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A Method for Evaluating the Potential of Geothermal Energy in Industrial Process Heat Applications

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A METHOD FOR EVALUATING THE POTENTIAL OF GEOTHERMAL ENERGY IN INDUSTRIAL PROCESS HEAT APPLICATIONS

ABSTRACT

A method is presented for evaluating the technical and economic potential of geothermal energy for industrial process heat applications. The core of the method is a computer program which can be operated either as a design analysis tool to match energy supplies and demands, or as an economic analysis tool if a particular design for the facility has already been selected.

Two examples are given to illustrate the functioning of the model and to demonstrate that results reached by use of the model closely parallel those that have been determined by more traditional techniques.

Other features of interest in the model include: (1) use of decision analysis techniques as well as classical methods to deal with questions relating optimization, (2) a tax analysis of current regulations governing percentage depletion for geothermal deposits, and (3) development of simplified correlations for the thermodynamic properties of salt solutions in water.

LEGAL NOTICE

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NOMENCLATURE

a_{ij}	=	constants, defined in text
A	=	heat transfer area
B	=	constant, defined in text
c	=	specific heat of incompressible substance
c_{salt}	=	salt concentration by mass in liquid portion of fluid
$C_{aft.tax}$	=	after-tax cash flow in current year
$C_{bef.tax}$	=	annual expenditures before taxes
C_{bond}	=	amount of bonds outstanding
C_{dep}	=	annual depreciation expense
C_{depl}	=	annual depletion deduction
C_{elect}	=	cost of electricity
C_{energy}	=	annual cost of energy
$C_{equip,j}$	=	installed cost of equipment piece j
$C_{equip,tot}$	=	total cost of equipment plus engineering, design, and administrative costs
C_{field}	=	cost of geothermal field development
C_{fossil}	=	cost of fossil fuel
C_{GT}	=	cost of geothermal fluid
$C_{initial}$	=	initial investment in system
C_{insur}	=	annual insurance premium
C_{int}	=	expenditure for interest on debt
C_{invst}	=	expenditure on investment in current dollars

NOMENCLATURE (Cont.)

$C_{invst,c}$	=	expenditure on investment in constant dollars
$C_{invst,d}$	=	expenditure on depreciable items, current dollars
C_{land}	=	cost of land acquisition
C_{maint}	=	annual maintenance costs
C_{other}	=	miscellaneous geothermal field investment costs (e.g. geophysical surveys, permit procurement)
$C_{process,j}$	=	installed cost of unit process j
$C_{prop.tax}$	=	annual property tax payments
C_{royal}	=	annual royalty payments
C_{trans}	=	cost of geothermal fluid transmission system
C_{well}	=	cost of each geothermal well
f	=	correction factor for heat transfer rate due to non-condensable gases
f_{cap}	=	plant capacity factor
f_{cr}	=	investment tax credit fraction
f_d	=	debt/equity ratio
f_{depl}	=	fraction of tangible well expenses attributable to depletable accounts
$f_{invst,i}$	=	fraction of investment made in year i
f_s	=	salvage value fraction of depreciable investment
f_{tang}	=	fraction of geothermal well costs attributable to tangible expenses

NOMENCLATURE (Cont.)

f_{tax}	=	marginal income tax rate
h	=	specific enthalpy
h	=	heat transfer coefficient
h_f	=	saturated liquid specific enthalpy
i_{debt}	=	interest rate on debt
i_{disc}	=	discount rate
i_{insur}	=	insurance premium rate
IRR	=	internal rate of return on investment
$j*$	=	discounted payback period
K	=	constant, defined in text
m	=	number of unit processes
m_{GT}	=	mass flow rate of geothermal fluid
n	=	depreciation lifetime
n	=	number of fluid streams
N_{well}	=	number of wells required
NPV	=	net present value of system savings
p	=	pressure
Q	=	heat transfer rate
Q_{elect}	=	electricity required
Q_{fossil}	=	fossil fuel required
r_i	=	inflation factor in year i
s	=	specific entropy

NOMENCLATURE (Cont.)

s_f = saturated liquid specific entropy

S_{taxes} = annual cash savings attributable to tax deductions and credits

t = temperature

T = absolute temperature

TC = total process hourly cost

u = specific internal energy

U = overall heat transfer conductance

v = specific volume

V = net present value of system savings

α = constant, defined in text

β = constant, defined in text

γ = constant, defined in text

Γ = ratio of heat transfer coefficients

Δ = change in a quantity

ε = heat exchanger effectiveness

ζ = fraction of energy supplied by fossil fuel

η = weight fraction of non-condensable gases

μ = ratio of fluid flow rates

τ = temperature minus 60°C

ϕ = ratio of heat transfer areas

ψ = ratio of energy supplied by fossil fuel to heat transfer rate of process

CHAPTER 1 - INTRODUCTION

A. Geothermal Energy and Process Heat Applications

Geothermal energy is a substantially untapped resource of the United States. The identified reserves, estimated to contain approximately 400×10^{18} J (379 Quads) of energy, are roughly equal in size to the domestic reserves of oil and natural gas (390×10^{18} J, 370 Quads).[1] Yet geothermal energy has not met its promise as an energy source. Several reasons can be advanced for this disappointing situation.

First, the utilization of geothermal energy has been hampered by the low thermodynamic availability that is characteristic of this resource: 50% of the resource base contains fluid cooler than 150°C.[2] Most geothermal reservoirs contain fluid too cool to be efficiently exploited for the production of electric power. Moreover, most deposits lie in unpopulated areas where needs for low-quality energy such as residential space heating are small. Thus, this significant energy resource remains untapped in part for want of suitable end uses.

However, many industrial processes do require large amounts of heat at temperatures comparable to those available from geothermal sources. In fact, process heat applications contribute 31.7% of the entire U.S. demand for energy and 25% of these applications require temperatures less than 200°C.[3] Such processes occur in industries such as food processing and pulp and paper manufacturing which require boiling or evaporation of water near atmospheric pressure. With the price of conventional sources of energy rising steeply, many of these industries would welcome the prospect of using geothermal energy if it proved to be cheaper alternative to fossil fuels. Similarly, government planners might well value increased utilization of an energy resource that is independent of foreign sheikdoms.

There is a second reason for the difficulties associated with utilization of geothermal energy for industrial process heat and for the disappointing record for this resource to date. Unlike fossil fuels, geothermal steam or hot water cannot be transported long distances to the point of intended use. Since the resource cannot be moved to the factory, the alternative in most cases is to move the factory to the resource. Except for those cases in which plants have been constructed by coincidence above a geothermal resource, the bottom line is then an economic trade-off among three factors: the cost of geothermal resource development, the cost of relocating an existing plant or constructing a new one near a geothermal deposit, and the cost of fossil fuels. Even if by chance an existing plant is located near a geothermal deposit, a trade-off still remains between the costs of geothermal resource development and retrofit of the plant and the cost of continued use of fossil fuels.

Implicit in the cost of geothermal field development is the risk of finding an unsatisfactory resource. This risk represents the third major reason for the disappointing record for geothermal energy in the U.S. Yet for every level of risk, there exists a potential economic return which would induce rational decisionmakers to invest. Risk therefore provides an additional factor in the trade-offs discussed above.

B. The Geothermal Project

1. Goals and philosophy

The trade-offs described in the previous section are being investigated by a group of researchers at M.I.T. The goal of the research is the creation of a general methodology for evaluation by management of geothermal energy use in industrial process heating applications.

Implicit in this statement of the goal of the project are several principles which have guided the work discussed in following chapters. First, the decision to utilize geothermal energy can only be made by managerial decisionmakers. Thus contact with representatives of industrial firms is essential if research is to remain relevant to their concerns and if its results are to be effectively communicated to industry. Furthermore, such results should be descriptive rather than prescriptive: they should aid managers in answering the questions of interest to them, rather than simply recommending a particular course of action.

Second, the methodology for evaluation mentioned above should be capable of application to a wide variety of industries. This requirement ensures development of a truly general methodology.

Third, the methodology should be flexible within each application in order to enhance its usefulness as an analysis tool.

Finally, the research should highlight those problems which currently hinder the development of geothermal energy. Among them is the problem of investment in further research: for example, how much is it worth to a manager to reduce the uncertainty concerning the temperature of a geothermal deposit by a given amount?

2. <u>The methodology</u>

The methodology for evaluating geothermal energy for process heat applications consists of two parts:

a comprehensive list of the parameters relevant to geothermal energy utilization, and a computer model which analyzes the technical and economic aspects of the evaluation.

Some of the parameters are derived from the voluminous literature on geothermal energy. The remainder are included in an attempt to fill obvious gaps in the initial list.

The parameters, which are listed in Table 1-1, are divided into five groups or "blocks": parameters relating to geothermal resources, locations, and costs (Block A); to environmental factors (Block B); to regulatory and governmental factors (Block C); to the industrial application (Block D); and to the project economics (Block E). Many of the parameters are either connected in a logical sense with or influenced in a mathematical sense by other parameters. To assist the reader in tracing these connections, the description of each parameter is followed by the list of numbers of other parameters which affect the given parameter.

The heart of the evaluation methodology is the computer model. The model addresses the problem of matching process energy demands with geothermal and auxiliary fossil fuel energy supplies. It analyzes the interrelationships of three factors: utilizing more low quality geothermal fluid, burning less fossil fuel, and changing the size

BLOCK A - GEOTHERMAL RESOURCES, LOCATIONS, AND COSTS

	PARAMETER	INDEPENDENT PARAMETER CONNECTION
1.	FIELD LOCATION	
2.	TYPE OF LAND: FEDERAL (KGRA OR NOT), STATE, OR PRIVATE	A1
3.	EXPLORATION TIME	A1, A2
4.	FIELD DEVELOPMENT TIME	A1, A2
5.	RESOURCE CHARACTERISTICS BY GEOTHERMAL STREAM: TEMPERATURE, PRESSURE, ENTHALPY, MASS FLOW RATE	A1
6.	RESOURCE CHEMICAL COMPOSITION: POLLUTANTS, TOXICITY, CORROSIVENESS	A1
7.	RECOVERABLE MATERIALS: METHANE, MINERALS	A1
8.	YEAR FOR WHICH PROJECT START IS CONTEMPLATED	
9.	COST OF GEOTHERMAL FLUID AND LOCAL COST OF POWER AND FOSSIL FUELS	A(all), C(all)
10.	LABOR MARKET ATTRACTIVENESS: UNION ACTIVITY, WORK FORCE AVAILABILITY, HOUSING, EDUCATIONAL, RECREATIONAL AND CULTURAL FACILITIES, ETC.	A1
11.	WAGE AND SALARY RATES	A1
12.	PRICE OF UTILITY CONNECTIONS	A1

TABLE 1-1 - PARAMETERS AFFECTING THE DEVELOPMENT OF GEOTHERMAL ENERGY (continued . . .)

PARAMETER	INDEPENDENT PARAMETER CONNECTION
FACTORS AFFECTING THE VALUE OF PARAMETER A9:	
13. FIELD LIFETIME: FUTURE REDUCTIONS IN MASS FLOW RATE, TEMPERATURES AND PRESSURES AS A RESULT OF EXPLOITATION	A1
14. AVERAGE WELL PRODUCTIVITY	A1
15. AVERAGE WELL DEPTH	A1
16. AVERAGE WELL SPACING	A1
17. DISPOSAL SYSTEM COST	A1, A6, A18-20
18. DISPOSAL OF COOLING WATER, EFFLUENTS, ETC.	A1
19. REINJECTION COST FOR WELLS, PUMPING	A6, A15, A18
20. CORROSION- AND EROSION- RESISTANT MATERIALS	A6
21. GAS PURIFICATION AND SEPARATION	A5, A6
22. NOISE SILENCERS	A5, B8
23. PUMPING COST IF NOT ARTESIAN WELL	A15
24. COST OF WELLS INCLUDING DRY HOLES	A1, A3, A4, A8, A15, A16, etc.
25. DISTRIBUTION PIPELINE LENGTH AND COST	A16
26. DISTRIBUTION PUMPING COST	A16
27. WELL REPLACEMENT AND REBORING COST	A6, A15
28. INTEREST ON BORROWED CAPITAL	A3, A4, C4

TABLE 1-1 (continued . . .)

	PARAMETER	INDEPENDENT PARAMETER CONNECTION
29.	DEPRECIATION AND DEPLETION INCLUDING REPLACEMENT WELLS	A(all), C6-7
30.	EXPLORATION COST	A1, A3, A8, A35
31.	DEVELOPMENT COST	A(all)
32.	RENTAL AND ROYALTY PAYMENTS	A2
33.	RETURN ON EQUITY AND ON INVEST-MENT DESIRED BY DEVELOPER	A(all)
34.	TAXES	A1, A2, C5-10
35.	FINANCING MIX OF DEVELOPER	
36.	LAND ACQUISITION COST	A1, A2
37.	ENGINEERING AND DESIGN FEES	A1, A6

BLOCK B - ENVIRONMENTAL FACTORS

	PARAMETER	INDEPENDENT PARAMETER CONNECTION
1.	SUBSIDENCE	A1
2.	INDUCED SEISMIC ACTIVITY	A1
3.	ECOLOGICAL DISRUPTION	A1
4.	POLLUTION	A1, A6, A7, D1
5.	WATER REQUIREMENTS FOR COOLING, EFFLUENT DISPOSAL, ETC.	A5, A18, B9, D1
6.	COMPETING WATER REQUIREMENTS	A1

TABLE 1-1 (continued . . .)

PARAMETER	INDEPENDENT PARAMETER CONNECTION
7. COMPETING LAND REQUIREMENTS	A1
8. NOISE	A1, A5, A6, A16, A22
9. DISPOSAL OF DRILLING MUD	A17-18, B4-5
10. ENVIRONMENTAL IMPACT STATEMENTS	A1-7, A13-25

BLOCK C - REGULATORY AND GOVERNMENTAL FACTORS

PARAMETER	INDEPENDENT PARAMETER CONNECTION
1. LEASING DELAYS	A1, A2
2. PROPERTY RIGHTS - LEGAL CHARACTER OF RESOURCE (MINERAL, WATER, SUI GENERIS, UNRESOLVED)	A1, A2
3. IMPACT ON TAXES AND REGULATION OF EXTRACTION OF MINERALS FROM BRINE	
4. LOAN GUARANTEES (ACT OF 1974)	
5. INTANGIBLE DRILLING COST TAX TREATMENT	
6. DEPLETION ALLOWANCE TAX TREATMENT	
7. DEPRECIATION TYPE AND SCHEDULE PERMITTED	
8. COUNTY PROPERTY TAXES	A1
9. STATE TAXES	A1

TABLE 1-1 (continued . . .)

PARAMETER		INDEPENDENT PARAMETER CONNECTION
10.	FEDERAL TAXES	C3-9
11.	RISK OF ZONING AND BUILDING CODE CONFLICTS	A1, A2
12.	RISK OF PROPERTY RIGHT CONFLICTS	C2-3

BLOCK D - INDUSTRIAL APPLICATION

PARAMETER		INDEPENDENT PARAMETER CONNECTION
1.	SPECIFIC INDUSTRY PROCESS CONSIDERED	
2.	PROCESS ENERGY DEMAND PROFILE	D1
3.	PRESENTLY USED POWER AND FUELS - TYPES	D1
4.	PRESENTLY USED POWER AND FUELS - CONSUMPTION	D1
5.	PLANT CAPACITY FACTOR AND SEASONAL LOAD FACTOR	D1
6.	PLANT OUTPUT BY PRODUCT	D1
7.	RAW MATERIALS TRANSPORTATION DISTANCE	A1, D1
8.	MARKET TRANSPORTATION DISTANCE	A1, D1
9.	ENERGY MISMATCH PROFILE BY TYPE AND CONSUMPTION	A5, D2
10.	INCREASE IN EQUIPMENT SIZE REQUIRED FOR GEOTHERMAL FLUID USE	A5, D2

TABLE 1-1 (Continued . . .)

PARAMETER		INDEPENDENT PARAMETER CONNECTION
11.	POTENTIAL FOR ENERGY CONSERVATION IN EXISTING PLANT	D2
12.	POTENTIAL FOR INCREASED INTERNAL ENERGY GENERATION IN EXISTING PLANT	D2
13.	LABOR REQUIREMENTS BY TYPE AND AMOUNT	D1
14.	PRODUCT MARKET GROWTH PROSPECTS	D1
15.	PRODUCT MARKET STABILITY	D1
16.	ORGANIZATIONAL ATTITUDE TOWARD DECENTRALIZATION	A1, D1, D7-8
17.	INDUSTRY EFFECT ON COMMUNITY - LABOR, HOUSING, ETC.	A1, B(all), C8, C11, E2-3
18.	COMMUNITY ATTITUDE TOWARD INDUSTRY	D1, D17

BLOCK E - ECONOMICS

PARAMETER		INDEPENDENT PARAMETER CONNECTION
1.	REQUIRED PROCESS INCREMENTAL INVESTMENT: ADDITIONAL HEAT EXCHANGER AREA, NUMBER OF EFFECTS IN MULTIPLE-EFFECT EVAPORATORS, CORROSION-RESISTANT MATERIALS, HEAT EXCHANGERS FOR GENERATING CLEAN STEAM, ETC.	A6, A9, D2, D10
2.	PLANT CONSTRUCTION TIME	D1

TABLE 1-1 - (Continued . . .)

	PARAMETER	INDEPENDENT PARAMETER CONNECTION
3.	PLANT CAPITAL COST	A1, D1, E1-2
4.	FINANCING MIX FOR PLANT	D1
5.	TAXES	C8-10, D1, E3
6.	ROYALTY PAYMENTS	A2, D6
7.	INSURANCE PAYMENTS	D1, E3
8.	INTEREST ON BORROWED CAPITAL	A3, A4, E2-4
9.	COST OF RAW MATERIALS TRANSPORTATION PER UNIT	A1, D1
10.	COST OF PRODUCT TRANSPORTATION PER UNIT	A1, D1
11.	COST OF PRODUCT AND EXPECTED INFLATION IN COST	D1
12.	COST OF FOSSIL FUELS PREVIOUSLY USED, INSURANCE, LABOR, ETC.	A1, D1
13.	INFLATION IN COST OF FOSSIL FUELS, INSURANCE, GENERAL PRICE INDEX, TAXES, LABOR, POWER, ETC.	A1, D1
14.	OPERATING AND MAINTENANCE COSTS	A7, A9, A11-12, C3, C5-10, D3-4, D6-8, E5-10
15.	TOTAL REVENUE AND ANNUAL INCOME STATEMENTS	A8-9, E(all)
16.	OVERALL SAVINGS VERSUS FOSSIL FUEL ALTERNATIVE OR OVERALL RETURN ON INVESTMENT AND RETURN ON EQUITY	E(all)

TABLE 1-1 - (Concluded)

of process equipment.

The computer model attempts to optimize the use of geothermal fluid to the maximum extent possible. In connection with this goal, it is important to note some distinguishing facts about the utilization of geothermal energy sources.

Two different methods are available to develop a geothermal field: direct investment by the interested user, and development by a second party who then sells fluid at "arm's length" to the user. In the first case, the cost to the user is concentrated at the outset, with smaller subsequent maintenance charges and no explicit cost for fluid. In the second, no initial charges are incurred, but the user must pay for fluid over the lifetime of the project.

In either situation, the costs of field development are essentially fixed by the number of wells drilled. Once a well has been drilled, extracting fluid at a higher flow rate adds little to the overall cost of the field. To lower the cost per kilogram of fluid produced, it is therefore advantageous to utilize the maximum flow rate attainable from the wells drilled. However, if the fluid temperature drops significantly as the flow rate increases, the drop in energy available from each kilogram of fluid may offset the lower cost. In either case, once a flow rate has been chosen, the cost of fluid per unit mass will then be fixed.

This phenomenon distinguishes geothermal energy from alternative sources of energy. The price of oil or gas is frequently quoted on a "per kJ" or "per Btu" basis. For geothermal energy, this price would be undefined: the cost per unit energy of geothermal energy depends upon the amount of energy extracted from each kilogram of fluid. It is therefore desirable to maximize the drop in enthalpy of the fluid in order to obtain the most energy per dollar. To attain this objective, the fluid must be cooled to as low a temperature as possible by transferring heat to an even cooler material.

This principle of extracting as much heat as possible from the geothermal fluid underlies the design of the energy supply and demand matching procedure used in the computer model. The output of the section of the computer program dealing with this procedure consists of figures for the amount of geothermal fluid used, for the quantity of auxiliary fossil fuel needed, and for the size of each piece of unit process equipment required. These figures then form the basis of the economic analysis to follow.

REFERENCES

1. Geothermal reserves consist of that portion of the identified accessible (hydrothermal) resource base to 3 km which can be extracted using current technology and is outside of National Parks. U.S. Geological Survey, Assessment of Geothermal Resources of the United States, USGS Circular 790, 1979, p. 157.

   Oil and natural gas figures correspond to the estimated proved reserves as of January 1, 1978 which are identified and economical to exploit. The Oil & Gas Journal, December 25, 1978, p. 103.

2. The identified and estimated undiscovered accessible (hydrothermal) resource base to 3 km (outside of National Parks) is 9650×10^{18} J, of which approximately 4800×10^{18} J is hotter than 150°C. USGS Circular 790, Op. Cit., p. 157.

3. Darmstadter, Joel, Conserving Energy, Baltimore: Resources for the Future, Inc., 1975, p. 20.

   InterTechnology Corporation Analyses of the Economic Potential of Solar Thermal Energy to Provide Industrial Process Heat, Final Report, Vol. 1, February 1977, NTIS NO. C00/2829-1, p.53.

CHAPTER 2 - THE COMPUTER-AIDED ANALYSIS METHODOLOGY

A. Introduction

The GEOTHM computer model developed in the course of this research is designed to aid in the evaluation of the technical and economic feasibility of geothermal process heat applications.

The computer program is designed to be well-documented, self-contained, and compact. The user's manual, reproduced as Appendix D below, should enable a typical user to learn how to operate the program in one to three days. While other computer codes in the geothermal field frequently require that the user provide supplementary computer software such as steam tables, the present model is a self-contained package which incorporates sorting routines, steam tables, and other necessary software. Nevertheless, the program is compact, requiring less than 2600 lines of code including all program comments. Written in basic FORTRAN without extensions, it runs on a minicomputer in one to one and a half seconds. The program is in the public domain.

1. Methodology

Two modes of operation are available. The first, called the automatic matching mode, is illustrated schematically in Fig. 2-1. The second, designated the manual matching mode, is shown in Fig. 2-2. Detailed flow charts are given in Appendix D.

The objective of the automatic matching mode is the matching of geothermal and conventional energy supplies with the energy demands of industrial processes. The program attempts to optimize the manner in which processes use energy by utilizing heuristic rules to select the most advantageous configuration of the system (i.e. which fluid flows should serve which heat exchangers; in what situations cascading of fluid streams should be employed, etc.). All process energy needs are satisfied either through use of geothermal fluid alone or, if necessary, by employing auxiliary fossil fuel. As this matching operation is performed, the program stores information concerning the heat exchangers, pumps, and compressors that were required to satisfy process energy needs. This section of the program is described in detail in Chapter 3.

The matching procedure is executed twice: once for a conventional base-line system (using no geothermal fluid) and once for the geothermal system.

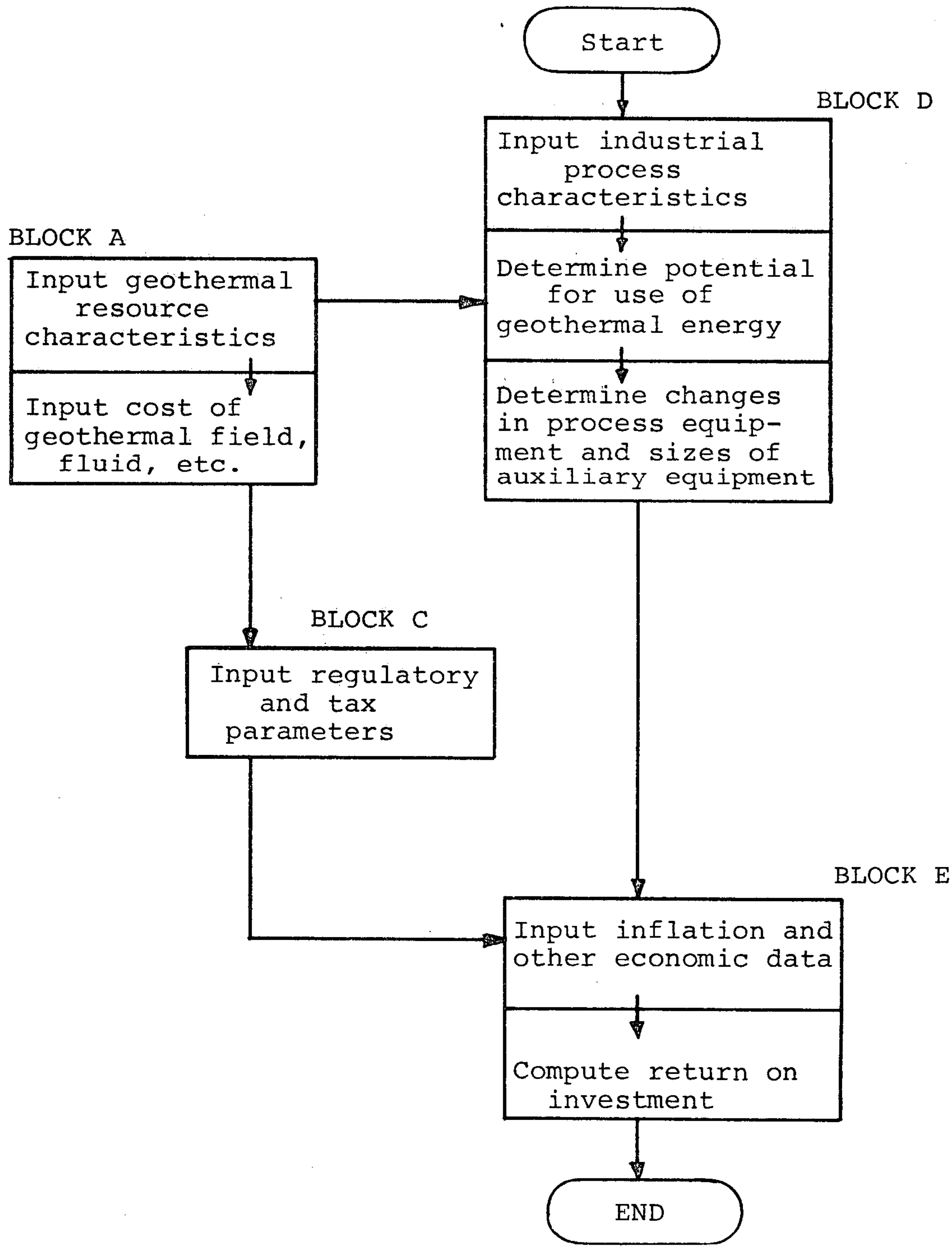

FIGURE 2-1 - SCHEMATIC OF AUTOMATIC MATCHING MODE OF OPERATION

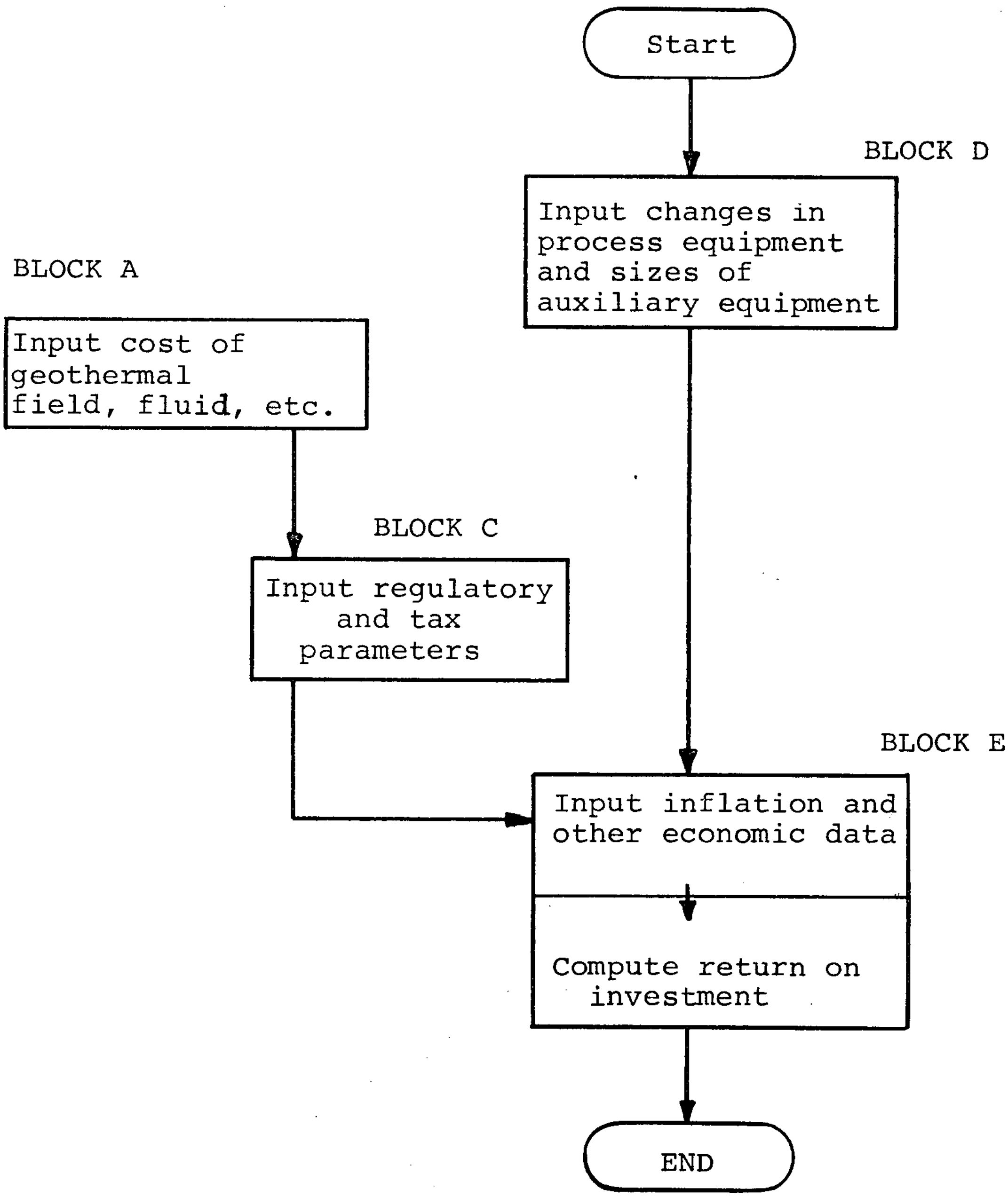

FIGURE 2-2 - SCHEMATIC OF MANUAL MATCHING MODE OF OPERATION

Finally, the program performs a full economic comparison of the two systems, including such considerations as the debt structure of the firm and tax incentives available to geothermal producers. The economic model is discussed further in Chapter 4.

In the second mode of operation (manual matching mode), the user must supply data concerning the technical results of matching energy supplies and demands. This information (which includes the quantity of fossil fuel used and the number and size of auxiliary equipment employed) then forms the basis for the economic comparison.

2. Capabilities

The program can be used in the automatic matching mode as a design tool to investigate the potential for geothermal energy in process heat applications. However, the human operator retains considerable control over the computer through his ability to change input data and to alter the settings of decision variables. This degree of control permits substantial interaction between the operator and the program. It is also the key to the flexibility of the program. Such interaction may occur either off-line with a batch-type computer facility or on-line if a time sharing facility is available: with only slight modification, the program can be operated in either mode.

While the program optimizes the use of geothermal energy to a certain extent, human judgment and interaction with the program frequently permit further improvement. This feature of the program has been retained intentionally to enable managers to understand the process by which results are obtained and to provide them the opportunity to ask the specific questions to which they desire answers.

Some of the capabilities of the automatic matching mode of operation are listed in Table 2-1.

The program can be used in the manual matching mode of operation to evaluate the feasibility of a proposed project by entering the design of the system (as determined by other means) as input into the economic analysis. Furthermore, this mode can be employed to investigate the sensitivity of the overall economics to changes in economic assumptions (e.g. in equipment costs, inflation estimates, etc.).

3. Required data for operation

For operation in the automatic matching mode, required input includes: geothermal resource characteristics at plant entrance (temperature, pressure, etc.), process application characteristics (required fluid flow rates, The computer program allows for:

1. Input streams of any phase (liquid, steam, or mixture)
2. Choice of flashing pressurized water
3. Choice of separating two-phase streams to liquid and vapor components
4. Auxiliary heating of input streams to meet process requirements
5. Compression of steam in stages with desuperheating
6. Consideration of requirements for electricity as well as for process heat
7. Processes requiring clean fluid or geothermal brine; direct injection of fluid or heat exchange from fluid, etc.
8. Computation of changes in equipment size necessary for the change to geothermal fluid
9. Cascading: use of fluid streams exiting from one process as input to another.

TABLE 2-1 - CAPABILITIES OF THE AUTOMATIC MATCHING MODE process energy needs, etc.), economic data (fossil fuel prices, well costs, tax rates, etc.), and a small number of decision variables which control the matching procedure. Output then consists of auxiliary equipment required (pumps, heat exchangers, etc.), fossil fuel and electrical energy consumption, and the resulting cash flows, rates of return, and payback periods. A full description of the necessary input is given in Appendix D.

For operation in the manual matching mode, input must include the economic data mentioned above, a list of auxiliary equipment necessary for the application under consideration, and auxiliary fuel consumption figures. Output consists of the cash flow and profitability measures mentioned above. Again, further details appear in Appendix D.

Any variable for which an exact value is not available may be left as a free parameter. For example, the geothermal resource temperature may be varied in the input to determine the temperature at which the application investigated would become economical.

4. Advantages

The program possesses many advantages over previous computer models. First, it is well-documented and transportable; a potential user need not fear months of effort merely to make the program operational. Second, it is self-contained; additional software is not needed. Third, it is flexible; the discussion above hopefully highlights a few of the possible types of questions it can address.

B. The Computer Program

The computer program has been written in modular form. A mainline program, GEOTHM, serves as a driver which guides the flow of control through the entire program package. In addition, several input and output subroutines handle most of the communication with the operator. These portions of the program package are described in the remainder of this chapter. The automatic matching procedure is performed by a set of subroutines, MATCH, SORT, SEPRAT, and SPLIT, which form the subject of Chapter 3. Economic considerations lie within the province of another subroutine, ECONMC, which is described in Chapter 4. Finally, the thermodynamic property values required by the automatic matching procedure are determined by another set of subroutines that are discussed in Appendix C.

1. The driver program GEOTHM

In the following paragraphs will be presented a general outline of the structure of the mainline driver program, GEOTHM. Flow charts and computer code listings for this program may be found in Appendix D.

The program first reads values for three parameters: the identification number for the present run, a control variable which specifies whether the automatic or manual matching mode of operation will be employed, and a control variable which determines whether single or multiple runs of the program will be made.

If multiple runs are to be made, the program uses a NAMELIST data input facility to change data between runs. This facility differs from one computer system to the next. All machine-dependent computer code is located in the GEOTHM mainline program and is clearly marked in the code listing. At present, the version of NAMELIST implemented in the code is that adopted by Digital Equipment Corporation for its VAX/VMS computers. Little effort is necessary on the part of a user to alter the appropriate lines of computer code to accord with the conventions of another computer.

If multiple runs are used, the program initializes the appropriate NAMELIST subroutines.

Next, the program reads and echo prints alphanumeric descriptions of the geothermal resource location and of the industrial application being considered.

The program then branches into two sections, one for the automatic mode of operation and one for the manual mode.

If the manual mode has been chosen, the program employs input and output subroutines (which are described in the next section) to read and echo print technical match data for the conventional and for the geothermal systems. Economic data are then read. The program then calls the economic analysis subroutine to estimate the cash flows attributable to each system and to determine the profitability of the geothermal application. Following this, the results of the economic analysis are printed. The program then stops execution if only a single run is intended. If multiple runs are required, the NAMELIST facility is invoked so that input data may be altered. The program then returns to the determination of cash flows mentioned above. The process terminates when the run variable is changed to indicate that more runs are not wanted.

If the automatic matching mode of operation has been selected, the program follows a different course. First, values are read for eleven decision variables which control the automatic matching procedure. Suitable messages are printed to identify which control options have been chosen. Next, data are read which specify the initial fluid streams (usually geothermal) that are available for matching. The first stream is always considered to be geothermal. A rating on a purity index is determined for each stream on the basis of its ratings upon a scaling index and a toxicity index. The latter ratings are given as input for each stream. If both the scaling and toxicity ratings are less than or equal to three, the stream is considered to be pure. Stream data are then echo printed.

The program then reads and prints data relating to unit process characteristics and economic parameters.

Next, the program calls the automatic matching subroutine in order to match energy demands and supplies for a conventional plant in which no geothermal fluid is used. The results of this procedure are printed by means of an output subroutine. The economic analysis subroutine is called to calculate cash flows for the conventional system.

The program now checks whether multiple runs are desired. If so, it offers the user the opportunity to alter input data before evaluation of the geothermal system. As will be discussed in Appendix D, this opportunity is useful in many situations. The program prints a table of data relating to the streams remaining after the conventional system has been analyzed and asks for new input data using NAMELIST. The user can indicate his desire to re-run the conventional case using new data, to run the geothermal case with or without new data, or to conclude the run entirely.

If the user has chosen to run the geothermal case, the program enters a "flow rate loop" in which it analyzes the geothermal system for a variety of geothermal fluid flow rates set by the user. For each flow rate, the automatic matching procedure is performed, an economic analysis made, and the results printed.

Finally, if multiple runs are desired, the program again gives the user the option of entering data for a new conventional system run, entering data for a new geothermal system run, or terminating the analysis.

2. Input-output subroutines

Four subroutines handle the bulk of input and output for the program package: MATRD, MATPRN, ECODAT, and ECORES.

The first of these, MATRD, reads the technical data that result from the matching of energy supplies and demands for the cases in which the manual matching mode of operation has been selected.

The second subroutine, MATPRN, prints the match result data. If the manual matching mode is used, this represents an echo print of the data read by subroutine

MATRD. If the automatic matching mode is employed, the data printed constitute the results of the matching procedure performed by subroutine MATCH.

The data are printed as follows. Each use of auxiliary energy sources is displayed separately, with three parameters given for each: temperature of the stream to which the energy is delivered, pressure of the stream to which it is delivered, and the quantity of energy per unit time in kilowatts. For electrical energy, each of the first pair of parameters is listed as zero. The next section to be printed presents data concerning equipment size characteristics, both for process equipment and for any additional equipment required (flash vessels, pumps, compressors, fossil fuel heaters, or heat exchangers). Two size parameters are given: the mass flow rate of fluid handled and a second parameter whose definition depends upon the type of equipment. For process equipment, it is the ratio of the new size to the old; for heat exchangers and fossil fuel heaters, the heat transfer rate; for pumps and compressors, the increase in fluid pressure; and for flash vessels and two-phase separators, the stream quality. Finally, the values of nine additional parameters are given: total process energy requirement, total use of electricity and of fossil fuel, total geothermal mass flow rate, total fluid enthalpy and availability at inlet and exit to the plant, and total mass flow rate of water required from external sources. As a check upon the match results, the program also computes and prints the error in the First Law (conservation of energy) for the plant as a whole. This figure usually varies from zero by a small amount because of inaccuracies in the thermodynamic properties evaluation routines.

The third input and output subroutine, ECODAT, reads and echo prints values for a wide variety of economic parameters. These parameters include the cost of each element of the geothermal field, the cost of auxiliary energy, inflation rates, depreciation variables, and tax variables.

The final subroutine, ECORES, prints the most important figures of the entire analysis: the economic bottom line. The subroutine first lists figures for the investment in current dollars for the geothermal system and the investment in constant dollars for the geothermal system, the geothermal field, and the conventional system. It then prints the net present value of the cash flows for both systems, the net present value of geothermal system savings, the discounted payback period, and the internal rate of return. Finally, the subroutine prints the annual cash flows for both systems.

CHAPTER 3 - THE MATCHING PROCEDURE

The heart of the methodology's automatic matching mode of operation is the procedure for matching energy supplies and demands. This procedure is implemented in a large subroutine (MATCH) and three smaller subroutines (SORT, SEPRAT, and SPLIT).

The organization of this chapter follows that of the computer programs, for which flow charts are given in Appendix D.

A. Supply Stream and Unit Process Initialization and Sorting

1. Initialization and sorting

Primary variables relating to stream or process characteristics are initialized to appropriate values in some cases by data read from an input file or data cards (as was described in Chapter 2) and in other cases by the BLOCK DATA subprogram. In the course of the matching procedure, stream and process data will be altered. However, in order to execute the matching procedure for a variety of geothermal fluid flow rates without re-reading data, the initial values of stream and process variables must remain untouched. The solution to this quandary lies in setting secondary variables equal to the values of the primary variables at the start of each execution. The secondary variables then are used for manipulation, leaving the primary variables undisturbed. The first section of the program implements this procedure, with primary variables designated by names ending in "I", for initial. Also initialized at this point are variables which relate to equipment size and auxiliary energy needs.

Next, processes and streams are sorted according to the principles set forth in Section H below. The total enthalpy and availability (the latter corresponding to an ambient temperature of 20°C) present in the input streams are also calculated for later use.

2. Supply-stream management

The geothermal fluid may arrive at the surface as compressed liquid, as a two-phase mixture, or as superheated vapor. In the second case, the program allows for separation into saturated vapor and liquid if so desired. This permits use of the higher heat transfer coefficient of condensing vapor to fullest advantage. In the case of compressed liquid, the program allows isenthalpic flashing to any given pressure, if desired, as well as the possibility of subsequent phase separation. Three input variables govern this procedure: two simply to decide whether flashing and separation are allowed, and one to set the minimum allowable flash pressure (which may be different for each stream). Neither self-beneficiation of streams using organic fluid cycles nor jet extraction of non-condensible gases is employed in the program.

This section marks the introduction of the first technical rules (a term defined in Chapter 5) of many to follow. Specifically, flashing of a stream is suppressed if (1) the stream has over ninety percent quality already, or (2) the saturation pressure associated with its present enthalpy is less than 0.05 bars above the minimum allowable flash pressure, or (3) the stream quality after flashing to this last pressure would be under ten percent. The numbers employed in these rules are assumed to approximate points at which the capital cost of the equipment involved begins to outweigh the utility of having flashed streams.

If permitted by the appropriate input control variable, two-phase streams are then separated by calling subroutine SEPRAT (to be discussed in Section H below).

The program records for future use the exit steam flow rate and pressure associated with the flash vessel and phase separator. Finally, the streams are resorted and their properties (flow rate, temperature, etc.) printed.

B. Process-Stream Matching Procedure

The program here commences an examination in turn of each unit process. For each process, a suitable fluid stream is selected to satisfy the energy needs of that process.

1. Electric energy requirements

The computer program takes into account not only use of fossil fuel and geothermal energy but also use of electricity. For the following reasons, the program pays special attention to the electric power requirements of preexisting equipment in addition to those of new apparatus.

In most industries, the quantity of energy employed as process heat is not directly related to the amount of electricity purchased to run plant equipment. However, in other industries, process heat and electricity requirements are connected more closely. A common practice in these industries is to generate high pressure steam in a fossil fuel boiler, pass the steam through a turbine to produce electricity, and then use the resulting low pressure steam for process heat needs. This procedure, known as cogeneration, reduces the overall entropy production associated with heating moderate temperature water directly with high temperature combustion products.

In process heat applications of geothermal energy, geothermal fluid replaces fluid heated by fossil fuel. If the replaced fluid is low pressure steam in a cogeneration system, the reduction in steam production and thus in the quantity of steam passing through the turbines results in a decrease in the amount of electricity generated. The firm must therefore purchase more electricity from outside utilities. The difference between the quantity of electricity purchased for a conventional and for a geothermal plant could therefore be greater than that expected solely on the basis of the increased number of compressors and other components. The power requirements of existing equipment must therefore be included in the analysis.

As the computer program is intended for use with any industry, provision is made for the electric power requirements of existing equipment in addition to those of new apparatus. In the program, an existing need for electricity is indicated whenever the user inputs a process with temperature and pressure requirements both equal to zero. An existing need for fossil fuel is indicated by a process with a negative pressure requirement. (See Section 1 of Appendix D for a further discussion of this procedure.) When such processes are encountered by the program matching section, an outside electricity or fossil fuel requirement is established. The matching procedure then continues with an examination of the next process.

Should a user of the program so desire, an electric generation module could be added to the program to permit automatic analysis of electric generation by means of cogeneration or geopressured resource applications. Implementation of such a module within the framework of the current computer program would not present any difficulties.

2. Stream selection logic

Given a particular unit process, the program must choose from the available fluid supply streams one which will satisfy the energy needs of that process. Since this choice affects the properties of the streams which will be available for the next process to be examined, some attention must be given to optimization of the stream selection logic. This complex problem will be discussed from a more general viewpoint in Chapter 5. The "rule-of-thumb" strategy considered there will be described in detail below.

The strategy adopted consists of use of an heuristic algorithm to select a stream for the process under consideration. Before the algorithm itself is given, several definitions must be introduced.

First, "sufficient mass flow rate" means that the flow rate of the stream being considered exceeds a certain fraction (given as an input parameter) of the flow rate normally required by the process. A different fraction may be used for single-phase as opposed to two-phase streams. This sufficiency criterion is necessary to limit the specific enthalpy drop of the fluid through the process to reasonable levels. Were the criterion not imposed, the program might choose a stream with a small flow-rate, potentially requiring temperature upgrading to hundreds of degrees to provide the proper total enthalpy drop for the process enthalpy requirement.

Second, "proper phase" indicates that the phase of the current stream is acceptable for use in the process: for processes requiring liquid, this means either a liquid stream or a two-phase stream of quality under 10%; for processes requiring condensing vapor, this means a stream of quality between 90% and "104%" (some superheat being of little importance because of the small heat capacity of the vapor); and for processes requiring superheated vapor, this means a two-phase stream of quality greater than 99% or a vapor stream. These definitions are chosen in order not to restrict stream selection unduly.

Third, a stream is defined to have the "correct purity" if it is clean (according to the criteria given in Chapter 2) and the process under consideration can accept only clean fluid or, alternatively, if it is impure and the process can accept impure fluid.

Fourth, a stream is said to possess "sufficient enthalpy" if the heat required by the current process could be extracted from the stream without the stream falling short of the temperature requirement of the process. (The temperature requirement criteria are described in Section E.2 below.)

Finally, the "temperature rule" selects a stream on the basis of temperature, choosing the stream with the lowest temperature, provided that its temperature is greater than the sum of the process temperature and the required unit process temperature difference (minus one degree Celsius to account for round-off errors). This sum approximates the stream inlet temperature needed by the process. If no such stream exists, the rule selects the stream with the highest temperature. By choosing the lowest temperature stream above the temperature sum, the program conserves streams of high thermodynamic availability; by choosing the highest temperature stream otherwise the program reduces the amount of energy which will be needed later for temperature upgrading.

The stream selection algorithm can now be introduced. It is designed to minimize the use of geothermal fluid and of auxiliary fossil fuel and to maximize the cascading of fluid streams from one process to another. Specifically, the algorithm requires that the program

(a) Choose a stream with sufficient enthalpy, sufficient mass flow, proper phase, and correct purity according to the temperature rule

(b) If no stream satisfies the criteria in (a), choose a stream with sufficient enthalpy, sufficient mass flow, and proper phase according to the temperature rule

(c) If no stream satisfies the criteria in (b), choose a stream with sufficient enthalpy, sufficient mass flow, and correct purity according to the temperature rule

(d) If no stream satisfies the criteria in (c), choose a stream with sufficient enthalpy and sufficient mass flow according to the temperature rule

(e) If no stream satisfies the criteria in (d), choose a stream with sufficient mass flow, proper phase, and correct purity according to the temperature rule

(f) If no stream satisfies the criteria in (e), choose a stream with sufficient mass flow and proper phase according to the temperature rule

(g) If no stream satisfies the criteria in (f), choose a stream with sufficient mass flow and correct purity according to the temperature rule

(h) If no stream satisfies the criteria in (g), choose a stream with sufficient mass flow according to the temperature rule

(i) If no stream satisfies the criteria in (h) and the process is of the direct-injection type (i.e. fluid is injected into the process chamber and cannot then be recirculated), draw enough ambient water to create a stream with sufficient mass flow

(j) If no stream satisfies the criteria in (h) and the process is of the heat-exchange type, satisfy its energy requirements by establishing a closed-loop recirculating fluid system in which the fluid is heated by a fossil fuel burner and cooled by the process.

The algorithm is summarized in Table 3-1. As will be described in the next section, this algorithm provides a tentative choice of stream which may be overruled depending upon the outcome of further tests to be discussed.

One assumption made in the computer program should be noted at this point. The computer requires that processes

Stream selection logic - hierarchy of choice

(a) H, $\dot{m}$, phase, purity

(b) H, $\dot{m}$, phase

(c) H, $\dot{m}$, purity

(d) H, $\dot{m}$

(e) $\dot{m}$, phase, purity

(f) $\dot{m}$, phase

(g) $\dot{m}$, purity

(h) $\dot{m}$

(i) direct-injection processes

used with the temperature rule

(j) heat-exchange processes.

Note that

H = sufficient enthalpy

$\dot{m}$ = sufficient mass flow

phase = proper phase

purity = correct purity.

These terms are defined more completely in the accompanying text.

TABLE 3-1 - THE STREAM SELECTION HIERARCHY whose energy needs were satisfied in conventional fossil-fueled systems by condensing vapor continue to utilize vapor in the new geothermal system; similarly, processes employing hot water in conventional cases must use liquid water in geothermal applications. The effect of this condition is to maintain the same approximate size for the new equipment as for the old since heat transfer coefficients will be similar in magnitude in both systems. Given that the prevailing ratio of energy (and thus hot fluid) cost to equipment cost is much higher than in the past, it is likely that the optimum tradeoff between fluid and equipment has moved in the direction of larger, more energy efficient equipment. This implies that use of hot water for a process which previously employed steam might be advantageous. The program nonetheless omits consideration of such a possibility. However, the same effect may be achieved by altering the specification of process characteristics and indicating to the computer a need for hot water instead of steam.

C. Process-Stream Efficiency Check and Brine Conversion

1. Efficiency check

Under some circumstances, a hot geothermal stream may prove less efficient in satisfying process energy needs than a stream heated by fossil fuel. This phenomenon can occur with a heat-exchange type process, for which the minimum possible auxiliary energy requirement is exactly equal to the process energy need. The equality results from the possibility of using a closed-loop system in which the energy removed from the fluid by the process is simply restored by a fossil fuel heater. In contrast, the amount of fossil fuel needed to upgrade a geothermal stream depends upon the current enthalpy of the stream and the enthalpy required by the process, and bears no relation to the process energy demand. For example, if the exit stream from the process proves to be hotter than the initial GT stream, some of the heat supplied by fossil fuel has not been consumed by the process. Even if cascading of the exit stream into another process is possible, this extra fossil fuel energy will be wasted unless the latter process could not have employed other geothermal streams without fossil fuel upgrading.

Unfortunately, there is no quick method of determining for a specific process and geothermal stream whether a closed-loop fossil system or an open-circuit geothermal system would be more efficient. Computation of the change in availability required to bring the selected stream to process inlet conditions would be the best estimate of the minimum auxiliary energy required were an open circuit to be chosen. (It would not be a completely appropriate figure, however, because of inefficiencies in equipment and practical limitations.) If the change in availability were found to exceed the availability required in a closed-loop system, a closed system should be utilized. However, basing the comparison upon enthalpies rather than availabilities substantially simplifies the calculations and focuses attention on the amount of fossil fuel directly expended.

The latter method is used in the program. The program therefore tests streams which have been selected for use with heat-exchange processes in order to determine whether utilization of a closed system would reduce auxiliary fossil fuel consumption. To estimate the required conditions at the inlet to the process, the test algorithm first requires calculation of the enthalpy associated with fluid at the process pressure and the minimum allowable fluid temperature (approximated by the sum of the process temperature and the required unit process temperature difference). The program then computes the energy needed to upgrade the chosen stream from its present enthalpy to this required inlet enthalpy. If this energy exceeds that required by the process by more than one percent of the latter, a closed-loop fossil system is used. Such a system is represented in the output by a fossil heater, an auxiliary fossil fuel energy requirement at the process pressure, and a new fluid stream listed as unavailable for further use. The user can readily identify such streams in the computer output since their listed temperature equals the sum mentioned above, while their pressure and enthalpy correspond to ambient conditions.

2. Brine conversion

Some processes (such as food cooking and sterilizing) require relatively pure water to avoid contamination. If a hot geothermal stream happens to be pure enough, the stream selection logic will prefer it to a dirtier stream. The need for a secondary heat exchanger to transfer heat from an impure stream to a clean one thus arises only when no appropriate geothermal stream has sufficient purity.

If a secondary heat exchanger is not required, the program branches to the next section. If brine conversion is necessary, the program begins by splitting the selected stream so that only a flow rate equal to that required by the process times a fraction given as an input parameter is used. A different value may be given for this upper limit flow rate fraction in the case of single-phase streams as opposed to that of two-phase streams. The flow splitting procedure avoids the unnecessary degradation of the remainder of the fluid which would otherwise ensue.

The program must now choose a pure stream to which the heat in the impure stream may be transferred. The algorithm adopted for this purpose selects the hottest pure stream of sufficient mass flow that has a temperature less than that of the impure stream minus twenty degrees Celsius. ("Sufficient mass flow" was defined in Section B.2 above.) If no such stream exists, the program establishes a stream of pure water at ambient conditions and of sufficient mass flow. The pure stream selected is then split as was the impure stream above.

The restriction that the temperature of the pure stream be at least 20°C cooler than the impure stream guarantees that Second Law constraints are not violated and that a secondary heat exchanger is not established when the potential heat transfer rate is too small. Selection of the hottest stream that meets this restriction serves to ensure that further requirements for auxiliary fossil fuel will be minimized.

A problem now arises concerning the treatment of the pure stream chosen. Frequently process requirements dictate that this stream be upgraded both in pressure and in phase. Since compression of liquid is less energy intensive than compression of vapor, an intuitive design rule would require compression of the pure stream first and then transfer of heat from the hot impure fluid. However, if after compression the pure stream's pressure exceeds that of the impure stream, its saturation temperature also will be higher. The impure stream will then be able to give up only as much heat as will raise the pure water to the temperature of the former minus the temperature difference across the heat exchanger. The energy not transferred from the impure fluid often must be supplied later by fossil fuel, creating exactly the kind of waste that the use of heat recovery from the impure fluid attempted to avoid.

The pure stream thus is compressed to the lesser of the pressure required by the process and that of the impure fluid minus 0.4 bars. The 0.4 bar pressure differential ensures a sufficient saturation temperature differential so that adequate heat transfer rates can be maintained. If the pressure of the impure stream is less than 0.9 bars greater than that of the pure stream, compression is suppressed. The purpose of this restriction is to avoid the capital cost of pumps if the pressure differential is too small (since the pure fluid may later have to be compressed by the remaining amount to the process pressure). Similarly, compression is suppressed as unnecessary if the pressure of the pure stream is greater than 0.01 bars below that required by the process. The compressor efficiency is assumed to equal 80%, and two percent of the total compression work is added to account for bearing and seal losses.

As will be noted in Chapter 5, these technical rules may not be optimum. However, they do lead to a physically workable design which can be used to generate a lower bound on economic performance.

The program now establishes a secondary heat exchanger and calculates the maximum amount of energy which could be transferred without violating Second Law constraints. The effectiveness ε, defined as

$$\varepsilon = \frac{\text{feasible heat transfer rate}}{\begin{pmatrix}\text{maximum heat transfer rate}\\ \text{consistent with Second Law}\end{pmatrix}}, \qquad [3.1]$$

is assumed to equal 85% (regardless of the fluid phases involved). The feasible heat transfer rate can then be computed. If this rate would result in a decrease in the enthalpy of the impure stream of under 50 J/g, the program rejects the establishment of the secondary heat exchanger and simply selects the pure stream for further use.

Occasionally the feasible heat transfer rate exceeds that necessary to warm the pure stream to the temperature required by the process. This situation can arise when the user attempts to close fluid loops by listing in the program input those streams which remain after the program completed execution the previous run. (This technique is described in Appendix D, Sections 1 and 6b.) When this technique is employed, the properties of a stream remaining after the program completes execution correspond to the fluid exit conditions required by a certain process. If this stream is then listed as an input stream and selected as a pure stream for use in a secondary heat exchanger, the amount of energy required to upgrade it to the fluid inlet conditions required by the process equals by definition the process energy requirement.

The program thus checks whether the pure stream could represent such a recirculated stream. If transfer to the stream of the energy required by the process yields a stream the properties of which satisfy the process temperature requirement, then the program restricts the heat transfer in the secondary heat exchanger to at most the process energy requirement. This procedure ensures that no more heat is transferred then is necessary to satisfy the process needs.

The heat transfer rate decided upon above then is employed to determine the increase in enthalpy of the pure stream and the corresponding decrease in enthalpy of the impure stream. Finally, stream parameters such as temperature are updated using the new enthalpy values.

D. Pressure Upgrading

1. Pressure reduction

For processes demanding two-phase fluid, the temperature and pressure required of the fluid are interrelated because at saturation fluid temperature is a function of pressure. It is important then that the pressure of the selected stream not be greater than that required by the process. Were the fluid pressure to exceed markedly the pressure needed by the process, the fluid temperature also would be higher than that required. As a result, the process equipment might be drastically smaller than in the conventional system, leading to material processing difficulties (too small residence times, etc.). Moreover, in retrofit applications the process equipment remains unchanged and there is no advantage to be gained from increasing process temperatures.

Therefore, if the process under consideration needs two-phase fluid and the pressure of the selected stream exceeds that required by the process by more than 0.5 bars, the stream is split as was described above (if necessary) and its pressure reduced isenthalpically to the process requirement. The margin of 0.5 bars guarantees that pressure reduction occurs only when truly necessary. Stream properties are then updated.

2. <u>Liquid phase pressure upgrading</u>

If the pressure of the selected stream exceeds the pressure needed by the process (minus 0.01 bars to account for round-off errors), pressure upgrading is not necessary and the program skips to the temperature upgrading section (Section E below).

If compression is required, the program will consider any stream with a quality less than 10% to be a liquid, since this figure is the upper cutoff in the stream selection logic for "correctness of phase" in the case of processes demanding liquid phase streams. It should be noted that while the program considers fluid of quality between 0.1% and 10% to be a liquid for the purposes of compression, in actuality two-phase compressors are not yet available commercially. A warning is therefore printed if the fluid quality lies between 0.1% and 10%.

The program begins by splitting the selected stream, if necessary, as was described above. The liquid stream then is compressed directly to the pressure required by the process. An efficiency of 80% is assumed again for the pump, and the work of compression is increased by 2% to allow for bearing and seal losses.

3. Two-phase and Vapor-phase pressure upgrading

Occasionally a two-phase stream must be compressed to a pressure acceptable to the process. Such a situation typically arises from the use of stream cascading or of secondary heat exchangers (brine conversion). Since two-phase compressors are not available (as was mentioned above), heat must be transferred to vaporize these streams before compression. The program therefore adds heat to the stream (using an auxiliary fossil fuel heater) to raise stream quality to 90% before attempting to compress the fluid.

The next question to be addressed is determination of the proper flow rate of fluid to be compressed. To minimize the compressor work required, the compression must take place in stages with desuperheating between stages. However, since desuperheating involves increasing the mass flow rate of the vapor by the mass of desuperheating water used, the amount of fluid necessary at the beginning of the compression process is somewhat less than the final quantity required by the process. In order not to compress unneeded vapor, the amount of fluid to be compressed should be the minimum amount sufficient to satisfy process needs. Typical calculations of the required flow rates demonstrate that for each kilogram of vapor needed at 3.10 bars pressure, no more than 0.96 kg of fluid at 1.0 bars should be compressed. The latter figure is termed the compression flow fraction. (The computed value remains valid even if no desuperheating at the final pressure is necessary.) Similar figures for vapor needed at 5.17 and 9.31 bars are 0.92 and 0.88 kg respectively. If the initial fluid has a quality of less than 99%, desuperheating is unlikely to be needed and so a compression flow fraction of 1.0 is used. Using these figures, the initial flow rate of the selected stream is then split as necessary.

A loop now follows which simulates a compressor. The pressure reached at the end of each compressor stage is determined by four rules. The first states that the stage pressure shall be the next higher standard pressure or the final pressure required by the process, whichever is lower. [Standard industrial steam pressures are 25, 45, 75, and 135 psia (1.72, 3.10, 5.17, and 9.31 bars).] The second rule amends the first by skipping the standard pressure immediately greater than the current stream pressure if the difference between the two is less than 0.75 bars. The third modifies the first two by dictating that the stage pressure be the final process pressure if the latter is less than 0.75 bars greater than the next standard pressure which otherwise would be selected. These two rules prevent the program from establishing a compressor stage for a small pressure differential. The fourth rule amends the first three by requiring that the vapor be compressed directly to the process pressure if the entropy of the vapor is less than the entropy of the final fluid condition desired as specified by the required process pressure and temperature. This rule provides a check upon the efficiency of employing desuperheating: if auxiliary heating would be required upon reaching the desired pressure, use of cold desuperheating water at intermediate stages would be wasteful. Desuperheating is therefore undesirable and the fluid stream should be compressed directly to the final pressure.

Once the stage pressure has been selected, the program establishes a compressor and compresses the selected stream. The compressor efficiency again is assumed to equal 80% and the compressor work is increased by 2% to account for bearing and seal losses. If desuperheating is required, water at ambient conditions is compressed directly to the current stream pressure and added to the stream. The flow rate of this ambient water is chosen so that the final mixed stream is saturated steam. Desuperheating is omitted if the desired pressure has been achieved and the process needs a superheated vapor stream.

Finally, the program determines whether the final pressure required by the process has been reached. If not, the program returns to find the next stage pressure.

E. Temperature Upgrading

Two factors lead to the conclusion that temperature upgrading for streams should be performed only after pressure upgrading. First, compressor work is less for a liquid than for a vapor. Thus if vapor is required and the selected stream is liquid, less auxiliary electricity must be purchased if the phase change occurs after compression. Second, compression usually involves an increase in stream temperature, which may obviate the need for further addition of heat. Subject to the exceptions that were discussed in Section C.2, the compurer program follows this rule and therefore considers addition of heat to the selected stream at this point.

1. Stream temperature check

If necessary, the program splits the selected stream as was described above. It then determines whether the temperature of the stream is sufficiently high to satisfy process requirements.

If the phase of the selected stream is "higher" than that required by the process (i.e. vapor instead of two-phase or two-phase instead of liquid), temperature upgrading is not necessary. [This occurs if the stream quality exceeds 10% and the process needs liquid or if the stream quality exceeds "104%" and the process needs saturated vapor.] The program therefore branches to Section F below. However, since this phase situation may conflict with certain assumptions made in Section F, a message is printed warning the user.

The crucial factor in the determination of temperature sufficiency is the magnitude of the unit process temperature differential. This parameter is defined as

$$\Delta t = \frac{(t_{stream,inlet} + t_{stream,exit})}{2} - t_{process}, \qquad [3.2]$$

where

$t_{stream,inlet}$ = temperature of selected stream at inlet to process

$t_{stream,exit}$ = temperature of selected stream at exit from process.

If the stream quality (defined in the conventional fashion) at inlet is less than "104%" and that at exit is greater than "-10%", the unit process temperature differential is defined instead as

$$\Delta t = t_{sat}(p_{stream}) - t_{process} , \qquad [3.3]$$

where

$$p_{stream} = \text{stream pressure},$$

since most of the enthalpy change of the stream occurs at the saturation temperature. If the temperature differential Δt is greater than a pre-set value given as an input parameter (minus 1°C to allow for round-off errors) and simultaneously the stream temperature at process exit exceeds the process temperature, the stream is adjudged sufficiently hot. The latter condition ensures that the Second Law is not violated.

The program employs the stream mass flow rate and the process energy requirement to compute the specific enthalpy drop experienced as the stream passes through the process. From this figure it then calculates the corresponding stream exit temperature and the unit process temperature differential. If temperature upgrading is not required, the program branches to Section F below.

2. Temperature upgrading - secondary heat exchangers

If temperature upgrading is required, the program searches for a hot impure stream for use as a source of heat. Such a stream (usually consisting of geothermal fluid) must be at least 15°C hotter than the current stream in order to become a candidate for a heat source.

The program evaluates for all such candidate streams the maximum amount of heat that could be transferred to the current stream. [An effectiveness of 85% is assumed for the heat exchanger.] The flow rate used in this evaluation for the candidate stream is the lesser of the actual flow rate and that flow rate which would just yield the largest heat transfer rate possible (subject to the Second Law). The program then chooses as a heat source the candidate stream for which the possible heat transfer rate is the largest. However, the program will not choose a stream if the enthalpy change of the current stream would be less than 50 J/g. If no stream can serve as a heat source according to the criteria above, the program branches to Section E.2 below concerning upgrading by use of fossil fuel heaters.

Next, if necessary, the candidate stream selected as a heat source is split. No greater flow is allowed than is needed to yield the maximum heat transfer rate permitted by the Second Law.

The program next checks whether use of a secondary heat exchanger between the source stream and the current stream would raise the temperature of the latter enough to satisfy the temperature sufficiency criterion given above. If it would do so, the program limits the heat transfer rate to the process energy requirement. The purpose of this limitation is identical to that of the limitation discussed in Section C.2 for brine conversion heat exchangers.

Finally, the program establishes the secondary heat exchanger, raises the enthalpy of the current stream by an amount corresponding to its flow rate and the heat transfer rate found above, and lowers the enthalpy of the source stream by a figure found by an analogous procedure. Stream properties such as temperature are then updated using the new enthalpy values.

The program then checks once again whether the temperature sufficiency criterion is met. If not, the program repeats the search for a hot impure stream to act as a heat source. The heat transfer limitation discussed above is modified for the second heat exchanger: the limiting rate is now the process energy requirement minus the heat transfer in the first heat exchanger. Only two such secondary heat exchangers are considered by the program; if the temperature sufficiency criterion is not met after the second heat exchanger, fossil fuel is used to upgrade the current stream in temperature. This procedure is described next.

3. Temperature upgrading - fossil fuel heaters

If temperature upgrading by means of fossil fuel heaters is required, an iterative calculation procedure is followed. The program estimates the stream temperature at process inlet which just satisfies the temperature efficiency criterion. As a first guess, the program tries the greater of the process temperature and the current stream temperature plus four degrees Celsius. The corresponding enthalpy is then found, from which is subtracted the enthalpy drop associated with the process energy requirement. From the result, the corresponding fluid exit temperature is determined.

Next, the unit process temperature differential (Δt) is computed and the temperature sufficiency criterion applied. If the criterion is not met, the estimate of the proper stream inlet temperature is raised 2.5°C and the above procedure is repeated.

Finally, the required quantity of fossil fuel is computed from the current value of stream enthalpy and the final value at inlet when the criterion is met. The program then establishes the fossil fuel heater and an auxiliary fossil fuel requirement.

F. The Unit Process

1. Unit process

This section of the program simulates the unit process itself. If necessary, the selected stream is split as was described previously. Next, the energy required by the process is transferred from the stream, thereby reducing its enthalpy. The final value of the unit process temperature differential can now be computed. Stream properties such as temperature are then updated. If the process is of the direct-injection type (see Appendix A for a definition), the stream is listed as unavailable for future use. Finally, if permitted by a control parameter, two-phase streams can be separated into liquid and vapor components at this point by calling subroutine SEPRAT (see Section H).

2. Unit process equipment size changes

The derivations of the equations governing the size of process equipment are given in Appendix A. The relevant equations used in the program are Eqs. A.5, A.13, and A.12. For the purposes of the computer code, the alternative definition of Δt given in Eq.3.3 is employed instead of that given in Eqs. 3.2 and A.1 if the stream quality at inlet is less than "104%" and that at exit is greater than "-10%."

3. Supply stream merging and sorting

As was discussed above, fluid streams frequently must be split. However, this procedure can lead to a fragmentation of fluid streams such that no single stream has a large enough mass flow rate to satisfy process requirements.

