUCTION LOWER THAN 0.! CHECK!',/)
      STOP
      END IF

      IF (ELEC.EQ.0.) GOTO 890
      END IF

      IF (CALC.EQ.2.) THEN
        STSOLL=XIN(1)
        IF (STSOLL.EQ.0.) GOTO 890
        END IF

11  IF (MODE.EQ.2) GO TO 20
    IF (MODE.EQ.3) GO TO 30

C*****
C*****
C***** THERMODYNAMIC CALCULATION
C*****
C*****
      TIN=PAR(5)
      PIN=PAR(6)
      POUT=PAR(7)
      PELMAX=PAR(8)

C**** STARTING VALUE FOR CALC=2
      IF (CALC.EQ.2) THEN
        IF (ELEC.LE.0..OR.ELEC.GT.PELMAX) ELEC=PELMAX/2.
        END IF

        PELMIN=PAR(9)
        GENER=PAR(10)
        PIPE=PAR(11)

        IF (TURB.EQ.2.) THEN
          TCON=PAR(7)
          GENER=PAR(10)
          NPEX=PAR(11)
          DO 14 I=1,NPEX
            PEX1(I)=PAR(11+I)

C**** CHECK OF EXTRACTION PRESSURE SPECIFICATIONS
          IF (PEX1(I).GT.PIN) THEN
            WRITE(6,8) TIME, INFO(1), INFO(2)
8  FORMAT(T2,'***** WARNING *****',/,

```

```

+T2,' TIME : ',E12.5,' UNIT : ',I3,' TYPE : ',I3,/,
+ ' !!! EXTRACTION PRESSURE GREATER THAN',/
+ '          TURBINE INLET PRESSURE          !!!',//)
PEX=PIN
END IF

RATEX1(I)=XIN(2+I)
14 CONTINUE
TA=XIN(2)
END IF

C***** UNIT CONVERSION
IF(UNITS.EQ.0.) THEN
IF(CALC.EQ.2) STSOLL=STSOLL/3600*0.454
TIN=(TIN-32)/1.8
PIN=PIN*0.00689
POUT=POUT*0.00689
IF(TURB.EQ.2.) THEN
TCON=TCON/1.8
DO 15 I=1,NPEX
PEX1(I)=PEX1(I)*0.00689
IF(PEX1(I).GT.PIN) THEN
WRITE(6,8) TIME, INFO(1), INFO(2)
PEX1(I)=PIN
END IF
15 CONTINUE
TA=(TA-32)/1.8
END IF
END IF

C***** IF PIPE HOOKED UP TO TURBINE
IF(TURB.EQ.1..AND.PIPE.EQ.1.) THEN
POUT=XIN(2)
IF(UNITS.EQ.0.) POUT=POUT*0.00689
END IF

C***** STARTVALUE FOR "POWER OUT OF RANGE" ERROR COUNTER
K=0.

13 IF(MODE.EQ.2) GO TO 20
IF(MODE.EQ.3) GO TO 30

C***** CHECK OF ELECTRICITY PRODUCTION RANGE
IF(ELEC.GT.PELMAX.OR.ELEC.LT.PELMIN) THEN
WRITE(6,9) TIME, INFO(1), INFO(2)
9 FORMAT(/,T2,'***** WARNING *****',/,
+T2,' TIME : ',E12.5,' UNIT : ',I3,' TYPE : ',I3,/,
+ ' !!! POWER PRODUCTION OUT OF RANGE !!!')

```

```

IF (ELEC.GT.PELMAX) THEN
ELEC=PELMAX
WRITE (6,*) 'ELEC. PROD. HIGHER THAN PELMAX : ELEC SET TO PELMAX!'
END IF

IF (ELEC.LT.PELMIN) THEN
ELEC=PELMIN
WRITE (6,*) 'ELEC. PROD. LOWER THAN PELMIN : ELEC SET TO PELMIN!'
END IF

K=K+1
IF (K.GT.100) STOP
END IF

C*****
C**** ESTIMATION OF TURBINE AND GENERATOR EFFICIENCY AS A FUNCTION OF
C**** TURBINE SIZE
C*****

2 PCOR=PELMAX/736.
N=0
IF (PELMAX.GT.3680..AND.PELMAX.LE.18400.) N=3
IF (PELMAX.GT.18400.) N=6
ETAI=A(1+N)+A(2+N)*PCOR+A(3+N)/PCOR
ETAG=B(1+N)+B(2+N)*PCOR+B(3+N)/PCOR
IF ((TURB.EQ.1..AND. GENER.EQ.0.) ! IF NO
GENERATOR
+ .OR. (TURB.EQ.2 .AND. GENER.EQ.0.)) ETAG=1.0

C*****
C**** INCREASE OF SPECIFIC STEAM CONSUMPTION DUE TO PART LOAD OPERATION
C*****
REL=ELEC/PELMAX
IF (ELEC.EQ.0.) GOTO 3
J=0
IF (TURB.NE.2.) J=3
STPL=D(1+J)+D(2+J)*REL+D(3+J)/REL
GO TO 4
3 STPL=0.
ELEC=0.
4 CALL STEAM ('SI', TIN, PIN, HIN, SIN, QIN, VIN, UIN, 12)
IF (TURB.EQ.2.) GO TO 5

C*****
C**** BACKPRESSURE STEAM TURBINE
C*****
SOUT=SIN
CALL STEAM ('SI', TOUT, POUT, HOUT, SOUT, QOUT, VOUT, UOUT, 24)
STCSPT=(1.+STPL)*ELEC/(ETAG*ETAI*(HIN-HOUT))
FREX=0.

```

```

      FROUT=STCSPT
      ETATUR=ELEC/ (STCSPT* (HIN-HOUT))

C**** CALCULATION OF STEAM OUTLET TEMPERATURE
      HOACT=(HIN - ELEC/STCSPT)
      CALL STEAM ('SI',TOACT,POUT,HOACT,SOACT,QOACT,VOACT,UOACT,23)
      GO TO 40

C*****
C**** CONDENSING STEAM TURBINE
C*****
      5 SEX=SIN
        DO 16 I=1,NPEX
          IF (PEX1(I).GT.0.) THEN
            CALL STEAM ('SI',TEX,PEX1(I),HEX1(I),SEX,QEX,VEX,UEX,24)
          END IF
16      CONTINUE

        TOUT=TA+TCON
        IF (TOUT.LE.10.) TOUT=10.
        SOUT=SIN
        CALL STEAM ('SI',TOUT,POUT,HOUT,SOUT,QOUT,VOUT,UOUT,14)
        CALL STEAM ('SI',TOUT,POUT1,HFWP,SFWP,0.,VFWP,UFWP,15)

        ENEX=0
        DO 17 I=1,NPEX
          ENEX=ENEX + RATEX1(I)*(HEX1(I)-HOUT)
17      CONTINUE

        STCSPT=(1.+STPL)*ELEC/ (ETAG*ETAI* ((HIN-HOUT)-ENEX))

        FREX=0.
        DO 18 I=1,NPEX
          FREX1(I)=RATEX1(I)*STCSPT
          FREX = FREX+FREX1(I)
18      CONTINUE
        FROUT=STCSPT-FREX
        HOUTR=HIN-ELEC/STCSPT
        QCOND=FROUT*(HOUTR-HFWP)
        ETATUR=ELEC/ (STCSPT* (HIN-HOUT))

C**** CALCULATION OF CONDENSER PRESSURE
      CALL STEAM ('SI',TOUT,PCON,HOUT,SOUT,1.,VOUT,UOUT,15)
      GO TO 40

C*****
C*****
C**** CALCULATION OF TURBINE PERFORMANCE FROM MANUFACTURERES

```

```

C**** PERFORMANCE CURVES
C*****
C*****

C**** SET PARAMETERS AND INPUTS
  20 N=PAR(5)
     M=PAR(6)

C**** CHECK OF NUMBER OF DATA POINTS
      IF (M.LE.5.AND.N.LE.10) GO TO 21
      WRITE(6,19) TIME, INFO(1), INFO(2)
  19 FORMAT(T2,'***** WARNING *****',/,
    +T2,' TIME : ',E12.5,' UNIT : ',I3,' TYPE : ',I3,/,
    + ' !!! TOO MANY PERFORMANCE VALUES !!!',/)
      CALL TYPECK(4,INFO,0,0,0)
      RETURN

  21 DO 22 I=1,M
  22 EX(I)=PAR(6+I)
     N1=M*N
     DO 23 I=1,N
  23 STCON(I)=PAR(6+M+I)
     DO 24 I=1,N1
  24 PEL(I)=PAR(6+N+M+I)
     PELMAX=PEL(N)

C**** CHECK OF ELECTRICITY PRODUCTION RANGE
      IF (ELEC.GT.PELMAX.OR.ELEC.LT.PELMIN) THEN
        WRITE(6,93) TIME, INFO(1), INFO(2)
  93 FORMAT(T2,'***** WARNING *****',/,
    +T2,' TIME : ',E12.5,' UNIT : ',I3,' TYPE : ',I3,/,
    + ' !!! ELECTRICITY PRODUCTION OUT OF RANGE (MODE 2) !',/)
        IF (ELEC.GT.PELMAX) THEN
          ELEC=PELMAX
          WRITE(6,*) 'ELEC. PROD. HIGHER THAN PELMAX : ELEC SET TO PELMAX!'
        END IF

        IF (ELEC.LT.PELMIN) THEN
          ELEC=PELMIN
          WRITE(6,*) 'ELEC. PROD. LOWER THAN PELMIN : ELEC SET TO PELMIN!'
        END IF
        K=K+1
        IF (K.GT.100) STOP
      END IF

C**** STARTING VALUE FOR STEP REDUCTION (SEE BELOW)
      IF (CALC.EQ.2) THEN
        IF (ELEC.LE.0..OR.ELEC.GT.PELMAX) ELEC=PELMAX/2.
      END IF

```

```

C**** CHECK EXTRACTION DATA
      IF (RATEX.GT.0.AND.M.EQ.1) THEN
        WRITE(6,25) TIME, INFO(1), INFO(2)
25  FORMAT(T2,'***** WARNING *****',/,
      +T2,' TIME : ',E12.5,' UNIT : ',I3,' TYPE : ',I3,/,
      + ' !!! NO EXTRACTION POSSIBLE !',//)
        CALL TYPECK(4,INFO,0,0,0)
        RETURN
      END IF

      IF (RATEX.GT.0.) GO TO 26

C*****
C**** INTERPOLATIVE CALCULATION OF STEAM CONSUMPTION WITHOUT EXTRACTION
C*****
      IF (ELEC.LE.PEL(1)) THEN
        ELEC=PEL(1)
        STCSPT=STCON(1)
        GO TO 41
      END IF

      IF (ELEC.GT.PEL(N)) ELEC=PEL(N)
      I=1
28  IF (ELEC.GT.PEL(I)) GO TO 27
      GRAD=(STCON(I)-STCON(I-1))/(PEL(I)-PEL(I-1))
      YB=STCON(I)-PEL(I)*GRAD
      STCSPT=ELEC*GRAD+YB
      GO TO 41
27  I=I+1
      GO TO 28

C*****
C**** INTERPOLATIVE CALCULATION OF STEAM CONSUMPTION WITH EXTRACTION
C*****

C**** CHECK OF MAGNITUDE OF EXTRACTION MASS FLOW RATE
26  IF (RATEX.GT.EX(M)) THEN
      WRITE(6,50) TIME, INFO(1), INFO(2)
50  FORMAT(T2,'***** WARNING *****',/,
      +T2,' TIME : ',E12.5,' UNIT : ',I3,' TYPE : ',I3,/,
      + ' ! EXTRACTION RATE HIGHER THAN A VALID PERFORMANCE CURVE !!',//)
      RATEX=EX(M)
      END IF

      J=1
292 IF (RATEX.GT.EX(J)) GO TO 29
      GRAD=(RATEX-EX(J-1))/(EX(J)-EX(J-1))
      DO 290 I=1,N
290  PELAC(I)=(PEL((J-1)*N+I)-PEL((J-2)*N+I))*GRAD+PEL((J-2)*N+I)
      GO TO 291

```

```

29 J=J+1
   GO TO 292
291 IF (ELEC.LE.PELAC(1)) THEN
   ELEC=PELAC(1)
   STCSPT=STCON(1)
   GO TO 41
   END IF

   IF (ELEC.GT.PELAC(N)) ELEC=PELAC(N)
   I=1
294 IF (ELEC.GT.PELAC(I)) GO TO 293
   GRAD=(ELEC-PELAC(I-1))/(PELAC(I)-PELAC(I-1))
   STCSPT=(STCON(I)-STCON(I-1))*GRAD+STCON(I-1)
   GO TO 41
293 I=I+1
   GO TO 294
41 FREX=RATEX*STCSPT
   FROUT=STCSPT-FREX
   GO TO 40

C*****
C*****
C**** CALCULATION OF STEAM TURBINE CHARACTERISTICS BY REGRESSION
C**** FORMULA. (STEAM MASS FLOW RATE IS A FUNCTION OF ELECTRICITY
C**** PRODUCTION RATE, REVOLUTIONS AND EXTRACTION MASS FLOW RATE)
C****
C**** MODE HAS NOT BEEN USED YET!!!!
C****
C*****
C*****

C**** SET PARAMETERS AND INPUTS
30 RPM=PAR(5)
   PELMAX=PAR(6)

   IF (CALC.EQ.2) THEN
   IF (ELEC.LE.0..OR.ELEC.GT.PELMAX) ELEC=PELMAX/2.
   END IF

   PELMIN=PAR(7)
   A1=PAR(8)
   A2=PAR(9)
   A3=PAR(10)
   A4=PAR(11)
   A5=PAR(12)
   A6=PAR(13)
   A7=PAR(14)
   A8=PAR(15)

```



```

A9=PAR(16)
A10=PAR(17)

C**** CHECK OF ELECTRICITY PRODUCTION RANGE
  IF (ELEC.GT.PELMAX.OR.ELEC.LT.PELMIN) THEN
    WRITE(6,39) TIME, INFO(1), INFO(2)
39 FORMAT(T2,'***** WARNING *****',/,
+T2,' TIME : ',E12.5,' UNIT : ',I3,' TYPE : ',I3,/,
+' !!! ELECTRICITY PRODUCTION OUT OF RANGE (MODE 3) !',//)
    IF (ELEC.GT.PELMAX) ELEC=PELMAX
    IF (ELEC.LT.PELMIN) ELEC=PELMIN
    K=K+1
    IF (K.GT.100) STOP
  END IF

C**** BEGIN OF ITERATIVE SOLUTION
36 I=0
  STA=0.
32 FREX=STA*RATEX
  STCSPT=A1+A2*ELEC+A3*ELEC**2.+A4*RPM+A5*RPM**2.+A6*FREX+
1      A7*FREX**2.+A8*ELEC*RPM+A9*ELEC*FREX+A10*RPM*FREX
  IF (ABS(STCSPT-STA).LE..00001) GO TO 31
  STA=STCSPT
  I=I+1
  IF (I.GT.200) THEN
    WRITE(6,35) TIME, INFO(1), INFO(2)
35 FORMAT(T2,'***** WARNING *****',/,
+T2,' TIME : ',E12.5,' UNIT : ',I3,' TYPE : ',I3,/,
+' !!!! NO CONVERGENCE ACHIEVED !!!!',//)
    GO TO 31
  END IF

  GO TO 32
31 FROUT=STCSPT-FREX

C*****
C**** CHECK FOR TYPE OF CALCULATION
40 IF (CALC.EQ.1) GOTO 99

C*****
C*****
C**** STEP REDUCTION METHOD TO OBTAIN ELECTRICITY PRODUCTION FROM
C**** STEAM FLOW RATE
C*****
C*****
  IF (STSOLL/STCSPT.LT..9) THEN
    ELEC=0.9*ELEC
  END IF
  IF (STSOLL/STCSPT.GT.1.1) THEN

```

```

ELEC=1.1*ELEC
END IF
IF (STSOLL/STCSPT.LT.0.99) THEN
ELEC=.99*ELEC
END IF
IF (STSOLL/STCSPT.GT.1.01) THEN
ELEC=1.01*ELEC
END IF
IF (STSOLL/STCSPT.LT..999) THEN
ELEC=.999*ELEC
END IF
IF (STSOLL/STCSPT.GT.1.001) THEN
ELEC=1.001*ELEC
END IF

C**** IN CASE OF LOW STEAM MASS FLOW RATE
      IF (ELEC.LT.PELMAX/10000.) THEN
        WRITE(6,98) TIME, INFO(1), INFO(2), STSOLL
98      FORMAT(T2,'***** WARNING *****',/,
+T2,' TIME : ',E12.5,' UNIT : ',I3,' TYPE : ',I3,/,
+' STEAM MASS FLOW RATE OF ',G,'KG/SEC NOT SUFFICIENT',/
+', ' FOR POWER PRODUCTION! ALL OUTPUTS SET TO ZERO!',/)
        GOTO 890
      END IF

      IF (STSOLL/STCSPT.LT.0.999.OR.STSOLL/STCSPT.GT.1.001) GOTO 13

C*****
C**** SET OUTPUTS
C*****

99  IF (UNITS.EQ.1..OR.MODE.NE.1) THEN
      OUT(1)=ELEC
      OUT(2)=STCSPT
      OUT(3)=FROUT
      OUT(4)=FREX
      OUT(5)=STCSPT/ELEC*3600.
      IF (UNITS.EQ.0.) OUT(5)=OUT(5)/3600
      OUT(6)=ELEC/PELMAX
      IF (MODE.EQ.1) OUT(7)=ETATUR
      IF (MODE.EQ.1 .AND. TURB.EQ.1) OUT(8)=TOACT
      IF (MODE.EQ.1.AND.TURB.EQ.2.) THEN
          OUT(8)=QCOND
          OUT(9)=PCON
          DO 97 I=1,NPEX
              OUT(9+I)=FREX1(I)
97      CONTINUE
      END IF

```

```

ELSE

OUT(1)=ELEC
OUT(2)=STCSPT/0.454*3600
OUT(3)=FROUT/0.454*3600
OUT(4)=FREX/0.454*3600
OUT(5)=STCSPT/0.454/ELEC*3600.
OUT(6)=ELEC/PELMAX
IF (MODE.EQ.1) OUT(7)=ETATUR
IF (MODE.EQ.1 .AND. TURB.EQ.1) OUT(8)=TOACT*1.8+32
IF (MODE.EQ.1.AND.TURB.EQ.2.) THEN
    OUT(8)=PCON/0.0068
    OUT(9)=QCOND/1.055*3600
    DO 96 I=1,NPEX
        OUT(9+I)=FREX1(I)/0.454*3600
96    CONTINUE
    END IF
    END IF

C**** SET ALL OUTPUTS TO ZERO IF NO LOAD
890 IF (CALC.EQ.2.AND.STSOLL.EQ.0.OR.CALC.EQ.1.AND.ELEC.EQ.0) THEN
    DO 891 I=1,14
        OUT(I)=0.
891 CONTINUE
    END IF

999 RETURN
END

```

Feedwater Pump

TYPE 43

C**** VERSION:10/28/88

SUBROUTINE TYPE43 (TIME,XIN,OUT,T,DTDT,PAR,INFO)

```

C*****
*
C****
C**** THIS ROUTINE CALCULATES THE ELECTRICITY OR STEAM CONSUMPTION
C**** OF A FEED WATER PUMP WITH PROVISION OF MANUFACTURERES PERFORMANCE
C**** DATA
C****
C*****
*
C*****
*
C      NOMENCLATURE: (IN ALPHABETICAL ORDER)
C
C      CON      : 1=WATER AND 2=CONDENSATE PUMP
C      FR       : FLOWRATE IN KG/S OR LB/HR
C      MODE=1   : NOT EXISTANT ANY MORE
C      MODE=2   : MANUFACTURERS PERFORMANCE CURVES
C      MODE=3   : REGRESSION FORMULAS
C      PES      : 1=ELECTRICAL AND 2=STEAM DRIVEN PUMP
C      RES      : ELECTRICITY DEMAND IN KW OR STEAM DEMAND IN KG/S OR LB/HR
C*****
*

```

```

      DIMENSION XIN(2),PAR(25),OUT(2),INFO(10),FW(20),PELST(20)
      IF (INFO(7).GE.0) GO TO 1

```

```

C**** FIRST CALL OF SIMULATION
      INFO(6)=2
      INFO(9)=0

```

```

C**** SET PARAMETERS AND INPUTS
1      MODE=PAR(1)
      PES=PAR(2)
      CON=PAR(3)
      UNITS=PAR(4)
      IF (MODE.GE.1.AND.MODE.LE.3.AND.PES.GE.1.AND.PES.LE.2.
+.AND.(UNITS.EQ.0..OR.UNITS.EQ.1.)) GOTO 11
      CALL TYPECK(4,INFO,0,0,0)
      RETURN

11     IF (MODE.EQ.2) GO TO 30

```

```

C*****

```

```

*
C*****
*
C**** MANUFACTURERS PERFORMANCE CURVE (INTERPOLATION)
C*****
*
C*****
*

C**** SET INPUTS AND PARAMETERS
  20 N=PAR(5)
    FR=XIN(1)
    IF (FR.EQ.0.) GOTO 890

C**** CHECK ON NUMBER OF DATA POINTS
  IF (N.LE.20) GO TO 23
  WRITE (6,28) TIME, INFO(1), INFO(2)
  28 FORMAT(T2,'***** WARNING *****',/,
    +T2,' TIME : ',E12.5,' UNIT : ',I3,' TYPE : ',I3,/,
    + '!!! TOO MANY PERFORMANCE VALUES !!!',//)
  CALL TYPECK (4,INFO,0,0,0)
  RETURN

  23 DO 21 I=1,N
    FW(I)=PAR(5+I)
  21 PELST(I)=PAR(5+N+I)

C**** CHECK OF WORKING RANGE
  IF (FR.LT.FW(1).OR.FR.GT.FW(N)) THEN
    WRITE (6,29) TIME, INFO(1), INFO(2)
  29 FORMAT(T2,'***** WARNING *****',/,
    +T2,' TIME : ',E12.5,' UNIT : ',I3,' TYPE : ',I3,/,
    + ' ! FEED WATER MASS FLOW RATE OUT OF RANGE !',/,
    + ' WRONG VALUE SET AS MIN/MAX VALUE OF WORKING RANGE.',//)
  CALL TYPECK(2,INFO,0,0,0)
  RETURN
  END IF

  IF (FR.EQ.FW(1)) THEN
    RES=PELST(1)
    GO TO 40
  END IF
  I=1
  25 IF (FR.GT.FW(I)) GO TO 24
    GRAD=(FR-FW(I-1))/(FW(I)-FW(I-1))
    RES=PELST(I-1)+GRAD*(PELST(I)-PELST(I-1))
    GO TO 40
  24 I=I+1
    GO TO 25

```

```

C*****
C*****
C**** REGRESSION FORMULA
C*****
C*****

C**** SET INPUTS AND PARAMETERS
  30 FR=XIN(1)
    IF (FR.EQ.0.) GOTO 890
    A1=PAR(5)
    A2=PAR(6)
    A3=PAR(7)

C**** COMPUTATION
    RES=A1+A2*FR+A3*FR*FR

C*****
*
C*****
*
C**** SET OUTPUTS
C*****
*

  40  OUT(1)=FR
      OUT(2)=RES

  890 IF (FR.EQ.0.) THEN
      OUT(1)=0.
      OUT(2)=0.
      END IF

      RETURN
      END

```

Deaerator/Desuperheater**TYPE 44**

C**** VERSION:10/28/88

SUBROUTINE TYPE44 (TIME,XIN,OUT,T,DTDT,PAR,INFO)

```

C*****
*
C
C   THIS ROUTINE CALCULATES
C   IN MODE 1: THE WATER AND STEAM DEMAND OF A DESUPERHEATER TO OBTAIN
C               A CERTAIN OUTLET TEMPERATURE AND STEAM MASS FLOW RATE
C   IN MODE 2: THE WATER AND LOW PRESSURE STEAM REQUIREMENTS
C               OF A COMBINATION OF FEED WATER CONTAINER, DEAERATOR
C               AND WATER TREATMENT PLANT
C
C*****
*
C*****
*
C   NOMENCLATURE : (IN ALPHABETICAL ORDER)
C
C   FRC   : IMAGINARY FLOWRATE IN CASE OF HIGH CONDENSATE RETURN
C   FRCON1: FLOW RATE OF CONDENSATE RETURN 1 IN KG/S OR LB/HR
C   FRCON2: FLOW RATE OF CONDENSATE RETURN 2 IN KG/S OR LB/HR
C   FRFW   : FLOW RATE OF FEEDWATER IN KG/S OR LB/HR
C   FRLOSS: FLOW RATE OF WATER LOSS IN KG/S OR LB/HR
C   FROUT  : OUTLET FLOW RATE OF DESUPERHEATER IN KG/S OR LB/HR
C   FRAW   : FLOW RATE OF RAW WATER IN KG/S OR LB/HR
C   FRST   : STEAM FLOW RATE IN KG/S OR LB/HR
C   FRWTR  : FLOW RATE OF TREATED WATER IN KG/S OR LB/HR
C   H...   : ENTHALPY
C   LOSS   : WATER LOSS DURING WATER TREATMENT IN %
C   MODE   : MODE 1 : DESUPERHEATER
C           MODE 2 : DEAERATOR, FW CONTAINER
C   PCOND1: PRESSURE OF CONDENSATE RETURN 1 IN MPA OR PSIA
C   PCOND2: PRESSURE OF CONDENSATE RETURN 2 IN MPA OR PSIA
C   PFW    : PRESSURE OF FEED WATER IN MPA OR PSIA
C   POUT   : PRESSURE OF STEAM LEAVING DESUPERHEATER IN MPA OR PSIA
C   PST    : STEAM INLET PRESSURE IN MPA OR PSIA
C   PWTR   : PRESSURE OF TREATED WATER IN MPA OR PSIA
C   TA     : AMBIENT TEMPERATURE IN C OR F
C   TFW    : TEMPERATURE OF FEED WATER IN C OR F
C   TCOND1: TEMPERATURE OF CONDENSATE RETURN 1 IN C OR F
C   TCOND2: TEMPERATURE OF CONDENSATE RETURN 2 IN C OR F
C   TOUT   : TEMPERATURE OF STEAM LEAVING DESUPERHEATER IN C OR F
C   TST    : STEAM INLET TEMPERATURE IN C OR F
C   TWTR1  : TEMPERATURE OF TREATED WATER ABOVE AMBIENT TEMP. IN C OR F
C*****
*

```

REAL LOSS

```

      DIMENSION XIN(4),PAR(13),OUT(5),INFO(10)

C**** SET INFO
      INFO(6)=5
      INFO(9)=0

C*****
**
C**** SET PARAMETERS AND INPUTS
C*****
**
      MODE = PAR(1)
      UNITS = PAR(2)
      TST = PAR(3)
      PST = PAR(4)
      TCON1 = PAR(5)
      PCON1 = PAR(6)

      IF (MODE.EQ.1) THEN
      TOUT = PAR(7)
      POUT = PAR(8)
      FROUT = XIN(1)
      GOTO 5
      END IF

      TCON2 = PAR(7)
      PCON2 = PAR(8)
      TWTR = PAR(9)
      PWTR = PAR(10)
      TFW = PAR(11)
      PFW = PAR(12)
      LOSS = PAR(13)

      FRFW = XIN(1)
      FRCON1= XIN(2)
      FRCON2= XIN(3)
      TA = XIN(4)

C*****
*
C**** MODE = 1 : DESUPERHEATER CALCULATIONS
C*****
*
      5 IF (MODE.EQ.1) THEN

C**** ENTHALPY CALCULATIONS
      IF (UNITS.EQ.1) THEN
      CALL STEAM ('SI',TST,PST,HST,SST,QST,VST,UST,12)
      CALL STEAM ('SI',TCON1,PCON1,HCON1,SCON1,QCON1,VCON1,UCON1,12)
      CALL STEAM ('SI',TOUT,POUT,HOUT,SOUT,QOUT,VOUT,UOUT,12)

```

```

ELSE
CALL STEAM ('EN', TST, PST, HST, SST, QST, VST, UST, 12)
CALL STEAM ('EN', TCON1, PCON1, HCON1, SCON1, QCON1, VCON1, UCON1, 12)
CALL STEAM ('EN', TOUT, POUT, HOUT, SOUT, QOUT, VOUT, UOUT, 12)
END IF

C**** MASS AND ENERGY BALANCES
FRCON1 = (FROUT/HCON1*(HOUT-HST))/(1-HST/HCON1)
FRST = FROUT - FRCON1

GOTO 1
END IF

C*****
*
C**** MODE=2 : DEAERATOR/FEED WATER CONTAINER
C*****
*
IF (UNITS.EQ.1) THEN
IF (TCON1.LE.10.) TCON1=10.
IF (TCON2.LE.10.) TCON2=10.
IF (TWTR.LE.10.) TWTR=10.

C**** ENTHALPY CALCULATIONS IN SI UNITS
CALL STEAM ('SI', TST, PST, HST, SST, QST, VST, UST, 12)
CALL STEAM ('SI', TCON1, PCON1, HCON1, SCON1, QCON1, VCON1, UCON1, 12)
CALL STEAM ('SI', TCON2, PCON2, HCON2, SCON2, QCON2, VCON2, UCON2, 12)
CALL STEAM ('SI', TWTR, PWTR, HWTR, SWTR, QWTR, VWTR, UWTR, 12)
CALL STEAM ('SI', TFW, PFW, HFW, SFW, QFW, VFW, UFW, 12)

ELSE

IF (TCON1.LE.50.) TCON1=50.
IF (TCON2.LE.50.) TCON2=50.
IF (TWTR.LE.50.) TWTR=50.