The program therefore combines streams of substantially similar properties. Specifically, streams are merged if four conditions are met: (a) neither stream is unavailable because of previous use in a direct-injection process; (b) both streams consist of pure fluid or of impure fluid; (c) the difference in pressure between the two streams does not exceed 0.2 bars; and (d) the difference in specific enthalpy between the two streams does not exceed 20 J/g. The temperature of the combined stream is then determined. The stream which "disappears" because of the merger is listed as a stream with zero flow rate and temperature.

The streams are sorted by temperature as was done at the beginning of the program. Finally, the current values of stream parameters (temperature, pressure, enthalpy, etc.) are printed so that the matching process may be followed by the user as it proceeds. Those streams with flow rates less than 20 kg/hr are omitted from the listing.

This avoids printing entries for streams which have been merged or split and thus have negligible or zero flow rates.

The program then returns to consider the needs of the next process (Section B).

G. Match Results

After all process needs have been satisfied, the program computes the total enthalpy and availability remaining in the fluid streams (other than closed-loop recirculating fluid circuits heated by fossil fuel), the total amount of fossil fuel heat needed, and the total consumption of electricity. It should be noted that no consideration is given to the occasional requirement for repressurization of effluent geothermal fluid prior to reinjection in the reservoir. The associated capital and operating costs of the reinjection pumps thus are not included in the analysis automatically. The user is free to allow for these costs in his input data.

H. Sorting, Phase Separation, and Flow Splitting

1. Sorting

The sorting subroutine SORT is required for two purposes in the program. The first is to arrange the fluid streams in descending order of temperature in order to allow the stream selection logic to function properly. The second is to arrange processes similarly so that high temperature processes are considered first. This procedure is intended to facilitate the use of stream cascading. If two supply streams possess identical temperatures, the stream with the smaller flow rate is placed higher in the ranking so that streams with large mass flows remain intact for later uses. For processes with identical temperature requirements, the process with larger flow is ranked higher so that cascading is possible.

The program uses a technique known as "bubble sorting" with unidirectional passes.[1] The maximum number of sorting passes potentially required through the streams equals one less than the number of streams to sort. To avoid excessive movement of data in the supply or process property vectors during the sorting procedure, a mapping vector is employed. This translates the stream rank number into the actual vector subscript of the stream or process and is used wherever a stream or process is referred to in the matching program.

2. Phase separation

The two-phase separation subroutine SEPRAT is called only if the appropriate control variable is set equal to unity. Separation will be suppressed, however, if the quality of the supply stream is less than 10% or greater than 90%. These figures represent estimates of the optimum tradeoff points between the capital cost of the separator and the utility of having separated streams.

3. Flow splitting

This simple subroutine, SPLIT, reproduces in the new stream the properties of the given stream and divides the flow rate of the original according to the mass flow rate specified when it is called.

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1. McCracken, D.D., A Guide to FORTRAN IV Programming, 2nd edition, New York: John Wiley & Sons, 1972, p.117.

CHAPTER 4 - ECONOMIC ANALYSIS PROCEDURES

A. General Considerations

While the technical analysis described in previous chapters may be of interest to some, the economic conclusions which follow are more likely to engage the attention of decision-makers. As these conclusions are extremely important, an attempt has been made in the following discussion to state explicitly all assumptions made in the course of developing the economic model.

Cost engineers divide investment estimates and economic analyses into five categories: order of magnitude, study, preliminary, definitive, and detailed. The present analysis would be termed a rough "study" estimate, with an accuracy of ±25%-30%. Project authorization is usually given on the basis of a preliminary-type estimate with an accuracy of ±12%: this estimate typically would cost approximately $100,000 for a $30 million project.[1] The purpose of the entire methodology developed here is to ascertain whether procuring this preliminary estimate is worthwhile and then to assist in the final decision-making process.

Many of the features included in the economic model presented below are somewhat superfluous, given the inaccuracies and uncertainties in more critical parameters. These options have been retained nonetheless for three reasons. First, their presence allows questions of public policy (e.g. appropriate tax incentives) to be addressed. Second, they permit performance of a more complete sensitivity analysis. Finally, their inclusion lends flexibility to the model and may help to answer the criticism of inflexibility that is often directed at cash-flow analyses.

A flow chart of the economic analysis module of the computer program is given in Appendix D.

B. Calculation of the Initial Capital Investment

The model first calculates the total initial investment in constant 1978 dollars. This investment includes engineering, design, and administrative costs as well as the cost of purchase and installation of equipment. However, working capital needs are omitted in order to bring the methodology into conformity with other cash-flow models in widespread use.

Equipment costs, including delivery and installation, are derived from the technical data generated by subroutine MATCH and typical cost curves.[2,3,4,5] These curves relate measures of equipment capacity to cost; on double logarithmic graphs the relationship is nearly linear.

The exponential relation that results from the assumption of linearity between the logarithms of capacity and cost provides the basis for most of the cost correlations found in the literature. Table 4-1 presents both the correlations used in the present economic model (denoted by asterisks) and other cost relations which may be of interest.[6] The cost figures yielded by these correlations are in mid-1978 dollars (Marshall and Swift equipment cost index of 550).

It should be noted that unit processes with similar energy needs frequently require similar auxiliary equipment (fluid pumps, compressors, etc). In an actual plant facility, these pieces of auxiliary equipment might be combined into one unit of larger capacity. As a result of the exponential cost functions adopted above, the cost of a combined unit is less than that of separate units. Conversely, if the size of equipment must be limited for ease of maintenance or other reasons, it may be advantageous in practice to employ two pieces of equipment instead of one for a single fluid stream and therefore to incur the higher cost of separate units.

Engineering, design, and administrative costs are calculated as 18% of the installed cost of all equipment other than unit process equipment. The total investment in equipment is then the sum of these ancillary costs and the

All costs are updated to mid-1978 using a Marshall and Swift index of 550.

ITEM	EQUATION, COST IN 1978	SOURCE
Fossil fuel heaters:		
process furnace*	$\$ = 422595 \left(\frac{Q \text{ in kW}}{5861.45}\right)^{0.68857}$	Guthrie, 125-29
industrial boiler 150 psig	$\$ = 963810 \left(\frac{\dot{m} \text{ in kg/hr}}{22679.6}\right)^{0.5}$	CE 3/3/75, 149
600 psig	$\$ = 1314286 \left(\frac{\dot{m} \text{ in kg/hr}}{22679.6}\right)^{0.5}$	CE 3/3/75, 149
Heat exchangers:		
shell and tube, carbon steel, under 300 psi	$\$ = 18951.9 \left(\frac{\text{surface area, m}^2}{18.58061}\right)^{0.68831}$	Guthrie, 138-44
*	$\$ = 61905 \left(\frac{\dot{m} \text{ in kg/hr}}{22679.6}\right)^{0.65}$	CE 3/3/75, 149
cooler	$\$ = 64762 \left(\frac{\dot{m} \text{ in kg/hr}}{22679.6}\right)^{0.66}$	CE 3/3/75, 149
evaporators, vertical tube*	$\$ = 354286 \left(\frac{\dot{m} \text{ in kg/hr}}{22679.6}\right)^{0.53}$	CE 3/3/75, 149
horizontal tube	$\$ = 289524 \left(\frac{\dot{m} \text{ in kg/hr}}{22679.6}\right)^{0.53}$	CE 3/3/75, 149
condensers	$\$ = 474359 + 1.7241 \ (\dot{m} \text{ in kg/hr})$	GEOCOST, p. 28
Compressors:		
centrifugal, motor drive*	$\$ = 144389 \left(\frac{Q \text{ in kW}}{149.14}\right)^{0.57483} + 9756 \left(\frac{Q \text{ in kW}}{59.656}\right)^{0.98189}$	Guthrie, 165-69
centrifugal, turbine drive	$\$ = 144389 \left(\frac{Q \text{ in kW}}{149.14}\right)^{0.57483} + 89755 \left(\frac{Q \text{ in kW}}{178.968}\right)^{0.40697} + 7805 \left(\frac{Q \text{ in kW}}{59.656}\right)^{0.30506}$	Guthrie, 165-71

TABLE 4-1 - EQUIPMENT COST CORRELATIONS

(continued . .)

ITEM	EQUATION, COST IN 1978	SOURCE
air compressor, under 125 psig	$\$ = 347619 \left(\frac{\dot{m} \text{ in kg/hr}}{22679.6}\right)^{0.28}$	CE 3/3/75, 149
centrifugal with motor $<13{,}000\ ft^3/min$	$\$ = 1.167 \exp[11.6351 + 0.67406R + 0.123145R^2]$ where $R = \ell n \left(\frac{Q \text{ in kW}}{745.7}\right)$	CE 10/10/77, 118
Turbogenerators:	$\$ = 474.359 \left(\frac{\dot{m} \text{ in kg/hr}}{0.45359237}\right)^{0.68}$	GEOCOST, 28
	$\$ = 46153.8 + 6410.3(Q \text{ in MWe})$	GEOCOST, 28
Pumps:		
AVS-horizontal, $t< 150°C$, $p< 22$ bars, $\dot{m}< 230{,}000$ kg/hr, $\Delta p < 10$ bars	$\$ = 1.183\exp[7.59589 + 0.58051R + 0.17915R^2]$ where $R = \ell n\left[\frac{(\dot{m} \text{ in kg/hr})(\Delta p \text{ in bars})}{449564.4}\right]$	CE 10/10/77, 121
unspecified type*	$\$ = 22.297[(\dot{m} \text{ in kg/hr})(\Delta p \text{ in bars})]^{0.568}$	GEOCOST, 28
centrifugal with motor	$\$ = 14285.7 \left(\frac{\dot{m} \text{ in kg/hr}}{22679.6}\right)^{0.52}$	CE 3/3/75, 149
centrifugal with turbine	$\$ = 28571.4 \left(\frac{\dot{m} \text{ in kg/hr}}{22679.6}\right)^{0.52}$	CE 3/3/75, 149
Steam flashing equipment:*	$\$ = 1.62591(\text{exit steam } \dot{m} \text{ in kg/hr})^{0.9996} \times (\text{inlet pressure in bars})^{0.09795}$	
Process Equipment:*	$\$ = (\text{cost of old equipment}) \times \left(\frac{\text{size of new equipment}}{\text{size of old equipment}}\right)^{0.6}$	GEOCOST, 28

TABLE 4-1 - (Continued ...)

SYMBOLS

$\dot{m}$ = fluid mass flow rate

Δp = pressure differential across the equipment

$\dot{Q}$ = input power or absorbed heat

SOURCES

Guthrie = Reference 5

CE 3/3/75 = Reference 3

GEOCOST = Reference 4

CE 10/10/77 = Reference 2

TABLE 4-1 (Concluded)

cost of the equipment itself, or

$$C_{equip,tot} = 1.18 \times \sum_j C_{equip,j} - 0.18 \times \sum_j C_{process,j}, \quad [4.1]$$

where

$C_{equip,tot}$ = total cost of equipment plus engineering, design, and administrative costs

$C_{equip,j}$ = installed cost of equipment piece j

$C_{process,j}$ = installed cost of unit process j.

Finally, the initial investment includes the cost of the geothermal field, computed as the sum of the following terms: the cost per well multiplied by the number of wells, the cost of the fluid transmission system from field to plant, the cost of land acquisition, and miscellaneous other costs (exploration, environmental planning, permit procurement, etc.):

$$C_{field} = C_{well}N_{well} + C_{trans} + C_{land} + C_{other}, \quad [4.2]$$

where

C_{field} = cost of geothermal field development

C_{well} = cost per well

N_{well} = number of wells required

C_{trans} = cost of fluid transmission system

C_{land} = cost of land acquisition

C_{other} = miscellaneous other costs.

The initial investment is thus

$$C_{initial} = C_{equip,tot} + C_{field}. \quad [4.3]$$

C. <u>Calculation of Cash Flows Before Federal Tax</u>

After the initial investment has been calculated, the next step is to compute before-tax cash flows. (Before this is done, however, the program finds the net income which will be imputed to the firm for the purposes of the percentage depletion allowance. A description of the procedures involved in this calculation is given in Appendix B.)

The program here enters a year-by-year loop beginning with the year of project start and extending over the lifetime of the project. Four inflation indices provide ample flexibility in dealing with relative as well as absolute price changes. They reflect inflation in the prices of fossil fuel, electricity, and geothermal fluid as well as escalation in general price levels (equipment, insurance, property taxes, maintenance, etc.). A different inflation rate for each of these four categories may be assumed for the period through 1986 as opposed to the period after 1986.

First to be calculated is the annual cash outlay for investment, specified as a given fraction of the initial investment and inflated to current dollars. The fraction used in any particular year is an independent input parameter. Thus,

$$C_{invst,i} = r_i f_{invst,i} C_{initial} , \qquad [4.4]$$

where

$C_{invst,i}$ = expenditure on investment in year i

r_i = inflation factor in year i

$= \prod_{j=1}^{i} (1 + r_j)^j$, in which r_j is the appropriate inflation rate in year j and i represents the current year

$f_{invst,i}$ = fraction of investment spent in year i.

Three cumulative investment figures are then brought up to date: the actual dollar amount spent (the sum of the annual cash outlays found above), the constant (1978) dollar amount spent thus far, and the actual dollar amount spent on depreciable items. If C_{invst}, $C_{invst,c}$, and $C_{invst,d}$ represent these three quantities respectively, then

$$C_{invst} = \sum_{j=1}^{i} C_{invst,j} \qquad [4.5]$$

$$C_{invst,c} = \sum_{j=1}^{i} f_{invst,j} \, C_{initial} \qquad [4.6]$$

$$C_{invst,d} = \sum_{j=1}^{i} \left\{ r_j f_{invst,j} \left[C_{equip,tot} + f_{tang} (1 - f_{depl}) C_{well} N_{well} + C_{trans} + C_{other} \right] + C^{*}_{int,j} \right\} , \qquad [4.7]$$

where

f_{tang} = fraction of geothermal well costs attributable to tangible expenses

f_{depl} = fraction of tangible well expenses attributable to depletable accounts

$C^{*}_{int,j}$ = annual expenditure for interest on debt (see below) if current year j is within construction period, otherwise equals zero

i = current year.

Appropriate values for f_{tang} and f_{depl} may be determined by consulting the guidelines given in Reference 7. Interest paid on debt during the construction period is capitalized as a depreciable expenditure.[8] It should be noted that cumulating these amounts at this point in the program is equivalent to assuming that all expenses for the current year which depend upon cumulative investment employ a figure which includes the current year's investment.

Next, energy costs for the year are determined in current dollars from the technical data provided by subroutine MATCH, from the 1978 prices given as input, and from the inflation factors. Included in this amount are expenditures for fossil fuel, electricity, and purchased geothermal fluid. The cost of energy is taken as zero until plant construction is completed; after that time, an input parameter gives a value for the annual capacity factor. For fossil fuel, burner efficiency is assumed to be 80%. Thus

$$C_{energy} = f_{cap}(8760)(3600)\left(\frac{C_{fossil}Q_{fossil}r_{i,fossil}}{0.80} + C_{elect}Q_{elect}r_{i,elect}\right) + f_{cap}(8760)C_{GT}\,\dot{m}_{GT}\,r_{i,GT}\quad, \qquad [4.8]$$

where

C_{energy} = cost of energy in year i

f_{cap} = plant capacity factor

C_{fossil} = cost of fossil fuel, 1978 \$/kJ

C_{elect} = cost of electricity, 1978 \$/kJ

C_{GT} = cost of geothermal fluid if purchased, 1978 \$/kg hr^{-1}

Q_{fossil} = fossil fuel required, kW

Q_{elect} = electricity required, kW

$\dot{m}_{GT}$ = mass flow rate of geothermal fluid, kg hr^{-1}.

The interest expense on indebtedness is calculated next. All loans, bonds, or other types of debt are assumed to be negotiated in the year of project start; deferred cash requirements due to extended construction periods may be deemed satisfied by implicit forward loans.[9] Bonds are assumed not to be called before maturity. The interest expense for the current year is then computed as the cumulative investment to date in current dollars, times the fraction financed by debt, times the interest rate paid, or

$$C_{int} = \frac{f_d}{(1+f_d)} C_{invst}\, i_{debt}, \qquad [4.9]$$

where

C_{int} = annual interest expense

f_d = debt/equity ratio

i_{debt} = interest rate on debt.

However, if bonds are no longer outstanding, C_{int} must be equal to zero.

The next expense calculated is the annual insurance premium, which equals the cumulative investment in constant dollars multiplied by the insurance rate and by an inflation factor, or

$$C_{insur} = C_{invst,c} \, i_{insur} \, r_{i,general} \,, \qquad [4.10]$$

where

C_{insur} = annual insurance premium, year i

i_{insur} = insurance rate.

This procedure implicitly assumes that insurance rates are constant in real terms, that inflated first cost is a fair approximation of replacement cost or insured value, and that technology changes and deterioration are minimal. In addition, no insurance is taken during construction for funds committed to firm contracts but not yet paid.

Annual plant maintenance costs are incurred once the plant begins operation. They are assumed to be constant in real terms, and are calculated, as were insurance costs, by applying an inflation factor to a fraction (given as an input parameter) of the initial investment in 1978 dollars. The maintenance cost for the geothermal field equals the annual field maintenance expense given as input multiplied by an inflation factor.

Property taxes are assumed to be paid during construction as well as during the operating life of the plant. The amount is found by a procedure identical to that used for plant maintenance costs.

The gross income imputed to the firm for depletion purposes is calculated next.[10] Royalties for the production of geothermal fluid are computed as a given fraction of this gross income figure.

Finally, a cash outlay for the retirement of bonds is made in the year in which they mature. The total annual cash outlays are then summed, yielding

$$C_{bef.tax} = C_{invst,i} + C_{energy} + C_{int} + C_{insur} + C_{maint} + C_{prop.tax} + C_{royal} + C^{*}_{bond}, \qquad [4.11]$$

where

$C_{bef.tax}$ = before tax cash expenditures for current year

C_{maint} = annual plant and geothermal field maintenance cost

$C_{prop,tax}$ = annual property tax payments

C_{royal} = annual royalty payments

C^{*}_{bond} = amount of bonds outstanding if current year is the year in which they mature, otherwise zero.

D. After-Tax Cash Flows

The first step along this road is to calculate the depreciation taken as an expense in the current year. The "sum-of-the-years'-digits" method is used. Depreciation begins when the asset is placed in service.[11] The asset cost upon which depreciation is based equals the total investment in current dollars, plus capitalized interest, minus expected salvage value (expressed as a given fraction of the total asset cost), minus investment chargeable to intangible drilling cost or depletable accounts. Thus

$$C_{depr.} = C_{invst,d} (1-f_s) \frac{2(n-i+1)}{n(n+1)} , \qquad [4.12]$$

where

$C_{depr.}$ = depreciation expense, year i

f_s = salvage value fraction of depreciable investment

n = depreciation lifetime.

The firm is assumed to incur sufficient tax liability from its various operations to offset the entire amount of tax deductions and credits created by this project. Thus the effect of taxes consists of a savings in tax payments equal to the investment tax credit taken (see below) plus the product of the marginal income tax rate times the appropriate deductions. Deductions are available for energy costs, depreciation, maintenance and repairs, insurance premiums, property taxes, interest on indebtedness, royalties, depletion, and intangible drilling costs.[12]

Thus

$$S_{taxes} = f_{tax} [C_{depr.} + C_{energy} + C_{int} + C_{insur} + C_{maint} + C_{prop.tax} + C_{deplet} + C_{royal} + (1-f_{tang})C_{well}N_{well}\ r_i f_{invst,i}] + f_{cr}\ r_i\ f_{invst,i}\ [C_{equip,tot} + f_{tang}\ (1-f_{depl})C_{well}N_{well} + C_{trans} + C_{other}] \quad , \qquad [4.13]$$

where

S_{taxes} = annual cash savings attributable to tax deductions and credits

f_{tax} = marginal income tax rate

C_{deplet} = depletion deduction - see text below

f_{cr} = investment tax credit fraction.

An investment tax credit is allowed on 100% of the current dollar investment in the given year, not including capitalization of interest or amounts properly chargeable to depletable or intangible drilling cost accounts.[13] It is assumed that the credit for energy equipment will be extended at the present rate beyond the current expiration date of 1982.[14]

The depletion deduction is calculated as the lesser of two amounts: the applicable percentage specified by statute multiplied by the gross geothermal production income imputed to the firm, or one-half the net income imputed.[15] This calculation is described in greater detail in Appendix B.

Finally, the net cash flow attributable to the project is calculated as the before-tax cash outlays minus the tax savings determined above, or

$$C_{aft.tax} = C_{bef.tax} - S_{taxes}, \qquad [4.14]$$

where

$C_{aft.tax}$ = after-tax cash flow in current year.

Before completing the yearly loop, the contribution of this year's net cash flow to net present value (to be discussed below) is found.

E. Economic Figures of Merit

After the annual cash flow data have been assembled by the program, the values of several overall economic indicators must be calculated. Three prominent indicators are the net present value, the discounted payback period, and the internal rate of return.[16] Economists continue to debate the significance and validity of these figures of merit.

As was explained in Chapter 2, the driving program first calls the economic model to find the cash flows associated with a conventional fossil-fueled system. Subsequent calls are made after the technical program analyzes each geothermal alternative. During the latter calls, the following economic comparison of conventional and geothermal plants is performed.

The net present value of each system is computed as annual cash flows are found:

$$NPV = \sum_{j=1}^{k} \frac{S_{system,j}}{(1 + i_{disc.})^{j-1}} , \qquad [4.15]$$

where

NPV = net present value of system savings S_{system}

$S_{system,\,j}$ = annual system cash savings

= $C_{aft.tax,fossil} - C_{aft.tax,\ geothermal}$

k = time in years from project start to end of plant operation

$i_{disc.}$ = discount rate given as input parameter.

It should be noted that the usual assumption (also made here) that cash transactions occur on the last day of the year understates the true present value by up to 11%.[17] As the program enters this comparison section, the cash flows corresponding to the fossil fuel alternative are subtracted from those of the geothermal alternative to produce an annual record of differential costs. The discounted payback period is computed at this point as the number of years j* required until the present value of differential costs becomes negative (or equivalently differential savings become positive):

$$0 = \sum_{j=1}^{j^*} \frac{S_{system,j}}{(1 + i_{disc.})^{j-1}} \quad . \qquad [4.16]$$

Finally, the internal rate of return ("IRR") is computed; it is defined as the discount rate m at which the present value of the differential costs or savings equals zero:

$$0 = \sum_{j=1}^{k} \frac{S_{system,j}}{(1 + m)^{j-1}} \quad . \qquad [4.17]$$

A bisection rule is followed to converge upon the proper value. The IRR is frequently indeterminate if the sign of the partial sum of discounted differential cash flows changes more than once: in this case a warning is printed.

As profitability indices (benefit/cost ratios) are rarely used in private industry, none are calculated here. Moreover, attempts to include such a measure would encounter some difficulty in evaluating benefits and costs.

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4. Huber, H.D., Bloomster, C.H., and Walter, R.A., *User Manual for GEOCOST: A Computer Model for Geothermal Cost Analysis, Volume 1, Steam Cycle Version*, Battelle (Pacific Northwest Laboratories), November 1975, p.28. Report no. BNWL-1942V1.

5. Guthrie, Kenneth M., *Process Plant Estimating, Evaluation, and Control*, Los Angeles: Craftsman Book Co., 1974.

6. Cost data were not found for two-phase separators as distinct from flashing equipment. The cost of a separator thus is assumed to be zero in the model since separators only appear in the program as integral parts of flashing equipment.
   Piping costs are omitted for two reasons. First, they are exceedingly difficult to estimate. Second, it is likely that the piping network for the conventional system and the geothermal system will not differ substantially. The incremental cost for piping will thus be small.

7. Rev. Rul. 77-188, 1977-1 C.B. 76; *Louisiana Land and Exploration Co. v. Commissioner*, 7 T.C. 507 (1946), *aff'd* 161 F.2d 842 (5th Cir. 1947); I.R.C. §263(c); Rev. Rul. 70-414, 1970-2 C.B. 132; Rev. Rul. 75-451, 1975-2 C.B. 330; Treas. Regs. §1.611-5(a) and §1.612-4(a).

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10. See Appendix B for further explanation of the procedure used to determine imputed gross income.

11. Treas. Reg. §1.167(a)-10(b); sum-of-years'-digits method, I.R.C. §167(b)(3).

12. Internal Revenue Code of 1954, §162; I.R.C. §167; I.R.C. §162 and Treas. Regs. §1.162-1(a) and §1.162-4; Treas. Reg. §1.162-1(a); I.R.C. §164(a); I.R.C. §163(a), §163(d)(4)(D); I.R.C. §611(a); I.R.C. §263(c) respectively.

13. I.R.C. §§38, 46(a)(2), 46(c)(2), 48(a)(1)(B)(i). Progress expenditures allowed in §46(d)(1).

14. Energy property is subject to an additional 10% credit above the standard credit until December 31, 1982. I.R.C. §46(a)(2) and §48(1)(3)(A)(viii).

15. I.R.C. §611, §613(a), §613(e).

16. For a description of these standard measures and how they are computed, see Sharpe, Op. Cit.

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CHAPTER 5 - OPTIMIZATION AND THE VALUE OF INFORMATION

A. Optimization

As was mentioned in Chapter 1, the decision to invest in geothermal energy depends largely upon the economic return. It is therefore important to optimize the use of geothermal energy in order to maximize this return.

1. What to optimize?

One portion of the program which could be optimized is the matching procedure described in chapter three. While the procedure incorporates one method of matching energy demands and supplies in a geothermal facility, the particular method adopted is not the only possible or feasible one. Even with the same values chosen for input parameters, each method will generally lead to a different facility design and thus to a different economic rate of return.

Three aspects of the matching procedure require the exercise of judgment and therefore present opportunities for optimization. The first may loosely be called technical rules. This rubric encompasses technical decisions such as the policy of desuperheating between stages of vapor compression and the value of effectiveness assumed for the secondary heat exchanger. The specific rules adopted were described in chapter three. The second flexible aspect of the matching procedure is the choice of geothermal fluid flow rate; any flow rate short of the maximum production capacity of the resource can be utilized if desired. The final aspect of the procedure is the stream selection logic used to match each unit process with a hot fluid stream. A wide variety of selection logics could be employed. A discussion of these problems from a theoretical as well as practical perspective will be presented below.

2. Technical rules

Economic tradeoffs are implicit in many decisions made in the course of the matching procedure. For example, any decision regarding the effectiveness of the secondary heat exchanger represents a balancing of the capital cost of the exchanger and the value of the heat transferred. However, as this decision has only a slight effect upon the remainder of the analysis, any variation from the optimum value will generally yield a negligible change in overall economic results. This conclusion holds true for other technical rules as well.

Since inclusion of such rules in the form of parameters to be optimized would complicate the program and yield insignificant benefits, no attempt is made to optimize the technical rules.

3. Choice of flow rate

With the sole exception of the geothermal fluid flow rate, the technical characteristics of unit processes and fluid streams are fixed by the choice of industrial application and location. The choice of a geothermal fluid flow rate at the wellhead (within the constraint of the maximum possible production rate) affects the relative fraction of fossil fuel to geothermal energy used to satisfy process energy needs. Since the economic results can be highly sensitive to the flow rate chosen, one must attempt to determine an optimum flow rate.

The complicated nature of the relation between flow rate and economic return precludes an analytic solution for the optimal flow rate. It is easiest therefore to run the computer program for a variety of flow rates and to choose that flow rate which yields the optimum economic results. The program permits multiple runs without the input of new data if only the geothermal fluid flow rate is altered.

It is assumed that optimization of the stream selection logic (to be discussed below) is independent of optimization of the geothermal fluid flow rate.

4. Choice of stream selection logic

The essence of the procedure used to match unit processes with geothermal supply streams is the control logic which governs the selection of a particular stream for a given process. The choices made in a given case can be represented by a matrix containing columns which correspond to unit processes and rows which correspond to fluid streams. The stream selection choices are represented by an "X" placed in each column at the row corresponding to the stream selected for that process. Such a matrix is shown in Fig. 5-1. [Although some features of the stream selection logic described in chapter three permit use of two or more streams for one process, this added complication will be omitted from the present analysis.]

In the notation adopted in the following discussion, there are m processes, n original fluid streams, and s streams created by splitting original streams into several smaller streams. Stream n+s+1 indicates water at ambient conditions. Such a stream can always be upgraded to process requirements using fossil fuel heaters and thus represents a possible stream choice. Finally, stream n+s+2 indicates a closed-loop fluid system in which water is circulated between a fossil heater and the process. It represents another possible stream choice if the process is not of the direct-injection type.

P R O C E S S

S T R E A M	1	2	3	. . .	m
1	X		X		
2					
3		X			
⋮					
n					
⋮					
n+s					X
n+s+1					
n+s+2					

FIGURE 5-1 - STREAM SELECTION MATRIX

In the sample matrix shown in Fig. 5-1, processes number 1 and 3 use stream 1 in series: the exit stream from process 1 becomes the input stream to process 3. Process 2 uses stream 3, and process m uses stream n+s.

A particular set of stream choices, or "control strategy", can thus be described by a vector of m integer decision variables, x_j, such that the value of x_j equals the number of the stream matched with process j. In decision analysis literature, each process would be termed a decision stage. The streams and their characteristics at each stage determine what would be called the system state. The goal of minimizing the total cost of satisfying the energy needs of all processes would be termed the objective. It should be noted that the problem is deterministic in the sense that the cost attributable to a control decision (stream selection choice) is fixed by the present system state and the decision taken.

At this point the problem superficially resembles the stagecoach example of dynamic programming.[1] However, two factors distinguish the problem from the stagecoach prototype.

First, the final results depend on the order in which processes are considered since each process extracts heat and therefore alters the streams available for later processes. No inherent ordering can be determined from temporal, spatial, or causal relationships. Nevertheless, it is assumed that an ordering can be established on intuitive grounds (e.g. ordering by decreasing process temperature to encourage stream cascading). Furthermore, it is assumed that such an ordering will generate "optimum" results when the rest of the matching procedure is optimized. These assumptions reduce the number of possible control strategies by a factor of m! (the factorial of m), which represents the number of ways in which the m processes may be arranged.

Second, the number of streams at any stage and the possible states of these streams depend upon the choice of streams (values of x_j) for all previous stages. For example, choice of a stream of low flow rate for a direct-injection process might result in fewer streams because effluent fluid does not exist for such processes. On the other hand, choice of a stream of higher flow rate might necessitate flow splitting and thus retain the original number of streams.

As a result of these two distinguishing factors, the decision problem is insoluble by conventional dynamic programming methods: one cannot "step" backwards from the last stage to the first without knowing the possible states at each previous stage.

In order to determine whether exhaustive search methods should be employed, it is useful to estimate the scale of the decision problem as measured by the number of possible control strategies (number of sets of stream choices). The number of control strategies is constrained by the necessity that a stream exist at a particular stage for it to be chosen at that stage. For example, if a stream is created by flow splitting at stage 5, it is unavailable for selection at stage 4. This constraint is equivalent to the assumption that decisions must be made in a purely sequential manner: stream choices cannot be reconsidered in light of later developments.

The maximum possible number of strategies is

$$\#\text{ of strategies} = \frac{(n+m+1)!}{n!\ (n+m)} , \qquad [5.1]$$

where

n = original number of fluid streams

m = number of unit processes

! = factorial sign.

In order to arrive at this expression, it has been assumed that the number of streams increases by one at each stage (as a result of either flow splitting or use of a new ambient water stream). In addition, it has been assumed that stream n+s+2 can only be chosen at the last stage, since in selecting it one does not increase the number of streams available for later processes.

The minimum possible number of strategies equals m. This situation arises if only one original fluid stream exists (n=1) and all processes are of the direct-injection type. The original stream may be selected for any one of the m processes while the other processes employ stream n+s+1.

For a small problem, n might equal one and m equal seven. [This corresponds to the second example given in the next chapter.] The possible number of control strategies lies somewhere between 7 and 45,360. The exact figure depends upon the type of processes and their ordering. Systems consisting primarily of direct-injection processes will result in figures closer to the lower bound, while systems consisting largely of heat-exchange processes will generate a larger number of possible strategies.

In certain cases, the number of possible strategies is also constrained by other requirements. For example, a stream may be matched with a process only if the stream possesses "sufficient mass flow rate" (as was defined in Chapter 3). Constraints such as these serve to limit the possible domain of the x_j to a much smaller range of control strategies. Thus the maximum number of feasible control strategies for the above problem (n-1, m=7) might be closer to 35,000 instead of 45,360.

The crucial parameter at this point is computer run time: if run times are sufficiently short, exhaustive search methods may be tried. The program described in Chapters 2, 3, and 4 executes one analysis in approximately one second. Thirty-five thousand strategies would therefore consume over 9.7 hours of computer time. Moreover, if any of the simplifying assumptions made throughout the above discussion were relaxed, this figure would increase dramatically.

Direct verification that the "rule-of-thumb" strategy adopted in Chapter 3 is optimal is therefore infeasible since an exhaustive search of control strategies requires too much computer time. Nevertheless, some confidence in the "rule-of-thumb" strategy may be justified, as will be demonstrated in the example described in Section B of Chapter 6 below.

B. Value of Information

One of the most important factors involved in the evaluation of geothermal energy is the uncertainty that surrounds the geothermal resource itself. This uncertainty, which relates primarily to the temperature and production flow rate of the resource, is translated into a corresponding uncertainty in the anticipated cost of the project.

A potential user of geothermal energy might wish to reduce this uncertainty by commissioning additional geological studies or even by drilling an initial production well. In the present context, these activities will be termed experiments. However, the user should weigh the cost of such experiments against the potential value of the information to be gained from them.

The value of information derived from experiment to a potential user of geothermal energy depends upon the effect possession of the information will have upon his decisionmaking. At one extreme is the situation in which the decision to utilize geothermal energy and the choice of plant design are made in advance. In this case, possession of information from an experiment cannot alter the expected net present value of the project. At the other extreme lies the situation in which the decision to use geothermal energy and the choice of plant design can be postponed until the information has been obtained. If no experiment is performed, the user will design the plant on the basis of the expected resource characteristics. Thus if resource characteristics are found to differ in actuality from their expected values, the user will have built a suboptimal plant. However, if an experiment is performed, the user can design the plant to make optimum use of the discovered characteristics of the resource.

The value of the information to the user is represented by the difference between the expected value of the project without experimentation and the expected value of the project with experimentation.[2] Therefore, a rational decision-maker who has the opportunity to perform the experiment at a cost less than this value should choose to do so. If the cost of the experiment will exceed the value of the information to be obtained, the decision-maker should proceed without the experiment.

This concept has important implications for the practice of geothermal resource assessment as well. The most important of these implications is that location-specific assessment efforts can be rigorously justified on the basis of the value of the information to be procured. Furthermore, such a justification cannot be made without consideration of a particular application, since the economics of the specific application determine in part the value of the information to be gained from the experiment.

The procedure used to calculate the value of information for a given application is outlined in the next section. An example is then presented in Section 2.

1. Calculation of the expected value of information

Among the simplifying assumptions made in the course of the analysis are the following. The net present value of the project is defined as the net present value of cash flows associated with the proposed system minus that associated with a conventional system. It is assumed that only a geothermal system can be used. Under certain circumstances, it is possible that the net present value of the project will be negative. If the user had the option of employing a conventional system, the net present value as defined here could never be below zero. It is also assumed that the user makes decisions solely upon the basis of their monetary consequences. It is further assumed that the user is not risk-averse. This condition is equivalent to the assumption that the value of a marginal dollar is constant regardless of the user's total financial wealth.

The second and third assumptions together imply that the net present value of the project is a sufficient measure of its attractiveness. In the present analysis, this figure is assumed to be a function of the geothermal fluid temperature and of the fluid flow rate used in the plant. [It is assumed that the plant design is optimized in terms of all other parameters.] The temperature is considered to be a random variable described by a probability distribution. The fluid flow rate is viewed as a decision variable under the control of the user since he is free to drill any number of wells into the geothermal reservoir. [The existence of this freedom depends upon the assumption that the reservoir is large compared to the range of possible flow rates.]

Thus

$$V = V(m,t) \quad , \qquad [5.2]$$

where

V = net present value of cash flows associated with the geothermal system minus that associated with a conventional system

m = mass flow rate of geothermal fluid purchased

t = temperature of the geothermal fluid.

To compute the value of information, one must first calculate the expected value of the project without experimentation and then ascertain the expected value with experimentation.

If no experiment is performed, the user can only attempt to maximize the expected project net present value. Applying the expectation operator (denoted by $< >$):

$$\langle V\rangle = \langle V(m,t)\rangle \quad . \qquad [5.3]$$

The maximum figure for this expected value will occur at a mass flow rate which can be found by differentiating with respect to m and setting the result equal to zero:

$$\frac{\partial\langle V\rangle}{\partial m} = 0 \quad . \qquad [5.4]$$

If the optimal value of m is denoted by m* and the optimal expected net present value by $\langle V\rangle^*$, the expected project net present value without experimentation can be written as

$$\langle V\rangle^* = \langle V(m^*,t)\rangle \quad . \qquad [5.5]$$

The expected project net present value with experimentation depends upon the accuracy of the experiment. If it is assumed that the experiment yields perfect information (i.e. it determines with certainty the true value of t, or t_{actual}), then after the experiment is performed the user can compute a precise value for V which corresponds to any choice of m:

$$V = V(m, t_{actual}) \quad . \qquad [5.6]$$

The user would then maximize the net present value by setting the **derivative** of V equal to zero,

$$\frac{\partial V}{\partial m} = 0 \quad , \qquad [5.7]$$

which gives the optimal value of m, m', and thus the optimal value of V,

$$V' = V(m', t_{actual}) \quad . \qquad [5.8]$$

However, a priori the user does not know the results of the experiment and thus cannot compute either m' or V'. Nevertheless, he can calculate an expected value:

$$\langle V' \rangle = \langle V'(m', t) \rangle \qquad [5.9]$$

This figure represents the prior expected project net present value if an experiment is performed.

The expected value of perfect information is defined to be the difference between the expected net present value if the best flow rate is chosen after perfect information is obtained and the expected net present value if the best flow rate is chosen without the benefit of further information. Thus

$$EVPI = \langle V' \rangle - \langle V \rangle^* , \qquad [5.10]$$

where

EVPI = expected value of perfect information.

2. An example

The net present value information required for the calculation of the EVPI is determined by utilizing the computer model described in previous chapters.

The model is run using data from the second example of Chapter 6. One modification is made in these data: it is assumed that the user pays for geothermal fluid on a "per unit mass" basis rather than investing directly in geothermal resource development. While the assumption of a constant price per unit mass may not be realistic over a wide range of flow rates, it is probably reasonable for the more limited range of flow rates of interest in this analysis.

The results for net present value as a function of mass flow rate and fluid temperature (as shown in Fig. 5-2) are represented by the following expression:

$$V = a_1 + a_2 m + a_3 m^2 + a_4 m^3 , \qquad [5.11]$$

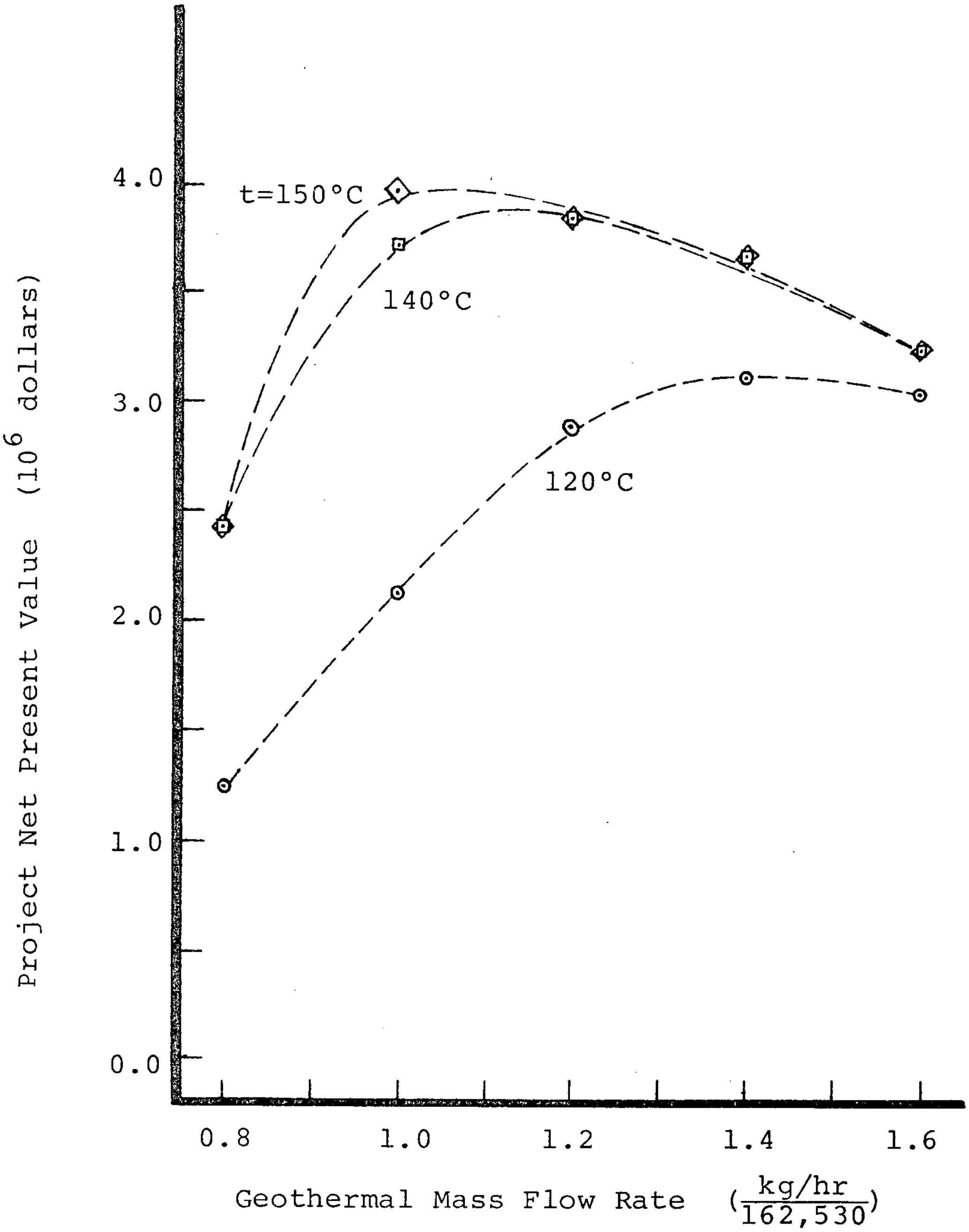

FIGURE 5-2 - NET PRESENT VALUE AS A FUNCTION OF GEOTHERMAL FLUID TEMPERATURE AND FLOW RATE where for the sake of convenience V is in millions of dollars and m is normalized by division by 162,530 kg/hr, and where the coefficients a_i are functions of temperature. For each fluid temperature a least-squares analysis is used to determine the values of a_1, a_2, a_3 and a_4 The coefficients are then cross-plotted against temperature. A linear least-squares analysis is then employed to yield expressions of the form

$$a_i = a_{i1} + a_{i2} \tau \quad , \tag{5.12}$$

where

$$\tau = t-60 \quad .$$

The reason for using τ instead of t will become clear in the following discussion. The coefficients determined by the present analysis are given in Table 5-1.

The next step is to assume a probability density function for the geothermal fluid temperature. On the basis of the geological record for Ontario, Oregon (the site of the Ore-Ida facility in Example 2), it is extremely unlikely that this temperature would be less than approximately 60°C. A two-tailed probability function is therefore inappropriate for modeling the distribution of possible

	$j=1$	$j=2$
a_{1j}	51.43	-0.9132
a_{2j}	-146.79	2.5378
a_{3j}	129.70	-2.1302
a_{4j}	-35.66	0.5651
d_{1j}	1.941	-8.961E-3

	b_i	c_i
$i = 1$	-17.06	-5.632
$i = 2$	43.54	0.535
$i = 3$	-30.07	-0.012
$i = 4$	6.72	1.189E-4
$i = 5$		-4.066E-7

Note: V = net present value in millions of dollars

$$m = \frac{\text{geothermal fluid flow rate, kg/hr}}{162{,}530}$$

$$\tau = (\text{geothermal fluid temperature, °C}) - 60 \quad .$$

TABLE 5-1 - COEFFICIENTS USED IN THE VALUE OF INFORMATION ANALYSIS fluid temperatures. A more suitable distribution is the log-normal function,

$$P(\tau) = \alpha\tau^{\beta} \exp[-\gamma(\ell n\ \tau)^2] \quad \text{for } \tau>0 \quad , \qquad [5.13]$$

where

$P(\tau)$ = probability of the fluid temperature being equal to τ

α,β,γ = constants. Note that normalization of the probability function forces

$$\alpha = \left(\frac{\gamma}{\pi}\right)^{1/2} \exp\left[-\frac{(\beta+1)^2}{4\gamma}\right] \quad .$$

Since the probability approaches zero as τ approaches zero and thus as t approaches 60°C, this function has the appropriate form. It can be shown by performing the following analysis with a different probability function that the ultimate results are relatively insensitive to the particular functional form assumed.

For the sake of completeness, it should be noted that use of the log-normal function implies that

$$\langle\tau\rangle = \exp\left(\frac{2\beta+3}{4\gamma}\right) \qquad [5.14]$$

$$\sigma^2(\tau) = \exp\left(\frac{2\beta+3}{2\gamma}\right) \left[\exp\left(\frac{1}{2\gamma}\right) - 1\right] \qquad [5.15]$$

and

$$\nu^2(\tau) = \exp(\frac{1}{2\gamma}) - 1 \quad , \qquad [5.16]$$

where

$\sigma(\tau)$ = standard deviation of τ

$\nu(\tau)$ = coefficient of variation of τ

$= \frac{\sigma(\tau)}{\langle\tau\rangle}$.

It is assumed for the purposes of this analysis that t equals 130°C ± 30%. However, it is ambiguous to state the uncertainty in terms of ±30% of the temperature. A more precise statement would be that three standard deviations equal 30% of the mean, or

$$\nu(\tau) = \frac{1}{3} \times 0.30 = 0.10 \quad . \qquad [5.17]$$

From Eqs. 5.14 and 5.16,

$\beta = 432.40$

$\gamma = 50.25$.

Now the expected net present value of the project in the absence of experimentation can be evaluated. By definition, the expected value of V is

$$\langle V\rangle = \int_0^\infty V(m,\tau)P(\tau)\, d\tau \quad . \qquad [5.18]$$

Replacing $V(m,\tau)$ by Eqs. 5.11 and 5.12, $P(\tau)$ by Eq. 5.13, and changing variables such that $x = \ell n\ \tau$ yields

$$\langle V \rangle = \int_{-\infty}^{\infty} \alpha(C + De^{x}) \exp[(\beta+1)x - \gamma x^2]\ dx \quad , \qquad [5.19]$$

where

$$C = \sum_{i=1}^{4} a_{i1} m^{i-1} \qquad [5.20]$$

$$D = \sum_{i=1}^{4} a_{i2} m^{i-1} \quad . \qquad [5.21]$$

Separating the two terms and completing the squares in the exponents gives

$$\langle V \rangle = \int_{-\infty}^{\infty} \alpha C \exp\ [-\gamma (x - \frac{\beta+1}{2\gamma})^2 + \frac{(\beta+1)^2}{4\gamma}]\ dx\ +$$

$$+ \int_{-\infty}^{\infty} \alpha D \exp\ [-\gamma (x - \frac{\beta+2}{2\gamma})^2 + \frac{(\beta+2)^2}{4\gamma}]\ dx \quad . \qquad [5.22]$$

If the constant term in each integral is extracted and variables changed once again such that

$$r = \sqrt{2\gamma}\ \ (x - \frac{\beta+1}{2\gamma}) \qquad [5.23]$$

and

$$s = 2\gamma \ (x - \frac{\beta+2}{2\gamma}) \quad , \qquad [5.24]$$

then Eq. 5.22 can be reformulated as

$$\langle V\rangle = \frac{\alpha C}{\sqrt{2\gamma}} \exp \left[\frac{(\beta+1)^2}{4\gamma}\right] \int_{-\infty}^{\infty} \exp \left[- \frac{r^2}{2}\right] dr \ +$$

$$+ \ \frac{\alpha D}{\sqrt{2\gamma}} \exp \left[\frac{(\beta+2)^2}{4\gamma}\right] \int_{-\infty}^{\infty} \exp \left[- \frac{s^2}{2}\right] ds \quad . \qquad [5.25]$$

But these integrals are each $\sqrt{2\pi}$ times the integral of the normal probability distribution over the entire domain. Since the latter integral must equal unity, the given integrals both equal $\sqrt{2\pi}$. Performing this substitution and replacing α by its value in terms of β and γ (given below Eq. 5.13) yields

$$\langle V\rangle = C + D \exp\left[\frac{2\beta+3}{4\gamma}\right]$$

or

$$\langle V\rangle = C + D\langle\tau\rangle \quad . \qquad [5.26]$$

Thus it can be seen that

$$\langle V\rangle = V(m,\langle\tau\rangle) \quad . \qquad [5.27]$$

To evaluate Eq. 5.4, define

$$b_i = a_{i1} + a_{i2} \langle\tau\rangle \quad . \qquad [5.28]$$

The values of the b_i for this example are listed in Table 5-1. Thus

$$\langle V\rangle = \sum_{i=1}^{4} b_i m^{i-1} \quad , \qquad [5.29]$$

and

$$\frac{\partial\langle V\rangle}{\partial m} = 0 = b_2 + 2b_3 m + 3b_4 m^2 \quad . \qquad [5.30]$$

Finally, the optimal value for m in the absence of an experiment, m*, can be determined to be

$$m^* = \frac{-b_3 - \sqrt{b_3^{\,2} - 3b_2 b_4}}{3b_4} \qquad [5.31]$$

$$= 1.239 \quad ,$$

since only the smaller root is of significance in this example. Substituting this result into Eq. 5.29 then yields the expected project value without experimentation:

$$\langle V(m^*,\tau)\rangle = 3.521 \text{ (dollars x } 10^{-6}) \quad . \qquad [5.32]$$

Next, the expected net present value of the project with experimentation must be evaluated. The optimal value of m after the experiment has been performed is found by differentiating V:

$$\frac{\partial V}{\partial m} = 0 = a_2 + 2a_3 m + 3a_4 m^2 \quad , \qquad [5.33]$$

or, solving,

$$m' = \frac{-a_3 - \sqrt{a_3^2 - 3a_2 a_4}}{3a_4} \quad , \qquad [5.34]$$

where it is again the smaller root which is of interest. This expression is awkward for the manipulations to follow. Since m' is a function of τ_{actual} through the coefficients a_i, the equation above may therefore be replaced by the linear relation

$$m' = d_{11} + d_{12}\,\tau \quad , \qquad [5.35]$$

which gives figures within 2.5% of those derived from Eq. 5.34 throughout the relevant domain. [The values of d_{11} and d_{12} for this example are given in Table 5-1.]

Then

$$V' = \sum_{i=1}^{4} (a_{i1} + a_{i2}\,\tau)(d_{11} + d_{12}\,\tau)^{i-1} \quad , \qquad [5.36]$$

or, rearranging,

$$V' = \sum_{i=1}^{5} c_i \tau^{i-1} \quad , \qquad [5.37]$$

where

$$c_1 = (a_{11} + a_{21}d_{11} + a_{31}d_{11}^{\ 2} + a_{41}d_{11}^{\ 3})$$

$$c_2 = (a_{12} + a_{21}d_{12} + a_{22}d_{11} + 2a_{31}d_{11}d_{12} + a_{32}d_{11}^{\ 2} + 3a_{41}d_{11}^{\ 2}d_{12} + a_{42}d_{11}^{\ 3})$$

$$c_3 = (a_{22}d_{12} + a_{31}d_{12}^{\ 2} + 2a_{32}d_{11}d_{12} + 3a_{41}d_{11}d_{12}^{\ 2} + 3a_{42}d_{11}^{\ 2}d_{12})$$

$$c_4 = (a_{32}d_{12}^{\ 2} + a_{41}d_{12}^{\ 3} + 3a_{42}d_{11}d_{12}^{\ 2})$$

$$c_5 = (a_{42}d_{12}^{\ 3}) \quad .$$

Values for the c_i are given in Table 5-1. The expected value of V' is

$$\langle V' \rangle = \int_0^\infty (\sum_{i=1}^{5} c_i \tau^{i-1}) \alpha \ \tau^\beta \exp[-\gamma(\ell n\ \tau)^2]\ d\tau \quad . \qquad [5.38]$$

Following the same procedure as was used above, change variables such that $x = \ln \tau$, separate terms, complete the squares in the exponents, and extract the constants from the integrals. Next, change variables once again such that

$$r = \sqrt{2\gamma}\ (x - \frac{\beta+1}{2\gamma})$$

$$s = \sqrt{2\gamma}\ (x - \frac{\beta+2}{2\gamma})$$

and analogous expressions are used for the remaining integrals. Each integral now equals $\sqrt{2\pi}$. Finally, substituting for α yields

$$\langle V' \rangle = c_1 + c_2 \exp[\frac{2\beta+3}{4\gamma}] + c_3 \exp[\frac{\beta+2}{\gamma}] + c_4 \exp[\frac{6\beta+15}{4\gamma}] + c_5 \exp[\frac{2\beta+6}{\gamma}] \quad . \qquad [5.39]$$

Evaluation of this expression reveals that for this example,

$$\langle V' \rangle = 3.561 \text{ (dollars x } 10^{-6}) \quad . \qquad [5.40]$$

One can now compute the expected value of perfect information using Eqs. 5.32 and 5.40. Substituting these equations into Eq. 5.10,

$$\begin{aligned} \text{EVPI} &= \$3.561 \times 10^6 - \$3.521 \times 10^6 \\ &= \$40,700. \end{aligned} \qquad [5.41]$$

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CHAPTER 6 - TWO APPLICATIONS OF THE METHODOLOGY

Two direct-use geothermal applications are analyzed in the following pages with the aid of the computer model described in previous chapters. The actual computer input and output statements are reproduced with explanatory comments in Appendix D.

A. Retrofit of a Pulp and Paper Mill - Example 1

As a part of this research, several industrial firms provided data from their plants for analysis using the computer program. The data included energy costs, projected inflation rates, taxes, and other economic figures as well as steam flow drawings and technical data relating to present facilities.

The following analysis employs data furnished by a firm engaged in pulp and paper manufacturing. Pursuant to an agreement concerning confidentiality of data, firm-specific and location-specific information has been omitted from the following discussion.

1. General approach

For this analysis, the manual matching mode of the program is used. As was discussed in Chapter 1, the geothermal fluid must be cooled to as low a temperature as possible in order to maximize the quantity of heat extracted per dollar of fluid. The analysis thus begins by identifying the coldest temperature indicated on the facility steam flow diagram: the fluid at 15.6°C entering the boiler deaerators from the demineralized water storage tanks. Since deaerators operate at saturation temperatures, this fluid must be heated a substantial amount by hot steam. Clearly, replacing some of the steam heat with geothermal heat would reduce the demand for steam and thus for fossil fuel.

The system configuration shown in Fig. 6-1 is therefore proposed. In the particular deaerator examined, condensate returned from the processes is not employed; together, make-up water and the steam used to heat it provide the entire flow rate required by the single boiler served by the deaerator.

2. Assumptions

Table 6-1 lists the important assumptions made in the analysis. Several points are of special interest and thus are discussed more extensively below.

The manner in which the new operating conditions of the deaerator affect its performance is uncertain (see assumption 1.e) and warrants further analysis by qualified plant personnel.

Since the purpose of utilizing geothermal energy is to reduce fossil fuel consumption, the decrease in boiler

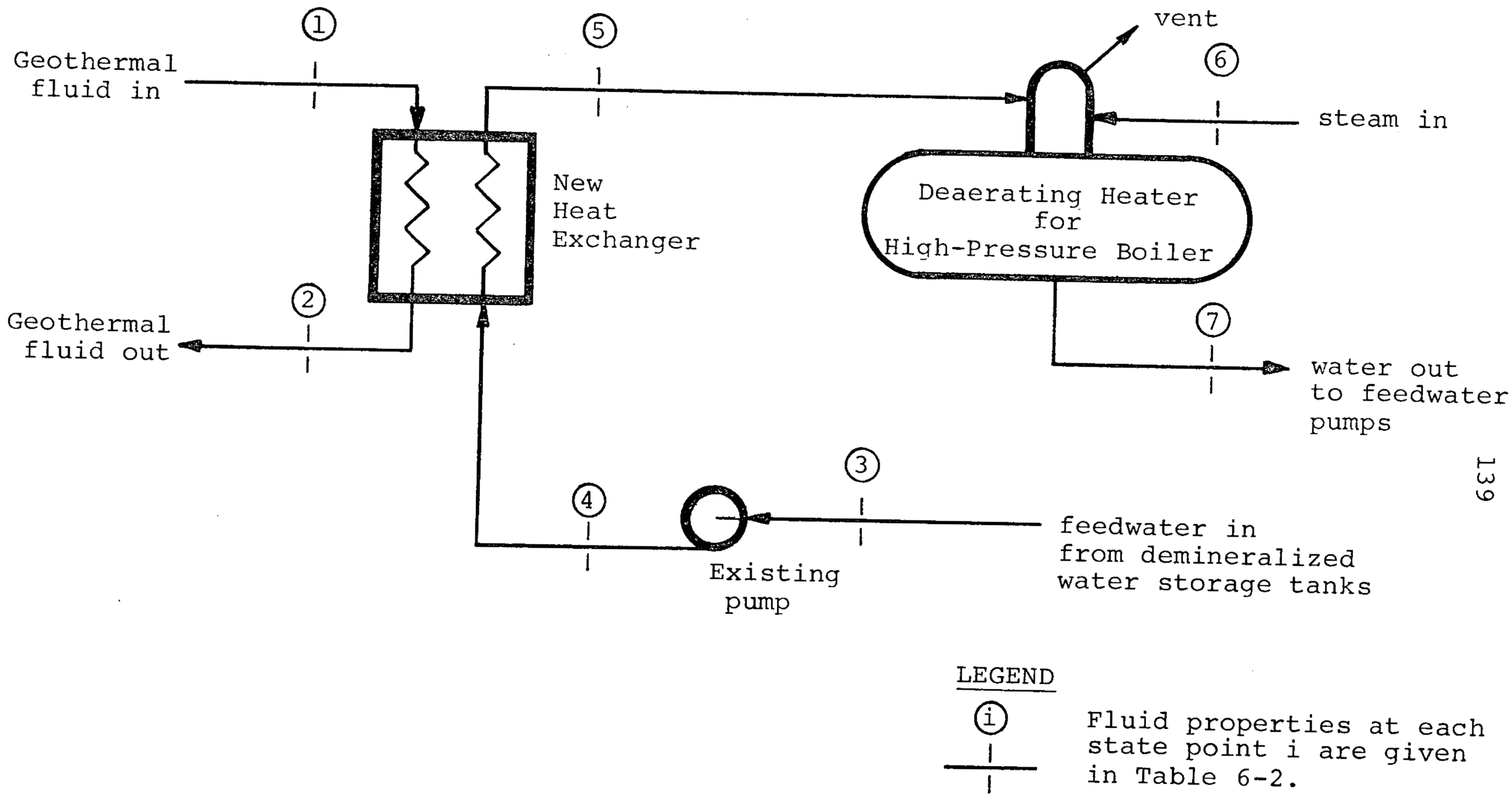


FIGURE 6-1 - PROPOSED GEOTHERMAL SYSTEM FOR EXAMPLE 1

1. ASSUMPTIONS RELATING TO THE PROPOSED AND EXISTING SYSTEMS:

   a. Steady state flow.
   b. No steam losses through vent condenser of deaerator.
   c. Gases expelled through vent condenser carry negligible sensible heat.
   d. Exit fluid from the deaerator is at saturation conditions.
   e. Deaerator and pumps, etc., will function properly at the reduced steam rate and increased feedwater rate assumed.
   f. The cost of changes in the demineralized water storage system, if any, is neglected.
   g. The reduction in steam requirements is assigned to the fossil fuel boilers, not to the recovery or hog fuel boilers.
   h. No reduction in electricity generation - any reduction in total plant steaming rate is absorbed by decreased flow through pressure release valves.
   i. New heat exchanger characteristics:
      -- two shell and tube units, each with half the total flow rate.
      -- heat exchanger effectiveness = 85% (maximum heat transfer from geothermal fluid consistent with normal design practice).

2. ASSUMPTIONS RELATING TO GEOTHERMAL RESOURCE DEVELOPMENT:

   a. Two production wells each = 10^5 kg/hr, saturated at a temperature left as a parameter.
   b. Two reinjection wells.
   c. Cost of field development: (1978 dollars)

-- exploration	= $ 500,000
-- land acquisition	= $ 200,000
-- cost per well	= $1,800,000
-- fluid transmission system	= $4,500,000
-- annual maintenance	= $ 250,000
-- intangible drilling cost fraction of well cost	= 60%
-- depletable account fraction of tangible well costs	= 80%

TABLE 6-1 - ASSUMPTIONS MADE IN THE ANALYSIS OF EXAMPLE 1

(continued . . .)

d. Royalties as percent of fluid value. Fluid value based on gross income from geothermal property as used to compute depletion allowance = 12%

e. Temperature loss in transmission = 20°C
f. Total dissolved solids content = 1,000 ppm.
g. Negligible scaling and corrosion.

3. ASSUMPTIONS RELATING TO TAX TREATMENT:

a. Depreciation lifetime = 13 years.
b. Depreciation method = sum of years' digits.
c. Salvage value for depreciation = 2% of depreciable investment.
d. Investment tax credit = 20%
e. Depletion allowance per Energy Tax Act of 1978.
f. Intangible drilling costs expensed.
g. Property tax rate = 2.2¢/dollar investment.
h. Overall marginal income tax rate (federal, state, local) = 48%.

4. ASSUMPTIONS RELATING TO ECONOMIC ANALYSIS, FINANCING, AND ADDITIONAL EXPENSES:

a. All costs and prices are in 1978 dollars.
b. Discount rate for net present value calculations = 20%
c. Financing method is ignored (i.e. no interest charges on debt).
d. Project starting date = 1982
e. Project construction time = 3 years.
f. Investment profile - 10% in first year, 40% in second, and 50% in third.
g. Operating lifetime = 15 years.
h. Fossil fuel cost in 1979 dollars = \$2.84/GJ = \$3.00/10^6 Btu.
i. Inflation factors:

	general	fossil fuel
through 1986:	7.5%	11.2%
after 1986:	7.0%	8.0%

TABLE 6-1 - ASSUMPTIONS MADE IN THE ANALYSIS OF EXAMPLE 1

(continued . . .)

j.	Insurance premium rate	= 0.12¢/dollar investment.
k.	Annual maintenance expenses	= 2.0¢/dollar investment.
l.	Annual capacity factor	= 75%.

TABLE 6-1 - ASSUMPTIONS MADE IN THE ANALYSIS OF EXAMPLE 1

(concluded)

steaming rate attributable to use of geothermal fluid must be assigned to the fossil fuel boilers only. For simplicity, the exit flow rate of the boiler associated with the deaerator being analyzed is assumed to remain constant, the decrease in overall steaming rate is assigned to other boilers which are served by a low pressure deaerator. As a result of this decrease, the low pressure deaerator water flow rate must also decrease, necessitating even less steam for deaerator operation. The iterative calculations required to balance the system could be performed somewhat more easily with energy models developed by industry than with the present methodology.[1] For the purposes of this analysis, however, the iteration requirement will be ignored. This omission biases the eventual results toward conservatism, since less fossil fuel will be needed than previously calculated.

Until recently, many industrial cogenerators have been unable to sell excess electricity because of legal restrictions. As a result, large quantities of high pressure steam are simply expanded through pressure release valves, bypassing the turbogenerators. A sufficient flow rate of such bypass flow is assumed to be present to absorb the reduction in low pressure steam production discussed above. Electrical energy generation then remains constant.

The geothermal fluid temperature cannot be estimated directly at this time because of insufficient information about the geothermal resource. Instead, each well is assumed to produce a fluid flow rate typical of successful wells, with temperature left as a parameter. A high cost per well is listed in Table 6-1 to reflect the difficult drilling conditions likely to exist in the igneous formations of the target area.

The cost of developing the geothermal field also depends upon the length of the required pipeline from the field to the plant. The cost will vary greatly according to the specific terrain encountered. More careful design would be necessary to reduce the uncertainty surrounding the $4.5 million (installed) figure assumed.

In conformity with provisions of the Energy Tax Act of 1978, intangible drilling costs are expensed for tax purposes, and a tax deduction is taken for depletion of the resource.

Finally, note that the present analysis does not consider the financing method (debt/equity ratio) used for the particular project. The omission of interest expenses is supported by a large proportion of the recent literature concerning the theory of capital expenditures.

3. Results

The thermodynamic properties of all fluid streams in the present and the proposed systems are shown in Table 6-2.

The most striking feature of the proposed system is the substantial reduction in steam usage (stream no. 6): 35,650 kg/hr (78,600 lbm/hr). The geothermal system evidently saves at least this much steam. Approximately 8,000 kg/hr of additional steam savings, which result from balancing the flow as previously mentioned between the fossil fuel boilers and the low pressure deaerator, are not included in the analysis. Fossil fuel savings thus are understated by roughly 18%. Neglecting this, approximately 25 MW(th) or 86 million Btu/hr of fossil fuel savings are realized.

Figure 6-2 displays the relationships among fossil fuel costs, geothermal fluid temperature at the plant entrance, and rate of return on investment. It must be noted that the internal rate of return ("IRR") refers to the entire cash investment and not merely to shareholders' equity.

Figure 6-3 illustrates the return on investment attainable by the firm if it develops the geothermal resource without resort to purchases of fluid from a field developer. Using the field development costs listed in

Stream no.	Total Dissolved Solids (ppm)	Pressure (MPa)	Temperature (degrees C)	Enthalpy (J/g)	Entropy (J/g-K)	Mass Flow Rate (kg/hr)
----- PROPOSED GEOTHERMAL SYSTEM -----						
1	1000	0.700	165.0	696.7	1.9901	200,000
2	1000	0.700	45.4	194.8	0.6538	200,000
3	0	0.101	15.6	65.7	0.2353	187,610
4	0	1.136	15.9	68.1	0.2399	187,610
5	0	1.136	143.1	603.2	1.7735	187,610
6	0	1.136	226.7	2884.0	6.7539	16,507
7	0	1.136	185.5	787.6	2.1932	204,117
----- PRESENT CONVENTIONAL SYSTEM -----						
3	0	0.101	15.6	65.7	0.2353	151,958
5 = 4	0	1.136	15.9	68.1	0.2399	151,958
6	0	1.136	226.7	2884.0	6.7539	52,158
7	0	1.136	185.5	787.6	2.1932	204,117

Note: 1 psi = 0.00689476 MPa
1 Btu/lbm = 2.326 J/g
1 Btu/lbm-°F = 4.1868 J/g-K
1 lbm = 0.45359237 kg

TABLE 6-2 - PROPERTIES OF FLUIDS AT STATE POINTS LISTED IN FIGURE 6-1

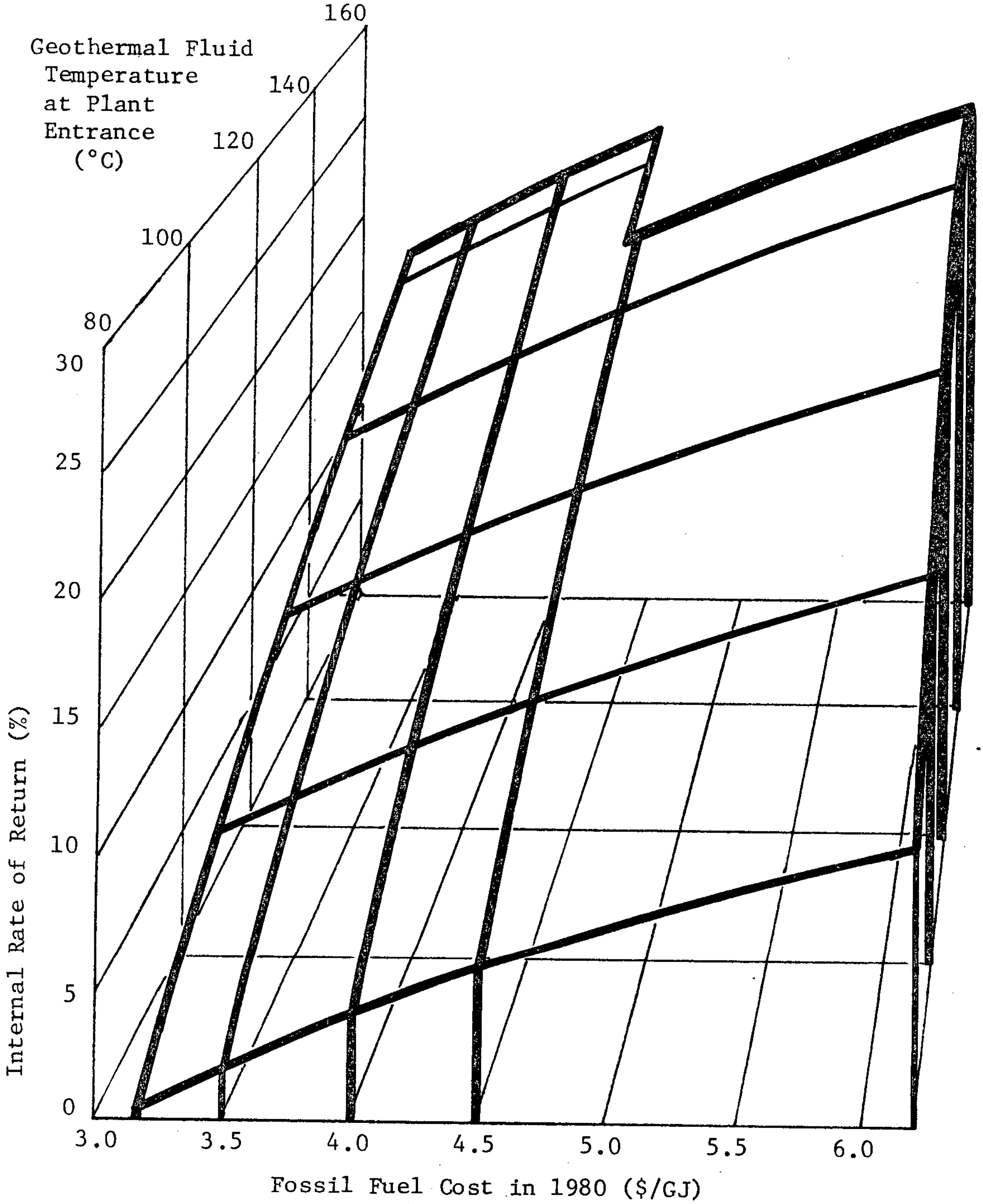


FIGURE 6-2 - INTERNAL RATE OF RETURN AS A FUNCTION OF FOSSIL FUEL COST AND GEOTHERMAL FLUID TEMPERATURE - EXAMPLE 1

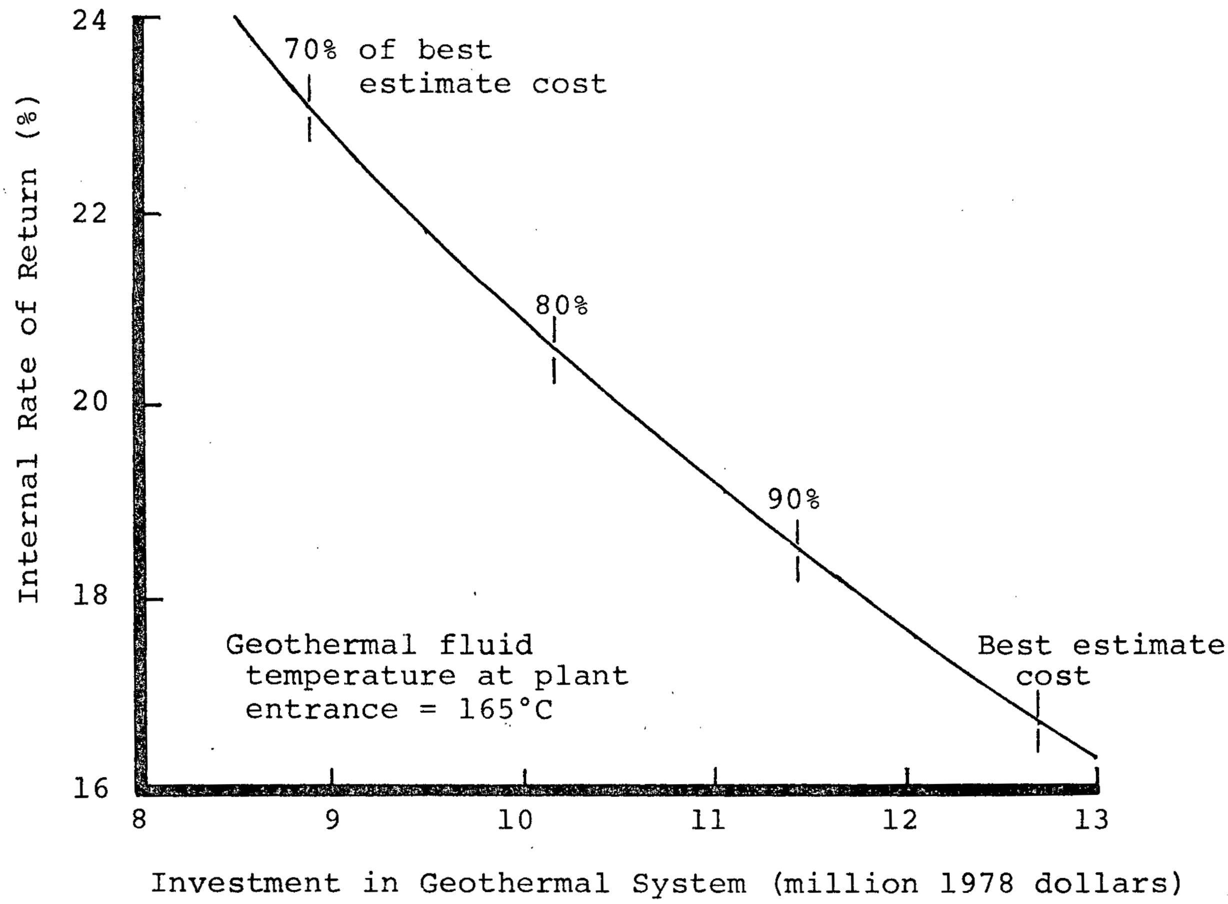


FIGURE 6-3 - INTERNAL RATE OF RETURN AS A FUNCTION OF INITIAL INVESTMENT FOR EXAMPLE 1

Table 6-1, the best estimate of total project costs is approximately \$12.7 million. The corresponding IRR is 16.6%. It is interesting to note that an IRR of 20% would be possible if only \$10.5 million were spent, the deficit being covered by \$2.2 million in governmental aid.

Given the present uncertainty in geothermal resource temperature and fossil fuel cost, the sensitivity of the IRR to variations in these factors is highly significant. Figure 6-4 shows the minimum fluid temperature needed to yield internal rates of return of 15% and 20% for a range of fossil fuel costs. Figure 6-5 gives another view of these relationships.

4. Conclusions

The proposed geothermal preheater for the boiler deaerator under examination should be considered carefully as more information about the potential of local geothermal resources surfaces. Governmental cost-sharing might raise prospective rates of return substantially while reducing the risk to the firm.

B. Retrofit of a Food-Processing Plant - Example 2

In November 1977, a subsidiary of H.J. Heinz Company, Ore-Ida Foods, submitted a proposal for federal cost-sharing in a geothermal retrofit of their potato-

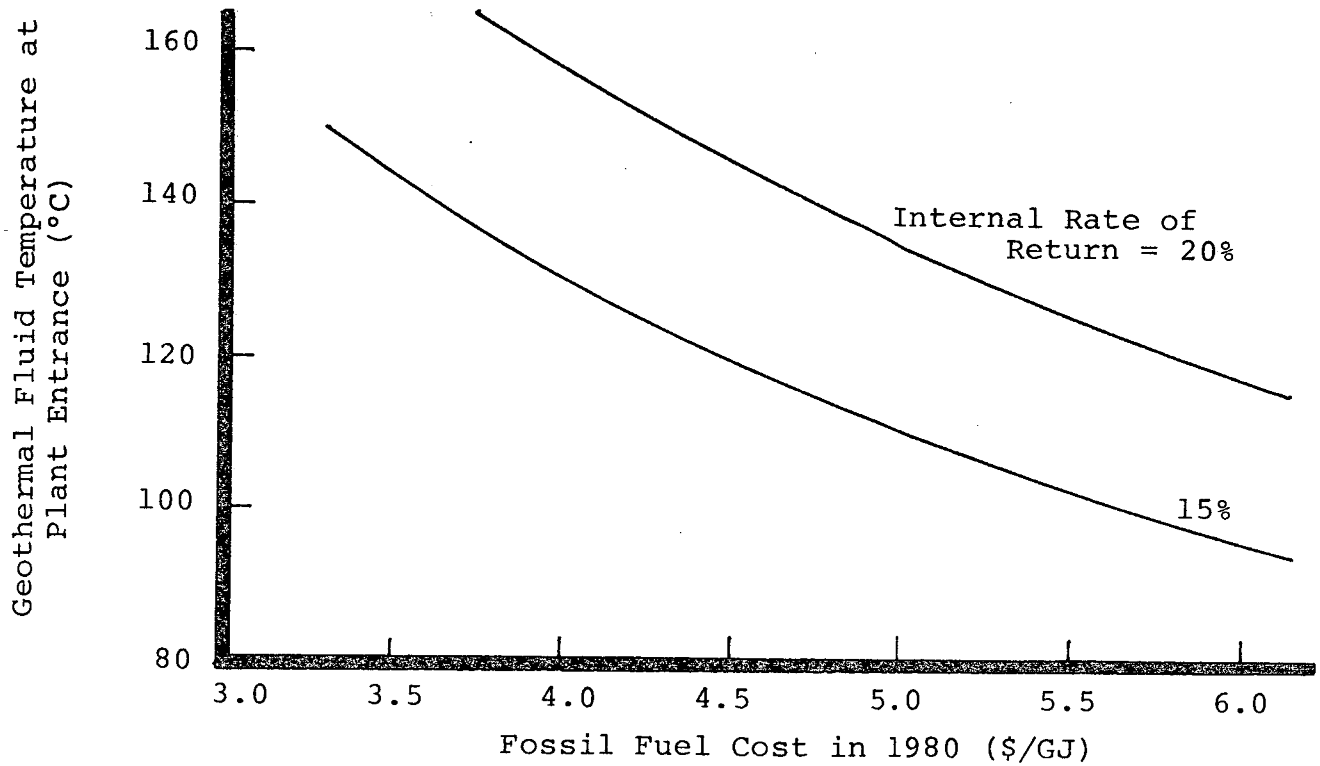


FIGURE 6-4 - GEOTHERMAL FLUID TEMPERATURE NEEDED FOR GIVEN INTERNAL RATES OF RETURN AS A FUNCTION OF FOSSIL FUEL COST

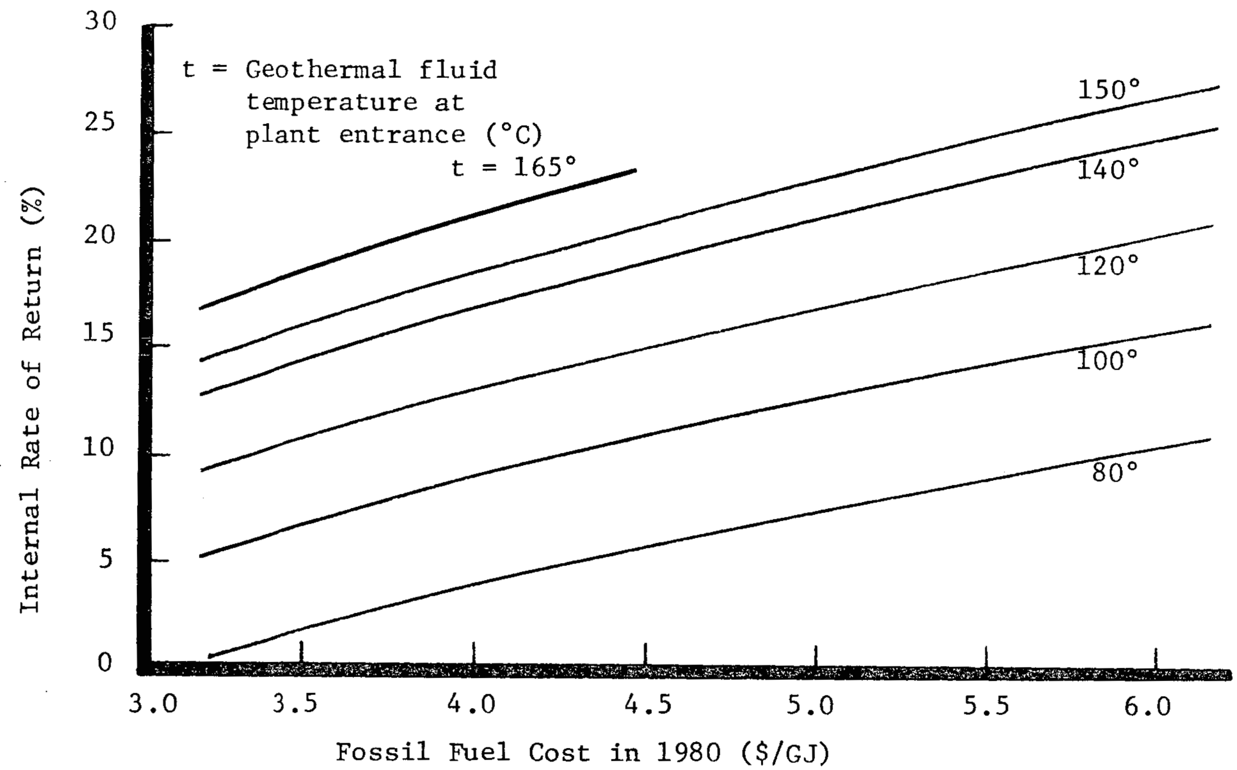


FIGURE 6-5 - INTERNAL RATES OF RETURN AS A FUNCTION OF FOSSIL FUEL COST WITH GEOTHERMAL FLUID TEMPERATURE AS A PARAMETER processing facility in Ontario, Idaho. The data contained in the proposal (which was subsequently approved) are sufficient for the application of the present computer methodology.

An analysis of the Ore-Ida facility using the methodology developed here serves two purposes. First, such an analysis provides a check upon the validity of the methodology: if the computer results were to differ significantly from those determined manually by the authors of the proposal, some doubt would be cast upon the methodology. Second, agreement between the results of the computer analysis and those of the proposal indicates that the computer methodology could be of value in the evaluation of future cost-sharing proposals submitted to the government.

1. <u>General approach and assumptions</u>

For this analysis, the automatic matching mode of the program is used. The characteristics of the seven processes indicated on the process flow sheet in the proposal are entered as input to the program along with values for economic variables and geothermal resource parameters. As far as is possible, the data used in the present analysis (listed in part in Table 6-3) correspond to that used by

Ore-Ida in the preparation of its proposal. Further comments relating to the input data employed are given in Appendix D.

2. Results

Figure 6-6 illustrates the fluid flow connections arrived at by the automatic computer methodology. Several features of this system should be noted. First, the geothermal fluid is reduced in temperature to an average of 53°C, approximately the same figure as given in the proposal. Second, the system designed by the computer utilizes seven heat exchangers while the system shown in the proposal employs eleven. However, the computer required use of a small fossil fuel heater which was unnecessary in the proposal. Third, the computer succeeded in cascading geothermal fluid through a series of heat exchangers: one geothermal stream passes through three heat exchangers and one unit process before reinjection.

The economic results calculated by the computer closedly parallel the figures given in Ore-Ida's proposal. (See Table 6-4.) The computer program overestimates the cost of retrofitting the plant (primarily due to the cost of the extra fossil burner) by 12%, well within the margin of error of 25% discussed in Chapter 4. It should be noted

1. ASSUMPTIONS RELATING TO THE PROPOSED AND EXISTING SYSTEMS:

    a. Steady state flow
    b. Processes in the proposed system must operate at the same flow rate and temperature as listed in the Ore-Ida proposal
    c. New heat exchanger characteristics:
       -- shell and tube units
       -- heat exchanger effectiveness = 85%

2. ASSUMPTIONS RELATING TO GEOTHERMAL RESOURE DEVELOPMENT:

    a. Two production wells- total = 162,500 kg hr^{-1}, 150°C
    b. One reinjection well
    c. Cost of field development: (1978 dollars)
       -- land acquisition = $ 0
       -- cost per well = $782,000
       -- fluid transmission system = $443,000
       -- other costs (exploration, project management, etc.) = $731,500
       -- annual field maintenance cost = $ 81,000
    d. Royalties = 0%
    e. Temperature loss in transmission = approx. 0°C
    f. Total dissolved solids content = 1,000 ppm

3. ASSUMPTIONS RELATING TO TAX TREATMENT:

    a. Depreciation lifetime = 15 years
    b. Depreciation method = sum of years' digits
    c. Salvage value for depreciation = 0%
    d. Investment tax credit = 10%
    e. Depletion allowance not allowed
    f. Intangible drilling cost deduction not allowed
    g. Property tax rate = 2.6¢/dollar investment
    h. Overall marginal income tax rate = 48%

TABLE 6-3 - ASSUMPTIONS MADE IN THE ANALYSIS OF EXAMPLE 2

(continued . . .)

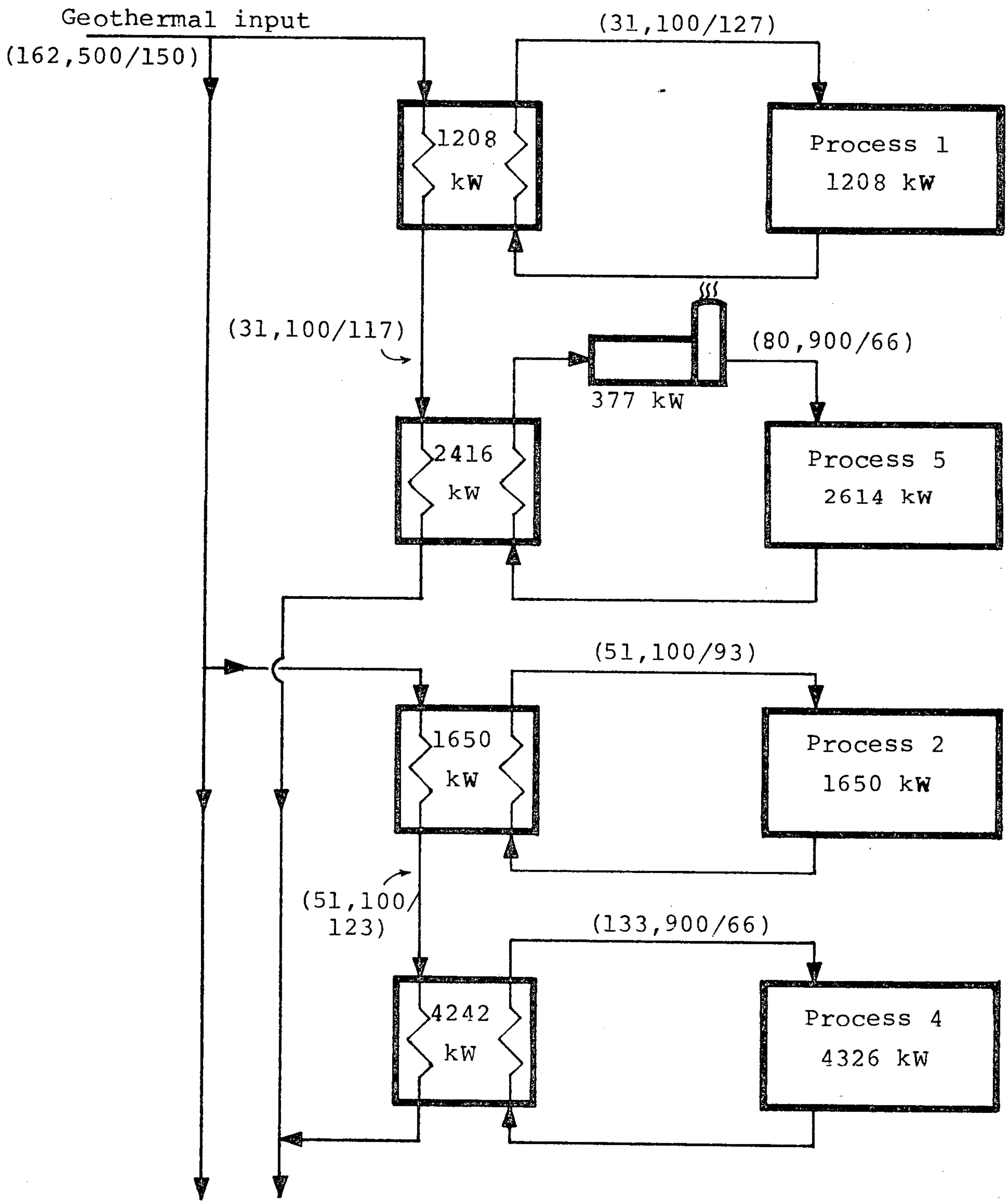
4. ASSUMPTIONS RELATING TO ECONOMIC ANALYSIS, FINANCING, AND ADDITIONAL EXPENSES:

   a. All costs and prices in 1978 dollars
   b. Discount rate for net present value calculations = 10%
   c. Financing method ignored (i.e. no interest charged on debt)
   d. Project starting date = 1978
   e. Project construction time = 2 years
   f. Investment profile - 18.1% in the first year, 81.9% in second
   g. Operating lifetime = 15 years
   h. Fossil fuel cost in 1978 dollars = \$2.25/GJ = \$2.37/10^6 Btu
   i. Inflation factors:

	general	fossil fuel	electricity
through 1986:	6.0%	10.74%	7.27%
after 1986:	6.0%	7.59%	7.27%

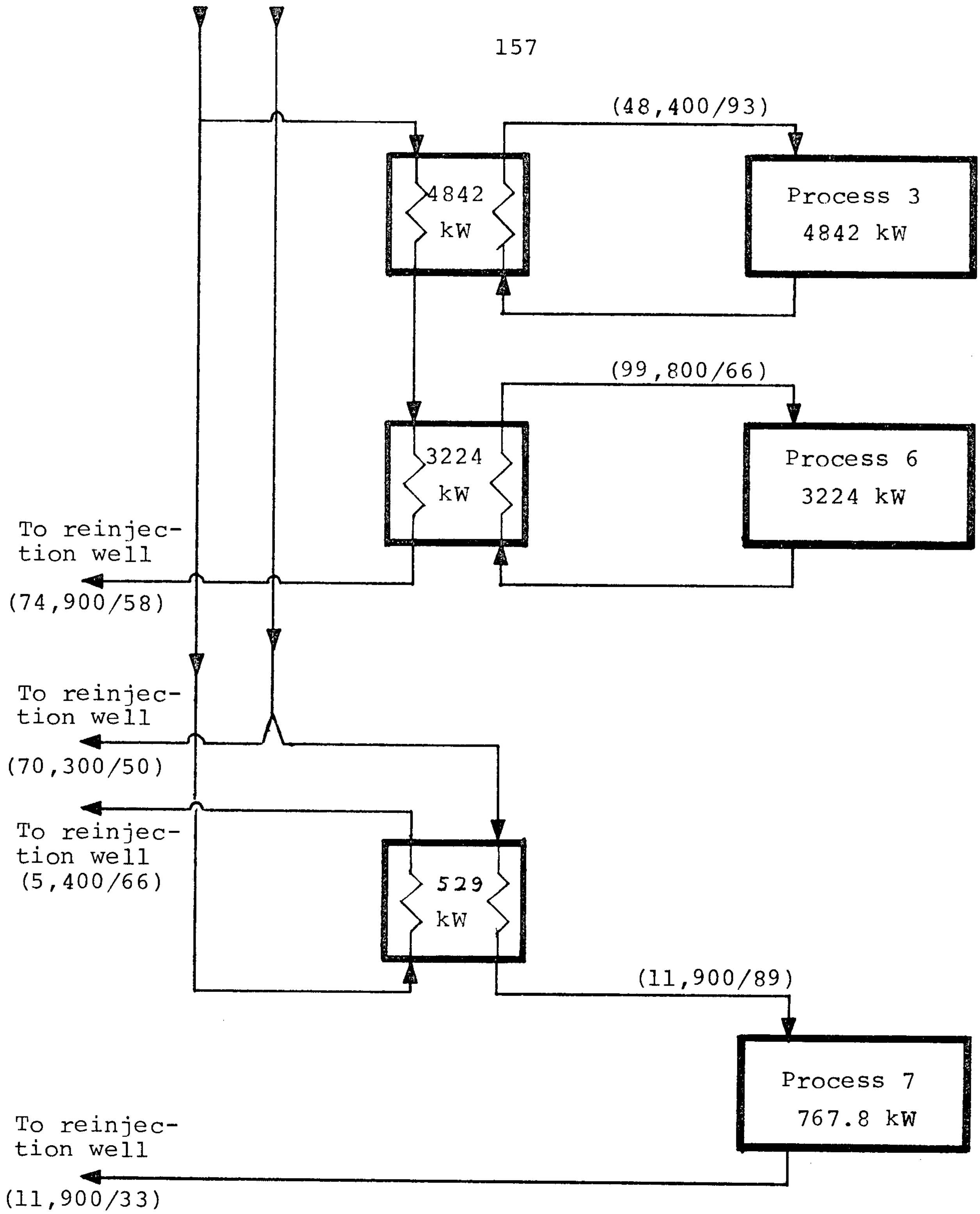
   j. Insurance premium rate = 0.11¢/dollar investment
   k. Annual maintenance expenses = 5.0¢/dollar investment
   l. Annual capacity factor = 60%

TABLE 6-3 - ASSUMPTIONS MADE IN THE ANALYSIS OF EXAMPLE 2 (concluded)



Stream parameter code:
(flow rate, kg hr^{-1}/temperature, °C)

FIGURE 6.6 - FLOW CONFIGURATION FOR EXAMPLE 2 (continued . . .)



Stream parameter code:
(flow rate, kg hr^{-1}/temperature, °C)

	Computer Analysis	Ore-Ida Proposal
Investment in geothermal field	$3.520 E6	$3.521 E6
Total investment in geothermal system	4.606 E6	4.490 E6
Net present value of geothermal system cash flows (at 10%)	4.499 E6	---
Net present value of system savings (at 10%)	3.170 E6	2.742 E6
Internal rate of return	19.72%	19.61%

NOTES:

1. All costs are in constant 1978 dollars.
2. The figure for investment in the geothermal field given in the proposal was used as input to the computer analysis since the latter does not estimate field development costs.
3. Costs do not include sums for reporting or operation of the system.

TABLE 6-4 - ECONOMIC RESULTS FOR EXAMPLE 2 that the program utilizes fewer heat exchangers yet estimates a somewhat higher cost. However, since the retrofit costs amount to 23.6% of the total cost of the geothermal system, the program overestimates system cost by only 2.6%. The most important figure for managerial decision-makers, the internal rate of return on the investment, was overestimated by only 0.6% (computer = 19.7%; Ore-Ida proposal = 19.6%). The economic analysis performed by the computer was comparable to that of the proposal in every respect save one: the former used the sum-of-years'-digits method of calculating depreciation, while the latter employed the double-declining balance method. This divergence has little effect upon the results.

3. Conclusions

The close agreement between the economic and technical results found by the present methodology and those contained in Ore-Ida's proposal indicates that the computer program achieves, at least in this case, its goal of quickly and accurately analyzing the potential for geothermal energy in industrial process heat applications. Such agreement also points to the possibility of using the methodology as an evaluative tool in the assessment of new cost-sharing proposals submitted to governmental agencies.

REFERENCES

1. See, for example, Thomas, K.V., "Process simulation program," TAPPI, 62(2):51 (1979).

CHAPTER 7 - CONCLUSION

The computer program described in the previous chapters is intended to provide a quick and accurate analysis of the use of geothermal energy in industrial process heat applications. It can be operated either as a design analysis tool to match energy supplies and demands, or as an economic analysis tool if a particular facility design has already been selected.

Two examples employing the computer model are presented in Chapter 6. In the first, the program is used to analyze the economics of a proposed geothermal application. The interactive feature of the model is used to perform a sensitivity analysis that outlines the economic conditions under which the application is profitable. In the second example, the program is employed as a design tool to automatically match process energy needs with geothermal energy supplies. Data are taken from a proposal for federal financial aid in constructing a geothermal facility. The technical and economic results yielded by the program closely parallel those found by the authors of the proposal using conventional design techniques. This correspondence attests to the validity of the computer model.

As the prices of conventional sources of energy continue to rise, geothermal resources will attract greater attention on the part of governmental policy-makers and industrial managers. These decision-makers will require the aid of analytical tools in evaluating the potential of geothermal energy. It is hoped that the present computer model will furnish such a tool.

APPENDIX A - ECONOMIC OPTIMIZATION OF UNIT PROCESSES USING GEOTHERMAL FLUID

I. INTRODUCTION

Interest in the utilization of geothermal energy for industrial process heat has grown markedly in recent years. Several industrial plants already employ geothermal energy, and the government is sponsoring a wide variety of geothermal demonstration facilities. As conventional fossil fuels become increasingly expensive and domestic geothermal resources better mapped, this trend will continue to gather momentum. Plant designers must now learn how to utilize geothermal resources efficiently.

The following analysis must not be considered a detailed prescription for design. Many assumptions will be made in order to illustrate the salient characteristics of geothermal resource utilization. Crucial among these is the assumption that the unit process may be optimized without regard to the remainder of the plant. In most situations the results of regional optimization differ significantly from those of global optimization. Another important assumption is that geothermal fluid is used directly in the process. With some variations, it would be possible to analyze the more common situation of a secondary heat exchanger in which energy is transferred from the geothermal fluid to a clean liquid. In spite of these simplifications, the general tenor, if not the details, of the following results should aid in more realistic attempts at process design.

II. SIZING OF PROCESS EQUIPMENT

Three types of process equipment will be examined. The first consists of a heat exchanger in which both the hot fluid stream used in a conventional fossil-fired plant and the stream to be employed in a new geothermal plant are single-phase streams. Thus, both streams are liquid or both are superheated vapor. In the second process type, both streams are in the two-phase region (i.e., a condenser). Finally, the third equipment type consists of an injection process in which the hot streams are introduced into direct contact with the process substance.

It will prove useful to derive at this point some equations relating to the first two types of processes. For these heat exchangers, the true heat transfer relations may be approximated by

$$Q = A\,U\,\Delta t \quad , \qquad [A.1]$$

where

Q = total heat transfer rate, kW

A = heat transfer area, m^2

U = overall heat transfer conductance, $kW\ m^{-2}\ K^{-1}$

= $(h_{hot}^{-1} + h_{process}^{-1})^{-1}$, where h indicates a heat transfer coefficient

Δt = effective temperature difference across the heat exchanger, °C

$= 0.5\ (t_{hot,inlet} + t_{hot,exit}) - t_{process,average}.$

Two assumptions implicit in this equation should be noted. First, the definition of U neglects the thermal resistance of the heat transfer surface itself as well as that of scale on the surface. Second, the above definition of Δt has been adopted instead of the more usual definition, the product of the log-mean temperature difference and a factor used to correct for departures from pure counterflow conditions. The expression employed here results in equations whose physical significance is more readily interpreted, in addition to facilitating the mathematical manipulations to follow. As will be shown below, the errors introduced by this approximation are small.

Since the Q necessary for a given process requirement remains constant whether the new geothermal system or the old conventional system is considered, the ratio of heat transfer area in the new situation to that in the old can be found from Eq. 1 to be

$$\phi = \frac{A_{new}}{A_{old}} = \left(\frac{U_{old}}{U_{new}}\right)\left(\frac{\Delta t_{old}}{\Delta t_{new}}\right) \qquad [A.2]$$

The ratio of conductances may be expanded from the definition of U as

$$\left(\frac{U_{old}}{U_{new}}\right) = \left(\frac{h_{hot,old}}{h_{hot,new}}\right)\left(\frac{h_{hot,new} + h_{process}}{h_{hot,old} + h_{process}}\right), \quad [A.3]$$

where it has been assumed that the process side heat transfer coefficient is independent of the hot side fluid (i.e. that $h_{process,old} = h_{process,new}$).

<u>Process Type 1</u> - <u>Single-Phase Heat Transfer</u>

For single-phase fluid streams one can use the McAdams turbulent flow correlation to estimate the magnitude of the hot-side heat transfer coefficient:[1]

$$h_{hot} = (\text{constant})\dot{m}_{hot}^{0.8} \quad [A.4]$$

Substitution of this relation into Eq. A.3 and of the result into Eq. A.2 yields

$$\phi = \left(\frac{\mu^{0.8}\Gamma + 1}{\mu^{0.8}(\Gamma + 1)}\right)\left(\frac{\overline{\Delta t}_{old}}{\Delta t_{new}}\right), \quad [A.5]$$

where

$$\mu = \dot{m}_{hot,new}/\dot{m}_{hot,old}$$

$$\Gamma = h_{hot,old}/h_{process} .$$

This formulation implicitly assumes that the characteristic flow diameter of the new heat exchanger (used to find the

Reynolds number) is identical to that of the old. Moreover, it assumes that fluid properties (Pr,μ,k) are unaffected by the substitution of geothermal fluid for conventional water or steam.

Unfortunately, Δt_{new} also depends upon the mass flow rate of the hot stream, since a larger flow rate results in a smaller stream temperature drop. This complication may be included in Eq. A.5 by noting that for a hot-side stream of constant specific heat

$$\Delta t_{new} = K_t - \frac{K_q}{\mu} \quad , \qquad [A.6]$$

where

$$K_t = t_{hot,inlet,new} - t_{process,average}$$

$$K_q = \frac{Q}{2\dot{m}_{hot,old}\, c_p} \quad .$$

Thus Eq. A.5 becomes

$$\phi = \left(\frac{\mu\Gamma + \mu^{0.2}}{\Gamma + 1}\right)\left(\frac{\Delta t_{old}}{K_t\mu - K_q}\right) \quad . \qquad [A.7]$$

Equation A.7 expresses for this process type the relationship between heat transfer area of the geothermal system and heat transfer area of the conventional system as a function of several variables. Of these variables, K_q, Δt_{old}, and Γ are independent of the characteristics of the new geothermal system. The ratio of surface areas thus is a function solely of the new hot-side mass flow rate, represented within μ, and of the hot-side inlet temperature, which appears in K_t.

Process Type 2 - Condensation Heat Transfer

Condensation heat transfer coefficients do not depend on mass flow rates, and thus h_{hot} in Eq. A.3 will vary only as some function of Δt. The overall heat transfer conductance is controlled not by h_{hot}, however, but by the much smaller $h_{process}$. Since the latter remains constant when geothermal fluid is substituted for the conventional hot-side fluid, the ratio of conductances in Eq. A.3 reduces to approximately unity.

However, the presence of non-condensable gases in the geothermal stream can adversely affect the heat transfer coefficient. Sparrow presents data in graphical form for the reduction in Q due to this effect, data which has been correlated as follows:[2]

$$Q_{actual} = f(\eta) \cdot Q_{without\ gases} \qquad [A.8]$$

$$f(\eta) = 1 - 2.01126\eta^{0.7933} , \qquad [A.9]$$

where

f = correction factor for Q due to the presence of non-condensable gases, a function of η

η = weight fraction of non-condensable gases in the stream.

With this addition, Equations A.1 and A.2 become respectively

$$Q = f(\eta)\ A\ U\ \Delta t \qquad [A.10]$$

$$\phi = \left(\frac{1}{f(\eta)}\right)\left(\frac{U_{old}}{U_{new}}\right)\left(\frac{\Delta t_{old}}{\Delta t_{new}}\right), \qquad [A.11]$$

since in the conventional system η equals zero by assumption and thus $f(\eta)$ equals unity. Noting that for condensing streams $t_{hot,inlet}$ equals $t_{hot,exit}$, and recalling from above that the ratio of heat transfer conductances (in the absence of non-condensables) is approximately one,

$$\phi = \left(\frac{1}{f(\eta)}\right)\left(\frac{t_{hot,old} - t_{process}}{t_{hot,new} - t_{process}}\right). \qquad [A.12]$$

For this type of process equipment, the ratio of heat transfer areas depends on the parameters whose values are determined by the characteristics of the conventional system ($t_{hot,old}$, $t_{process}$), and on only two new variables: the new hot-side stream temperature and the non-condensable gas content of that stream.

Process Type 3 - Direct Fluid Injection

The dimensions of direct injection process equipment are controlled by several factors, the most important of which is reaction kinetics. Unfortunately, a general method of predicting reaction kinetics as a function of fluid characteristics (temperature, pressure, etc.) remains outside the scope of this analysis. For present purposes it has been assumed that the size of the equipment used is proportional to the process substance residence time in the reactor. Furthermore, it is assumed that the required residence time is inversely proportional to the absolute temperature at which the process operates. Finally, it is assumed that the operation temperature of the process is characterized by the average hot fluid temperature in the equipment, since the fluid is in intimate contact with the process substance.

Upon these assumptions, the ratio of the size of the new equipment (suitably measured) to that of the old, ϕ, may be determined:

$$\phi = \frac{(t_{process} + \Delta t_{old} + 273.15)}{(t_{process} + \Delta t_{new} + 273.15)} , \qquad \text{[A.13]}$$

where the $t_{process}$, Δt notation has been retained for the purposes of comparison with previous expressions. It is important to note that the details of the individual process being considered will impose restrictions upon the range of validity of this formulation.

III. OPTIMIZATION OF PROCESSES WITHOUT AUXILIARY FOSSIL FUEL

In those cases in which the temperature of the geothermal fluid exceeds that of the process by a sufficient amount, auxiliary fossil fuel need not be used to upgrade the thermodynamic availability of the fluid. For these cases the optimum size of equipment and quantity of fluid may be determined by the following analysis.

As a first-order approximation, the initial cost of process equipment is proportional to its size. The cost of geothermal fluid is similarly proportional to the flow rate purchased. The total annualized cost of the process therefore is assumed to be

$$TC = K_a' \text{ (size)} + K_m' \dot{m}_{GT} \quad , \qquad [A.14]$$

or

$$TC = K_a \phi + K_m \mu \quad , \qquad [A.15]$$

where

TC = total hourly cost of the process, \$/hour

K_a = capital cost of the conventional equipment, multiplied by a capital recovery factor and divided by the product of the length of a year in hours times the plant capacity factor, \$/hour

K_m = cost per unit of geothermal mass flow rate, multiplied by the conventional system flow rate $\dot{m}_{hot,old}$, \$/hour.

By differentiating with respect to μ, a stationary point of total cost can be located:

$$\frac{d(TC)}{d\mu} = 0 = K_a \frac{d\phi}{d\mu} + K_m \quad , \qquad [A.16]$$

or rearranging,

$$\frac{d\phi}{d\mu} = -\frac{K_m}{K_a} \quad . \qquad [A.17]$$

Process Type 1 - Single-Phase Heat Transfer

The ratio of heat transfer areas, ϕ, was given for this process type in Eq. A.7, which is equivalent to

$$\phi = \gamma \left(\frac{\mu\Gamma + \mu^{0.2}}{K_t \mu - K_q} \right) \quad , \qquad [A.18]$$

where

$$\gamma = \frac{\Delta t_{old}}{\Gamma + 1}$$

Differentiation of this expression yields

$$\frac{d\phi}{d\mu} = -\gamma \frac{(0.8K_t \mu^{0.2} + 0.2\, K_q \mu^{-0.8} + K_q \Gamma)}{(K_t \mu - K_q)^2} \quad . \qquad [A.19]$$

Substitution into Eq. A.17 then gives

$$\frac{(0.8K_t \mu^{0.2} + 0.2K_q \mu^{-0.8} + K_q \Gamma)}{(K_t \mu - K_q)^2} = \frac{K_m}{\gamma K_a} \quad , \qquad [A.20]$$

which represents an implicit solution for the optimal value of μ.

An example is given in Figure A-1. The solution is noteworthy because it illustrates a common characteristic of geothermal applications: the large magnitude of operating costs as compared with capital costs. In addition, the total cost is highly sensitive to the quantity of fluid required, a situation which underscores the importance of careful design to minimize fluid usage.

Process Type 2 - Condensation Heat Transfer

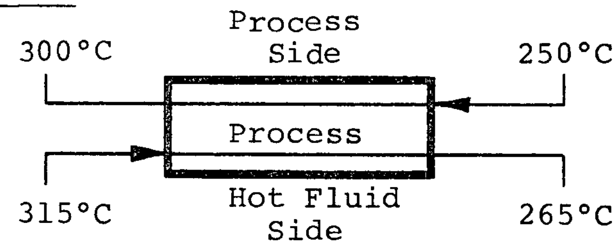
An examination of Eq. A.12 reveals that for this process type, ϕ does not depend, at least in a first-order approximation, upon the mass flow rate variable μ. The mass flow rate is determined by the magnitude of the required heat transfer rate and by the amount of non-condensable gases present. As a result, no first-order optimization is possible.

A second-order analysis would include the effects of pressure drop and pumping power, as well as the small variation in the overall heat transfer conductance due to the influence of Δt on the condensation heat transfer coefficient.

Process Type 3 - Direct Fluid Injection

Injection processes can be categorized by the phase of fluid used. In those cases in which steam is injected and condensed in the reactor, a first-order optimi-

CONVENTIONAL SYSTEM:



Parameters:

Parameter	Value	Parameter	Value
Γ	2.0	$t_{process,average}$	275°C
$t_{hot,inlet}$	315°C	$t_{hot,exit}$	265°C
$\dot{m}_{hot,old}$	68,120 kg/hr	Capital Cost	\$140,000
Capital recovery factor at 15%, 20 yrs.	0.15976	Capacity factor	75%
		Geothermal fluid unit cost	$\$700/10^6$ kg

Computed variables:

$$\Delta t_{old} = 0.5(315+265) - 275 = 15°C$$

$$Q = \frac{68120}{3600}(4.1868)(315-265) = 3961.2 \text{ kW}$$

$$K_q = \frac{3961.2}{2\left(\frac{68120}{3600}\right)(4.1868)} = 25°C$$

$$\gamma = \frac{15}{2.0 + 1} = 5.0°C$$

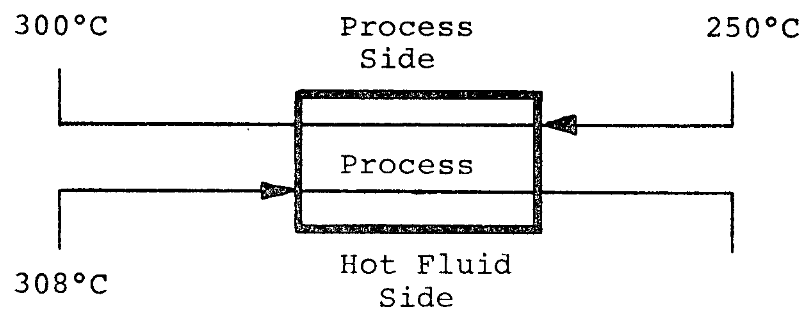
$$K_a = 140{,}000 \frac{0.15976}{0.75(8760)} = \$3.404/\text{hr}$$

$$K_m = (700\text{x}10^{-6})(68120) = \$47.684/\text{hr}$$

FIGURE A-1 - EXAMPLE OPTIMIZATION OF TYPE 1 PROCESS WITHOUT AUXILIARY FOSSIL FUEL

(continued)

GEOTHERMAL SYSTEM:



Parameters:

Geothermal fluid inlet temperature = 308°C

Computed variables:

$$K_t = 308 - 275 = 33°C$$

OPTIMIZATION:

From Eq. A.20,

$$\frac{26.4\mu^{0.2} + 5\mu^{-0.8} + 50}{(33\mu - 25)^2} = \frac{47.684}{(5.0)3.404} .$$

Solving by trial and error gives

$$\mu_{optimum} = 0.921 ,$$

which yields

$\phi_{optimum} = 2.62$

$TC_{optimum} = \$52.84/hr$, of which

\$8.93/hr is due to capital costs and

\$43.91/hr is due to fluid costs.

FIGURE A-1 (concluded)

zation is not possible and the comments made in the preceding section apply. However, in those cases in which single-phase fluid is utilized, the following analysis appears appropriate.

Equation A.13 (the expression for ϕ for this process type) can be rearranged as

$$\phi = \frac{B}{0.5t_{hot,inlet,new} + 0.5t_{hot,exit,new} + 273.15} , \qquad [A.21]$$

in which it proves convenient to define

$$B = 0.5(t_{hot,inlet,old} + t_{hot,exit,old}) + 273.15 \quad . \qquad [A.22]$$

An energy balance can be used to determine $t_{hot,exit,new}$ in Eq. A.21 as follows:

$$Q = \dot{m}_{old} \, \mu \, c_p \, (t_{in} - t_{h,out}) \quad , \qquad [A.23]$$

where

$$t_{in} = t_{hot,inlet,new} \quad , \ ^\circ C$$

$$t_{h,out} = t_{hot,exit,new} \quad , \ ^\circ C \quad .$$

Reactions which are endothermic or exothermic could be modeled by a slight change in the right-hand side of this equation.

This formulation is grounded upon two important assumptions. First, it is assumed that the process substance and the hot fluid stream do not necessarily come to thermal equilibrium. This assumption is clearly met in many common processes. Consequently, the exit temperature of the hot fluid is a function not only of Q but also of μ.

Second, it is assumed that the total quantity of heat transferred in the conventional system is identical to that in the new system, an assumption which necessitates further explanation. It may be recalled that the "job" of this type of process equipment is defined solely in terms of process temperatures and residence times. For example, the "job" of a cooker in the food processing industry essentially consists of raising the temperature of the food to a certain level. If the characteristic Biot number of the food is moderately small, the temperature throughout the food product will be almost uniform.[3] The temperature profiles of the food will then be approximately the same regardless of what external fluid temperature is applied; the sole difference will be the rate at which the temperature increases. In this situation the temperature profile of food which has just been cooked at a low temperature will resemble that of food which has been cooked at a higher temperature. As a result, the total amount of energy absorbed by the food will remain unchanged if the process temperature is raised, and thus the total heat transferred will also remain constant.

Rearrangement of Eq. A.23 then yields

$$t_{h,out} = t_{in} - \frac{Q}{\dot{m}_{old}\, c_p\, \mu} = t_{in} - \frac{2K_q}{\mu} . \qquad [A.24]$$

A Second Law constraint limits the acceptable values of $t_{h,out}$ and thus of μ, since the hot fluid exit temperature must be no lower than that of the process substance. Thus

$$t_{h,out} \geq t_{p,out} \quad , \qquad [A.25]$$

where

$$t_{p,out} = t_{process,exit} \text{ , °C } .$$

An energy balance on the process substance analogous to Eq. A.23 gives

$$Q = \dot{m}_p\, c_{p,p}\, (t_{p,out} - t_{p,in}) \text{ ,} \qquad [A.26]$$

or

$$t_{p,out} = t_{p,in} + \frac{Q}{\dot{m}_p\, c_{p,p}} \quad , \qquad [A.27]$$

where

$\dot{m}_p$ = mass rate of process substance, kg hr^{-1}

$c_{p,p}$ = specific heat of process substance, kJ kg^{-1} K^{-1}

$t_{p,in}$ = inlet temperature of process substance, °C.

Applying the constraint A.25 by substitution of Eqs. A.24 and A.27 yields after manipulation

$$\mu \geq \frac{2\,K_q}{\left(t_{in} - t_{p,in} - \frac{Q}{\dot{m}_p\,c_{p,p}}\right)} \quad . \qquad [A.28]$$

With this constraint in mind, substitution of Eq. A.24 into Eq. A.21 gives

$$\phi = \frac{B\mu}{T_{in}\,\mu - K_q} \quad , \qquad [A.29]$$

where

$$T_{in} = t_{in} + 273.15.$$

Differentiation with respect to μ then permits the result to be substituted into the optimization condition (Eq. A.17), giving

$$\frac{d\phi}{d\mu} = -\frac{BK_q}{(T_{in}\,\mu - K_q)^2} = -\frac{K_m}{K_a} \quad , \qquad [A.30]$$

or rearranging,

$$\frac{BK_a K_q}{K_m} = (T_{in}\,\mu - K_q)^2 \qquad [A.31]$$

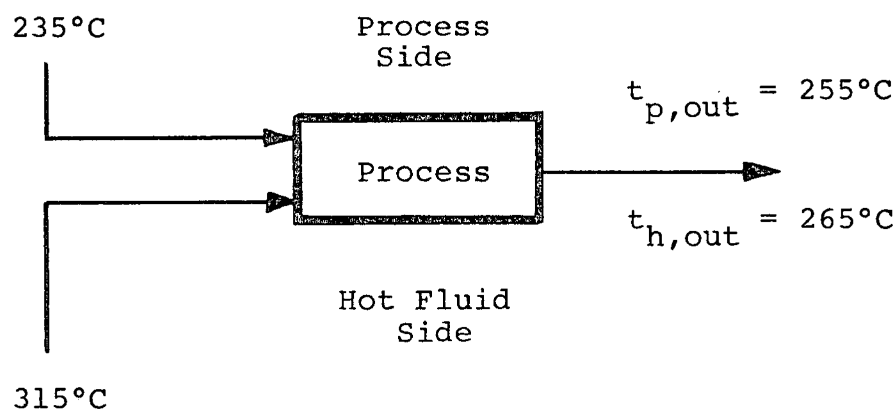
Taking the positive square root and solving,

$$\mu_{optimum} = \frac{K_q + \sqrt{\frac{BK_a K_q}{K_m}}}{T_{in}}\,, \qquad [A.32]$$

subject to the constraint given by Eq. A.28.[4]

An example is given in Fig. A-2. Note that optimization tends to minimize the use of expensive geothermal fluid and that fluid costs again dominate the total process cost. Unfortunately, the Second Law constraint severely limits the possible reduction in flow rate. The restrictiveness of this limitation is highly dependent on the geothermal fluid inlet temperature: if t_{in} = 315°C instead of 308°C, then μ = 0.833 and TC = $43.17/hr.

CONVENTIONAL SYSTEM:



Values for all parameters used in this case are identical to those shown in Fig. A-1 except as noted.

Parameters

$t_{hot,exit,old} \qquad = 265°C$

Computed variables:

$B = 0.5(315 + 265) + 273.15 \qquad = 563.15\ K$

$$\frac{Q}{\dot{m}_p\, c_{p,p}} = t_{p,out} - t_{p,in} = 254 - 235 \quad = 20°C$$

GEOTHERMAL SYSTEM:

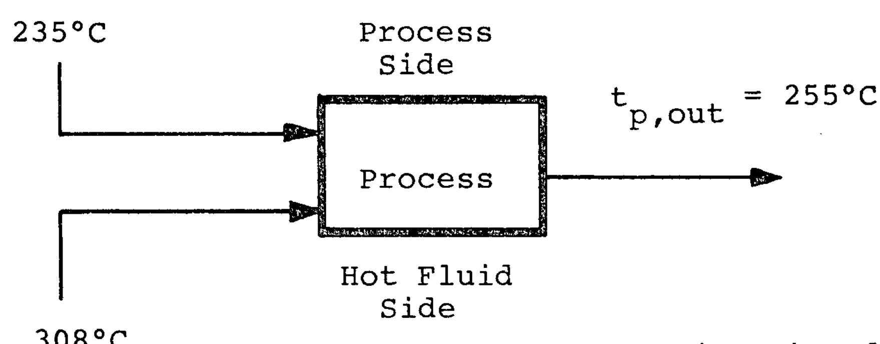


FIGURE A-2

(continued)

Parameters:

Geothermal fluid inlet temperature, $t_{in} = 308°C$

Computed variables:

$$T_{in} = 308 + 273.15 \quad = 581.15°C$$

OPTIMIZATION:

From Eq. A.32,

$$\mu = \frac{25 + \sqrt{\dfrac{(563.15)(3.404)(25)}{(47.684)}}}{581.15} ,$$

yielding

$$\mu_{optimum} = 0.0976.$$

However, the constraint Eq. A.28 gives

$$\mu \geq \frac{2(25)}{(308 - 235 - 20)}$$

or

$$\mu \geq 0.9434 \quad .$$

Using this latter figure,

$$t_{h,out} = 255°C$$

$$\phi = 1.015$$

TC = \$48.44/hr, of which

\$3.46/hr is due to capital costs and

\$44.98/hr is due to fluid costs.

FIGURE A-2 - EXAMPLE OPTIMIZATION OF TYPE 3 PROCESS WITHOUT AUXILIARY FOSSIL FUEL (concluded)

IV. OPTIMIZATION OF PROCESSES WITH AUXILIARY FOSSIL HEAT

In situations in which geothermal fluid temperatures are insufficient to supply process needs, fossil fuels must be burned to supplement or replace geothermal energy. The configuration of equipment shown in Fig. A-3 is assumed to hold throughout this section. The system features an auxiliary fossil-fueled heater upstream of the process equipment which boosts the temperature of the geothermal fluid to a preset value.

A parameter must be defined at this point to describe the fraction of total energy use that is supplied by fossil fuel. However, each possible definition presents difficulties. Use of the ratio of energy added by fossil fuel to process energy requirements can be misleading. For example, the inlet stream to the heater could be at a lower temperature (at the limit, ambient conditions) than the exit stream from the process, indicating that more energy was put into the stream than was taken out. The ratio suggested then would have a value greater than unity, an inappropriate figure for a parameter designed to measure the fraction of heat supplied by fossil fuel.

A better definition is given by

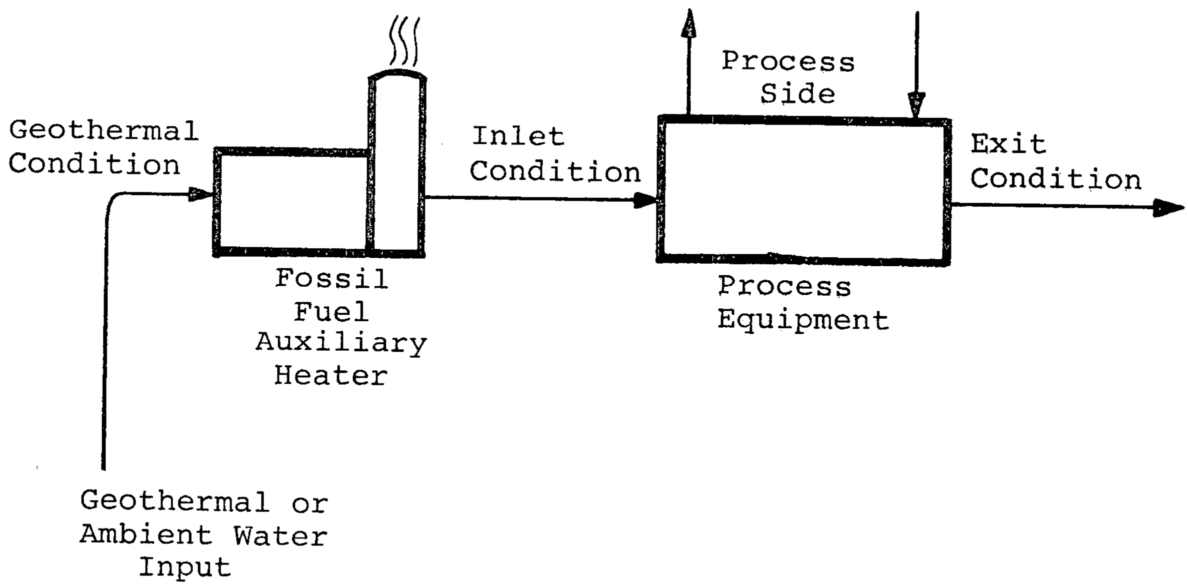


FIGURE A-3 - SYSTEM CONFIGURATION FOR PROCESSES WITH AUXILIARY FOSSIL HEAT

$$\zeta = \frac{\text{heat added by fossil fuel}}{\text{total enthalpy in stream at inlet above ambient}}$$

$$= \frac{H_{in} - H_{GT}}{H_{in} - H_{amb}} \quad , \qquad [A.33]$$

where

H = total enthalpy rate, kJ hr^{-1}

in = condition at inlet to process unit, or equivalently at exit from auxiliary heater

GT = condition at inlet to the auxiliary heater - either geothermal fluid or water at ambient conditions if geothermal fluid is not used at all

amb = ambient conditions (here taken to be 20°C).

Now ζ ranges from zero for no use of fossil fuel to unity for water drawn at ambient conditions (no geothermal fluid used).

The cost equation (A.15) must be expanded by the addition of a term representing the cost of fossil fuel utilization:

$$TC = K_a \phi + K_m \mu + K_f \Psi \quad , \qquad [A.34]$$

where

K_f = the cost per unit energy of fossil fuel, including the annualized capital investment required for the auxiliary heater, multiplied by the heat transfer rate of the process in the conventional system, Q, $/hr

Ψ = ratio of energy supplied by fossil fuel to the heat transfer rate of the process in the conventional system, Q.

The total cost is thus a function of μ, ζ, and assorted constants. The minimum cost is found by differentiating with respect to μ and ζ, setting the results equal to zero, and solving the two equations simultaneously. The coupled equations become

$$\frac{\partial(TC)}{\partial\mu} = 0 = K_a \frac{\partial\phi}{\partial\mu} + K_m + K_f \frac{\partial\Psi}{\partial\mu} \qquad [A.35]$$

$$\frac{\partial(TC)}{\partial\zeta} = 0 = K_a \frac{\partial\phi}{\partial\zeta} + K_f \frac{\partial\Psi}{\partial\zeta} \qquad [A.36]$$

Process Type 1 - Single-Phase Heat Transfer

In most single-phase flows, the enthalpy can be expressed as a function of temperature alone. Equation A.33 can then be recast:

$$\zeta = \frac{t_{in} - t_{GT}}{t_{in} - t_{amb}} , \qquad [A.37]$$

where the subscripts are as defined above. From Eq. A.37 and the definition of K_t in Eq. A.6,

$$K_t = t_{in} - t_{process,average}$$

$$= \frac{t_{GT} - t_p + \zeta\ (t_p - t_{amb})}{1 - \zeta} \quad , \qquad [A.38]$$

where

$$t_p = t_{process,average} \; .$$

Keeping in mind that K_t is now a function of ζ, the two partial derivatives of ϕ can be derived from Eq. A.18. Furthermore, from the definition of Ψ after Eq. A.34,

$$\Psi = \frac{\mu\dot{m}_{hot,old}\ c_p\ (t_{in} - t_{GT})}{Q} \quad , \qquad [A.39]$$

or

$$\Psi = \frac{\mu(t_{in} - t_{GT})}{2\ K_q} \quad , \qquad [A.40]$$

in which it has been assumed that the fossil heater does not change the phase of the geothermal fluid. This can be rewritten as a function of ζ by using Eq. A.37, giving

$$\Psi = \frac{\mu\zeta(t_{GT} - t_{amb})}{2\ K_q(1-\zeta)} \quad , \qquad [A.41]$$

from which the two partial derivatives of Ψ can be evaluated. The four derivatives of ϕ and Ψ are given in the footnotes.[5]

Unfortunately, the complexity of the four partial derivatives precludes solution of Eqs. A.35 and A.36 analytically. Returning then to the original cost equation A.34, which can be rewritten as

$$TC = K_a\gamma\left(\frac{\mu\Gamma + \mu^{0.2}}{K_t\mu - K_q}\right) + K_m\mu + K_f\,\frac{\mu\zeta(t_{GT} - t_{amb})}{2K_q(1-\zeta)}\ , \quad [A.42]$$

the minimum cost can be found by trial and error.

In those cases for which the geothermal fluid temperature is sufficient for satisfaction of process energy needs, the optimization procedure forces ζ to zero. The optimum value of μ then corresponds to that derived from the rule in Eq. A.20.

In those cases for which t_{GT} is too low, optimization tends to drive μ towards zero and t_{in} towards infinity. It is curious that although they depend on μ and t_{in}, ϕ and Q_{fossil} remain finite. These weird tendencies of μ and t_{in} in the optimization process suggest that at least one important constraint upon the system has been overlooked.

Among the factors neglected thus far in the analysis are the following. First, the size of the auxiliary heater is a function of mass flow rate and temperature as well as of heat transfer rate. For example, the equipment size approaches infinity as the required fluid temperature at the heater exit nears the flame temperature. Second, the assumption of single-phase flow fails to hold as the fluid temperature passes the boiling point. Third, the size of the process heat exchanger is limited by the available space in the factory. Fourth, the equations used to predict heat transfer coefficients are no longer applicable for low flow rates, rates at which flow in the heat exchanger becomes laminar instead of turbulent.

These difficulties serve to create feasibility boundaries which limit the range of values which parameters can assume. As the above results indicate, the optimization procedure will then generate a boundary solution. In particular, one can assume that these difficulties result in a constraint on the maximum allowable value of t_{in}. If t_{in} is then fixed at this boundary value, ζ can be found from Eq. A.37 and the total cost (TC) becomes a function of only one variable: μ. The cost equation A.34 thus can be rewritten using Eq. A.40 as

$$TC = K_a \gamma \left(\frac{\mu\Gamma + \mu^{0.2}}{K_t \mu - K_q} \right) + K_m \mu + K_f \frac{\mu(t_{in} - t_{GT})}{2 K_q} \quad . \qquad [A.43]$$

Differentiation with respect to μ, equation to zero, and rearrangement then yields

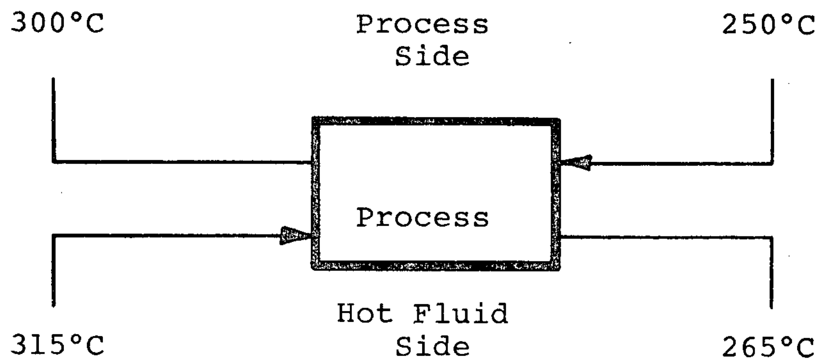
$$\frac{K_m}{K_a \gamma} + \frac{K_f (t_{in} - t_{GT})}{2K_q \, K_a \gamma} = \frac{0.8 \, K_t \, \mu^{0.2} + 0.2 \, K_q \, \mu^{-0.8} + \Gamma K_q}{(K_t \mu - K_q)^2}$$

[A.44]

This equation represents an implicit solution for the value of μ which minimizes the total cost, given the constraint upon t_{in}.

An example is worked out in Figure A-4. Note that as in the previous examples, optimization tends to reduce the quantity of fluid used and to increase the size of equipment employed. If no geothermal fluid were used (ζ = 1.0, ambient temperature water heated to 315°C by the heater), the process cost would be $297.88/hr, of which $294.47/hr would be due to the cost of fossil fuel. If the assumed cost figures are accurate, the geothermal system thus would generate significant savings.

CONVENTIONAL SYSTEM:



Parameters:

Parameter	Value	Parameter	Value
Γ	2.0	$t_{process,average}$	275°C
$t'_{hot,inlet}$	315°C	$t_{hot,exit}$	265°C
$\dot{m}_{hot,old}$	68,120 kg/hr	Capital cost	\$140,000
Capital recovery factor at 15%,20yrs	0.15976	Capital factor	75%
		Geothermal fluid unit cost	\$700/10^6 kg
		Fossil fuel unit cost	\$3.50/10^6 kJ

Computed variables:

$$\Delta t_{old} = 0.5\ (315 + 265) - 275 = 15°C$$

$$Q = \frac{68120}{3600}\ (4.1868)(315\text{-}265) = 3961.2\ kW$$

$$K_q = \frac{3961.2}{2(\frac{68120}{3600})(4.1868)} = 25°C$$

$$\gamma = \frac{15}{2.0+1} = 5.0°C$$

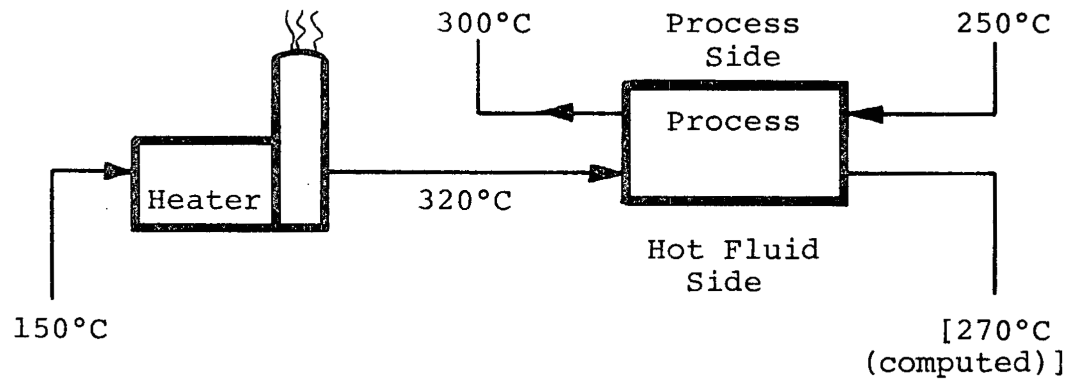
$$K_a = 140{,}000\ \frac{0.15976}{0.75(8760)} = \$3.404/hr$$

$$K_m = (700X10^{-6})(68120) = \$47.684/hr$$

FIGURE A-4 - EXAMPLE OPTIMIZATION OF TYPE 1 PROCESS WITH AUXILIARY FOSSIL FUEL (continued)

$$K_f = (3.5 \times 10^{-6})(3961.2 \times 3600) \quad = \$49.911/hr$$

GEOTHERMAL SYSTEM:



Parameters:

Geothermal fluid temperature t_{GT} = 150°C

Inlet temperature (assumed) t_{in} = 320°C

Computed variables:

$$K_t = 320-275 \qquad = 45°C$$

$$\zeta = \frac{320-150}{320-20} \qquad = 0.567$$

OPTIMIZATION:

From Eq. A.44,

$$\frac{47.684}{(3.404)(5.0)} + \frac{49.911(320-150)}{2(25)(3.404)(5.0)} = \frac{0.8(45)\mu^{0.2}+0.2(25)\mu^{-0.8}+2.0(25)}{(45\mu - 25)^2}$$

Solving by trial and error gives

$$\mu_{optimum} = 0.6146,$$

which yields

$$\phi_{optimum} = 4.02$$

$TC_{optimum}$ = \$147.29/hr, of which
\$13.70/hr is due to capital costs,
\$29.30/hr is due to fluid costs, and
\$104.29/hr is due to fossil fuel costs.

FIGURE A-4 - (concluded)

Process Type 2 - Condensation Heat Transfer

The optimization of this type of process with auxiliary fossil heat presents problems similar to those discussed in the last section concerning optimization without fossil heat. In addition, mathematical difficulties associated with the necessity of upgrading saturated vapor in pressure as well as in temperature require a more sophisticated analysis than that possible here.

Process Type 3 - Direct Fluid Injection

In those injection processes in which steam is injected and condensed in the reactor, a first-order optimization is not possible and the above comments apply. If single-phase fluid is injected, however, the analysis becomes slightly more tractable.

The governing optimization relations are Eqs. A.35 and A.36. The former can be expanded for this process type with the aid of Eqs. A.30 and A.40 as

$$\frac{\partial (TC)}{\partial \mu} = 0 = - \frac{BK_a K_q}{(T_{in}\mu - K_q)^2} + K_m + \frac{K_f}{2K_q}(t_{in} - t_{GT}). \qquad [A.45]$$

The latter can be expressed equivalently as a derivative of TC with respect to t_{in}, since t_{in}, T_{in}, and ζ are uniquely related by Eqs. A.29 and A.37. With this modification, the second optimization relation becomes

$$\frac{\partial(TC)}{\partial(t_{in})} = 0 = -\frac{BK_a\mu^2}{(T_{in}\mu - K_q)^2} + \frac{K_f}{2K_q}\mu \quad . \qquad [A.46]$$

To these two equations must be appended the constraint inequality A.28.