C**** ENTHALPY CALCULATIONS IN BRITISH UNITS
CALL STEAM ('EN', TST, PST, HST, SST, QST, VST, UST, 12)
CALL STEAM ('EN', TCON1, PCON1, HCON1, SCON1, QCON1, VCON1, UCON1, 12)
CALL STEAM ('EN', TCON2, PCON2, HCON2, SCON2, QCON2, VCON2, UCON2, 12)
CALL STEAM ('EN', TWTR, PWTR, HWTR, SWTR, QWTR, VWTR, UWTR, 12)
CALL STEAM ('EN', TFW, PFW, HFW, SFW, QFW, VFW, UFW, 12)
END IF

C**** MASS AND ENERGY BALANCES
C FRWTR=(FRFW*(HFW-HST)-FRCON1*(HCON1-HST)-FRCON2*(HCON2-HST))
C 1/(HWTR-HST)
C FRST=FRFW-FRCON1-FRCON2-FRWTR
C FRST=(FRFW*HFW-FRCON1*HCON1-FRCON2*HCON2-(FRFW-FRCON1-FRCON2)*

```

```

      *HWTR) / (HST-HWTR)
      FRWTR=FRFW - FRCON1-FRCON2-FRST

C**** WATER LOSS DURING WATER TREATMENT
      FRRAW=FRWTR/(1.-LOSS/100.)
      FRLOSS=FRRAW-FRWTR
      IF (FRWTR.GE.0.) GOTO 1

C*****
****
C      CORRECTION IN CASE OF HIGH CONDENSATE RETURN: WATERLOSS IS
CALCULATED
C      SO THAT SUFFICIENT STEAM CAN BE ADDED TO REALIZE DESIRED FW
CONDITIONS;
C      WATER LOSS CONSISTS OF CONDENSATE RETURN WITH LOWER ENTHALPY IF
TWO
C      CONDENSATE STREAMS ARE PRESENT.
C      NO WATER TREATMENT OF RAW WATER NECESSARY.
C      ONLY ONE CONDENSATE STREAM
C*****
****

      IF (FRCON1.EQ.0.) THEN
        HCOND=HCON2
        FRCOND=FRCON2
      END IF
      IF (FRCON2.EQ.0.) THEN
        HCOND=HCON1
        FRCOND=FRCON1
      END IF

      IF (FRWTR.LT.0..AND.FRCON1.EQ.0..OR.FRWTR.LT.0..AND.FRCON2.EQ.0.)
+ THEN
        FRC=FRFW*(HFW-HST)/(HCOND-HST)
        FRST=FRFW-FRC
        FRLOSS=FRCOND-FRC
        FRWTR=0.
        FRRAW=0.
        GO TO 1
      END IF

C**** IN CASE OF TWO CONDENSATE STREAMS
      IF (HCON1.GE.HCON2.AND.FRWTR.LT.0.) THEN
        FRC=(FRFW*(HFW-HST)-FRCON1*(HCON1-HST))/(HCON2-HST)
      IF (FRC.LE.FRCON2) THEN
        FRST=FRFW-FRCON1-FRC
        FRLOSS=FRCON2-FRC
        FRWTR=0.
        FRRAW=0.
        GO TO 1

```

```

END IF
FRC=(FREW*(HFW-HST)-FRCON2*(HCON2-HST))/(HCON1-HST)
FRST=FREW-FRCON2-FRC
FRLOSS=FRCON1-FRC
FRWTR=0.
FRRAW=0.
GO TO 1
END IF

```

```

IF (HCON1.LT.HCON2.AND.FRWTR.LT.0.) THEN
FRC=(FREW*(HFW-HST)-FRCON2*(HCON2-HST))/(HCON1-HST)
IF (FRC.LE.FRCON1) THEN
  FRST=FREW-FRCON2-FRC
  FRLOSS=FRCON1-FRC
  FRWTR=0.
  FRRAW=0.
  GO TO 1
END IF
FRC=(FREW*(HFW-HST)-FRCON1*(HCON1-HST))/(HCON2-HST)
FRST=FREW-FRCON1-FRC
FRLOSS=FRCON2-FRC
FRWTR=0.
FRRAW=0.
GO TO 1
END IF

```

```

C*****
**
C**** SET OUTPUTS
C*****
**

```

```

1 IF (MODE.EQ.1) THEN
  OUT(1)=FRST
  OUT(2)=FRCON1
  GOTO 999
END IF

```

```

  OUT(1)=FREW
  OUT(2)=FRWTR
  OUT(3)=FRST
  OUT(4)=FRRAW
  OUT(5)=FRLOSS

```

```

999 RETURN
END

```

Heat Exchanger**TYPE 66**

C**** VERSION:10/28/88

SUBROUTINE TYPE66 (TIME,XIN,OUT,T,DTDT,PAR,INFO)

```

C*****
C****
C**** THIS SUBROUTINE MODELS A HEAT EXCHANGER IN ORDER TO
C**** CALCULATE THE NECESSARY MASSFLOW TO ACHIEVE A CERTAIN
C**** CHANGE OF STATE OF THE SECOND FLUID
C****
C*****
C*****
C
C   NOMENCLATURE: (IN ORDER OF APPEARANCE)
C
C   MODE   : MODE=1 : WATER OR STEAM (NO PHASE CHANGE)
C            MODE=2 : STEAM CONDENSED
C            MODE=3 : STEAM EVAPORATED
C            MODE=4 : SPECIFY CP OF FIRST FLUID IF NO WATER
C            MODE=5 : CONDENSER/EVAPORATOR FOR WATER
C
C   UNIT   : 0=BU, 1=SI
C
C   CPF     : SPECIFIC HEAT OF SECOND FLUID
C
C   PEVAP   : PRESSURE AT WHICH WATER ON SECONDARY SIDE EVAPORATES
C
C   PRESS   : PRESSURE OF STEAM IN HX
C
C   TSTIN   : INLET TEMPERATURE OF STEAM
C
C   TSTOUT  : OUTLET TEMPERATURE OF STEAM
C
C   TFIN    : INLET TEMP. OF SECOND FLUID
C
C   TFOUT   : OUTLET TEMP. OF SECOND FLUID
C
C   MF      : MASSFLOWRATE OF SECOND FLUID
C
C   Q       : HEAT TRANSFER RATE
C
C   HIN     : INLET ENTHALPY OF STEAM
C
C   HOUT    : OUTLET ENTHALPY OF STEAM
C
C   MST     : MASSFLOW RATE OF STEAM
C*****

```

```

DIMENSION XIN(4),PAR(7),OUT(2),INFO(10)
REAL MF,MST

```

```

C*****
C**** SET PARAMETERS AND INPUTS
C*****

```

```

MODE   = PAR(1)
UNIT   = PAR(2)
CPF    = PAR(3)
IF(MODE.EQ.5) PEVAP=PAR(3)
PRESS  = PAR(4)
TSTIN  = PAR(5)
IF(MODE.EQ.1.OR.MODE.EQ.4) TSTOUT = PAR(6)

```

```

IF (MODE.EQ.4) CP = PAR(7)

TFIN = XIN(1)
TFOUT = XIN(2)
MF = XIN(3)

IF (MODE.NE.1.AND.MODE.NE.2.AND.MODE.NE.3.AND.MODE.NE.4) THEN
CALL TYPECK(4,INFO,0,0,0)
RETURN
END IF

C*****
C**** HEATING OR COOLING LOAD ON SECONDARY ('F')-SIDE: MODE 1-4
C*****

IF (MODE.LE.4) THEN
Q = CPF*MF*(TFOUT-TFIN)
END IF

C*****
C**** FOR EVAPORATION ON F-SIDE: MODE 5
C*****

IF (MODE.EQ.5) THEN

IF (UNITS.EQ.1) THEN
CALL STEAM('SI',TFIN,PEVAP,HFIN,SFIN,QFIN,VFIN,UFIN,12)
CALL STEAM('SI',TFOUT,PEVAP,HFOUT,SFOUT,QFOUT,VFOUT,UFOUT,12)

ELSE

CALL STEAM('EN',TFIN,PEVAP,HFIN,SFIN,QFIN,VFIN,UFIN,12)
CALL STEAM('EN',TFOUT,PEVAP,HFOUT,SFOUT,QFOUT,VFOUT,UFOUT,12)

END IF

Q=MF*(HFOUT-HFIN)
END IF

C*****
C**** CALCULATION OF STEAM/WATER MASSFLOW ON PRIMARY SIDE (ALL MODES)
C*****

IF (UNIT.EQ.1) THEN
CALL STEAM('SI',TSTIN,PRESS,HIN,SIN,QIN,VIN,UIIN,12)

IF (MODE.EQ.1) THEN
CALL STEAM('SI',TSTOUT,PRESS,HOUT,SOUT,QOUT,VOUT,UOUT,12)
ELSE IF (MODE.EQ.2 .OR. MODE.EQ.5) THEN
QOUT=0.

```



```

      CALL STEAM('SI',TSTOUT,PRESS,HOUT,SOUT,QOUT,VOUT,UOUT,25)
    ELSE IF (MODE.EQ.3) THEN
      QOUT=1.
      CALL STEAM('SI',TSTOUT,PRESS,HOUT,SOUT,QOUT,VOUT,UOUT,25)
    END IF

  ELSE

    CALL STEAM('EN',TSTIN,PRESS,HIN,SIN,QIN,VIN,WIN,12)

    IF (MODE.EQ.1) THEN
      CALL STEAM('EN',TSTOUT,PRESS,HOUT,SOUT,QOUT,VOUT,UOUT,12)
    ELSE IF (MODE.EQ.2 .OR. MODE.EQ.5) THEN
      QOUT=0.
      CALL STEAM('EN',TSTOUT,PRESS,HOUT,SOUT,QOUT,VOUT,UOUT,25)
    ELSE IF (MODE.EQ.3) THEN
      QOUT=1.
      CALL STEAM('EN',TSTOUT,PRESS,HOUT,SOUT,VOUT,UOUT,25)
    END IF

  END IF

  MST = Q/(HIN-HOUT)
  IF (MODE.EQ.4) MST = Q/(CP*(TSTIN-TSTOUT))

C*****
C**** SET OUTPUTS
C*****
  OUT(1)=MST
  OUT(2)=TSTOUT

  CONTINUE
END

```

Steam Pipe**TYPE 40**

C**** VERSION:10/28/88

SUBROUTINE TYPE40 (TIME,XIN,OUT,T,DTDT,PAR,INFO)

```

C*****
C****
C**** THIS SUBROUTINE CALCULATES THE HEAT LOSSES AND PRESSURE DROPS
C**** IN A STEAM PIPELINE
C****
C*****
C*****
C      NOMENCLATURE: (IN ALPHABETICAL ORDER)
C
C      ALPHA : THERMAL DIFFUSITIVY
C      CF      : FRICTION COEFFICIENT
C      CP      : SPECIFIC HEAT OF STEAM IN J/KG/K
C      DE      : OUTER DIAMETER OF PIPE IN M OR FT
C      DEMP    : PRESSURE DROP IN MPA OR PSI
C      DI      : INNER DIAMETER OF PIPE IN M OR FT
C      DINS    : OUTER DIAMETER OF INSULATION IN M OR FT
C      FAK     : FACTOR
C      HEXT    : EXTERIOR HEAT TRANSFER COEFF. IN W/M**2*K OR BTU/HR/FT^2/F
C      K       : THERMAL CONDUCTIVITY OF STEAM IN W/MK OR BTU/FT/F
C      KINS    : THERMAL      "      OF INSULATION IN W/MK OR BTU/FT/F
C      KP      : THERMAL CONDUCTIVITY OF PIPE IN W/MK OR BTU/FT/F
C      L       : LENGTH OF PIPE IN M OR FT
C      MDOT    : MASS FLOW RATE IN KG/S OR LB/HR
C      MU      : STEAM VISCOSITY IN PA*S
C      MVP     : MEAN VALUE OF PRESSURE IN PIPE
C      MVT     : MEAN VALUE OF TEMPERATURE IN PIPE
C      NU      : NUSSELT-NUMBER
C      PEN     : PECLET-NUMBER
C      PINP    : INPUT PRESSURE IN MPA OR PSIA
C      POUTP   : OUTPUT PRESSURE IN MPA OR PSIA
C      PRN     : PRANDTL-NUMBER
C      PRO     : PIPE ROUGHNESS IN MM OR INCH
C      QLOSS   : TOTAL HEAT LOSS IN W OR BTU/HR
C      RE      : REYNOLDSNUMBER
C      ROAV    : STEAM DENSITY IN KG/M**3
C      RTOT    : TOTAL THERMAL RESISTANCE IN W/K
C      TA      : AMBIENT TEMP. IN C OR F
C      TINP    : INPUT TEMP. IN C OR F
C      TOUTP   : OUTPUT TEMP. IN C OR F
C      UNITS   : 1: INPUT/OUTPUT IN SI UNITS
C              : 2: IN/OUT IN BRITISH UNITS
C      WST     : STEAM VELOCITY IN M/S
C
C*****
***

```

```

REAL NU,L,KP,KINS,MU,MDOT,MODE,K1,MU1,MVT,MVTCPH,MVTCPL,K,MVP
DIMENSION XIN(4),OUT(5),PAR(10),INFO(10),A(8),B(7)

C***** DATA FOR CORRELATIONS TO DETERMINE KP AND MU
DATA(A(I),I=1,8)/1.76E01,5.87E-02,1.04E-04,-4.51E-08,
+1.0351E02,4.198E-01,-2.771E-05,2.1482E14/
DATA(B(I),I=1,7)/4.07E-01,8.04E01,1.858E03,-5.90,
+3.53E02,6.765E02,1.021E02/
DATA PI /3.14159/

C*****
C***** SET PARAMETERS AND INPUTS
C***** MODE=1:INPUT PRESSURE AND TEMP. ARE INLET CONDITIONS
C***** MODE=2:INPUT PRESSURE AND TEMP. ARE DESIRED OUTLET COND.
C*****
MODE=PAR(1)
UNITS=PAR(2)
L =PAR(3)
DI =PAR(4)
DE =PAR(5)
DINS=PAR(6)
KP =PAR(7)
KINS=PAR(8)
HEXT=PAR(9)
PRO =PAR(10)

MDOT=XIN(1)
TINP=XIN(2)
PINP=XIN(3)
TA =XIN(4)

C***** UNIT CONVERSION
IF (UNITS.EQ.0.) THEN
L=L*0.3048
DI=DI*0.3048
DE=DE*0.3048
DINS=DINS*0.3048
KP=KP*0.57782
KINS=KINS*0.57782
HEXT=HEXT*0.17612
PRO=PRO*25.4
MDOT=MDOT/3600*0.454
TINP=(TINP-32)/1.8
PINP=PINP*0.00689
TA=(TA-32)/1.8
END IF

C***** CHECK RANGE OF PARAMETERS AND INPUTS

```

```

        IF (MODE.NE.1.AND.MODE.NE.2) GOTO 60
        IF (UNITS.NE.1.AND.UNITS.NE.0) GOTO 60
        GOTO 62
60      WRITE(6,61) TIME, INFO(1), INFO(2)
61      FORMAT(T2,'***** WARNING *****',/,
+T2,' TIME : ',E12.5,' UNIT : ',I3,' TYPE : ',I3,/,
+'CHECK RANGE OF PARAMTERS AND INPUTS !',//)

C**** SET INFO
62      INFO(6)=5.
        INFO(9)=0.

C**** INITIAL VALUES FOR ITERATION
        POUTP=PINP
        TOUTP=TINP

C*****
C**** PROPERTY CALCULATIONS
C*****

C**** CALCULATION OF SPECIFIC HEAT CP
        MVT=TINP
        MVP=PINP
        MVTCPH=MVT+10
        MVTCPH=MVT-10
        CALL STEAM('SI',MVTCPH,MVP,HST1,SST,QST,VSTAV,U,12)
        CALL STEAM('SI',MVTCPH,MVP,HST2,SST,QST,VSTAV,U,12)
        CP=(HST1-HST2)/20.*1000.

C**** DENSITY CALCULATION
        CALL STEAM('SI',MVT,MVP,HST,SST,QST,VSTAV,UST,12)
        ROAV=1./VSTAV

C**** CHECK
        IF (HST.LE.2107.) THEN
            WRITE(6,50) TIME, INFO(1), INFO(2)
50      FORMAT(T2,'***** WARNING *****',/,
+T2,' TIME : ',E12.5,' UNIT : ',I3,' TYPE : ',I3,/,
+' WARNING !!! STEAM CONDENSATION IN PIPE !!!',//)
            CALL TYPECK(2,INFO,0,0,0)
            END IF

C**** CALCULATION OF KP AND MU FROM CORRELATIONS
        K1=A(1)+A(2)*MVT+A(3)*MVT**2.+A(4)*MVT**3.
        K=(K1+(A(5)+A(6)*MVT+A(7)*MVT**2.)*ROAV/1000.+A(8)*
+ (ROAV/1000.))**2./MVT**(4.2))/1000.
        MU1=B(1)*MVT+B(2)
        IF (MVT.GT.300.) GOTO 3
        MU=(MU1-ROAV/1000.*(B(3)+B(4)*MVT))*1.E-07
        GOTO 4

```

```

3      MU=(MU1+B(5)*ROAV/1000.+B(6)*(ROAV/1000.)**2.+B(7)*
      *(ROAV/1000.)**3.)*1.E-07

```

```

C*****
C**** CALCULATION OF DIMENSIONLESS NUMBERS AND OTHER VALUES
C*****

```

```

4      RE=4.*MDOT/(PI*DI*MU)
      WST=4.*MDOT/(DI**2.*PI*ROAV)
      ALPHA=K/(CP*ROAV)
      PRN=MU/(ROAV*ALPHA)
      PEN=WST*DI/ALPHA

```

```

C*****
C*****
C**** CALCULATION OF HEATLOSSES
C*****
C*****

```

```

C**** CHECK: LAMINAR OR TURBULENT
      IF (RE.GT.2300.) GOTO 5

```

```

C**** CALC. OF NUSSELT NUMBER FROM EMPIRICAL CORRELATION

```

```

C**** LAMINAR FLOW
      NU=3.65+(0.0668*PEN*DI/L)/(1.+0.045*(PEN*DI/L)**(2./3.))
      GOTO 10

```

```

C**** TURBULENT FLOW
5      NU=0.024*RE**0.786*PRN**0.45*(1.+(DI/L)**(2./3.))

```

```

C**** HEATLOSS CALCULATIONS

```

```

10     HINT=NU*K/DI
      RTOT=1./(HINT*2.*PI*DI/2.*L)+ALOG(DE/DI)/(2.*PI*KP*L)+
      +ALOG(DINS/DE)/(2.*PI*KINS*L)+1./(HEXT*2.*PI*DINS/2*L)
      IF (MODE.EQ.1) FAK=-1.
      IF (MODE.EQ.2) FAK=1.
      TOUTP=TA+(TINP-TA)*EXP(FAK/(RTOT*MDOT*CP))
      QLOSS=MDOT*CP*(TINP-TOUTP)*(-FAK)

```

```

C*****
C*****
C**** DETERMINATION OF PRESSURE DROP
C*****
C*****
      IF (RE.LE.2300.) THEN
        CF=16./RE
      ELSE

```

```

      IF (RE.LE. (DI*1000/PRO*LOG10 (0.1*DI*1000/PRO))) THEN

C*****
C**** CALCULATION OF FRICTION COEFFICIENTS FROM EMPIRICAL CORRELATIONS
C*****

C**** IN CASE OF SMOOTH PIPE
      CF=0.25*0.309/(LOG10 (RE/7.))**2.
      END IF
      IF (RE.GT. (DI*1000./PRO*LOG10 (0.1*DI*1000./PRO)).AND.RE.LT.
+ (400.*DI*1000./PRO*LOG10 (3715*DI/PRO))) THEN

C**** TRANSITION ZONE
      CF=0.25*0.0055*(1.+(2.*10.*PRO/DI+10.**6./RE)**(1./3.))
      END IF
      IF (RE.GE. (400.*DI*1000./PRO*LOG10 (3715*DI/PRO))) THEN

C**** ROUGH PIPE
      CF=0.25/(2.*LOG10 (3715.*DI/PRO))**2.
      END IF
      END IF

C**** CALC. OF PRESSURE DROP
      IF (MODE.EQ.1) THEN
      IF ((4.*CF*L/DI*WST**2./PINP/10.**6.*ROAV).GE.1.) GOTO 30
      DELP=PINP*(1.-SQRT (1.-4.*CF*L/DI*WST**2./PINP/10.**6.*ROAV))
      POUTP=PINP-DELP
      ELSE
      POUTP=SQRT (PINP**2.+(2.*CF*ROAV*L/DI*WST**2./10.**6.)**2.)+
+      2.*CF*ROAV*L/DI*WST**2./10.**6.

      J=0
25  CALL STEAM ('SI',TOUTP,POUTP,HOUT,SOUT,QOUT,VO,UO,12)
      RO=1./VO
      WST=4.*MDOT/(DI**2*PI*RO)
      DELP=POUTP*(1.-SQRT (1.-4.*CF*L/DI*WST**2./POUTP/10.**6.*RO))
      PEXNEW=POUTP-DELP
      IF (J.GT.2000) GOTO 30
      IF (PEXNEW.LE.PINP) GOTO 28
      POUTP=POUTP-0.01
      J=J+1
      GOTO 25
28  DELP=POUTP-PINP
      END IF

C**** CHECK IF FLOW RATE POSSIBLE
      IF (POUTP.LE.0) THEN
30  WRITE (6,52) TIME, INFO(1), INFO(2)
52  FORMAT (T2,'***** WARNING *****',/,

```

```

+T2,' TIME : ',E12.5,' UNIT : ',I3,' TYPE : ',I3,/,
+ 'MASSFLOW*PIPEROUGHNESS/DIAMETER RATIO IS TOO HIGH ;',/
+,' OPERATION OF PIPE IMPOSSIBLE: CHOSE NEW VALUES !',//)
CALL TYPECK(2,INFO,0,0,0)
END IF

C**** CHECK IF CONDENSATION IN PIPE
CALL STEAM ('SI',TOUTP,POUTP,HOUT,SOUT,QOUT,VOUT,UOUT,12)
IF(HOUT.LE.2107.) THEN
WRITE(6,54) TIME, INFO(1), INFO(2)
54  FORMAT(T2,'***** WARNING *****',/,
+T2,' TIME : ',E12.5,' UNIT : ',I3,' TYPE : ',I3,/,
+ ' WARNING !!! STEAM CONDENSATION IN PIPE !!!',//)
CALL TYPECK(2,INFO,0,0,0)
END IF

C*****
C**** SET OUTPUT
C*****
40 IF (UNITS.EQ.1.) THEN
OUT(1)=MDOT
OUT(2)=TOUTP
OUT(3)=POUTP
OUT(4)=QLOSS
OUT(5)=DELP

ELSE

OUT(1)=MDOT*3600/0.454
OUT(2)=TOUTP*1.8+32
OUT(3)=POUTP/0.00689
OUT(4)=QLOSS*3.4123
OUT(5)=DELP/0.00689
END IF

RETURN
END

```

Efficiency Calculator**TYPE 55**

C***** VERSION:10/28/88

SUBROUTINE TYPE55 (TIME,XIN,OUT,T,DTDT,PAR,INFO)

C*****

C****

C**** THIS ROUTINE CALCULATES THE FIRST AND SECOND LAW
C**** AS WELL AS THE PURPA EFFICIENCY OF A COGENERATION
C**** PLANT WHICH SUPPLIES ELECTRICITY AND HEAT
C**** IN THE FORM OF STEAM OR HOT WATER.

C****

C*****

C*****

C

C NOMENCLATURE : IN ALPHABETICAL ORDER

C

C AVELEC : TOTAL AVAILABILITY OF ELECTRICITY BALANCE

C AVST : TOTAL AVAILABILITY OF STEAM/WATER FLOWS

C AVFUEL : TOTAL AVAILABILITY OF FUEL MASS FLOW

C CEL : COST OF ELECTRICITY IN \$/KWHR

C CST : COST OF STEAM (ONLY FIRST STEAM FLOW IN LIST)
C IN \$/LB OR \$/KG

C EL(I) : ELECTRICITY CONSUMPTION (-) OR PRODUCTION (+)

C ELT : TOTAL ELECTRICITY CONSUMPTION OR PRODUCTION

C EFF1 : FIRST LAW EFFICIENCY

C EFF2 : SECOND LAW EFFICIENCY

C EFFP : PURPA EFFICIENCY

C ENST : ENERGY OF STEAM

C LHV(I) : LOWER HEATING VALUE FOR FUEL I IN BTU/LB OR KJ/KG

C MST(I) : STEAM/WATER MASS FLOW RATE I OUT (+) OR IN (-)

C MSTOUT : MASS FLOW OF LEAVING STEAM

C MFUEL(I) : FUEL MASS FLOW RATE I

C NFUEL : NUMBER OF FUEL CONSUMERS

C NEL : NUMBER OF ELECTRICITY GENERATORS (+) OR CONSUMERS (-)

C NSTFL : NUMBER OF STEAM FLOWS OUT (+) OR IN (-)

C PREF : REFERENCE PRESSURE FOR STEAM/WATER AT DEAD STATE

C PST(I) : PRESSURE OF S/W MASS FLOW I

C TREF : REFERENCE TEMPERATURE FOR STEAM/WATER AT DEAD STATE

C TST(I) : TEMPERATURE OF S/W MASS FLOW I

C UNIT : 0 : BRITISH UNITS

C 1 : SI UNITS

C*****

DIMENSION XIN(30),PAR(39),OUT(9),INFO(10)

DIMENSION TST(10),PST(10),EL(10)

DIMENSION HST(5),SST(5),QST(5),UST(5),VST(5)

REAL MSTOUT,MST(10),LHV(10),MFUEL(10)

INFO(6)=9

```

C*****
C**** SET PARAMETERS
C*****
      UNIT = PAR(1)
      NFUEL = PAR(2)
      NEL = PAR(3)
      NSTFL = PAR(4)
      PREF = PAR(5)
      TREF = PAR(6)
      CEL = PAR(7)

      DO 5 I=1,NFUEL
      LHV(I) = PAR(7+I)
5      CONTINUE

      DO 10 I=1,NSTFL
      PST(I) = PAR(7+NFUEL+I)
10     CONTINUE

      DO 15 I=1,NSTFL
      TST(I) = PAR(7+NFUEL+NSTFL+I)
15     CONTINUE

C*****
C**** SET INPUTS
C*****
      DO 20 I=1,NFUEL
      MFUEL(I) = XIN(I)
20     CONTINUE

      ELT = 0.

      DO 25 I=1,NEL
      EL(I) = XIN(NFUEL+I)
      ELT = ELT+EL(I)
25     CONTINUE

      MSTOUT = 0.
      DO 35 I=1,NSTFL
      MST(I) = XIN(NFUEL+NEL+I)
      IF (MST(I).GT.0.) MSTOUT = MSTOUT + MST(I)
35     CONTINUE

C*****
C**** AVAILABILITY AND ENERGY CALCULATIONS

```

C*****

C**** TOTAL AVAILABILITY OF FUEL (ASSUMING AVFUEL=LHV!)

AVFUEL=0.

DO 50 I=1,NFUEL

AVFUEL = AVFUEL+MFUEL(I)*LHV(I)

50 CONTINUE

C**** TOTAL AVAILABILITY OF ELECTRICITY

AVELEC=ELT

IF (UNIT.EQ.0) AVELEC=AVELEC*3412.

IF (UNIT.EQ.1) AVELEC=AVELEC*3600.

C**** ENERGY CONTENT AND TOTAL AVAILABILITY OF HEAT

AVST = 0.

ENST = 0.

IF (UNIT.EQ.1.) THEN

CALL STEAM('SI',TREF,PREF,HREF,SREF,QREF,VREF,UREF,12)

DO 60 I=1,NSTFL

CALL STEAM('SI',TST(I),PST(I),HST(I),SST(I),

+ QST(I),VST(I),UST(I),12)

AVSTO=AVSTO+MST(I)

AVST=AVST+MST(I)*((HST(I)-HREF) - (TREF+273.15)*(SST(I)-SREF))

ENST=ENST+MST(I)*(HST(I)-HREF)

60 CONTINUE

ELSE

CALL STEAM('EN',TREF,PREF,HREF,SREF,QREF,VREF,UREF,12)

DO 61 I=1,NSTFL

CALL STEAM('EN',TST(I),PST(I),HST(I),SST(I),

+ QST(I),VST(I),UST(I),12)

AVST=AVST+MST(I)*((HST(I)-HREF) - (TREF+460)*(SST(I)-SREF))

ENST=ENST+MST(I)*(HST(I)-HREF)

61 CONTINUE

END IF

C**** IN ORDER TO AVOID ERROR IN CASE PLANT IS NOT OPERATING:

```

IF (AVFUEL.LE.0.) THEN
  EFF1=0.
  EFF2=0.
  EFFP=0.
  GOTO 99
END IF

```

```

C*****
C**** EFFICIENCY CALCUATIONS
C*****

```

```

C**** CALCULATION OF FIRST LAW EFFICIENCY
  EFF1 = (AVELEC+ENST)/AVFUEL

```

```

C**** CALCULATION OF PURPA EFFICIENCY
  EFFP = (AVELEC+0.5*ENST)/AVFUEL

```

```

C**** CALCULATION OF THE SECOND LAW EFFICIENCY

  EFF2 = (AVELEC+AVST)/AVFUEL

```

```

C*****
C**** CALCULATION OF COST OF STEAM (BASED ON ASSUMPTION THAT
C**** AVAILABILITY OF HEAT AND POWER HAVE SAME VALUE)
C**** ADD. ASSUMPTION: ALL OUTGOING STEAM FLOWS HAVE SAME AVAILABILITY
C*****

```

```

  IF (NSTFL.GT.0) THEN

```

```

    IF (UNIT.EQ.0.) THEN

```

```

      CALL STEAM('EN',TREF,PREF,HREF,SREF,QREF,VREF,UREF,12)

```

```

      CALL STEAM('EN',TST(1),PST(1),HST(1),SST(1),
+ QST(1),VST(1),UST(1),12)

```

```

      AVST1=HST(1)-HREF - (TREF+460)*(SST(1)-SREF)

```

```

      CST = CEL * AVST1/3412.

```

```

    END IF

```

```

    IF (UNIT.EQ.1.) THEN

```

```

      CALL STEAM('SI',TREF,PREF,HREF,SREF,QREF,VREF,UREF,12)

```

```

      CALL STEAM('SI',TST(1),PST(1),HST(1),SST(1),
+ QST(1),VST(1),UST(1),12)

```

```

      AVST1=(HST(1)-HREF) - (TREF+273)*(SST(1)-SREF)

```

```

      CST = CEL * AVST1/3600.

```

END IF

END IF

C*****

C**** OUTPUT

C*****

99 OUT (1) = EFF2
OUT (2) = AVFUEL
OUT (3) = AVELEC
OUT (4) = AVST
OUT (5) = ENST
OUT (6) = MSTOUT
OUT (7) = EFF1
OUT (8) = EFFP
OUT (9) = CST
RETURN
END

Operational Cost**Calculator**TYPE 46

C**** VERSION:10/28/88

SUBROUTINE TYPE46 (TIME,XIN,OUT,T,DTDT,PAR,INFO)

```

C*****
*
C****
C**** THIS ROUTINE COMPUTES THE OPERATIONAL COSTS OF A COGENERATION
PLANT
C**** IN $/HR
C****
C*****
*
C*****
*
C      NOMENCLATURE: (IN ALPHABETICAL ORDER)
C
C      CEX   : ELECTRICITY EXPORT COST IN $/HR ( NEGATIVE !! )
C      CIM   : ELECTRICITY IMPORT COST IN $/HR
C      CNG   : NATURAL GAS COST IN $/HR
C      CD    : DIESEL COST IN $/HR
C      CC    : COAL COST IN $/HR
C      CM    : MAINTENANCE COST IN $/HR
C      COAL  : COAL CONSUMPTION IN KG/SEC OR LB/HR BY INDIVIDUAL CONSUMER
C      COALS : OVERALL COAL CONSUMPTION IN KG/SEC OR LB/HR
C      CW    : WATER COST IN $/HR
C      CTOT  : OPERATIONAL COST IN $/HR
C      DNG   : SPECIFIC NATURAL GAS PRICE IN $/UNIT NAT. GAS
C      DD    : SPECIFIC DIESEL PRICE IN $/UNIT DIESEL FUEL
C      DC    : DIESEL CONSUMPTION IN KG/SEC OR LB/HR OF INDIVIDUAL
COMPONENT
C      DCS   : OVERALL DIESEL CONSUMPTION IN KG/SEC OR LB/HR
C      DCOAL : SPECIFIC COAL PRICE IN $/UNIT COAL
C      DELEX : ELECTRICITY EXPORT PRICE IN $/KWH
C      DELIM : ELECTRICITY IMPORT PRICE IN $/KWH
C      DMAIN : SPECIFIC MAINTENANCE COST IN $/HR
C      DWTR  : SPECIFIC RAW WATER TREATMENT PRICE IN $/KG OR $/LB
C      FRWTR : RAW WATER DEMAND IN KG/SEC OR LB/HR
C      NEGEN : NUMBER OF ELECTRICITY GENERATORS
C      NECON : NUMBER OF ELECTRICITY CONSUMERS
C      NG    : NUMBER OF NATURAL GAS CONSUMER
C      NGC   : NATURAL GAS CONSUMPTION IN KG/SEC OR LB/HR OF INDIVIDUAL
COMPONENT
C      NGCS  : OVERALL NATURAL GAS CONSUMPTION IN KG/SEC OR LB/HR
C      ND    : NUMBER OF DIESEL CONSUMER
C      NC    : NUMBER OF COAL CONSUMERS
C      PEL   : ELECTRICITY PRODUCTION OR CONSUMPTION (NEGATIVE!) IN KW
C      PELCT : TOTAL ELECTRICITY CONSUMPTION
C      PELGT : TOTAL ELECTRICITY GENERATION

```



```

C
C      (NOTE: IF SIMULATION TIMESTEP IS NOT 1 HR, REPLACE HR BY TIMESTEP)
C*****
*
      REAL NGC,NGCS
      DIMENSION PELCON(10),PELGEN(10),NGC(10),DC(10),COAL(10)
      DIMENSION XIN(45),PAR(11),OUT(8),INFO(10)

      INFO(6)=8
      INFO(9)=0

C*****
C**** SET PARAMETERS AND INPUTS
C*****

      UNITS=PAR(1)
      NEGEN=PAR(2)
      NECON=PAR(3)
      NG=PAR(4)
      ND=PAR(5)
      NC=PAR(6)
      DNG=PAR(7)
      DD=PAR(8)
      DCOAL=PAR(9)
      DMAIN=PAR(10)
      DWTR=PAR(11)

      DELEX=XIN(1)
      DELIM=XIN(2)
      FRWTR=XIN(3)

C**** INPUT ELECTRICITY GENERATION
      PELGT=0.
      DO 1 I=1,NEGEN
      PELGEN(I)=XIN(3+I)
1  PELGT=PELGT+PELGEN(I)
      IF(NEGEN.EQ.0.) PELGT=0.