The unconstrained optimum values for μ and t_{in} can be found by the following procedure. Equations A.45 and A.46 are each manipulated to isolate $(T_{in}\mu - K_q)^2$; the results are equated and an expression found for μ alone as a function of t_{in}. Rearrangement of Eq. A.46 then yields a second equation for t_{in} in terms of μ which, upon substitution into the previous result, gives a single equation with μ as the sole variable:

$$\mu_{opt.,unconstrained} = \frac{2BK_aK_fK_q}{(K_fT_{GT} - 2K_mK_q)^2} \quad , \qquad [A.47]$$

where

$$T_{GT} = t_{GT} + 273.15 \quad .$$

The optimum value for t_{in} is then determined from Eq. A.46 as

$$t_{in,opt.,unconstrained} = \frac{K_q}{\mu} + \sqrt{\frac{2BK_aK_q}{K_f\mu}} - 273.15 \quad . \qquad [A.48]$$

Unfortunately, an example shows that the constraint inequality can be grossly violated: using the same assumptions as were employed in Fig. A-2, with the value of K_f taken from Fig. A-4,

$$\mu_{opt.,unconst.} = 0.0136 \text{ and}$$
$$t_{in,opt.,unconst.} = 2210°C .$$

From Eq. A.28, μ is constrained for this value of t_{in} to be no less than 0.0256, a condition clearly not met.

The following analysis demonstrates that the constrained optimum lies on the curve defined by the equality in the constraint expression A.28. The fact that the total process cost is minimized on the boundary of the feasible domain for μ and t_{in} can be established by showing that the first derivative of TC is non-negative as one moves away from the boundary. Both partial derivatives must be examined.

If the first derivative of TC with respect to μ is non-negative for all μ greater than or equal to μ_{bound}, where the latter is defined by the equality in Eq. A.28, the first half of the proposition can be confirmed. The derivative is given in Eq. A.45:

$$\frac{\partial(TC)}{\partial\mu} = -\frac{BK_aK_q}{(T_{in}\mu-K_q)^2} + K_m + \frac{K_f}{2K_q}(t_{in} - t_{GT}) \geq 0, \quad [A.49]$$

or rearranging,

$$\mu \geq \frac{K_q}{T_{in}} \left\{ 1 + \sqrt{\frac{2BK_a}{2K_mK_q + K_f(t_{in} - t_{GT})}} \right\} \quad . \qquad [A.50]$$

If μ_{bound} is greater than the critical value of μ defined by the right-hand side of this expression, the derivative must be non-negative for all μ_{bound}, thus satisfying Eq. A.28. Substitution of μ_{bound} (from A.28) for μ above then gives after some manipulation

$$\left(\frac{T_{in} - T_{p,out}}{T_{in} + T_{p,out}} \right)^2 - \frac{K_f}{2BK_a} (t_{in} - t_{GT}) - \frac{K_mK_q}{BK_a} \leq 0 \qquad [A.51]$$

where

$$T_{p,out} = t_{p,out} + 273.15 \quad .$$

If this inequality is satisfied, it will have been established that the minimum feasible value of TC with respect to μ occurs at μ_{bound}. Since the first term typically is of order 10^{-3}, while the second and third terms are each of order -1, the condition is met.

Similarly, the second part of the proposition can be established if the first derivative of TC with respect to t_{in} is non-negative for all t_{in} greater than or equal to $t_{in,bound}$, where the latter is defined by inverting Eq. A.28 and by assuming that the two sides are equal. From Eq. A.46, the derivative is

$$\frac{\partial(TC)}{\partial(t_{in})} = -\frac{BK_a\mu^2}{(T_{in}\mu - K_q)^2} + \frac{K_f}{2K_q}\mu \geq 0 \quad , \qquad [A.52]$$

or

$$t_{in} \geq \frac{K_q}{\mu} - 273.15 + \sqrt{\frac{2BK_aK_q}{K_f\mu}} \quad . \qquad [A.53]$$

If $t_{in,bound}$ is greater than this critical value of t_{in}, the derivative must be non-negative for all t_{in} in turn greater than $t_{in,bound}$, thus satisfying the constraint. Inversion of Eq. A.28 yields (using the equality)

$$t_{in,bound} = t_{p,out} + \frac{2K_q}{\mu} \quad , \qquad [A.54]$$

which, upon substitution above, gives after manipulation

$$T_{p,out}^2\,\mu^2 + (2T_{p,out}\,K_q - \frac{2BK_aK_q}{K_f})\,\mu + K_q^2 \geq 0 \quad . \qquad [A.55]$$

If this condition is met, it will have been proven that the minimum feasible value of TC with respect to t_{in} occurs at $t_{in,bound}$. Since the first and third terms are positive and the coefficient of μ in the second term is typically of order 10^4, the inequality is satisfied.

The minimum feasible value of TC therefore occurs on the constraint boundary. This reduces the problem to a single-variable optimization since t_{in} and μ are now uniquely related by the equality in Eq. A.28. Unfortunately, the total process cost is minimized on this boundary as μ approaches zero and t_{in} approaches infinity: substitution of Eq. A.28 into the equation for TC (Eq. A.34) and differentiation gives a result which, when set equal to zero, cannot be solved for real values of μ. As proved to be the case in the analysis of Process Type 1 above, an arbitrary limit must therefore be assumed on the value of either μ or t_{in}. If the limit is taken at $\mu = 0.5$ and the parameter values listed in Fig. A-2 are assumed to hold here, Eq. A.54 then yields a figure for t_{in} of 355°C. If t_{GT} is assumed equal to 150°C,

$$\phi = 0.974$$

$$\zeta = 0.612$$

$$\Psi = 2.05$$

TC = \$129.48/hr, of which

\$3.32/hr is due to capital costs

\$23.84/hr is due to fluid costs, and

\$102.32/hr is due to fossil fuel costs.

V. CONCLUSION

The foregoing analysis illustrates the difficulties associated with the optimization of unit processes which utilize geothermal fluid. In most cases, boundary solutions are obtained in which second-order considerations of factory space, material temperature limits, and required fluid flow rates control the solution.

FOOTNOTES

1. The proportionality of the heat transfer coefficient to the 0.8 power of the mass flow rate is a common feature of turbulent flow heat transfer correlations. See Rohsenow, W.M. and Choi, H.Y., *Heat, Mass, and Momentum Transfer*. Englewood Cliffs, N.J.: Prentice-Hall, Inc., 1961, pp.192-193.

2. Sparrow, E.M., Minkowycz, W.J., and Saddy, M., *Int. J. Heat Mass Transfer*, 10: 1829-1845 (1967). The expression in Eq. A.9 was found by using the method of least-squares to fit a power curve to the data given in the article for T_∞ = 212°F. The coefficient of determination for this fit, using data points at η = 0.005, 0.02, 0.05, and 0.1, was r^2 = 0.99986. The dependence of $f(\eta)$ on temperature was slight.

3. The Biot number is defined as hr_o/k, where h is the surface heat transfer coefficient, r_o a characteristic dimension (radius), and k the thermal conductivity of the substance. Rohsenow, *Op. Cit.*, p.115. If the Biot number is small, the rate at which heat is conducted throughout the body is sufficiently fast that the overall heat transfer rate is controlled by the resistance to heat flow at the surface, measured by h. The temperature gradient within the body is therefore small.

FOOTNOTES (Continued)

4. If $\mu_{optimum} > \mu_{bound}$ (where $\mu_{optimum}$ is defined in Eq. A.32 and μ_{bound} is defined by the equality in Eq. A.28), the solution for μ is clearly $\mu_{optimum}$. If $\mu_{optimum} < \mu_{bound}$, the solution must lie at the boundary of the feasible region delimited by μ_{bound}. The fact that TC is minimized by this boundary solution is guaranteed because the first derivative of TC with respect to μ is positive for all μ greater than $\mu_{optimum}$ and thus for all $\mu \geq$ bound $> \mu_{optimum}$.

5. The four partial derivatives are:

$$\frac{\partial \phi}{\partial \mu} = \gamma \left\{ \frac{-0.8\ K_t \mu^{0.2} - 0.2\ K_q \mu^{-0.8} - \Gamma K_q}{(K_t \mu - K_q)^2} \right\}$$

$$\frac{\partial \phi}{\partial \zeta} = \gamma \left\{ \frac{(-\mu^2 \Gamma - \mu^{1.2})(t_{GT} - t_{amb})}{(1-\zeta)^2 (K_t \mu - K_q)^2} \right\}$$

$$\frac{\partial \Psi}{\partial \mu} = \frac{\zeta (t_{GT} - t_{amb})}{2K_q (1-\zeta)}$$

$$\frac{\partial \Psi}{\partial \zeta} = \frac{\mu (t_{GT} - t_{amb})}{2K_q\ (1-\zeta)^2} .$$

APPENDIX B - PERCENTAGE DEPLETION FOR GEOTHERMAL ENERGY: AN ALTERNATIVE METHOD FOR CALCULATION OF GROSS INCOME

I. INTRODUCTION

While administrators and regulators strive to mold the world about them into a finite set of situations, each governed by a particular rule, new events obstinately resist such categorization. Innovations eventually force the introduction of new classifications into regulatory schemes, but in the interim these innovations must somehow be accomodated into the existing framework. The tax treatment of geothermal energy presents a continuing example of this problem.[1]

Section 613(a) of the Internal Revenue Code of 1954 provides, in part, that the allowance for depletion shall be a given percentage of gross income from the property.[2] However, prior to 1975, the Code omitted any reference to geothermal energy, the closest classification being oil and gas wells. The courts tried to categorize geothermal steam as a gas for depletion purposes in two early cases: Reich v. Commissioner and Rowan v. Commissioner.[3] In Reich, the taxpayer claimed percentage depletion on geothermal steam. Although geothermal fluid was nowhere mentioned in the Code, the court held that the steam was a "gas" within the meaning of the statute and thus qualified for a depletion allowance. However, as the Internal Revenue Service refused to acquiesce in the ruling, the classification issue remained unsettled.

In the Tax Reduction Act of 1975, Congress amended the Code to permit percentage depletion on any geothermal deposit determined to be a gas.[4] While the Act created an explicit category in the Code for geothermal steam, it still neglected hot water deposits, which constitute the overwhelming majority of geothermal resources. Thus it appeared that investors seeking to take percentage depletion on geothermal resources would run into hot water if the deposit did not contain dry steam.[5]

The long-awaited Energy Tax Act of 1978 substantially clarified matters by creating a new classification encompassing all types of geothermal deposits.[6] New Section 613(e) of the Code authorizes depletion allowances for any geothermal resource, and to identify the applicable percentage, prescribes use of a diminishing scale identical to that employed for certain oil and gas wells. While the new tax category for geothermal energy resolves the question of whether such resources qualify for the depletion allowance, it fails to address the issue of how gross income is to be computed. As we shall see, the present computational framework for gross income is inadequate to deal with nonelectric uses of geothermal energy.

II. THE CALCULATION OF PERCENTAGE DEPLETION ALLOWANCES

The deduction for percentage depletion is computed by multiplying gross income from the property by a statutory percentage. Although the Energy Tax Act of 1978 extends percentage depletion to geothermal deposits by creating a separate category, the Regulations continue to define gross income for only two cases: oil and gas, and "other minerals."[7] The problem, again, is to fit geothermal resources into the appropriate category.

The Oil and Gas Category

The history of tax treatment of geothermal deposits favors the gas classification. Both the Reich decision and the depletion provision contained in the Tax Reduction Act of 1975 explicitly associate geothermal steam with gas. In a different context, the Energy Tax Act of 1978 amends Section 263(c) of the Code to provide that the option to deduct intangible drilling costs shall extend to geothermal deposits (steam or hot water) "to the same extent and in the same manner as such expenses are deductible in the case of oil and gas wells."[8]

The Regulations governing percentage depletion for oil and gas employ two measures of gross income. The first involves income from an actual sale: Treasury Regulation§1.613-3(a) defines gross income for this category as "the amount for which the taxpayer sells the oil or gas in the immediate vicinity of the well." Frequently, however, the crude product is not sold immediately: it may be processed and refined prior to sale, or utilized by the manufacturing arm of an integrated field-developer and manufacturer. In this situation, the Regulations require use of the second measure of gross income: income from constructive sales based on a locally established "representative market or field price" for the crude product at the wellhead. The integrated developer-refiner or developer-manufacturer is considered for depletion purposes to be selling the crude product to himself; the price received by comparable non-integrated developers is thus attributed to him.[9]

It is at this point that difficulties arise in the tax treatment of geothermal energy. To appreciate their nature, one must distinguish between the two major uses of geothermal energy: electric-power and direct-use applications.

In those situations in which geothermal resources are employed to generate electricity, the field developer rarely operates the generating facility. The developer seeks to avoid the regulation concomitant with utility status, while the utility is either prohibited from engaging in such development activities or disinclined to enter a risky area in which it possesses no expertise. The arm's length sale of fluid from developer to utility creates an easily ascertainable sale price for the determination of gross income. Percentage depletion may then be calculated using this amount. Since electric-power applications have provoked most of the litigation and remain the most significant form of geothermal installation, utilization of the actual sales definition of gross income has thus far proved acceptable.

Frequently resource temperatures are too low to generate electricity economically. This lower-quality geothermal fluid can still be usefully employed in direct-use applications: the heat contained in the fluid is simply transferred to an industrial process or utilized for space heating. Here the final user of the energy often drills the wells and develops the field; no actual sale price exists, as the developer is integrated with the user.

The Regulations then indicate that a representative market price should be used to determine gross income. Unfortunately, no representative market exists at present for low-temperature geothermal fluid. The only sales involve the higher-temperature steam used for electric-power applications, a situation clearly not comparable and thus not "representative."[10] Moreover, even the existence of numerous sales of fluid for direct-use applications would not suffice to establish a representative market. Reservoirs of geothermal fluid differ greatly in temperature, pressure, required development costs, and other factors. The fluid resource being sold in a given location would not be comparable to that sold in another.

If, however, one considered the commodity being sold in the constructive sale to be energy rather than geothermal fluid, a representative price might be found in the markets for fossil fuels. Several writers have proposed a representative market price method in which geothermal energy is priced by comparison with the cost of an equivalent quantity of energy derived from fossil fuels, for which established markets exist.[11] This proposal avoids the pitfalls of the representative market price scheme based on geothermal fluid as the commodity. However, a unit of energy delivered by geothermal fluid and one given off by the combustion of fossil fuel are not truly equivalent: since fossil fuels burn at temperatures far exceeding those of geothermal fluid, they can provide energy to higher temperature processes than would be possible with geothermal energy sources. In thermodynamics, this notion of "quality" of energy or of the ability of energy to perform useful work is termed "availability." The more versatile fossil fuels, which possess a higher "availability," should thus command a higher price per unit of energy than should geothermal resources.

Unfortunately, even were geothermal fluid to be priced comparably to fossil fuels on an availability basis, a method sufficiently esoteric to encounter opposition from the I.R.S., economic considerations would militate against acceptance of any representative market price method based on fossil fuel prices. In tying the price of geothermal energy for tax purposes to that of coal, for example, one must assume that a geothermal energy market, were one to exist, would be subject to economic and political pressures similar to those experienced by the market for coal. However, there is little reason to believe that the market for one energy source is influenced by the same forces that affect the market for another; the oil market is much more susceptible to international pressures than is the coal market.

The "Other Minerals" Category

Gross income thus cannot be calculated for direct-use applications by either the actual sale price or the representative market price methods listed in the oil and gas category. Unfortunately, there is no case law concerning percentage depletion for direct-use geothermal applications, and the Regulations in the oil and gas category do not offer further guidance.

There is some justification for turning at this point to the Regulations governing percentage depletion for "other minerals." The Court of Claims has indicated that additional methods (such as those listed in the "other minerals" category) could be applied to oil and gas when, as in the present case, the above methods proved inapplicable.[12] This decision seems to imply that use of the additional methods need not be confined to cases concerning "other minerals." Alternatively, there are some grounds for arguing that geothermal resources should be classified as minerals *ab initio*. One state classifies such resources as minerals.[13] Furthermore, the courts have held that reservations of mineral rights either by the Federal Government or by private parties encompass geothermal resources.[14]

Section 1.613-4, concerning "other minerals," requires use of the actual sale price method or, if that is not possible, the representative market price method.[15] Both of these were described and rejected above. Unlike the regulations for oil and gas, however, this provision continues, stating that if a representative price cannot be ascertained, gross income should be imputed to the developer in proportion to the costs incurred to extract the mineral. Under this cost-based method, called the proportionate profits method, gross sales (actual or constructive) from the first marketable product made from the mineral are multiplied by a fraction the numerator of which is the total annual mining cost attributable to that product, and the denominator of which is the total annual cost (mining and non-mining) attributable to that product.[16] The justification for this cost-based approach lies in the principle that "each dollar of the total costs paid or incurred to produce, sell, and transport the first marketable product . . . . . earns the same percentage of profit."[17]

While the principle appears to be reasonable, it is important to note that only annual costs are considered in the proportionate profits method: initial capital costs are neglected. This formulation is appropriate for traditional mining enterprises, in which annual costs for the extraction of minerals dominate the initial costs. In the case of direct-use geothermal applications, however, methods based upon annual costs such as the proportionate profits scheme are unsuitable: annual costs, which consist primarily of maintenance charges, are minor in comparison with the capital investment required. The profits attributable to the use of geothermal fluid constitute a return on initial rather than annual costs. As a result, the proportionate profits method also fails to yield reasonable estimates of gross income for depletion purposes.

All is not lost, however: the Regulations permit the taxpayer to request (and hopefully obtain) a determination by the I.R.S. that an alternative method of computation which he proposes is more appropriate than the proportionate profits scheme.[18] According to the Regulations, the standard for appropriateness is whether, "under the particular facts and circumstances, the [proportionate profits method] consistently fail[s] to clearly reflect gross income from mining, and the alternative method being considered more clearly reflects gross income from mining...."[19] The burden of proof rests upon the taxpayer. Three possible alternatives are specifically suggested in the Regulations: a method based upon representative schedules, a scheme using prices outside the taxpayer's market, and a method utilizing a rate of return on the relevant investment.[20]

The first two alternatives are merely variations o the representative market price theme. The representative schedule rule permits use of a pricing formula to determine crude mineral prices for integrated producers if such a formula is in general use among unintegrated producers. Again the lack of a representative market for low-temperature geothermal fluid precludes adoption of this procedure. A method using prices outside the taxpayer's local market for the same substance is unfeasible for similar reasons. Unfortunately, the return on investment method, the only cost-based method other than that of proportionate profits, is reserved for future regulation, and no explanation of the particular scheme envisioned is given.

III. THE RATE OF RETURN ON INVESTMENT METHOD

For direct-use geothermal applications, the procedures listed in existing regulations based upon actual sales prices, representative market prices, or annual costs do not provide an appropriate method for calculating gross income from the property. The absence of a market for geothermal fluid and the lack of correlation between annual expenses and the true cost of extracting fluid comprise the principal impediments to such schemes.

Any alternative method of calculation for direct-use applications suggested by the taxpayer must address these difficulties. First, the method should relate gross income most closely to the initial investment, since geothermal wells require small expenses during production but large expenditures during development. Second, such a cost-based method must estimate the gross income which a hypothetical unintegrated producer would derive from the sale of his fluid, so that a gross income equal to this amount may be imputed to the integrated geothermal developer.

As will be shown, the return on investment scheme is such a method.[21] In its simplest form, gross income as determined by this procedure depends upon three factors: the rate base, an appropriate rate of return, and operating expenses. The principle involved is straightforward: an investor expects to earn a minimum net income on his investment. If he cannot obtain a price for his goods sufficient to cover all operating expenses and still leave the required profit, he will not invest at all. Thus by multiplying the geothermal investment, or rate base, by the proper rate of return, one may estimate the profit required by any geothermal developer, in particular an unintegrated producer. To compute the value of gross income which yields this profit one need only add to the profit a sum representating operating expenses and all taxes. Each of the three elements of a return on investment scheme will be examined in turn, with the emphasis on applying the method to the present situation.[22]

The rate base is essentially equivalent to the capital investment in the project. By explicitly including the initial investment in computing gross income, the return on investment method overcomes the difficulties which plague the proportionate profits method.

Two approaches are possible for evaluating the rate base for geothermal property. The first and theoretically more correct approach employs the adjusted basis provided in Section 1011 of the Code, with the addition of expensed intangible drilling costs and the subtraction of tax credits taken at the time of investment. Since this measure of investment represents the total cash outlay upon which an investor in an unintegrated firm expects a return, it is the appropriate figure to utilize in estimating the gross income which constitutes that return. That this rate base contains expenditures which fall into depreciable accounts or which may be expensed for tax purposes should cause no alarm; the ultimate goal is to ascertain the dollar return an investor would require on his investment.

The second approach defines the rate base as equal to the basis for cost depletion purposes determined in Treasury Regulation §1.612-1.[23] This approach takes cognizance of the reluctance of regulators to adopt new philosophies and methods. As the Internal Revenue Service has already sanctioned the definition of cost employed for cost depletion, it is likely that such a definition would prove more acceptable. Moreover, omitting depreciable investment and expensed intangible drilling costs from this basis will result in an understatement of the gross income required and thus of the depletion deduction allowable, an outcome of dubious economic merit but one easily defensible before the I.R.S.[24]

The definition of an appropriate rate of return is to some extent subjective, and thus finding a proper rate for geothermal investments may prove problematical. One approach involves a comparable earnings standard, which allows the investor returns similar to those earned at the same time and in the same part of the country on investments attended by corresponding risks and uncertainties.[25] Another approach provides that a proper rate of return should "enable the company to operate successfully, to maintain its financial integrity, to attract capital and to compensate its investors for the risks assumed . . . ."[26]

The most tractable approach to determining rates of return for geothermal applications is based upon the comparable earnings standard. Companies engaged in oil and gas drilling experience types of risk similar to those encountered by geothermal producers, and thus rates earned by such companies could be employed in this context without excessive error.[27]

Operating expenses constitute the remaining element of the basic return on investment model. One list of operating expenses already used in the calculation of the depletion deduction appears in Treasury Regulation §1.613-5, in which the enumerated expenses are subtracted from gross income in order to compute taxable income for the purposes of a limitation on the depletion deduction. These expenses may be employed in the return on investment method. Since the product of the rate base and the rate of return discussed above equals net income after taxes, not only operating expenses but also federal income tax liability must be added to net income to arrive at gross income.[28]

Two elaborations upon the basic "return on investment" model are frequently employed. The first concerns inflation, which can quickly erode the real return earned by the investor. The second involves the time value of money. While one court recently characterized a discounted cash flow analysis which includes this factor as an "esoteric costing methodology which counsel could scarcely describe in their briefs or at oral argument," the principle of discounting cash flows is both long established and well accepted.[29]

The return on investment model presented here constitutes an alternative method of calculating gross income for the purposes of the depletion allowance. It is true that selection of an appropriate rate of return still depends upon considerations that are somewhat subjective. However, in the case of direct-use geothermal applications, the return on investment method is the only suitable method mentioned in the Regulations. Since the method does not require an actual sale of the extracted product, it can be applied to integrated resource developers. The method can be used for products lacking representative markets because it is not dependent on market price comparisons. Furthermore, by relating gross income to initial costs, it is more appropriate than methods based upon annual costs (such as the proportionate profits method) for those products which require large capital investments. Finally, the method suggested here fits well into the present structure of the Code by utilizing concepts such as cost depletion basis and allowable deductions which are already defined on the Code.

IV. CONCLUSION

While the Energy Tax Act of 1978 has explicitly extended the percentage depletion deduction to geothermal resources, it neglects the issue of how to compute gross income for depletion purposes. Three generic methods of calculating gross income are given in the Regulations: income from actual sales, income from constructive sales based on a representative market price, and income imputed to the taxpayer in proportion to the annual costs incurred for resource extraction.

Since direct-use geothermal applications frequently involve an integrated field developer-fluid user, no sale is made and the first method fails. The second method succumbs to the lack of a representative market for geothermal fluid or energy. Finally, the last method yields an inappropriate estimate of gross income because the annual costs of extracting geothermal fluid are minor in comparison to the initial capital investment.

One additional method, based upon the return expected on the capital investment, is listed in the Regulations although no details are given. The present paper expands upon this suggestion to offer a detailed alternative method of calculating gross income. Gross income as determined by this method depends upon three factors: the rate base, a rate of return, and operating expenses. To integrate the method into the present framework of the Code, the definitions of cost depletion basis and allowable expenses given in the Code are adopted for the rate base and operating expenses respectively. By multiplying the geothermal investment (rate base) by the rate of return, the net income required by the developer may be estimated. If operating expenses and taxes are added to this figure, the gross income which yields this net income can be found. The method is thus independent of the need for either an actual sale or a representative market. Moreover, since it explicitly includes the capital investment, it avoids the pitfalls of methods based solely on annual costs.

The rate of return method presented here offers some respite for the taxpayer who can justify it as an alternative method of calculation. As with all regulatory procedures, its efficiency and durability must await the test of innovations to come.

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FOOTNOTES

1. For a non-technical overview of geothermal energy resources, see Million, "The Application of Depletion to Geothermal Resources," 9 U. Mich. J. L. Ref. 233 (1976).

2. The depletion deduction is actually the larger of the amounts figured for cost depletion and percentage depletion. In addition, the deduction must not exceed 50% of the taxpayer's taxable income, computed without allowance for depletion. Treas. Reg. §1.613-1. Finally, excess depletion is a tax preference item. I.R.C. §57(a)(8).

3. Arthur E. Reich v. Commissioner of Internal Revenue, 52 T.C. 700 (1969), aff'd 454 F.2nd 1157 (9th Cir. 1972); George D. Rowan et al. v. Commissioner of Internal Revenue, 28 T.C.M. 797 (1969), aff'd 454 F.2d 1157 (9th Cir. 1972). Both Reich and Rowan were involved in drilling at the Geysers field in California, now the largest geothermal electric power installation in the world. The deduction of intangible drilling costs by both taxpayers was also upheld by the courts.

4. Tax Reduction Act of 1975, Pub. L. No. 94-12, 89 Stat. 26, creating I.R.C. §613A(b)(1)(C). Superseded by provisions of the Energy Tax Act of 1978, Pub. L. No. 95-618, 92 Stat. 3174.

5. In the first case involving hot water wells rather than steam, the court denied a deduction for intangible drilling costs on the grounds that only steam qualified. Miller v. U.S., 78-1 U.S.T.C. ¶9127 (D.C.C.D. Cal. 1977).

   The applicability of depletion allowances to geothermal resources prior to the Energy Tax Act of 1978 is discussed in Million, supra, and Maxfield, "Income Taxation of Geothermal Resources," 13 Land Water L. Rev. 217 (1977).

6. Energy Tax Act of 1978, Pub. L. No. 95-618, 92 Stat. 3174. The provisions of this Act relating to geothermal energy are described in Eisenstat, "Geothermal Taxation: Impact of Energy Tax Act of 1978," 27 Oil & Gas Tax Q. 273 (1979).

7. Treas. Regs. §§1.613-3(a) and 1.613-4 respectively. The Internal Revenue Service has not yet begun active consideration of regulations governing percentage depletion for geothermal energy. [Personal communication (unofficial) with Mr. Max Riley, Engineering and Valuation Branch, July 10, 1979.]

8. I.R.C. §263(c) as amended by Energy Tax Act of 1978, Pub. L. No. 95-618, §402(a)(1), 92 Stat. 3201. For a more detailed analysis of this question, see Million, _supra_. See also the comments to which notes 12-14, _infra_, are attached.

9. The principle that an integrated developer should employ a price representative of unintegrated developers was firmly established in _U.S. v. Cannelton Sewer Pipe Co._: "As we see it, the miner-manufacturer is but selling to himself the crude mineral that he mines, insofar as the depletion allowance is concerned." 364 U.S. 76, 87 (1960).

10. See Dutcher, J. L. and Moir, L. H., "Geothermal Steam Pricing at the Geysers, Lake and Sonoma Counties, California," _Eleventh Intersociety Energy Conversion Engineering Conference Proceedings_, Vol. I, pp. 786-789.

    While representative prices for geothermal fluid of high temperature conceivably could be adjusted to yield an estimated price for a given low temperature resource, it is unlikely that such an estimated price would be acceptable to the I.R.S. See the discussion _infra_ and Treas. Reg. §1.613-4(c)(4).

11. Dolan, W. M., "Considerations for the Pricing of Geothermal Energy," and Greider, Bob, "Pricing of Geothermal Energy," in _Proceedings: EPRI Annual Geothermal Program Project Review and Workshop_, Kah-nee-ta, Warm Springs, Oregon, July 25-28, 1977. Report ER-660-SR.

    The equivalent energy pricing method proposed in these articles is suggested for contractual purposes between non-integrated developers and users. In tying the price of geothermal energy to that of fossil fuel, the user can guarantee that geothermal energy will always be less expensive than the alternatives, while the developer can take advantage of increases in price of the alternative to his product.

Since the Treasury Regulations do not explicitly allow use of this method for depletion purposes, the taxpayer would have to petition the I.R.S. as discussed in footnote 18 below.

12. Panhandle Eastern Pipe Line Co. v. U.S., 408 F.2d 690 (Ct.Cl.1969). The taxpayer must use "a 'representative market or field price,' if an acceptable price of such nature can be established. Neither the court's decision in [Hugoton Production Co. v. U.S., 349 F.2d 418 (Ct. Cl. 1965)] nor the regulation requires the impossible, i.e. the use of a price that cannot be determined representative, or as precluding us from applying some other formula that produces a fair result." 408 F.2d at 718.

13. Hawaii Rev. Stat. §182-1(1). Idaho, Montana, and Washington declare geothermal resources to be sui generis (1972 Idaho Sess. Laws 751; Mont. Rev. Code §81-2602(1) (Supp. 1977); Wash. Rev. Code Ann. §79.76.040 (Supp. 1978)). Utah and Wyoming do not define geothermal resources, but regulate them under water law statutes (Utah Code Ann. §73-1-20 (Supp. 1979); Wyo. Stat. Ann. §41-3-901).

14. Geothermal Kinetics, Inc. v. Union Oil Co. of California, 75 Ca.App.3d 56, 141 Cal. Rptr. 879 (1977); U.S. v. Union Oil Co. of California, 549 F.2d 1271 (9th Cir. 1977), cert. den. 434 U.S. 930, reh. den. 435 U.S. 911.

15. Sale price method, Treas. Reg. §1.613-4(b); Representative market or field price method, §1.613-4(c).

16. Treas. Regs. §1.613-4(d)(1) and §1.613-4(d)(4)(ii).

17. Treas. Reg. §1.613-4(d)(4)(i).

18. In order to utilize an alternative methodology for computing gross income, the taxpayer must request permission from the I.R.S. to do so pursuant to Treas. Reg. §1.613-4(d)(1)(ii)(d). The procedures governing this application appear in I.R.S. Rev. Proc. 74-43, 74-2 C.B. 496.

19. Treas. Reg. §1.613-4(d)(1)(ii)(c).

20. Treas. Regs. §1.613-4(d)(1)(ii)(e) and §1.613-4(d)(5), (6), and (7).

21. The concept of fixing prices based on a return on investment has frequently come under theoretical attack. A particularly cogent critique by Justice Jackson in an opinion in Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591, 628 (1944) argued that rate of return methods were suitable for utilities which provide services primarily through investment (e.g. streetcar companies laying track and purchasing cars). In drilling for natural gas (or geothermal fluid), however, one producer could easily spend five times the amount another invests to obtain the same quantity of gas, a situation hardly justifying the former being allowed to charge five times as much for his gas. "The service one renders to society in the gas business is measured by what he gets out of the ground, not by what he puts into it, and there is little more relation between the investment and the results than in a game of poker." Hope, supra, at 649.

    Yet few workable alternatives exist, especially for geothermal applications for which the notion of mineral replacement value is difficult if not impossible to implement. In addition, methods based on historical cost and rates of return are easier for regulatory authorities to administer than schemes involving either present or future valuation. "Administrative expedience, the pursuit of the achievable rather than the perfect, provides a reasoned basis for . . . judgment." Tenneco Oil Co. et al. v. Federal Energy Regulatory Commission, 571 F.2d 834, 841 (5th Cir. 1978), cert. dis. 439 U.S. 801.

22. The actual method of calculation proposed by this paper is set out algebraically in Appendix II.

23. The principal differences between this basis and the basis considered above are that (1) the cost depletion basis excludes amounts recoverable through depreciation deductions, (2) it excludes the residual value of land and improvements, and (3) it excludes intangible drilling costs. Treas. Regs. §1.612-1(b)(1) and §1.1016-2(a).

24. The underestimation of gross income inherent in using the cost depletion basis is to some extent offset by inclusion in the basis of that portion of the cost which is recovered through the investment tax credit.

25. Southern Louisiana Area Rate Cases v. F.P.C., 428 F.2d 407, reh. 444 F.2d 125, cert. den. 400 U.S. 950; In re Permian Basin Area Rate Cases, 390 U.S. 747, 806 (1968), reh. den. 392 U.S. 917; F.P.C. v. Hope Natural Gas Co., supra, at 605.

26. F.P.C. v. Hope Natural Gas Co., supra, at 605. See also Tenneco Oil Co. v. F.E.R.C., supra, at 840.

27. Note that an approach based upon the weighted cost of capital for the firm fails for the individual, as opposed to corporate, taxpayers who are frequently involved in direct-use applications. In any case, the risks attending the rest of the firm's activities need bear no relationship to those involved in production of geothermal fluid, and thus such an approach would fail the "comparable earnings" test discussed previously.

    Methods based upon returns earned by drilling companies engaged in geothermal exploration will founder upon the same obstacles encountered in the search for representative market prices: the absence of an identifiable market or of similar firms engaged in geothermal drilling.

28. The procedure for computing this allowance is set out in Appendix II.

29. Shell Oil Co. et al. v. Federal Power Commission, In re National Rate Cases for New Gas, 520 F.2d 1061, 1080 (5th Cir. 1975), cert. den. 426 U.S. 941. This case upheld F.P.C. Opinion 699-H, 52 F.P.C. 1604 (1974), which employed discounted cash flow methodologies. For a succinct description of the fundamental assumptions involved, see R.N. Anthony and J.S. Reece, Management Accounting. Fifth Edition. Homewood, IL: Richard Irwin, Inc., 1975, Chapter 19.

    The procedures used to include inflation and the time value of money are set out in Appendix I.

APPENDIX I - THE INCORPORATION OF DISCOUNTING AND INFLATION IN THE METHODOLOGY

The fundamental premise of the discounted cash flow methodology is that the net present value of all cash flows must equal zero at the required rate of return. R.N. Anthony and J.S. Reece, Management Accounting, supra. If for simplicity of method it is assumed that all investment is made in year zero, and that the net income to be received by the investor is constant from year one to year n, then the following relation must be satisfied:

$$I = Ar + Ar^2 + Ar^3 + \ldots + Ar^n ,$$

where

I = initial investment in the project
A = constant annual net income to the investor
r = present value of one dollar received one year from now, equal to $1/(1+i_{real})$, where i_{real} is the required rate of return in real terms.

It can be shown that the above equation is equivalent to:

$$A = I \left[\frac{r - 1}{r^{n+1} - r} \right] ,$$

thus determining the requisite value of net income once the initial investment, project lifetime, and required rate of return are established.

Two procedures can be used to incorporate the effects of inflation. In the first, an estimated future rate of inflation is used to determine net income in constant dollars, which is then adjusted year by year by employing an appropriate price index to find net income in current dollars. Alternatively, net income as found above in constant dollars can be inflated from year to year by the inflation rate estimated at project start. The latter method possesses the advantage of simplicity and definiteness. In either case, inflation can be accounted for simply by redefining r in the equation above:

$$r = \left[\frac{1 + e}{1 + i_{nom}} \right]$$

where

e = estimated future inflation rate
i_{nom} = required rate of return in nominal terms

The annual net income needed to yield the proper rate of return is then given in constant year-zero dollars by A in the equation above. To convert to current year m dollars, one must multiply A by $(1+e)^m$, represent m years of inflation.

APPENDIX II - CALCULATION OF GROSS INCOME BY THE PROPOSED RETURN ON INVESTMENT METHOD

The basic relation between gross income and net income can be represented by the following equation:

$$A = (G - E)(1 - t) \quad ,$$

where

A = net income
G = gross income
E = operating expenses, including state taxes
t = federal income tax rate.

Rearranging this equation to isolate gross income yields

$$G = \frac{A}{(1 - t)} + E \quad .$$

Note that the allowance for federal taxes mentioned previously is included in arriving at gross income. Inflation and discounting of cash flows are incorporated by substituting for A in the expression above the relation developed in Appendix I:

$$G = I \left\{ \frac{r - 1}{(r^{n+1} - r)(1 - t)} \right\} (1 + e)^m + E \quad ,$$

where

$r = (1 + e)/(1 + i_{nom})$

e = estimated future inflation rate, in decimal form

i_{nom} = required rate of return in nominal terms, decimal

n = estimated production lifetime of the geothermal field

m = number of years from start of production to present, counting the first year of production as year one

t = federal income tax rate, in decimal form

I = cost depletion basis in the property at the start of production, Treas. Reg. §1.612.1

E = operating expenses for the current year as defined in Treas. Reg. §1.613-5, in current dollars

G = gross income in current dollars.

The last equation can now be employed to determine gross income from the property for direct-use geothermal applications.

APPENDIX C - THERMODYNAMIC PROPERTIES OF PURE AND SALINE (GEOTHERMAL) WATER

A. INTRODUCTION

In order to evaluate the performance of proposed processes utilizing geothermal energy, it is essential to determine the thermodynamic properties of fluid streams at various points in the system. The method described on the following pages ascertains the values of these properties for either pure water or salt solutions, correlating temperature, pressure, enthalpy, and entropy in the liquid, two-phase, and vapor regions.

The corresponding FORTRAN computer formulation is coded in one subroutine and twenty-six function subprograms, sixteen of which represent correlations of the properties of pure water. The subroutine chooses the appropriate correlations, validates input data, and embodies a large fraction of the salt solution algorithms. Including nonexecutable comment lines, the entire formulation requires less than 910 lines of code.

B. ALGORITHMS FOR PURE WATER

1. Correlations and algorithms

Since property values are frequently needed in process energy calculations, a major consideration in the design of property correlations is that of speed. To avoid the time-consuming iteration required by current computer codes, separate correlations have been developed for each combination of independent and dependent variables:

Liquid -	$t(p,h)$	$h(p,s)$
	$s(p,h)$	$h(p,t)$
Two-phase -	$h_f(p)$	$s_f(p)$
	$h_g(p)$	$s_g(p)$
	$t(p)$	$p(t)$
	$p(h_f)$	$p(h_g)$
Vapor -	$t(p,h)$	$h(p,s)$
	$s(p,h)$	$h(p,t)$.

The correlation equations themselves are expressed in terms of dimensionless reduced variables (i.e. P/P_c, $T_{abs}/T_{abs,c}$, h/h_c, and s/s_c, where c indicates values at the critical point). The subprograms, however, accept and return data in metric units (bars, °C, J/g, and J/g-K).

Polynomial relations are employed in all but one of the correlation equations. (For reasons of accuracy, the correlation giving saturation pressure as a function of temperature has the form $p = c_1 + c_2/T + c_3 \ln T + c_4 T$.) Unfortunately, the use of polynomials of high degree results in unacceptably long computation times, while lower degree polynomials suffer from inaccuracy if the entire domain of interest is considered as a whole. The scheme adopted here avoids these difficulties by dividing the domain of each independent variable into sections. A parabola is then fit to the endpoints and an inner point of each section. (The vapor phase correlations are split at 4.2 bars and 235°C; the liquid phase correlations are divided in temperature only at 160°C; the saturation line correlations are split at 2.8 and 6.35 bars except for the relations $h_g(p)$, $s_g(p)$, and $p(t)$, which remain unbroken.)

The underlying data for the correlations were taken from Reference 1.

In choosing the appropriate correlations when pressure and temperature constitute the given input data, the main subroutine considers fluid to be two-phase if its temperature differs by no more than one degree Celsius from the saturation temperature associated with the fluid pressure. The property values returned in this case correspond to saturated vapor because pressure and temperature are not independent variables within the two-phase region.

2. Error limits

The graphs presented on the following sixteen pages illustrate the errors inherent in the correlation equations. The computer program writes a warning message if the values of independent variables passed to the correlations fall outside the domain within which errors are less than one percent.

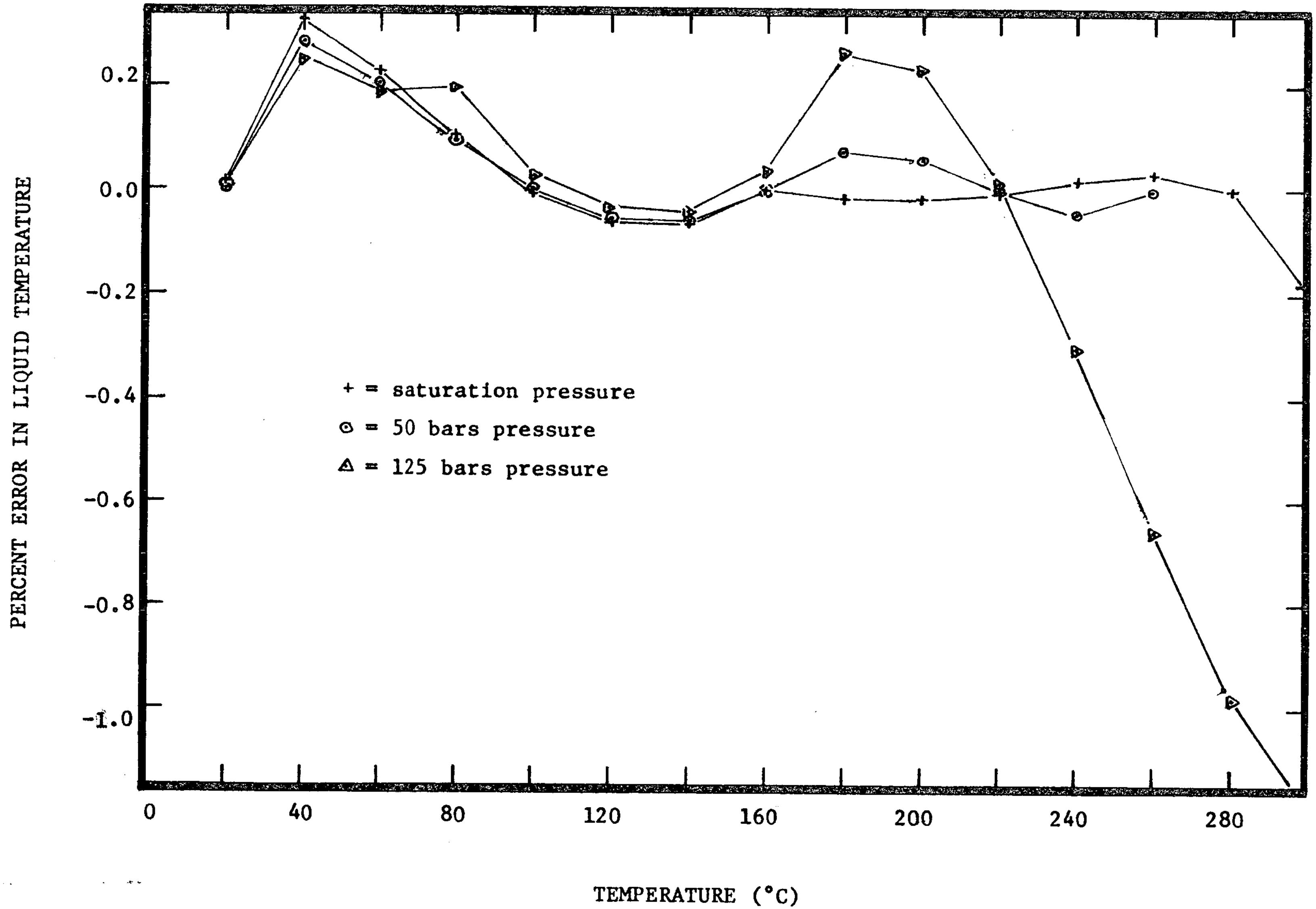


FIGURE C-1 - ERRORS IN CORRELATION TLIQ (P,H)

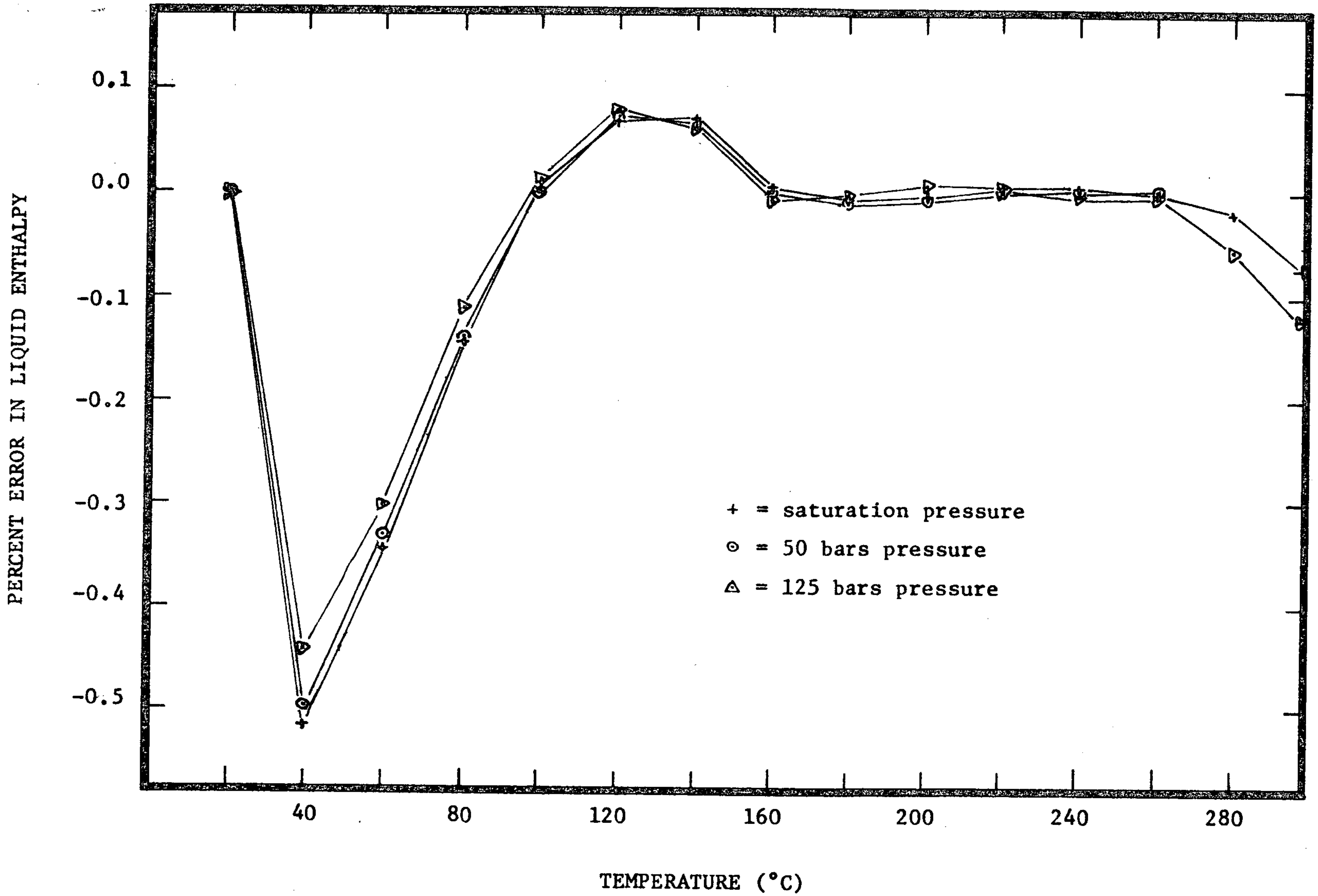


FIGURE C-2 - ERRORS IN CORRELATION HLIQ (P,S)

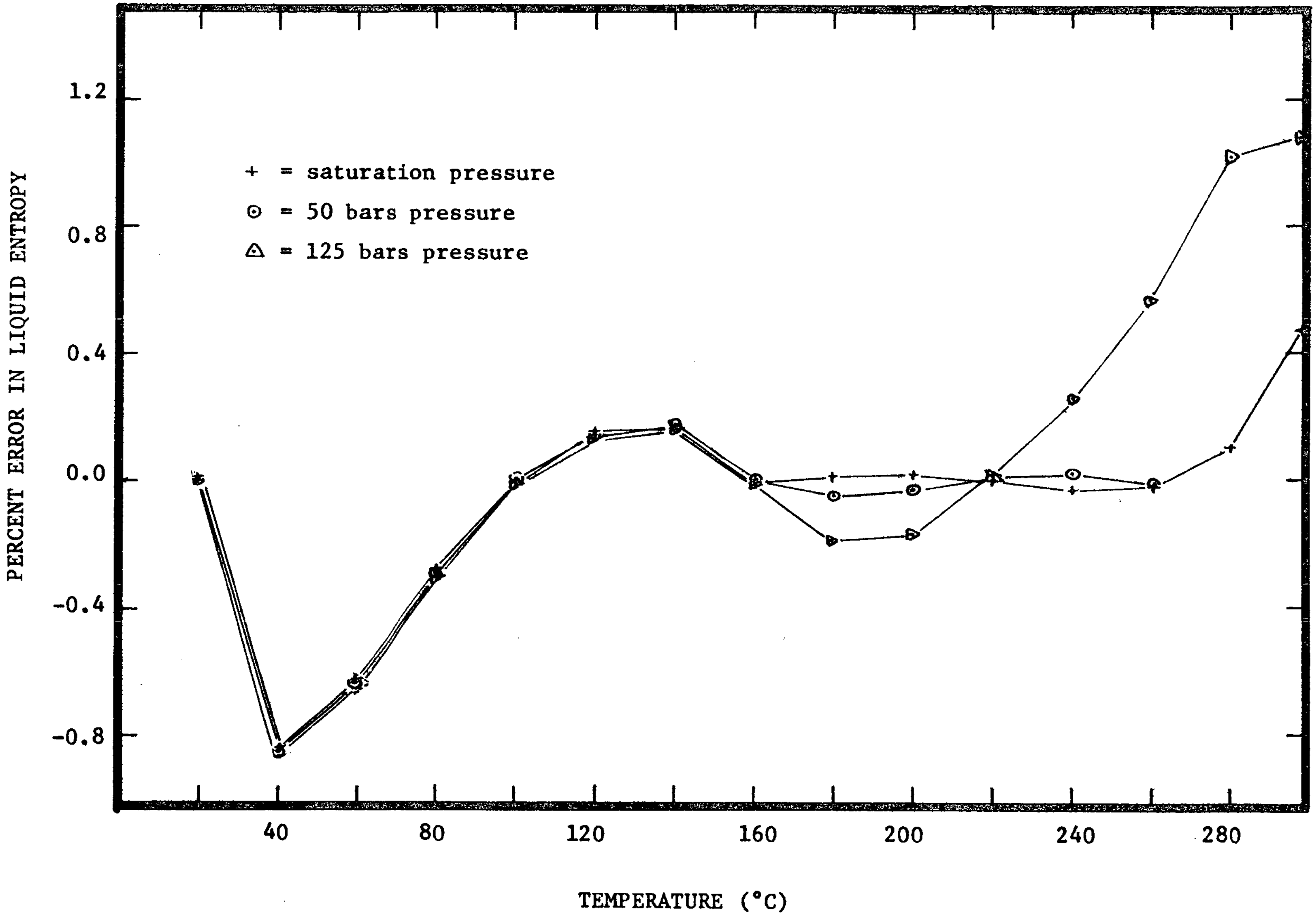


FIGURE C-3 - ERRORS IN CORRELATION SLIQ (P,H)

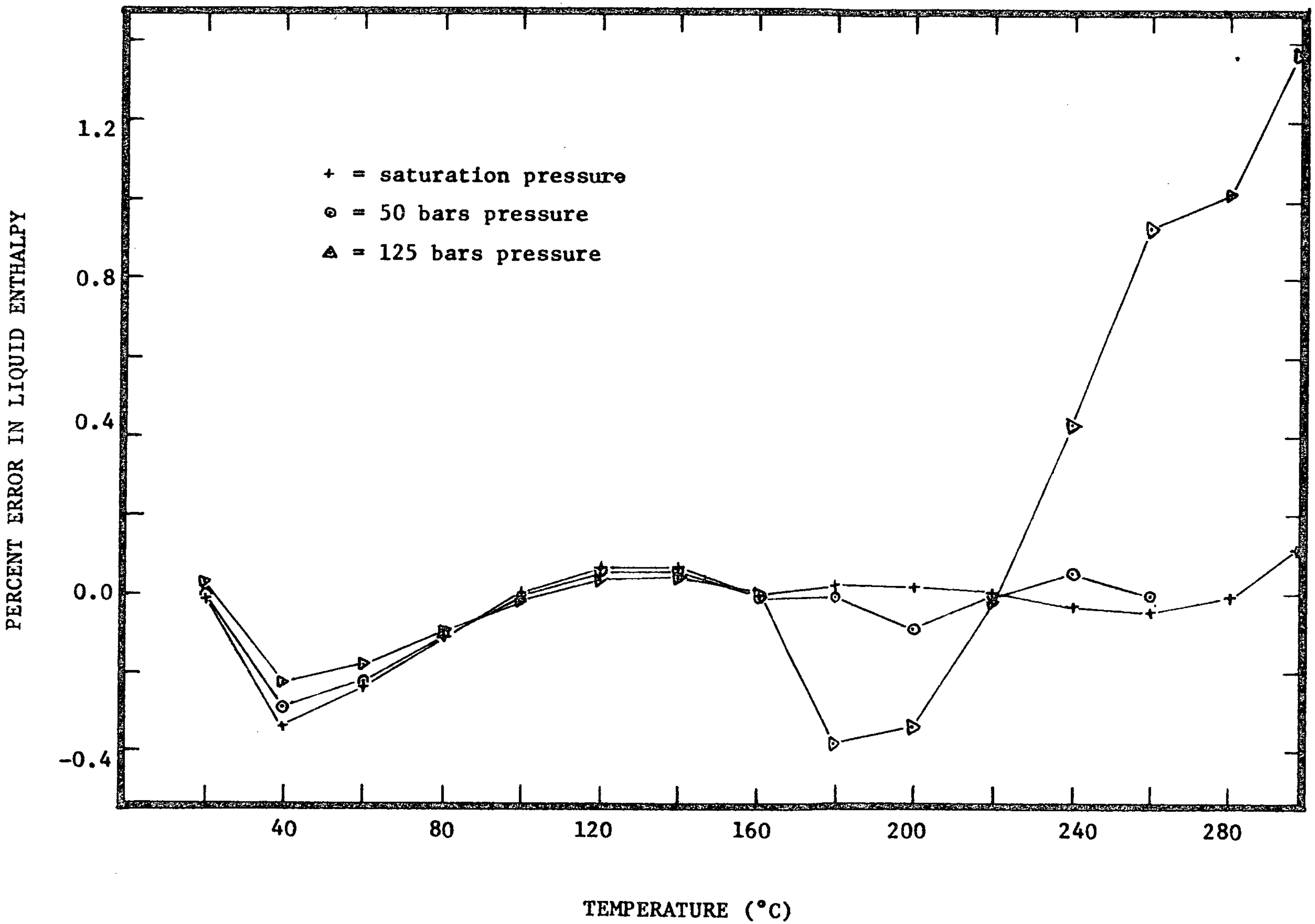


FIGURE C-4 - ERRORS IN CORRELATION HLPT (P,T)

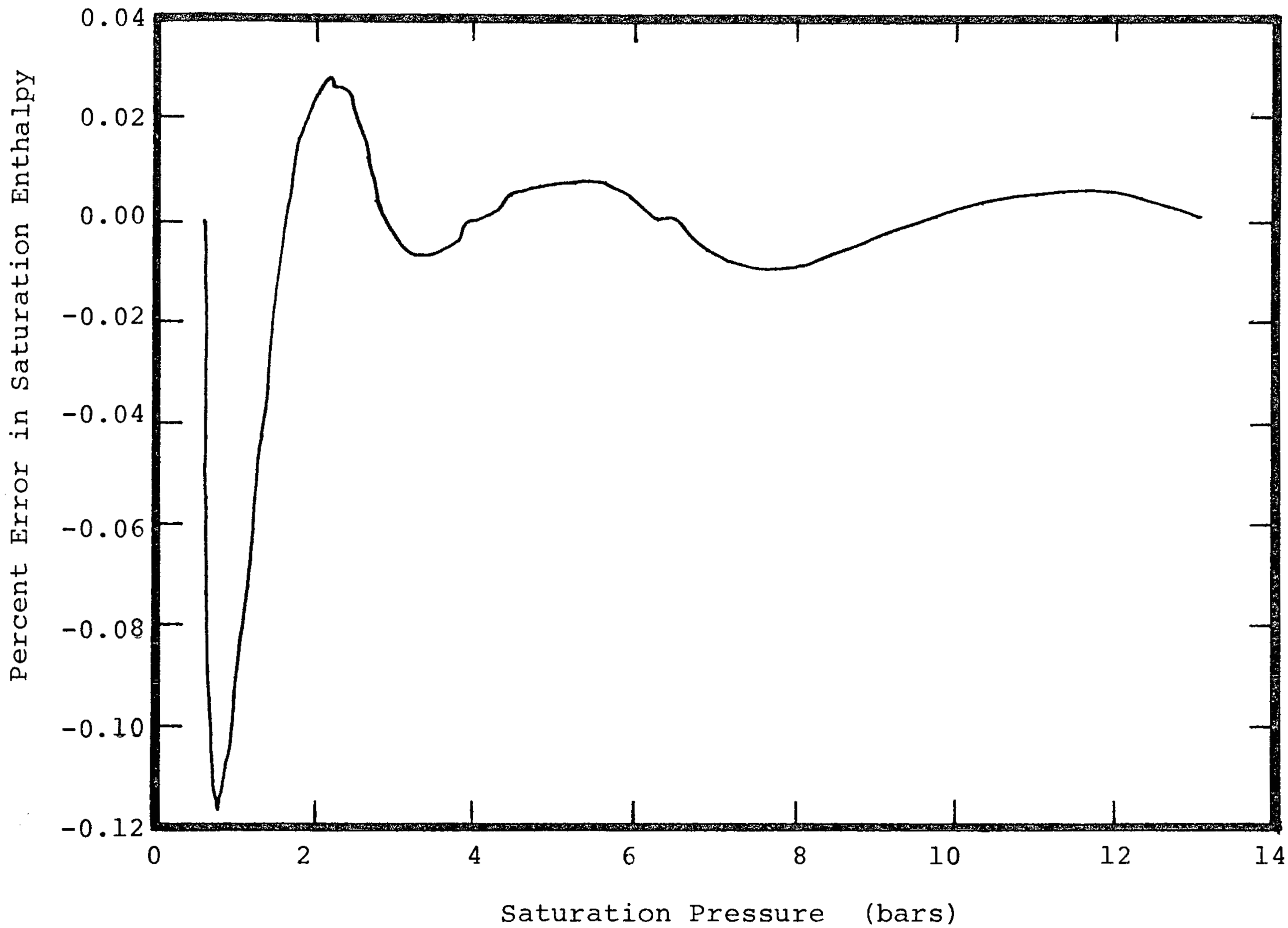


FIGURE C-5 - ERRORS IN CORRELATION HFSAT(P)

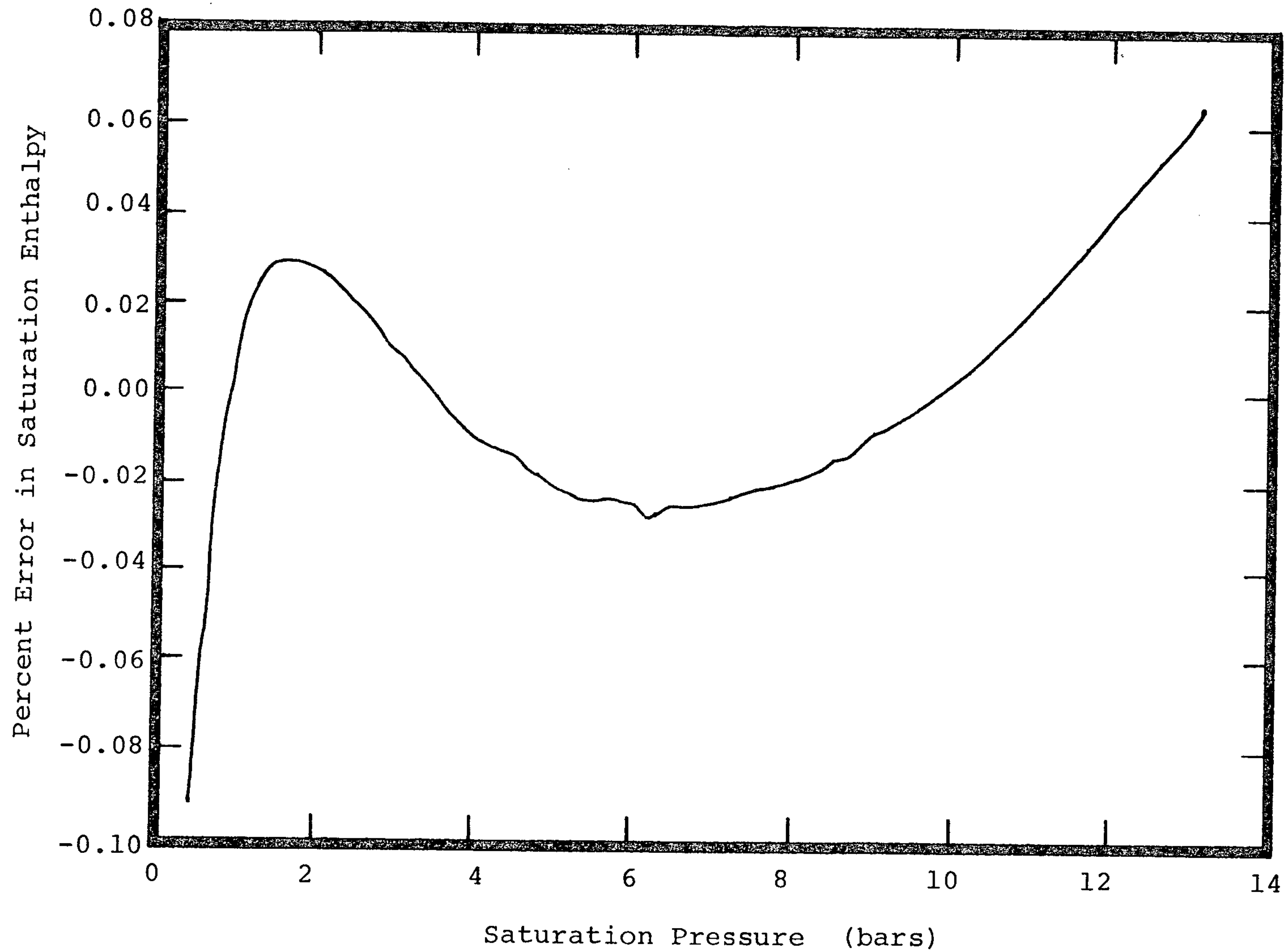


FIGURE C-6 - ERRORS IN CORRELATION HGSAT(P)

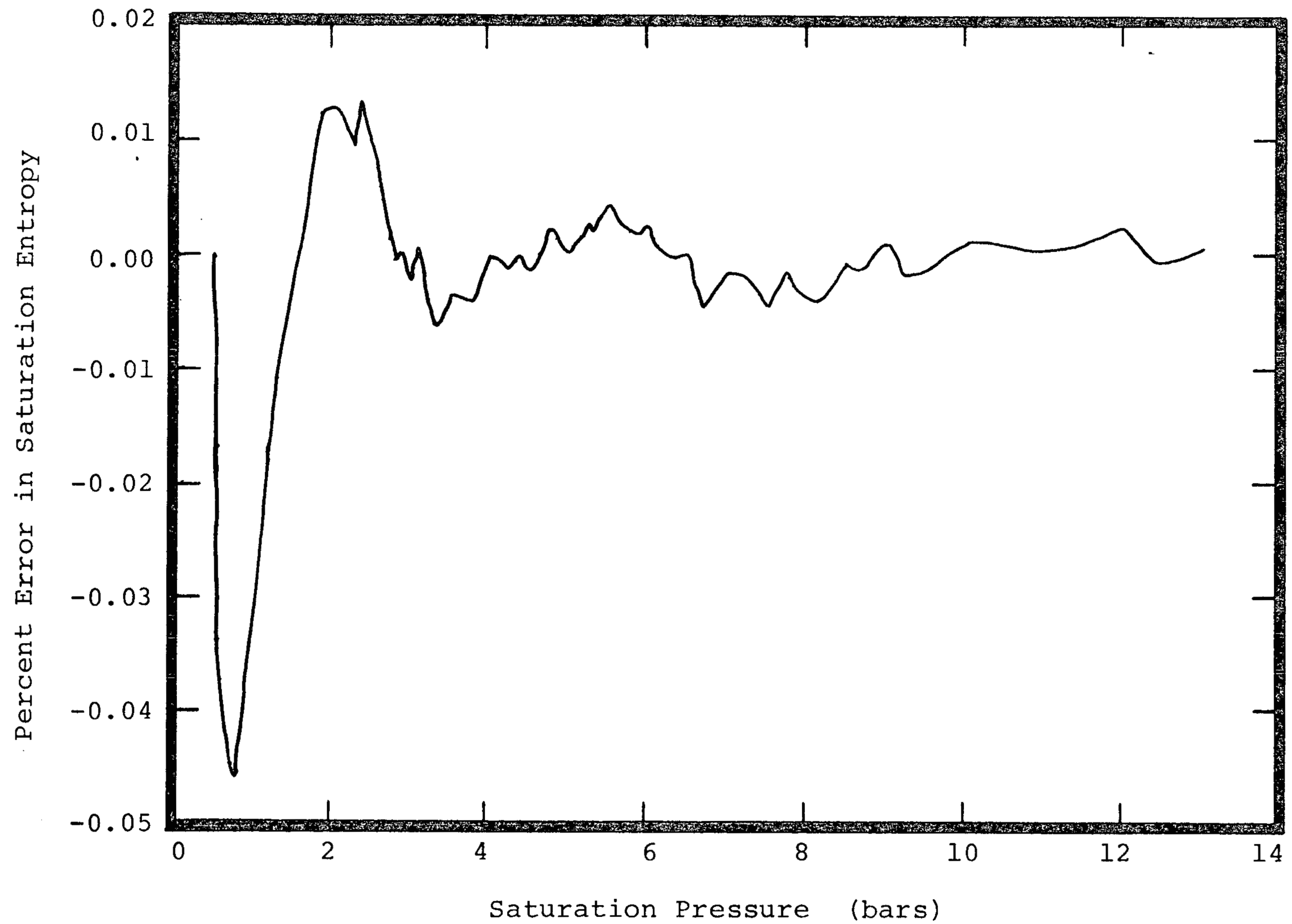


FIGURE C-7 - ERRORS IN CORRELATION SFSAT(P)

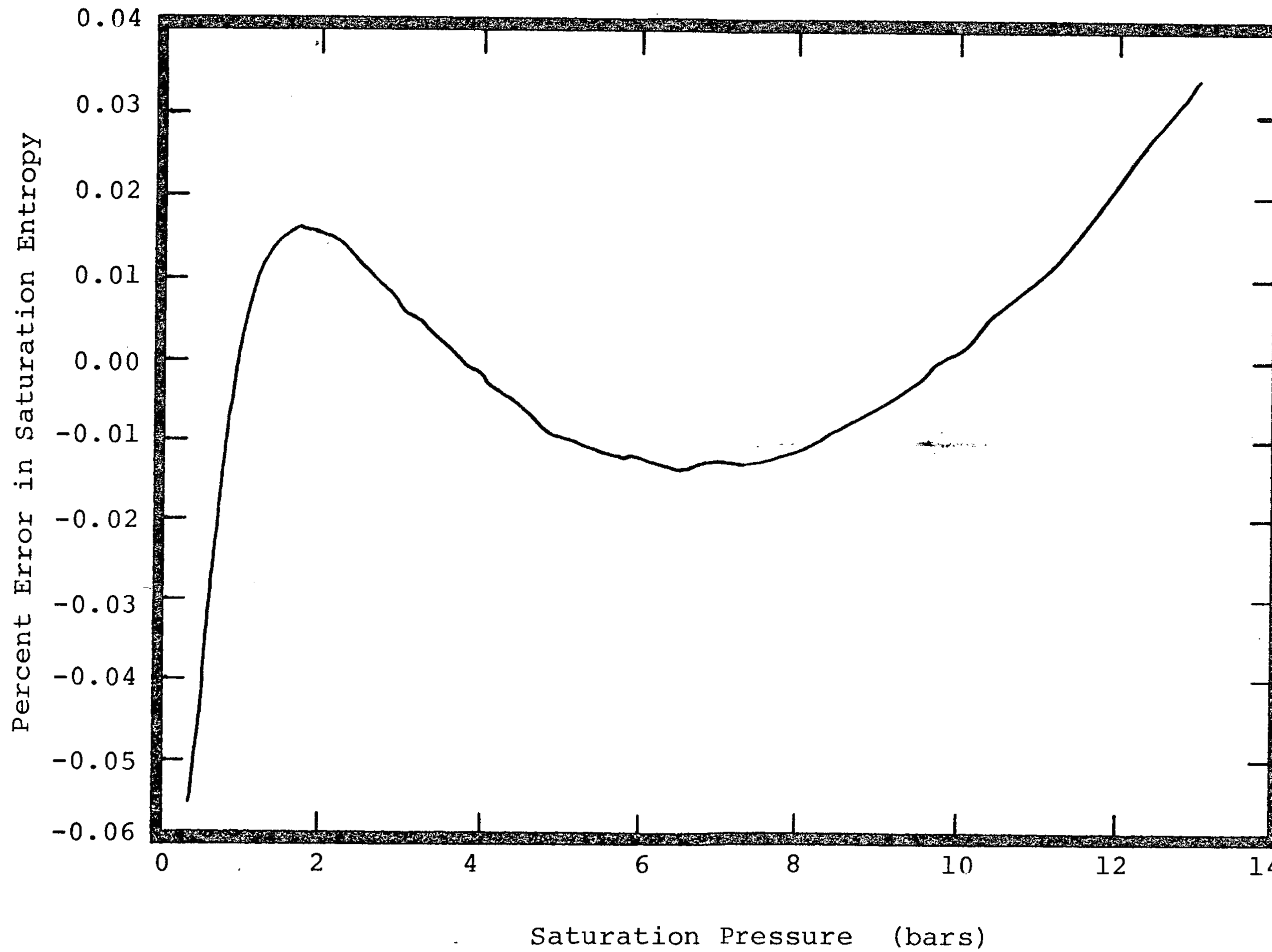


FIGURE C-8 - ERRORS IN CORRELATION SGSAT(P)

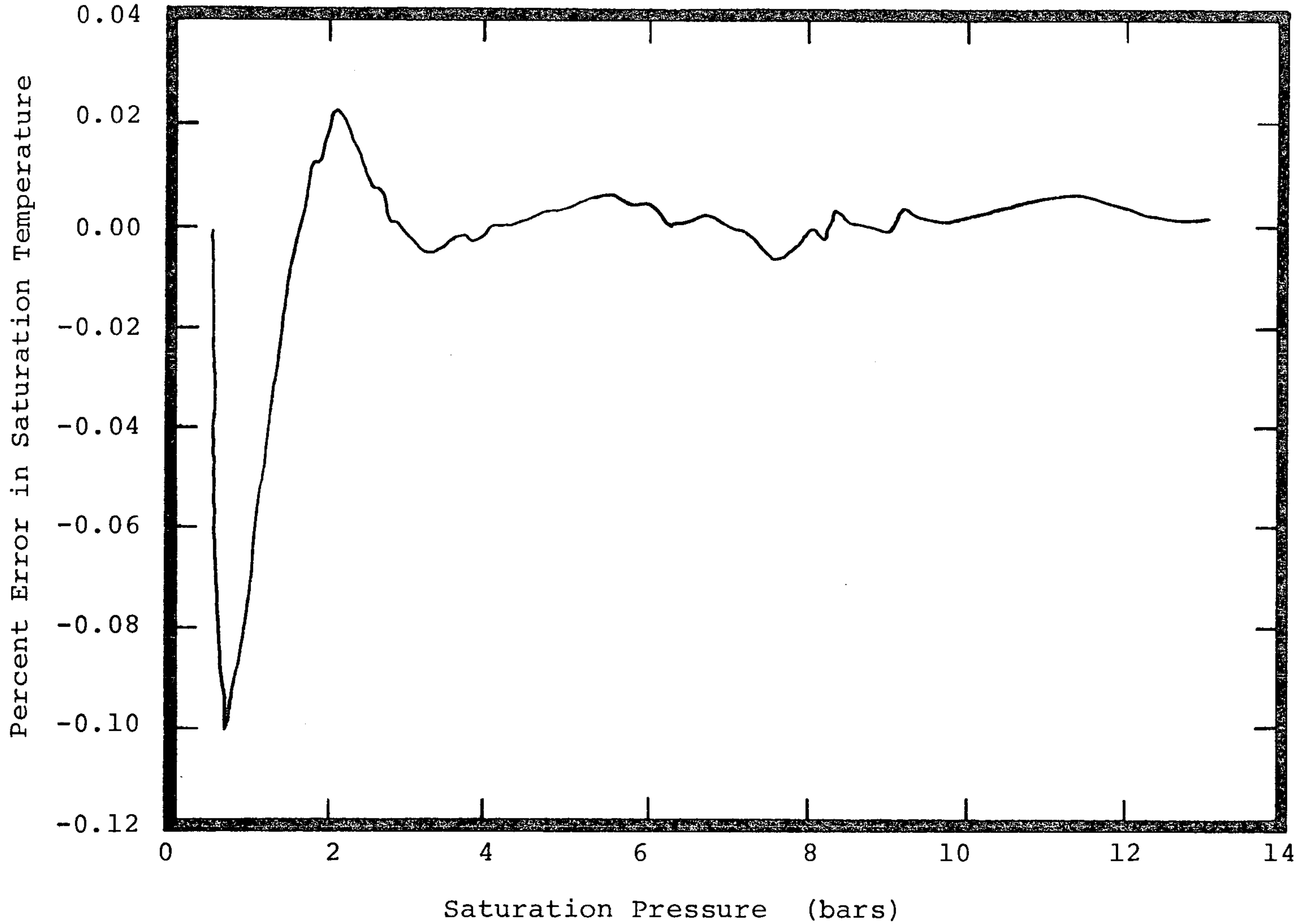


FIGURE C-9 - ERRORS IN CORRELATION TSAT(P)

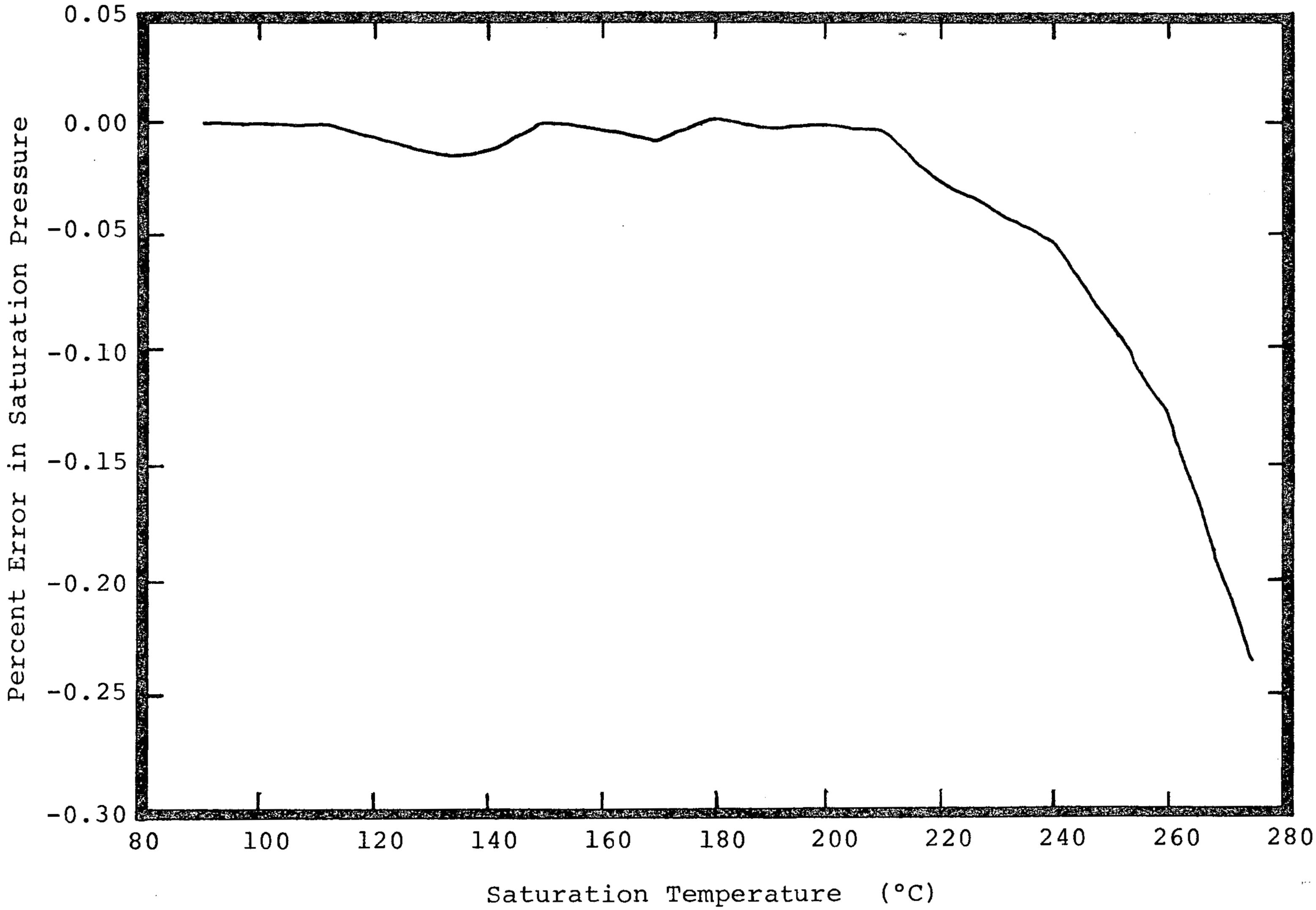


FIGURE C-10 - ERRORS IN CORRELATION PSTT(T)

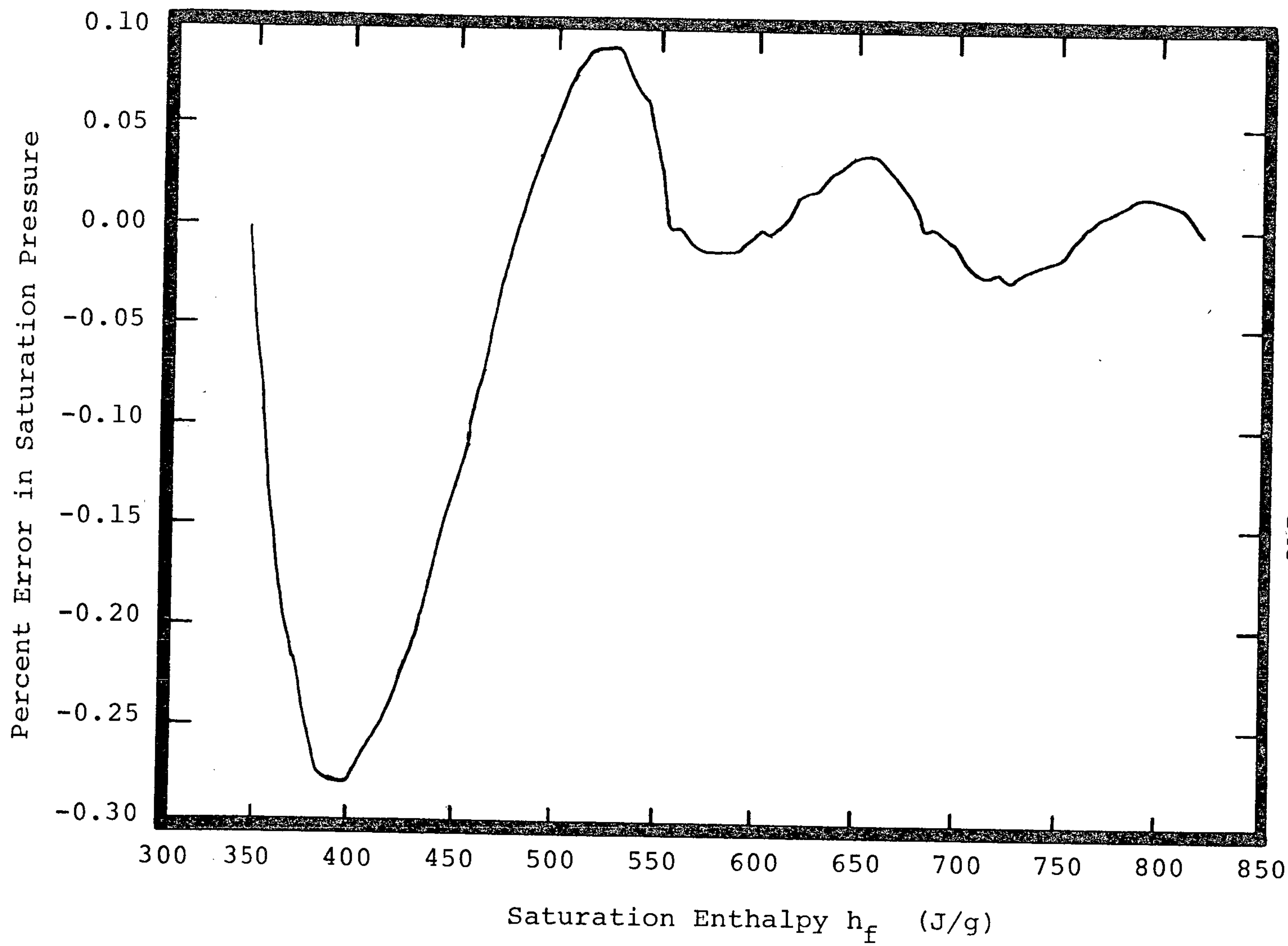


FIGURE C-11 - ERRORS IN CORRELATION PSTHF(HF)

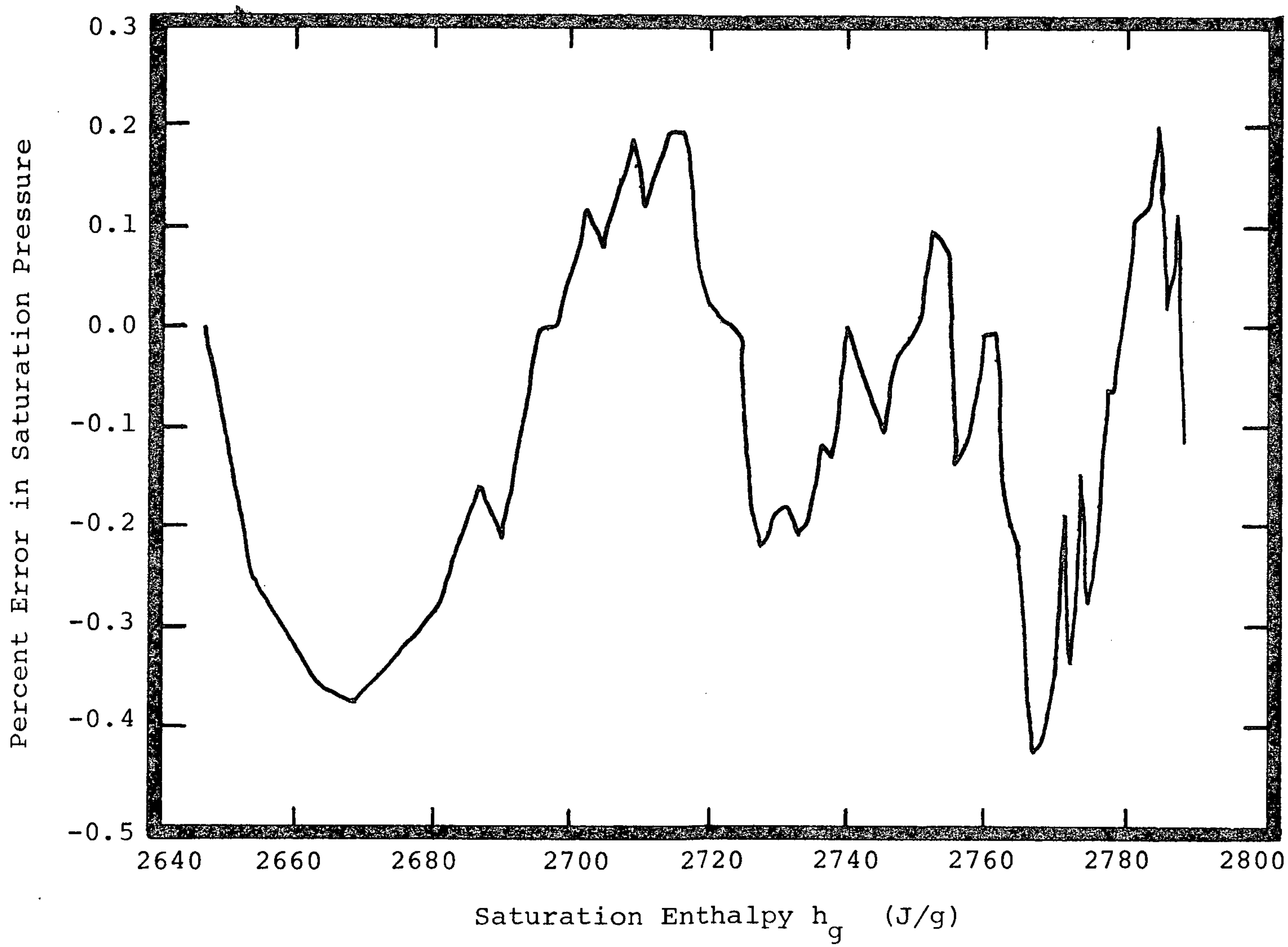


FIGURE C-12 - ERRORS IN CORRELATION PSTHG(HG)

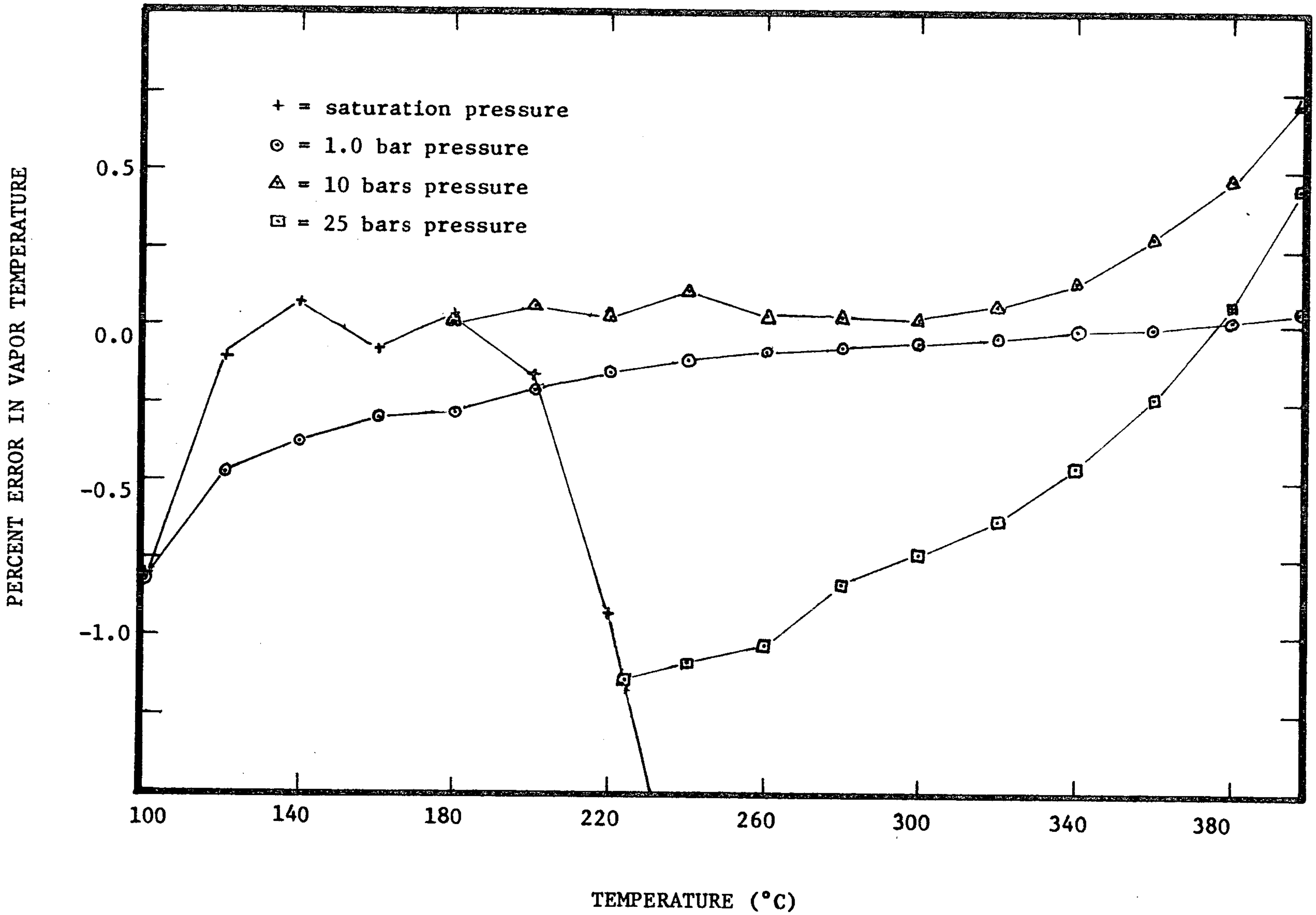


FIGURE C-13 - ERRORS IN CORRELATION TSUP (P,H)

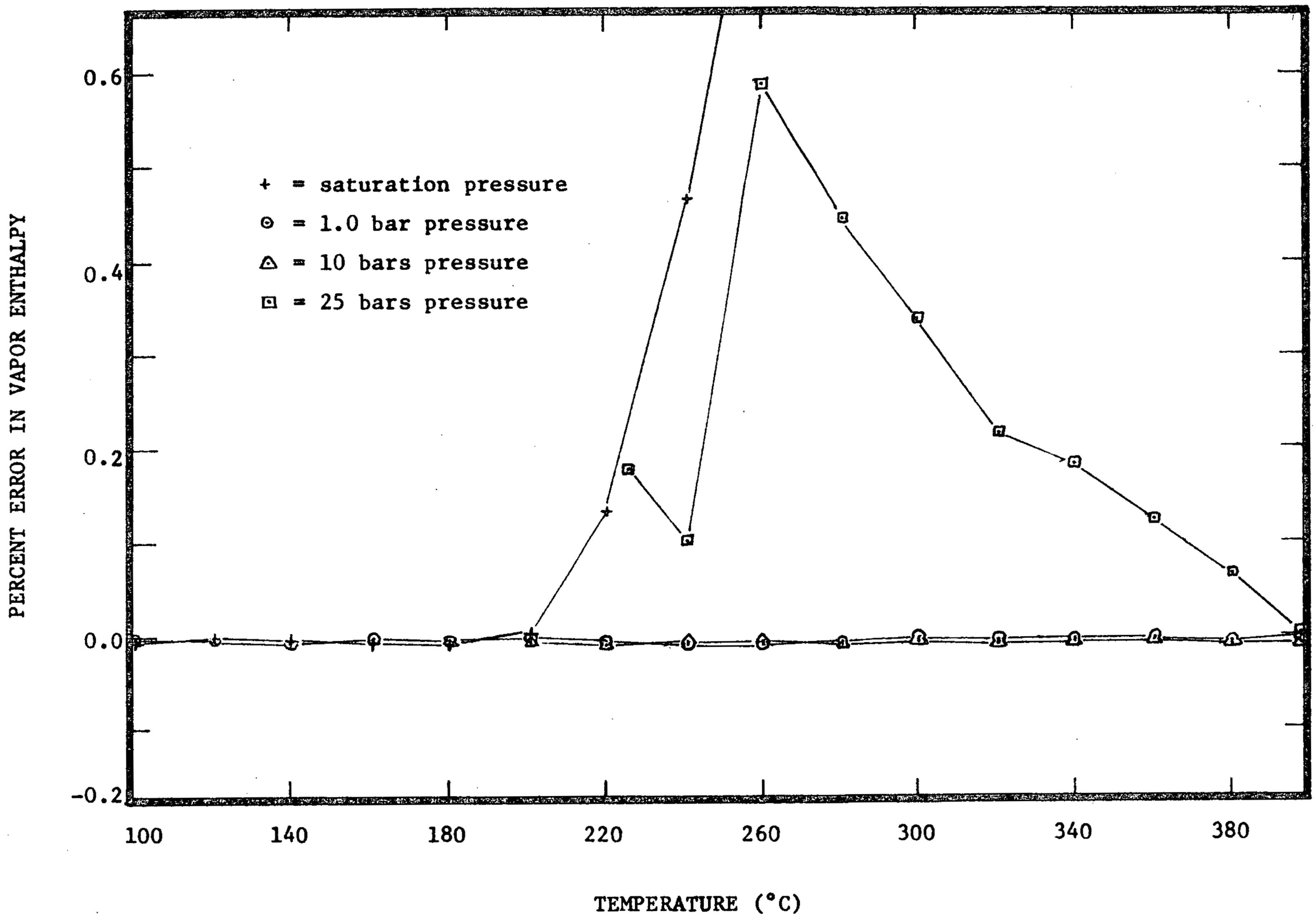


FIGURE C-14 - ERRORS IN CORRELATION HSUP (P,S)

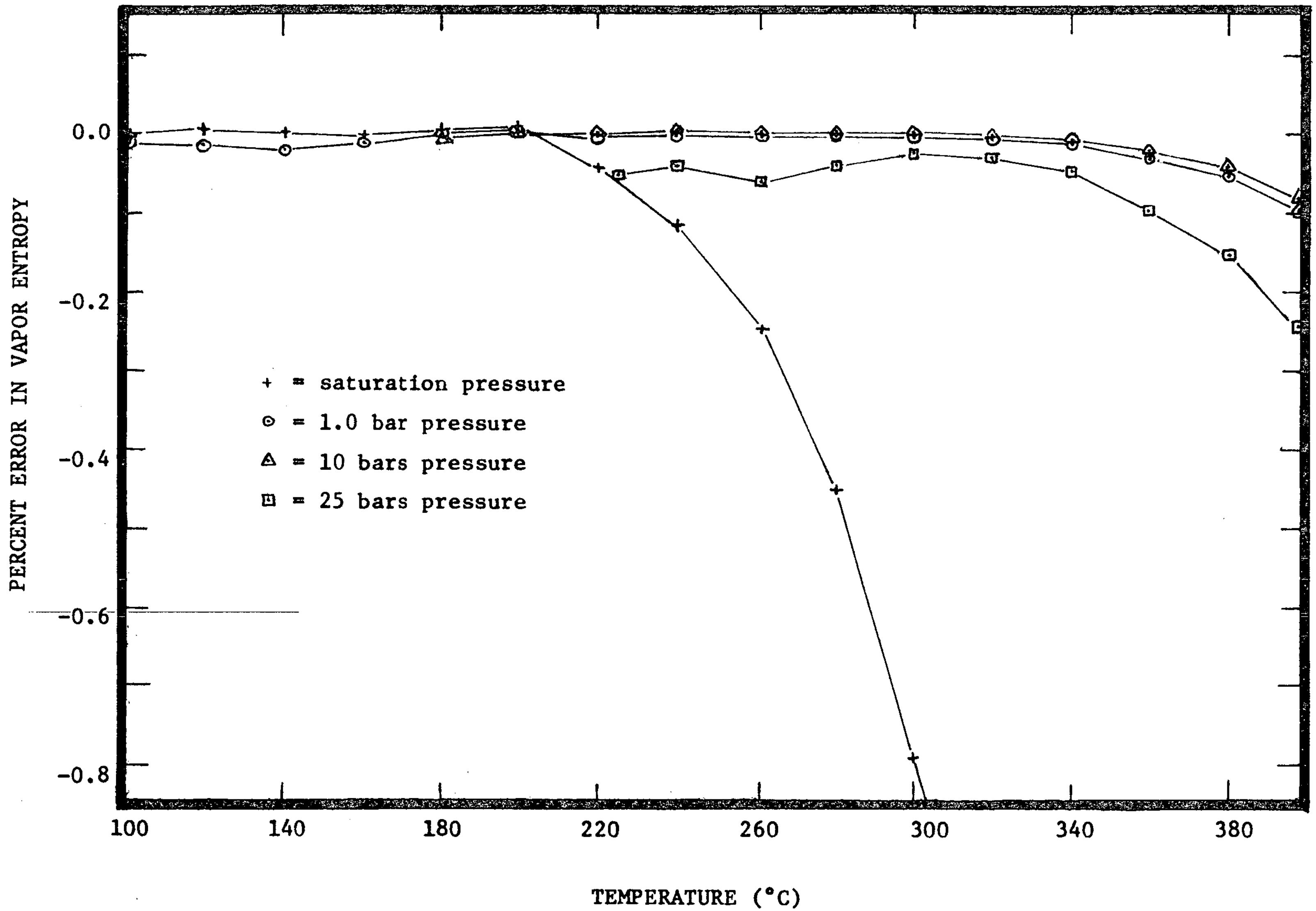


FIGURE C-15 - ERRORS IN CORRELATION SSUP (P,H)

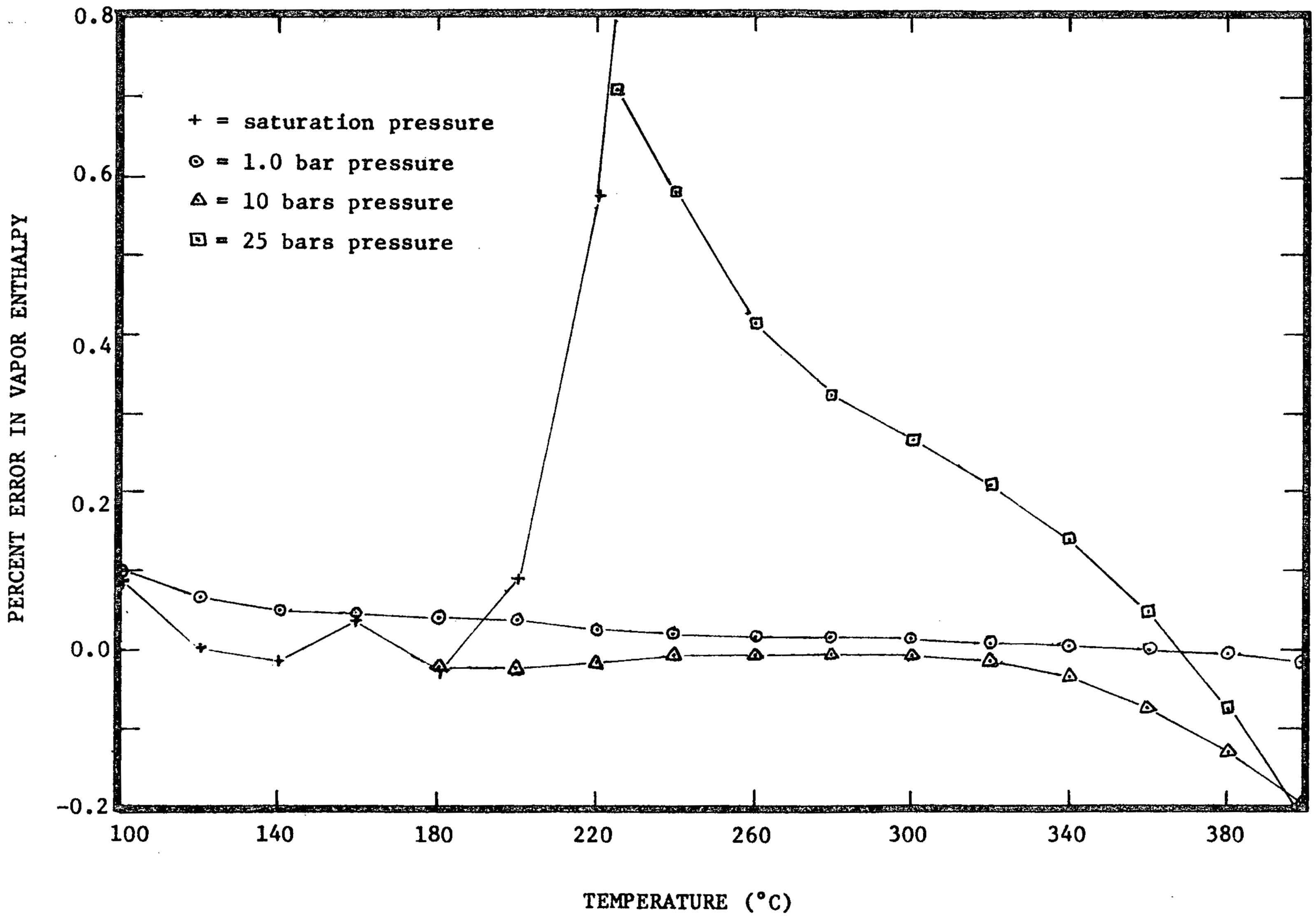


FIGURE C-16 - ERRORS IN CORRELATION HSPT (P,T)

C. ALGORITHMS FOR SALT SOLUTIONS IN WATER

For the purposes of choosing between the pure and saline water algorithms, the computer program considers fluid to be saline if its total dissolved solids content exceeds 10^{-5} (mass fraction basis). The correlations given here assume that the salt content of the brine is composed of potassium, calcium, and sodium chlorides in the ratio 1.00:1.95:3.55 respectively. However, the specific heat equation uses data for pure sodium chloride solutions.

1. Property correlations

The first correlation, taken from Reference 2, relates the saturation pressure of pure water to that of brine at the same temperature:

$$p_{sat,brine}(t) = a_1 \times p_{sat,water}(t) \quad , \qquad [C.1]$$

where

$$a_1 = \sum_{i=1}^{6} a_{1i}\, c_{salt}^{\,i-1} \qquad [C.2]$$

c_{salt} = salt concentration by mass in liquid portion of fluid.

Values for the constants a_{ij} throughout this report are listed in Table C-1 at the conclusion of this section.

The second correlation, also taken from Reference 2, determines saturated liquid enthalpy as a function of brine temperature:

$$h_f = a_4(t)^{a_5} \quad , \qquad [C.3]$$

where a_4 and a_5 are defined by power series in c_{salt} in an analogous fashion to Eq. C.2. Enthalpy in Eq. C.3 is defined in Btu/lbm and temperature in °F.

The third correlation, developed from the data given in Reference 3, relates saturated liquid entropy to brine temperature:

$$s_f = a_2 + a_3 t + a_6 t^2 \quad , \qquad [C.4]$$

where the constants are functions of c_{salt} as in the previous correlations. The correlation was found by fitting quadratic equations in temperature to the tabulated data at 100, 300, and 600°F for constant salt concentrations of 5, 10, 15, 20, and 25%. This procedure gave a set of coefficients a_2, a_3, and a_6 corresponding to each salinity. Fourth-order equations in salt concentration were then fitted to these coefficients, yielding power series for the coefficients as functions of salinity. For this correlation, temperature must be given in °C and entropy is computed in J/g-K.

The fourth correlation determines brine enthalpy as a function of temperature. From the definition of enthalpy,

$$dh = du + pdv + vdp \quad . \qquad [C.5]$$

It is assumed that in the liquid region brine is an incompressible liquid and that its specific heat is a function of temperature only.[5] Defining the specific heat at constant volume and noting that specific volume is a constant for an incompressible fluid, Eq. C.5 becomes

$$dh = cdT + vdp \quad , \qquad [C.6]$$

where

$$c = c_v = \text{specific heat.}$$

If Eq. C.6 is integrated along an isobar, the subcooled liquid enthalpy can be found:

$$h - h_f = \int_{sat} c\, dT \quad . \qquad [C.7]$$

The specific heat can be expressed as a function of temperature alone:

$$c = a_7 + a_8 T + a_9 T^2 \quad , \qquad [C.8]$$

in which the units of temperature are degrees Kelvin. The power series expressions for a_7, a_8, and a_9 in terms of salinity were determined by fitting parabolas in temperature (at 10, 20, and 30°C) to specific heat data in Reference 4 for salt concentrations of 0, 10, and 25%. Power series were then fit to the resulting coefficients of the parabolas. Substitution of Eq. C.8 into Eq. C.7 and integration yields

$$h = h_f + a_7(T-T_{sat}) + \frac{a_8}{2}(T^2-T_{sat}^2) + \frac{a_9}{3}(T^3-T_{sat}^3) , \qquad [C.9]$$

where

h = brine enthalpy, J/g

T = brine temperature, K

h_f = brine saturated enthalpy at brine temperature

T_{sat} = saturation temperature associated with brine pressure and salinity.

The fifth correlation determines brine entropy as a function of temperature. From the Gibbs equation,

$$ds = \frac{1}{T} du + \frac{p}{T} dv \qquad [C.10]$$

Using the fact that specific volume is a constant in this case and employing the definition of specific heat,

$$ds = \frac{c}{T}\,dT \quad , \qquad [C.11]$$

or integrating,

$$s - s_f = \int_{sat} \frac{c}{T}\,dT \quad . \qquad [C.12]$$

The expression for specific heat given in Eq. C.8 can be substituted into this integral, yielding the final correlation

$$s = s_f + a_7 \ln \frac{T}{T_{sat}} + a_8(T-T_{sat}) + \frac{a_9}{2}(T^2-T^2_{sat}) . \qquad [C.13]$$

2. Algorithms

Different algorithms are used depending on which properties are given as input.[6]

--Pressure and Quality Given --

As a saline brine is evaporated, the salt concentration in the remaining liquid increases until the salt saturation point is reached. Thereafter salt precipitates out of the solution while the concentration remains constant. Since the total mass of liquid and vapor does not change during evaporation, the total dissolved solids content must eventually decrease to zero as the fluid quality increases to unity.

The brine correlations presented in the previous section depend on the concentration of salt in the liquid fraction of the stream and not in general on the total dissolved content. This concentration can be determined from a mass balance as

$$c_{salt} = \frac{TDS}{(1 - x)} \quad , \qquad [C.14]$$

where

x = fluid quality
TDS = total dissolved solids content: mass of salts divided by total mass of salts, liquid, and vapor.

However, the salt concentration cannot exceed the maximum solubility, a parameter arbitrarily set at 0.50 grams of salt per gram of solution in data statements at the beginning of the computer code. The true value of the solubility is actually a complex function of temperature, the type of salts present, and other factors.[7]

The salt concentration, defined as the lesser of the solubility and the quantity given by Eq. C.14, is utilized together with the brine pressure in Eq. C.1 to determine the saturation pressure for pure water corresponding to the (unknown) brine temperature. The brine temperature then can be found from this pressure using the pure water correlation $t_{sat}(p)$.

The next step is to evaluate the vapor temperature. Due to the effect of salt on the boiling temperature of the brine, at thermal equilibrium the vapor will be superheated with respect to the saturation temperature for pure vapor at the common brine-vapor pressure. The degree of equilibrium achieved is described by a parameter (listed in a DATA satement in the computer formulation) which defines a fractional superheat:

$$\mathrm{SUPRHT} = \frac{t_{vapor} - t_{sat,pure}(p_{brine})}{t_{brine} - t_{sat,pure}(p_{brine})} . \qquad [C.15]$$

Given a value of this parameter, the vapor temperature can be found. The "fluid" temperature is considered by the computer program to be that of the brine for fluid qualities below 50% and that of the vapor for qualities greater than 50%. At present SUPRHT is set equal to unity in the program; brine and vapor temperatures are thus identical.

The vapor enthalpy can now be calculated from the brine pressure and vapor temperature by use of a pure superheated steam correlation, h(p,t). The saturated liquid enthalpy is determined from the brine temperature by Eq. C.3. If the liquid salt concentration is less than 5%, the algorithm utilizes a linear interpolation in c_{salt} to find the value of h_f, using the results of the pure water correlation $h_f(p)$ and of Eq. C.3 at 5% salinity.

--Saturated Liquid Enthalpy and Quality Given --

This algorithm has been implemented only for fluid quality of 0%. Equation C.3 is inverted to find brine temperature from saturated liquid enthalpy:

$$t = \left(\frac{h_f}{a_4} \right)^{(1/a_5)} \qquad [C.16]$$

The saturation pressure for pure water corresponding to this temperature is found by correlation $p_{sat}(t)$. Equation C.1 then yields the brine pressure. If the salt concentration is less than 5%, linear interpolation between 5% concentration and the result for pure water [found by correlation $p_{sat}(h_f)$] is employed.

-- Pressure and Temperature Given --

The phase of the fluid (liquid, two-phase, or vapor) must first be determined. Using the same procedure as was employed in the first algorithm above (p and x given), the brine saturation temperature and vapor temperature are found from the brine pressure and assumed qualities of zero and unity. The computer program defines the two-phase region as extending from one degree Celsius below the brine saturation temperature to one degree above the vapor temperature. By comparison with the given temperature, the fluid phase is readily determined.

If superheated fluid is indicated by this test, the program branches to the appropriate pure water algorithm since the salt content of vapor is zero. For two-phase fluid, the lack of independence of pressure and temperature in the two-phase region forces the arbitrary assumption of 100% quality: properties returned by the program correspond to those of pure vapor at the brine pressure and vapor temperature. For subcooled liquid, Eqs. C.3, C.4, C.9, and C.13 are used to find h_f, s_f, h, and s respectively. A linear interpolation is again employed for liquid salt concentrations below 5%.

--Pressure and Enthalpy or Entropy Given --

A FORTRAN function subprogram is used in this section to reduce the quantity of redundant code. Given salt concentration, pressure, degree of vapor superheat (SUPRHT), and either enthalpy or entropy, it calculates by the methods described above the brine and vapor temperatures, saturated liquid and vapor enthalpies, and fluid quality. A call to this subprogram using TDS as the salt concentration which returns a computed quality less than zero indicates that the fluid is subcooled, since c_{salt} equals TDS throughout the liquid region. Similarly, a call to the subprogram using the maximum solubility which returns a computed quality greater than unity indicates that the fluid must be superheated vapor. If this latter be the case, the program branches to the appropriate pure vapor algorithm because superheated vapor cannot contain appreciable quantities of salt.

Unfortunately, for subcooled liquid the procedure which calculates enthalpy or entropy as a function of temperature cannot be inverted. The program therefore iterates, assuming a brine temperature and calculating enthalpy or entropy to compare with the given value. A bisection iteration scheme is followed, with endpoints initially at 18°C and the saturation temperature corresponding to the brine pressure and salinity. The scheme guarantees convergence (to 0.1 J/g for enthalpy or 0.0003 J/g-K for entropy) in less than 15 iterations for the domain of interest.

For fluid in the two-phase region, the fluid quality and therefore the liquid salt concentration are unknown. Here the program iterates to find the salt concentration. Assumption of a particular value yields in turn brine and vapor temperatures, saturated liquid and vapor enthalpies or entropies, fluid quality, and a computed salt concentration (from Eq. C.14). This last at convergence should equal the value of c_{salt} initially assumed. The bisection scheme employed again guarantees convergence (to 0.3%) within fifteen iterations.

3. Error limits

There are several sources for error in the above correlations and algorithms.

Most importantly, the underlying data are uncertain. Measurements of the thermodynamic properties of brines are just beginning to be made and various studies differ widely in the reported values of saturation pressure, density, enthalpy, and entropy.[8] The data upon which these correlations are based are claimed to be accurate to within 5% between 27°C and 230°C and between 0% and 35% salinities.

Unfortunately, the specific heat data is limited to very low temperature ranges; extensive extrapolation is thus required. Moreover, the specific heat correlation uses data for pure sodium chloride solutions, while the other correlations assume a more complex solution of potassium, calcium, and sodium chlorides in the ratio 1.00:1.95:3.55 respectively. The extent to which actual brines differ in their composition from these figures also affects the accuracy of this formulation.

The correlations given here match the data in the

International Critical Tables and the Dittman report to within 1% throughout the domain given in these references.

a	i					
	1	2	3	4	5	6
a_{1i}	1.0	-0.617	0.1955	-7.253	12.73	0
a_{2i}	0.022722	1.8610	-17.556	78.319	-123.65	0
a_{3i}	0.013641	-0.055156	0.50699	-2.2488	3.5328	0
a_{4i}	0.2447	0.5337	1.379	-6.679	9.47	0
a_{5i}	1.225	-0.4617	-1.002	5.58	-5.371	-4.615
a_{6i}	-8.5416E-6	1.0078E-4	-1.2313E-3	5.6281E-3	-8.8325E-3	0
a_{7i}	6.4678	-66.272	178.26	0	0	0
a_{8i}	-0.013823	0.37061	-1.0211	0	0	0
a_{9i}	2.0553E-5	-5.5441E-4	1.4888E-3	0	0	0

TABLE C-1 - CONSTANTS IN THE CORRELATION EQUATIONS FOR SALINE FLUID

D. USER GUIDE TO THE COMPUTER FORMULATION

1. Input format

All input and output is given in the argument list of the main subroutine PROPTY. The call statement to the subroutine is of the form

```
CALL PROPTY(INDEX1, INDEX2, TDS, P, T, H, S,
            X, PHASE, HF, HG)    ,          [C.17]
```

where

INDEX1 = parameter specifying which variables are given as input (see below)

INDEX2 = parameter specifying which variables are desired as output (see below)

TDS = total dissolved solids content, kg/kg

P = pressure, bars

T = temperature, °C

H enthalpy, J/g

S = entropy, J/g-K

X = fluid quality: mass of vapor divided by total mass

PHASE = integer variable equal to one for subcooled liquid, two for two-phase fluid, and three for superheated vapor

HF = saturated liquid enthalpy, J/g

HG = saturated vapor enthalpy, J/g .

Appropriate values for the two indices governing input and output can be calculated from the following equation:

$$\text{INDEX} = \sum_{i=1}^{8} J_i \, (2^{i-1}) \quad , \qquad [C.18]$$

where J_i equals one if the i^{th} parameter in the following list is chosen, and equals zero otherwise.

$\underline{i}$	parameter	corresponding term in summation
1	P	1
2	T	2
3	H	4
4	S	8
5	X	16
6	PHASE	32
7	HF	64
8	HG	128

A value for the total dissolved solids content, TDS, must <u>always</u> be given as input and therefore is not included in the list.

Only some of the possible combinations of input and output variables are currently implemented in subroutine PROPTY; the available combinations are listed in

Table C-2. Other combinations may be possible with the current program but have not been explicitly tested. Warning messages concerning the validity of input data are printed on logical unit 6.

As was discussed above, evaporation of brines changes the total dissolved solids content. However, the value of TDS cannot be altered in subroutine PROPTY because properties are frequently determined only for use in system decision rules. It is the responsibility of the user to check the returned property values after every operation involving evaporation or addition of fluid, and to adjust appropriately the value of TDS in his calling program if solubility limits are exceeded.

INDEX1, INDEX2	Input variables	Output variables
3,4	P,T	H
3,8	P,T	S
3,52	P,T	H, X, PHASE
5,2	P,H	T
5,8	P,H	S
5,18	P,H	T, X
5,34	P,H	T, PHASE
5,48	P,H	X, PHASE
5,50	P,H	T, X, PHASE
5,56	P,H	S, X, PHASE
5,208	P,H	X, HF, HG
9,4	P,S	H
9,196	P,S	H, HF, HG
17,2	P,X	T
17,192	P,X	HF, HG
17,194	P,X	T, HF, HG
80,1	HF,X=0.0	P

TABLE C-2 - COMBINATIONS OF INPUT AND OUTPUT VARIABLES CURRENTLY IMPLEMENTED IN SUBROUTINE PROPTY

2. Example input and output

A sample call to subroutine PROPTY is as follows:

CALL PROPTY(17, 194, 0.1, 4.448, T, Dl, D2,
0.0, Il, HF, HG) , [C.19]

in which Dl, D2, and Il are dummy variables. This call statement requests values for temperature and saturated liquid and vapor enthalpies corresponding to the given pressure (4.448 bars) and quality (0.0).

T = 150.02

HF = 580.28

HG = 2749.26 .

3. <u>Flow charts, variable lists, and computer program listings</u>

The flow charts, variable lists, and computer program listings for the thermodynamic properties algorithms are given in Appendix D.

REFERENCES

1. Keenan, J.H., *et al.*, *Steam Tables, Thermodynamic Properties of Water Including Vapor, Liquid, and Solid Phases*, International Edition - Metric Units; New York: John Wiley and Sons, 1969.

2. Miller, A.B., *Brine-Steam Properties Computer Program for Geothermal Energy Calculations*, Lawrence Livermore Laboratory report no. UCRL-52495, June 27, 1978. This report is based upon correlations and data given in Reference 3 below.

3. Dittman, G.L., *Calculation of Brine Properties*, Lawrence Livermore Laboratory report no. UCID-17406, February 16, 1977, p.21.

4. *International Critical Tables*, Vol. II, New York: McGraw-Hill Book Company, 1927, p. 328.

5. For a discussion of the thermodynamics of incompressible liquids, see Reynolds, W.C., and Perkins, H.C., *Engineering Thermodynamics*, New York: McGraw-Hill Book Co., 1970, p.224.

6. The first three algorithms are taken in part from Miller, *Op. Cit.*.

7. Miller, *Op. Cit.*, p.5.

8. See Dittman, *Op. Cit.*, pp. 1, 2, 10-12.

APPENDIX D - USER GUIDE TO THE COMPUTER MODEL

1. Notes on data input

The following comments are intended to elucidate the process by which data are prepared for the computer.

First, it is important to choose an appropriate set of industrial processes for analysis. The set can include any number of processes from a single unit process to the entire plant. Since the number of processes to be considered can be changed after the first computer run, a reasonable estimate of the appropriate process set is sufficient for preliminary purposes. One good estimate consists of all processes which require fluid temperatures that do not exceed the temperature of the geothermal resource.

Second, if the automatic matching mode of operation is selected, a small number of dummy processes should be added to the input data to permit more flexible interactive use of the program. [For examples of how to establish a dummy process, see below.] A dummy process is not related to an actual physical unit process. It allows the user to introduce into the analysis cost and energy requirement data that are not determined automatically by the program. Typically, one dummy process might represent an additional cost item (e.g. the cost of geothermal reinjection pumps). Another might represent a fossil fuel requirement (e.g. the fuel required for a boiler outside the system boundaries which provides steam to an input supply stream). A third might represent a requirement for electricity (e.g. the additional electricity needed after elimination of a turbogenerator).

For example, a requirement for fossil fuel may arise when a boiler outside the system boundaries is needed in the conventional case but not in the geothermal case (e.g. the elimination of a power boiler in a paper and pulp plant fueled by geothermal energy). As was discussed in Chapter 3, a process with a pressure requirement (PP) of -1.0 is interpreted by the program as a dummy process indicating a need for fossil fuel. The quantity of fossil fuel needed equals the dummy process energy requirement (QP). The cost of the boiler should be entered as the process cost (CAREA). If the boiler is not needed in the geothermal case, the user should alter these values when the program requests additional data between its analysis of the conventional case and of the geothermal case. At this point, the user should set CAREA equal to zero (since the boiler is not part of the geothermal system) and set QP equal to zero (since the need for fossil fuel no longer exists in the geothermal system without the boiler).

Another example of the use of dummy processes occurs in those cases in which a need for electricity arises in the geothermal system but not in the conventional system. The prototype for this example is a turbogenerator which can be eliminated in the geothermal system. Initially, a dummy process is established which is interpreted as a need for electricity: temperature and pressure requirements (TP and PP) are both equal to zero. The electrical energy requirement is set equal to zero (by setting QP equal to zero) since electrical energy needs in the conventional case are satisfied in part by the turbogenerator. The cost of the turbogenerator set is entered in CAREA. If the interactive operation option has been chosen, the program will request changes in data after completing the automatic matching procedure for the conventional case. At this point, the user should set the (dummy) process energy requirement, QP, equal to the electrical capacity of the turbogenerator. This is a consequence of the elimination of the turbogenerator for the geothermal case: the electricity requirements previously satisfied by the turbogenerator must now be met by purchases of electricity from the local utility. In addition, CAREA should now be set equal to zero since the cost of the turbogenerator disappears when the turbogenerator is eliminated for the geothermal system.

A third point to note in the preparation of data is that only certain variables can be altered interactively. As the program is currently written, these are TSI, PSI, HSI, MSI, PSF, CFLUID, CFOSSL, CELECT, CINFLT, DEBTEQ, TAXRAT, CDSCNT, FINVST, QPI, INAME, and CAREA. [For definitions of these variables, see Section D.3 below.] However, the lines of code implementing the interactive "NAMELIST" feature must be altered for each computer facility. In adapting these lines to a new facility, the user may add more variables to the above list. Note that INAME must be included in the list if interactive operation is desired since interactive program execution is terminated when it is set equal to zero.

Fourth, the program assumes that only the first fluid stream listed in the input data consists of geothermal fluid. This assumption is employed only if CFLUID is not equal to zero (i.e. geothermal fluid is purchased from a field developer) or if STARTM is not equal to FINALM (i.e. multiple runs are to be made automatically with varying geothermal fluid flow rates).

Fifth, the values of economic and financial parameters should be established in accordance with the policies of the user organization. For example, the minimum rate of return required by a company on investments of this level of risk should be used as the discount rate in the program. If such a policy does not exist, the values to be employed can be found in the literature or estimated by the decision-maker for whom the analysis is being performed.

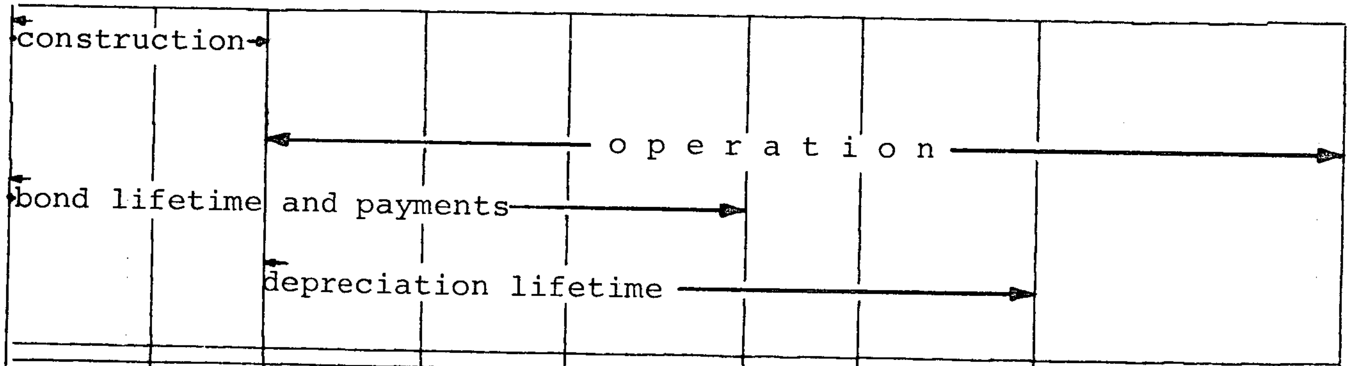
Sixth, the characteristics of the geothermal resource must be determined. If wells have not yet been drilled, these characteristics (temperature, pressure, flow rate, etc.) must be estimated. In general, the "most likely" geological estimate should be employed. The user can then investigate interactively the sensitivity of the overall results to the specific values assumed for the relevant parameters. It should be noted that the input to the program includes nine values representing the probability distributions for geothermal resource temperature, flow rate, and cost. However, none of these values are included in the analysis at present. If desired, computer code may be added to analyze explicitly the probabilistic aspects of the geothermal resource characteristics.

Seventh, the user should note that PHASE, the fluid phase required for a particular unit process and specified by program input, must correspond to the fluid phase as determined by the fluid temperature and pressure required for that process, TP+DELTA1 and PP.

Eighth, the definitions of program variables which relate to periods of time are illustrated in Fig. D-1. This Figure demarcates the commencement and termination of the period to which each variable refers.

Ninth, the user should note that for processes which employ single-phase fluid, the required process temperature difference, DELTA1, controls the size of the new process equipment. However, for processes which employ two-phase fluid the situation is somewhat different. This results from the fact that during condensation, stream temperature is a constant fixed solely by the steam pressure. Since equipment size is a function of stream temperature, which in turn depends upon the required fluid pressure for that process, PP, it is this required stream pressure which serves to control the size of process equipment employing two-phase fluid.

Finally, the user should note that thermodynamic limitations restrict the range of values which DELTA1 and PP can assume. Specifically, the value of DELTA1 must be positive in order to ensure that the Second Law is not violated. Furthermore, this law requires that the saturation temperature associated with PP exceed the process temperature, TP, in the case of processes using two-phase fluid.



	IBEGIN		IBEGIN+ ICONST		IBEGIN+ LIFEBD- 1		IBEGIN+ ICONST+ LIFETM- 1	IBEGIN+ ICONST+ ILIFE- 1
Year	1978	1979	1980	1981	1982	1983	1984	1985
Year for Depreciation Purposes			1	2	3	4	5	
Project Year	1	2	3	4	5	6	7	8

IBEGIN = 1978
ICONST = 2
ILIFE = 6
LIFETM = 5
LIFEBD = 5

FIGURE D-1 - ECONOMIC TIME VARIABLES - AN EXAMPLE

CARD	COLUMN	FIELD	VARIABLE	DESCRIPTION	UNITS
1	1-5	I5	RUNNUM	Identification number for this run	-
	6-10	I5	IMATCH	Decision variable: 0= matching not performed; 1= matching performed	-
	11-15	I5	INAME	Decision variable: 0= no more runs 1= new geothermal system run 2= new conventional system run	-
2	1-80	40A2	LOCATE(40)	Alphanumeric description of geothermal field location and resource type	-
3	1-80	40A2	INDUST(40)	Alphanumeric description of specific industry application	-

* *

If IMATCH = 1, skip to card 16

* *

Match Result Data: Cards 4-9ff relate to the conventional system:

CARD	COLUMN	FIELD	VARIABLE	DESCRIPTION	UNITS
4	1-5	I5	MAT(4)	Number of auxiliary energy sources	-
	6-10	I5	MAT(1)	Number of pieces of process and auxil-iary equipment	-
	11-15	I5	MAT(2)	Number of unit processes	-
	16-20	I5	MAT(3)	Number of input supply streams	-
5	1-10	F10.5	XMAT(5)	Total mass flow rate of geothermal fluid purchased	kg/hr
	11-20	F10.5	XMAT(6)	Total mass flow rate of ambient water required	kg/hr
	21-30	F10.5	XMAT(9)	Total process energy requirements	kW
	31-40	F10.5	XMAT(7)	Total quantity of electricity purchased from utility	kW
	41-50	F10.5	XMAT(8)	Total quantity of fossil fuel heat re-quired	kW
	51-60	F10.5	XMAT(4)	Total enthalpy of input supply streams	kW
	61-70	F10.5	XMAT(3)	Total enthalpy of streams at exit	kW
	71-80	F10.5	XMAT(2)	Total availability of input supply streams	kW
6	1-10	F10.5	XMAT(1)	Total availability of streams at exit	kW

CARD	COLUMN	FIELD	VARIABLE	DESCRIPTION	UNITS

---------- Input one card as follows for each of the MAT(4) energy sources -------

CARD	COLUMN	FIELD	VARIABLE	DESCRIPTION	UNITS
7ff	1-10	F10.3	XMAT6(I)	Temperature to which auxiliary energy is delivered	deg. C
	11-20	F10.3	XMAT3(I)	Pressure to which auxiliary energy is delivered	bars
	21-30	F10.3	XMAT4(I)	Quantity of auxiliary energy required	kW

---------- Input one card as follows for each of the MAT(1) pieces of equipment --

CARD	COLUMN	FIELD	VARIABLE	DESCRIPTION	UNITS
8ff	1-5	I5	MAT2(J)	Equipment type code: see variable lists	-
	6-15	F10.5	XMAT5(J)	Equipment size parameter: mass flow rate	kg/hr
	16-25	F10.5	XMAT1(J)	Equipment size parameter: see variable lists	Various

---------- Input cards as follows as needed for the MAT(2) processes, eight per card -------

CARD	COLUMN	FIELD	VARIABLE	DESCRIPTION	UNITS
9ff	1-80	8E10.3	XMAT2(J)	Cost of process equipment, item J	1978 $

CARD	COLUMN	FIELD	VARIABLE	DESCRIPTION	UNITS
Match Result Data: Cards 10-15ff relate to the geothermal system:					
10	1-5	I5	Z	Number of auxiliary energy sources	-
	6-10	I5	IAREA	Number of pieces of process and auxiliary equipment	-
	11-15	I5	MI	Number of unit processes	-
	16-20	I5	NI	Number of input supply streams	-
11	1-10	F10.5	MS(1)	Total mass flow rate of geothermal fluid purchased	kg/hr
	11-20	F10.5	MWATER	Total mass flow rate of ambient water required	kg/hr
	21-30	F10.5	QSUM	Total process energy requirements	kW
	31-40	F10.5	QESUM	Total quantity of electricity purchased from utility	kW
	41-50	F10.5	QFSUM	Total quantity of fossil fuel heat required	kW
	51-60	F10.5	ENTOTL	Total enthalpy of input supply streams	kW
	61-70	F10.5	ENTOT2	Total enthalpy of streams at exit	kW
	71-80	F10.5	AVAILS	Total availability of input supply streams	kW
12	1-10	F10.5	AVAIL2	Total availability of streams at exit	kW

CARD	COLUMN	FIELD	VARIABLE	DESCRIPTION	UNITS
---------- Input one card as follows for each of the Z energy sources ------------					
13ff	1-10	F10.3	TM(I)	Temperature to which auxiliary energy is delivered	deg. C
	11-20	F10.3	PM(I)	Pressure to which auxiliary energy is delivered	bars
	21-30	F10.3	QM(I)	Quantity of auxiliary energy required	kW
---------- Input one card as follows for each of the IAREA pieces of equipment ---					
14ff	1-5	I5	ITYP(J)	Equipment type code: see variable lists	-
	6-15	F10.5	SIZE(J)	Equipment size parameter: mass flow rate	kg/hr
	16-25	F10.5	AREA(J)	Equipment size parameter: see variable lists	Various
---------- Input cards as follows as needed for the MI processes, eight per card --					
15ff	1-80	8E10.3	CAREA(J)	Cost of process equipment, item J	1978 $

* *

Skip to economic data input, card 23

* *

CARD	COLUMN	FIELD	VARIABLE	DESCRIPTION	UNITS
Continuing with input for IMATCH = 1 :					
16	1-5	I5	ISEPRT	Decision variable: 0= separation of two-phase streams not allowed; 1= separation allowed	-
	6-10	I5	ISPRT2	Decision variable: 0= separation of two-phase streams at unit process exits not allowed; 1= separation allowed	-
	11-15	I5	IFLASH	Decision variable: 0= flashing of supply streams not allowed; 1= flashing allowed	-
	16-20	I5	IAUX	Decision variable: 0= normal stream-process matching rules apply; 1= auxiliary energy alone used for high temperature processes (i.e. processes with TSUM(J) > highest TS(I)	-
	21-28	F8.3	STARTM	Starting value for geothermal supply mass flow rate fraction	-
	29-36	F8.3	FINALM	Final value of geothermal supply mass flow rate fraction	-
	37-44	F8.3	DELTAM	Decrement size for geothermal supply mass flow rate fraction	-
				Mass flow rate cut-off fractions:	
	45-52	F8.3	MCHECK(1)	Lower bound for single phase flows	-
	53-60	F8.3	MCHECK(2)	Upper bound for single phase flows	-
	61-68	F8.3	MCHECK(3)	Lower bound for condensing streams	-
	69-76	F8.3	MCHECK(4)	Upper bound for condensing streams	-
17	1-5	I5	NI	Number of input geothermal streams	-

CARD	COLUMN	FIELD	VARIABLE	DESCRIPTION	UNITS
---------- Input three cards as follows for each of the NI streams ---------------					
18ff	1-10	F10.3	TSI(I)	Temperature of stream I	deg. C
	11-20	F10.3	PSI(I)	Pressure of stream I	bars
	21-30	F10.3	HSI(I)	Enthalpy of stream I	J/g
	31-50	F20.3	MSI(I)	Mass flow rate of stream I	kg/hr
19ff	1-30	15A2	COMPON(15)	Alphanumeric description of fluid chemistry	-
	31-40	F10.1	TDI(I)	Total dissolved solids	g/g
	41-45	I5	ISCALE	Scaling index: 0= none; 10= severe	-
	46-50	I5	ITOXIC	Toxicity index: 0= distilled water; 10= fatal	-
	51-60	F10.2	ETI(I)	Non-condensable gases present in stream	g/g
20ff	1-10	F10.3	PSF(I)	Minimum allowable flash pressure for stream I	bars
21	1-5	I5	MI	Number of unit processes	-

CARD	COLUMN	FIELD	VARIABLE	DESCRIPTION	UNITS
---------- Input one card as follows for each of the MI processes ---------------					
22ff	1-8	F8.3	TPI(J)	Required temperature for process J	deg. C
	9-16	F8.3	PPI(J)	Required pressure for process J	bars
	17-26	E10.3	QPI(J)	Required heat transfer rate for process J	kW
	27-36	E10.3	MPI(J)	Mass flow rate used in conventional system for process J	kg/hr
	37-41	I5	IPPURI(J)	Purity and injection parameter for process J : 0= dirty fluid allowed, heat exchange type process 1= pure fluid required, heat exchange type process 2= dirty fluid allowed, direct injection type process 3= pure fluid required, direct injection type process	-
	42-46	I5	PHASEI(J)	Supply stream phase required for process J: 1= liquid, 2= two-phase, 3= vapor	-
	47-54	F8.3	GAMMAI(J)	Ratio of hot-side to process-side heat transfer coefficients for process J, conventional system	-
	55-62	F8.3	DELT1I(J)	Temperature increment required for process J: see variable list for precise definition	deg. C
	63-70	F8.3	DELT2I(J)	Temperature increment used for process J in the conventional system: see variable list for precise definition	deg. C
	71-80	E10.3	CAREA(J)	Cost of process equipment, item J, in the conventional system	1978 $

- -

CARD	COLUMN	FIELD	VARIABLE	DESCRIPTION	UNITS
Continuing with input of economic data for either IMATCH = 0 or IMATCH = 1 :					
23	1-5	I5	NWELLP	Number of production wells needed	-
	6-10	I5	NWELLI	Number of extra wells (dry holes, injection wells) needed	-
	11-20	F10.2	NWELLR	Number of replacement wells needed per year per producing well	no./year
	21-30	E10.1	CLAND	Land acquisition cost	$
	31-40	E10.1	CWELL	Cost to drill one geothermal well	$/well
	41-50	E10.1	CTRANS	Cost of collection and transmission system, excluding flash equipment	$
	51-60	E10.1	COTHER	Exploration, environmental planning, and other costs in 1978 dollars	$
	61-70	E10.1	CMAINT	Annual GT field operation, maintenance, and allocated administrative costs	$/year
	71-80	E10.1	CREPLC	Cost of replacement wells	$
24	1-10	E10.1	TANGBL	Fraction of geothermal well drilling costs attributable to tangible property	-
	11-20	E10.1	DPLBAS	Fraction of tangible geothermal well cost allocatable to depletable accounts	-
	21-30	E10.1	CFLUID	Cost of geothermal fluid per kg	$/kg