C**** INPUT ELECTRICITY CONSUMPTION
      PELCT=0.
      DO 5 I=1,NECON
      PELCON(I)=XIN(3+NEGEN+I)
5  PELCT=PELCT+PELCON(I)
      IF(NECON.EQ.0.) PELCT=0.

C**** INPUT NATURAL GAS CONSUMPTION
      NGCS=0.
      DO 2 I=1,NG
      NGC(I)=XIN(3+NEGEN+NECON+I)

```

```

      2 NGCS=NGCS+NGC(I)
      IF (NG.EQ.0.) NGCS=0.

C**** INPUT DIESEL CONSUMPTION
      DCS=0.
      DO 3 I=1,ND
      DC(I)=XIN(3+NEGEN+NECON+NG+I)
      3 DCS=DCS+DC(I)
      IF (ND.EQ.0.) DCS=0.

C**** INPUT COAL CONSUMPTION
      COALS=0.
      DO 4 I=1,NC
      COAL(I)=XIN(3+NEGEN+NECON+NG+ND+I)
      4 COALS=COALS+COAL(I)
      IF (NC.EQ.0.) COALS=0.

C*****
C**** CALCULATION OF OPERATIONAL COSTS IN $/HR
C*****

C**** COSTS OF ELECTRICITY EXPORT
      CEX=(-1)*DELEX*PELGT

C**** COSTS OF ELECTRICITY IMPORT
      CIM=DELIM*PELCT

C**** NATURAL GAS
      CNG=NGCS*DNG*3600.
      IF (UNITS.EQ.0.) CNG=CNG/3600

C**** DIESEL
      CD=DCS*DD*3600.
      IF (UNITS.EQ.0.) CD=CD/3600

C**** COAL
      CC=COALS*DCOAL*3600.
      IF (UNITS.EQ.0.) CC=CC/3600

C**** LABOR AND MAINTENANCE
      CM=DMAIN

C**** WATER MAKE UP
      CW=DWTR*FRWTR*3600.
      IF (UNITS.EQ.0.) CW=CW/3600

C**** TOTAL COSTS
      CTOT=CEX+CIM+CNG+CD+CC+CM+CW

```

```
C*****  
C**** SET OUTPUTS  
C*****
```

```
OUT(1)=CEX  
OUT(2)=CIM  
OUT(3)=CNG  
OUT(4)=CD  
OUT(5)=CC  
OUT(6)=CM  
OUT(7)=CW  
OUT(8)=CTOT
```

```
RETURN  
END
```

Economic Analysis

TYPE 56

C**** VERSION:10/28/88

SUBROUTINE TYPE56 (TIME,XIN,OUT,T,DTDT,PAR,INFO)

```

C*****
C****
C**** THIS ROUTINE COMPARES THE ECONOMIC ATTRACTIVENESS OF TWO
C**** DIFFERENT PLANTS (BASE CASE:B VERSUS A:ALTERNATIVE) BY
C**** PERFORMING THE VARIOUS ECONOMIC ANALYSIS TECHNIQUES (SEE MODES)
C*****
C*****
C      NOMENCLATURE: (IN ALPHABETICAL ORDER)
C
C      A..      : OF ALTERNATIVE      (REPLACE '.' BY A OR B IN ALL
FOLLOWING
C      B..      : OF BASE CASE          VARIABLES AND PARAMETERS)
C
C      .CAPEX : CAPITAL EXPENDITURE AT BEGINNING OF FIRST PERIOD
C
C      .ELG   : ELECTRICITY GENERATION IN FIRST PERIOD IN KWH
C      .ELGP  : INCREASE IN ELECTR. GENERATION PER PERIOD IN %
C      .ELG$  : PRICE OF GENERATED ELECTRICITY IN $/KWH
C      .ELG$P : INCREASE OF PRICE FOR GEN. ELEC. IN % (EXCL. INFLATION)
C
C      .ELC   : ELECTRICITY CONSUMPTION IN FIRST PERIOD IN KWH
C      .ELCP  : INCREASE IN ELECTR. CONSUMPTION PER PERIOD IN %
C      .ELC$  : PRICE OF CONSUMED ELECTRICITY IN $/KWH
C      .ELC$P : INCREASE OF PRICE FOR CONS. ELEC. IN % (EXCL. INFLATION)
C
C      .ELCOST: PRESENT WORTH OF ELECTRICITY COST
C
C      .EUAC  : EQUIVALENT UNIFORM ANNUAL COSTS
C
C      .F(I)  : UNITS OF FUEL CONSUMPTION OF FUEL I IN FIRST PERIOD
C      .FP(I) : INCREASE IN CONSUMPTION PER PERIOD IN %
C      .F$(I) : PRICE OF FUEL IN $/UNIT
C      .F$(I) : INCREASE OF PRICE FOR FUEL IN % (EXCL. INFLATION)
C
C      .FCOST : PRESENT WORTH OF FUEL COSTS
C
C      .MS$(I): MISCELLANEOUS COSTS IN FIRST PERIOD IN $
C      .MS$P  : INCREASE IN MISC. COSTS IN % PER PERIOD (EXCL. INFLATION)
C
C      .MSCOST: PRESENT WORTH OF MISC. COSTS
C
C      .OM$   : LABOR AND MAINTENANCE COST IN FIRST PERIOD IN $
C      .OM$P  : INCREASE OF AOM$ PER PERIOD IN %
C
C      .OMCOST: PRESENT WORTH OF LABOR AND MAINTENANCE COSTS

```

```

C
C .OPCOST: PRESENT WORTH OF OPERATIONAL COSTS IN $
C .DCOST : DERIVATIVE OF .OPCOST WITH RESPECT TO ROR
C
C
C DCOST : (BOPCOST+BCAPEX) - (AOPCOST+ACAPEX)
C DDCOST : DERIVATIVE OF DCOST WITH RESPECT TO ROR
C
C MODE : 1: LIFE CYCLE COST ANALYSIS, CALCULATING THE PRESENT
C        WORTH OF ALL COSTS FOR THE TWO OPTIONS AND THE
C        EQUIVALENT ANNUAL CASH FLOW
C        2: INCREMENTAL RATE OF RETURN CALCULATION
C
C N      : ANALYSIS PERIOD IN YEARS
C NFA    : NUMBER OF FUELS IN USE FOR ALTERNATIVE
C NFB    : NUMBER OF FUELS IN USE FOR BASE CASE
C NMSA   : NUMBER OF MISC. COST ITEMS FOR ALTERNATIVE
C NMSB   : NUMBER OF MISC. COST ITEMS FOR BASE CASE
C RINF   : RATE OF INFLATION
C ROR    : INCREMENTAL RATE OF RETURN
C*****

      DIMENSION XIN(24),PAR(50),OUT(6),INFO(10)
      DIMENSION AMS$(5),AMS$(5),AF(3),AFP(3),AF$(3),AF$(3)
      DIMENSION BMS$(5),BMS$(5),BF(3),BFP(3),BF$(3),BF$(3)

C*****
C**** SET PARAMETERS
C*****

      MODE = PAR(1)
      N    = PAR(2)
      RINF = PAR(3)/100.

      NFB  = PAR(4)
      NFA  = PAR(5)
      NMSB = PAR(6)
      NMSA = PAR(7)

      BELGP = PAR(8)/100
      BELG$ = PAR(9)
      BELG$P= PAR(10)/100

      AELGP = PAR(11)/100
      AELG$ = PAR(12)
      AELG$P= PAR(13)/100

      BELCP = PAR(14)/100
      BELC$ = PAR(15)
      BELC$P= PAR(16)/100

```

```

AELCP = PAR(17)/100
AELC$ = PAR(18)
AELC$P= PAR(19)/100

BOM$P = PAR(20)/100

AOM$P = PAR(21)/100

DO 5 I=1,NFB
BFP(I) = PAR(21+I)/100
BF$(I) = PAR(21+NFB+I)
BF$P(I)= PAR(21+2*NFB+I)/100
5  CONTINUE

DO 10 I=1,NFA
AFP(I) = PAR(21+3*NFB+I)/100
AF$(I) = PAR(21+4*NFB+I)
AF$P(I)= PAR(21+5*NFB+I)/100
10 CONTINUE

DO 15 I=1,NMSB
BMS$P(I)= PAR(21+3*NFB+3*NFA+I)/100
15 CONTINUE

DO 20 I=1,NMSA
AMS$P(I)= PAR(21+3*NFB+3*NFA+NMSB+I)/100
20 CONTINUE

ROR=PAR(21+3*NFB+3*NFA+NMSB+NMSA+1)/100

C*****
C**** SET INPUTS
C*****
BCAPEX = XIN(1)
ACAPEX = XIN(2)

BELG   = XIN(3)
BELC   = XIN(4)

AELG   = XIN(5)
AELC   = XIN(6)
DO 25 I=1,NFB
BF(I)  = XIN(6+I)
25 CONTINUE

DO 30 I=1,NFA
AF(I)  = XIN(6+NFB+I)
30 CONTINUE

```

```

      BOM$ = XIN(6+NFB+NFA+1)
      AOM$ = XIN(6+NFB+NFA+2)

      DO 35 I=1,NMSB
      BMS$(I) = XIN(6+NFB+NFA+2+I)
35      CONTINUE

      DO 40 I=1,NMSA
      AMS$(I) = XIN(6+NFB+NFA+2+NMSB+I)
40      CONTINUE

C*****
C****  FOR MODE=2: BEGIN OF ITERATION FOR RATE OF RETURN
C*****

      IF (MODE.EQ.2) THEN
      ROR=ROR
      K =0.
      END IF

C*****
C****  START OF CALCULATIONS
C*****
11      BOPCOST=0.
      BELCOST=0.
      BFCOST =0.
      BOMCOST=0.
      BMSCOST=0.

      AOPCOST=0.
      AELCOST=0.
      AFCOST =0.
      AOMCOST=0.
      AMSCOST=0.

C*****
C****  FOR MODE 2
C*****
      IF (MODE.EQ.2) THEN
      BDOPCOST=0.
      BDEL COST=0.
      BDFCOST =0.
      BDOMCOST=0.
      BDMSCOST=0.

      ADOPCOST=0.
      ADEL COST=0.
      ADFCOST =0.

```



```

ADOMCOST=0.
ADMSCOST=0.

END IF

DO 100 I=1,N
C*****
C**** CALCULATION OF INDIVIDUAL OPERATIONAL COSTS FOR BASE CASE
C*****

C**** CALCULATION OF ELECTRICITY COSTS
      BELCOST = BELCOST +
      + (BELC * (1+BELCP)**I * BELC$ * (1+BELC$P)**I / (1+ROR)**I -
      - BELG * (1+BELGP)**I * BELG$ * (1+BELG$P)**I / (1+ROR)**I) *
      * (1+RINF)**I

C**** CALCULATION OF FUEL COSTS
      DO 55 J=1,NFB
      BFCOST= BFCOST +
      + BF(J) * (1+BFP(J))**I * BF$(J) * (1+BF$(J))**I / (1+ROR)**I *
      * (1+RINF)
55    CONTINUE

C**** CALCULATION OF LABOR AND MAINTENANCE COSTS
      BOMCOST= BOMCOST + BOM$ * (1+BOM$P)**I / (1+ROR)**I * (1+RINF)

C**** CALCULATION OF MISC. COSTS
      DO 60 J=1,NMSB
      BMSCOST= BMSCOST +
      + BMS$(J) * (1+BMS$(J))**I / (1 + ROR)**I * (1+RINF)
60    CONTINUE

C*****
C**** CALCULATION OF INDIVIDUAL OPERATIONAL COSTS FOR ALTERNATIVE
C*****

C**** CALCULATION OF ELECTRICITY COSTS
      AELCOST = AELCOST +
      + (AELC * (1+AELCP)**I * AELC$ * (1+AELC$P)**I / (1+ROR)**I -
      - AELG * (1+AELGP)**I * AELG$ * (1+AELG$P)**I / (1+ROR)**I) *
      * (1+RINF)

C**** CALCULATION OF FUEL COSTS
      DO 65 J=1,NFA
      AFCOST= AFCOST +
      + AF(J) * (1+AFP(J))**I * AF$(J) * (1+AF$(J))**I / (1+ROR)**I *
      * (1+RINF)
65    CONTINUE

C**** CALCULATION OF LABOR AND MAINTENANCE COSTS

```

```

      AOMCOST= AOMCOST + AOM$ * (1+AOM$P)**I / (1+ROR)**I *
      * (1+RINF)

C***** CALCULATION OF MISC. COSTS
      DO 70 J=1,NMSA
      AMSCOST= AMSCOST +
      + AMS$(J) * (1+AMS$P(J))**I / (1 + ROR)**I * (1+RINF)
70    CONTINUE

C*****
C***** CALCULATION OF DERIVATIVE OF OPERATIONAL COSTS FOR BASE CASE
C      WITH RESPECT TO ROR : ONLY IF MODE = 2.
C*****
      IF (MODE.EQ.2) THEN

C***** ELECTRICITY COSTS
      BDELCOST = BDELCOST +
      + (BELC * (1+BELCP)**I * BELC$ * (1+BELC$P)**I -
      - BELG * (1+BELGP)**I * BELG$ * (1+BELG$P)**I) * (1+RINF) *
      * (-1) * I * (1+ROR)**(I-1) / (1+ROR)**(2*I)

C***** FUEL COSTS
      DO 75 J=1,NFB
      BDFCOST= BDFCOST +
      + ( BF$(J) * (1+BFP(J))**I * BF$(J) * (1+BFP$P(J))**I) * (1+RINF) *
      + (-1) * I * (1+ROR)**(I-1) / (1+ROR)**(2*I)
75    CONTINUE

C***** LABOR AND MAINTENANCE COSTS
      BDOMCOST= BDOMCOST +
      + (BOM$ * (1+BOM$P)**I) * (1+RINF) *
      * (-1) * I * (1+ROR)**(I-1) / (1+ROR)**(2*I)

C***** MISC. COSTS
      DO 80 J=1,NMSB
      BDMSCOST= BDMSCOST +
      + (BMS$(J) * (1+BMS$P(J))**I) * (1+RINF) *
      * (-1) * I * (1+ROR)**(I-1) / (1+ROR)**(2*I)
80    CONTINUE

C*****
C***** CALCULATION OF DERIVATIVE OF OPERATIONAL COSTS FOR ALTERNATIVE
C      WITH RESPECT TO ROR : ONLY IF MODE = 2.
C*****

C***** ELECTRICITY COSTS
      ADELCOST = ADELCOST +
      + (AELC * (1+AELCP)**I * AELC$ * (1+AELC$P)**I -

```

```

-      AELG * (1+AELGP)**I * AELG$ * (1+AELG$P)**I) * (1+RINF) *
*      (-1) * I * (1+ROR)**(I-1) / (1+ROR)**(2*I)

C**** FUEL COSTS
      DO 85 J=1,NFA
      ADFCOST= ADFCOST +
+      ( AF(J) * (1+AFP(J))**I * AF$(J) * (1+AF$P(J))**I) * (1+RINF) *
+      (-1) * I * (1+ROR)**(I-1) / (1+ROR)**(2*I)
85      CONTINUE

C**** LABOR AND MAINTENANCE COSTS
      ADOMCOST= ADOMCOST +
+      (AOM$ * (1+AOM$P)**I) * (1+RINF) *
+      (-1) * I * (1+ROR)**(I-1) / (1+ROR)**(2*I)

C**** MISC. COSTS
      DO 90 J=1,NMSA
      ADMSCOST= ADMSCOST +
+      (AMSS$(J) * (1+AMSSP(J))**I) * (1+RINF) *
+      (-1) * I * (1+ROR)**(I-1) / (1+ROR)**(2*I)
90      CONTINUE

      END IF

100     CONTINUE

C*****
C**** ADDITION OF INDIVIDUAL COSTS
C*****

C**** ADDITION OF INDIVIDUAL COSTS FOR BASE CASE (PRESENT WORTH!)
      BOPCOST = BELCOST + BFCOST + BOMCOST + BMSCOST + BCAPEX

C**** ADDITION OF INDIVIDUAL COSTS FOR ALTERNATIVE (PRESENT WORTH!)
      AOPCOST = AELCOST + AFCOST + AOMCOST + AMSCOST + ACAPEX

C**** EQUIVALENT ANNUAL COST CALCULATION FOR BASE CASE
      IF (ROR.NE.0) THEN
      BEUAC = BOPCOST * ROR*(1+ROR)**N / ((1+ROR)**N - 1)

C**** EQUIVALENT ANNUAL COST CALCULATION FOR ALTERNATIVE
      AEUAC = AOPCOST * ROR*(1+ROR)**N / ((1+ROR)**N - 1)
      END IF

*****
C**** FOR MODE=2: ITERATION TO FIND ROR WITH NEWTON-RAPHSON
*****

```

```

      IF (MODE.EQ.2) THEN

C***** DERIVATIVE OF OPER. COST OF BASE CASE WITH RESPECT TO ROR
      BDCOST = BDELCOST + BDFCOST + BDOMCOST + BDMS COST

C***** DERIVATIVE OF OPER. COST OF ALTERNATIVE WITH RESPECT TO ROR
      ADCOST = ADELCOST + ADFCOST + ADOMCOST + ADMSCOST

C***** NEWTON RAPHSON:
      DCOST=BOPCOST - AOPCOST

      DDCOST= BDCOST - ADCOST

      WRITE (*,*) 'ROR=',ROR

      ROROLD = ROR

C***** WARNING IN CASE OF ZERO SLOPE
      IF (DDCOST.EQ.0) THEN
        WRITE (6,98) TIME, INFO(1), INFO(2)
98      FORMAT(T2,'***** WARNING *****',/,
+T2,' TIME : ',E12.5,' UNIT : ',I3,' TYPE : ',I3,/,
+ ' PLEASE CHOSE DIFFERENT FIRST GUESS FOR RATE OF RETURN !',/)
        STOP
        END IF

      ROR = ROR - DCOST/DDCOST

      IF (ABS (ROR-ROROLD) .LE.0.0001) GOTO 200

      K=K+1
      IF (K.GT.10000) THEN
        WRITE (6,99) TIME, INFO(1), INFO(2)
99      FORMAT(T2,'***** WARNING *****',/,
+T2,' TIME : ',E12.5,' UNIT : ',I3,' TYPE : ',I3,/,
+ ' NO CONVERGENCE FOR RATE-OF-RETURN CALCULATION !',/)
        STOP
        END IF

      GOTO 11

      END IF

C*****
C***** SET OUTPUTS
C*****
200  OUT(1) = ROR*100.
      OUT(2) = N
      OUT(3) = BOPCOST

```

OUT(4) = AOPCOST
OUT(5) = BEUAC
OUT(6) = AEUAC

RETURN
END

Load Profile
Generator
TYPE 65

C**** VERSION:10/28/88

SUBROUTINE TYPE65 (TIME,XIN,OUT,T,DTDT,PAR,INFO)

```

C*****
C****
C**** THIS ROUTINE GENERATES THE OVERALL LOAD PROFILE FOR
C**** THE SYSTEM CONSISTING OF THE CAMPUS AND THE CLIN. SCI. CENTER
C****
C*****
C*****
C      NOMENCLATURE: (IN ALPHABETICAL ORDER)
C
C      CHMSTA : FIRST MONTH OF CHILLER OPERATION
C      CHDSTA : DAY OF START OF CHILLER OPERATION
C      CHMEND : LAST MONTH OF CHILLER OPERATION
C      CHDEND : DAY OF END OF CHILLER OPERATION
C      CLOW   : DAILY TOTAL LOW PRESSURE STEAM DEMAND (LEAVING CSP)
C      CHI    :      "      "      HIGH      "      "      "      "
C      CSC    : DAILY TOTAL STEAM DEMAND FOR CLINICAL SCIENCE CENTER
C      CTOT   : DAILY TOTAL STEAM PRODUCTION OF CSP
C      CTOTAV : AVERAGE HOURLY DAILY STEAM PRODUCTION OF CSP
C      CTOW   : DAILY TOTAL STEAM FLOW FROM CHARTER TO WALNUT
C      DAYSTA : DAY OF START OF SIMULATION
C      DAYEND : DAY OF END OF SIMULATION
C      DOW    : DAY OF WEEK
C      HOD    : HOUR OF DAY
C      HTDB   : HOURLY DRY BULB TEMPERATURE
C      HTWB   : HOURLY WET BULB TEMPERATURE
C      HCLOW  : HOURLY LOW PRESSURE STEAM DEMAND (LEAVING PLANT)
C      HCHI   : HOURLY HIGH      "      "      "      "
C      HCAIR  : HOURLY AIR COMPRESSOR POWER DEMAND
C      HLOAD  : HOURLY COOLING LOAD
C      MONSTA : MONTH OF START OF SIMULATION
C      MONEND : MONTH OF END OF SIMULATION
C      MODE   : 1: READ IN AND PUT OUT HOURLY DATA
C              2: SPECIFY TIME OF OPERATION AND GENERATE HOURLY DATA.
C              3: MODE 2 + CSP AND WSP INTERCONNECTED
C      TWBAV  : DAILY AVERAGE WET BULB TEMP.
C      TAV    :      "      "      DRY      "      "
C      WS     : WS=0 : INDICATES NO CHILLER OPERATION (WINTER)
C              WS=1 : INDICATES CHILLER OPERATION (SUMMER)
C      WTOC   : DAILY TOTAL STEAM FLOW FROM WALNUT TO CHARTER
C      WC...  : SWITCH ON AND SHUT OFF TIMES OF WSP CHILLERS
C*****
      INTEGER HOD, DAY, DOW, CMON, CDAY, CHOD, DAYSTA, DAYEND, CHMSTA, CHDSTA
      INTEGER CHMEND, CHDEND
      DIMENSION PAR(10), OUT(15), INFO(10)

```

DIMENSION A(24),B(24),C(24),D(24),E(24)

C*****
**

C**** FACTORS FOR HOURLY LOAD PROFILE: A:WINTER WEEKDAY, B:WINTER WEEKEND,

C**** C:SUM175, D:SUM10, E:COMPRESSED AIR

C*****

DATA (A(HOD),HOD=1,24) / 0.991, 0.993, 1.01, 1.015, 1.02, 1.03,
+1.08, 1.125, 1.10, 1.062, 1.02, 0.985, 0.98, 0.962, 0.94, 0.915,
+0.94, 0.967, 0.97, 0.973, 0.97, 0.965, 0.98, 0.99/

DATA (B(HOD),HOD=1,24) / 1.01, 1.003, 1.005, 1.004, 1.018, 1.032,
+1.04, 1.048, 1.03, 1.015, 1.004, 0.993, 0.98, 0.968, 0.973,
+0.978, 0.988, 0.995, 0.994, 0.993, 0.993, 0.993, 1.007, 1.014/

DATA (C(HOD),HOD=1,24) / 0.9, 0.85, 0.8, 0.825, 0.85, 0.97, 1.05,
+1.07, 1.1, 1.08, 1.05, 1.1, 1.15, 1.11, 1.08, 1.07, 1.05, 1.0,
+1.0, 1.0, 1.0, 1.0, 1.0, 1.0/

DATA (D(HOD),HOD=1,24) / 0.96, 0.96, 0.96, 0.95, 0.94, 0.96,
+0.98, 1.0, 1.02, 1.04, 1.06, 1.07, 1.08, 1.07, 1.06, 1.04, 1.02,
+1.0, 0.99, 0.98, 0.97, 0.96, 0.96, 0.97/

DATA (E(HOD),HOD=1,24) / 5*0.75,15*1.0,4*0.75/

C*****

C**** SET PARAMETERS

C*****

MODE = PAR(1)
MONSTA = PAR(2)
DAYSTA = PAR(3)
MONEND = PAR(4)
DAYEND = PAR(5)
DOWSTA = PAR(6)
CHMSTA = PAR(7)
CHDSTA = PAR(8)
CHMEND = PAR(9)
CHDEND = PAR(10)

IF (MODE.EQ.3) THEN
WCMSTA = PAR(11)
WCDSTA = PAR(12)
WCMEND = PAR(13)
WCDEND = PAR(14)
END IF

C*****


```

C**** ROUTING FOR INITIAL TIMESTEPS
C*****
      IF(INFO(7).EQ.-1) THEN
        OPEN (UNIT=10 , STATUS = 'OLD')
        OPEN (UNIT=11 , STATUS = 'OLD')

        IF(MODE.EQ.1) THEN
          OPEN (UNIT=12 , STATUS = 'OLD')
        END IF

        HOD=1
        DOW=DOWSTA
        HLOAD=0.
        GOTO 999
      END IF
      IF(INFO(8).EQ.2) GOTO 3

C*****
C*****
C**** READ IN DATA FROM FILE WITH DAILY STEAM VALUES AND HOURLY
C**** TEMPERATURES AND GENERATE HOURLY COOLING AND HEATING LOAD PROFILE
C*****
C*****

C*****
C**** READ IN DAILY DATA
C*****

      2  IF(TIME.EQ.1) GOTO 20
          HOD=HOD+1
          IF (HOD.EQ.25) THEN
            HOD=1
            DOW=DOW+1
            IF (DOW.GT.7) DOW=1

      3  READ (10,5,END=998) MON, DAY, TAV, TWBAV, CTOT, CLOW, CHI,
          + WTOT, WTOC, CTOW, CSC
      5  FORMAT(I2,T6,I2,T11,F4.0,T16,F4.0,T22,F6.0,T29,F6.0,T37,F6.0,
          +T44,F8.0,T54,F5.0,T61,F5.0,T68,F5.0)
          IF (MON.LT.MONSTA.OR.MON.EQ.MONSTA.AND.DAY.LT.DAYSTA) GOTO 3

C**** CHECK FOR TERMINATION OF SIMULATION
      IF (MON.EQ.1 .AND. DAY .EQ. 1.) GOTO 13

      IF (MON.EQ.MONEND.AND.DAY.GE.DAYEND) THEN
        REWIND(10)
        REWIND(11)
        REWIND(12)
        WRITE(6,12) TIME, INFO(1), INFO(2)
      12  FORMAT(T2,'***** WARNING *****',/,

```

```
+T2,' TIME : ',E12.5,' UNIT : ',I3,' TYPE : ',I3,/,
+ ' DESIRED DATE FOR END OF SIMULATION REACHED !!!',/)
```

```
STOP
END IF
```

```
C**** CALCULATE HOURLY AVERAGES FROM DAILY TOTALS
```

```
13 CLOWAV=CLOW/24.
    CHIAV =CHI/24.
    CTOTAV=CTOT/24.
    WTOTAV=WTOT/24.
    CSCAV =CSC/24.
    CTOWAV=CTOW/24.
    WTOCAV=WTOC/24.
```

```
C**** AIR COMPRESSOR POWER : USUALLY WORTHINGTON AC
    CAIRAV = 170.
```

```
C*****
C**** CORRECTIONS OF STEAM FLOW NUMBERS IN LOG SHEETS
C*****
```

```
C**** CORRECTION OF 10 PSIG MASS FLOW RATE TO COMPENSATE FOR INACCURATE
C**** METER WHICH IS NOT PRESSURE CORRECTED (12 PSIG ACTUAL PRESSURE
C**** INSTEAD OF 10 PSIG AT WHICH THE METER IS CALIBRATED AT
    CLOWAV=CLOWAV * 1.2
    CHIAV = CHIAV * 1.02
```

```
C**** CORRECTION OF DAILY TOTALS TO TAKE ADDITIONAL AND NOT METERED
C**** STEAM USERS INTO ACCOUNT AS THERE ARE:
```

```
C**** STEAM FOR WEEKS HALL BYPASSES METER : APPROX 1%
    CHIAV=CHIAV*1.01
C**** STEAM FOR PRIMAT RESEARCH BYPASSES METER : APPROX. 2%
    CHIAV = CHIAV * 1.02
C**** OCT87 - AUG88 : OPEN VALVE : APPROX. 3%
    IF (MON.GE.10.OR.MON.LE.2) CHIAV = CHIAV*1.03
```

```
END IF
```

```
C*****
C**** READ IN HOURLY TEMPERATURE DATA
C*****
```

```
14 READ (11,15,END=998)CMON,CDAY,CHOD,HTDB,HTWB
15 FORMAT (I3,T7,I2,T12,I2,T17,F4.0,T23,F4.0)
    IF (CMON.LT.MONSTA.OR.CMON.EQ.MONSTA.AND.CDAY.LT.DAYSTA) GOTO 14
```

```

C*****
C**** DETERMINATION IF CSP CHILLERS ARE RUNNING (=1) OR NOT (=0)
C*****
      IF ( (MON.LT.CHMSTA.OR.MON.GT.CHMEND) .OR.
+       (MON.EQ.CHMSTA.AND.DAY.LT.CHDSTA) .OR.
+       (MON.EQ.CHMEND.AND.DAY.GT.CHDEND) ) THEN
      WS=0.
      ELSE
      WS=1.
      END IF

C*****
C*****
C**** MODE 1: READ IN ACTUAL HOURLY VALUES FOR SPECIFIC DAY FROM
C****      EXTERNAL FILE
C*****
C*****
      IF (MODE.EQ.1) THEN
      READ (12, *, END=998) HOUR, CLOAD, MCH1, MCH2, MCH3, MWCWP, B1LOG, B2LOG,
+ B3LOG, B4LOG, B5LOG
      BLOGT=B1LOG+B2LOG+B3LOG+B4LOG+B5LOG
      FACTOR=BLOGT/CTOTAV

      IF (WS.EQ.0) THEN
      HCLW= CLOWAV*FACTOR
      HCHI = CHIAV*FACTOR
      ELSE
      HCLW= CLOWAV*D (HOD)
      HCHI = CHIAV*C (HOD)
      END IF

      HLOAD=0.80*CLOAD
      HCAIR=CAIRAV*E (HOD)
      GOTO 20
      END IF

C*****
C*****
C**** MODE 2 OR 3: GENERATE PROFIL FROM DAILY TOTALS FOR ANY PERIOD
C*****
C*****

C*****
C**** STEAM LOAD
C*****

C**** WINTER PROFILE GENERATION

```

```

IF (WS.EQ.0.) THEN

  IF (DOW.LT.6) THEN
    HCLW=CLOWAV*A (HOD)
    HCHI =CHIAV *A (HOD)
  ELSE
    HCLW=CLOWAV*B (HOD)
    HCHI =CHIAV *B (HOD)
  END IF

  HLOAD=0.
  HCAIR=CAIRAV*E (HOD)
ELSE

C***** SUMMER LOAD PROFILE GENERATION IN BTU/HR*10^(-3)
  HCLW=CLOWAV*D (HOD)
  HCHI =CHIAV *C (HOD)
  HCAIR=CAIRAV*E (HOD)

C*****
C***** COOLING LOAD
C*****

C***** CHILLER LOAD GENERATION FOR MODE 2:  CSP CHILLERS
  IF (DOW.LT.6) THEN
    HLOAD=-85535 + 842*HOD - 920*HTDB + 4339*HTWB
  ELSE
    HLOAD=-215394 + 20*HOD - 2703*HTDB + 8414*HTWB

  END IF

C***** CORRECTION FOR EARLY AND LATE SUMMER
  IF (MON.LE.5 .OR. MON.GE.9) THEN
    HLOAD = -50836 + 757*HOD - 2741*HTDB + 5526*HTWB
  END IF

  IF (HLOAD.LE.2800.) HLOAD=2800.

  END IF

C***** CORRECTION FOR CONTRADICTORY LOG DATA:TOTAL LOAD NOT SUM OF
C***** INDIVIDUAL LOADS, BUT ABOUT 30% HIGHER, LOAD CORRELATION BASED
C***** ON TOTAL VALUES, TAKE AVERAGE VALUE
  HLOAD=HLOAD*0.80

C*****
C***** FOR MODE=3: LOAD GENERATION FOR WSP CHILLERS
C*****

  IF (MODE.EQ.3) THEN

```

```

C**** DETERMINATION IF WSP CHILLERS ARE RUNNING (=1) OR NOT (=0)
      IF ( (MON.LT.WCMSTA.OR.MON.GT.WCMEND) .OR.
+       (MON.EQ.WCMSTA.AND.DAY.LT.WCDSTA) .OR.
+       (MON.EQ.WCMEND.AND.DAY.GT.WCDEND) ) THEN
        CW=0.
      ELSE
        CW=1.
      END IF

```

```

      IF (CW.EQ.1) THEN
        WLOAD= -34400 + 103*HOD + 305*HTDB + 639*HTWB
        IF (WLOAD.LE.2800.) WLOAD=2800.

```

```

C**** FOR FREE COOLING MODE: CHILLER COMPRESSOR NOT OPERATING
      IF (HTWB.LT.50) WLOAD=0.
      ELSE
        WLOAD=0.
      END IF

```

```

      END IF

```

```

C*****
*
C**** SET OUTPUT
C*****
*

```

```

20  OUT(1) =MON
    OUT(2) =DAY
    OUT(3) =DOW
    OUT(4) =HOD
    OUT(5) =HTDB
    OUT(6) =HTWB
    OUT(7) =HCLOW*1000
    OUT(8) =HCHI*1000
    OUT(9) =HCAIR
    OUT(10)=HLOAD*1000

```

```

      IF (MODE.EQ.3) THEN
        OUT(11)=WLOAD*1000
        OUT(12)=WTOTAV*1000
        OUT(13)=WTOCAV*1000
        OUT(14)=CTOWAV*1000
        OUT(15)=CSCAV*1000
      END IF

```

```

      GOTO 999

```

```
998  WRITE(6,997) TIME, INFO(1), INFO(2)
997  FORMAT(T2,'***** WARNING *****',/,
+T2,' TIME : ',E12.5,' UNIT : ',I3,' TYPE : ',I3,/,
+' END OF INPUT FILE REACHED, SIMULATION STOPPED !!!',/)
STOP

999  CONTINUE
END
```

**Control for
Entire System
TYPE 69**

C**** VERSION:10/28/88

SUBROUTINE TYPE69 (TIME,XIN,OUT,T,DTDT,PAR,INFO)

C*****

C****

C**** THIS SUBROUTINE PERFORMS THE OPERATIONAL CONTROL OF THE
C**** INTERLINKED COGEN SYSTEM CONSISTING OF CHARTER STREET PLANT,
C**** BLOUNT STREET PLANT AND WALNUT STREET PLANT

C****

C*****

C*****

C NOMENCLATURE: (IN ALPHABETICAL ORDER)

C

C CHI : 175PSI STEAM PRODUCTION OF CSP IN 87/88 (REFERENCE YEAR)

C CLOW : 10PSI STEAM PRODUCTION OF CSP IN 87/88

C CMGE : ABSOLUT (CMGE>1) OR RELATIV (CMGE<1) STEAM SUPPLY BY MG&E

C CHWSP : LOAD ON CHILLERS AT WSP (IF OPERATING)

C CHCSP : CHILLED WATER LOAD ON CSP CHILLERS

C CLOCSP : 10PSI STEAM LOAD ON CSP

C CHLOAD : CHILLED WATER LOAD OF UW

C CMGE : MAXIMUM STEAM FLOW FROM MGE

C CRCSP : CONDENSATE RETURN TO CSP

C CRMGE : CONDENSATE RETURN TO MGE

C CSC : STEAM DEMAND BY CLINICAL SCIENCE CENTER

C CTOW : STEAM SUPPLY FROM CSP TO WSP

C DAY : DAY OF MONTH

C DEMCSP : MINIMUM STEAM FLOW SUPPLIED BY CSP

C HWSP : HOURLY STEAM PRODUCTION BY WSP (FROM LOG)

C MODEST : MODE FOR SYSTEM CONFIGURATION AND CONTROL

C MODECH : MODE TO DETERMINE CHILLER OPERATION AT WSP

C MONTH : MONTH OF YEAR TO DO SEASONAL CONTROL IF NECESSARY

C STTOT : TOTAL 175PSI STEAM DEMAND OF SYSTEM AS FROM LOGS

C STCHW : STEAM DEMAND FOR 2 EXISTING WSP CHILLERS

C STNCH : STEAM DEMAND FOR NEW CHILLER

C STCSP : 175PSI STEAM LOAD ON CSP

C STWSP : 175PSI STEAM LOAD ON WSP BOILERS

C STMGE : 175PSI STEAM LOAD ON MG&E

C WLOAD : CHILLED WATER LOAD FOR WSP (INPUT)

C WTOC : STEAM SUPPLY FROM WSP TO CSP

C*****

DIMENSION PAR(2),XIN(14),OUT(10),INFO(10)

INFO(6)=10

C*****

C**** SET PARAMETERS AND INPUTS

C*****


```

MODEST = PAR(1)
MODECH = PAR(2)

MONTH = XIN(1)
DAY = XIN(2)
CHI = XIN(3)
CLOW = XIN(4)
CHLOAD = XIN(5)
DEMCSP = XIN(6)
CMGE = XIN(7)
STCHW = XIN(8)
HWSP = XIN(9)
WTOC = XIN(10)
CTOW = XIN(11)
CSC = XIN(12)
WLOAD = XIN(13)
STCHC = XIN(14)

C*****
C**** CALCULATION OF TOTAL 175PSIG STEAM DEMAND OF SYSTEM
C*****
      SYSTOT=CHI + (CSC+WTOC+STCHW-CTOW)
      IF (SYSTOT.LT.CHI) SYSTOT=CHI

      IF (MODEST.EQ.6) SYSTOT=SYSTOT + STCHC

      GOTO (100,200)MODECH

C*****
C*****CHILLER CONTROL*****
C*****

C**** CHILLED WATER CONTROL MODE 1: NO NEW CHILLERS AT WSP,
C**** NO INTERCONNECTION
      100 CHCSP = CHLOAD
          CHWSP = WLOAD

      GOTO 5

C*****

C**** CHILLED WATER CONTROL MODE 2: 1 NEW 3500 TON STEAM DRIVEN
C**** CHILLER AT WSP, INTERCONNECTION OF TWO CHILLED WATER LOOPS
      200 CHCSP = CHLOAD
          CHWSP = WLOAD

      IF (CHLOAD.GT.0.) THEN
          CHWSP = WLOAD+42.E6
          CHCSP = CHLOAD - 42.E6
      END IF

```

```

IF (CHCSP.LT.0.) THEN
CHWSP = WLOAD+CHLOAD
CHCSP = 0.
END IF

```

```

C*****
C*****STEAM LOAD DISTRIBUTION*****
C*****

```

```

5      GOTO (10,20,30,40,50,60,70)MODEST

```

```

C*****
C**** CONTROL MODE 1: MG&E NOT PART OF SYSTEM, LOAD AND SYSTEM
C**** OPERATION AS IN 87/88
C**** (INPUT DATA FROM LOGS FOR CSP AND WSP)
C*****

```

```

10     CLOCSP= CLOW
        STCSP = CHI
        STWSP = HWSP
        STMGE = 0.
        CRCSP = 0.83*(STCSP+CLOCSP)
        CRMGE = 0.
        GOTO 300

```

```

C*****
C**** CONTROL MODE 2: MG&E NOT PART OF SYSTEM, CHECK MODE
C*****

```

```

20     CLOCSP= CLOW
        STCSP = CHI
        STWSP = (SYSTOT-CHI)*1.2      ! *1.2, BECAUSE OF INTERNAL CSPT
        STMGE = 0.
        CRCSP = 0.83*(STCSP+CLOCSP)
        CRMGE = 0.
        GOTO 300

```

```

C*****
C**** CONTROL MODE 3: MG&E NOT PART OF SYSTEM, WSP BOILERS DO NOT RUN
C*****

```

```

30     CLOCSP= CLOW
        STCSP=SYSTOT
        STWSP=0.
        STMGE = 0.
        CRCSP = 0.83*(STCSP+CLOCSP)
        CRMGE = 0.
        GOTO 300

```

```

C*****

```

```

C***** CONTROL MODE 4: CSP SHUT DOWN IF CHILLERS ARE NOT RUNNING ,
C***** IF CHILLERS OPERATING: CSP RUNS AS USUAL WITH AIR COMPRESSOR
C*** SWITCHED TO ELECTRIC
C*****
40  IF (CHLOAD.EQ.0.) THEN
      STMGE=SYSTOT+CLOW
      STCSP=0.
      CLOCSP=0.
      STWSP=0.

      IF (STMGE.GT.CMGE) THEN
          STMGE = CMGE
          STCSP = SYSTOT+CLOW-CMGE
          CLOCSP= 0.
          END IF

      ELSE

          STMGE=0.
          STCSP=SYSTOT
          CLOCSP=CLOW
          STWSP=0.

          END IF

      CRCSP = 0.83*(STCSP+CLOCSP)
      CRMGE = 0.83*STMGE
      GOTO 300

C*****
C***** CONTROL MODE 5: CSP SHUT DOWN ALL YEAR LONG, AIR COMPRESSORS,
C***** CHILLERS AND CHILLER PUMPS RUN ELECTRICALLY
C*****
50  STMGE=SYSTOT+CLOW
      STCSP=0.
      CLOCSP=CLOW
      STWSP=0.
      CRCSP=0.

      IF (STMGE.GT.CMGE) THEN
          STWSP = STMGE - CMGE
          STMGE=CMGE
          END IF

      IF (STMGE.LT.DEMCSP) THEN
          STWSP = STMGE
          STMGE = 0.
          END IF

```

```
CRMGE= 0.83*STMGE
CRCSP= 0.83*STWSP
```

```
GOTO 300
```

```
C*****
C**** CONTROL MODE 6: ALL EQUIPMENT AT CSP SWITCHED TO 175 PSI
C**** ALL EQUIPMENT REMAINS STEAMDRIVEN
C**** MG&E SUPPLIES CONSTANT (CMGE>1) OR VARIABLE (0<CMGE<1)
C**** STEAM FLOW (CMGE IS INPUT!)
C*****
```

```
60  CLOCSP=0.
    STWSP=0.
```

```
STMGE=CMGE
```

```
STCSP = (SYSTOT+CLOW)-STMGE
```

```
IF (STCSP.LT.DEMCSP) THEN
STMGE = SYSTOT+CLOW-DEMCSP
IF (STMGE.LT.0.) STMGE=0
```

```
STCSP = DEMCSP
IF ((SYSTOT+CLOW).LT. DEMCSP) STCSP=SYSTOT+CLOW
```

```
END IF
```

```
CRCSP = 0.83*STCSP
CRMGE = 0.83*STMGE
```

```
GOTO 300
```

```
C*****
C**** CONTROL MODE 7: MGE PROVIDES CONSTANT LOAD AS LONG AS CSP GETS
C**** AT LEAST A CERTAIN MINIMUM LOAD ON C175
C*****
```

```
70  CLOCSP=0.
    STWSP=0.
```

```
STMGE=CMGE
```

```
STCSP = (SYSTOT+CLOW)-STMGE
```

```
IF (STCSP.LT.DEMCSP) THEN
STMGE = SYSTOT+CLOW-DEMCSP
IF (STMGE.LT.0.) STMGE=0
```

```
STCSP = DEMCSP
IF ((SYSTOT+CLOW).LT. DEMCSP) STCSP=SYSTOT+CLOW
```

END IF

CRCSP = 0.83*STCSP

CRMGE = 0.83*STMGE

GOTO 300

C*****

C*****OUTPUT*****

C*****

300 OUT(1)=STCSP
OUT(2)=CLOCSP
OUT(3)=STWSP
OUT(4)=STMGE
OUT(5)=BCSP
OUT(6)=CHCSP
OUT(7)=CHWSP
OUT(8)=CRCSP
OUT(9)=CRMGE
OUT(10)=SYSTOT

301 CONTINUE

RETURN

END

**Control for
Charter Street Plant
TYPE 68**

C***** VERSION:10/28/88

SUBROUTINE TYPE68 (TIME,XIN,OUT,T,DTDT,PAR,INFO)

```

C*****
*
C****
C**** THIS ROUTINE CONTROLS THE OPERATIONAL STRATEGY OF THE
C**** CHARTER STREET PLANT, MORE SPECIFICALLY IT PERFORMS
C**** THE CONTROL OF :TRURBINE/GENERATOR, BOILERS, BOILER FANS
C**** DEAERATOR,CHILLERS AND VARIOUS STEAM FLOWS WITHIN THE PLANT.
C****
C*****
*
C*****
*
C      NOMENCLATURE: IN ALPHABETICAL ORDER
C
C      B1LOG : BOILER STEAM PRODUCTION IN 1000LBS FROM LOGSHEETS
C      CH2   : FRACTION OF TOTAL CHILLED WATER LOAD THAT CHILLER #2 TAKES
C      CHI   : OUTGOING HIGH PRESSURE STEAM
C      CLOAD : TOTAL CHILLER LOAD
C      CLOW  : OUTGOING LOW PRESSURE STEAM
C      EXC10F: 10PSIG STEAM EXCESS FROM BOILER FANS (NOT NEEDED FOR
CAMPUS)
C      EXC10T: TOTAL EXCESS 10 PSIG STEAM
C      HOD   : HOUR OF DAY
C      LCH1  : CHILLER LOAD FOR CHILLER #1 IN BTU/HR
C      MAIRB1: COMBUSTION AIR MASS FLOW RATE FOR BOILER #1
C      MAIRT : TOTAL MASS FLOW RATE OF COMBUSTION AIR
C      MCOND : CONDENSATE MASS FLOW RATE
C      MFAN1 : STEAM DEMAND FOR FANS OF BOILER #1
C      MLOSS : WATER LOSS FLOW RATE
C      MODE  : 1: SIMULATION FOR SINGLE DAYS WITH ACCURATE INPUT DATA
C              2: EXTENDED SIMULATION WITH TYPICAL LOAD PROFILES FOR
87/88
C              3: LIKE 2, BUT FOR FUTURE OPERATION (NO USE OF GAS IF
POSSIBLE)
C              4: LIKE 3,BUT PLANT SWITCHED TO 175 PSI FOR FUTURE
SIMULATIONS
C              CHILLERS 175-COND STEAM DRIVEN, AC,PCWP,FWP ELECTRIC
C              5: LIKE 4, BUT PCWP 175-COND STEAM DRIVEN, FW PUMPS 175-
10PSI
C              6: LIKE 3, BUT ADDITIONAL BP TURBINE AS BYPASS (MTMAX
=300,000)
C              7: LIKE 3, BUT UPGRADED BACKPRESSURE TURBINE/GEN. (TO 6
MW)
C      MON   : MONTH OF YEAR
C      MPRV1 : STEAM FLOW THROUGH 600-175PSIG PRV

```

```

C      MPRV2 : STEAM FLOW THROUGH 175- 10PSIG PRV
C      MPRV3 : STEAM FLOW THROUGH 175- 60PSIG PRV
C      MPRV4 : STEAM FLOW THROUGH 60- 10PSIG PRV
C      MSTAC : STEAM FLOW TO AIR COMPRESSOR TURBINE
C      MSTADD: ADDITIONAL STEAM DEMAND FOR 600-175PSIG SECTION EVEN IF
C              TURBINE/GENERATOR IS OFF
C      MSTAH : STEAM FLOW TO AIRHEATER
C      MSTCH : STEAM MASS FLOW RATE THROUGH CHILLER COMPRESSOR TURBINES
C      MSTCWP: STEAM FLOW TO PRIMARY CHILLED WATER PUMP
C      MSTDA : STEAM FLOW TO DEARATOR
C      MSTDES: STEAM FLOW TO DESUPERHEATER
C      MSTFWP: STEAM FLOW THROUGH FEEDWATER PUMPS
C      MST2ST: STEAM FLOW THROUGH 2ND STAGE HEATER
C      MSTTOT: TOTAL STEAM FLOW TO 600-175PSIG SECTION
C      MSTTUR: STEAM MASS FLOW RATE THROUGH TURBINE GENERATOR
C      MSTT2 : STEAM MASS FLOW RATE THROUGH ADD. TURB. GEN. IF MODE=6
C      MTMAX : MAXIMUM STEAM FLOW RATE THROUGH TURBINE/GENERATOR
C      MWCWP : WATER MASS FLOW TO BE HANDLED BY CHILLED PRIMARY WATER
PUMP
C      MWDES : WATER FLOW TO DESUPERHEATER
C      PLB1  : PART LOAD FACTOR OF BOILER #1
C      STBTOT: TOTAL STEAM PRODUCTION
C      STB1  : STEAM PRODUCTION OF BOILER 1
C      TDB   : DRY BULB TEMPERATURE
C      TWB   : WET BULB TEMPERATURE
C*****

```

```

      IMPLICIT REAL (M)
      REAL LCH1,LCH2,LCH3
      INTEGER MODE, MON
      DIMENSION XIN(23),PAR(1),OUT(23),INFO(10)

```

```

C**** FIRST CALL OF SIMULATION
      INFO(6)=23

```

```

C*****
*
C**** SET INPUTS AND PARAMETERS
C*****
*

```

```

      MODE = PAR(1)

```

```

      MON = XIN(1)
      DAY = XIN(2)
      HOD = XIN(3)
      TDB = XIN(4)
      TWB = XIN(5)
      CLOW = XIN(6)
      CHI = XIN(7)
      MSTDES= XIN(8)

```



```

MSTAH = XIN(9)
MSTAC = XIN(10)
MSTCWP= XIN(11)
MSTCH = XIN(12)
MSTFWP= XIN(13)
MWDES = XIN(14)
MST2ST= XIN(15)
MSTDA = XIN(16)
MAIRB1= XIN(17)
MAIRB2= XIN(18)
MAIRB3= XIN(19)
MAIRB4= XIN(20)
MAIRB5= XIN(21)
MSTAH2= XIN(22)
CLOAD = XIN(23)

C**** IN CASE OF SHUT DOWN OF PLANT: SET OUTPUTS TO ZERO
IF (CHI.EQ.0. .AND. CLOW.EQ.0. .AND. CLOAD.EQ.0.) THEN
DO 10 I=1,22
OUT(I)=0.
10 CONTINUE
GOTO 998
END IF

IF (MODE.EQ.1) THEN

C**** OPEN FILE WITH DAILY STEAM TOTALS
IF (INFO(7).EQ.-1) THEN
OPEN (UNIT = 14, STATUS='OLD')
TIMOLD=-1.
GOTO 998
END IF

C**** READ IN VALUES AT BEGINNING OF NEW DAY
IF (TIME.NE.TIMOLD) THEN
IF (TIME.EQ.1) GOTO 990
READ (14, *, END=999) HOUR, FORGET, MCH1, MCH2, MCH3, MWCWP,
+ B1LOG, B2LOG, B3LOG, B4LOG, B5LOG

TIMOLD=TIME
END IF
END IF

IF (INFO(7).EQ.-1) GOTO 998

C*****
*
C**** GENERATOR CONTROL
C*****

```

*

```

IF (MODE.NE.4 .AND. MODE.NE.5) THEN
  PRVMIN = 15000
  MPRV1 = PRVMIN
  MSTADD= 0.

```

```

C**** MAX STEAM FLOW THROUGH TURBINE
MTMAX=120000.
IF (MODE.EQ.7) MTMAX=210000.
IF (MODE.EQ.6) MTMAX=300000.
MTMIN= 30000.

```

```

C**** TOTAL STEAM FLOW NEEDED FOR 175PSIG SECTION
MSTTOT = MSTDES + MSTAH + MPRV3 + CLOW + EXC10F

```

```

C**** CALCULATION OF POSSIBLE STEAM MASS FLOW THROUGH TURBINE/GENERATOR
MSTTUR = MSTTOT - MSTAC - MSTCWP - PRVMIN
IF (MSTTUR.GT.MTMAX) THEN
  MPRV1 = MSTTUR - MTMAX + PRVMIN
  MSTTUR= MTMAX
ELSE IF (MSTTUR.LT.MTMIN) THEN
  MSTADD = (-1)*MSTTUR + MTMIN
  MSTTUR = MTMIN
ELSE
  MSTTUR = MSTTUR
END IF

END IF

```

```

C**** FOR MODE 4 AND 5
IF (MODE.EQ.4 .OR. MODE.EQ.5) THEN
  MSTTOT = CHI + MSTAH + MPRV3 + CLOW + EXC10F + MSTAC + MSTCWP
  MSTADD=0.
END IF

```

```

C**** CONTROL OF 2 BACK PRESSURE TURBINES
IF (MODE.EQ.6) THEN

  MSTT2=190000.
  MSTT1=MSTTUR-190000.
  IF (MSTTUR.LT.220000) THEN
    MSTT1=MSTTUR*0.5
    MSTT2=MSTTUR*0.5
  END IF

  IF (MSTTUR.LT.190000.) THEN
    MSTT1=0.
    MSTT2=MSTTUR
  END IF

```

```

      IF (MSTTUR.LT.110000.) THEN
      MSTT2=0.
      MSTT1=MSTTUR
      END IF

```

```

      MSTTUR=MSTT1

```

```

END IF

```

```

C*****
*
C**** BOILER CONTROL
C*****
*

```

```

C**** TOTAL STEAM PRODUCTION
      STBTOT = MSTTOT + MSTADD + MSTCH + MSTFWP

```

```

C**** HOURLY PART LOAD CALCULATIONS IN MODE 1
      IF (MODE.EQ.1) THEN
      BLOG=B1LOG+B2LOG+B3LOG+B4LOG+B5LOG
      PLB1=B1LOG/BLOG
      PLB2=B2LOG/BLOG
      PLB3=B3LOG/BLOG
      PLB4=B4LOG/BLOG
      PLB5=B5LOG/BLOG
      END IF

```

```

C*****
*

```

```

C**** MODE 2
C**** DETERMINATION OF NUMBER OF BOILERS OPERATING
      IF (MODE.EQ.2) THEN
      IF (HOD.EQ.1) THEN

```

```

          IF (STBTOT.LT.130000.) THEN
          PLB1=0.
          PLB2=0.
          PLB3=0.
          PLB4=1.
          PLB5=0.
          END IF

```

```

          IF (STBTOT.GT.130000.) THEN
          PLB1=0.
          PLB2=0.25
          PLB3=0.

```

```
PLB4=0.  
PLB5=0.75  
END IF
```

```
IF (STBTOT.GT.220000.) THEN  
PLB1=0.2  
PLB2=0.2  
PLB3=0.  
PLB4=0.  
PLB5=0.6  
END IF
```

```
IF (STBTOT.GT.280000.) THEN  
PLB1=0  
PLB2=0.  
PLB3=0.2  
PLB4=0.35  
PLB5=0.45  
END IF
```

```
IF (STBTOT.GT.330000.) THEN  
PLB1=0.2  
PLB2=0.  
PLB3=0.2  
PLB4=0.3  
PLB5=0.3  
END IF
```

```
IF (STBTOT.GT.400000.) THEN  
PLB1=0.15  
PLB2=0.15  
PLB3=0.15  
PLB4=0.25  
PLB5=0.3  
END IF
```

```
END IF  
END IF
```

```
C**** MODE 3,4,5,6,7: USE GAS AS LITTLE AS POSSIBLE  
C**** DETERMINATION OF NUMBER OF BOILERS OPERATING  
IF (MODE.GT.2) THEN  
IF (HOD.EQ.1) THEN
```

```
IF (STBTOT.LT.130000.) THEN  
PLB1=0.  
PLB2=0.  
PLB3=0.  
PLB4=1.
```

```
PLB5=0.  
END IF
```

```
IF (STBTOT.GT.130000.) THEN  
PLB1=0.25  
PLB2=0.  
PLB3=0.  
PLB4=0.75  
PLB5=0.  
END IF
```

```
IF (STBTOT.GT.220000.) THEN  
PLB1=0.25  
PLB2=0.25  
PLB3=0.  
PLB4=0.5  
PLB5=0.  
END IF
```

```
IF (STBTOT.GT.280000.) THEN  
PLB1=0.25  
PLB2=0.25  
PLB3=0.  
PLB4=0.5  
PLB5=0.  
END IF
```

```
IF (STBTOT.GT.330000.) THEN  
PLB1=0.2  
PLB2=0.2  
PLB3=0.2  
PLB4=0.4  
PLB5=0.  
END IF
```

```
IF (STBTOT.GT.400000.) THEN  
PLB1=0.15  
PLB2=0.15  
PLB3=0.15  
PLB4=0.3  
PLB5=0.25  
END IF
```

```
END IF  
END IF
```

```
C**** CALCULATION OF STEAM PRODUCTION OF INDIVIDUAL BOILERS  
STB1=PLB1 * STBTOT  
STB2=PLB2 * STBTOT  
STB3=PLB3 * STBTOT
```

STB4=PLB4 * STBTOT
STB5=PLB5 * STBTOT

```

C*****
*
C**** FAN CONTROL
C*****
*
C**** STEAM DEMAND FOR STEAM TURBINE DRIVEN FANS (LINEAR RELATIONSHIP
ASS.)
      MFAN1 = 9050 * MAIRB1/200000
      MFAN2 = 9050 * MAIRB2/200000
      MFAN3 = 9050 * MAIRB3/200000
      MFAN4 = 22500* MAIRB4/350000
      MFAN5 = 17000* MAIRB5/400000

      MFAN = MFAN1 + MFAN2 + MFAN3 + MFAN4 + MFAN5

C**** TOTAL AIR FLOW RATE AS INPUT FOR AIR HEATER, AIR HEATER CONTROL
      MAIRT = 1.5*(MAIRB1 + MAIRB2 + MAIRB3 + MAIRB4 + MAIRB5)
      IF (MON.GT.5 .AND. MON.LT.9 .OR. TDB.GT.80) MAIRT = 0.