CARD	COLUMN	FIELD	VARIABLE	DESCRIPTION	UNITS
				Temperature t such that:	
25	1-10	F10.1	PROBT(1)	probability of t(actual) < t = 25%	deg. C
	11-20	F10.1	PROBT(2)	probability of t(actual) < t = 50%	deg. C
	21-30	F10.1	PROBT(3)	probability of t(actual) < t = 75%	deg. C
				Mass flow rate per well m such that:	
	31-40	E10.1	PROBM(1)	probability of m(actual) < m = 25%	kg/hr
	41-50	E10.1	PROBM(2)	probability of m(actual) < m = 50%	kg/hr
	51-60	E10.1	PROBM(3)	probability of m(actual) < m = 75%	kg/hr
				Cost of fluid c such that:	
26	1-10	E10.1	PROBC(1)	probability of c(actual) < c = 25%	$/kg
	11-20	E10.1	PROBC(2)	probability of c(actual) < c = 50%	$/kg
	21-30	E10.1	PROBC(3)	probability of c(actual) < c = 75%	$/kg
27	1-5	I5	IBEGIN	Year of project start	year
	6-10	I5	ICONST	Planning and construction time for project	years
	11-15	I5	ILIFE	Project operating lifetime. Must be less than or equal to 40-ICONST	years

---------- Enter the distribution of construction costs on the next four ----------
cards, ten per card

CARD	COLUMN	FIELD	VARIABLE	DESCRIPTION	UNITS
28-31	1-80	10F8.4	FINVST(I)	Fraction of construction costs incurred in year I	-

- -

CARD	COLUMN	FIELD	VARIABLE	DESCRIPTION	UNITS
32	1-10	F10.5	CFOSSL	Cost of fossil fuel in 1978	$/kJ
	11-20	F10.5	CELECT	Cost of electricity in 1978	$/kJ
				Inflation rates:	
33	1-10	F10.3	CINFLT(1)	price index through 1986	-
	11-20	F10.3	CINFLT(2)	fossil fuel through 1986	-
	21-30	F10.3	CINFLT(3)	electricity through 1986	-
	31-40	F10.3	CINFLT(4)	geothermal fluid through 1986	-
	41-50	F10.3	CINFLT(5)	price index after 1986	-
	51-60	F10.3	CINFLT(6)	fossil fuel after 1986	-
	61-70	F10.3	CINFLT(7)	electricity after 1986	-
	71-80	F10.3	CINFLT(8)	geothermal fluid after 1986	-
34	1-5	I5	LIFETM	Depreciation lifetime	years
	6-15	F10.5	SALVAG	Fractional salvage value for depreciation purposes	-
35	1-5	I5	LIFEBD	Bond lifetime to maturity	years
	6-15	F10.5	BONDRT	Interest rate on bonds	-
	16-25	F10.5	DEBTEQ	Debt to equity ratio for project financing	-
36	1-10	F10.5	TAXCRD	Investment tax credit rate	-
	11-20	F10.5	PROPTX	Property tax rate in 1978	-
	21-30	F10.5	TAXRAT	Overall marginal income tax rate	-

CARD	COLUMN	FIELD	VARIABLE	DESCRIPTION	UNITS
37	1-10	F10.5	CINSUR	Insurance premium rate in 1978	-
	11-20	F10.5	COPRAT	General operating and maintenance cost rate in 1978	-
	21-30	F10.5	OPFRAC	Capacity factor = hours operated per year/8760	-
38	1-10	F10.5	CDSCNT	Discount rate for present value analysis	-
	11-20	F10.5	ROIREQ	Required rate of return on GT investment, in nominal terms	-
	21-30	F10.5	CROYAL	Royalty payment as fraction of value of steam or heat used	-

VARIABLE	DEFINITION	PROGRAM	TYPE	UNITS
	***** A *****			
A1(CSALT) to A9(CSALT)	Brine correlation constants	PROPTY	Func.	Various
ANNINC	Annual net imputed income from GT property in constant 1978 dollars	ECONMC	-	$
AREA(J)	Equipment size parameter; definition for given value of ITYP(J): 1=Q, 2= P2-P1, 3=Q, 4=P1, 5=quality, 6=Q, 7=area(new)/area(old), 8=Q	/E/	-	N/D or kW or bars
AVAIL2	Sum of exit stream availabilities	MATCH	-	kW
AVAILS	Sum of supply stream availabilities	MATCH	-	kW
	***** B *****			
B	Subcooled liquid enthalpy or entropy	PROPTY	-	J/g or J/g-K
BONDRT	Interest rate on bonds (decimal)	/F/	-	-
	***** C *****			
CAREA(J)	Cost of process equipment, item J	/F/	-	$
CASNUM	Number of case considered in this run	GEOTHM	Integer	-
CASH(I)	Annual cash flow in current dollars	/F/	-	$
CASHF(I)	Annual cash flow for conventional system in current dollars	/F/	-	$
CAVG	Average salt concentration in itera-	PROPTY	-	g/g

VARIABLE	DEFINITION	PROGRAM	TYPE	UNITS
	tion for CSALT			
CDSCNT	Discount rate	/F/	-	-
CELECT	Cost of electricity in 1978	/F/	-	$/kJ
CFIELD	Total initial investment in geothermal field, 1978 dollars	ECONMC	-	$
CFLUID	Cost of geothermal fluid in 1978	/E/	-	$/kg
CFOSSL	Cost of fossil fuel in 1978	/F/	-	$/kJ
	Cumulative inflation factors:			
CINF(1)	price index	ECONMC	-	-
CINF(2)	fossil fuel	ECONMC	-	-
CINF(3)	electricity	ECONMC	-	-
CINF(4)	geothermal fluid	ECONMC	-	-
CINFLT(I)	Annual inflation factors as above, with 1-4 indicating rates through 1986 and 5-8 for years after 1986	/F/	-	-
CINSUR	Insurance premium rate in 1978	/F/	-	$/$
CINVSF	Total investment for a conventional system in 1978 dollars	/F/	-	$
CINVST	Total investment for a geothermal system in 1978 dollars	/F/	-	$
CLAND	Land acquisition cost	/G/	-	$
CMAINT	Annual GT field operation, maintenance and allocated administrative cost	/G/	-	$/year
COMPON(15)	Alphanumeric list of principal elements in the chemistry of the geothermal fluid	GEOTHM	Integer*2	-
COPRAT	General operating and maintenance cost rate in 1978	/F/	-	$/$
COSTGT	Annual expenses attributable to geothermal field development, in current dollars	ECONMC	-	$
COSTS	Total annual cash outlay before taxes	ECONMC	-	$

VARIABLE	DEFINITION	PROGRAM	TYPE	UNITS
	in current dollars			
COTHER	Exploration, environmental planning, and other costs, total, in 1978 $	/G/	-	$
CREPLC	Cost of replacement wells	/G/	-	$
CROYAL	Royalty payment as fraction of value of steam or heat used	/G/	-	$/$
CSALT	Salt concentration in liquid portion of stream	PROPTY	-	g/g
CSALT1	Lower iteration limit for salt concentration	PROPTY	-	g/g
CSALT2	Upper iteration limit for salt concentration	PROPTY	-	g/g
CTRANS	Cost of fluid collection and distribution system	/G/	-	$
CUMGTC	Cumulative investment in geothermal field development in 1978 dollars	/G/	-	$
CUMGTV	Cumulative investment in geothermal filed development in current dollars	/G/	-	$
CUMINA	Cumulative investment for depreciation purposes in current dollars	ECONMC	-	$
CUMINC	Cumulative investment in 1978 dollars	ECONMC	-	$
CUMINV	Cumulative investment in current dollars	/F/	-	$
CWELL	Cost of one geothermal well	/G/	-	$/well

***** D *****

VARIABLE	DEFINITION	PROGRAM	TYPE	UNITS
D1 to D6	Dummy variables for subroutine PROPTY calls	MATCH	-	-
DEBTEQ	Debt to equity ratio for project	/F/	-	-

VARIABLE	DEFINITION	PROGRAM	TYPE	UNITS
	financing			
DELT1I(J)	Unit process temperature difference required: equals the average of the minimum acceptable stream temperature at inlet to the process and the resulting temperature at exit from the process, minus the process temperature	/A/	-	deg. C
DELT2I(J)	Unit process present temperature difference: equals the average of the present stream temperature at inlet to the process and the present temperature at exit from the process, minus the process temperature	/A/	-	deg. C
DELTA1(J)	Unit process temperature difference required, defined as for DELT1I(J)	/D/	-	deg. C
DELTA2(J)	Unit process present temperature difference, defined as for DELT2I(J)	/D/	-	deg. C
DELTA3(J)	Unit process new temperature difference: defined as above, with figures from the stream actually used	/D/	-	deg. C
DELTAM	Geothermal supply mass flow rate fraction increment	GEOTHM	-	-
DELTHS	Change in stream enthalpy	MATCH	-	J/g
DEPLET	Annual depletion allowance from GT property, current dollars	ECONMC	-	$
DEPREC	Annual depreciation expense	ECONMC	-	$
DIFF	Iteration convergence parameter	PROPTY	-	g/g or deg. C
DPLBAS	Fraction of tangible geothermal well costs allocatable to depletable accounts	/G/	-	-

VARIABLE	DEFINITION	PROGRAM	TYPE	UNITS
	***** E *****			
ENTOT2	Total enthalpy of streams at exit	/E/	-	kW
ENTOTL	Total enthalpy of input supply streams	/E/	-	kW
ETA(I)	Mass fraction of non-condensable gases present in input stream	/D/	-	g/g
ETI(I)	Mass fraction of non-condensable gases present in input stream	/A/	-	g/g
ERROR	Percent error in conservation of energy due to inaccuracies in the program	GEOTHM	-	%
	***** F *****			
FINALM	Final geothermal supply mass flow rate fraction	GEOTHM	-	-
FINDH	Indicates if enthalpy is desired	PROPTY	Logical	-
FINDHF	Indicates if saturated liquid enthalpy is desired	PROPTY	Logical	-
FINDHG	Indicates if saturated vapor enthalpy is desired	PROPTY	Logical	-
FINDP	Indicates if pressure is desired	PROPTY	Logical	-
FINDPH	Indicates if phase is desired	PROPTY	Logical	-
FINDS	Indicates if entropy is desired	PROPTY	Logical	-
FINDT	Indicates if temperature is desired	PROPTY	Logical	-
FINDX	Indicates if quality is desired	PROPTY	Logical	-
FINSUM	Summation of FINVST(I), I=1,40	ECONMC	-	-
FINVST(I)	Fraction of investment in 1978	/F/	-	-

VARIABLE	DEFINITION	PROGRAM	TYPE	UNITS
	dollars spent in year I from project start			
FLAG	Validity flag in internal rate of return calculation	ECONMC	Integer	-
FOFETA	Heat transfer rate with non-condensables divided by rate without them; a function of ETA(I)	MATCH	-	-
FRAC	Current geothermal supply mass flow rate fraction	GEOTHM	-	-

***** G *****

VARIABLE	DEFINITION	PROGRAM	TYPE	UNITS
GAMMA(J)	Ratio of old hot side to process side heat transfer coefficients	/D/	-	-
GAMMAI(J)	Ratio of old hot side to process side heat transfer coefficients	/A/	-	-
GIVNHF	Indicates if saturated liquid enthalpy is given	PROPTY	Logical	-
GIVNP	Indicates if pressure is given	PROPTY	Logical	-
GIVNPH	Indicates if pressure and enthalpy are given	PROPTY	Logical	-
GIVNPS	Indicates if pressure and entropy are given	PROPTY	Logical	-
GIVNPT	Indicates if pressure and temperature are given	PROPTY	Logical	-
GTSYST	Control variable: .TRUE.= geothermal system; .FALSE.= fossil system	ECONMC	Logical	-

VARIABLE	DEFINITION	PROGRAM	TYPE	UNITS
	***** H *****			
H	Specific enthalpy	Algor.	-	J/g
HB	Specific enthalpy of saturated liquid brine	PROPTY	-	J/g
HDESUP	Enthalpy of desuperheating water	MATCH	-	J/g
HF	Enthalpy of saturated liquid	All	-	J/g
HFINAL	Exit stream enthalpy	MATCH	-	J/g
HFIVE	Specific enthalpy of saturated liquid brine at brine temperature and 5% salt concentration	PROPTY	-	J/g
HFSAT	Enthalpy of saturated liquid - property algorithm	MATCH	-	J/g
HG	Enthalpy of saturated vapor	All	-	J/g
HGSAT	Enthalpy of saturated vapor - property algorithm	MATCH	-	J/g
HLIQ	Enthalpy of subcooled liquid - property algorithm	MATCH	-	-
HNEW	Exit stream enthalpy	MATCH	-	J/g
HPURE	Enthalpy of saturated pure water at saturation pressure associated with brine temperature	PROPTY	-	J/g
HR	Reduced enthalpy	Algor.	-	-
HS(I)	Supply stream enthalpy	/D/	-	J/g
HSI(I)	Supply stream enthalpy	/A/	-	J/g
HSPT	Enthalpy of superheated vapor - property algorithm	MATCH	-	J/g
HSSFNL	Stream enthalpy at process exit, assuming an isentropic process	MATCH	-	J/g
HSUP	Enthalpy of superheated vapor - property algorithm	MATCH	-	-
HV	Specific enthalpy of vapor	PROPTY	-	J/g

VARIABLE	DEFINITION	PROGRAM	TYPE	UNITS
	***** I *****			
I	Counter or index	Various	-	-
I	[Usually] supply stream index	All	-	-
I1, I2	Temporary storage indices	SORT	-	-
I4	Dummy variable for subroutine PROPTY call	MATCH	-	-
IAREA	Number of pieces of process and auxiliary equipment	/E/	-	-
IAUX	Decision variable: 0= normal energy profile matching; 1= satisfy processes with TP(J) greater than hottest geothermal stream solely by auxiliary heat	/A/	-	-
IBEGIN	Year of project start	/F/	-	year
ICOND	Subscript of MCHECK chosen by stream type: see definition of MCHECK	MATCH	-	-
ICONST	Planning and construction time for project	/F/	-	years
IEQPHS	Process-stream phase equality: 0= unlike phases; 1= like phases. See text on MATCH for more precise definition of "like phases"	MATCH	-	-
IFINAL	Year of project termination	ECONMC	-	year
IFINAL	Total project lifetime including construction	ECONMC	-	years
IFINAL	Vapor compression region index - after compression	MATCH	-	-
IFIRST	Supply stream index associated with hottest stream	MATCH	-	-
IFLASH	Decision variable: 0= flashing of geothermal streams not permitted;	/A/	-	-

VARIABLE	DEFINITION	PROGRAM	TYPE	UNITS
	1= flashing permitted			
ILIFE	Project operating lifetime. Must be less than or equal to 40-ICONST	/F/	-	years
IMATCH	Decision variable: 0= input match results; 1= perform energy profile matching	GEOTHM	-	-
IN	Input data set reference number	All	-	-
INAME	Decision variable: 0= no more runs 1= new geothermal system run 2= new conventional system run	GEOTHM	-	-
INDEX1	Variable specifying input parameters for subroutine PROPTY: see text on PROPTY for appropriate values	PROPTY	-	-
INDEX2	Variable specifying output parameters for subroutine PROPTY: see text on PROPTY for appropriate values	PROPTY	-	-
INDUST(40)	Alphanumeric description of specific industry application	GEOTHM	Int.*2	-
INTER	Number of order interchanges in current sorting pass	SORT	-	-
IOUT	Output data set reference number	All	-	-
IPAYBK	Discounted payback period	/F/	-	year
IPPURE(J)	Unit process characteristics: 0= takes unclean streams; 1= takes clean streams only; 2= unclean, direct injection; 3= clean, direct injection	/D/	-	-
IPPURI(J)	Unit process characteristics: see above	/A/	-	-
IPUR	Unit process stream requirement:	MATCH	-	-

VARIABLE	DEFINITION	PROGRAM	TYPE	UNITS
	0= unclean allowed; 1= clean stream only			
IRR	Internal rate of return on geothermal system as compared to the conventional system	/F/	Real	-
IRR1	Lower limit in iteration for IRR	ECONMC	Real	-
IRR2	Upper limit in iteration for IRR	ECONMC	Real	-
IRRAVG	Average value of IRR	ECONMC	Real	-
ISCALE	Supply stream scaling index: 0= none through 10= severe	GEOTHM	-	-
ISEPRT	Decision variable: 0= two-phase stream separation not allowed; 1= separation allowed	/A/	-	-
ISPRT2	Decision variable: 0= two-phase separation not allowed in matching procedure; 1= separation allowed	/A/	-	-
ISPURE(I)	Supply stream characteristics: 0= unclean fluid; 1= clean fluid; 2= unclean, unavailable; 3= clean, unavailable	/D/	-	-
ISPURI(I)	Supply stream characteristics: see above	/A/	-	-
ISTART	Vapor compression region index - before compression	MATCH	-	-
ITOTAL	Total number of unit processes and items of auxiliary equipment	MATCH	-	-
ITOXIC	Supply stream toxicity index: 0= pure through 10= fatal	GEOTHM	-	-
ITYP(J)	Type of auxiliary or process equipment: 1= evaporator heat exchanger 2= pump 3= vapor compressor	/E/	-	-

VARIABLE	DEFINITION	PROGRAM	TYPE	UNITS
	4= flash vessel 5= two-phase stream separator 6= fossil fuel boiler or heater 7= process equipment 8= nonevaporator heat exchanger			
IYEAR	Year since commencement of project	ECONMC	-	years

***** J *****

VARIABLE	DEFINITION	PROGRAM	TYPE	UNITS
J	Counter or index	Various	-	-
J	[Usually] unit process index	All	-	-

***** K *****

VARIABLE	DEFINITION	PROGRAM	TYPE	UNITS
K	Number of streams or processes	SORT	-	-
K	Counter or index	Various	-	-
K1	Time period counter	ECONMC	-	years

***** L *****

VARIABLE	DEFINITION	PROGRAM	TYPE	UNITS
L	Counter or index	Various	-	-
L	Index for supply stream to be separated from two-phase to two single-phase streams	SEPRAT	-	-

VARIABLE	DEFINITION	PROGRAM	TYPE	UNITS
L	Maximum number of sorting passes required	SORT	-	-
LIFEBD	Bond lifetime to maturity	/F/	-	years
LIFETM	Depreciation lifetime allowed by IRS	/F/	-	years
LOCATE(40)	Alphanumeric description of geothermal field location	GEOTHM	Int.*2	-
LORDER(I)	Transformation vector for streams or processes: used to rank streams and processes by temperature	SORT	-	-

***** M *****

VARIABLE	DEFINITION	PROGRAM	TYPE	UNITS
M	Current number of unit processes	/D/	-	-
M1	Time period counter	ECONMC	-	years
M(I)	Mass flow rate of process or stream	SORT	-	kg/hr
MAT(1)	Number of pieces of process and auxiliary equipment	GEOTHM	-	-
MAT(2)	Initial number of unit processes	GEOTHM	-	-
MAT(3)	Initial number of supply streams	GEOTHM	-	-
MAT(4)	Number of auxiliary energy supplies	GEOTHM	-	-
MAT2(J)	Type of auxiliary or process equipment: see definition for ITYP(J)	GEOTHM	-	-
MATCH	Subroutine which matches energy demand to supply	GEOTHM	-	-
	Mass flow rate cut-off fractions:			
MCHECK(1)	Lower bound, single-phase flows	/A/	Real	-
MCHECK(2)	Upper bound, single-phase flows	/A/	Real	-
MCHECK(3)	Lower bound, condensing flows	/A/	Real	-
MCHECK(4)	Upper bound, condensing flows	/A/	Real	-
MCMPRS	Vapor compression mass flow ratio:	MATCH	Real	-

VARIABLE	DEFINITION	PROGRAM	TYPE	UNITS
	estimate of kg of fluid required to yield one kg of compressed fluid after addition of desuperheating water			
MDESUP	Desuperheating water flow rate	MATCH	Real	kg/hr
MI	Initial number of unit processes	/A/	-	-
MNEW	Maximum allowable stream flow rate	MATCH	Real	kg/hr
MORDER(J)	Transformation vector for unit processes: used to rank processes by temperature	/D/	-	-
MP(J)	Mass flow rate for unit process	/D/	Real	kg/hr
MPI(J)	Mass flow rate for unit process	/A/	Real	kg/hr
MS(I)	Current mass flow rate of supply stream	/D/	Real	kg/hr
MSI(I)	Initial mass flow rate of supply stream	/A/	Real	kg/hr
MSTAND(I)	Vapor compression mass flow rate cut-offs: used to compute MCMPRS	MATCH	Real	-
MTOTAL	Total supply stream mass flow rate	/E/	Real	kg/hr
MTRY	Temporary storage of stream flow rate	MATCH	-	kg/hr
MWATER	Total external water supply required	/E/	Real	kg/hr

***** N *****

VARIABLE	DEFINITION	PROGRAM	TYPE	UNITS
N	Current number of supply streams	/D/	-	-
N1	Time period counter	ECONMC	-	years
NI	Initial number of supply streams	/A/	-	-
NORDER(I)	Transformation vector for supply streams: used to rank streams by temperature	/D/	-	-

VARIABLE	DEFINITION	PROGRAM	TYPE	UNITS
NWELLI	Number of extra wells (dry holes, injection wells) needed	/G/	-	-
NWELLP	Number of producing wells needed	/G/	-	-
NWELLR	Number of replacement wells needed per year per producing well	/G/	Real	/yr-well
NX	Sorting index: 1= supply streams; 2= processes	SORT	-	-

***** O *****

VARIABLE	DEFINITION	PROGRAM	TYPE	UNITS
OPFRAC	Capacity factor = hours operated per year/8760	/F/	-	-
OUTENG	Annual cash outlay for energy in current dollars	ECONMC	-	$
OUTINS	Annual cash outlay on insurance in current dollars	ECONMC	-	$
OUTINT	Annual cash outlay for bond interest in current dollars	ECONMC	-	$
OUTINV	Annual cash outlay on investment in current dollars	ECONMC	-	$
OUTOPT	Annual cash outlay for maintenance in current dollars	ECONMC	-	$
OUTTXP	Annual cash outlay on property taxes in current dollars	ECONMC	-	$

VARIABLE	DEFINITION	PROGRAM	TYPE	UNITS
	***** p *****			
P	Stream pressure	Algor.	-	bars
PERCNT	Applicable percentage of gross income for depletion purposes	ECONMC	-	-
PFIVE	Brine saturation pressure at given enthalpy and 5% salt concentration	PROPTY	-	bars
PHASE(J)	Unit process phase requirement: 1= liquid, 2= two-phase, 3= vapor	/D/	Integer	-
PHASEI(J)	Unit process phase requirement: as above	/A/	Integer	-
PHASUP	Supply stream phase; as above	MATCH	Integer	-
PM(Z)	Pressure requirement for auxiliary energy process Z	/D/	-	bars
PP(J)	Unit process pressure requirement	/D/	-	bars
PPI(J)	Unit process pressure requirement	/A/	-	bars
PPURE	Pure water saturation pressure associated with brine temperature assuming given enthalpy and 5% salt concentration	PROPTY	-	bars
PR	Reduced pressure	Algor.	-	-
PREVAL	Net present value of annual cash flows	ECONMC	-	$
PROBC(I)	Cost of fluid probability distribution: there is a 25%, 50%, and 75% chance that the actual cost of fluid will be no greater than PROBC(1), PROBC(2), and PROBC(3) respectively	/G/	-	$/kg
PROBM(I)	Geothermal fluid flow rate probability distribution: there is a 25%, 50%, and 75% chance that the actual flow rate will be no greater than PROBM(1), PROBM(2), and PROBM(3) respectively	/G/	-	kg/hr

VARIABLE	DEFINITION	PROGRAM	TYPE	UNITS
PROBT(I)	Geothermal temperature probability distribution: there is a 25%, 50%, and 75% chance that the actual temperature will be no greater than PROBT(1), PROBT(2), and PROBT(3) respectively	/G/	-	deg. C
PROFIT	Profitability index: equals PV of cash savings/PV of investment	/F/	-	-
PROPTX	Property tax rate in 1978	/F/	-	-
PROPTY	Subroutine which computes fluid properties	MATCH	-	-
PS(I)	Supply stream pressure	/D/	-	bars
PSF(I)	Minimum allowable flash pressure for supply streams	/A/	-	bars
PSI(I)	Supply stream pressure	/A/	-	bars
PSTAGE	Vapor compression stage pressure	MATCH	-	bars
PSTAND(I)	Vapor compression pressure cut-offs	MATCH	-	bars
PSTHF	Pressure associated with saturated liquid enthalpy - property algorithm	PROPTY	-	-

***** Q *****

QESUM	Total auxiliary electricity required	/E/	-	kW
QFSUM	Total auxiliary fossil fuel required	/E/	-	kW
QM(Z)	Auxiliary energy used in process Z	/D/	-	kW
QP(J)	Unit process energy requirement	/D/	-	kW
QPI(J)	Unit process energy requirement	/A/	-	kW
QSUM	Total process energy requirements	/E/	-	kW
QTRAN1	Heat transfer rate in secondary heat exchanger	MATCH	-	kW

VARIABLE	DEFINITION	PROGRAM	TYPE	UNITS
QTRANS	Heat transfer rate in unit process	MATCH	-	kW
QTRY	Temporary storage for heat transfer rate	MATCH	-	kW
QUAL(--)	Function which determines quality given pressure, salt concentration, and either enthalpy or entropy	PROPTY	Func.	-

***** R *****

VARIABLE	DEFINITION	PROGRAM	TYPE	UNITS
R1	Inverse of required rate of return on GT investment, in real terms, plus one, until 1986	ECONMC	-	-
R2	Inverse of required rate of return on GT investment, in real terms, plus one, after 1986	ECONMC	-	-
RATIO	Equipment capacity ratio	MATCH	-	-
ROIREQ	Required rate of return on GT investment in nominal terms	/G/	-	-
ROYLTY	Annual royalty expense for geothermal fluid in current dollars	ECONMC	-	$
RUNNUM	Run identification number	GEOTHM	Integer	-

***** S *****

VARIABLE	DEFINITION	PROGRAM	TYPE	UNITS
S	Specific entropy	Algor.	-	-
SALVAG	Fractional salvage value for depreciation purposes	/F/	-	-

VARIABLE	DEFINITION	PROGRAM	TYPE	UNITS
SAVING(I)	Annual cash saving of geothermal system relative to fossil system	/F/	-	$
SB	Specific entropy of saturated liquid brine	PROPTY	-	J/g-K
SEPRAT	Subroutine to separate two-phase components	MATCH	-	-
SF	Entropy of saturated liquid	MATCH	-	J/g-K
SFINAL	Vapor compression entropy cut-off	MATCH	-	J/g-K
SFIVE	Saturated brine entropy at brine temperature and 5% salt concentration	PROPTY	-	J/g-K
SFSAT	Entropy of saturated liquid - property algorithm	PROPTY	-	-
SG	Entropy of vapor	PROPTY	-	J/g-K
SGSAT	Entropy of saturated vapor - property algorithm	PROPTY	-	-
SIZE(J)	Size parameter of auxiliary or process equipment: equals the mass flow rate of supply stream or, for flash vessels, the exit steam flow rate	/E/	-	kg/hr
SLIQ	Entropy of subcooled liquid - property algorithm	PROPTY	-	J/g-K
SOLBLE	Solubility of salt in water	All	-	g/g
SORT	Stream or process sorting subroutine	MATCH	-	-
SPLIT	Stream dividing subroutine	MATCH	-	-
SR	Reduced entropy	Algor.	-	-
SS	Stream entropy	MATCH	-	J/g-K
SSUP	Entropy of superheated vapor - property algorithm	PROPTY	-	-
STARTM	Starting geothermal supply mass flow rate fraction	GEOTHM	-	-
STORE	Temporary storage variable	ECONMC	-	-
SUPRHT	Fractional superheat of vapor in the evaporation of brine: see text	PROPTY	-	-

VARIABLE	DEFINITION	PROGRAM	TYPE	UNITS
	on PROPTY for further definition			
SV	Specific entropy of saturated vapor	PROPTY	-	J/g-K

***** T *****

VARIABLE	DEFINITION	PROGRAM	TYPE	UNITS
T	Temperature of current fluid stream	PROPTY	-	deg. C
T1	Lower iteration limit for temperature	PROPTY	-	deg. C
T2	Upper iteration limit for temperature	PROPTY	-	deg. C
T(I)	Temperature of process or stream	SORT	-	deg. C
TANGBL	Fraction of geothermal well costs attributable to tangible property	/G/	-	-
TAVG	Average stream temperature in current iteration	PROPTY	-	deg. C
TAXCRD	Investment tax credit rate	/F/	-	-
TAXES	Effect of tax deductions and credits on annual tax expense	ECONMC	-	$
TAXRAT	Overall marginal income tax rate	/F/	-	-
TB	Temperature of saturated brine at given pressure and salt concentration	PROPTY	-	deg. C
TBFIVE	Temperature of saturated brine at given enthalpy and 5% salt concentration	PROPTY	-	deg. C
TDI(I)	Total dissolved solids in fluid stream	/A/	-	g/g
TDS	Total dissolved solids in fluid stream	PROPTY	-	g/g
TDS(I)	Total dissolved solids in fluid stream	/D/	-	g/g
TEMP	Temperature of hottest supply stream	MATCH	-	deg. C
TEMPER	Saturation temperature associated with stream pressure	MATCH	-	deg. C
TEMPT	Temporary storage of temperature	MATCH	-	deg. C
TLIQ	Temperature of subcooled liquid -	PROPTY	-	-

VARIABLE	DEFINITION	PROGRAM	TYPE	UNITS
	property algorithm			
TM(Z)	Temperature requirement for auxiliary energy process number Z	/D/	-	deg. C
TNEW	Exit stream temperature	MATCH	-	deg. C
TP(J)	Unit process temperature requirement	/D/	-	deg. C
TPI(J)	Unit process temperature requirement	/A/	-	deg. C
TR	Reduced temperature	Algor.	-	-
TS(I)	Supply stream temperature	/D/	-	deg. C
TSAT	Saturation temperature associated with stream pressure - property algorithm	MATCH	-	-
TSI(I)	Supply stream temperature	/A/	-	deg. C
TSUM(J)	Sum of TP(J) and DELTA1(J)	MATCH	-	deg. C
TSUP	Temperature of superheated vapor - property algorithm	MATCH	-	-
TV	Temperature of vapor	PROPTY	-	deg. C

***** X *****

VARIABLE	DEFINITION	PROGRAM	TYPE	UNITS
X	Quality of two-phase mixture	Various	-	-
XMAT(1)	Total availability of streams at exit	GEOTHM	-	kW
XMAT(2)	Total availability of input supply streams	GEOTHM	-	kW
XMAT(3)	Total enthalpy of streams at exit	GEOTHM	-	kW
XMAT(4)	Total enthalpy of input supply streams	GEOTHM	-	kW
XMAT(5)	Total mass flow rate of geothermal fluid purchased	GEOTHM	-	kg/hr
XMAT(6)	Total external water supply required	GEOTHM	-	kg/hr
XMAT(7)	Total auxiliary electricity required	GEOTHM	-	kW
XMAT(8)	Total auxiliary fossil fuel required	GEOTHM	-	kW
XMAT(9)	Total process energy requirements	GEOTHM	-	kW

VARIABLE	DEFINITION	PROGRAM	TYPE	UNITS
XMAT1(J)	Equipment size parameter: see definition of AREA(J)	GEOTHM	-	N/D or kW or bars
XMAT2(J)	Cost of process equipment, item J	GEOTHM	-	$
XMAT3(I)	Pressure to which auxiliary energy is delivered	GEOTHM	-	bars
XMAT4(I)	Quantity of auxiliary energy required	GEOTHM	-	kW
XMAT5(J)	Equipment size parameter: equals the supply stream mass flow rate, or for flash vessels, the exit steam flow rate	GEOTHM	-	kg/hr
XMAT6(I)	Temperature to which auxiliary energy is delivered	GEOTHM	-	deg. C
XMUP8	Ratio of supply stream mass flow rate to that associated with the process, all raised to the 0.8 power	MATCH	-	-
XNEW	Quality of exit two-phase mixture	MATCH	-	-
XNPV	Net present value of geothermal system project cash flows	/F/	-	$
XNPVF	Net present value of conventional system cash flows	/F/	-	$
XNPVSV	Net present value of geothermal system savings relative to the conventional system	GEOTHM	-	$
XSFNL	Quality of exit stream, assuming an isentropic process	MATCH	-	-

***** Y *****

Y	Stream selection hierarchy index	MATCH	Integer	-

VARIABLE	DEFINITION	PROGRAM	TYPE	UNITS
	***** Z *****			
Z	Number of auxiliary energy supplies	/D/	Integer	-

4. Flow charts

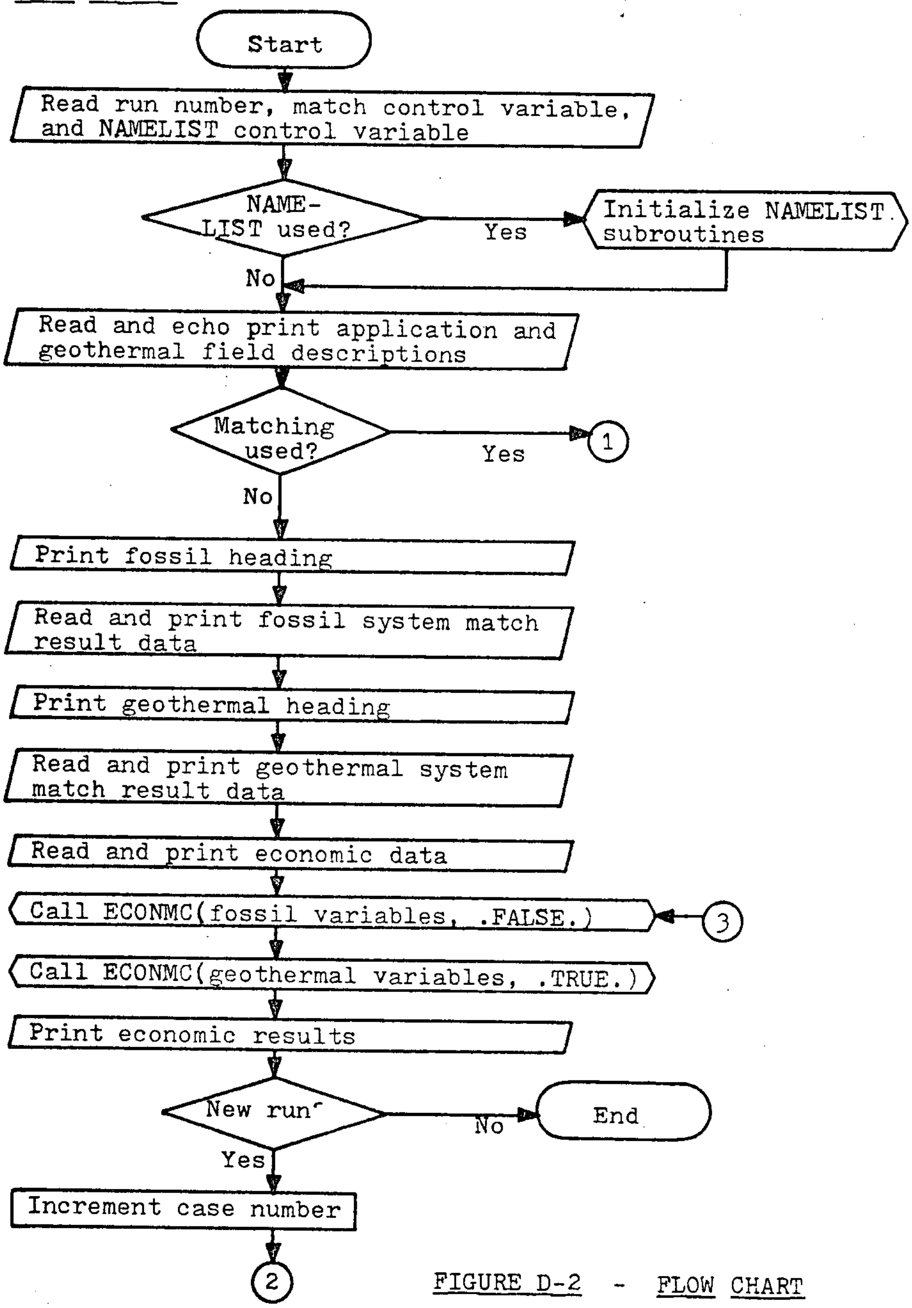
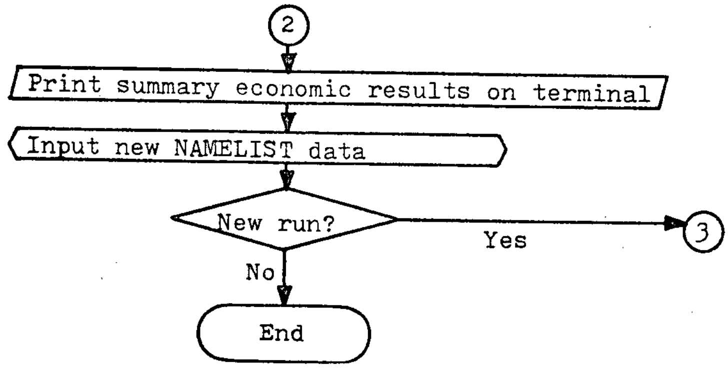
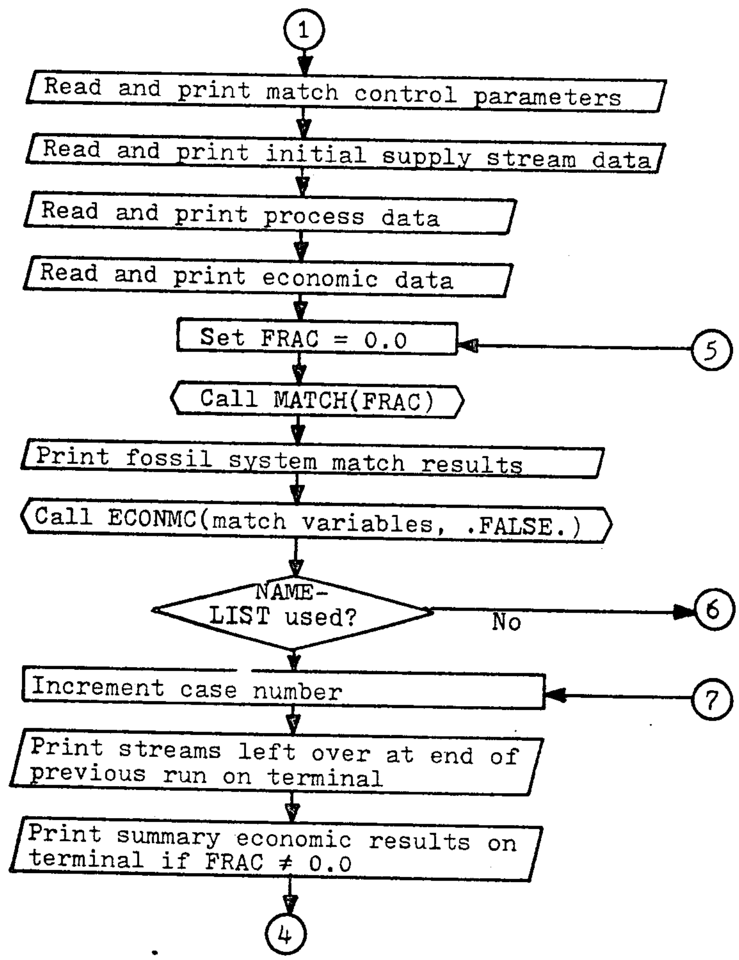
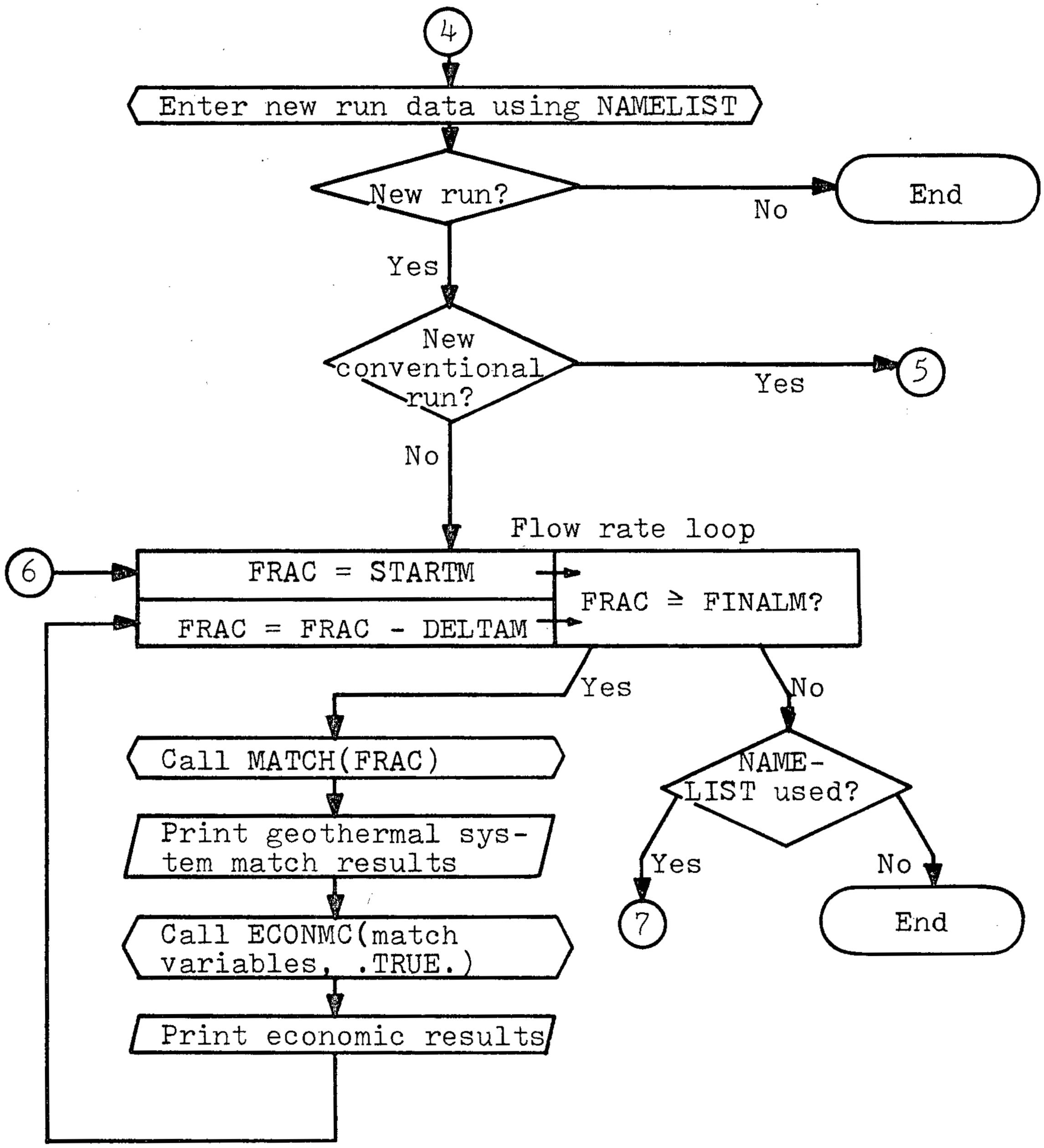


FIGURE D-2 - FLOW CHART FOR PROGRAM GEOTHM


2
Print summary economic results on terminal
Input new NAMELIST data
New run?
Yes
3
No
End


1
Read and print match control parameters
Read and print initial supply stream data
Read and print process data
Read and print economic data
Set FRAC = 0.0
5
Call MATCH(FRAC)
Print fossil system match results
Call ECONMC(match variables, .FALSE.)
NAME-
LIST used?
No
6
Increment case number
7
Print streams left over at end of
previous run on terminal
Print summary economic results on
terminal if FRAC ≠ 0.0
4


4
Enter new run data using NAMELIST
New run?
No
End
Yes
New conventional run?
Yes
5
No
Flow rate loop
6
FRAC = STARTM
FRAC = FRAC - DELTAM
FRAC ≥ FINALM?
Yes
No
Call MATCH(FRAC)
Print geothermal system match results
Call ECONMC(match variables, .TRUE.)
Print economic results
NAMELIST used?
Yes
No
7
End

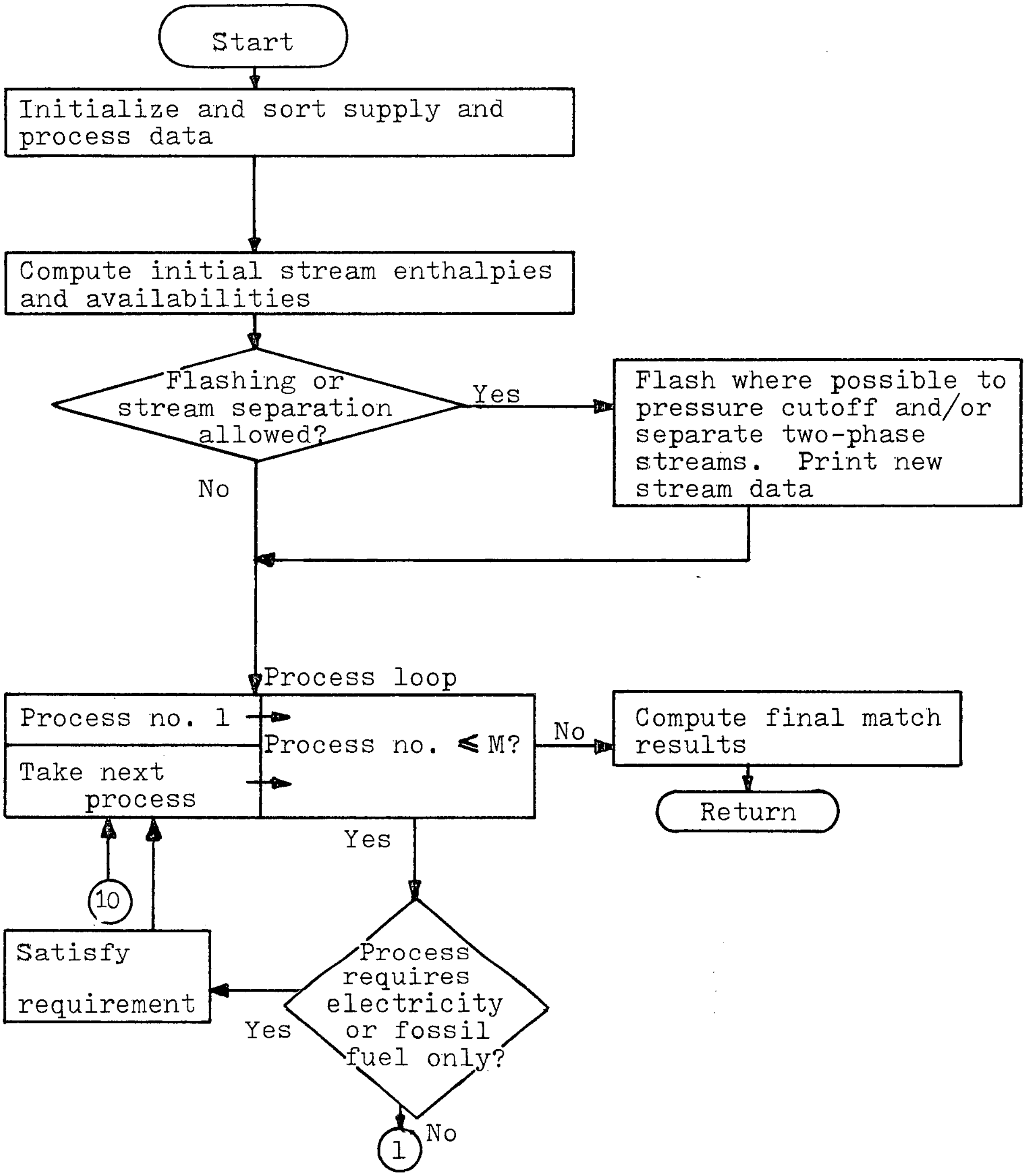
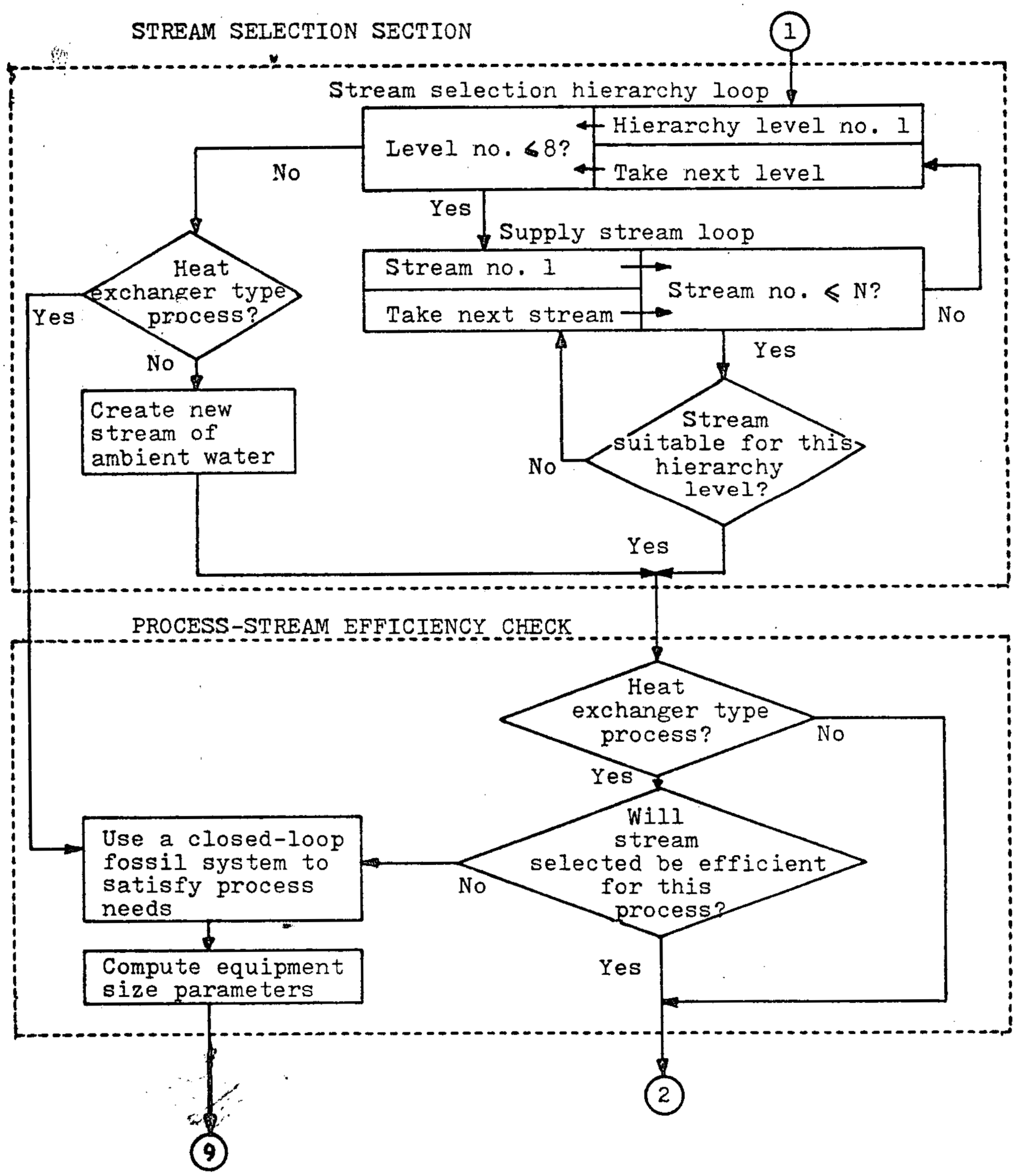
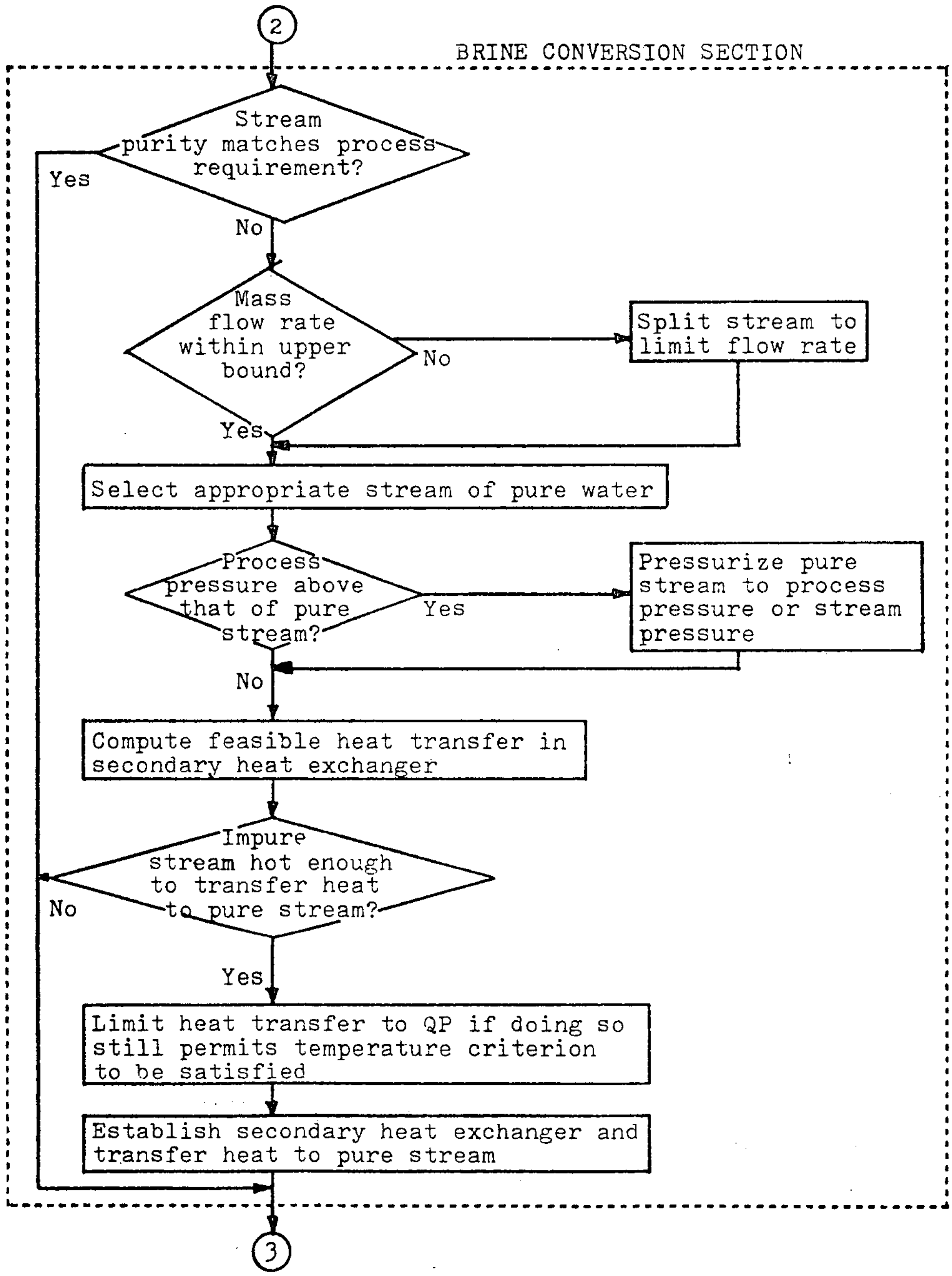
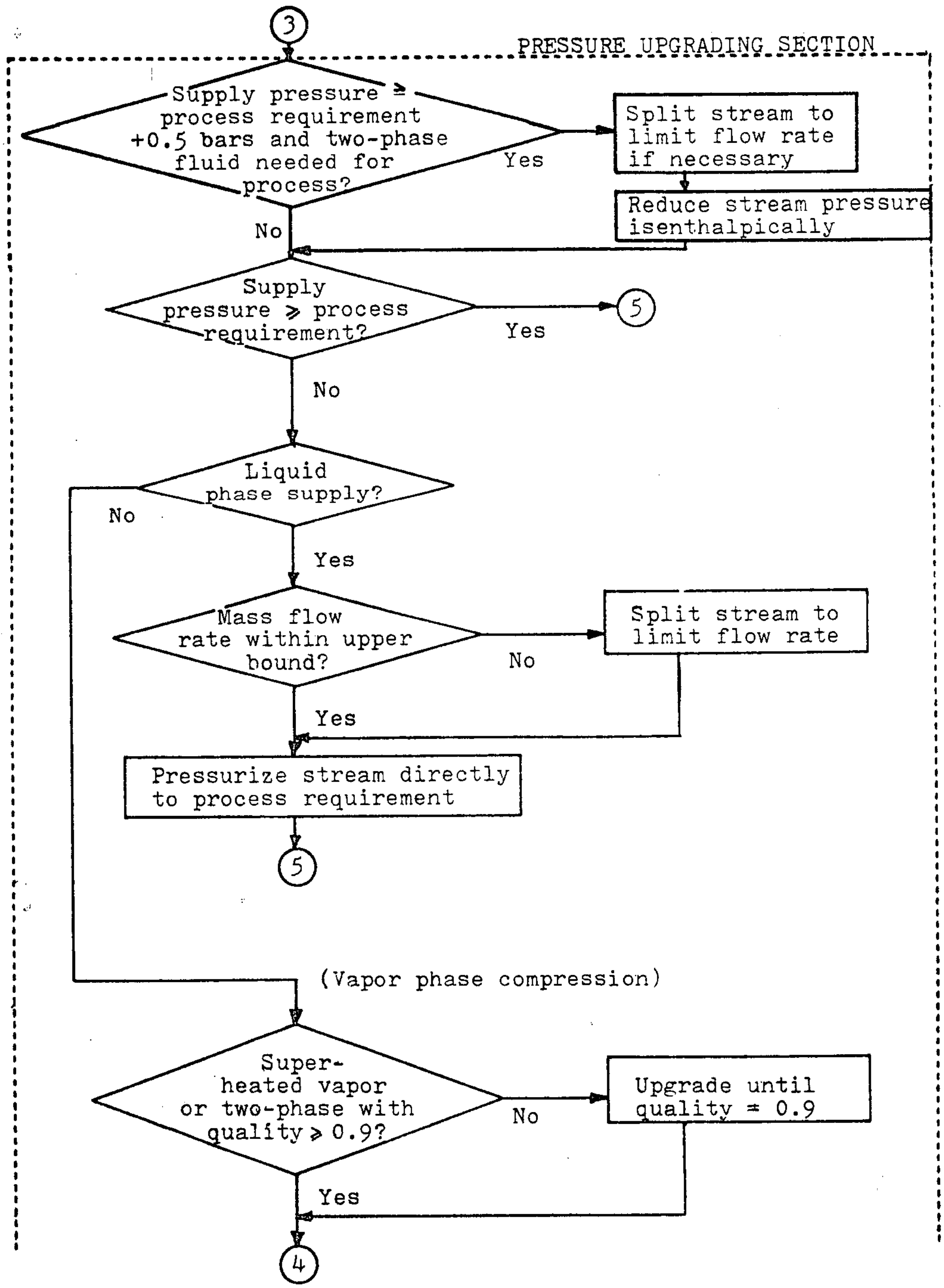
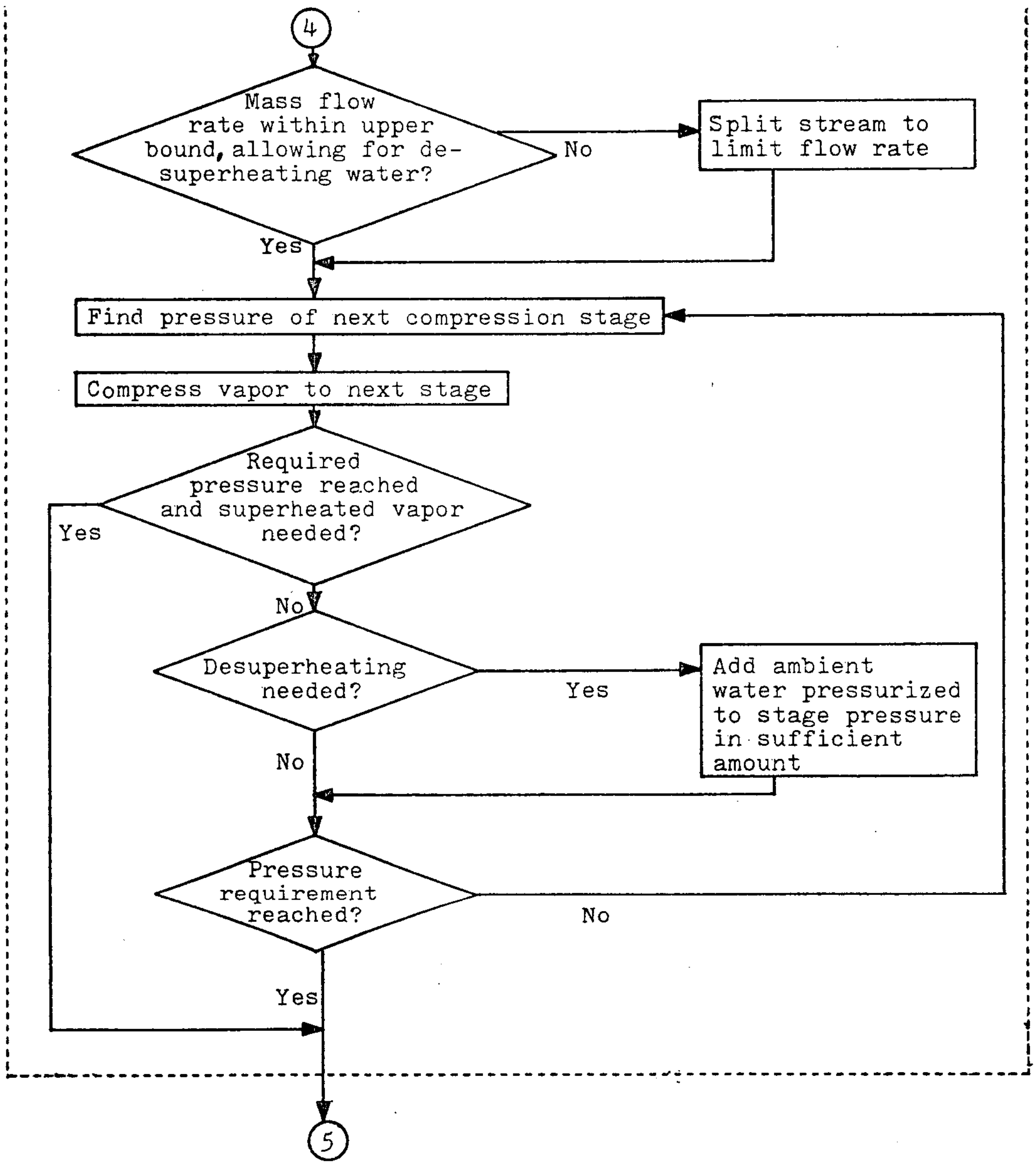


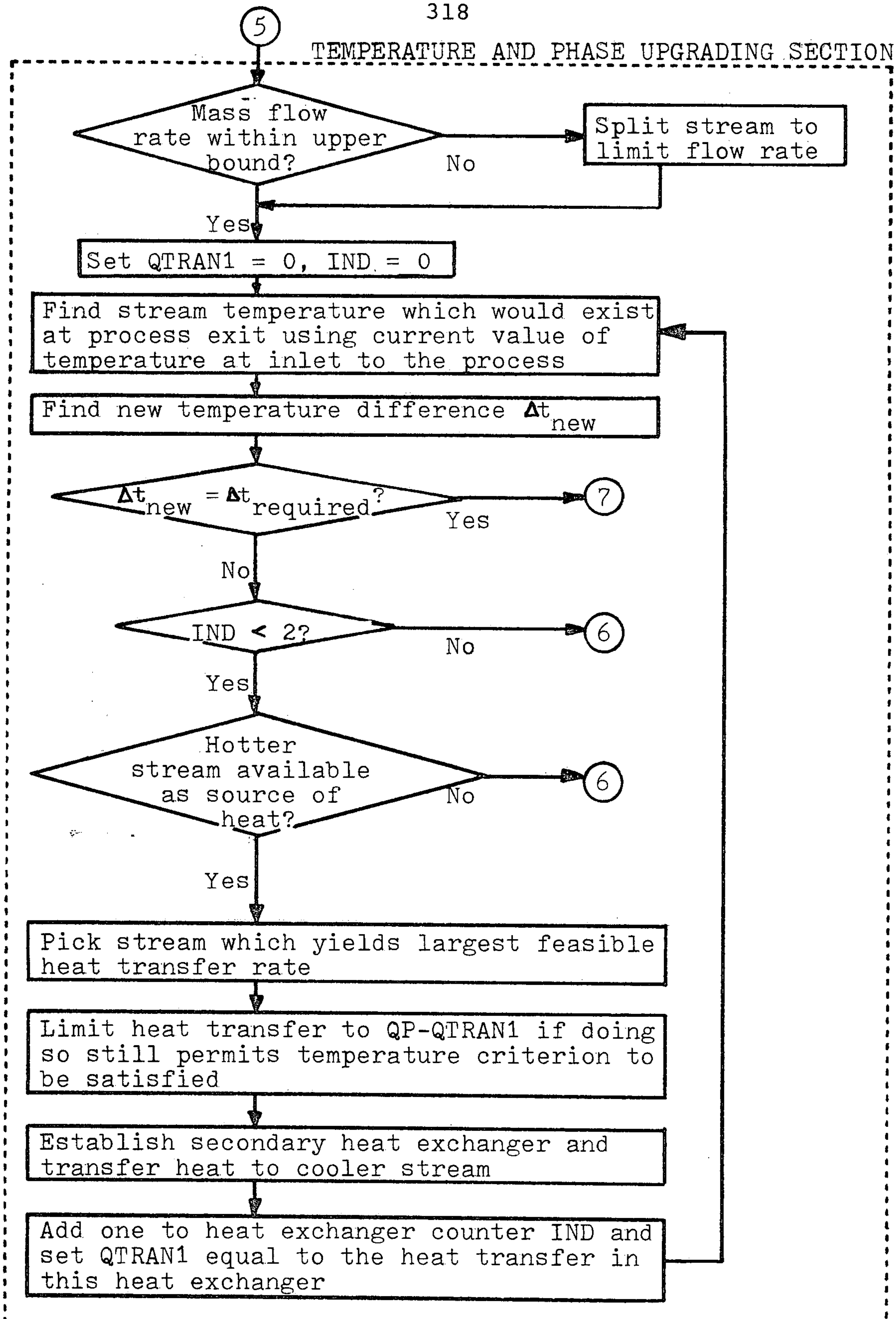
FIGURE D-3 - FLOW CHART FOR PROGRAM MATCH

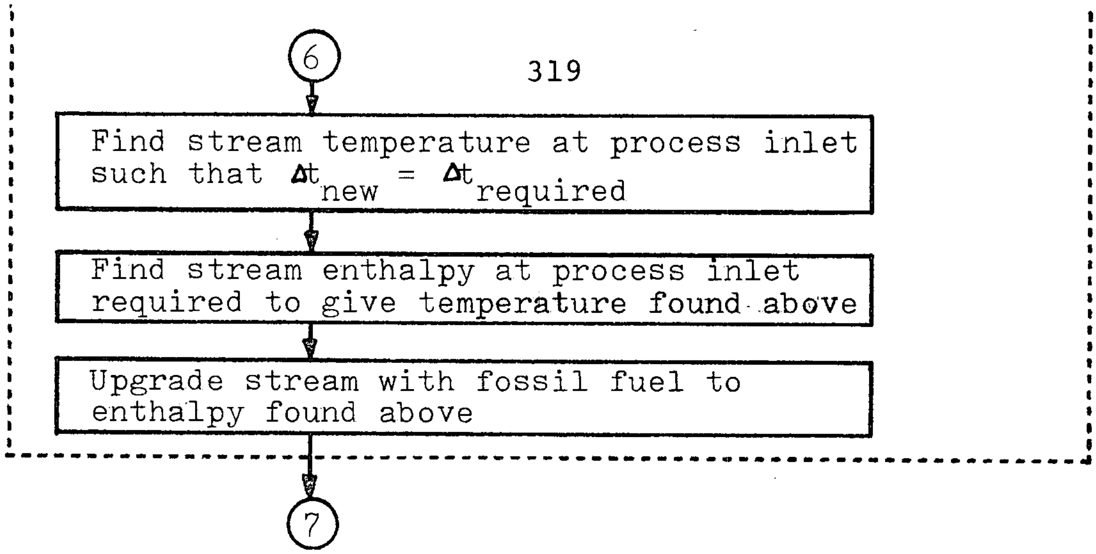

STREAM SELECTION SECTION
1
Stream selection hierarchy loop
Level no. ≤ 8?
Hierarchy level no. 1
Take next level
No
Yes
Supply stream loop
Heat exchanger type process?
Yes
No
Stream no. 1
Take next stream
Stream no. ≤ N?
No
Yes
Create new stream of ambient water
Stream suitable for this hierarchy level?
No
Yes
PROCESS-STREAM EFFICIENCY CHECK
Heat exchanger type process?
No
Yes
Use a closed-loop fossil system to satisfy process needs
Will stream selected be efficient for this process?
No
Yes
Compute equipment size parameters
9
2