C**** BAGHOUSE TURBINES: STARTED TO OPERATE IN JANUARY 1988
      IF (MODE.LE.2) THEN

          IF (MON.EQ.1 .OR. MON.EQ.2) THEN
              MFAN=MFAN+(MAIRB1+MAIRB2+MAIRB3)/600000*25000+MAIRB4/350000*25000
          END IF

          ELSE

              MFAN=MFAN+(MAIRB1+MAIRB2+MAIRB3)/600000*25000+MAIRB4/350000*25000

          END IF

C**** CALCULATION OF STEAM BALANCE AT 10PSIG DIVERTER : PRV2,EXC10F
      IF (MFAN.LT.CLOW) THEN
          MPRV2=CLOW-MFAN
          EXC10F=0.
      ELSE
          MPRV2=0.
          EXC10F=MFAN-CLOW
      END IF

C*****
*
C**** DEAERATOR CONTROL
C*****

```

*

C***** ASSUMPTION OF 17% WATER LOSS ON CAMPUS

MCOND = 0.83 * (CHI + CLOW) - MWDES

MLOSS = 0.17 * (CHI + CLOW)

C***** FOR MODE 1-4,6: CALCULATIONS FOR MPRV3 (175-60) AND MPRV4 (60-10)

IF (MODE.NE.5) THEN

MPRV3 = MSTDA - EXC10F - (MSTFWP - MST2ST) + MSTA2

EXC10T = 0.

IF (MPRV3.LT.0.) THEN

EXC10T = (-1) * MPRV3

MPRV3 = 0.

END IF

MPRV4 = MPRV3 + (MSTFWP - MST2ST)

END IF

C***** FOR MODE 5: CALCULATIONS FOR MPRV3 (175-60) AND MPRV4 (60-10)

C*** (AC, PCWP 175-COND, FW PUMPS 175 - 10)

IF (MODE.EQ.5) THEN

MPRV3 = MSTDA - EXC10F - MSTFWP + MSTA2

EXC10T = 0

IF (MPRV3.LT.0.) THEN

EXC10T = (-1) * MPRV3

MPRV3 = 0.

END IF

MPRV4 = MPRV3 - MST2ST

END IF

C*****

*

C***** CHILLER CONTROL

C*****

*

C***** MODE 1

IF (MODE.EQ.1) THEN

MCTOT=MCH1 + MCH2 + MCH3

IF (MCTOT.GT.0.) THEN

CH1=MCH1/MCTOT

CH2=MCH2/MCTOT

CH3=MCH3/MCTOT

END IF

END IF

C*****

★

```

C***** MODE 2
C***** DETERMINATION OF NUMBER OF CHILLERS OPERATING
C***** IF CHILLERS NOT OPERATING:
      IF (MODE.NE.1) THEN

          IF (CLOAD.EQ.0.) THEN
              LCH1=0.
              LCH2=0.
              LCH3=0.
              MWCWP=0.
              GOTO 990
          END IF

C***** IF CHILLERS OPERATING: DETERMINATION OF NUMBER OF OPERATING
CHILLERS
C***** FOR THAT DAY FROM LOAD
      IF (CLOAD.LT.7.2E7) THEN
          CH1=0.
          CH2=0.
          CH3=1.
          END IF

          IF (CLOAD.GE.7.2E7) THEN
              CH1=0.33
              CH2=0.
              CH3=0.66
              END IF

          IF (CLOAD.GE.1.E8) THEN
              CH1=0.25
              CH2=0.25
              CH3=0.5
              END IF

          MWCWP = 12.0E6
          END IF

          LCH1=CLOAD*CH1
          LCH2=CLOAD*CH2
          LCH3=CLOAD*CH3

C*****
★
C***** SET OUTPUT
C*****
★
990   OUT(1) = STBTOT

```



```

OUT(2) = STB1
OUT(3) = STB2
OUT(4) = STB3
OUT(5) = STB4
OUT(6) = STB5
OUT(7) = MSTTUR
OUT(8) = MPRV1
OUT(9) = MPRV2
OUT(10)= MPRV3
OUT(11)= MPRV4
OUT(12)= EXC10T
OUT(13)= MCOND
OUT(14)= MLOSS
OUT(15)= MAIRT
OUT(16)= LCH1
OUT(17)= LCH2
OUT(18)= LCH3
OUT(19)= MWCWP
OUT(20)= EXC10F
OUT(21)= MSTADD
OUT(22)= MFAN
IF (MODE.EQ.6) OUT(23)=MSTT2
GOTO 998

C**** IF END OF INPUT FILE REACHED
999  WRITE(6,997) TIME, INFO(1), INFO(2)
997  FORMAT(T2,'***** WARNING *****',/,
+T2,' TIME : ',E12.5,' UNIT : ',I3,' TYPE : ',I3,/,
+' END OF INPUT FILE REACHED, SIMULATION STOPPED !!!',/)
STOP

998  CONTINUE
RETURN
END

```

**Control for
Walnut Street Plant
TYPE 70**

C***** VERSION:10/28/10

SUBROUTINE TYPE70 (TIME,XIN,OUT,T,DTDT,PAR,INFO)

```

C*****
C****
C**** THIS ROUTINE PERFORMS THE OPERATIONAL CONTROL OF THE
C**** WALNUT STREET HEATING AND COOLING PLANT
C****
C*****
C*****
C
C   NOMENCLATURE: IN ALPHABETICAL ORDER
C
C   CLOAD   : TOTAL CHILLED WATER LOAD
C   CHL...  : LOAD ON EACH CHILLER
C   MODE    : MODE 1: WSP RUNS AS IN 87/88
C             MODE 2: WSP IS RUN BY SYSTEM CONTROLLER
C             MODE 3: WSP IS RUN BY SYSTEM CONTROLLER, THIRD CHILLER
C   STBWSP  : TOTAL BOILER STEAM PRODUCTION
C   STB...  : STEAM LOAD ON EACH BOILER
C*****

```

DIMENSION XIN(2),PAR(1),OUT(5),INFO(10)

INFO(6)=5

```

C*****
C**** SET PARAMETERS AND INPUTS
C*****
C   MODE=PAR(1)

```

```

C   CLOAD = XIN(1)
C   STBWSP= XIN(2)

```

```

C*****
C**** CONTROL OF WSP CHILLERS
C*****
C   IF (CLOAD.LT.3.6E7) THEN
C     CHL1=CLOAD
C     CHL2=0.
C     CHL3=0.
C
C   ELSE IF (CLOAD.GE.3.6E7) THEN
C     CHL1=CLOAD/2.
C     CHL2=CLOAD/2.
C     CHL3=0.
C
C   ELSE IF (CLOAD.GE.8.E7 .AND. MODE.EQ.3) THEN

```

```
CHL1=CLOAD/3.  
CHL2=CLOAD/3.  
CHL3=CLOAD/3.  
END IF
```

```
C*****
```

```
C**** CONTROL OF WSP BOILERS (IF OPERATING)
```

```
C*****
```

```
STBWSP=STBWSP*1.2          ! *1.2 BCAUSE OF INTERNAL CONSUMPTION
```

```
IF (STBWSP.LT.100000) THEN
```

```
STB1=STBWSP
```

```
STB2=0.
```

```
ELSE
```

```
STB1=STBWSP/2.
```

```
STB2=STBWSP/2.
```

```
END IF
```

```
C*****
```

```
C**** OUTPUT
```

```
C*****
```

```
OUT (1) = STB1
```

```
OUT (2) = STB2
```

```
OUT (3) = CHL1
```

```
OUT (4) = CHL2
```

```
OUT (5) = CHL3
```

```
CONTINUE
```

```
RETURN
```

```
END
```

**Control for
Blount Street Cycle
TYPE 71**

C**** VERSION:10/28/88

SUBROUTINE TYPE71 (TIME,XIN,OUT,T,DTDT,PAR,INFO)

```

C*****
C****
C**** THIS ROUTINE PERFFORMS THE OPERATIONAL CONTROL OF THE
C**** MG&E BLOUNT STREET PLANT; THE MAJOR TASK IS TO CONTROL
C**** THE INTERACTION OF THE CONDENSING STEAM TURBINE AND THE
C**** FEEDWATER HEATERS
C****
C*****
C*****
C
C  NOMENCLATURE : IN ALPHABETICAL ORDER
C
C  FREX   : FRACTION OF EXTRACTION FOR EVERY EXTRACTION POINT
C  MODE   : MODE 1: 1250 CONDENSING TURB. WITH UP TO 6 EXTR. POINTS
C           DIRECT STEAM LINE TO UW
C           MODE 2: 825 CONDENSING TURB. WITH UP TO 6 EXTR. POINTS,
C           2 BOILERS, DIRECT LINE TO UW
C           MODE 3: 1250 CONDENSING TURB. WITH UP TO 6 EXTR. POINTS,
C           CONDENSER/EVAPORATOR TO UW LOOP
C           MODE 4: 825 CONDENSING TURB. WITH UP TO 6 EXTR. POINTS,
C           2 BOILERS, CONDENSER/EVAP. TO UW LOOP
C           MODE 5: 1250 BACK PRESSURE TURB. (NO EXTRACTION),
C           FLOW DIVERTER TO DA, DIRECT STEAM TO UW
C           MODE 6: 825 BPT, " , 2 BOILERS
C           MODE 7: 1250 BPT, CONDENSER/EVAPORATOR TO UW LOOP
C           MODE 8: 825 PLT, " , 2 BOILERS
C
C  NEXTR  : NUMBER OF EXTRACTION POINTS IF CONDENSING STEAM TURBINE
C  PEL    : DESIRED ELECTRICITY PRODUCTION OF TURBINE
C  STB..  : BOILER STEAM PRODUCTION
C  STCTIN : INLET MASS FLOW RATE FOR CONDENSING STEAM TURBINE
C  STEXTR : EXTRACTION MASS FLOW RATE
C
C*****
C
C  DIMENSION XIN(9),PAR(2),OUT(9),INFO(10)
C  DIMENSION STEXTR(6),FREX(6)
C
C  INFO(6)=9
C
C*****
C**** SET PARAMETERS AND INPUTS
C*****
C  MODE = PAR(1)
C  NEXTR= PAR(2)

```

```

      STBTOT=XIN(1)
      PEL    =XIN(2)

      IF (MODE.LE.4) THEN
      STCTIN=XIN(3)
      DO 10 I=1,NEXTR
      STEXTR(I)=XIN(3+I)
10    CONTINUE
      END IF

C*****
***
C**** MODE 1,2,3,4: PROCEDURE IN CASE OF CONDENSING TURBINE WITH
EXTRACTION
C****          CALCULATION OF EXTRACTION FRACTIONS
C*****
***
      IF (MODE.LE.4) THEN
      FREXT=0.
      DO 20 I=1,NEXTR
      FREX(I)=STEXTR(I)/STCTIN
20    CONTINUE
      END IF

C*****
C**** ONLY ONE BOILER OPERATING (OPTION FOR MORE BOILERS TAKEN OUT)
C*****
      STB1=STBTOT
      STB2=0.

C*****
C**** OUTPUTS
C*****

      OUT(1)=STB1
      OUT(2)=STB2
      OUT(3)=PEL

      IF (MODE.LE.4) THEN
      DO 30 I=1,NEXTR
      OUT(3+I)=FREX(I)
30    CONTINUE
      END IF

      RETURN
      END

```

Appendix C

**System Descriptions and
Summary of Results**

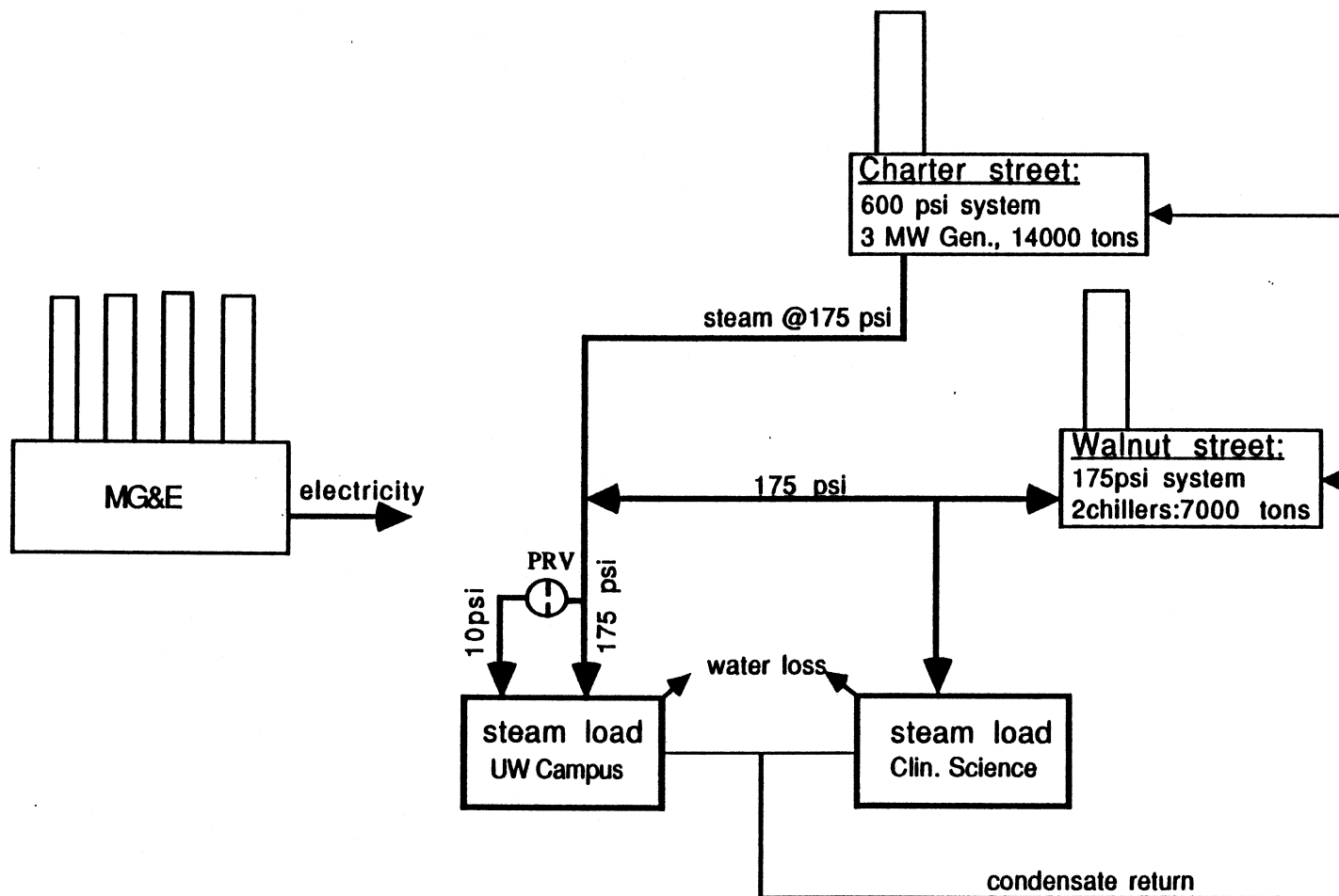


Figure C.1 System 0 (present configuration)

System 0:**Description:**

present configuration at Charter Street (see Ch. 3.1) and Walnut Street (see Ch.1):

note:

- electrically driven equipment (pumps, fans etc.) has not been included in simulation
- only one feedwater pump (#7) is steam driven;
- one air compressor turbine (Worthington) operates parallel to T/G unit throughout the year
- PCW pump runs at design point whenever chilled water is provided to campus

Control of system is similar to actual operation in 1987/88; electricity generation in simulation is higher than in reality (see Ch.3); System 0 serves for additional verifications of simulation (besides model of just CSP) by comparison of results to actual data for both plants

Cost estimates for major modifications: no modifications, since present system

Table C.1.a Estimates of operational costs at UW for first year (see Ch. 5)

Item	annual cost in \$
coal costs	2,488,000
natural gas costs at CSP	3,657,000
natural gas costs at WSP	756,400
electricity sale	-540,000
electricity purchase	723,800
labor	1,350,000
maintenance	475,000
supplies and services	400,000
steam purchase	none
TOTAL	9,310,200

Table C.1.b Annual summary for **System 0** (Actual system in 87/88)

Parameter	Units	Total
Fuel consumption	[tons coal]	119,250
	[J*10 ¹²]	3,221
Electr. generation	[MWh]	18,100
	[J*10 ¹²]	65.1
Add. electr. consumption	[MWh]	0
	[J*10 ¹²]	0
Chiller power	[MWh]	28,500
	[J*10 ¹²]	102.6
other useful power	[MWh]	2,700
	[J*10 ¹²]	9.8
Steam for space heating	[lbs*10 ⁶]	1,524
	[J*10 ¹² energy]	1,841
	[J*10 ¹² availab.]	475
Steam produced	[lbs*10 ⁶]	2,190
	[J*10 ¹² energy]	2,541
	[J*10 ¹² availab.]	969
η_1	[%]	62.5
η_2	[%]	20.2

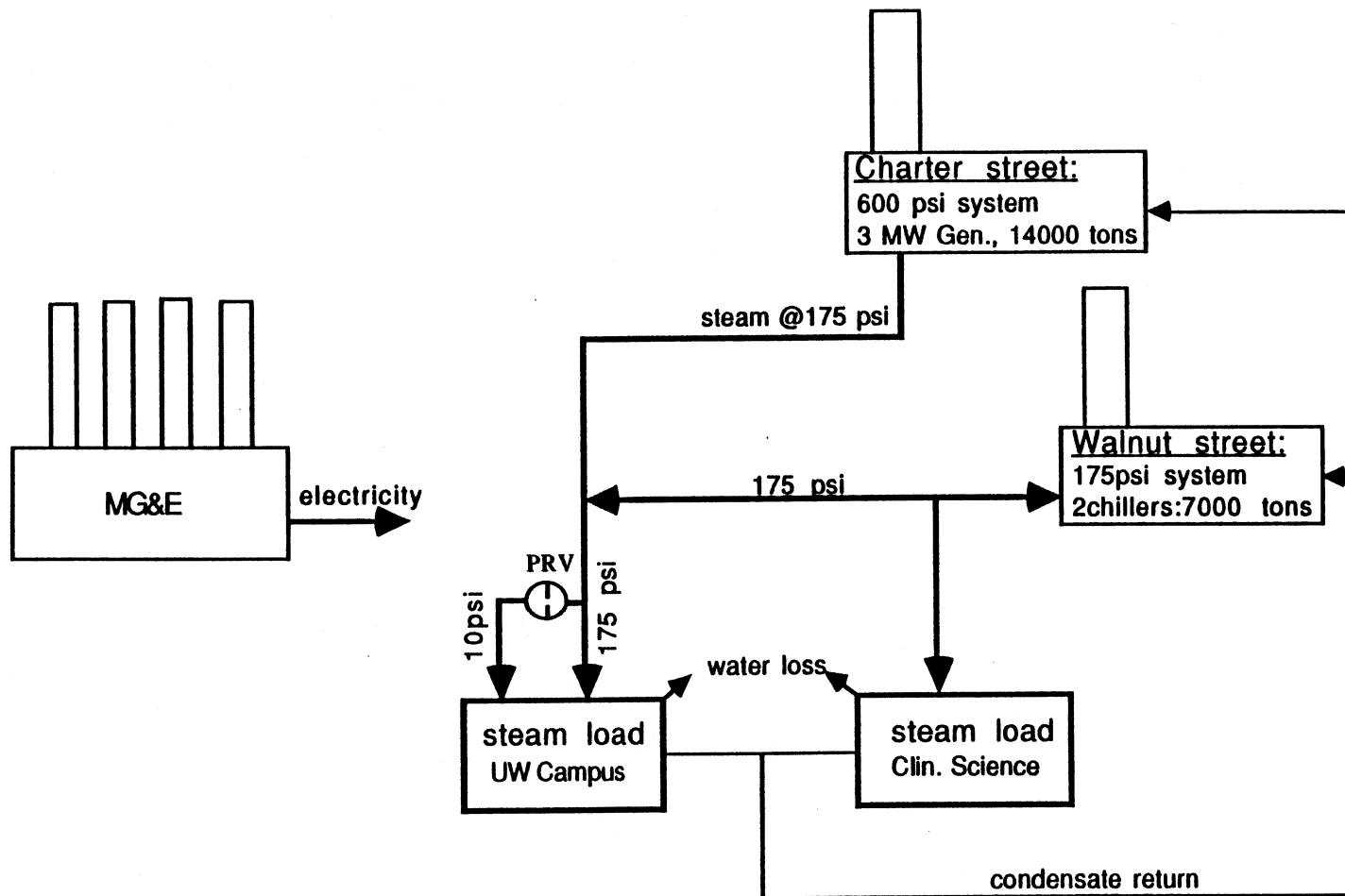


Figure C.2 System 1 (base case for systems without additional chiller, present configuration with modified control)

System 1:**Description:**

equipment configuration is the same as in System 0

Control :

- entire steam load is imposed on CSP, i.e. steam generators at WSP only run if capacity of CSP is exceeded;
- only coal-fired boilers at CSP are operating if possible
- steam driven baghouse turbines run throughout the year
- optimal control for turbine/generator is assumed, i.e. max. available steam flow is used to generate electricity

Cost estimates for major modifications: no changes, since base case

Table C.2.a Estimates of operational costs at UW for first year (see Ch. 5)

Item	annual cost in \$
fuel costs	5,752,300
electricity sale	-630,000
electricity purchase	723,800
labor	1,350,000
maintenance	475,000
supplies and services	400,000
steam purchase	/
TOTAL	8,071,100

Results of economic analysis: (see Ch.5 for explanations)

Life Cycle Costs: \$ 90,180,000

Note: This value should not be taken as an estimate of the absolute life-cycle costs, but only as a basis for comparison of alternative configurations.

Table C.2.b Annual summary for **System 1** (base case)

Parameter	Units	Total
Fuel consumption	[tons coal]	119,840
	[J*10 ¹²]	3,238
Electr. generation	[MWh]	21,000
	[J*10 ¹²]	75.6
Add. electr. consumption	[MWh]	0
	[J*10 ¹²]	0
Chiller power	[MWh]	28,500
	[J*10 ¹²]	102.6
other useful power	[MWh]	2,700
	[J*10 ¹²]	9.8
Steam for space heating	[lbs*10 ⁶]	1,524
	[J*10 ¹² energy]	1,841
	[J*10 ¹² availab.]	475
Steam produced	[lbs*10 ⁶]	2,210
	[J*10 ¹² energy]	2,541
	[J*10 ¹² availab.]	969
Steam for CSP chiller compr.	[lbs*10 ⁶]	254
Steam for WSP chiller compr.	[lbs*10 ⁶]	80
η_1	[%]	62.6
η_2	[%]	20.5

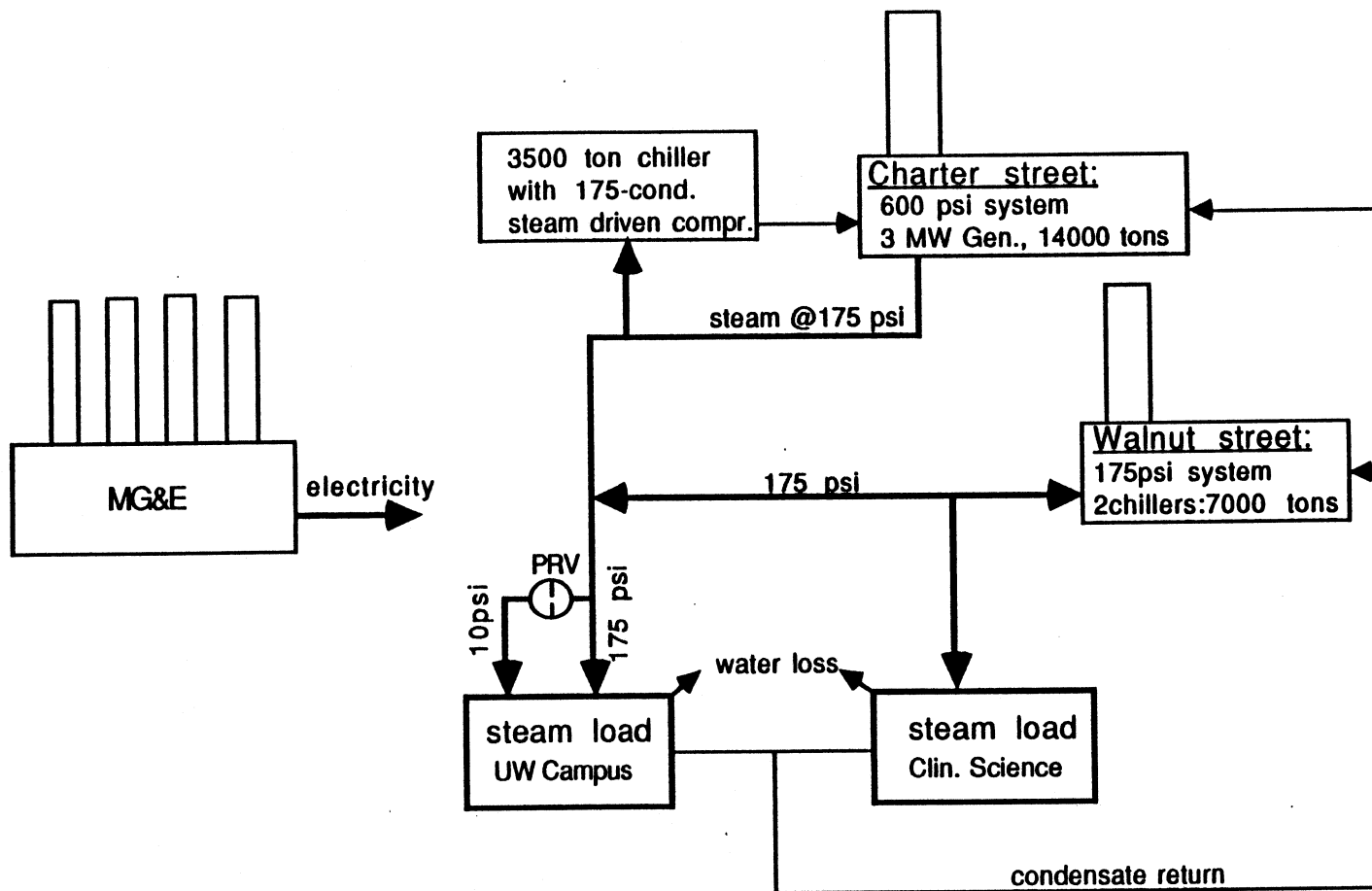


Figure C.3 System 2a (present configuration with additional steam driven chiller unit)

System 2a:**Description:**

equipment configuration is basically the same as in base case; one 3500 ton chiller with a 175psig-condensing steam turbine driven compressor is added to system

Control :

- similar to base case
- new chiller is primarily operated in order to increase electricity generation at CSP

Cost estimates for major modifications:

additional steam turbine driven chiller	\$ 5,000,000

TOTAL	\$ 5,000,000

Table C.3.a Estimates of operational costs at UW for first year (see Ch. 5)

Item	annual costs in \$
fuel costs	5,793,600
electricity sale	-719,400
electricity purchase	723,800
labor	1,350,000
maintenance	475,000
supplies and services	400,000
steam purchase	/
TOTAL	8,023,000

Results of economic analysis: (see Ch.5 for explanations)

Life Cycle Savings compared to System 2b: \$ 1,102,000

Internal Rate of Return: 63 %

Note: The economic analysis is based on the following estimates:

additional cost for steam instead of electrically driven chiller: \$ 200,000

average price for electricity purchase: \$ 0.042 / kWh

Table C.3.b Annual summary for **System 2a** (base case for all systems with additional chiller)

Parameter	Units	Total
Fuel consumption	[tons coal]	120,700
	[J*10 ¹²]	3,259
Electr. generation	[MWh]	23,980
	[J*10 ¹²]	86.3
Add. electr. consumption	[MWh]	0
	[J*10 ¹²]	0
Chiller power	[MWh]	28,500
	[J*10 ¹²]	102.6
other useful power	[MWh]	2,700
	[J*10 ¹²]	9.8
Steam for heating	[lbs*10 ⁶]	1,524
	[J*10 ¹² energy]	1,841
	[J*10 ¹² availab.]	475
Steam produced	[lbs*10 ⁶]	2,234
	[J*10 ¹² energy]	2,566
	[J*10 ¹² availab.]	978
η_1	[%]	62.6
η_2	[%]	20.6

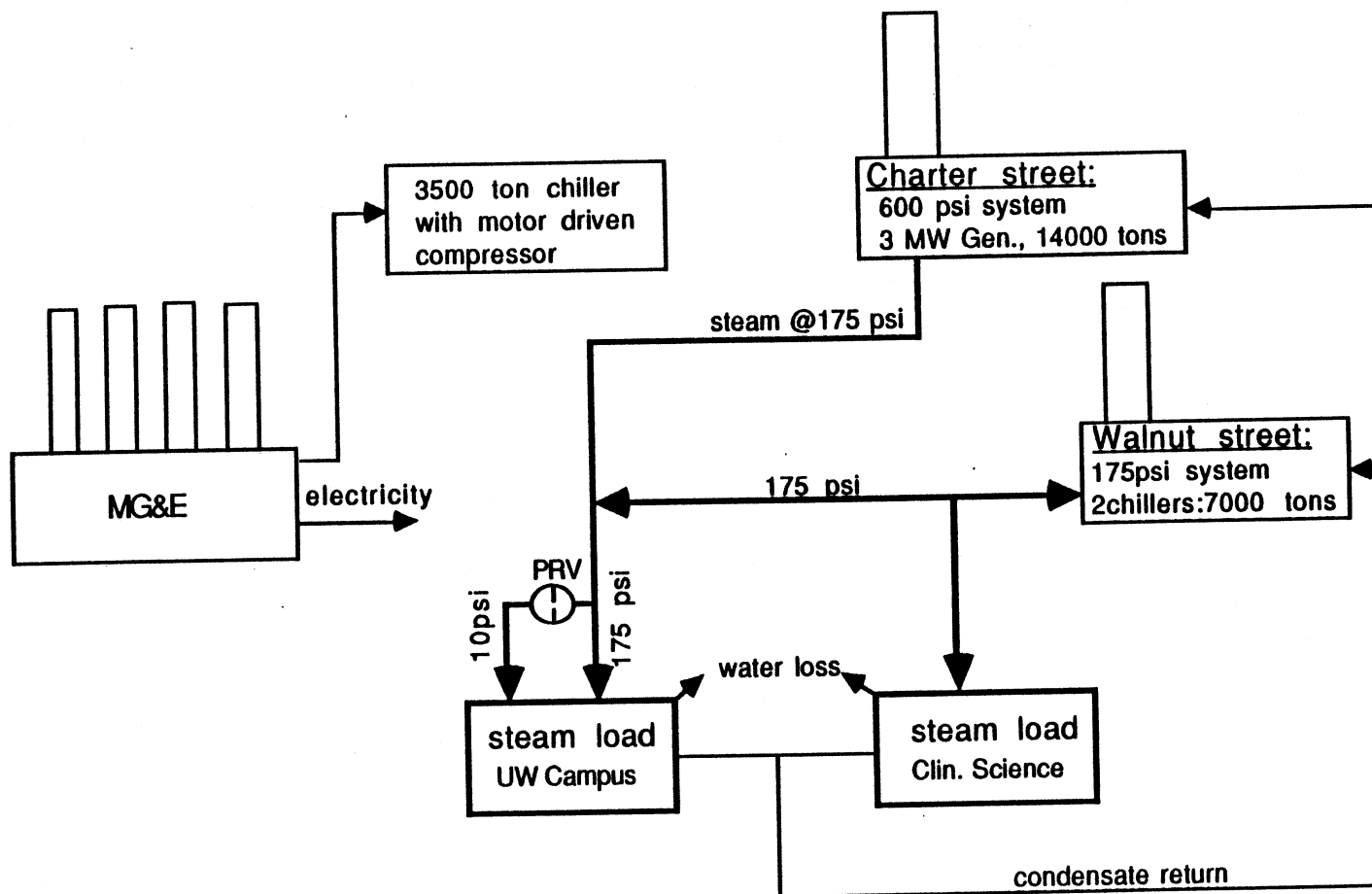


Figure C.4 System 2b (present configuration with additional electrically driven chiller unit)

System 2b:**Description:**

equipment configuration is basically the same as in base case; one 3500 ton chiller with an electric motor driven compressor is added to system

Control :

- similar to base case
- new chiller is operated like in System 2a (for comparison)

Cost estimates for major modifications:

additional chiller with electric motor	4,800,000

TOTAL	4,800,000

Table C.4.a Estimates of operational costs at UW for first year (see Ch. 5)

Item	annual costs in \$
fuel costs	5,525,300
electricity sale	-630,000
electricity purchase	1,011,500
labor	1,350,000
maintenance	475,000
supplies and services	400,000
steam purchase	/
TOTAL	8,131,800

Results of economic analysis: (see Ch.5 for explanations)

Life Cycle Costs: \$ 95,660,000

Note: Similar to System 1, these costs should not be used as an absolute value, but only for comparative purposes.

Table C.4.b Annual summary for **System 2b** (additional electricically driven chiller)

Parameter	Units	Total
Fuel consumption	[tons coal]	115,110
	[J*10 ¹²]	3,107
Electr. generation	[MWh]	21,000
	[J*10 ¹²]	75.7
Add. electr. consumption	[MWh]	6,850
	[J*10 ¹²]	23.3
Chiller power	[MWh]	28,500
	[J*10 ¹²]	102.6
other useful power	[MWh]	2,700
	[J*10 ¹²]	9.8
Steam for space heating	[lbs*10 ⁶]	1,524
	[J*10 ¹² energy]	1,841
	[J*10 ¹² availab.]	475
Steam produced	[lbs*10 ⁶]	2,117
	[J*10 ¹² energy]	2,545
	[J*10 ¹² availab.]	928
η_1	[%]	64.5
η_2	[%]	20.5

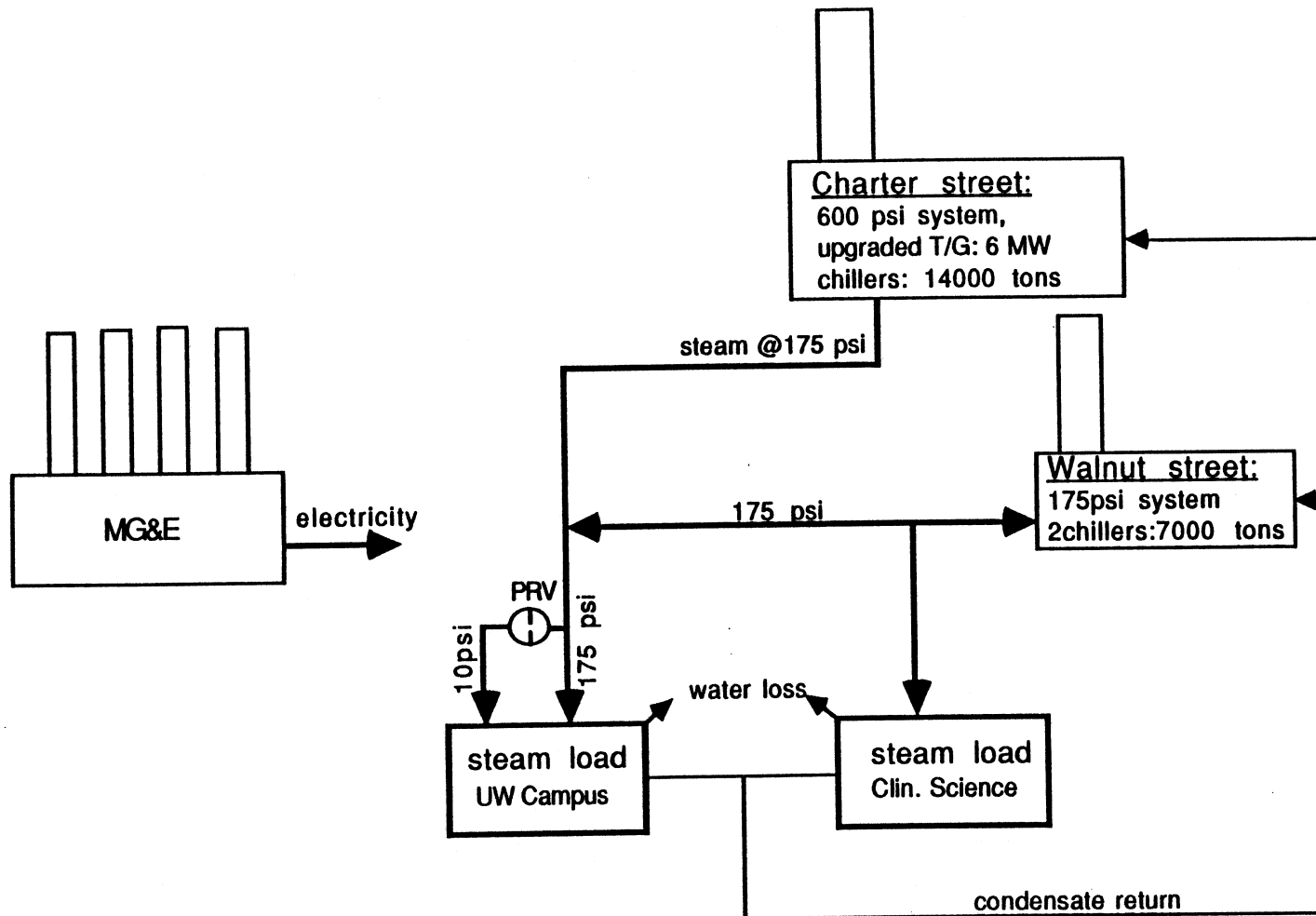


Figure C.5 System 3a (present configuration with upgraded 6 MW turb./generator at Charter Street)

System 3a:**Description:**

equipment configuration similar to base case with following modifications:

- Turbine/generator upgraded from 3 MW to 6 MW (heat rate 35 lb / kWh)
- new air compressor and PCW pump with electric motors instead of steam driven ones

Control :

- same as in base case
- upgraded turbine permits steam flow of 210,000 lb/hr

Cost estimates for major modifications:

upgrading of turbine/generator	\$3,000,000
electrically driven air compressor	\$280,000
electrically driven PCW pump	\$210,000

TOTAL	\$3,490,000

Table C.5.a Estimates of operational costs at UW for first year (see Ch. 5)

Item	annual costs in \$
fuel costs	5,784,000
electricity sale	-1,062,600
electricity purchase	837,200
labor	1,350,000
maintenance	475,000
supplies and services	400,000
steam purchase	/
TOTAL	7,783,600

Results of economic analysis: (see Ch.5 for explanations)

Life Cycle Savings compared to base case: \$ -270,000 (no savings in analysis period)

Internal Rate of Return: 8.0 %

Table C.5.b Annual summary for System 3a (upgraded turbine/generator at CSP)

Parameter	Units	Total
Fuel consumption	[tons coal]	120,500
	[J*10 ¹²]	3,254
Electr. generation	[MWh]	35,420
	[J*10 ¹²]	126.0
Add. electr. consumption	[MWh]	2,700
	[J*10 ¹²]	9.8
Chiller power	[MWh]	28,500
	[J*10 ¹²]	102.6
other useful power	[MWh]	2,700
	[J*10 ¹²]	9.8
Steam for space heating	[lbs*10 ⁶]	1,524
	[J*10 ¹² energy]	1,841
	[J*10 ¹² availab.]	475
Steam produced	[lbs*10 ⁶]	2,222
	[J*10 ¹² energy]	2,555
	[J*10 ¹² availab.]	974
η_1	[%]	63.6
η_2	[%]	21.6

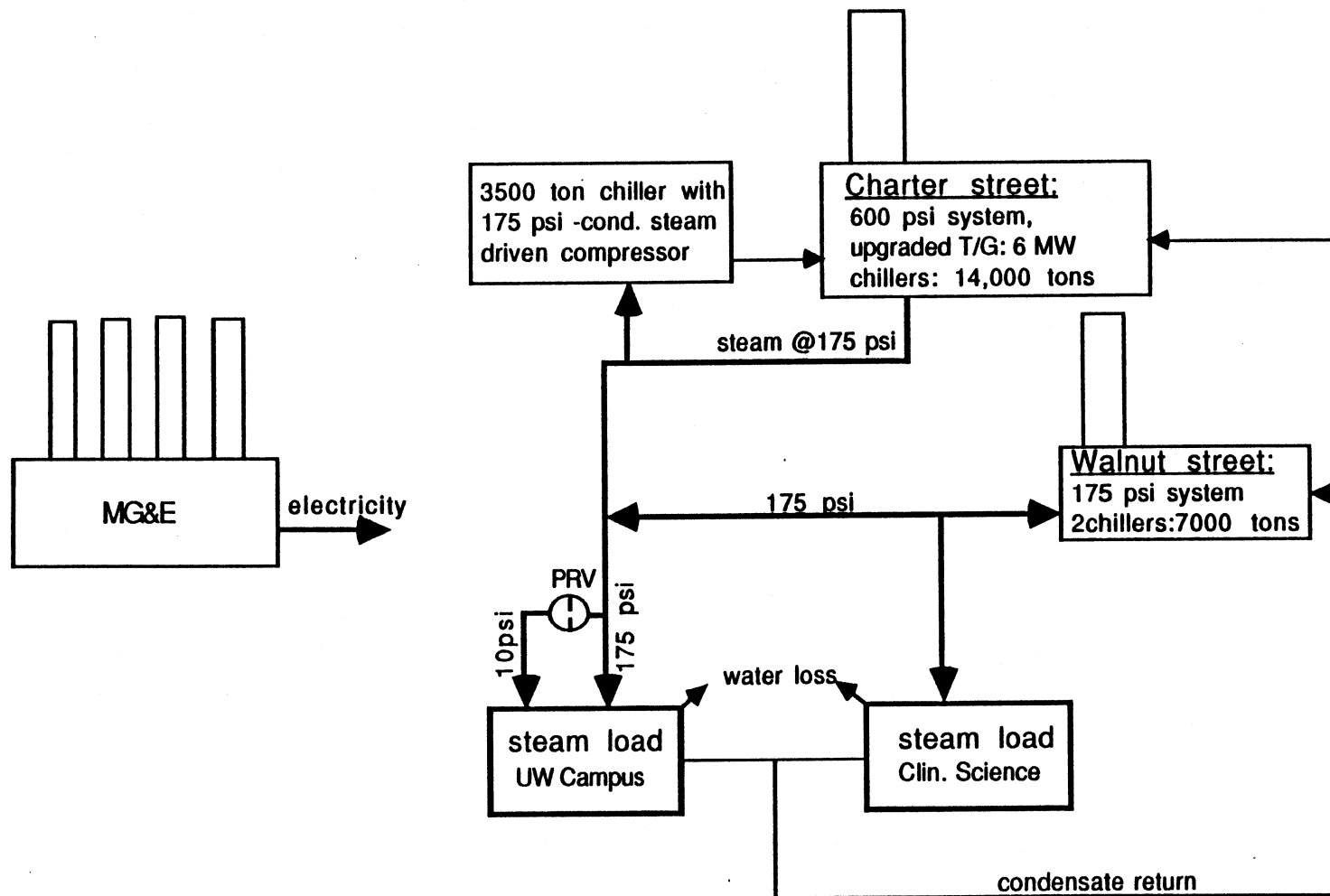


Figure C.6 System 3b (present configuration with upgraded 6 MW turb./generator at Charter Street and new chiller)

System 3b:

Description:

equipment configuration similar to base case with following modifications:

- Turbine/generator upgraded from 3 MW to 6 MW
- new air compressor and PCW pump with electric motors
- additional 3500 ton chiller with 175psig-condensing compressor turbine (note: new chiller is similar to those at WSP and is slightly more efficient than the existing old ones at CSP, but still needs a higher steam mass flow, because of the 175-condensing turbine)

Control :

- same as in base case
- upgraded turbine permits a steam flow of 210,000 lb/hr

Cost estimates for major modifications:

upgrading of turbine/generator	\$3,000,000
electrically driven air compressor	\$280,000
electrically driven PCW pump	\$210,000
additional steam turbine driven chiller	\$5,000.000

TOTAL	\$8,490,000

Table C.6.a Estimates of operational costs at UW for first year (see Ch. 5)

Item	annual costs in \$
fuel costs	5,822,400
electricity sale	-1,161,900
electricity purchase	847,000
labor	1,350,000
maintenance	475,000
supplies and services	400,000
steam purchase	/
TOTAL	7,732,500

Results of economic analysis: (see Ch.5 for explanations)

Life Cycle Savings compared to base case (System 2a): \$ -270,000 (no savings)

Internal Rate of Return: 8.1 %

Table C.6.b Annual summary for System 3b (upgraded turbine and add. chiller)

Parameter	Units	Total
Fuel consumption	[tons coal]	121,300
	[J*10 ¹²]	3,274
Electr. generation	[MWh]	38,730
	[J*10 ¹²]	139.4
Add.electr. consumption	[MWh]	2,700
	[J*10 ¹²]	9.8
Chiller power	[MWh]	28,500
	[J*10 ¹²]	102.6
other useful power	[MWh]	2,700
	[J*10 ¹²]	9.8
Steam for space heating	[lbs*10 ⁶]	1,524
	[J*10 ¹² energy]	1,841
	[J*10 ¹² availab.]	475
Steam produced	[lbs*10 ⁶]	2,236
	[J*10 ¹² energy]	2,571
	[J*10 ¹² availab.]	980
η_1	[%]	63.6
η_2	[%]	21.9

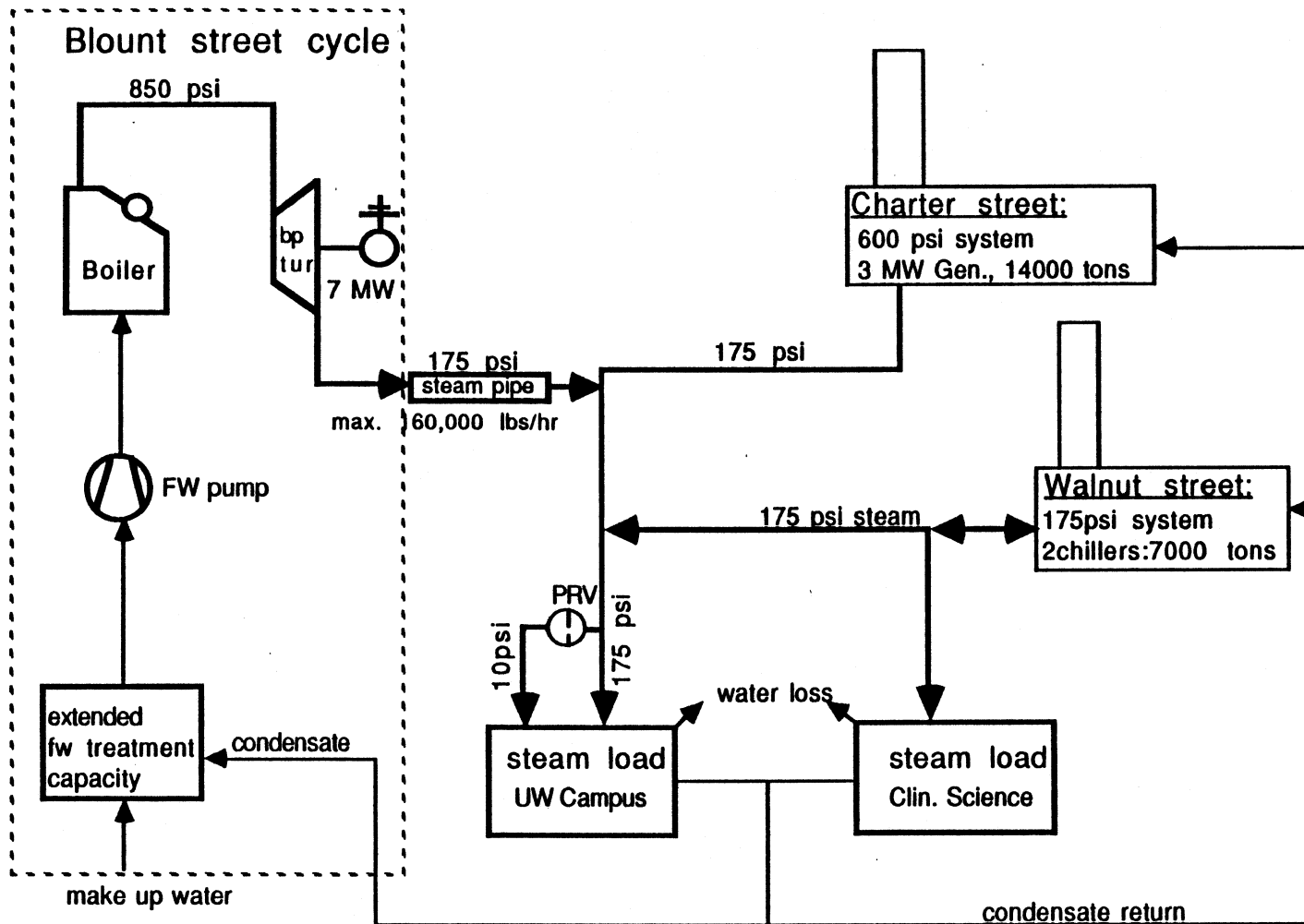


Figure C.7 System 4a (present CSP and WSP; MG&E cogenerates with 7 MW backpressure turbine in 850 psig cycle)

System 4a:**Description:**

MG&E: up to 160,000 lb/hr of steam at 180 psig are extracted from 7 MW backpressure steam turbine in the present 850 psig cycle; a desuperheater (for the exiting steam) and a deaerator are part of system

CSP: equipment configuration similar to base case with following modifications:

- new air compressor and PCW pump with electric motors instead of steam driven ones

Control :

- MG&E supplies steam only from October until April; during the summer months the steam demand on CSP is sufficient to generate electricity with its 3 MW T/G unit, but too low to cogenerate at MG&E on a continuous basis.

Cost estimates for major modifications:

construction of steam pipe	\$6,500,000
7 MW back pressure turbine at MG&E	\$2,200,000
electrically driven air compr. at CSP	\$280,000
electrically driven PCW pump at CSP	\$210,000
TOTAL	\$9,190,000

Table C.7.a Estimates of operational costs at UW for first year (see Ch. 5)

Item	annual costs in \$
fuel costs	3,583,000
electricity sale	-546,000
electricity purchase	779,800
labor	1,350,000
maintenance	370,000
supplies and services	400,000
steam purchase	1,710,000
TOTAL	7,646,800

Results of economic analysis: (see Ch.5 for explanations)

Life Cycle Savings compared to base case (System 1): \$ -4,340,000 (no savings)

Internal Rate of Return: 0.9 %

Table C.7.b Annual summary for System 4a (MGE 850, 7 MW back pressure, steam supply only in winter)

Parameter	Units	CSP+WSP	MG&E	TOTAL
Fuel consumption	[tons coal]	74,645	49,521	124,165