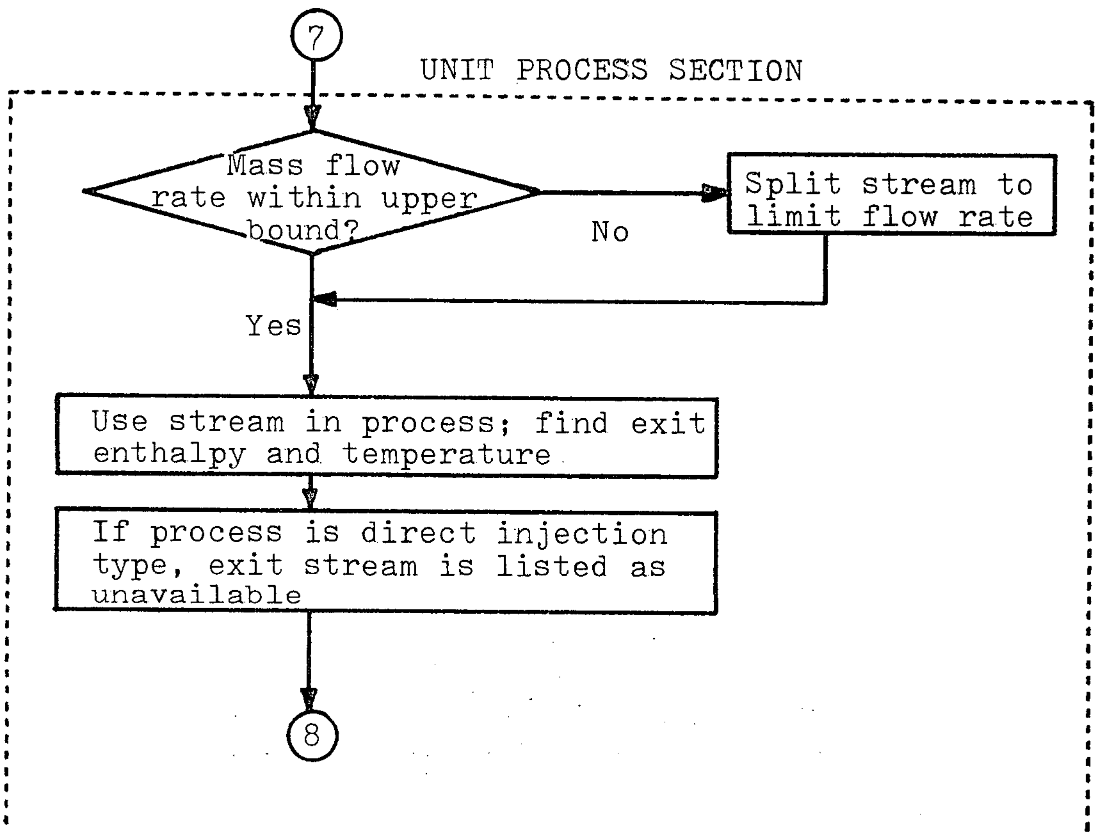

2
BRINE CONVERSION SECTION
Stream purity matches process requirement?
Yes
No
Mass flow rate within upper bound?
No
Split stream to limit flow rate
Yes
Select appropriate stream of pure water
Process pressure above that of pure stream?
Yes
Pressurize pure stream to process pressure or stream pressure
No
Compute feasible heat transfer in secondary heat exchanger
Impure stream hot enough to transfer heat to pure stream?
No
Yes
Limit heat transfer to QP if doing so still permits temperature criterion to be satisfied
Establish secondary heat exchanger and transfer heat to pure stream
3

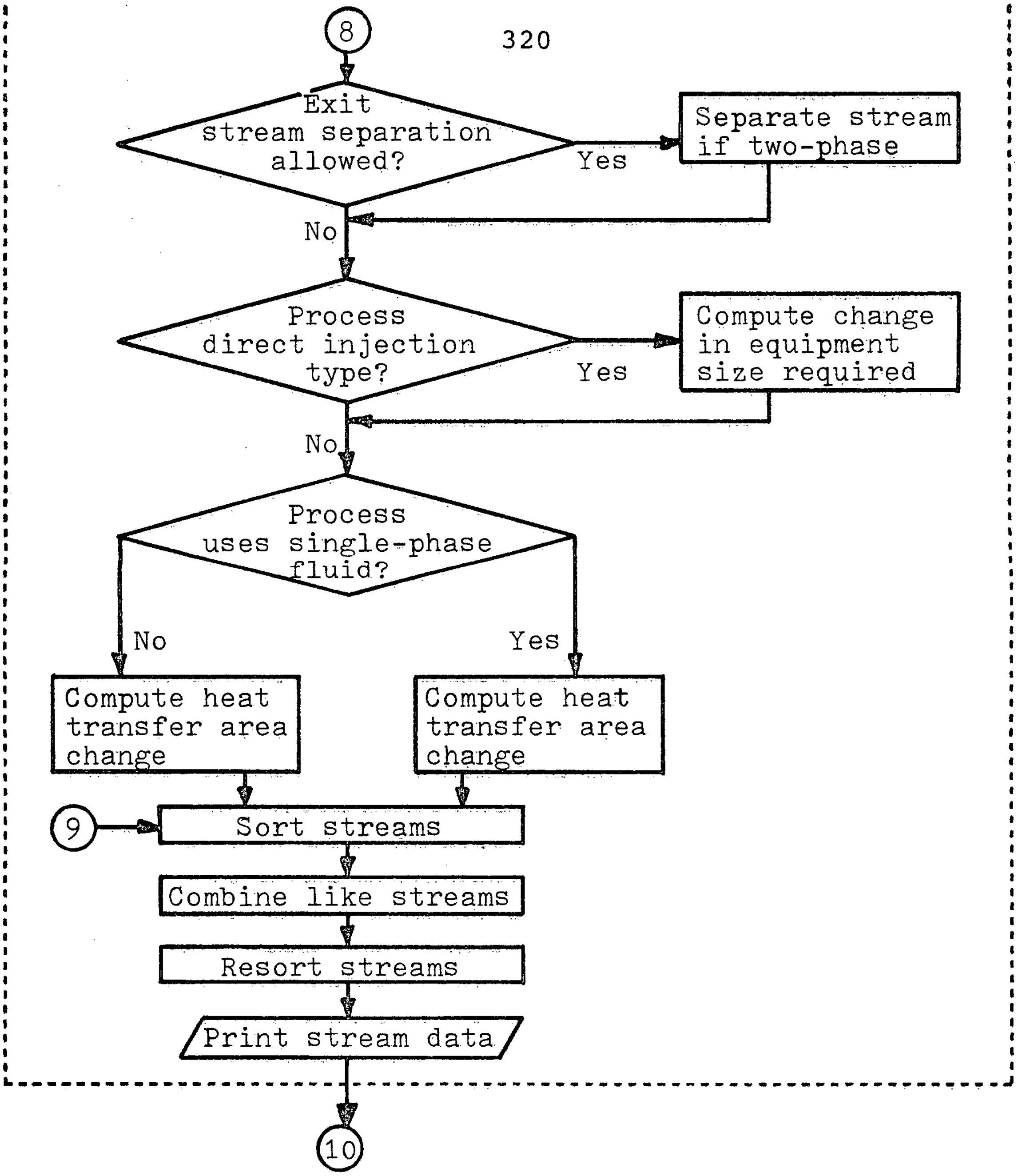

3
PRESSURE UPGRADING SECTION
Supply pressure ≥ process requirement +0.5 bars and two-phase fluid needed for process?
Yes
Split stream to limit flow rate if necessary
Reduce stream pressure isenthalpically
No
Supply pressure ≥ process requirement?
Yes
5
No
Liquid phase supply?
No
Yes
Mass flow rate within upper bound?
No
Split stream to limit flow rate
Yes
Pressurize stream directly to process requirement
5
(Vapor phase compression)
Super-heated vapor or two-phase with quality ≥ 0.9?
No
Upgrade until quality = 0.9
Yes
4


4
Mass flow rate within upper bound, allowing for de-superheating water?
No
Split stream to limit flow rate
Yes
Find pressure of next compression stage
Compress vapor to next stage
Required pressure reached and superheated vapor needed?
Yes
No
Desuperheating needed?
Yes
Add ambient water pressurized to stage pressure in sufficient amount
No
Pressure requirement reached?
No
Yes
5


5
TEMPERATURE AND PHASE UPGRADING SECTION
Mass flow rate within upper bound?
No
Split stream to limit flow rate
Yes
Set QTRAN1 = 0, IND = 0
Find stream temperature which would exist at process exit using current value of temperature at inlet to the process
Find new temperature difference Δt_{new}
$\Delta t_{new} = \Delta t_{required}$?
Yes
7
No
IND < 2?
No
6
Yes
Hotter stream available as source of heat?
No
6
Yes
Pick stream which yields largest feasible heat transfer rate
Limit heat transfer to QP-QTRAN1 if doing so still permits temperature criterion to be satisfied
Establish secondary heat exchanger and transfer heat to cooler stream
Add one to heat exchanger counter IND and set QTRAN1 equal to the heat transfer in this heat exchanger


6
Find stream temperature at process inlet such that $\Delta t_{new} = \Delta t_{required}$
Find stream enthalpy at process inlet required to give temperature found above
Upgrade stream with fossil fuel to enthalpy found above
7


7
UNIT PROCESS SECTION
Mass flow rate within upper bound?
No
Split stream to limit flow rate
Yes
Use stream in process; find exit enthalpy and temperature
If process is direct injection type, exit stream is listed as unavailable
8


8
Exit stream separation allowed?
Yes
Separate stream if two-phase
No
Process direct injection type?
Yes
Compute change in equipment size required
No
Process uses single-phase fluid?
No
Yes
Compute heat transfer area change
Compute heat transfer area change
9
Sort streams
Combine like streams
Resort streams
Print stream data
10

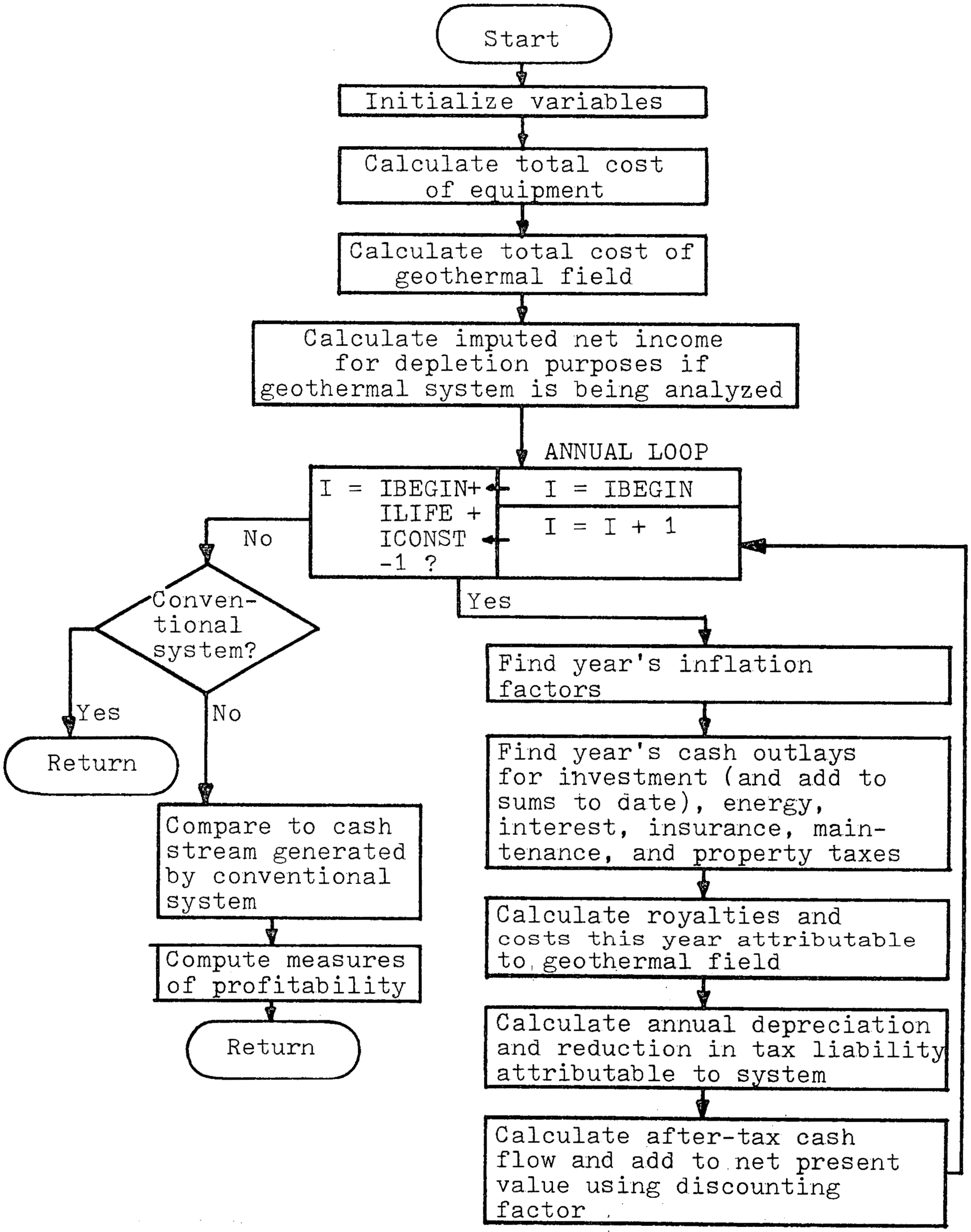


FIGURE D-4 - FLOW CHART FOR PROGRAM ECONMC

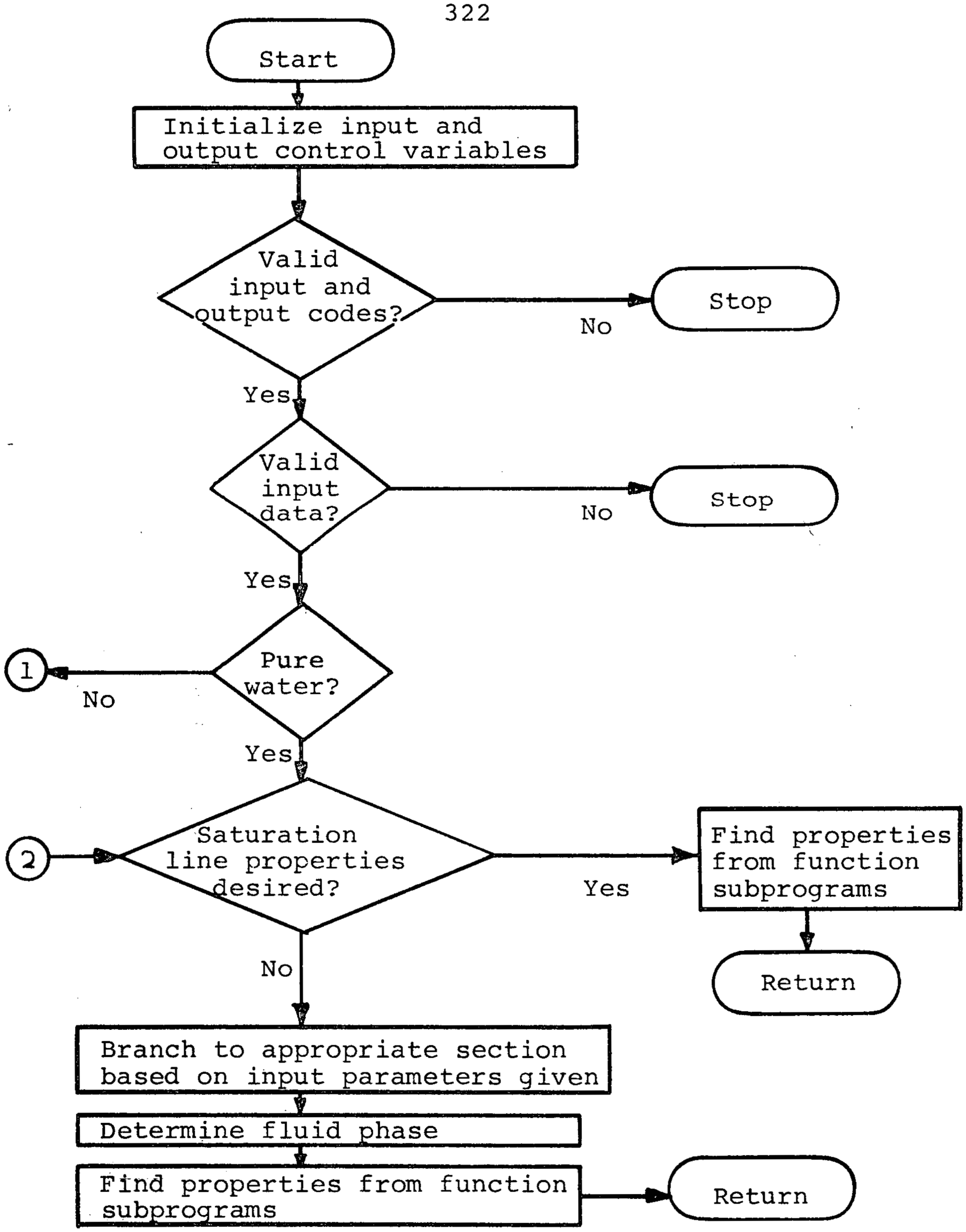
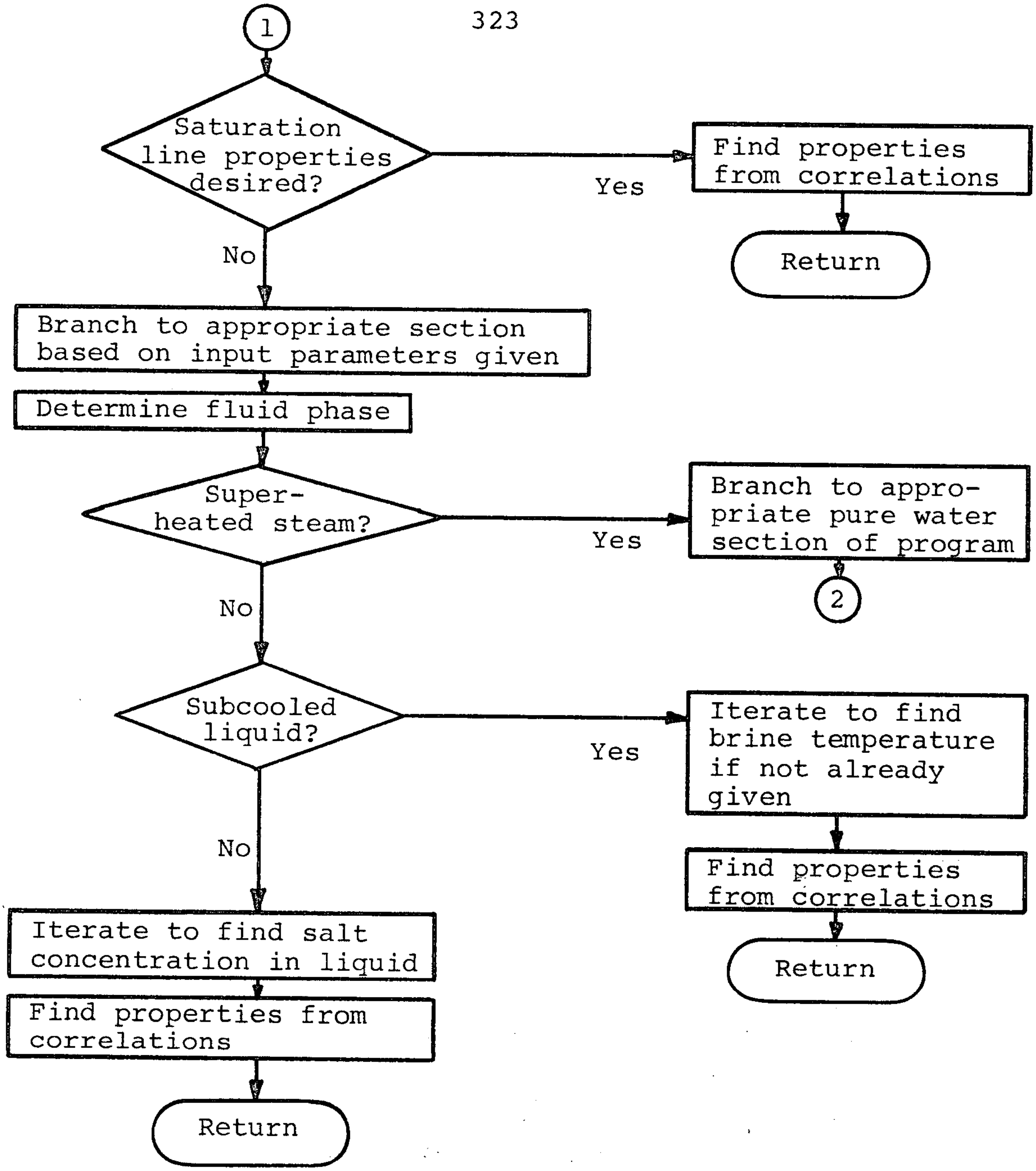


FIGURE D-5 - FLOW CHART FOR SUBROUTINE PROPTY


1
Saturation line properties desired?
Yes
No
Find properties from correlations
Return
Branch to appropriate section based on input parameters given
Determine fluid phase
Super-heated steam?
Yes
No
Branch to appro-priate pure water section of program
2
Subcooled liquid?
Yes
No
Iterate to find brine temperature if not already given
Find properties from correlations
Return
Iterate to find salt concentration in liquid
Find properties from correlations
Return

5. Computer program listings

a. Program GEOTHM

```
C ***********************************************************
C *                                                         *
C *         THIS PROGRAM ANALYZES THE POTENTIAL OF          *
C *        GEOTHERMAL ENERGY FOR USE IN INDUSTRIAL          *
C *              PROCESS HEAT APPLICATIONS                  *
C *                                                         *
C ***********************************************************
C *                                                         *
C *  -- THIS PROGRAM WAS WRITTEN IN 1979 BY MICHAEL B.      *
C *       PACKER AT THE MASSACHUSETTS INSTITUTE OF TECH-    *
C *       NOLOGY FOR THE DEPARTMENT OF ENERGY.              *
C *  -- METRIC UNITS ARE EMPLOYED THROUGHOUT:               *
C *       TEMPERATURE= DEGREES C     PRESSURE= BARS         *
C *       ENTHALPY   = KJ/KG         ENTROPY = J/G-K        *
C *       FLOW RATE  = KG/HR         ENERGY  = KJ           *
C *       ENERGY RATE= KW                                   *
C *  -- THE PROGRAM CALLS THE FOLLOWING SUBPROGRAMS:        *
C *       MATRD = READS MATCH RESULT DATA                   *
C *       MATPRN= PRINTS MATCH RESULT DATA                  *
C *       ECODAT= READS AND PRINTS ECONOMIC DATA            *
C *       ECORES= PRINTS ECONOMIC RESULTS                   *
C *       MATCH = PERFORMS STREAM-PROCESS MATCHING          *
C *       ECONMC= PERFORMS ECONOMIC ANALYSIS                *
C *                                                         *
C *       THREE NAMELIST SUBROUTINES ARE ALSO CALLED.       *
C *       SUBROUTINE MATCH CALLS NUMEROUS SUBROUTINES       *
C *         IN ADDITION.   SEE ITS LISTING FOR DETAILS.     *
C *       A BLOCK DATA SUBPROGRAM IS ALSO NEEDED.           *
C *  -- SEPARATE DOCUMENTATION INCLUDES FLOW CHARTS,        *
C *       COMPLETE VARIABLE LISTS, AN INPUT GUIDE,          *
C *       AND A "WALK-THROUGH" DESCRIPTION OF PROGRAM       *
C *       OPERATING PRINCIPLES.                             *
C *                                                         *
C ***********************************************************
C
      REAL IRR, MCHECK(4), MP(50), MPI(50), MS(50), MSI(50),
     1 MTOTAL, MWATER    , NWELLR
      INTEGER CASNUM, PHASE(50), PHASEI(50), PHASUP, RUNNUM,
     1 Y, Z
      INTEGER*2 COMPON(15), INDUST(40), LOCATE(40)
      DIMENSION    CAREA(50), XMAT(9)   , XMAT1(50), XMAT2(50),
     1  XMAT3(50), XMAT4(50), XMAT5(50), XMAT6(50), MAT(4)    ,
     1 MAT2(50)
C ----- THREE LINES FOLLOW FOR NAMELIST (MACHINE-DEPENDENT) ---
      PARAMETER NUM=16
      CHARACTER*15 NAMES(NUM)
      INTEGER*4 IDESC(NUM)
C
```

```
      COMMON /A/ DELT1I(50), DELT2I(50), ETI(50), GAMMAI(50),
     1 HSI(50), MCHECK    , MPI       , MSI     , PPI(50)    ,
     1 PSF(50), PSI(50)   , QPI(50)   , TDI(50), TPI(50)    ,
     1 TSI(50), IAUX      , IFLASH    , IPPURI(50), ISEPRT ,
     1 ISPRT2 , ISPURI(50), MI        , NI      , PHASEI
      COMMON /D/ DELTA1(50), DELTA2(50), DELTA3(50), ETA(50),
     1 GAMMA(50) , HS(50)  , MP         , MS         , PM(50) ,
     1 PP(50)    , PS(50)  , QM(50)     , QP(50)     , TDS(50),
     1 TM(50)    , TP(50)  , TS(50)     , IPPURE(50),
     1 ISPURE(50), M       , MORDER(50), N           ,
     1 NORDER(50), PHASE   , Z
      COMMON /E/ AREA(50), AVAIL2  , AVAILS, CFLUID, ENTOT2,
     1 ENTOTL  , MTOTAL  , MWATER  , QESUM , QFSUM , QSUM  ,
     2 SIZE(50), IAREA   , ITYP(50)
      COMMON /F/ BONDRT, CASH(40) , CASHF(40) , CDSCNT ,
     1 CELECT , CFOSSL, CINFLT(8), CINSUR    , CINVSF , CINVST,
     1 COPRAT , CUMINV, DEBTEQ    , FINVST(40), IRR    , OPFRAC,
     1 PROFIT , PROPTX, SALVAG    , SAVING(40), TAXCRD , TAXRAT,
     1 XNPV   , XNPVF , IBEGIN    , ICONST    , ILIFE  , LIFEBD,
     1 LIFETM , IPAYBK
      COMMON /G/ CLAND    , CMAINT  , COTHER, CREPLC, CROYAL,
     1 CTRANS   , CUMGTC  , CUMINC  , CWELL , DPLBAS, NWELLR,
     2 PROBC(3), PROBM(3), PROBT(3), ROIREQ, TANGBL, NWELLI,
     3 NWELLP
C
      DATA IN, IOUT, CASNUM/8,6,1/
C
C ----- READ RUN TYPE, APPLICATION AND GT FIELD DESCRIPTIONS -
C
      READ  (IN,1020)   RUNNUM, IMATCH, INAME
      IF (INAME .EQ. 0) GO TO 100
C ----- EIGHT LINES FOLLOW FOR NAMELIST (MACHINE-DEPENDENT) ---
      CALL NML$NAMESET(NAMES,'TSI,PSI,HSI,MSI,PSF,CFLUID,'//
     1 'CFOSSL,CELECT,CINFLT,DEBTEQ,TAXRAT,CDSCNT,FINVST,QPI,'//
     1 'INAME,CAREA')
      CALL NML$DESSTUF(IDESC,%DESCR(TSI),%DESCR(PSI),
     1 %DESCR(HSI),%DESCR(MSI),%DESCR(PSF),%DESCR(CFLUID),
     1 %DESCR(CFOSSL),%DESCR(CELECT),%DESCR(CINFLT),
     1 %DESCR(DEBTEQ),%DESCR(TAXRAT),%DESCR(CDSCNT),
     1 %DESCR(FINVST),%DESCR(QPI),%DESCR(INAME),%DESCR(CAREA))
C
  100 READ  (IN,1160)   LOCATE
      WRITE (IOUT,1161) RUNNUM, CASNUM
      WRITE (IOUT,1162) LOCATE
      READ  (IN,1660)   INDUST
      WRITE (IOUT,1662) INDUST
      IF (IMATCH .EQ. 1) GO TO 150
C *************************************************************
```

```
C
C ----- PROCESS-STREAM MATCHING NOT PERFORMED ---------------
C
C ************************************************************
C
C ----- READ AND PRINT MATCH RESULT DATA --------------------
C
      WRITE (IOUT,1161) RUNNUM, CASNUM
      WRITE (IOUT,1028)
      CALL MATRD(XMAT1   , XMAT(1), XMAT(2), XMAT2   , XMAT(3),
     1  XMAT(4), XMAT(5), XMAT(6), XMAT3   , XMAT(7), XMAT(8),
     1  XMAT4   , XMAT(9), XMAT5   , XMAT6   , MAT(1) , MAT2    ,
     1  MAT(2) , MAT(3) , MAT(4) )
      CALL MATPRN(XMAT1  , XMAT(1), XMAT(2), XMAT2   , XMAT(3),
     1  XMAT(4), XMAT(5), XMAT(6), XMAT3   , XMAT(7), XMAT(8),
     1  XMAT4   , XMAT(9), XMAT5   , XMAT6   , MAT(1) , MAT2    ,
     1  MAT(2) , MAT(3) , MAT(4) )
      IF (MAT(2) .GT. 0) WRITE (IOUT,2130) (J,XMAT2(J),
     1                                        J = 1,MAT(2))
      WRITE (IOUT,1161) RUNNUM, CASNUM
      WRITE (IOUT,1029)
      CALL MATRD( AREA, AVAIL2, AVAILS, CAREA, ENTOT2,
     1  ENTOTL, MSI(1), MWATER, PM    , QESUM, QFSUM ,
     1  QM     , QSUM   , SIZE   , TM    , IAREA, ITYP  ,
     1  MI     , NI     , Z      )
      CALL MATPRN(AREA, AVAIL2, AVAILS, CAREA, ENTOT2,
     1  ENTOTL, MSI(1), MWATER, PM    , QESUM, QFSUM ,
     1  QM     , QSUM   , SIZE   , TM    , IAREA, ITYP  ,
     1  MI     , NI     , Z      )
      IF (MI .GT. 0) WRITE (IOUT,2130) (J, CAREA(J), J = 1,MI)
C
C ----- READ AND PRINT ECONOMIC DATA, THEN DO ANALYSIS -------
C
      CALL ECODAT(RUNNUM, CASNUM)
  120 WRITE (IOUT,1161) RUNNUM, CASNUM
      CALL ECONMC(XMAT1  , XMAT2, CFLUID, XMAT(5), XMAT(6),
     1  XMAT(7), XMAT(8), XMAT5, MAT(1), MAT2    , .FALSE.)
      CALL ECONMC(AREA, CAREA, CFLUID, MSI(1), MWATER, QESUM,
     1  QFSUM,     SIZE, IAREA, ITYP   , .TRUE.)
      CALL ECORES(1.0)
C
C ----- PREPARE NEW RUN IF DESIRED -------------------------
C
      IF (INAME .EQ. 0) WRITE (IOUT,9999)
      IF (INAME .EQ. 0) STOP
      CASNUM= CASNUM + 1
      XNPVSV= XNPV - XNPVF
      WRITE (5,2440) XNPVSV, IPAYBK, IRR
```

```
      WRITE (IOUT,1161) RUNNUM, CASNUM
C         FOLLOWING TWO LINES ARE MACHINE-DEPENDENT **********
      CALL NAMELIST('ENTER NEXT RUN DATA:',NAMES,IDESC,NUM,
     1  5,IOUT,5)
      IF (INAME .LE. 0) WRITE (IOUT,9999)
      IF (INAME .LE. 0) STOP
      GO TO 120
C ***********************************************************
C
C ----- PROCESS-STREAM MATCHING PERFORMED --------------------
C
C ***********************************************************
C
C ----- READ AND PRINT CONTROL PARAMETERS --------------------
C
  150 READ  (IN,1750) ISEPRT, ISPRT2, IFLASH, IAUX,
     1                STARTM, FINALM, DELTAM, (MCHECK(I),I=1,4)
      IF (ISEPRT .EQ. 1) WRITE (IOUT,1755)
      IF (ISEPRT .EQ. 0) WRITE (IOUT,1756)
      IF (ISPRT2 .EQ. 1) WRITE (IOUT,1760)
      IF (ISPRT2 .EQ. 0) WRITE (IOUT,1761)
      IF (IFLASH .EQ. 1) WRITE (IOUT,1765)
      IF (IFLASH .EQ. 0) WRITE (IOUT,1766)
      IF (IAUX   .EQ. 1) WRITE (IOUT,1770)
      IF (IAUX   .EQ. 0) WRITE (IOUT,1771)
      WRITE (IOUT,1780) STARTM, FINALM, DELTAM,
     1                  (MCHECK(I), I=1,4)
      IF (FINALM .GT. STARTM) WRITE (IOUT,1782)
      IF (FINALM .GT. STARTM) STOP
C
C ----- READ AND PRINT INITIAL SUPPLY STREAM DATA ------------
C
      READ  (IN,1200) NI
      WRITE (IOUT,1161) RUNNUM, CASNUM
      WRITE (IOUT,1202)
      DO 160 I = 1,NI
       READ (IN,1204) TSI(I), PSI(I), HSI(I), MSI(I)
       READ (IN,1206) COMPON, TDI(I), ISCALE, ITOXIC, ETI(I)
       READ (IN,1208) PSF(I)
       IF (ISCALE.GE.4 .OR.  ITOXIC.GE.4) ISPURI(I)= 0
       IF (ISCALE.LE.3 .AND. ITOXIC.LE.3) ISPURI(I)= 1
       WRITE (IOUT,1230) TSI(I), PSI(I), HSI(I), MSI(I),
     1                PSF(I), COMPON, TDI(I), ISCALE, ITOXIC,
     1                ETI(I), ISPURI(I)
  160 CONTINUE
C
C ----- READ AND PRINT PROCESS DATA --------------------------
C
```

```
      READ  (IN,1700) MI
      WRITE (IOUT,2000)
      DO 300 J = 1,MI
       READ (IN,1702) TPI(J), PPI(J), QPI(J), MPI(J),
     1                 IPPURI(J), PHASEI(J), GAMMAI(J),
     1                 DELT1I(J), DELT2I(J), CAREA(J)
       WRITE (IOUT,2008) J, TPI(J), PPI(J), QPI(J), MPI(J),
     1                 IPPURI(J), PHASEI(J), GAMMAI(J),
     1                 DELT1I(J), DELT2I(J)
  300 CONTINUE
      WRITE (IOUT,2130) (J, CAREA(J), J=1,MI)
C
C ----- READ AND PRINT ECONOMIC DATA -----------------------
C
      CALL ECODAT(RUNNUM, CASNUM)
C
C ----- PERFORM MATCH FOR CONVENTIONAL SYSTEM ---------------
C
  700 FRAC  = 0.0
      WRITE (IOUT,1161) RUNNUM, CASNUM
      WRITE (IOUT,1010) FRAC
      CALL MATCH(FRAC)
      WRITE (IOUT,1161) RUNNUM, CASNUM
      WRITE (IOUT,1790) FRAC
      MS(1) = MSI(1)*FRAC
      CALL MATPRN(AREA, AVAIL2, AVAILS, CAREA, ENTOT2,
     1  ENTOTL, MS(1) , MWATER, PM    , QESUM, QFSUM ,
     1  QM     , QSUM  , SIZE  , TM    , IAREA, ITYP  ,
     1  MI     , NI    , Z      )
      CALL ECONMC(AREA, CAREA, CFLUID, MS(1), MWATER, QESUM,
     1  QFSUM,    SIZE, IAREA, ITYP  , .FALSE.)
C
C ----- ENTER NEW DATA IF DESIRED FOR GEOTHERMAL CASE --------
C
      IF (INAME .EQ. 0) GO TO 800
  710 CASNUM= CASNUM + 1
      WRITE (5,2400)
      DO 720 K = 1,N
       I      = NORDER(K)
       IF (MS(I) .LT. 20.0) GO TO 720
       WRITE (5,2420) I, TS(I), PS(I), HS(I), MS(I),
     1                 ISPURE(I), ETA(I), TDS(I)
  720 CONTINUE
      IF (FRAC .NE. 0.0) XNPVSV= XNPV - XNPVF
      IF (FRAC .NE. 0.0) WRITE (5,2440) XNPVSV, IPAYBK, IRR
      WRITE (IOUT,1161) RUNNUM, CASNUM
C         FOLLOWING TWO LINES ARE MACHINE-DEPENDENT **********
      CALL NAMELIST('ENTER NEXT RUN DATA:',NAMES,IDESC,NUM,
```

```
     1  5,IOUT,5)
      IF (INAME .EQ. 0) WRITE (IOUT,9999)
      IF (INAME .EQ. 0) STOP
      IF (INAME .EQ. 2) GO TO 700
C
C ----- GEOTHERMAL FLOW RATE LOOP ---------------------------
C
  800 FRAC  = STARTM
  810  WRITE (IOUT,1161) RUNNUM, CASNUM
       WRITE (IOUT,1010) FRAC
       CALL MATCH(FRAC)
       WRITE (IOUT,1161) RUNNUM, CASNUM
       WRITE (IOUT,1790) FRAC
       MS(1) = MSI(1)*FRAC
       CALL MATPRN(AREA, AVAIL2, AVAILS, CAREA, ENTOT2,
     1   ENTOTL, MS(1) , MWATER, PM     , QESUM, QFSUM ,
     1   QM     , QSUM   , SIZE   , TM     , IAREA, ITYP   ,
     1   MI     , NI     , Z      )
       WRITE (IOUT,1161) RUNNUM, CASNUM
       CALL ECONMC(AREA, CAREA, CFLUID, MS(1), MWATER, QESUM,
     1   QFSUM,    SIZE, IAREA, ITYP   , .TRUE.)
       CALL ECORES(FRAC)
       FRAC  = FRAC - DELTAM
      IF (FRAC .GE. FINALM) GO TO 810
C
      IF (INAME .EQ. 0) WRITE (IOUT,9999)
      IF (INAME .EQ. 0) STOP
      GO TO 710
C
 1000 FORMAT (1H1)
 1010 FORMAT (1H0,40HM A T C H I N G   S U B R O U T I N E    ,
     1 17HR U N:     FRAC = ,F6.4/1H+,23H_______   __,
     1 22H_______    __)
 1020 FORMAT (3I5)
 1028 FORMAT (1H0,40HC O N V E N T I O N A L   S Y S T E M    ,
     1 34HM A T C H   R E S U L T   D A T A:)
 1029 FORMAT (1H0,40HG E O T H E R M A L   S Y S T E M   M A ,
     1 30HT C H   R E S U L T   D A T A:)
 1160 FORMAT (40A2)
 1161 FORMAT (1H1,21HR U N   N U M B E R: ,I3,13H.   C A S E  ,
     1 14H N U M B E R: ,I3/1H+,19H__   _____,9X,
     1 21H___   _____/)
 1162 FORMAT (1H0,29HGEOTHERMAL RESOURCE LOCATION:/1H ,2X,40A2)
 1200 FORMAT (I5)
 1202 FORMAT (1H0,36HS U P P L Y   S T R E A M   D A T A:/)
 1204 FORMAT (3F10.3,F20.3)
 1206 FORMAT (15A2,F10.1,2I5,F10.2)
 1208 FORMAT (F10.3)
```

```
1230 FORMAT (1H0,40HTEMPERATURE . . . . . . . . . . . . . . . . ,
    1 5H. . =,F11.2,3H  C/1H ,28HPRESSURE. . . . . . . . . . . ,
    1 17H. . . . . . . . =,F11.3,6H  BARS/1H ,12HENTHALPY. . ,
    1 33H. . . . . . . . . . . . . . . . . . =,F11.2,5H  J/G/1H ,
    1 45HMASS FLOW RATE. . . . . . . . . . . . . . . . =,1PE11.4,
    1 7H  KG/HR/1H ,38HMINIMUM ALLOWABLE FLASH PRESSURE. . . ,
    1 7H. . . =,0PF11.3,6H  BARS/1H ,21HFLUID CHEMISTRY . . .,
    1 26H . . . . . . . . . . . =  ,15A2/1H ,13HTOTAL DISSOLV,
    1 32HED SOLIDS. . . . . . . . . . . . =,F11.5,7H  KG/KG/1H ,
    1 45HSCALING INDEX . . . . . . . . . . . . . . . . =,I11/1H ,
    1 45HTOXICITY INDEX. . . . . . . . . . . . . . . . =,I11/1H ,
    1 45HAMOUNT OF NON-CONDENSABLE GAS PRESENT . . . =,F11.4,
    1 7H  KG/KG/1H ,38HCOMPUTED STREAM PURITY PARAMETER. . . ,
    1 7H. . . =,I11)
1660 FORMAT (40A2)
1662 FORMAT (1H0,31HINDUSTRIAL PROCESS APPLICATION:/1H ,2X,
    1 40A2)
1700 FORMAT (I5)
1702 FORMAT (2F8.3,2E10.3,2I5,3F8.3,E10.3)
1750 FORMAT (4I5,7F8.3)
1755 FORMAT (1H0,38HSUPPLY STREAM PHASE SEPARATION ALLOWED)
1756 FORMAT (1H0,42HSUPPLY STREAM PHASE SEPARATION NOT ALLOWED)
1760 FORMAT (1H0,39HGENERAL STREAM PHASE SEPARATION ALLOWED)
1761 FORMAT (1H0,43HGENERAL STREAM PHASE SEPARATION NOT ALLOWED)
1765 FORMAT (1H0,30HSUPPLY STREAM FLASHING ALLOWED)
1766 FORMAT (1H0,34HSUPPLY STREAM FLASHING NOT ALLOWED)
1770 FORMAT (1H0,39HPROCESSES WITH TEMPERATURES ABOVE HOTTE,
    1 20HST GT STREAM WILL BE/1H ,23H  HEATED SOLELY BY FOSS,
    1 7HIL FUEL)
1771 FORMAT (1H0,39HPROCESSES WITH TEMPERATURES ABOVE HOTTE,
    1 24HST GT STREAM WILL NOT BE/1H ,19H  HEATED SOLELY BY ,
    1 11HFOSSIL FUEL)
1780 FORMAT (1H0,40HGEOTHERMAL SUPPLY FLOW RATE FRACTION: ST,
    1 5HART =,F6.3/1H ,40X,5HEND =,F6.3/1H ,34X,11HSTEP SIZE =,
    1 F6.3/1H0,29HMASS FLOW RATE CUTOFF POINTS:/1H ,4F7.3)
1782 FORMAT (1H0,37HINVALID INPUT DATA:   FINALM > STARTM)
1790 FORMAT (1H0,40HE N E R G Y   P R O F I L E   M A T C H ,
    1 27H  R E S U L T S:    FRAC = ,F6.4)
2000 FORMAT (//1H0,39HI N D U S T R I A L   A P P L I C A T I,
    1 25H O N   P R O C E S S E S:/1H0,18HPROCESS  TEMP  PRE,
    1 52HSSURE  HEAT  FLOW RATE  PURE  PHASE  H.T.C.  DELT1  ,
    1 5HDELT2/1H ,9X,30H(C)    (BARS)   (KW)   (KG/HR),25X,
    1 10H(C)    (C)/)
2130 FORMAT (1H0,40HCURRENT PROCESS EQUIPMENT COSTS:  PROCES,
    1 7HS  COST/36X,I3,4H   $,1PE9.3/(36X,I3,E13.3))
2008 FORMAT (1H ,I4,F9.1,F8.3,1P2E10.3,I4,I6,0PF10.2,2F7.2)
2400 FORMAT (//1H0,37HF L U I D   S T R E A M S   A F T E R,
    1 9H   R U N:/1H0,
```

```
    1 51H  SUPPLY  TEMPERATURE  PRESSURE  ENTHALPY  FLOW RAT,
    1 24HE  PURE  NON-COND.   TDS/1H ,10X,14H(DEGREES C)   ,
    1 27H(BARS)     (J/G)      (KG/HR)/)
 2420 FORMAT (1H ,2X,I4,F12.1,F12.3,F10.2,1PE12.4,I5,0PF10.4,
    1 F10.5)
 2440 FORMAT (/1H0,10HXNPVSV = $,1PE11.4,14H     IPAYBK = ,
    1 I3,17H YEARS      IRR = ,2PF8.4,2H %/)
 9999 FORMAT (/1H0,17HNORMAL END OF JOB)
C
      END
      BLOCK DATA
      REAL MCHECK(4), MPI(50), MSI(50)
      INTEGER PHASEI(50)
      COMMON /A/ DELT1I(50), DELT2I(50), ETI(50), GAMMAI(50),
     1  HSI(50), MCHECK    , MPI        , MSI     , PPI(50)    ,
     1  PSF(50), PSI(50)   , QPI(50)    , TDI(50), TPI(50)    ,
     1  TSI(50), IAUX      , IFLASH     , IPPURI(50), ISEPRT ,
     1  ISPRT2 , ISPURI(50), MI         , NI      , PHASEI
C
      DATA DELT1I, DELT2I , ETI, GAMMAI, HSI, MPI, MSI, PPI, PSF,
     1  PSI, QPI, TDI, TPI, TSI, IPPURI, ISPURI, PHASEI
     1  /700*0.0, 150*0/
C
      END
```

b. Program MATRD

```
      SUBROUTINE MATRD( AREA   , AVAIL2, AVAILS, CAREA, ENTOT2,
     1  ENTOTL, MSIOF1, MWATER, PM     , QESUM , QFSUM, QM     ,
     2  QSUM   , SIZE  , TM     , IAREA , ITYP  , MI    , NI, Z )
C
C ********* PROGRAM READS MATCH RESULT DATA *****************
C
      REAL MSIOF1, MWATER
      INTEGER Z
      DIMENSION AREA(50), CAREA(50), PM(50), QM(50), SIZE(50),
     1  TM(50), ITYP(50)
C
      DATA IN, IOUT/8,6/
C
      READ (IN,1030) Z, IAREA, MI, NI
      READ (IN,1032) MSIOF1, MWATER, QSUM   , QESUM , QFSUM,
     1               ENTOTL, ENTOT2, AVAILS, AVAIL2
      IF (Z     .GT. 0) READ (IN,1034) (TM(I),PM(I),QM(I),I=1,Z)
      IF (IAREA .GT. 0) READ (IN,1036) (ITYP(J),SIZE(J),AREA(J),
     1                                 J = 1,IAREA)
      IF (MI    .GT. 0) READ (IN,1038) (CAREA(J), J = 1,MI)
C
      RETURN
C
 1030 FORMAT (4I5)
 1032 FORMAT (8F10.5/F10.5)
 1034 FORMAT (3F10.3)
 1036 FORMAT (I5,2F10.5)
 1038 FORMAT (8E10.3)
      END
```

c. Program MATPRN

```
      SUBROUTINE MATPRN(AREA  , AVAIL2, AVAILS, CAREA, ENTOT2,
     1 ENTOTL, MSOF1 , MWATER, PM    , QESUM , QFSUM, QM    ,
     2 QSUM  , SIZE  , TM    , IAREA , ITYP  , MI    , NI, Z )
C
C ********* PROGRAM PRINTS MATCH RESULT DATA *****************
C
      REAL MSOF1, MWATER
      INTEGER EQPTYP(5,8), Z
      DIMENSION AREA(50), CAREA(50), PM(50), QM(50), SIZE(50),
     1 TM(50), ITYP(50)
C
      DATA EQPTYP(1,1), EQPTYP(2,1), EQPTYP(3,1), EQPTYP(4,1),
     1 EQPTYP(5,1), EQPTYP(1,2), EQPTYP(2,2), EQPTYP(3,2),
     2 EQPTYP(4,2), EQPTYP(5,2), EQPTYP(1,3), EQPTYP(2,3),
     3 EQPTYP(3,3), EQPTYP(4,3), EQPTYP(5,3), EQPTYP(1,4),
     4 EQPTYP(2,4), EQPTYP(3,4), EQPTYP(4,4), EQPTYP(5,4),
     5 EQPTYP(1,5), EQPTYP(2,5), EQPTYP(3,5), EQPTYP(4,5),
     6 EQPTYP(5,5)/'EVAP','ORAT','OR. ','. . ','. . ',
     7 'LIQU','ID P','UMP ','. . ','. . ','VAPO','R CO',
     8 'MPRE','SSOR','. . ','FLAS','H VE','SSEL','. . ',
     9 '. . ','TWO-','PHAS','E SE','PARA','TOR '/
      DATA EQPTYP(1,6), EQPTYP(2,6), EQPTYP(3,6), EQPTYP(4,6),
     1 EQPTYP(5,6), EQPTYP(1,7), EQPTYP(2,7), EQPTYP(3,7),
     2 EQPTYP(4,7), EQPTYP(5,7), EQPTYP(1,8), EQPTYP(2,8),
     3 EQPTYP(3,8), EQPTYP(4,8), EQPTYP(5,8)/'FOSS','IL F',
     4 'UEL ','HEAT','ER. ','PROC','ESS ','EQUI','PMEN',
     5 'T . ','HEAT',' EXC','HANG','ER. ','. . '/
C
      DATA IN, IOUT/8,6/
C
      WRITE (IOUT,1800)
      IF (Z .GT. 0) WRITE (IOUT,1810) (TM(I),PM(I),QM(I),I=1,Z)
      WRITE (IOUT,1820)
      IF (IAREA .EQ. 0) GO TO 790
      DO 790 J = 1,IAREA
       IT    = ITYP(J)
       WRITE (IOUT,1830) J, (EQPTYP(L,IT), L=1,5), SIZE(J),
     1                   AREA(J)
  790 CONTINUE
      ERROR = 100.0*(ENTOTL-ENTOT2+QESUM+QFSUM-QSUM)/QSUM
      WRITE (IOUT,1840) QSUM  , QESUM , QFSUM , MSOF1 ,
     1                  ENTOTL, ENTOT2, AVAILS, AVAIL2,
     2                  MWATER, ERROR
C
      RETURN
C
 1800 FORMAT (/1H0,26HAUXILIARY ENERGY REQUIRED:/1H ,6H  TEMP,
     134H (C)  PRESSURE (BARS)  ENERGY (KW)/)
```

```
1810 FORMAT (1H ,2X,0PF7.2,F13.3,1PE17.4)
1820 FORMAT (1H0,20HEQUIPMENT SIZE DATA:/1H ,12H  EQUIPMENT ,
    149H    DESCRIPTION    SIZE PARAMETER 1    PARAMETER 2)
1830 FORMAT (1H ,2X,I5,5X,5A4,2F15.4)
1840 FORMAT (1H0,40HTOTAL PROCESS ENERGY REQUIREMENT. . . . ,
    15H. . =,1PE11.4,4H  KW/1H ,25HTOTAL PROCESS ELECTRICITY,
    220H USE . . . . . . . =,E11.4,4H  KW/1H ,9HTOTAL PRO,
    336HCESS AUXILIARY FOSSIL FUEL HEAT. . =,E11.4,4H  KW/
    41H ,45HTOTAL GEOTHERMAL SUPPLY MASS FLOW RATE. . . =,
    5E11.4,7H  KG/HR/1H ,32HTOTAL SUPPLY STREAM ENTHALPY. . ,
    613H. . . . . . =,E11.4,4H  KW/1H ,18HTOTAL SUPPLY STREA,
    727HM ENTHALPY AT EXIT. . . . =,E11.4,4H  KW/1H ,5HTOTAL,
    840H SUPPLY STREAM AVAILABILITY. . . . . . =,E11.4,3H  K,
    91HW/1H ,45HTOTAL SUPPLY STREAM AVAILABILITY AT EXIT. . =,
    1E11.4,4H  KW/1H ,35HTOTAL MASS FLOW OF WATER REQUIRED .,
    210H . . . . =,E11.4,7H  KG/HR/1H ,19HFIRST LAW ERROR . .,
    326H . . . . . . . . . . . . . =,0PF11.4,3H  %)
     END
```

d. Program ECODAT

```
      SUBROUTINE ECODAT(RUNNUM, CASNUM)
C
C ********* PROGRAM READS AND PRINTS ECONOMIC DATA ***********
C
      REAL MTOTAL, MWATER, NWELLR, IRR
      INTEGER CASNUM, RUNNUM, Z
C
      COMMON /E/  AREA(50), AVAIL2  , AVAILS, CFLUID, ENTOT2,
     1 ENTOTL  , MTOTAL  , MWATER  , QESUM , QFSUM , QSUM  ,
     2 SIZE(50), IAREA   , ITYP(50)
      COMMON /F/ BONDRT, CASH(40) , CASHF(40) , CDSCNT ,
     1 CELECT , CFOSSL, CINFLT(8), CINSUR    , CINVSF , CINVST,
     2 COPRAT , CUMINV, DEBTEQ   , FINVST(40), IRR    , OPFRAC,
     3 PROFIT , PROPTX, SALVAG   , SAVING(40), TAXCRD , TAXRAT,
     4 XNPV   , XNPVF , IBEGIN   , ICONST    , ILIFE  , LIFEBD,
     5 LIFETM , IPAYBK
      COMMON /G/  CLAND    , CMAINT  , COTHER, CREPLC, CROYAL,
     1 CTRANS   , CUMGTC   , CUMINC  , CWELL , DPLBAS, NWELLR,
     2 PROBC(3), PROBM(3), PROBT(3), ROIREQ, TANGBL, NWELLI,
     3 NWELLP
C
      DATA IN, IOUT/8,6/
C
  700 READ  (IN,2100)  NWELLP, NWELLI, NWELLR, CLAND , CWELL ,
     1                 CTRANS, COTHER, CMAINT, CREPLC, TANGBL,
     2                 DPLBAS, CFLUID, PROBT , PROBM , PROBC
      READ  (IN,2102)  IBEGIN, ICONST, ILIFE,  FINVST, CFOSSL,
     1                 CELECT, CINFLT, LIFETM, SALVAG, LIFEBD,
     2                 BONDRT, DEBTEQ, TAXCRD, PROPTX, TAXRAT,
     3                 CINSUR, COPRAT, OPFRAC, CDSCNT, ROIREQ,
     4                 CROYAL
      WRITE (IOUT,1161) RUNNUM, CASNUM
      WRITE (IOUT,2120) NWELLP, NWELLI, NWELLR, CLAND , CWELL ,
     1                 CTRANS, COTHER, CMAINT, CREPLC, TANGBL,
     2                 DPLBAS, CFLUID
      WRITE (IOUT,2122) PROBT,  PROBM,  PROBC
      WRITE (IOUT,2126) IBEGIN, ICONST, ILIFE,  FINVST, CFOSSL,
     1                 CELECT, CINFLT, LIFETM, SALVAG, LIFEBD,
     2                 BONDRT, DEBTEQ, TAXCRD, PROPTX
      WRITE (IOUT,2127) TAXRAT, CINSUR, COPRAT, OPFRAC, CDSCNT,
     1                 ROIREQ, CROYAL
C
      RETURN
C
 1161 FORMAT (1H1,21HR U N   N U M B E R: ,I3,13H.   C A S E ,
     114H N U M B E R: ,I3/1H+,19H__    ______,9X,
     221H___    ______/)
 2100 FORMAT (2I5,F10.2,6E10.1/3E10.1/3F10.1,3E10.1/3E10.1)
```

```
2102 FORMAT (3I5/10F8.4/10F8.4/10F8.4/10F8.4/2F10.5/8F10.3/
    1I5,F10.5/I5,2F10.5/3F10.5/3F10.5/3F10.5)
2120 FORMAT (1H0,26HE C O N O M I C   D A T A:/1H0,7HNUMBER ,
    138HOF PRODUCING WELLS NEEDED. . . . . . =,I11/1H ,3HNUM,
    242HBER OF EXTRA WELLS . . . . . . . . . . . . =,I11/1H ,
    345HNEW WELLS PER YEAR PER PRODUCING WELL . . . =,F11.3,
    410H  (YEAR)-1/1H ,35HLAND ACQUISITION COST . . . . . . . ,
    510H . . . . =,F11.0,8H  1978 $/1H ,18HCOST PER WELL . . . ,
    627H. . . . . . . . . . . . . . =,F11.0,8H  1978 $/1H ,
    745HCOST OF FLUID TRANSMISSION SYSTEM . . . . . =,F11.0,
    88H  1978 $/1H ,38HOTHER COSTS (EXPLORATION, ETC.) . . . ,
    97H. . . =,F11.0,8H  1978 $/1H ,22HANNUAL FIELD MAINTENAN,
    123HCE COST . . . . . . . =,F11.0,8H  1978 $/1H ,6HANNUAL,
    239H COST FOR REPLACEMENT WELLS . . . . . =,F11.0,5H  197,
    33H8 $/1H ,38HFRACTION OF WELL COSTS ATTRIBUTABLE TO/1H ,
    445H  TANGIBLE EXPENSE. . . . . . . . . . . . . =,2PF11.4,
    53H  %/1H ,32HFRACTION OF TANGIBLE WELL COSTS /1H ,
    645H  ALLOCATABLE TO DEPLETABLE ACCOUNTS. . . . =,F11.4,
    73H  %/1H ,43HCOST OF GEOTHERMAL FLUID. . . . . . . . . . ,
    82H =,F11.4,10H  CENTS/KG)
2122 FORMAT (1H0,40HPROBABILITY DISTRIBUTION FOR STREAM TEMP,
    18HERATURE:/1H ,9X,34HP(ACTUAL T .LE. GIVEN T)= 25% AT T,
    22H =,F11.2,3H  C/1H ,33X,12H= 50% AT T =,F11.2,3H  C/
    31H ,33X,12H= 75% AT T =,F11.2,3H  C/1H0,12HPROBABILITY ,
    434HDISTRIBUTION FOR STREAM FLOW RATE:/1H ,9X,8HP(ACTUAL,
    528H M .LE. GIVEN M)= 25% AT M =,1PE11.4,7H  KG/HR/1H ,
    633X,12H= 50% AT M =,E11.4,7H  KG/HR/1H ,33X,9H= 75% AT ,
    73HM =,E11.4,7H  KG/HR/1H0,26HPROBABILITY DISTRIBUTION F,
    817HOR COST OF FLUID:/1H ,9X,23HP(ACTUAL C .LE. GIVEN C,
    913H)= 25% AT C =,2PF11.5,6H  C/KG/1H ,33X,9H= 50% AT ,
    13HC =,F11.5,6H  C/KG/1H ,33X,12H= 75% AT C =,F11.5,
    26H  C/KG)
2126 FORMAT (1H0,40HPROJECT STARTING DATE . . . . . . . . . . ,
    15H. . =,I11/1H ,36HPROJECT CONSTRUCTION TIME . . . . . ,
    29H. . . . =,I11,7H  YEARS/1H ,22HPROJECT OPERATING LIFE,
    323H. . . . . . . . . . . =,I11,7H  YEARS/1H0,8HFRACTION,
    436H OF TOTAL INVESTMENT MADE EACH YEAR:,4(/1H ,10F6.3)/
    51H0,45HCOST OF FOSSIL FUEL IN 1978 . . . . . . . . . =,
    66PF11.4,6H  $/GJ/1H ,31HCOST OF ELECTRICITY IN 1978 . . ,
    714H . . . . . . =,F11.4,6H  $/GJ/1H0,15HINFLATION FACTO,
    836HRS:  PRICE  FOSSIL  ELECT.  GT FLUID/3X,9HTHROUGH 1,
    94H986:,2PF9.2,1H%,F7.2,1H%,F7.2,1H%,F7.2,1H%/3X,5HAFTER,
    16H 1986:,F11.2,F8.2,F8.2,F8.2/1H0,18HDEPRECIATION LIFET,
    227HIME . . . . . . . . . . . . =,I11,7H  YEARS/1H ,4HSALV,
    341HAGE VALUE AS PERCENTAGE OF INVESTMENT . =,F11.2,3H  %/
    41H ,45HBOND LIFETIME TO MATURITY . . . . . . . . . . =,I11,
    57H  YEARS/1H ,38HBOND INTEREST RATE. . . . . . . . . . . ,
    67H. . . =,F11.2,3H  %/1H ,26HDEBT/EQUITY RATIO . . . . ,
```

```
     719H. . . . . . . . . . =,0PF11.2/1H ,17HINVESTMENT TAX CR,
     828HEDIT . . . . . . . . . . . . =,2PF11.2,3H  %/1H ,3HPRO,
     942HPERTY TAX RATE . . . . . . . . . . . . . . =,F11.2,
     19H  CENTS/$)
2127 FORMAT (1H ,40HOVERALL MARGINAL INCOME TAX RATE. . . . ,
     15H. . =,2PF11.2,3H  %/1H ,26HINSURANCE PREMIUM RATE. . ,
     219H. . . . . . . . . =,F11.2,9H  CENTS/$/1H ,8HOPERATIN,
     337HG AND MAINTENANCE COST RATE . . . . =,F11.2,7H  CENTS,
     42H/$/1H ,43HANNUAL CAPACITY FACTOR. . . . . . . . . . . .,
     52H =,F11.2,3H  %/1H ,31HDISCOUNT RATE . . . . . . . . . .,
     614H . . . . . . . =,F11.2,3H  %/1H ,19HRATE OF RETURN REQU,
     720HIRED BY INVESTORS ON/1H ,25H  DEPLETABLE INVESTMENT .,
     820H . . . . . . . . . . =,F11.2,3H  %/1H ,13HROYALTIES ON ,
     932HGEOTHERMAL FLUID PRODUCTION. . =,F11.2,3H  %)
      END
```

e. Program ECORES

```
      SUBROUTINE ECORES(FRAC)
C
C ********* PROGRAM PRINTS ECONOMIC RESULTS *****************
C
      REAL IRR
      DATA IN, IOUT/8,6/
C
      COMMON /F/ BONDRT, CASH(40) , CASHF(40) , CDSCNT ,
     1 CELECT , CFOSSL, CINFLT(8), CINSUR    , CINVSF , CINVST,
     2 COPRAT , CUMINV, DEBTEQ    , FINVST(40), IRR    , OPFRAC,
     3 PROFIT , PROPTX, SALVAG    , SAVING(40), TAXCRD , TAXRAT,
     4 XNPV   , XNPVF , IBEGIN    , ICONST    , ILIFE  , LIFEBD,
     5 LIFETM , IPAYBK
      COMMON /G/  CLAND    , CMAINT   , COTHER, CREPLC, CROYAL,
     1 CTRANS   , CUMGTC   , CUMINC   , CWELL , DPLBAS, NWELLR,
     2 PROBC(3), PROBM(3), PROBT(3), ROIREQ, TANGBL, NWELLI,
     3 NWELLP
C
  850 XNPVSV= XNPV - XNPVF
      WRITE (IOUT,2300) FRAC, CUMINC, CUMINV, CUMGTC, CINVSF,
     1                 XNPV, XNPVF , XNPVSV, IPAYBK, IRR
      WRITE (IOUT,2302)
      IFINAL= IBEGIN + ILIFE + ICONST - 1
      DO 870 I=IBEGIN,IFINAL
       IYEAR= I - IBEGIN + 1
       WRITE (IOUT,2304) IYEAR, I, CASHF(IYEAR), CASH(IYEAR),
     1                   SAVING(IYEAR)
  870 CONTINUE
C
      RETURN
C
 2300 FORMAT (1H0,42HE C O N O M I C   R E S U L T S:    FRAC =,
     1F7.4/1H0,
     137HTOTAL INVESTMENT IN GEOTHERMAL SYSTEM/3X,9HIN CONSTA,
     234HNT DOLLARS . . . . . . . . . . . . =,1PE11.4,3H  $/3X,
     343HIN CURRENT DOLLARS. . . . . . . . . . . . . =,E11.4,
     43H  $/1H ,36HTOTAL INVESTMENT IN GEOTHERMAL FIELD/3X,
     443HIN CONSTANT DOLLARS . . . . . . . . . . . . =,E11.4,
     43H  $/1H ,39HTOTAL INVESTMENT IN CONVENTIONAL SYSTEM/
     53X,43HIN CONSTANT DOLLARS . . . . . . . . . . . =,E11.4,
     63H  $/1H ,42HNET PRESENT VALUE OF GT SYSTEM CASH FLOWS. ,
     73H. =,E11.4,3H  $/1H ,30HNET PRESENT VALUE OF CONVENTIO,
     83HNAL/3X,43HSYSTEM CASH FLOWS . . . . . . . . . . . . =,
     9E11.4,3H  $/1H ,35HNET PRESENT VALUE OF SYSTEM SAVINGS,
     110H . . . . =,E11.4,3H  $/1H ,22HDISCOUNTED PAYBACK PER,
     223HIOD . . . . . . . . . . =,I11,7H  YEARS/1H ,8HINTERNAL,
     337H RATE OF RETURN . . . . . . . . . . =,2PF11.4,3H  %)
 2302 FORMAT (1H0,40HCASH FLOWS:  YEAR      FOSSIL       GEOTH,
```

```
     117HERMAL       SAVING/)
2304 FORMAT (1H ,8X,I3,I6,4H    $,1PE10.3,4H    $,E10.3,4H    $,
    1E10.3)
      END
```