	[J*10 ¹²]	2,015	1,337	3,353
Electr. generation	[MWh]	18,200	32,183	50,380
	[J*10 ¹²]	65.5	116	181.5
Add. electr. cons.	[MWh]	2,700	3,000	5,700
	[J*10 ¹²]	9.8	10.8	20.6
Chiller power	[MWh]	28,500	0	28,500
	[J*10 ¹²]	102.6	0	102.6
other useful power	[MWh]	2,700	0	2,700
	[J*10 ¹²]	9.8	0	9.8
Steam for space heating	[lbs*10 ⁶]	751	773	1,524
	[J*10 ¹² energy]	957	934	1,841
	[J*10 ¹² availab.]	234	241	475
Steam produced	[lbs*10 ⁶]	1,373	930	2,303
	[J*10 ¹² energy]	1,578	1,160	2,738
	[J*10 ¹² availab.]	602	482	1,084
η_1	[%]	55.8	77.7	63.1
η_2	[%]	20.0	25.9	22.3

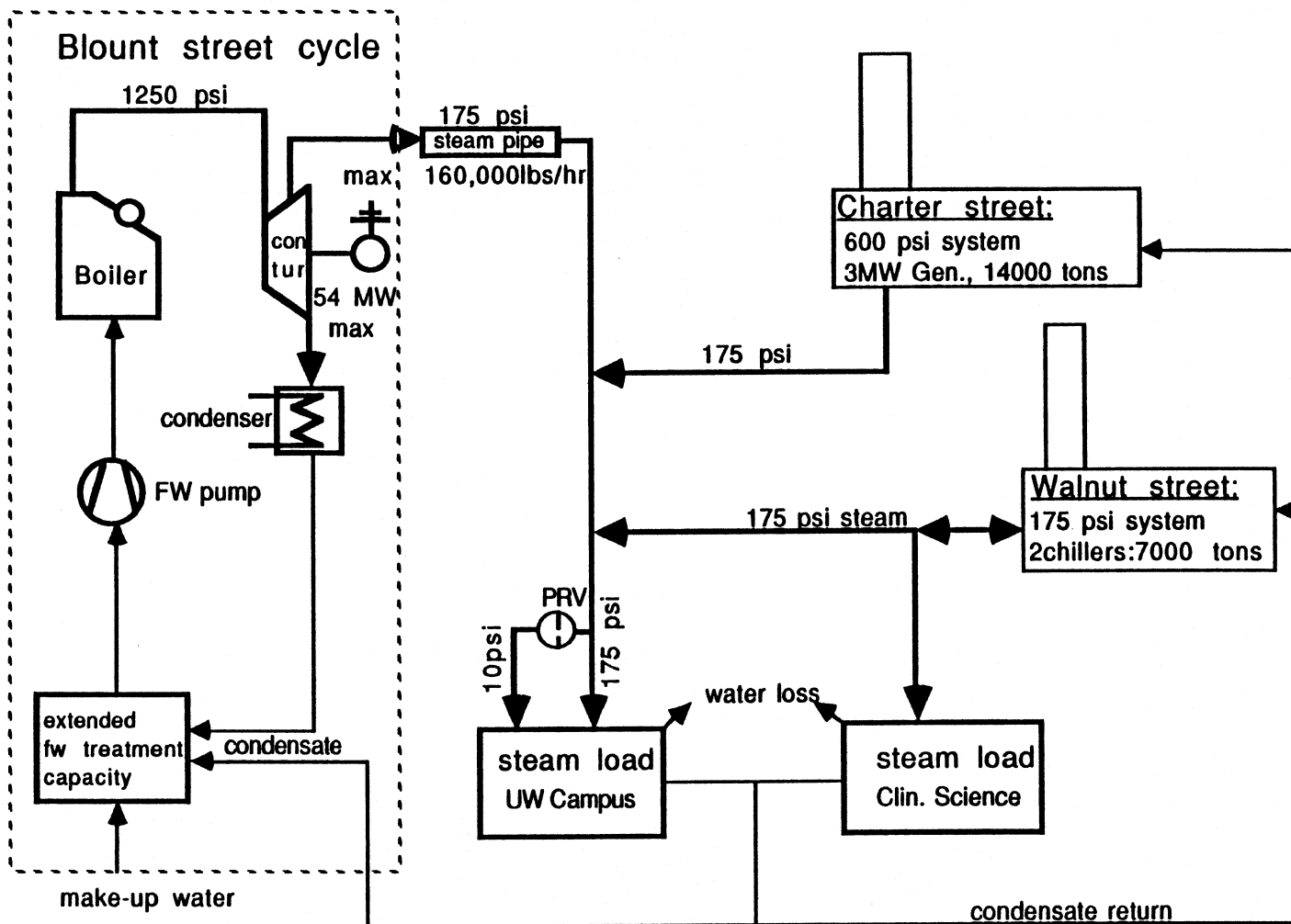


Figure C.8 System 4b (present CSP and WSP; MG&E cogenerates with 54 MW condensing steam turbine in 1250 psi cycle)

System 4b:**Description:**

MG&E: up to 160,000 lb/hr of steam at 180 psig are extracted from 54 MW condensing steam turbine in the present 1250 psig cycle; desuperheater for exiting steam; deaerator and 4 feedwater heaters are part of cycle

CSP: same configuration as in System 4a

Control :

- MG&E supplies steam only from October until April; unit is blockloaded at 40 MW; the steam demand in the summer is too low and too irregular to justify extraction from MG&E; the utility might also need all available capacity to meet peak electricity demands in the cooling season; furthermore the steam demand on CSP is sufficient to generate electricity with its 3 MW T/G unit

Cost estimates for major modifications:

construction of steam pipe	\$6,500,000
extraction option at condensing turbine	(not available)*
electrically driven air compr. at CSP	\$280,000
electrically driven PCW pump at CSP	\$210,000
TOTAL	7,990,000

*: assume: \$1,000,000

Table C.8.a Estimates of operational costs at UW for first year (see Ch. 5)

Item	annual costs in \$
fuel costs	3,504,000
electricity sale	-498,000
electricity purchase	772,000
labor	1,350,000
maintenance	365,000
supplies and services	400,000
steam purchase	1,961,000
TOTAL	7,854,800

Results of economic analysis: (see Ch.5 for explanations)

Life Cycle Savings compared to base case (System 1): \$ -5,430,000 (no savings)

Internal Rate of Return: -4.3 %

Table C.8.b Annual summary for **System 4b** (MGE 1250, extraction from 54 MW condensing turbine only in winter)

Parameter	Units	CSP+WSP	MG&E	TOTAL
Fuel consumption	[tons coal]	73,000	167,100	240,100
	[J*10 ¹²]	1,970	4,513	6,483
Electr. generation	[MWh]	16,600	350,400	367,000
	[J*10 ¹²]	60.0	1,261	1,321
Add. electr. cons.	[MWh]	2,700	30,000	32,700
	[J*10 ¹²]	9.8	108	117.8
Chiller power	[MWh]	28,500	0	28,500
	[J*10 ¹²]	102.6	0	102.6
other useful power	[MWh]	2,700	0	2,700
	[J*10 ¹²]	9.8	0	9.8
Steam for space heating	[lbs*10 ⁶]	784	740	1,524
	[J*10 ¹² energy]	947	894	1,841
	[J*10 ¹² availab.]	244	231	475
Steam produced	[lbs*10 ⁶]	1,337	3,135	4,472
	[J*10 ¹² energy]	1,537	3,962	5,499
	[J*10 ¹² avail.]	568	1,731	2,299
η_1	[%]	56.3	45.4	48.7
η_2	[%]	20.6	30.1	27.6

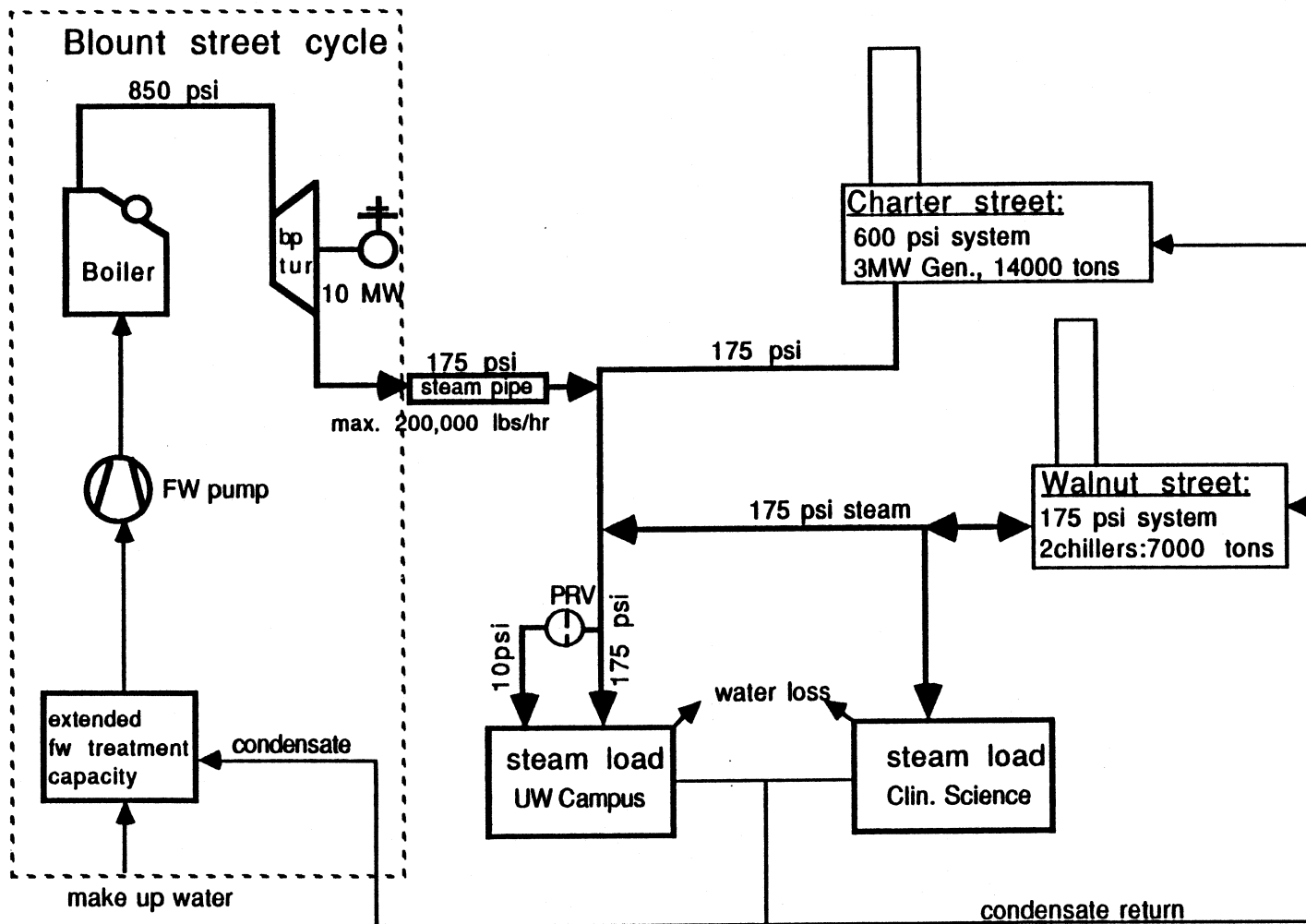


Figure C.9 System 4c (present CSP and WSP; MG&E cogenerates with 10 MW backpressure turbine in 850 psi cycle)

System 4c:**Description:**

MG&E: up to 200,000 lb/hr of steam at 180 psig are extracted from 10 MW backpressure steam turbine in the present 850 psig cycle

CSP: same as in System 4a

Control : steam supply from MG&E is as high as possible; CSP provides steam to campus only if capacity of MG&E (200,000 lb/hr) is exceeded and CSP meets internal loads (chiller compressors, pumps etc.)

Cost estimates for major modifications:

construction of steam pipe	\$6,500,000
10 MW back pressure turbine at MG&E	\$2,400,000
electrically driven air compr. at CSP	\$280,000
electrically driven PCW pump at CSP	\$210,000
TOTAL	\$9,390,000

Table C.9.a Estimates of operational costs at UW for first year (see Ch. 5)

Item	annual costs in \$
fuel costs	2,287,000
electricity sale	-221,000
electricity purchase	774,800
labor	1,350,000
maintenance	310,000
supplies and services	400,000
steam purchase	2,983,000
TOTAL	7,853,800

Results of economic analysis: (see Ch.5 for explanations)

Life Cycle Savings compared to base case (System 1): \$ -6,750,000 (no savings)

Internal Rate of Return: -5.4 %

Table C.9.b Annual summary for **System 4c** (MGE 850, 10 MW backpressure turbine, steam supply all year long)

Parameter	Units	CSP+WSP	MG&E	TOTAL
Fuel consumption	[tons coal]	47,650	76,580	124,230
	[J*10 ¹²]	1,285	2,068	3,353
Electr. generation	[MWh]	7,360	51,600	58,930
	[J*10 ¹²]	26	186	212
Add. electr. cons.	[MWh]	2,700	5,000	7,700
	[J*10 ¹²]	9.8	18	27.8
Chiller power	[MWh]	28,500	0	28,500
	[J*10 ¹²]	102.6	0	102.6
other useful power	[MWh]	2,700	0	2,700
	[J*10 ¹²]	9.8	0	9.8
Steam for space heating	[lbs*10 ⁶]	164	1,360	1,524
	[J*10 ¹² energy]	198	1,642	1,841
	[J*10 ¹² availab.]	51	424	475
Steam produced	[lbs*10 ⁶]	871	1,509	2,380
	[J*10 ¹² energy]	1,002	1,883	2,885
	[J*10 ¹² availab.]	382	782	1,164
η_1	[%]	25.4	86.7	63.8
η_2	[%]	14.0	28.6	23.0

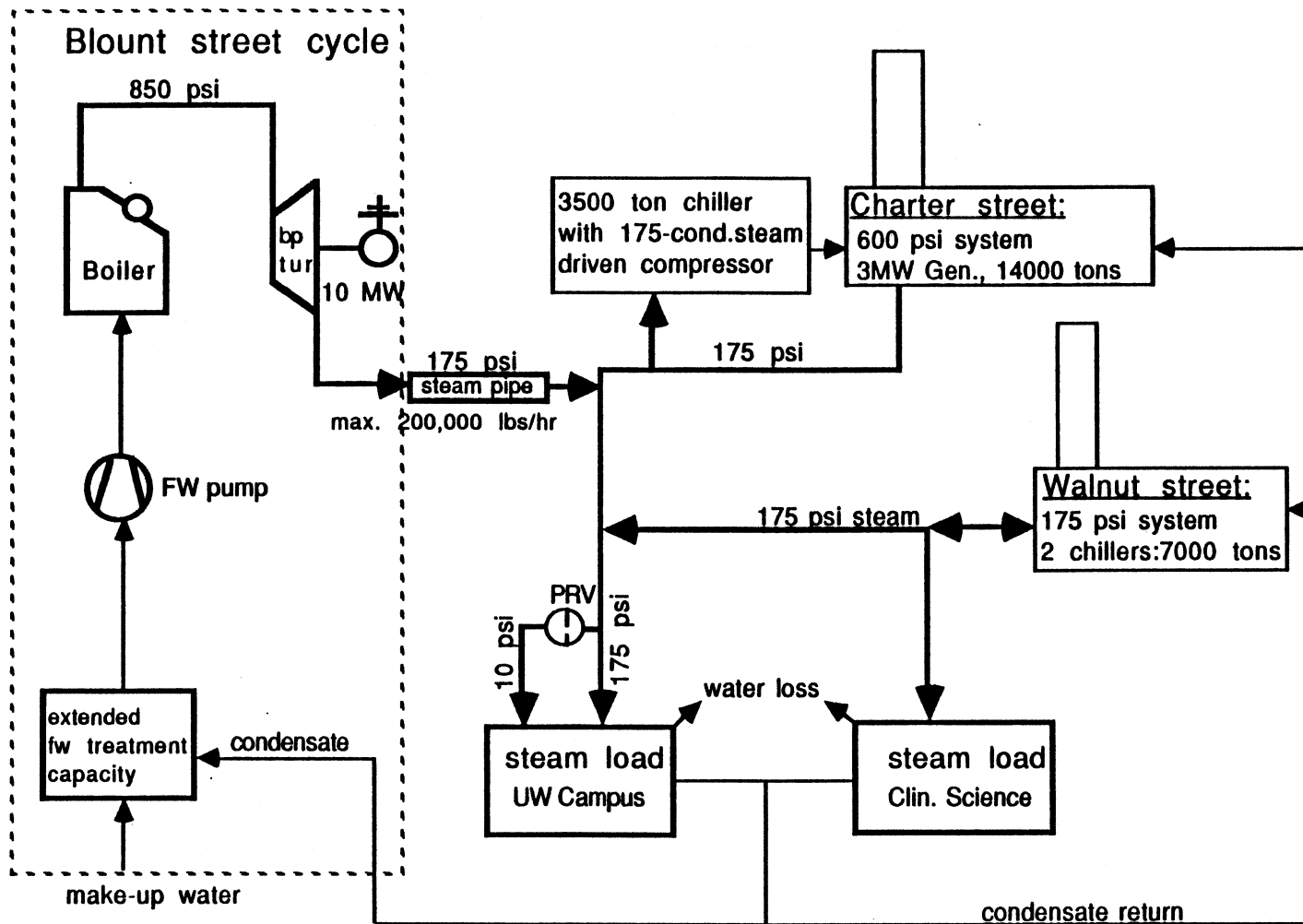


Figure C.10 System 4d (present CSP and WSP with additional chiller;
MG&E cogenerates with 10 MW backpressure turbine in 850 psi cycle)

System 4d:**Description:****MG&E:** same as in System 4c**CSP:** addition of a new 3500 ton chiller with a 175 psig condensing compressor turbine**Control :** same as in System 4c

- new chiller is operated as frequently as possible to increase demand for 175 psig steam and thus to increase electricity generation and efficiency of turbine/generators

Cost estimates for major modifications:

construction of steam pipe	\$6,500,000
10 MW back pressure turbine at MG&E	\$2,400,000
electrically driven air compr. at CSP	\$280,000
electrically driven PCW pump at CSP	\$210,000
additional chiller with steam turbine drive	\$5,000,000
TOTAL	\$14,390,000

Table C.10.a Estimates of operational costs at UW for first year (see Ch. 5)

Item	annual costs in \$
fuel costs	2,005,000
electricity sale	-220,000
electricity purchase	738,000
labor	1,350,000
maintenance	295,000
supplies and services	400,000
steam purchase	3,212,000
TOTAL	\$7,780,000

Results of economic analysis: (see Ch.5 for explanations)

Life Cycle Savings compared to base case (System 2a): \$ - 6,460,000 (no savings)

Internal Rate of Return: - 4.5 %

Table C.10.b Annual summary for System 4d (MGE 850, 10 MW back pressure turbine, CSP with additional steam driven chiller)

Parameter	Units	CSP+WSP	MG&E	TOTAL
Fuel consumption	[tons coal]	41,770	82,208	123,978
	[J*10 ¹²]	1,127	2,220	3,347
Electr. generation	[MWh]	7,340	56,366	63,706
	[J*10 ¹²]	26	203	229
Add. electr. cons.	[MWh]	2,700	5,250	7,950
	[J*10 ¹²]	9.8	18.9	28.7
Chiller power	[MWh]	28,500	0	28,500
	[J*10 ¹²]	102.6	0	102.6
other useful power	[MWh]	2,700	0	2,700
	[J*10 ¹²]	9.8	0	9.8
Steam for space heating	[lbs*10 ⁶]	56	1,468	1,524
	[J*10 ¹² energy]	68	1,773	1,841
	[J*10 ¹² availab.]	17	458	475
Steam produced	[lbs*10 ⁶]	761	1,627	2,388
	[J*10 ¹² energy]	875	2,030	2,905
	[J*10 ¹² availab.]	333	843	1,176
η_1	[%]	17.4	88.1	64.3
η_2	[%]	12.9	28.9	23.5

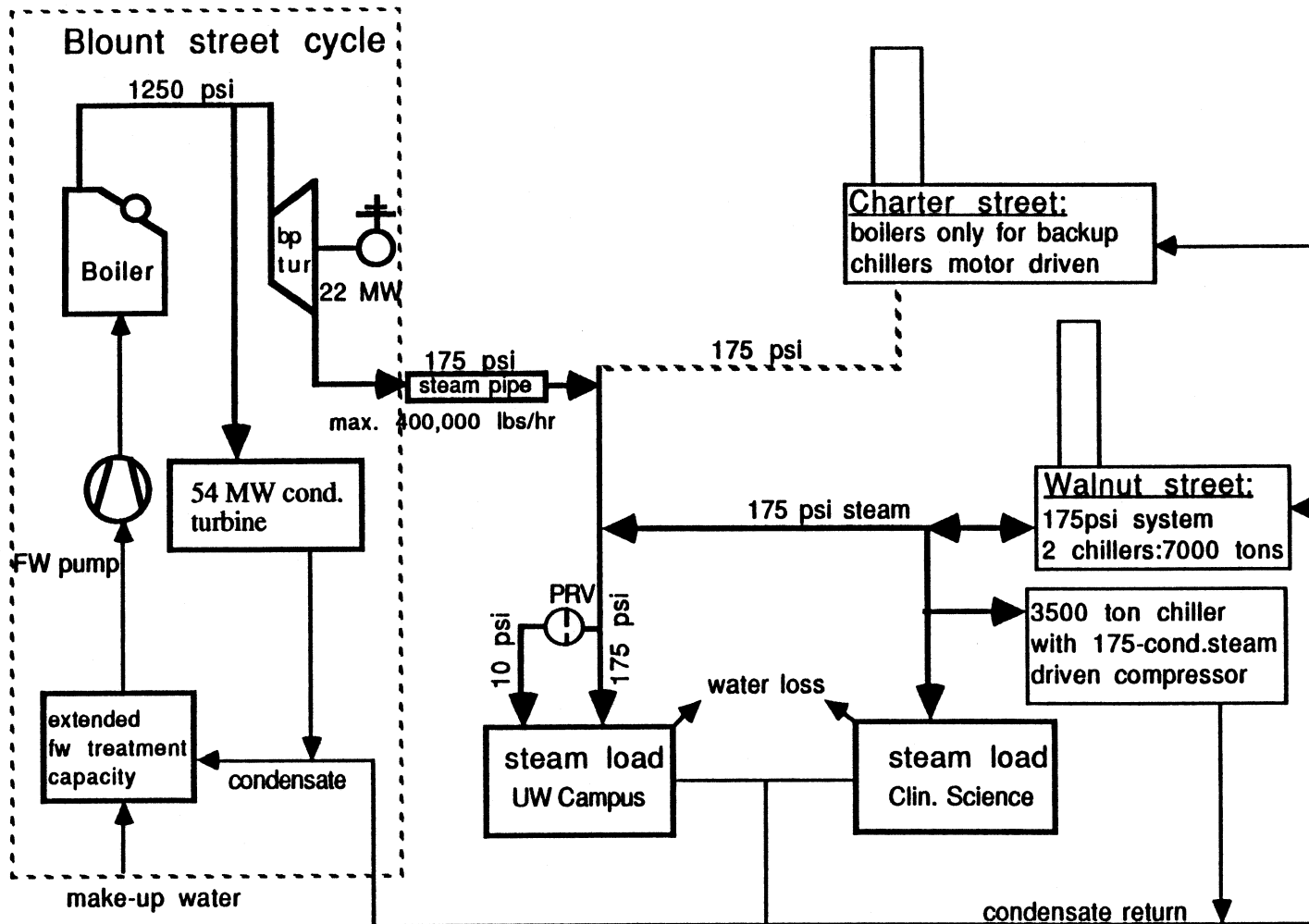


Figure C.11 System 4e (present CSP (idling) and WSP with additional chiller; MG&E cogenerates with 22 MW backpressure turbine parallel to existing 54 MW condensing steam turbine in 1250 psi cycle)

System 4e:

Description:

MG&E: up to 400,000 lb/hr of steam at 180 psig can be supplied by extraction from 22 MW backpressure steam turbine in 1250 psig cycle, which is installed parallel to existing condensing steam turbine; cycle includes desuperheater for extracted steam and deaerator for feedwater preheating and treatment; the maximum boiler capacity of 450,000 lb/hr is used, when 400,000 lb/hr are supplied to campus

CSP: boilers are only started up in case of an emergency, steam cycle is idling

- chiller compressors, air compressors and PCW pump are motor driven
- additional 3500 ton chiller with steam turbine drive (same as in System 4d)

WSP: boilers with max. capacity of 300,000 lb/hr serve as primary backup for system

Control : steam supply from MG&E is as high as possible; it is assumed that there are no limitations for cogeneration at MG&E (due to electricity demand peaks in the summer for instance)

- WSP takes swings in demand and provides additional steam if capacity of MG&E (450,000 lb/hr) is exceeded
- additional chiller runs whenever possible to minimize electricity demand for motor driven units at CSP

Cost estimates for major modifications:

construction of steam pipe	\$6,500,000
22 MW back pressure turbine at MG&E	\$5,300,000
electrically driven air compr. at CSP	\$280,000
electrically driven PCW pump at CSP	\$210,000
motor drives for chillers at CSP	\$1,600,000
additional chiller with steam turbine drive	\$5,000,000

TOTAL	\$18,890,000

Table C.11.a Estimates of operational costs at UW for first year (see Ch. 5)

Item	annual costs in \$
fuel costs	12,000
electricity sale	0
electricity purchase	1,336,400
labor	1,350,000
maintenance	200,000
supplies and services	400,000
steam purchase	4,346,000
TOTAL	7,644,400

Results of economic analysis: (see Ch.5 for explanations)

Life Cycle Savings compared to base case (System 2a): \$ -9,360,000 (no savings)

Internal Rate of Return: - 3.8 %

Table C.11.b Annual summary for System 4e (CSP idles, MGE 1250, 22 MW back-pressure turbine)

Parameter	Units	CSP+WSP	MG&E	TOTAL
Fuel consumption	[tons coal]	200	104,700	104,900
	[J*10 ¹²]	5	2,825	2,830
Electr. generation	[MWh]	0	84,330	84,330
	[J*10 ¹²]	0	304	304
Add. electr. cons.	[MWh]	18,200	9,500	27,700
	[J*10 ¹²]	65.6	32.5	98.0
Chiller power	[MWh]	15,500	13,000	28,500
	[J*10 ¹²]	55.8	46.8	102.6
other useful power	[MWh]	2,700	0	2,700
	[J*10 ¹²]	9.8	0	9.8
Steam for space heating	[lbs*10 ⁶]	0	1,524	1,524
	[J*10 ¹² energy]	0	1,841	1,841
	[J*10 ¹² availab.]	0	475	475
Steam for chiller comp.	[lbs*10 ⁶]	0	220	220
Steam produced	[lbs*10 ⁶]	2.6	1,910	1,912
	[J*10 ¹² energy]	3.3	2,304	2,307
	[J*10 ¹² availab.]	1.4	1,008	1,010
η_1	[%]	/	76.4	76.3
η_2	[%]	/	28.1	28.0

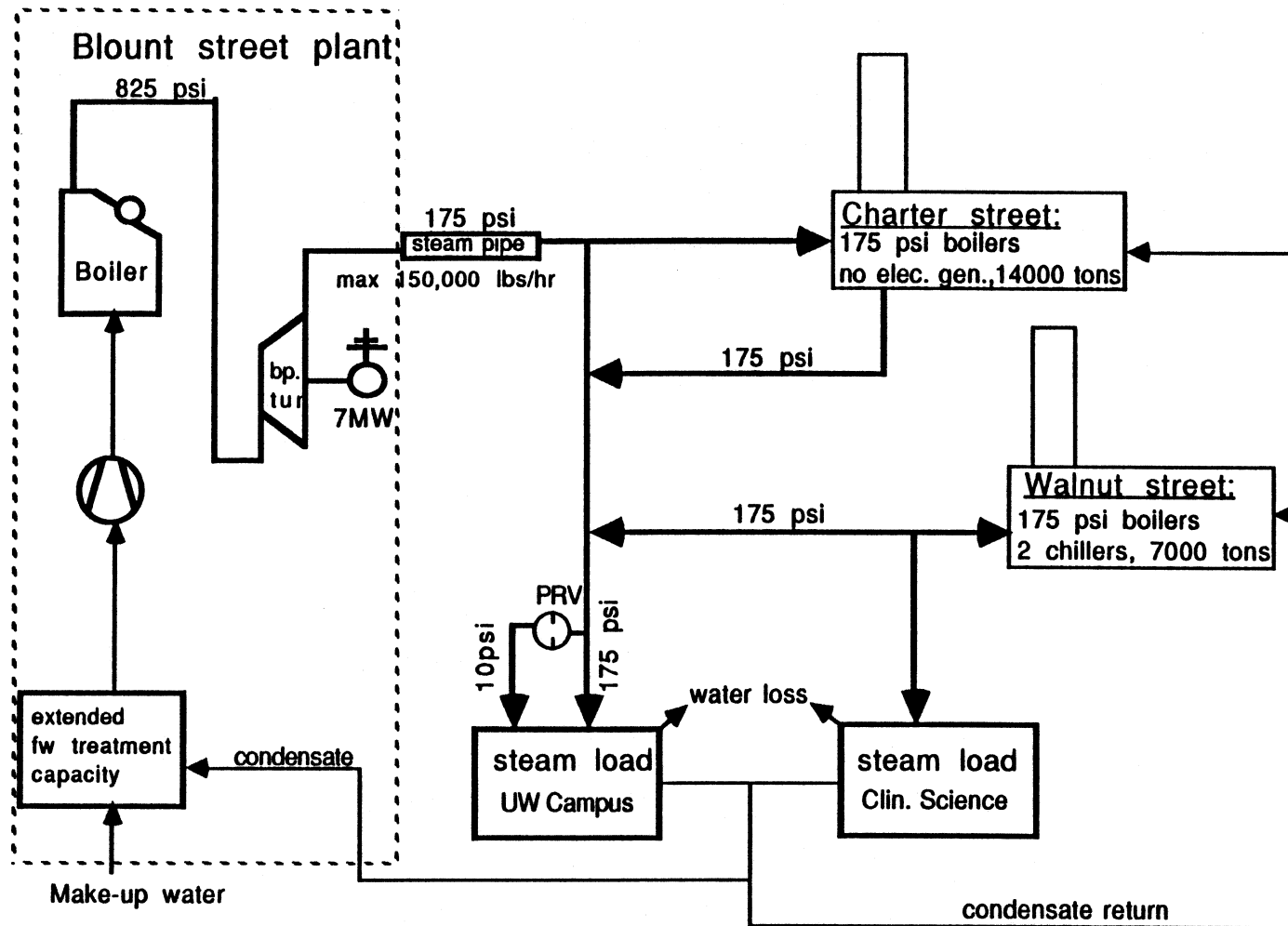


Figure C.12.a System 5 (CSP with 175 psi header system; MG&E cogenerates with 7 MW backpressure turbine in 850 psi cycle)

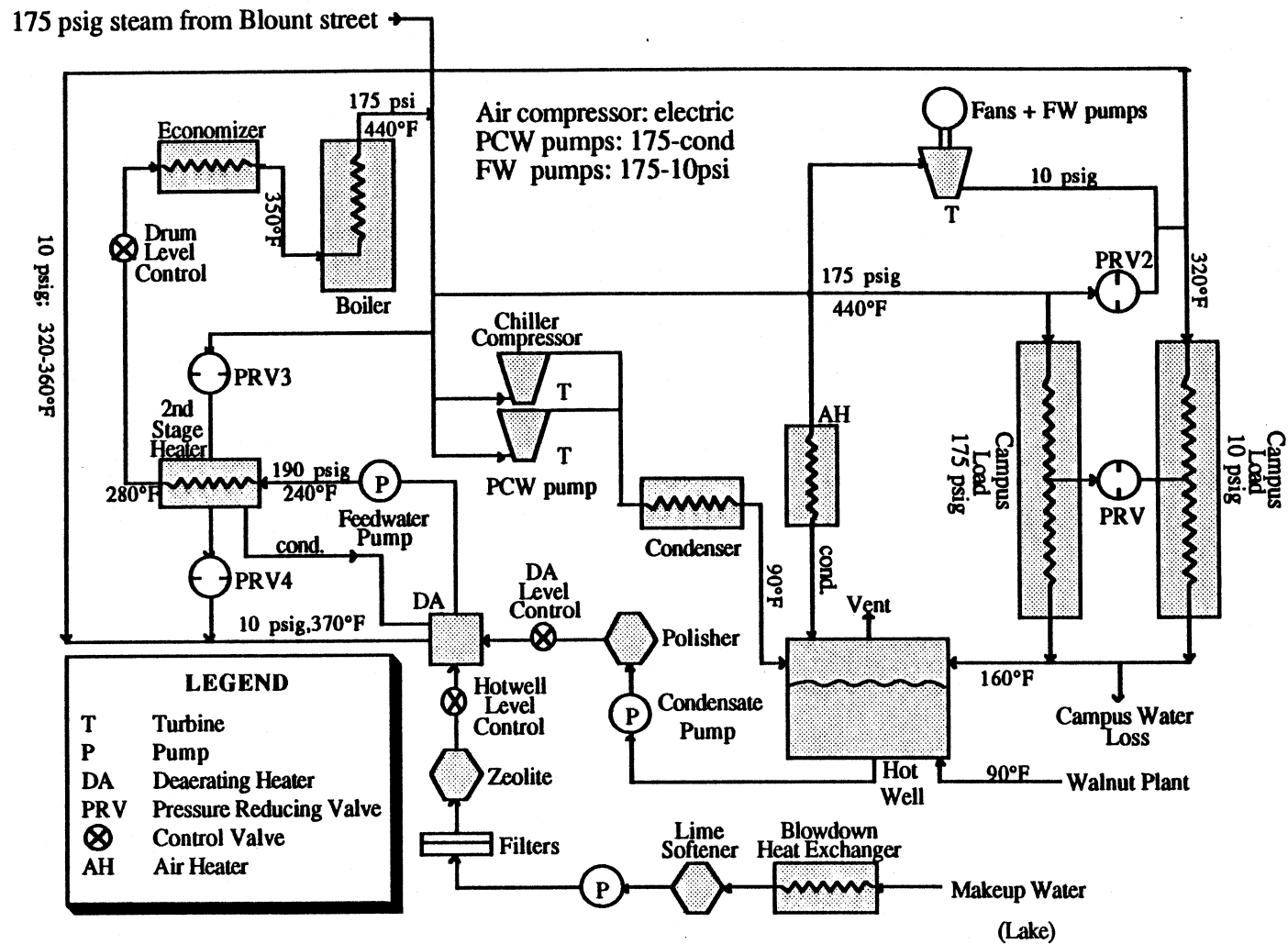


Figure C.12.b Steam/water cycle of modified Charter Street plant with 175 psig header system

System 5:

Description:

MG&E: a maximum steam flow of 150,000 lb/hr is issued from a 7 MW backpressure turbine, which is part of the 850 psi cycle (similar to System 4a)

CSP: boilers generate steam at 175 psig, 440°F

- turbine/generator is eliminated
- chiller compressors have 175-condensing steam turbine drives
- steam driven feedwater pumps operate between 175 psig and 10 psig
- PCW pump is driven by 175 psig-condensing turbine
- air compressors are electrically driven

Control : MG&E supplies as much steam as possible and boilers at CSP serve only as back up

Cost estimates for major modifications:

construction of steam pipe	\$6,500,000
7 MW back pressure turbine at MG&E	\$2,200,000
electrically driven air compr. at CSP	\$280,000
transformation of plant to 175 psig	(not available)*
TOTAL	\$10,980,000

*: assumption: \$2,000,000

Table C.12.a Estimates of operational costs at UW for first year (see Ch. 5)

Item	annual costs in \$
fuel costs	2,490,000
electricity sale	/
electricity purchase	689,000
labor	1,350,000
maintenance	305,000
supplies and services	400,000
steam purchase	2,676,000
TOTAL	7,916,000

Results of economic analysis: (see Ch.5 for explanations)

Life Cycle Savings compared to base case (System 1): \$ - 9,040,000 (no savings)

Internal Rate of Return: - 9.5 %

Table C.12.b Annual summary for **System 5** (CSP 175 psig, MGE 850, 7 MW back pressure turbine)

Parameter	Units	CSP+WSP	MG&E	TOTAL
Fuel consumption	[tons coal]	51,875	73,700	125,575
	[J*10 ¹²]	1,401	1,988	3,389
Electr. generation	[MWh]	0	49,200	49,200
	[J*10 ¹²]	0	178	178
Add. electr. cons.	[MWh]	1,400	5,000	6,400
	[J*10 ¹²]	5.0	18.0	23.0
Chiller power	[MWh]	28,500	0	28,500
	[J*10 ¹²]	102.6	0	102.6
other useful power	[MWh]	2,700	0	2,700
	[J*10 ¹²]	9.8	0	9.8
Steam for space heating	[lbs*10 ⁶]	306	1,218	1,524
	[J*10 ¹² energy]	370	1,470	1,841
	[J*10 ¹² availab.]	96	379	475
Steam produced	[lbs*10 ⁶]	1,036*	1,378	2,414
	[J*10 ¹² energy]	1,054	1,720	2,774
	[J*10 ¹² availab.]	323	713	1,036
η_1	[%]	34.1	82.0	62.2
η_2	[%]	14.5	27.1	21.9

*: steam generated at 175 psig, 440°F

Appendix D
Example for
TRNSYS Deck

*DECK VERSION:10/28/88

```
*****
***** EXAMPLE FOR SIMULATION DECK:  SYSTEM 4A:
*****
***** (THIS DECK INCLUDES ALMOST ALL COMPONENTS THAT WERE USED IN THE
***** VARIOUS SYSTEM CONFIGURATIONS WHICH HAVE BEEN INVESTIGATED IN THE
***** COURSE OF THE STUDY)
*****
*
*
*      CSP : AC,PCW PUMP ELECTRIC
*      WSP : PRESENT CONFIGURATION, BOILERS DO NOT OPERATE
*      MGE : 7 MW BP TURBINE, NO HX, 850PSIG 2.0E5 LBS/HR BOILER
*
*      CONTROL 4: MGE PROVIDES CONSTANT STEAM FLOW
*                  OF 160000LBS/HR IN HEATING SEASON (OCT-MAY)
*                  CSP SATISFIES DEMAND IN REST OF YEAR
*
*****
```

NOLIST

SIMULATION 0. 8770. 1.
 WIDTH 72
 TOLERANCES 0.005 0.005
 LIMITS 50. 50.

```
*****
**** LOAD PROFIL GENERATION AND SYSTEM CONTROL
*****
```

UNIT 1 TYPE 65 LOAD PROFILE GENERATOR

PARAMETERS 14

*MODE MONSTA DAYSTA MONEND DAYEND DOWSTA CHMSTA DHDSTA CHMEND CHDEND
 3. 1. 1. 12. 32. 4. 5. 7. 10. 7.

*WCMSTA WCDSTA WCMEND WCDEND
 3. 6. 11. 27.

*NO INPUTS

*OUTPUTS 15

* 1 2 3 4 5 6 7 8 9 10
 *MON DAY DOW HOD HTDB HTWB HCLW HCHI HCAIR HLOAD
 *11 12 13 14 15
 *WLOAD WTOTAV WTOCAV CTOWAV CSCAV

```
*****
UNIT 2 TYPE 68 CHARTER STREET PLANT CONTROLLER
PARAMETER 1
```

3.
*MODE

INPUTS 23

*MON DAY
1,1 1,2

*HOD TDB TWB CLOW CHI MSTDES MSTAH MSTAC MSTCWP MSTCH MSTFWP MWDES
1,4 1,5 1,6 3,2 3,1 14,1 15,1 0,0 0,0 12,1 25,2 14,2

*MST2ND MSTDA MAIRB1 MAIRB2 MAIRB3 MAIRB4 MAIRB5 MSTAH2 CLOAD
27,1 28,3 18,7 19,7 20,7 21,7 22,7 16,1 1,10

*STARTING VALUES:

*MON DAY
1. 1.

*HOD TDB TWB CLOW CHI MSTDES MSTAH MSTAC MSTCWP MSTCH MSTFWP MWDES
1. 20. 20. 1.E4 1.E5 1.E4 5.E3 0. 0. 0. 2.E4 1.E4

*MST2ND MSTDA MAIRB1 MAIRB2 MAIRB3 MAIRB4 MAIRB5 MSTAH2 CLOAD
1.E4 5.E4 1.E6 1.E6 1.E6 1.E6 1.E6 5.E3 1.E6

*OUTPUTS 24:

*STBTOT STB1 STB2 STB3 STB4 STB5 MSTTUR MPRV1 MPRV2 MPRV3 MPRV4 EXC10T
* 1 2 3 4 5 6 7 8 9 10 11 12

*MCOND MLOSS MAIRT LCH1 LCH2 LCH3 MWCWP EXC10F MSTADD MFAN
* 13 14 15 16 17 18 19 20 21 22

UNIT 3 TYPE 69 OPERATIONAL CONTROL FOR ENTIRE SYSTEM
PARAMETERS 2
*MODEST MODECH
4. 1.

INPUTS 14

*MONTH DAY CHI CLOW CHLOAD DEMCSP CMGE STCHW HWSP WTOC CTOW CSC WLOAD
1,1 1,2 1,8 1,7 1,10 0,0 0,0 30,1 0,0 1,13 1,14 1,15 1,11

*STCHC
12,1

*MONTH DAY CHI CLOW CHLOAD DEMCSP CMGE STCHW HWSP WTOC CTOW CSC WLOAD
1. 1. 1.E5 1.E5 1.E7 5.E4 1.6E5 1.E5 0. 0. 0. 1.5 0.

*STCHC
0.

*OUTPUTS 9

*STCSP CLOCSP STWSP STMGE BCSP CHCSP CHWSP CRCSP CRMGE
* 1 2 3 4 5 6 7 8 9

```

*****
UNIT 4 TYPE 70 CONTROL FOR WALNUT STREET HEATING PLANT
PARAMETERS 1
*MODE
  2.

```

```

INPUTS 2
*CLOAD STWSP
  3,7  3,3
  4.E7  0.

```

```

*OUTPUT 5
*STB1 STB2 CHL1 CHL2 CHL3
* 1    2    3    4    5

```

```

*****
UNIT 5 TYPE 71 CONTROL FOR THE MG&E BLOUNT STREET PLANT
PARAMETERS 2
*MODE NEXTR
  6.  0.

```

```

INPUTS 3
*STBTOT PEL STCTIN
  35,2  0,0  35,2
  2.E5  40.E3  1.E6
*OUTPUTS 3

```

```

*STB1 STB2 PEL
* 1    2    3

```

```

*****
**** CHARTER STREET PLANT
*****

```

```

*****
**** CHILLED WATER PLANT
*****

```

```

UNIT 6 TYPE 15 CHILLER #1 : POWER= 0. + 0.000066*LOAD
PARAMETERS 6
0. 0. 1. 0. 3. -4.
INPUTS 3
2,16  0,0  0,0
20.E6 0.000066  0.
*OUTPUT

```

*POWER.

```
*****
UNIT 7 TYPE 48 COMPRESSOR COND. STEAM TURBINE FOR CHILLER #1
PARAMETERS 11
*MODE TURB  UNIT  CALC  TIN  PIN  DELT  PMAX  PMIN  GEN  NEX
  1.   2.    0.   1.  680. 580. 40.  3000. 100.  1.   0.
INPUTS 2
*PEL  TWB
  6,1  1,6
2000. 80.
*OUTPUTS 9
*PEL  STCSPT  STOUT  STEXTR  LB/KWH  PLR  EFF  PCON  QOUT
* 1    2      3      4      5      6    7    8    9
```

```
*****
UNIT 8 TYPE 15 CHILLER #2 : POWER= 0. + 0.000066*LOAD
PARAMETERS 6
0. 0. 1. 0. 3. -4.
INPUTS 3
2,17  0,0  0,0
20.E6 0.000066  0.
*OUTPUT
*POWER
```

```
*****
UNIT 9 TYPE 48 COMPRESSOR COND. STEAM TURBINE FOR CHILLER #2
PARAMETERS 11
*MODE TURB  UNIT  CALC  TIN  PIN  DELT  PMAX  PMIN  GEN  NEX
  1.   2.    0.   1.  680. 580. 40.  3000. 100.  1.   0.
INPUTS 2
*PEL  TWB
  8,1  1,6
2000. 80.
*OUTPUTS 9
*PEL  STCSPT  STOUT  STEXTR  LB/KWH  PLR  EFF  PCON  QCON
* 1    2      3      4      5      6    7    8    9
```

```
*****
UNIT 10 TYPE 15 CHILLER #3 : POWER= 0. + 0.000064*LOAD
PARAMETERS 6
0. 0. 1. 0. 3. -4.
INPUTS 3
2,18  0,0  0,0
20.E6 0.000064  0.
```

*OUTPUT
*POWER

UNIT 11 TYPE 48 COMPRESSOR COND. STEAM TURBINE FOR CHILLER #3

PARAMETERS 11

*MODE	TURB	UNIT	CALC	TIN	PIN	DELT	PMAX	PMIN	GEN	NEX
1.	2.	0.	1.	680.	580.	40.	5800.	100.	1.	0.

INPUTS 2

*PEL TWB
10,1 1,6
2000. 80.

*OUTPUTS 9

*PEL	STCSPT	STOUT	STEXTR	LB/KWH	PLR	EFF	PCON	QCON
* 1	2	3	4	5	6	7	8	9

UNIT 12 TYPE 15 ADDITION OF STEAM FOR CHILLER COMPRESSORS

PARAMETERS 6

0. 0. 3. 0. 3. -4

INPUTS 3

7,2 9,2 11,2
1.E4 1.E4 3.E4

*OUTPUTS 1

* MSTCHILLERTOTAL

*

UNIT 13 TYPE 43 PRIMARY CHILLED WATER PUMP (MODE 2)

PARAMETERS 11

*MODE	PES	CON	UNIT	NVAL	FRW1	FRW2	FRW3	PEL1	PEL2	PEL3
2.	2.	1.	0.	3.	0.	1.E5	12.E6	0.	200.	430.

INPUTS 2

*MCWP TAMB
2,19 0,0
12.E6 80.

*OUTPUTS 2

*MFW PELFWP
* 1 2

**** STEAM CYCLE:

UNIT 14 TYPE 44 DESUPERHEATER

PARAMETERS 8

*MODE	UNIT	TSTIN	PSTIN	TWTR	PWTR	TOUT	POUT
1.	0.	570.	195.	160.	195.	440.	195.

INPUTS 1

*FROUT

3,1

1.E5

*OUTPUTS 2

*FRST FRWTR

* 1 2

UNIT 15 TYPE 66 AIRHEATER 175PSIG-CONDENSING

PARAMETERS 5

*MODE	UNIT	CPF	PRESS	TSTIN
2.	0.	.24	195.	570.

INPUTS 3

*TFIN TFOUT MF

1,5 0,0 2,15

10. 100. 2.E6

*OUTPUTS 1

*MFRST

* 1

UNIT 16 TYPE 66 AIRHEATER 10PSIG-CONDENSING

PARAMETERS 5

*MODE	UNIT	CPF	PRESS	TSTIN
2.	0.	.24	27.	370.

INPUTS 3

*TFIN TFOUT MF

1,5 0,0 2,15

10. 100. 2.E6

*OUTPUTS 1

*MFRST

* 1

UNIT 17 TYPE 48 TURBINE/GENERATOR 3MW

PARAMETERS 11

*MODE	TURB	UNIT	CALC	TSTIN	PSTIN	PSTOUT	ELMAX	ELMIN	GEN	PIPE
1.	1.	0.	2.	700.	615.	195.	3750.	100.	1.	0.

INPUTS 1

*MSTTUR

2,7
5.E4

*OUTPUTS 7

*PEL	STCSPT	STOUT	STEX	LB/KWH	PLR	EFF	TOUT
* 1	2	3	4	5	6	7	8

UNIT 18 TYPE 50 BOILER #1 (COAL)

PARAMETERS 20

*MODE BOIL UNIT TFWIN PFWIN TOUT POUT STMAX STMIN BLOWDN

1. 1. 0. 280. 680. 700. 615. 1.2E5 0.4E5 5.

*TGMAX TGMIN SURF Kwall TC FUEL ARATE XC XH2 XAS

420. 360. 4000. 2.8 2000. 2. 1.3 .73 .052 .07

INPUTS 5

*STB1 TAMB TSUR TFUEL TAIR

2,2 0,0 0,0 1,6 1,6

5.E4 80. 80. 10. 80.

*OUTPUTS 9

*STB1 FWFR FRBWDN FUEL ETAB1 QFUEL MAIR TAIR LHV

* 1 2 3 4 5 6 7 8 9

UNIT 19 TYPE 50 BOILER #2 (COAL)

PARAMETERS 20

*MODE BOIL UNIT TFWIN PFWIN TOUT POUT STMAX STMIN BLOWDN

1. 1. 0. 280. 680. 700. 615. 1.2E5 0.4E5 5.

*TGMAX TGMIN SURF Kwall TC FUEL ARATE XC XH2 XAS

420. 360. 4000. 2.8 2000. 2. 1.3 .73 .052 .07

INPUTS 5

*STB2 TAMB TSUR TFUEL TAIR

2,3 0,0 0,0 1,6 1,6

5.E4 80. 80. 10. 80.

*OUTPUTS 9

*STB2 FWFR FRBWDN FUEL ETAB2 QFUEL MAIR TAIR LHV

* 1 2 3 4 5 6 7 8 9

UNIT 20 TYPE 50 BOILER #3 (COAL)

PARAMETERS 20

*MODE BOIL UNIT TFWIN PFWIN TOUT POUT STMAX STMIN BLOWDN

1. 1. 0. 280. 680. 700. 615. 1.2E5 0.4E5 5.

*TGMAX TGMIN SURF Kwall TC FUEL ARATE XC XH2 XAS

420. 360. 4000. 2.8 2000. 2. 1.3 .73 .052 .07

INPUTS 5

*STB3 TAMB TSUR TFUEL TAIR

2,4 0,0 0,0 1,6 1,6

5.E4 80. 80. 10. 80.

*OUTPUTS 9

*STB3	FWFR	FRBWDN	FUEL	ETAB3	QFUEL	MAIR	TAIR	LHV
* 1	2	3	4	5	6	7	8	9

UNIT 21 TYPE 50 BOILER #4 (COAL)

PARAMETERS 20

*MODE	BOIL	UNIT	TFWIN	PFWIN	TOUT	POUT	STMAX	STMIN	BLOWDN
1.	1.	0.	280.	680.	700.	615.	2.0E5	0.4E5	5.

*TGMAX	TGMIN	SURF	KWALL	TC	FUEL	ARATE	XC	XH2	XAS
380.	320.	5000.	2.8	2000.	2.	1.3	.73	.052	.07

INPUTS 5

*STB4	TAMB	TSUR	TFUEL	TAIR
2,5	0,0	0,0	1,6	1,6
8.E4	80.	80.	10.	80.

*OUTPUTS 9

*STB4	FWFR	FRBWDN	FUEL	ETAB4	QFUEL	MAIR	TAIR	LHV
* 1	2	3	4	5	6	7	8	9

UNIT 22 TYPE 50 BOILER #5 (NATURAL GAS)

PARAMETERS 20

*MODE	BOIL	UNIT	TFWIN	PFWIN	TOUT	POUT	STMAX	STMIN	BLOWDN
1.	1.	0.	280.	680.	700.	615.	3.0E5	0.5E5	5.

*TGMAX	TGMIN	SURF	KWALL	TC	FUEL	ARATE	YCH4	YC2H6	YN2
380.	300.	6000.	2.8	2100.	1.	1.2	.83	.12	.05

INPUTS 5

*STB5	TAMB	TSUR	TFUEL	TAIR
2,6	0,0	0,0	1,6	0,0
9.E4	80.	80.	10.	80.

*OUTPUTS 9

*STB5	FWFR	FRBWDN	FUEL	ETAB5	QFUEL	MAIR	TAIR	LHV
* 1	2	3	4	5	6	7	8	9

UNIT 23 TYPE 15 FEED WATER ADDITION OF BOILERS 1-3, 4+5 AND ALL TOGETHER

PARAMETERS 12

0. 0. 3. 0. 3. -3. 0. 0. 3. -3. 3. -4.

INPUTS 5

*FWB1	FWB2	FWB3	FWB4	FWB5
18,2	19,2	20,2	21,2	22,2
5.E4	5.E4	5.E4	5.E4	5.E4

*OUTPUTS 3

*FWFR1-3	FWFR4+5	FWFRALL
* 1	2	3

UNIT 24 TYPE 43 #3 FW PUMP FOR BOILERS 1,2,3 (ELECTRICALLY DRIVEN)

PARAMETERS 15

*MODE	PES	CON	UNIT	NVAL	FRW1	FRW2	FRW3	FRW4	FRW5
2.	2.	1.	0.	5.	0.	0.1E5	1.0E5	2.E5	3.3E5
					PEL1	PEL2	PEL3	PEL4	PEL5
					0.	135.	180.	235.	300.

INPUTS 2

*MFW TAMB

23,1 0,0

2.E5 80.

*OUTPUTS 2

*MFW PEL

* 1 2

UNIT 25 TYPE 43 #7 FW PUMP FOR BOILERS 4+5 (STEAM DRIVEN, 600-60 PSIG)

PARAMETERS 15

*MODE	PES	CON	UNIT	NVAL	FRW1	FRW2	FRW3	FRW4	FRW5
2.	2.	1.	0.	5.	0.	0.1E5	1.0E5	2.E5	3.3E5
					ST1	ST2	ST3	ST4	ST5
					0.	1.3E4	1.8E4	2.0E4	2.2E4

INPUTS 2

*MFW TAMB

23,2 0,0

2.E5 80.

*OUTPUTS 2

*MFW MSTFWP

* 1 2

UNIT 27 TYPE 66 2ND STAGE HEATER

PARAMETERS 5

*MODE	UNIT	CPF	PRESS	TSTIN
2.	0.	1.	75.	400.

INPUTS 3

*TFIN TFOUT MF

0,0 0,0 23,3

240. 280. 2.E5

*OUTPUTS 2

*MSTEAM TWOUT

* 1 2

UNIT 28 TYPE 44 DEAERATOR

PARAMETERS 13

*MODE	UNITS	TST	PST	TCON1	PCON1	TCON2	PCON2	TTWTR	PTWTR
2.	0.	400.	27.	140.	27.	260.	40.	140.	27.

*TFW	PFW	LOSS%
240.	27.	0.

INPUTS 4

*MFW	MCON1	MCON2	TAMB
23,3	2,13	27,1	0,0
3.E5	2.E5	1.E4	80.

*OUTPUTS 5

*FRFW	FRWTR	FRST	FRRW	FRLOSS
* 1	2	3	4	5

 UNIT 29 TYPE 46 CALCULATION OF OPERATIONAL COSTS

PARAMETERS 11

*UNIT	NELG	NELC	NNG	ND	NC	NGPRICE	DP	CP	MCOST	RWPRICE
0.	1.	2.	1.	0.	4.	.048	.038	.024	0.	0.0

INPUTS 11

*EXPRICE	IMPRICE	MRWTR	PELP	PELAC	PELCWP	NGC	CB1	CB2	CB3	CB4
0,0	0,0	28,4	17,1	1,9	13,2	22,4	18,4	19,4	20,4	21,4
0.030	0.030	5.E4	2000.	500.	0.	1.E3	1.E3	1.E3	1.E3	1.E3

*OUTPUTS 8

*ELEX\$	ELIM\$	NG\$	D\$	COAL\$	MAINT\$	RAWW\$	TOT\$
* 1	2	3	4	5	6	7	8

 **** WALNUT STREET PLANT (BOILERS DO NOT OPERATE)

 **** CHILLED WATER PLANT (CHILLERS HAVE HIGHER EFFICIENCY THAN AT CSP)

UNIT 31 TYPE 15 CHILLER #1 : POWER= 0. + 0.000054*LOAD

PARAMETERS 6

0. 0. 1. 0. 3. -4.

INPUTS 3

4,3	0,0	0,0
20.E6	0.000054	0.

*OUTPUT

*POWER

 UNIT 32 TYPE 48 COMPRESSOR COND. STEAM TURBINE FOR CHILLER #1
 PARAMETERS 11

```
*MODE TURB  UNIT  CALC  TIN  PIN  DELT  PMAX  PMIN  GEN  NEX
  1.   2.   0.   1.  380. 190.  26.   2500. 100.  1.   0.
```

```
INPUTS 2
```

```
*PEL  TWB
```

```
31,1  1,6
```

```
2000. 80.
```

```
*OUTPUTS 9
```

```
*PEL  STCSPT  STOUT  STEXTR  LB/KWH  PLR  EFF  PCON  QCON
```

```
* 1    2        3        4        5        6    7    8    9
```

```
*****
```

```
UNIT 33 TYPE 15 CHILLER #2 : POWER= 0. + 0.000054*LOAD
```

```
PARAMETERS 6
```

```
0. 0. 1. 0. 3. -4.
```

```
INPUTS 3
```

```
4,4    0,0    0,0
```

```
20.E6 0.000054  0.
```

```
*OUTPUT
```

```
*POWER
```

```
*****
```

```
UNIT 34 TYPE 48 COMPRESSOR COND. STEAM TURBINE FOR CHILLER #2
```

```
PARAMETERS 11
```

```
*MODE TURB  UNIT  CALC  TIN  PIN  DELT  PMAX  PMIN  GEN  NEX
```

```
  1.   2.   0.   1.  380. 190.  26.   2500. 100.  1.   0.
```

```
INPUTS 2
```

```
*PEL  TWB
```

```
33,1  1,6
```

```
2000. 80.
```

```
*OUTPUTS 9
```

```
*PEL  STCSPT  STOUT  STEXTR  LB/KWH  PLR  EFF  PCON  QCON
```

```
* 1    2        3        4        5        6    7    8    9
```

```
*****
```

```
UNIT 30 TYPE 15 ADDITION OF STEAM FOR CHILLER COMPRESSORS
```

```
PARAMETER 1
```

```
3.
```

```
INPUTS 2
```

```
32,2  34,2
```

```
1.E4  1.E4
```

```
*ST1  ST2
```

```
*OUTPUT 1
```

```
* STTOT
```

 * COGENERATION CYCLE AT BLOUNT STREET CONSISTING OF:
 * 7MW BACK PRESSURE STEAM TURB. IN 850PSI CYCLE,
 * NO HEAT EXCHANGER, NO FWHEATERS, 1 DEARATOR, 1 DESUPERHEATER

 UNIT 42 TYPE 40 STEAM PIPE FROM BLOUNT STREET TO CAMPUS
 PARAMETERS 10

*MODE	UNIT	LENGTH	DI	DE	DINS	KP	KINS	HEXT	PROUGH
2	0	13000	2.0	2.04	2.44	26	0.033	0.93	0.0036

INPUTS 4

*MSTEAM	TOUT	POUT	TA
3,4	0,0	0,0	1,5
2.E5	440.	190	60.

*OUTPUTS 5

*MSTEAM	TIN	PIN	QLOSS	ΔP
* 1	2	3	4	5

 UNIT 35 TYPE 48 BACK PRESSURE 7 MW STEAM TURBINE
 PARAMETERS 11

*MODE	TURB	UNIT	CALC	TSTIN	PSTIN	POUT	PMAX	PMIN	GEN	PIPE
1.	1.	0.	2.	825.	870.	202.	7000.	0.	1.	1.

INPUTS 2

*MSTEAM	POUT
44,1	42,3
160000.	200.

*OUTPUTS 8

*PEL	STCSPT	STOUT	STEXTR	LB/KWH	PLR	EFF	TOUT
*1	2	3	4	5	6	7	8

 UNIT 39 TYPE 44 DESUPERHEATER
 PARAMETERS 8

*MODE	UNIT	TSTIN	PSTIN	TWTR	PWTR	TOUT	POUT
1.	0.	570.	202.	140.	202.	450.	202.

INPUTS 1

*FROUT
44,5
1.E5

*OUTPUTS 2

*FRST	FRWTR
* 1	2

UNIT 36 TYPE 50 BOILER MG&E #5 (COAL)

PARAMETERS 20

*MODE BOIL UNIT TFWIN PFWIN TOUT POUT STMAX STMIN BLOWDN
1. 1. 0. 295. 950. 825. 870. 2.0E5 0.5E5 0.

*TGMAX TGMIN SURF K WALL TC FUEL ARATE XC XH2 XAS
350. 250. 5000. 2.5 2000. 2. 1.2 0.73 0.052 0.07

INPUTS 5

*STB1 TAMB TSUR TFUEL TAIR
35,2 0,0 0,0 0,0 0,0
5.E4 80. 80. 80. 80.

*OUTPUTS 9

*STB1 FWFR FRBWDN FUEL ETAB1 QFUEL MAIR TAIR LHV
* 1 2 3 4 5 6 7 8 9

UNIT 37 TYPE 43 CONDENSATE PUMP

PARAMETERS 13

*MODE PES CON UNIT NVAL FRW1 FRW2 FRW3 FRW4 PEL1 PEL2 PEL3 PEL4
2. 1. 1. 0. 4. 0. 1.E4 4.4E5 6.E5 0. 300. 500. 600.

INPUTS 2

*MFW TAMB
3,9 1,5
1.E5 50.

*OUTPUTS 2

*MFW PEL
* 1 2

UNIT 40 TYPE 43 MAIN FW PUMP

PARAMETERS 13

*MODE PES CON UNIT NVAL FRW1 FRW2 FRW3 FRW4 PEL1 PEL2 PEL3 PEL4
2. 1. 1. 0. 4. 0. 1.E4 4.8E5 8.E5 0. 500. 600. 1100.

INPUTS 2

*MFW TAMB
36,2 1,5
2.E5 50.

*OUTPUTS 2

*MFW PEL
* 1 2

UNIT 41 TYPE 44 DEAERATOR (STEAM THROTTLED FROM 202 PSI)

PARAMETERS 13

*MODE UNITS TST PST TCON PCON TCON2 PCON2 TTWTR PTWTR

```

      2.      0.      550. 202. 120.  65.   350.  140.  90.   60.
*TFW  PFW  LOSS%
 295. 66.   1.5
INPUTS 4
*MFW  MCON1  MCON2  TAMB
36,2  3,9    0,0    0,0
3.E5  2.E5    0.    80.
*OUTPUTS 5
*FRW  FRWTR  FRST  FRRW  FRLOSS
* 1      2      3      4      5

```

UNIT 44 TYPE 15 AUX. CALCULATIONS

PARAMETERS 29

```

0. 0. 3. -4.
0. 0. 3. 0. 3. -1. -1. 1. -4.
0. -1. -1. 1. -4.
0. -1. -1. 1. -4.
0. -4.
0. 0. 4. -4.

```

INPUTS 10

```

*STDES STDA FW123 ELCP  ELFWP  CRCSP  CRMGE  STMGE  SYSTOT  STCHW
39,1  41,3  24,2  37,2  40,2   3,8    3,9   42,1  3,10  30,1
1.E5  1.E4   0.   1.E3  1.E3  1.E5    1.E5  1.E5  2.E5  5.E4

```

*OUTPUT 6

```

* STBTOT  ELCONSMGE  -CRCSP  -CRMGE  STMGET  HEAT175
*   1         2         3         4         5         6

```

UNIT 45 TYPE 46 CALCULATION OF OPERATIONAL COSTS FOR MG&E

PARAMETERS 11

```

*UNIT  NELG  NELC  NNG  ND   NC   NGPRICE  DP   CP   MCOST  RWPRICE
 0.    1.    2.    0.  0.   1.   .048   .038  .024   0.    0.001

```

INPUTS 7

```

*EXPRICE IMPRICE MRWTR PELT1  PELCP  PELFW  CB1
 0,0    0,0    0,0  35,1   37,2   40,2  36,4
0.030  0.030    0. 10000.  500.   500.  1.E3

```

*OUTPUTS 8

```

*ELEX$  ELIMS$  NG$  D$   COAL$  MAINT$  RAWW$  TOT$
*  1      2      3   4     5       6       7      8

```

UNIT 38 TYPE 55 EFFICIENCY CALCULATIONS FOR MGE

PARAMETERS 12

```

* UNIT NFUEL  NEL  NSTFL  PREF  TREF  CEL   LHVM  PST1  PST2  TST1  TST2
 0.    1.    2.    2.    15.   80.  0.03 12800. 202. 15.   440. 140

```


INPUTS 5

*MFM	TURBM	CONP	MGE175	CRMGE
36,4	35,1	44,2	44,5	44,4
0.	0.	0.	0.	0.

*OUTPUTS 9

*EFF2	AVFUEL	AVELEC	AVST	ENST	MSTOUT	EFF1	EFFP	CST
* 1	2	3	4	5	6	7	8	9

UNIT 46 TYPE 55 CALCULATION OF OVERALL SYSTEM EFFICIENCY

PARAMETERS 21

*UNIT	NFUEL	NEL	NSTFL	PREF	TREF	CEL	LHV1	LHV2	LHV3	LHV4
0.	6.	8.	4.	15.	80.	0.03	12800.	12800.	12800.	12800.

*LHV5	LHVM	PST1	PST2	PST3	PST4	TST1	TST2	TST3	TST4
19600.	12800.	190.	27.	15.	15.	440.	320.	140.	140.

INPUTS 18

*MF1	MF2	MF3	MF4	MF5	MFM	CH1	CH2	CH3	TURBC	CH1W
18,4	19,4	20,4	21,4	22,4	36,4	6,1	8,1	10,1	17,1	31,1

*CH2W	TM	ELCONS	HEAT175	CLOW	CRCSP	CRMGE
33,1	35,1	44,2	44,6	1,7	44,3	44,4

*STARTVALUES

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

*OUTPUTS 9

* EFF	AVFUEL	AVELEC	AVST	ENST	MSTOUT	EFF1	EFFP	CST
* 1	2	3	4	5	6	7	8	9

**** OUTPUT

**** DAILY SUMMARY

UNIT 43 TYPE 28 DAILY SIM SUM 1

PARAMETERS 37

24.	0.	8770.	0.	2.	0.	-1.	24.	2.	-4.	0.	-1.	24.	2.	-4.	0.	-4.
0.	-4.	0.	-4.	0.	-4.	0.	-4.	0.	-1.	24.	2.	-4.				
0.	-1.	24.	2.	-4.	0.	-4.										

INPUTS 10

1,1	1,2	3,1	2,1	44,5	35,1	37,1	35,7	36,5	17,1

LABELS 10

MONTH DAY STCSP STBTOT STMGE PELMGE MFWCP EFFT M EFFBM PELC

 **** MONTHLY SUMMARY

UNIT 48 TYPE 28 MONTHLY SUMMARY CSP

PARAMETERS 25

-1. 0. 8800. 0. 1. 0. -4. 0. -4. 0. -4. 0. -4. 0. -4.
 0. -4. 0. -4. 0. -4. 0. -4. 0. -4.

INPUTS 10

2,1 17,1 29,3 29,5 29,7 29,8 1,7 3,1 3,10 46,1

LABELS 10

STCSP PELCSP NG\$C COAL\$C WTR\$C TOT\$C CLOW CHI SYSTOT EFF

 UNIT 50 TYPE 28 MONTHLY SUMMARY MGE

PARAMETERS 25

-1. 0. 8800. 0. 1. 0. -4. 0. -4. 0. -4. 0. -4. 0. -4.
 0. -4. 0. -4. 0. -4.

INPUTS 10

35,1 44,2 35,3 41,3 35,15 36,1 45,5 45,7 45,8 38,1

LABELS 10

PELMGE PELMCONS STTUR MEX3 MEX6 MSTB \$COALM \$RAWW \$TOTM EFF2M

 **** ANNUAL SUMMARY

UNIT 47 TYPE 28 YEARLY SUMMARY

PARAMETERS 37

8760. 0. 8770. 0. 1. 0. -4. 0. -4. 0. -4. 0. -4.
 0. -4. 0. -4. 0. -1. 8760. 2. -4.
 0. -1. 8760. 2. -4. 0. -1. 8760. 2. -4.
 0. -1. 8760. 2. -4.

INPUTS 10

29,5 45,5 17,1 45,1 29,8 45,8 46,1 38,1 38,9 46,7

LABELS 10

\$CCSP \$CMGE PELCSP \$PELMGE \$TOTCSP \$TOTMGE EFFS EFFM CST EFF1

```
*****  
UNIT 26 TYPE 28 YEARLY SUMMARY 2  
PARAMETERS 15  
8760. 0. 8770. 0. 1. 0. -4. 0. -4. 0. -4. 0. -4.  
INPUTS 5  
3,4 36,1 3,1 3,2 2,1  
LABELS 5  
MGECSF STMGEB CSF175 CSF10 CSFB  
  
END
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