f. Program MATCH

```
      SUBROUTINE MATCH(FRAC)
C
C ***********************************************************
C *                                                         *
C *        PROGRAM MATCHES GEOTHERMAL SUPPLY TO             *
C *             INDUSTRIAL PROCESS DEMAND                   *
C *                                                         *
C ***********************************************************
C *                                                         *
C * -- THIS PROGRAM WAS WRITTEN IN 1979 BY MICHAEL B.       *
C *       PACKER AT THE MASSACHUSETTS INSTITUTE OF TECH-    *
C *       NOLOGY FOR THE DEPARTMENT OF ENERGY               *
C * -- METRIC UNITS ARE EMPLOYED THROUGHOUT:                *
C *       TEMPERATURE= DEGREES C     PRESSURE= BARS         *
C *       ENTHALPY   = KJ/KG         ENTROPY = J/G-K        *
C *       FLOW RATE  = KG/HR         ENERGY  = KJ           *
C *       ENERGY RATE= KW                                   *
C * -- THE PROGRAM CALLS THE FOLLOWING SUBPROGRAMS:         *
C *       PROPTY= CALCULATES THERMODYNAMIC PROPERTIES       *
C *       SEPRAT= SEPARATES TWO-PHASE STREAMS               *
C *       SORT  = SORTS STREAMS OR PROCESSES BY TEMPERATURE *
C *       SPLIT = SPLITS STREAMS IN TWO                     *
C * -- SEPARATE DOCUMENTATION INCLUDES FLOW CHARTS,         *
C *       COMPLETE VARIABLE LISTS, AND A "WALK-THROUGH"     *
C *       DESCRIPTION OF PROGRAM OPERATING PRINCIPLES.      *
C * -- PROGRAM LINE KEY:                                    *
C *       120  SUPPLY AND PROCESS INITIALIZATION AND SORTING *
C *       200  MATCHING PROCEDURE BEGINS                    *
C *       300  END OF SUPPLY STREAM LOOP                    *
C *       450  EFFICIENCY CHECK AND BRINE CONVERSION        *
C *       500  PRESSURE UPGRADING                           *
C *       700  TEMPERATURE UPGRADING                        *
C *       800  UNIT PROCESS                                 *
C *       880  END OF PROCESS LOOP                          *
C *       882  MATCH RESULTS                                *
C *                                                         *
C ***********************************************************
C
      REAL MCHECK(4), MCMPRS, MDESUP, MNEW, MP(50), MPI(50),
     1 MS(50), MSI(50), MSTAND(4), MTOTAL, MTRY, MWATER
      INTEGER PHASE(50), PHASEI(50), PHASUP, Y, Z
      DIMENSION PSTAND(4), TSUM(50)
C
      COMMON /A/ DELT1I(50), DELT2I(50), ETI(50), GAMMAI(50),
     1 HSI(50), MCHECK    , MPI        , MSI     , PPI(50)    ,
     1 PSF(50), PSI(50)   , QPI(50)    , TDI(50), TPI(50)     ,
     1 TSI(50), IAUX      , IFLASH     , IPPURI(50), ISEPRT   ,
     1 ISPRT2 , ISPURI(50), MI         , NI      , PHASEI
```

```
      COMMON /D/  DELTA1(50), DELTA2(50), DELTA3(50), ETA(50),
     1  GAMMA(50)  , HS(50)   , MP         , MS          , PM(50) ,
     1  PP(50)     , PS(50)   , QM(50)     , QP(50)      , TDS(50),
     1  TM(50)     , TP(50)   , TS(50)     , IPPURE(50),
     1  ISPURE(50), M         , MORDER(50), N            ,
     1  NORDER(50), PHASE     , Z
      COMMON /E/  AREA(50), AVAIL2  , AVAILS, CFLUID, ENTOT2,
     1  ENTOTL   , MTOTAL  , MWATER  , QESUM , QFSUM , QSUM   ,
     2  SIZE(50), IAREA    , ITYP(50)
C
      DATA IN, IOUT/8, 6/
      DATA SOLBLE/0.50/
      DATA PSTAND, MSTAND, SFINAL/1.72, 3.10, 5.17, 9.31, 1.00,
     1      0.96, 0.92, 0.88, 10.0/
      DATA D1,D2,D3,D4,D5,D6,I4/6*1.0E6, 30000/
C
C ----- INITIALIZE AND SORT SUPPLY AND PROCESS DATA ----------
C
      QSUM  = 0.0
  120 DO 125 I = 1,50
        TM(I)     = 0.0
        PM(I)     = 0.0
        QM(I)     = 0.0
        NORDER(I)= I
        MORDER(I)= I
        TS(I)     = TSI(I)
        PS(I)     = PSI(I)
        HS(I)     = HSI(I)
        MS(I)     = MSI(I)
        ETA(I)    = ETI(I)
        TDS(I)    = TDI(I)
        ISPURE(I)= ISPURI(I)
        TP(I)     = TPI(I)
        PP(I)     = PPI(I)
        QP(I)     = QPI(I)
        MP(I)     = MPI(I)
        IPPURE(I)= IPPURI(I)
        GAMMA(I) = GAMMAI(I)
        PHASE(I) = PHASEI(I)
        DELTA1(I)= DELT1I(I)
        DELTA2(I)= DELT2I(I)
        ITYP(I)   = 0
        SIZE(I)   = 0.0
        AREA(I)   = 1.0
        TSUM(I)   = TP(I) + DELTA1(I)
        QSUM      = QSUM + QP(I)
  125 CONTINUE
      IAREA = MI
```

```
      MWATER= 0.0
      MS(1) = MSI(1)*FRAC
      M     = MI
      CALL SORT(TSUM, MP, MORDER, M, 2)
      N     = NI
      CALL SORT(TS, MS, NORDER, N, 1)
      ENTOTL= 0.0
      AVAILS= 0.0
      MTOTAL= 0.0
      L       = N
      DO 160 K = 1,L
       I      = NORDER(K)
       IF (MS(I) .LT. 20.0) GO TO 160
       CALL PROPTY(5,56,TDS(I),PS(I),D1,HS(I),SS,X,PHASUP,D2,D3)
  128  ENTOTL= ENTOTL + HS(I)*MS(I)/3600.0
       AVAILS= AVAILS + (HS(I)-293.15*SS)*MS(I)
       MTOTAL= MTOTAL + MS(I)
C
C ----- SUPPLY STREAM MANAGEMENT:  SEPARATE PHASES -----------
C         AND FLASH PRESSURIZED WATER IF POSSIBLE
C                      AND ALSO DESIRED
C
       IF (IFLASH.EQ.0 .AND. ISEPRT.EQ.0) GO TO 160
       IF (PHASUP.EQ.2 .AND. X.GT.0.9) GO TO 150
       IF (PHASUP.EQ.3 .OR. IFLASH.EQ.0)  GO TO 160
       CALL PROPTY(80,1,TDS(I),PSAT,D1,D2,D3,0.0,I4,HS(I),D6)
       IF (PSAT-PSF(I) .LT. 0.05) GO TO 160
       CALL PROPTY(5,18,TDS(I),PSF(I),TEMPT,HS(I),D1,X,I4,D3,D4)
       IF (X .LT. 0.1) GO TO 160
       TS(I) = TEMPT
       IAREA = IAREA + 1
       ITYP(IAREA)= 4
       SIZE(IAREA)= X*MS(I)
       AREA(IAREA)= PS(I)
       PS(I)       = PSF(I)
  150  IF (ISEPRT .EQ. 0) GO TO 160
       CALL SEPRAT(I)
  160 CONTINUE
      AVAILS= (AVAILS + 2.8971*MTOTAL)/3600.0
      CALL SORT(TS, MS, NORDER, N, 1)
C
      IF (IFLASH .EQ. 0) GO TO 170
      WRITE (IOUT,931)
      DO 170 K = 1,N
       I      = NORDER(K)
       IF (MS(I) .LT. 20.0) GO TO 170
       WRITE (IOUT,932) I, TS(I), PS(I), HS(I), MS(I),
     1                  ISPURE(I), ETA(I), TDS(I)
```

```
 170 CONTINUE
     WRITE (IOUT,900)
C *************************************************************
C
C ----- START MATCHING PROCEDURE ------------------------------
C
C *************************************************************
 200 Z        = 0
     IFIRST= NORDER(1)
     TEMP   = TS(IFIRST)
     DO  880 K = 1,M
      J       = MORDER(K)
      IF (TSUM(J) .GT. 0.0) GO TO 205
      Z       = Z + 1
      PM(Z)   = PP(J)
      QM(Z)   = QP(J)
      ITYP(J)= 7
      SIZE(J)= 0.0
      AREA(J)= 1.0
      GO TO 880
 205  Y       = 1
      IF (IAUX.EQ.1 .AND. TSUM(J).GT.TEMP .AND. IPPURE(J)
    1     .LE.1) GO TO 340
      IF (IAUX.EQ.1 .AND. TSUM(J).GT.TEMP .AND. IPPURE(J)
    1     .GE.2) GO TO 451
      I1      = 0
      I2      = 0
 250  DO 300 L = 1,N
C
C ----- STREAM SELECTION LOGIC --------------------------------
C
       I      = NORDER(L)
       IF (ISPURE(I) .GE. 2) GO TO 300
       CALL PROPTY(5,48,TDS(I),PS(I),D1,HS(I),D2,X,PHASUP,D3,D4)
       ICOND = 1
       IF (PHASUP.EQ.2) ICOND = 3
       IF (Y .GT. 4) GO TO 260
       DELTHS= 3600.0*QP(J)/(MP(J)*MCHECK(ICOND+1))
       HNEW   = HS(I) - DELTHS
       IF (HNEW .LT. 80.0) GO TO 300
       CALL PROPTY(5,18,TDS(I),PS(I),TNEW,HNEW,D1,XNEW,I4,
    1     D4,D5)
       CALL PROPTY(17,2,TDS(I),PS(I),TEMPT,D1,D2,0.5,I4,D4,D5)
       DELTA3(J)= (TS(I)+TNEW)/2.0 - TP(J)
       IF (X.LT.1.04 .AND. XNEW.GT.-0.10) DELTA3(J)= TEMPT-TP(J)
       IF (DELTA3(J).LT.DELTA1(J)-1.0 .OR.
    1     TNEW.LT.TP(J)-1.0) GO TO 300
 260   IPUR   = IPPURE(J)
```

```
      IF (IPPURE(J) .EQ. 2) IPUR= 0
      IF (IPPURE(J) .EQ. 3) IPUR= 1
      IF ((Y.EQ.4.OR.Y.EQ.8) .AND. MS(I).GE.MP(J)*
     1    MCHECK(ICOND)) GO TO 280
      IF ((Y.EQ.3.OR.Y.EQ.7) .AND. ISPURE(I).EQ.IPUR .AND.
     1    MS(I).GE.MP(J)*MCHECK(ICOND)) GO TO 280
      IF (Y.EQ.3 .OR. Y.EQ.4 .OR. Y.GE.7) GO TO 300
      IEQPHS= 0
      IF (PHASE(J).EQ.1 .AND. (PHASUP.EQ.1 .OR. (PHASUP.EQ.
     1    2.AND.X.LT.0.1))) IEQPHS= 1
      IF (PHASE(J).EQ.2 .AND. ((PHASUP.EQ.2.AND.X.GT.0.9)
     1    .OR. (PHASUP.EQ.3.AND.X.LT.1.04))) IEQPHS= 1
      IF (PHASE(J).EQ.3 .AND. (PHASUP.EQ.3 .OR. (PHASUP.EQ.
     1    2.AND.X.GT.0.99)))                   IEQPHS= 1
      IF ((Y.EQ.2.OR.Y.EQ.6) .AND. IEQPHS.EQ.1 .AND. MS(I).GE.
     1    MP(J)*MCHECK(ICOND)) GO TO 280
      IF ((Y.EQ.1.OR.Y.EQ.5) .AND. ISPURE(I).EQ.IPUR .AND.
     1    IEQPHS.EQ.1 .AND. MS(I).GE.MP(J)*MCHECK(ICOND))
     1    GO TO 280
      GO TO 300
 280  IF (TS(I) .GE. TSUM(J)-1.0) I1 = I
      IF (I2 .EQ. 0) I2 = I
 300  CONTINUE
      IF (I1.EQ.0 .AND. I2.EQ.0) GO TO 320
      I     = I2
      IF (I1.NE.0) I= I1
      GO TO 450
 320  Y     = Y + 1
      IF (Y .LE. 8) GO TO 250
 340  IF (IPPURE(J) .LE. 1) GO TO 451
      MWATER= MWATER + MP(J)
      I     = N+1
      TS(I) = 20.0
      PS(I) = 1.01325
      HS(I) = 84.045
      MS(I) = MP(J)
      ISPURE(I)= 1
      ETA(I)= 0.0
      TDS(I)= 0.0
      X     = -0.148
      PHASUP= 1
      N     = N+1
      GO TO 500
C ***************************************************************
C
C ----- PROCESS-STREAM EFFICIENCY CHECK AND BRINE CONVERSION -
C
C ***************************************************************
```

```
  450 CALL PROPTY(5,48,TDS(I),PS(I),D1,HS(I),D2,X,PHASUP,D3,D4)
      IF (IPPURE(J) .GE. 2) GO TO 453
C
C ----- PROCESS-STREAM EFFICIENCY CHECK ----------------------
C
      CALL PROPTY(3,4,TDS(I),PP(J),TSUM(J),HFINAL,D1,D2,I4,D4,D5)
      QTRANS= (HFINAL-HS(I))*MP(J)/3600.0
      IF (QTRANS .LT. 1.05*QP(J)) GO TO 453
  451 Z      = Z + 1
      TM(Z) = TSUM(J)
      PM(Z) = PP(J)
      QM(Z) = QP(J)
      TS(N+1)      = TSUM(J)
      PS(N+1)      = 1.01325
      HS(N+1)      = 84.045
      MS(N+1)      = MP(J)
      ISPURE(N+1)= 3
      ETA(N+1)     = 0.0
      TDS(N+1)     = 0.0
      N            = N + 1
      ITYP(J)      = 7
      SIZE(J)      = MP(J)
      AREA(J)      = 1.0
      IAREA        = IAREA + 1
      ITYP(IAREA)= 6
      SIZE(IAREA)= MP(J)
      AREA(IAREA)= QP(J)
      GO TO 870
C
C ----- BRINE CONVERSION ------------------------------------
C
  453 IF (IPPURE(J).EQ.0 .OR. IPPURE(J).EQ.2 .OR.
     1    ISPURE(I).EQ.1) GO TO 500
      MNEW   = MP(J)*MCHECK(ICOND+1)
      IF (MS(I) .GT. MNEW) CALL SPLIT(TS,PS,HS,MS,ISPURE,ETA,
     1    TDS,MNEW,N,I)
C
  454 DO 455 L2 = 1,N
       ITRY   = NORDER(L2)
       IF (ITRY.NE.I .AND. ISPURE(ITRY).EQ.1 .AND. MS(ITRY).GE.
     1     MP(J)*MCHECK(ICOND) .AND. TS(ITRY).LT.TS(I)-20.0)
     2     GO TO 456
  455 CONTINUE
      ITRY     = N+1
      N        = N+1
      TS(ITRY)= 20.0
      PS(ITRY)= 1.01325
      HS(ITRY)= 84.045
```

```
      MS(ITRY)= MS(I)
      ISPURE(ITRY)= 1
      ETA(ITRY)   = 0.0
      TDS(ITRY)   = 0.0
      X           = -0.148
      PHASUP      = 1
      MWATER  = MWATER + MS(ITRY)
  456 MNEW    = MP(J)*MCHECK(ICOND+1)
      IF (MS(ITRY) .GT. MNEW) CALL SPLIT(TS,PS,HS,MS,ISPURE,
     1     ETA, TDS, MNEW, N, ITRY)
      IF (PP(J).LE.PS(ITRY)+0.01 .OR. PS(I).LE.PS(ITRY)+0.9)
     1     GO TO 457
      PSTAGE  = AMIN1(PP(J),PS(I)-0.4)
      CALL PROPTY(5,8,TDS(ITRY),PS(ITRY),D1,HS(ITRY),SS,D2,I4,D4,D5)
      CALL PROPTY(9,4,TDS(ITRY),PSTAGE,D1,HSSFNL,SS,D2,I4,D4,D5)
      DELTHS  = (HSSFNL-HS(ITRY))/0.8
      HS(ITRY)= HS(ITRY) + DELTHS
      Z       = Z + 1
      QM(Z)   = 1.02*DELTHS*MS(ITRY)/3600.0
      IAREA   = IAREA + 1
      ITYP(IAREA)= 2
      SIZE(IAREA)= MS(ITRY)
      AREA(IAREA)= PSTAGE - PS(ITRY)
      PS(ITRY)= PSTAGE
C
  457 CALL PROPTY(3,4,TDS(ITRY),PS(ITRY),TS(I),HNEW,D1,D2,I4,
     1            D4,D5)
      QMAX1   = MS(ITRY)*(HNEW-HS(ITRY))/3600.0
      CALL PROPTY(3,4,TDS(I),PS(I),TS(ITRY),HNEW,D1,D2,I4,D4,D5)
      QMAX2   = MS(I)*(HS(I)-HNEW)/3600.0
      QMAX    = AMIN1(QMAX1, QMAX2)
      DELTHS  = 3060.0*QMAX/MS(I)
      IF (DELTHS .GT. 50.0) GO TO 458
      I       = ITRY
      GO TO 500
  458 IF (DELTHS*MS(I)/3600.0.LE.QP(J) .OR. TS(ITRY).LT.
     1     TP(J)-1.0) GO TO 470
      HNEW    = HS(ITRY) + 3600.0*QP(J)/MS(ITRY)
      CALL PROPTY(5,18,TDS(ITRY),PS(ITRY),TNEW,HNEW,D1,XNEW,
     1     I4,D4,D5)
      CALL PROPTY(17,2,TDS(ITRY),PS(ITRY),TEMPT,D1,D2,0.5,I4,
     1     D4,D5)
      CALL PROPTY(5,48,TDS(ITRY),PS(ITRY),D1,HS(ITRY),D2,X,
     1     PHASUP,D4,D5)
      DELTA3(J)= (TNEW+TS(ITRY))/2.0 - TP(J)
      IF (XNEW.LT.1.04 .AND. X.GT.-0.10) DELTA3(J)=TEMPT-TP(J)
      IF (DELTA3(J).LT.DELTA1(J)-1.0 .OR.
     1     TS(ITRY).LT.TP(J)-1.0) GO TO 470
```

```
      DELTHS   = 3600.0*QP(J)/MS(I)
C
  470 HS(ITRY)= HS(ITRY) + DELTHS*MS(I)/MS(ITRY)
      HS(I)    = HS(I)    - DELTHS
      CALL PROPTY(5,2,TDS(I),PS(I),TS(I),HS(I),D1,D2,I4,D4,D5)
      QTRANS   = DELTHS*MS(I)/3600.0
      I        = ITRY
      CALL PROPTY(5,50,TDS(I),PS(I),TS(I),HS(I),D1,X,PHASUP,D2,D3)
      IF (PHASUP.EQ.2 .AND. TDS(I).GT.(1.0-X)*SOLBLE) TDS(I)=
     1    (1.0-X)*SOLBLE
      IF (PHASUP .EQ. 3) TDS(I)= 0.0
C
      IAREA  = IAREA + 1
      IF (X.GT.0.1 .AND. X.LT.1.04) ITYP(IAREA)= 1
      IF (X.LE.0.1 .OR.  X.GE.1.04) ITYP(IAREA)= 8
      SIZE(IAREA)= MS(I)
      AREA(IAREA)= QTRANS
C ************************************************************
C
C ----- PRESSURE UPGRADING SECTION --------------------------
C
C ************************************************************
  500 IF (PS(I).LT.PP(J)+0.50 .OR. PHASE(J).NE.2) GO TO 502
      MNEW   = MP(J)*MCHECK(ICOND+1)
      IF (MS(I) .GT. MNEW) CALL SPLIT(TS,PS,HS,MS,ISPURE,ETA,
     1    TDS,MNEW,N,I)
      PS(I) = PP(J)
      CALL PROPTY(5,50,TDS(I),PS(I),TS(I),HS(I),D1,X,PHASUP,D2,D3)
C
  502 IF (PS(I) .GE. PP(J)-0.01) GO TO 700
      IF (PHASUP.EQ.3 .OR. (PHASUP.EQ.2.AND.X.GT.0.1))
     1                                         GO TO 550
C
C ----- LIQUID PHASE SUPPLY PRESSURE UPGRADING ---------------
C
      MNEW   = MP(J)*MCHECK(ICOND+1)
      IF (MS(I) .GT. MNEW) CALL SPLIT(TS,PS,HS,MS,ISPURE,ETA,
     1    TDS,MNEW,N,I)
C
  505 IF (PHASUP.EQ.2 .AND. X.GE.0.001) WRITE (IOUT,970) I, X
      CALL PROPTY(5,8,TDS(I),PS(I),D1,HS(I),SS,D2,I4,D4,D5)
      CALL PROPTY(9,4,TDS(I),PP(J),D1,HSSFNL,SS,D2,I4,D4,D5)
  510 DELTHS= (HSSFNL-HS(I))/0.8
      HS(I) = HS(I) + DELTHS
C
      IAREA = IAREA + 1
      ITYP(IAREA)= 2
      SIZE(IAREA)= MS(I)
```

```
      AREA(IAREA)= PP(J) - PS(I)
C
      PS(I) = PP(J)
      CALL PROPTY(5,34,TDS(I),PS(I),TS(I),HS(I),D1,D2,PHASUP,D3,D4)
C
      Z     = Z + 1
      QM(Z) = 1.02*DELTHS*MS(I)/3600.0
      GO TO 700
C
C ----- VAPOR PHASE SUPPLY PRESSURE UPGRADING ----------------
C
  550 IF (PHASUP.EQ.3 .OR. (PHASUP.EQ.2.AND.X.GT.0.9))
     1                                          GO TO 555
      CALL PROPTY(17,192,TDS(I),PS(I),D1,D2,D3,0.9,I4,HF,HG)
      IF (TDS(I) .GT. 0.1*SOLBLE) TDS(I)= 0.1*SOLBLE
      DELTHS= 0.9*HG + 0.1*HF - HS(I)
      HS(I) = DELTHS + HS(I)
C
      Z     = Z + 1
      TM(Z) = TS(I)
      PM(Z) = PS(I)
      QM(Z) = DELTHS*MS(I)/3600.0
      IAREA = IAREA + 1
      ITYP(IAREA)= 6
      SIZE(IAREA)= MS(I)
      AREA(IAREA)= QM(Z)
C
  555 ISTART= 0
      IFINAL= 0
      DO 560 ICOUNT= 1,4
       IF (PS(I) .GE. PSTAND(ICOUNT)) ISTART= ICOUNT
       IF (PP(J) .GE. PSTAND(ICOUNT)) IFINAL= ICOUNT
  560 CONTINUE
      MCMPRS= 1.0
      IF (ISTART.EQ.IFINAL .OR. X.LT.0.99) GO TO 565
      MCMPRS= MSTAND(IFINAL)/MSTAND(ISTART+1)
  565 MNEW  = MCMPRS*MP(J)*MCHECK(ICOND+1)
      IF (MS(I) .GT. MNEW) CALL SPLIT(TS,PS,HS,MS,ISPURE,ETA,
     1    TDS,MNEW,N,I)
C
  567 IF (PHASE(J) .EQ. 2) GO TO 570
      CALL PROPTY(3,8,TDS(I),PP(J),TP(J),D1,SFINAL,D2,I4,D4,D5)
  570 CALL PROPTY(5,8,TDS(I),PS(I),D1,HS(I),SS,D2,I4,D4,D5)
      IF (ISTART.NE.IFINAL .AND. PSTAND(ISTART+1)-PS(I)
     1    .LE.0.75)          ISTART= ISTART + 1
      IF (ISTART.NE.IFINAL) PSTAGE= PSTAND(ISTART+1)
      IF (ISTART.EQ.IFINAL .OR. (PHASE(J).EQ.3.AND.
     1    SS.LT.SFINAL) .OR. PP(J)-PSTAND(ISTART+1).LE.0.75)
```

```
     1                      PSTAGE= PP(J)
C
      CALL PROPTY(9,4,TDS(I),PSTAGE,D1,HSSFNL,SS,D2,I4,D4,D5)
  575 DELTHS= (HSSFNL-HS(I))/0.8
      HS(I) = HS(I) + DELTHS
C
      IAREA = IAREA + 1
      ITYP(IAREA)= 3
      SIZE(IAREA)= MS(I)
      AREA(IAREA)= 1.02*DELTHS*MS(I)/3600.0
C
      PS(I) = PSTAGE
      CALL PROPTY(5,50,TDS(I),PS(I),TS(I),HS(I),D1,X,PHASUP,
     1    D3,D4)
      IF (PHASUP.EQ.2 .AND. TDS(I).GT.(1.0-X)*SOLBLE) TDS(I)=
     1    (1.0-X)*SOLBLE
      IF (PHASUP .EQ. 3) TDS(I)= 0.0
      IF (PHASUP .EQ. 3) ICOND = 1
C
      Z     = Z + 1
      QM(Z) = 1.02*DELTHS*MS(I)/3600.0
C
C ----- DESUPERHEATING SECTION --------------------------------
C
      IF (PHASE(J).EQ.3 .AND. PS(I).EQ.PP(J)) GO TO 700
      IF (PHASUP .EQ. 2) GO TO 580
      CALL PROPTY(9,196,0.0,PS(I),D1,HSSFNL,0.2965,D2,I4,HF,HG)
      DELTHS= (HSSFNL-84.045)/0.8
      HDESUP= 84.045 + DELTHS
      MDESUP= MS(I)*(HS(I)-HG)/(HG-HDESUP)
      MWATER= MWATER + MDESUP
C
      IAREA = IAREA + 1
      ITYP(IAREA)= 2
      SIZE(IAREA)= MDESUP
      AREA(IAREA)= PS(I) - 1.01325
      Z     = Z + 1
      QM(Z) = 1.02*DELTHS*MDESUP/3600.0
C
      TDS(I)= TDS(I)*MS(I)/(MS(I)+MDESUP)
      CALL PROPTY(17,2,TDS(I),PS(I),TS(I),D1,D2,1.0,I4,D4,D5)
      HS(I) = HG
      MS(I) = MS(I) + MDESUP
      X     = 1.0
C
  580 PHASUP= 2
      IF (PS(I) .EQ. PP(J)) GO TO 700
      ISTART= ISTART + 1
```

```
      GO TO 570
C ************************************************************
C
C ----- TEMPERATURE AND PHASE UPGRADING SECTION --------------
C
C ************************************************************
  700 MNEW   = MP(J)*MCHECK(ICOND+1)
      IF (MS(I) .GT. MNEW) CALL SPLIT(TS,PS,HS,MS,ISPURE,ETA,
     1    TDS,MNEW,N,I)
C
  705 CALL PROPTY(5,48,TDS(I),PS(I),D1,HS(I),D2,X,PHASUP,D3,D4)
      IND    = 0
      IF ((PHASE(J).EQ.1.AND.X.GE.0.1) .OR. (PHASE(J).EQ.2
     1     .AND.X.GE.1.04)) IND = 1
      IF (IND .EQ. 1) WRITE (IOUT,990) I, J, PS(I), HS(I)
      IF (IND .EQ. 1) GO TO 800
C
      IND    = 0
      QTRAN1= 0.0
  706 DELTHS= 3600.0*QP(J)/MS(I)
      HNEW   = HS(I) - DELTHS
      IF (HNEW .LT. 80.0) GO TO 707
      CALL PROPTY(5,18,TDS(I),PS(I),TNEW,HNEW,D1,XNEW,I4,D4,D5)
      CALL PROPTY(17,2,TDS(I),PS(I),TEMPT,D1,D2,0.5,I4,D4,D5)
      DELTA3(J)= (TS(I)+TNEW)/2.0 - TP(J)
      IF (X.LT.1.04 .AND. XNEW.GT.-0.10) DELTA3(J)= TEMPT-TP(J)
      IF (DELTA3(J).GE.DELTA1(J)-1.0 .AND.
     1    TNEW.GE.TP(J)-1.0) GO TO 800
  707 IF (IND .EQ. 2) GO TO 710
C
C ----- TEMPERATURE UPGRADING NEEDED - CHECK IF ANOTHER ------
C         GEOTHERMAL STREAM CAN BE USED IN A SECONDARY
C         HEAT EXCHANGER
C
      I1     = 0
      QTRANS= 0.0
      DO 708 L2 = 1,N
       ITRY   = NORDER(L2)
       IF (ITRY.EQ.I .OR. ISPURE(ITRY).NE.0 .OR. TS(ITRY).LT.
     1     TS(I)+15.0) GO TO 708
       CALL PROPTY(3,4,TDS(I),PS(I),TS(ITRY),HNEW,D1,D2,I4,D4,D5)
       QMAX1 = MS(I)*(HNEW-HS(I))/3600.0
       CALL PROPTY(3,4,TDS(ITRY),PS(ITRY),TS(I),HNEW,D1,D2,I4,
     1     D4,D5)
       MTRY   = AMIN1(MS(ITRY),3600.0*QMAX1/(HS(ITRY)-HNEW))
       QTRY   = MTRY*(HS(ITRY)-HNEW)/3600.0
       IF (0.85*QTRY .LT. QTRANS) GO TO 708
       DELTHS= 0.85*(HS(ITRY)-HNEW)*MTRY/MS(I)
```

```
      IF (DELTHS .LT. 50.0) GO TO 708
      I1     = ITRY
      QTRANS= 0.85*QTRY
      MNEW   = MTRY
  708 CONTINUE
      IF (I1 .EQ. 0) GO TO 710
C
      IF (MS(I1) .GT. MNEW) CALL SPLIT(TS,PS,HS,MS,ISPURE,ETA,
     1    TDS,MNEW,N,I1)
      IF (QTRANS.LE.QP(J)-QTRAN1) GO TO 709
      HNEW      = HS(I) + 3600.0*(QP(J)-QTRAN1)/MS(I)
      CALL PROPTY(5,18,TDS(I),PS(I),TNEW,HNEW,D1,XNEW,I4,D4,D5)
      CALL PROPTY(17,2,TDS(I),PS(I),TEMPT,D1,D2,0.5,I4,D4,D5)
      CALL PROPTY(5,48,TDS(I),PS(I),D1,HS(I),D2,X,PHASUP,D4,D5)
      DELTA3(J)= (TNEW+TS(I))/2.0 - TP(J)
      IF (XNEW.LT.1.04 .AND. X.GT.-0.10) DELTA3(J)= TEMPT-TP(J)
      IF (DELTA3(J).LT.DELTA1(J)-1.0 .OR.
     1    TS(I).LT.TP(J)-1.0) GO TO 709
      DELTHS    = 3600.0*(QP(J)-QTRAN1)/MS(I)
      QTRANS    = QP(J) - QTRAN1
C
  709 HS(I1)= HS(I1) - DELTHS*MS(I)/MS(I1)
      HS(I) = HS(I) + DELTHS
      CALL PROPTY(5,2,TDS(I1),PS(I1),TS(I1),HS(I1),D1,D2,I4,
     1    D4,D5)
      CALL PROPTY(5,50,TDS(I),PS(I),TS(I),HS(I),D1,X,PHASUP,
     1    D2,D3)
      IF (PHASUP.EQ.2 .AND. TDS(I).GT.(1.0-X)*SOLBLE) TDS(I)=
     1    (1.0-X)*SOLBLE
      IF (PHASUP.EQ.3) TDS(I)= 0.0
C
      IND   = IND + 1
      QTRAN1= QTRANS
      IAREA = IAREA + 1
      IF (X.GT.0.1 .AND. X.LT.1.04) ITYP(IAREA)= 1
      IF (X.LE.0.1 .OR.  X.GE.1.04) ITYP(IAREA)= 8
      SIZE(IAREA)= MS(I)
      AREA(IAREA)= QTRANS
      GO TO 706
C
C ----- TEMPERATURE UPGRADING --------------------------------
C
  710 DELTHS= 3600.0*QP(J)/MS(I)
      HNEW  = HS(I) - DELTHS
      IF (HNEW .LT. 80.0) GO TO 715
      CALL PROPTY(5,18,TDS(I),PS(I),TNEW,HNEW,D1,XNEW,I4,D4,D5)
      CALL PROPTY(17,2,TDS(I),PS(I),TEMPT,D1,D2,0.5,I4,D4,D5)
      DELTA3(J)= (TS(I)+TNEW)/2.0 - TP(J)
      IF (X.LT.1.04 .AND. XNEW.GT.-0.10) DELTA3(J)= TEMPT-TP(J)
      IF (DELTA3(J).GE.DELTA1(J)-1.0 .AND.
```

```
    1    TNEW.GE.TP(J)-1.0) GO TO 800
C
  715 TS(I) = TS(I) + 4.0
      IF (TS(I) .LE. TP(J)-1.0) TS(I)= TP(J)
  720 CALL PROPTY(3,52,TDS(I),PS(I),TS(I),HFINAL,D1,X,PHASUP,
    1    D3,D4)
      QTRANS= (HFINAL-HS(I))*MS(I)/3600.0
      HNEW  = HFINAL - DELTHS
      IF (HNEW .LT. 80.0) GO TO 725
      CALL PROPTY(5,18,TDS(I),PS(I),TNEW,HNEW,D1,XNEW,I4,D4,D5)
      DELTA3(J)= (TS(I)+TNEW)/2.0 - TP(J)
      IF (X.LT.1.04 .AND. XNEW.GT.-0.10) DELTA3(J)= TEMPT-TP(J)
      IF (DELTA3(J).GE.DELTA1(J)-1.0 .AND.
    1    TNEW.GE.TP(J)-1.0) GO TO 730
  725 TS(I) = TS(I) + 2.5
      GO TO 720
C
  730 HS(I) = HFINAL
      Z     = Z + 1
      TM(Z) = TS(I)
      PM(Z) = PS(I)
      QM(Z) = QTRANS
C
      IAREA = IAREA + 1
      ITYP(IAREA)= 6
      SIZE(IAREA)= MS(I)
      AREA(IAREA)= QM(Z)
      IF (PHASUP.EQ.2 .AND. TDS(I).GT.(1.0-X)*SOLBLE) TDS(I)=
    1     (1.0-X)*SOLBLE
      IF (PHASUP .EQ. 3) TDS(I)= 0.0
C ***********************************************************
C
C ----- UNIT PROCESS SECTION --------------------------------
C
C ***********************************************************
  800 MNEW  = MP(J)*MCHECK(ICOND+1)
      IF (MS(I) .GT. MNEW) CALL SPLIT(TS,PS,HS,MS,ISPURE,ETA,
    1    TDS,MNEW,N,I)
C
C ----- UNIT PROCESS ----------------------------------------
C
  805 DELTHS= 3600.0*QP(J)/MS(I)
      HNEW  = HS(I) - DELTHS
      CALL PROPTY(5,50,TDS(I),PS(I),TNEW,HNEW,D1,XNEW,PHASUP,
    1    D3,D4)
      IF (TNEW .LT. TP(J)-1.0) WRITE (IOUT,1100) I, J, TNEW
      DELTA3(J)= (TS(I)+TNEW)/2.0 - TP(J)
      CALL PROPTY(17,2,TDS(I),PS(I),TEMPT,D1,D2,0.5,I4,D4,D5)
```

```
      CALL PROPTY(5,48,TDS(I),PS(I),D1,HS(I),D2,X,I4,D4,D5)
      IF (X.LT.1.04 .AND. XNEW.GT.-0.10) DELTA3(J)= TEMPT-TP(J)
C
      TS(I) = TNEW
      HS(I) = HNEW
      IF (IPPURE(J) .GE. 2) ISPURE(I) = ISPURE(I) + 2
      IF (ISPRT2.EQ.1 .AND. ISPURE(I).LE.1 .AND. PHASUP.EQ.2)
     1    CALL SEPRAT(I)
C
C ----- PROCESS EQUIPMENT SIZE CHANGES -----------------------
C
      IF (IPPURE(J) .LE. 1) GO TO 830
      ITYP(J)= 7
      SIZE(J)= MS(I)
      AREA(J)= (TP(J)+DELTA2(J)+273.15)/(TP(J)+DELTA3(J)+
     1          273.15)
      GO TO 870
C
  830 IF (PHASE(J).EQ.1 .OR. PHASE(J).EQ.3) GO TO 835
      ITYP(J)= 7
      SIZE(J)= MS(I)
      FOFETA = 1.0 - 2.01126*ETA(I)**0.7933
      AREA(J)= DELTA2(J)/(FOFETA*DELTA3(J))
      GO TO 870
  835 XMUP8  = (MS(I)/MP(J))**0.8
      ITYP(J)= 7
      SIZE(J)= MS(I)
      AREA(J)= (XMUP8*GAMMA(J)+1.0)*DELTA2(J)/(XMUP8*
     1           (GAMMA(J)+1.0)*DELTA3(J))
C
C ----- SORT AND PRINT STREAMS REMAINING AFTER PROCESS -------
C
  870 CALL SORT(TS, MS, NORDER, N, 1)
      NMIN1 = N - 1
      DO 874 I1 = 1,NMIN1
       IF (MS(I1).EQ.0.0 .OR. ISPURE(I1).GE.2) GO TO 874
       IPLUS1 = I1 + 1
       DO 872 I2 = IPLUS1,N
        IF (MS(I2).EQ.0.0 .OR. ISPURE(I2).GE.2 .OR.
     1      ISPURE(I1).NE.ISPURE(I2)) GO TO 872
        IF (ABS(PS(I1)-PS(I2)).GT.0.2 .OR.
     1      ABS(HS(I1)-HS(I2)).GT.20.0) GO TO 872
        HS(I1) = (HS(I1)*MS(I1)+HS(I2)*MS(I2))/(MS(I1)+MS(I2))
        TDS(I1)= (TDS(I1)*MS(I1)+TDS(I2)*MS(I2))/(MS(I1)+MS(I2))
        ETA(I1)= (ETA(I1)*MS(I1)+ETA(I2)*MS(I2))/(MS(I1)+MS(I2))
        MS(I1) = MS(I1) + MS(I2)
        CALL PROPTY(5,2,TDS(I1),PS(I1),TS(I1),HS(I1),D1,
     1      D2,I4,D4,D5)
```

```
      TS(I2) = 0.0
      MS(I2) = 0.0
  872  CONTINUE
  874 CONTINUE
      CALL SORT(TS, MS, NORDER, N, 1)
C
      WRITE (IOUT,930) J
      DO 875 L = 1,N
       I      = NORDER(L)
       IF (MS(I) .LT. 20.0) GO TO 875
       WRITE (IOUT,932) I, TS(I), PS(I), HS(I), MS(I),
     1                  ISPURE(I), ETA(I), TDS(I)
  875 CONTINUE
  880 CONTINUE
C ***********************************************************
C
C ----- COMPUTE MATCH RESULTS --------------------------------
C
C ***********************************************************
  882 ENTOT2= 0.0
      AVAIL2= 0.0
      DO 885 K = 1,N
       I      = NORDER(K)
       IF (MS(I).LT.20.0 .OR. HS(I).EQ.84.045) GO TO 885
       CALL PROPTY(5,8,TDS(I),PS(I),D1,HS(I),SS,D2,I4,D4,D5)
       ENTOT2= ENTOT2 + HS(I)*MS(I)/3600.0
       AVAIL2= AVAIL2 + (HS(I)-293.15*SS)*MS(I)
  885 CONTINUE
      ENTOTL= ENTOTL + 84.045*MWATER/3600.0
      AVAIL2= (AVAIL2 + 2.8971*(MTOTAL+MWATER))/3600.0
      QESUM  = 0.0
      QFSUM  = 0.0
      DO 890 I = 1,Z
       IF (TM(I).EQ.0.0 .AND. PM(I).EQ.0.0) QESUM= QESUM+QM(I)
       IF (TM(I).GT.0.0 .OR.  PM(I).LT.0.0) QFSUM= QFSUM+QM(I)
  890 CONTINUE
C
      RETURN
C
C
  900 FORMAT (1H1)
  930 FORMAT (//1H0,37HF L U I D   S T R E A M S   A F T E R,
     1 17H   P R O C E S S ,I3,2H :/1H0,
     1 51H  SUPPLY  TEMPERATURE  PRESSURE  ENTHALPY  FLOW RAT,
     1 24HE  PURE  NON-COND.   TDS/1H ,10X,14H(DEGREES C)    ,
     1 27H(BARS)     (J/G)      (KG/HR)//)
  931 FORMAT (//1H0,37HG E O T H E R M A L   S U P P L Y   S,
     1 43HT R E A M S   A F T E R   F L A S H I N G:/1H0,
```

```
     1 51H  SUPPLY  TEMPERATURE  PRESSURE  ENTHALPY  FLOW RAT,
     1 24HE  PURE  NON-COND.   TDS/1H ,10X,14H(DEGREES C)    ,
     1 27H(BARS)    (J/G)     (KG/HR)/)
 932 FORMAT (1H ,2X,I4,F12.1,F12.3,F10.2,1PE12.4,I5,0PF10.4,
     1 F10.5)
 970 FORMAT (1H0,40HCOMPRESSION OF TWO-PHASE MIXTURE ATTEMPT,
     1 3HED:/1H ,12H  STREAM NO.,I3,10H, QUALITY=,F7.4)
 990 FORMAT (1H0,40HSUPPLY STREAM PHASE HIGHER THAN NEEDED: /
     1 1H ,12H  STREAM NO.,I3,13H, PROCESS NO.,I3,9H, STREAM ,
     1 10HPRESSURE =,F7.3,5H BARS/1H ,19H  STREAM ENTHALPY =,
     1 F8.2,6H KJ/KG)
1100 FORMAT (1H0,31HTEMPERATURE UPGRADING OF STREAM,I3,4H FOR,
     1 8H PROCESS,I3,6H GIVES/1H ,18HA VALUE FOR TNEW (,F6.2,
     1 20H C) THAT IS TOO LOW.)
      END
```

g. Program SEPRAT

```
      SUBROUTINE SEPRAT(L)
C
C ******** PROGRAM SEPARATES TWO-PHASE SUPPLY STREAMS ********
C ********   INTO DISTINCT VAPOR AND LIQUID STREAMS    ********
C
      REAL MCHECK(4), MP(50), MPI(50), MS(50), MSI(50),
    1 MTOTAL, MWATER
      INTEGER PHASE(50), PHASEI(50), Y, Z
      COMMON /A/ DELT1I(50), DELT2I(50), ETI(50), GAMMAI(50),
    1  HSI(50), MCHECK    , MPI         , MSI    , PPI(50)    ,
    1  PSF(50), PSI(50)   , QPI(50)     , TDI(50), TPI(50)    ,
    1  TSI(50), IAUX      , IFLASH      , IPPURI(50), ISEPRT  ,
    1  ISPRT2 , ISPURI(50), MI          , NI     , PHASEI
      COMMON /D/  DELTA1(50), DELTA2(50), DELTA3(50), ETA(50),
    1  GAMMA(50) , HS(50)   , MP          , MS          , PM(50) ,
    1  PP(50)    , PS(50)   , QM(50)      , QP(50)      , TDS(50),
    1  TM(50)    , TP(50)   , TS(50)      , IPPURE(50),
    1  ISPURE(50), M        , MORDER(50), N              ,
    1  NORDER(50), PHASE    , Z
      COMMON /E/  AREA(50), AVAIL2   , AVAILS, CFLUID, ENTOT2,
    1  ENTOTL    , MTOTAL   , MWATER   , QESUM , QFSUM , QSUM   ,
    2  SIZE(50), IAREA     , ITYP(50)
      DATA IN, IOUT/8, 6/
      DATA SOLBLE/0.50/
C
      CALL PROPTY(5,208,TDS(L),PS(L),D1,HS(L),D2,X,I4,HF,HG)
      IF (X.LT.-0.02 .OR. X.GT.1.02) WRITE (IOUT,900) L,PS(L),X
      IF (X.LT.0.1 .OR. X.GT.0.9) RETURN
C
      TS(N+1)= TS(L)
      PS(N+1)= PS(L)
      HS(N+1)= HF
      MS(N+1)= (1.0-X)*MS(L)
      ISPURE(N+1)= ISPURE(L)
      ETA(N+1)    = 0.0
      TDS(N+1)    = AMIN1(TDS(L)/(1.0-X),SOLBLE)
      IAREA = IAREA + 1
      ITYP(IAREA)= 5
      SIZE(IAREA)= MS(L)
      AREA(IAREA)= X
      HS(L)   = HG
      TDS(L) = 0.0
      MS(L)   = X*MS(L)
      N       = N + 1
C
      RETURN
  900 FORMAT (1H0,40H----- QUALITY OUT OF BOUNDS IN SUBROUTIN,
    1 14HE SEPRAT -----/1H ,8X,8HSTREAM =,I3,12H, PRESSURE =,
```

```
1 F6.2,11H, QUALITY =,F8.3)
 END
```

h. Program SORT

```
      SUBROUTINE SORT(T, M, LORDER, K, NX)
C
C ******** PROGRAM REARRANGES PROCESSES OR SUPPLY   ***********
C ******** STREAMS IN DECREASING TEMPERATURE ORDER ***********
C
      REAL M(50)
      DIMENSION LORDER(50), T(50)
C
      L     = K - 1
      IF (L .EQ. 0) RETURN
  100 INTER = 0
      DO 200 I = 1,L
       I1    = LORDER(I)
       I2    = LORDER(I+1)
       IND   = 0
       IND1  = 0
       IF ((M(I1).LE.M(I2).AND.NX.EQ.1) .OR. (M(I1).GE.
     1     M(I2).AND.NX.EQ.2)) IND1 = 1
       IF (ABS(T(I1)-T(I2)).LE.0.2 .AND. IND1.EQ.1) IND = 1
       IF (T(I1)-T(I2).GT.0.2 .OR. IND.EQ.1) GO TO 200
       INTER= INTER + 1
       IHOLD= LORDER(I)
       LORDER(I)  = LORDER(I+1)
       LORDER(I+1)= IHOLD
  200 CONTINUE
      IF (INTER.EQ.0 .OR. L.EQ.1) RETURN
      GO TO 100
C
      END
```

i. Program SPLIT

```
      SUBROUTINE SPLIT(TS,PS,HS,MS,ISPURE,ETA,TDS,MNEW,N,I)
C
C ******** PROGRAM SPLITS STREAMS WITH EXCESSIVE FLOW RATE ***
C
      REAL MNEW, MS(50)
      DIMENSION ETA(50), HS(50), PS(50), TDS(50), TS(50),
     1  ISPURE(50)
C
      TS(N+1)      = TS(I)
      PS(N+1)      = PS(I)
      HS(N+1)      = HS(I)
      MS(N+1)      = MS(I) - MNEW
      ISPURE(N+1)= ISPURE(I)
      ETA(N+1)     = ETA(I)
      TDS(N+1)     = TDS(I)
      MS(I)        = MNEW
      N            = N + 1
C
      RETURN
      END
```

j. Program ECONMC

```
      SUBROUTINE ECONMC(AREA, CAREA, CFLUID, MSOF1, MWATER,
     1  QESUM, QFSUM,   SIZE, IAREA, ITYP  , GTSYST)
C
C **********************************************************
C *                                                        *
C *          PROGRAM PERFORMS ECONOMIC ANALYSIS            *
C *                                                        *
C **********************************************************
C *                                                        *
C *   -- THIS PROGRAM WAS WRITTEN IN 1979 BY MICHAEL B.    *
C *        PACKER AT THE MASSACHUSETTS INSTITUTE OF TECH-  *
C *        NOLOGY FOR THE DEPARTMENT OF ENERGY.            *
C *   -- METRIC UNITS ARE EMPLOYED THROUGHOUT:             *
C *        FLOW RATE  = KG/HR        ENERGY  = KJ          *
C *        ENERGY RATE= KW                                 *
C *   -- SEPARATE DOCUMENTATION INCLUDES FLOW CHARTS,      *
C *        COMPLETE VARIABLE LISTS, AND A "WALK-THROUGH"   *
C *        DESCRIPTION OF PROGRAM OPERATING PRINCPLES.     *
C *                                                        *
C **********************************************************
C
      REAL IRR, IRR1, IRR2, IRRAVG, MSOF1, MWATER, NWELLR
      INTEGER FLAG, Z
      LOGICAL GTSYST
      DIMENSION AREA(50), CAREA(50), CINF(4), SIZE(50),
     1  ITYP(50)
C
      COMMON /F/ BONDRT, CASH(40) , CASHF(40) , CDSCNT ,
     1  CELECT , CFOSSL, CINFLT(8), CINSUR    , CINVSF , CINVST,
     1  COPRAT , CUMINV, DEBTEQ   , FINVST(40), IRR    , OPFRAC,
     1  PROFIT , PROPTX, SALVAG   , SAVING(40), TAXCRD , TAXRAT,
     1  XNPV   , XNPVF , IBEGIN   , ICONST    , ILIFE  , LIFEBD,
     1  LIFETM , IPAYBK
      COMMON /G/  CLAND   , CMAINT  , COTHER, CREPLC, CROYAL,
     1  CTRANS   , CUMGTC   , CUMINC   , CWELL , DPLBAS, NWELLR,
     2  PROBC(3), PROBM(3), PROBT(3), ROIREQ, TANGBL, NWELLI,
     3  NWELLP
      DATA IN, IOUT/8, 6/
C
C ----- INITIALIZE VARIABLES -------------------------------
C
      DO 100 I=1,40
       CASH(I)= 0.0
  100 CONTINUE
      XNPV   = 0.0
      CINVST= 0.0
      CUMINV= 0.0
      CUMGTV= 0.0
```

```
      CUMINC= 0.0
      CUMGTC= 0.0
      CUMINA= 0.0
C
C ----- CALCULATE INITIAL INVESTMENT -----------------------
C
      DO 200 J=1,IAREA
       IF (ITYP(J) .EQ. 1) CINVST= CINVST + 354286.0*(SIZE(J)/
     1      22679.6)**0.53
       IF (ITYP(J) .EQ. 2) CINVST= CINVST + 22.297*
     1      (SIZE(J)*AREA(J))**0.568
       IF (ITYP(J) .EQ. 3) CINVST= CINVST + 144389.1*(AREA(J)/
     1      (1.02*149.14))**0.57483 + 9756.0*(AREA(J)/(1.02*
     2      59.656))**0.98189
       IF (ITYP(J) .EQ. 4) CINVST= CINVST + 1.625910*
     1      (SIZE(J)**0.9996)*(AREA(J)**0.09795)
       IF (ITYP(J) .EQ. 5) CINVST= CINVST + 0.0
       IF (ITYP(J) .EQ. 6) CINVST= CINVST + 422595.1*(AREA(J)/
     1      5861.445)**0.68857
       IF (ITYP(J) .EQ. 7) CINVST= CINVST + (CAREA(J)*
     1      AREA(J)**0.6)/1.18
       IF (ITYP(J) .EQ. 8) CINVST= CINVST + 61905.0*(SIZE(J)/
     1      22679.6)**0.65
  200 CONTINUE
      CINVST= 1.18*CINVST
      CFIELD= 0.0
      IF (GTSYST)      CFIELD= CWELL*FLOAT(NWELLP+NWELLI) +
     1    CTRANS + CLAND + COTHER
      CINVST= CINVST + CFIELD
C
C ----- CALCULATE IMPUTED NET INCOME FOR DEPLETION PURPOSES --
C
      IFINAL= IBEGIN + ILIFE + ICONST - 1
      ANNINC= 0.0
      IF (.NOT.GTSYST) GO TO 230
      R1    = (1.0+CINFLT(1))/(1.0+ROIREQ)
      R2    = (1.0+CINFLT(5))/(1.0+ROIREQ)
      K1    = IBEGIN + ICONST - 1978
      M1    = 8 - K1
      N1    = IFINAL - 1986
      IF (CINFLT(1).LT.ROIREQ .AND. CINFLT(5).LT.ROIREQ)
     1    GO TO 210
      STORE = ILIFE
      WRITE (IOUT,1020) ROIREQ, CINFLT(1), CINFLT(5)
C
  210 STORE = (R1**K1)*((R1**(M1+1)-1.0)/(R1-1.0) + (R1**M1)*
     1  (R2**(N1+1)-R2)/(R2-1.0))
      IF (M1 .LT. 0) STORE = (R1**8)*(R2**(N1+1)-R2)/(R2-1.0)
```

```
      FINSUM= 0.0
      DO 220 I=1,40
       FINSUM= FINSUM + FINVST(I)
  220 CONTINUE
      ANNINC= TANGBL*DPLBAS*FINSUM*CWELL*FLOAT(NWELLP+NWELLI)/
     1  (STORE*(1.0-TAXRAT))
C
C ----- CALCULATE ANNUAL BEFORE-TAX CASH FLOWS ---------------
C
  230 DO 400 I=IBEGIN,IFINAL
      IF (I .GT. 1986) GO TO 250
      CINF(1)= (1.0+CINFLT(1))**(I-1978)
      CINF(2)= (1.0+CINFLT(2))**(I-1978)
      CINF(3)= (1.0+CINFLT(3))**(I-1978)
      CINF(4)= (1.0+CINFLT(4))**(I-1978)
      GO TO 260
  250 CINF(1)= ((1.0+CINFLT(1))**8)*((1.0+CINFLT(5))**(I-1986))
      CINF(2)= ((1.0+CINFLT(2))**8)*((1.0+CINFLT(6))**(I-1986))
      CINF(3)= ((1.0+CINFLT(3))**8)*((1.0+CINFLT(7))**(I-1986))
      CINF(4)= ((1.0+CINFLT(4))**8)*((1.0+CINFLT(8))**(I-1986))
C
  260 OUTINV= CINVST*FINVST(I-IBEGIN+1)*CINF(1)
      CUMINV= CUMINV + OUTINV
      CUMGTV= CUMGTV + CFIELD*FINVST(I-IBEGIN+1)*CINF(1)
      CUMINA= CUMINA + CINVST*FINVST(I-IBEGIN+1)*CINF(1)
      IF (GTSYST) CUMINA= CUMINA - CWELL*FLOAT(NWELLP+NWELLI)*
     1    (1.0-TANGBL*(1.0-DPLBAS))*FINVST(I-IBEGIN+1)*CINF(1)
     1    - CLAND*FINVST(I-IBEGIN+1)*CINF(1)
      CUMINC= CUMINC + CINVST*FINVST(I-IBEGIN+1)
      CUMGTC= CUMGTC + CFIELD*FINVST(I-IBEGIN+1)
      OUTENG= 0.0
      IF (I .GE. IBEGIN+ICONST) OUTENG= QFSUM*CFOSSL*OPFRAC*
     1    3.1536E7*CINF(2)/0.80 + QESUM*CELECT*OPFRAC*3.1536E7*
     1    CINF(3) + MSOF1*CFLUID*OPFRAC*8760.0*CINF(4)
      OUTINT= 0.0
      IF (I .LE. IBEGIN+LIFEBD-1) OUTINT= CUMINV*BONDRT*DEBTEQ/
     1    (1.0+DEBTEQ)
      OUTINS= CUMINC*CINSUR*CINF(1)
      OUTOPT= 0.0
      IF (I .GE. IBEGIN+ICONST) OUTOPT= (CUMINC-CUMGTC)*
     1    COPRAT*CINF(1)
      IF (GTSYST .AND. I.GE.IBEGIN+ICONST) OUTOPT= OUTOPT +
     1    CMAINT*CINF(1)
      OUTTXP= CUMINC*PROPTX*CINF(1)
C
      COSTS = OUTINV + OUTENG + OUTINT + OUTINS + OUTOPT + OUTTXP
      ROYLTY= 0.0
      COSTGT= 0.0
```

```
      IF (.NOT.GTSYST) GO TO 300
      COSTGT= CFIELD*FINVST(I-IBEGIN+1)*CINF(1) + CUMGTC*CINSUR*
     1  CINF(1) + CUMGTC*PROPTX*CINF(1)
      IF (I .LE. IBEGIN+LIFEBD-1) COSTGT= COSTGT + CUMGTV*BONDRT*
     1     DEBTEQ/(1.0+DEBTEQ)
      IF (I .GE. IBEGIN+ICONST)   COSTGT= COSTGT + CMAINT*CINF(1)
      IF (I .GE. IBEGIN+ICONST)   ROYLTY= CROYAL*(ANNINC*CINF(1) +
     1     COSTGT)
  300 COSTS = COSTS + ROYLTY
      IF (I .EQ. IBEGIN+LIFEBD-1) COSTS= COSTS + CUMINV*
     1     DEBTEQ/(1.0+DEBTEQ)
C
C ----- CALCULATE ANNUAL AFTER-TAX CASH FLOWS ----------------
C
      DEPREC= 0.0
      IF (I.GE.IBEGIN+ICONST .AND. I.LE.IBEGIN+ICONST+LIFETM-1)
     1     DEPREC= CUMINA*(1.0-SALVAG)*2.0*FLOAT(LIFETM-I+
     1     IBEGIN+ICONST)/FLOAT(LIFETM*(LIFETM+1))
      IF (I.LT.IBEGIN+ICONST .AND. I.LE.IBEGIN+LIFEBD-1)
     1     CUMINA= CUMINA + OUTINT
C
      DEPLET= 0.0
      IF (.NOT.GTSYST .OR. I.LT.IBEGIN+ICONST) GO TO 350
      IF (I .LE. 1980) PERCNT= 0.22
      IF (I .EQ. 1981) PERCNT= 0.20
      IF (I .EQ. 1982) PERCNT= 0.18
      IF (I .EQ. 1983) PERCNT= 0.16
      IF (I .GE. 1984) PERCNT= 0.15
      DEPLET= AMIN1(PERCNT*(ANNINC*CINF(1)+COSTGT) , 0.50*
     1  ANNINC*CINF(1))
C
  350 TAXES = -TAXRAT*(DEPREC+OUTENG+OUTINT+OUTINS+OUTOPT+
     1  OUTTXP+DEPLET+ROYLTY) - TAXCRD*CINVST*FINVST(I-IBEGIN+
     1  1)*CINF(1)
      IF (GTSYST) TAXES= TAXES - (TAXRAT*(1.0-TANGBL)-
     1     TAXCRD*(1.0-TANGBL*(1.0-DPLBAS)))*CWELL*
     1     FLOAT(NWELLP+NWELLI)*FINVST(I-IBEGIN+1)*CINF(1)
C
      IYEAR = I - IBEGIN + 1
      CASH(IYEAR)= -COSTS - TAXES
      XNPV  = XNPV + CASH(IYEAR)/(1.0+CDSCNT)**(IYEAR-1)
      IF (.NOT.GTSYST) CASHF(IYEAR)= CASH(IYEAR)
  400 CONTINUE
      IF (GTSYST) GO TO 430
      CINVSF= CUMINC
      XNPVF = XNPV
      RETURN
C
```

```
C ----- COMPARE RESULTS OF GEOTHERMAL AND FOSSIL SYSTEMS ------
C
  430 IFINAL= ILIFE + ICONST
      IPAYBK= 100
      SAVING(1)= CASH(1) - CASHF(1)
      PREVAL   = SAVING(1)
      FLAG     = 0
      IF (PREVAL .GE. 0.0) IPAYBK= 1
      DO 450 I = 2,IFINAL
       SAVING(I)= CASH(I) - CASHF(I)
       PREVAL   = PREVAL + SAVING(I)/(1.0+CDSCNT)**(I-1)
       IF (IPAYBK.EQ.100 .AND. PREVAL.GE.0.0) IPAYBK= I
       IF (SAVING(I)*SAVING(I-1) .LT. 0.0) FLAG= FLAG + 1
  450 CONTINUE
      IRR   = 0.0
      ITER  = 0
      IRR1  = 0.0
      IRR2  = 2.0
      ERROR = 1.0E-5*ABS(CASH(1))
  460 IRRAVG= 0.5*(IRR1+IRR2)
      PREVAL= 0.0
      DO 470 I=1,IFINAL
       PREVAL= PREVAL + SAVING(I)/(1.0+IRRAVG)**(I-1)
  470 CONTINUE
      IF (ABS(PREVAL) .LE. ERROR) GO TO 500
      ITER  = ITER + 1
      IF (ITER .GT. 30) WRITE (IOUT,1000) IRRAVG, PREVAL
      IF (ITER .GT. 30) GO TO 500
      IF (PREVAL .GT. 0.0) IRR1= IRRAVG
      IF (PREVAL .LE. 0.0) IRR2= IRRAVG
      GO TO 460
C
  500 IF (FLAG .GE. 2) WRITE (IOUT,1010) FLAG, IRRAVG, PREVAL
      IRR   = IRRAVG
  999 RETURN
C
 1000 FORMAT (1H0,41HITERATION FOR INTERNAL RATE OF RETURN DOE,
     1 15HS NOT CONVERGE:/3H    ,7HIRRAVG=,1PE11.4,9H, PREVAL=,
     1 E11.4)
 1010 FORMAT (1H0,40H----- WARNING:  INTERNAL RATE OF RETURN ,
     1 22HMAY BE UNDEFINED -----/1H ,21H  CASH FLOWS CHANGE S,
     1 4HIGN ,I1,7H TIMES./1H ,9H  IRRAVG=,1PE11.4,9H, PREVAL=,
     1 E11.4)
 1020 FORMAT (1H0,37HREQUIRED RATE OF RETURN IS TOO LOW:  ,
     1  2PF6.2,15H%  IS LESS THAN/1H ,14H  INFLATION  (,F6.2,
     1  6H% AND ,F6.2,2H%))
C
      END
```

k. Program PROPTY

```
      SUBROUTINE PROPTY(INDEX1,INDEX2,TDS,P,T,H,S,X,PHASUP,HF,HG)
C
C ***********************************************************
C *                                                         *
C *        MASTER PROGRAM FOR THE EVALUATION OF            *
C *        THERMODYNAMIC PROPERTIES OF WATER OR            *
C *                 BRINE IN ANY PHASE                      *
C *                                                         *
C ***********************************************************
C *                                                         *
C * -- THIS PROGRAM WAS WRITTEN IN 1979 BY MICHAEL B.       *
C *      PACKER AT THE MASSACHUSETTS INSTITUTE OF TECH-     *
C *      NOLOGY FOR THE DEPARTMENT OF ENERGY.               *
C * -- METRIC UNITS ARE EMPLOYED THROUGHOUT:                *
C *      TEMPERATURE= DEGREES C    PRESSURE= BARS           *
C *      ENTHALPY   = KJ/KG        ENTROPY = J/G-K          *
C * -- SEVERAL SUBPROGRAMS ARE CALLED:                      *
C *      QUAL:  RETURNS TWO-PHASE QUALITY GIVEN P AND H     *
C *             OR S FOR SALT SOLUTIONS                     *
C *      SALT CORRELATION CONSTANTS:  FUNCTIONS A1(CSALT)   *
C *             THROUGH A6(CSALT)                           *
C *      STEAM TABLE CORRELATIONS:                          *
C *        SATURATION LINE - HFSAT(P), HGSAT(P), PSTHF(HF), *
C *             PSTT(T), SFSAT(P), SGSAT(P), TSAT(P)        *
C *        VAPOR REGION - HSPT(P,T), HSUP(P,S), SSUP(P,H),  *
C *             TSUP(P,H)                                   *
C *        LIQUID REGION - HLIQ(P,S), HLPT(P,T), SLIQ(P,H), *
C *             TLIQ(P,H)                                   *
C * -- SEPARATE DOCUMENTATION INCLUDES FLOW CHARTS,         *
C *      COMPLETE VARIABLE LISTS, AND A "WALK-THROUGH"      *
C *      DESCRIPTION OF PROGRAM OPERATING PRINCIPLES.       *
C *                                                         *
C ***********************************************************
C
      INTEGER PHAS, PHASUP
      LOGICAL FINDH, FINDHF, FINDHG, FINDP , FINDPH, FINDS ,
     1  FINDT,FINDX, GIVNHF, GIVNP , GIVNPH, GIVNPS, GIVNPT
C
      DATA IN, IOUT/8, 6/
      DATA SOLBLE, SUPRHT/0.5, 1.0/
C
C ----- INITIALIZE AND SET INPUT AND OUTPUT CONTROL VARIABLES --
C
      GIVNP = .FALSE.
      GIVNPT= .FALSE.
      GIVNPH= .FALSE.
      GIVNPS= .FALSE.
      GIVNHF= .FALSE.
```

```
      FINDP = .FALSE.
      FINDT = .FALSE.
      FINDH = .FALSE.
      FINDS = .FALSE.
      FINDX = .FALSE.
      FINDPH= .FALSE.
      FINDHF= .FALSE.
      FINDHG= .FALSE.
C
      IF (INDEX1 .EQ.17) GIVNP = .TRUE.
      IF (INDEX1 .EQ. 3) GIVNPT= .TRUE.
      IF (INDEX1 .EQ. 5) GIVNPH= .TRUE.
      IF (INDEX1 .EQ. 9) GIVNPS= .TRUE.
      IF (INDEX1 .EQ.80) GIVNHF= .TRUE.
      IF (GIVNP.OR.GIVNPT.OR.GIVNPH.OR.GIVNPS.OR.GIVNHF)
     1    GO TO 100
      WRITE (IOUT,9000) INDEX1, INDEX2
      STOP
C
  100 IND = INDEX2
      IF (INT(FLOAT(IND)/128.0).GT. 0) FINDHG= .TRUE.
      IND = MOD(IND,128)
      IF (INT(FLOAT(IND)/64.0) .GT. 0) FINDHF= .TRUE.
      IND = MOD(IND,64)
      IF (INT(FLOAT(IND)/32.0) .GT. 0) FINDPH= .TRUE.
      IND = MOD(IND,32)
      IF (INT(FLOAT(IND)/16.0) .GT. 0) FINDX = .TRUE.
      IND = MOD(IND,16)
      IF (INT(FLOAT(IND)/8.0)  .GT. 0) FINDS = .TRUE.
      IND = MOD(IND,8)
      IF (INT(FLOAT(IND)/4.0)  .GT. 0) FINDH = .TRUE.
      IND = MOD(IND,4)
      IF (INT(FLOAT(IND)/2.0)  .GT. 0) FINDT = .TRUE.
      IND = MOD(IND,2)
      IF (IND .EQ. 1)         FINDP = .TRUE.
      IF (FINDP.OR.FINDT.OR.FINDH.OR.FINDS.OR.FINDX.OR.
     1  FINDPH.OR.FINDHF.OR.FINDHG) GO TO 110
      WRITE (IOUT,9010) INDEX1, INDEX2
      STOP
C
C ----- CHECK INPUT DATA FOR PROPER DOMAIN ------------------
C
  110 IF (TDS.LT.0.0 .OR. TDS.GT.0.35)   GO TO 120
      IF (P.GT.220.88 .AND. .NOT.GIVNHF) GO TO 120
      IF ((T.LT.10.0.OR.T.GT.374.14) .AND. GIVNPT) GO TO 120
      IF (((H.LT.0.0.OR.H.GT.3700.0).AND.GIVNPH).OR.((HF.LT.0.0
     1     .OR.HF.GT.3700.0).AND.GIVNHF)) GO TO 120
      IF ((S.LT.0.0.OR.S.GT.10.0) .AND. GIVNPS) GO TO 120
```

```
      GO TO 200
  120 WRITE (IOUT,9020) INDEX1, TDS, P, T, H, S
      STOP
C
C ----- SALINITY CHECK -------------------------------------
C
  200 IF (TDS .GT. 1.0E-5) GO TO 500
C ************************************************************
C
C ----- DETERMINATION OF PROPERTIES OF PURE WATER ------------
C
C ************************************************************
      IF (GIVNP .OR. GIVNHF) GO TO 210
      PHASUP= 1
      IF (GIVNPT) GO TO 250
      IF (GIVNPH) GO TO 300
      IF (GIVNPS) GO TO 350
      STOP
C
C ----- SATURATION LINE PROPERTIES ALONE DESIRED -------------
C
  210 IF (FINDP)  P  = PSTHF(HF)
      IF (FINDT)  T  = TSAT(P)
      IF (FINDHF) HF = HFSAT(P)
      IF (FINDHG) HG = HGSAT(P)
      RETURN
C
C ----- PRESSURE AND TEMPERATURE GIVEN -----------------------
C
  250 TEMPER= TSAT(P)
      IF (T .GE. TEMPER-1.0) PHASUP= 2
      IF (T .GT. TEMPER+1.0) PHASUP= 3
      IF (.NOT.FINDX .AND. .NOT.FINDH .AND. PHASUP.EQ.2)
     1    GO TO 270
      IF (PHASUP .EQ. 1) H= HLPT(P,T)
      IF (PHASUP .EQ. 2) H= HGSAT(P)
  260 IF (PHASUP .EQ. 3) H= HSPT(P,T)
      IF (FINDX) HF= HFSAT(P)
      IF (FINDX) X = (H-HF)/(HGSAT(P)-HF)
  270 IF (.NOT.FINDS) RETURN
      IF (PHASUP .EQ. 1) S= SLIQ(P,H)
      IF (PHASUP .EQ. 2) S= SGSAT(P)
      IF (PHASUP .EQ. 3) S= SSUP(P,H)
      RETURN
C
C ----- PRESSURE AND ENTHALPY GIVEN --------------------------
C
  300 HF     = HFSAT(P)
```

```
      HG     = HGSAT(P)
      X      = (H-HF)/(HG-HF)
      IF (H .GE. HF) PHASUP= 2
      IF (H .GT. HG) PHASUP= 3
      IF (.NOT.FINDT) GO TO 320
      IF (PHASUP .EQ. 1) T= TLIQ(P,H)
      IF (PHASUP .EQ. 2) T= TSAT(P)
      IF (PHASUP .EQ. 3) T= TSUP(P,H)
  320 IF (.NOT.FINDS) RETURN
      IF (PHASUP .EQ. 1) S= SLIQ(P,H)
      IF (PHASUP .EQ. 2) S= X*SGSAT(P) + (1.0-X)*SFSAT(P)
      IF (PHASUP .EQ. 3) S= SSUP(P,H)
      RETURN
C
C ----- PRESSURE AND ENTROPY GIVEN --------------------------
C
  350 SF     = SFSAT(P)
      SG     = SGSAT(P)
      IF (S .GE. SF) PHASUP= 2
      IF (S .GT. SG) PHASUP= 3
      X      = (S-SF)/(SG-SF)
      IF (.NOT.FINDHF .AND. .NOT.FINDHG .AND. PHASUP.NE.2)
     1    GO TO 370
      HF     = HFSAT(P)
      HG     = HGSAT(P)
      IF (PHASUP .EQ. 2) H= X*HG + (1.0-X)*HF
  370 IF (PHASUP .EQ. 1) H= HLIQ(P,S)
      IF (PHASUP .EQ. 3) H= HSUP(P,S)
      RETURN
C ***********************************************************
C
C ----- DETERMINATION OF PROPERTIES OF SALT SOLUTIONS --------
C
C ***********************************************************
  500 IF (GIVNP)  GO TO 550
      IF (GIVNHF) GO TO 600
      PHASUP= 1
      IF (GIVNPT) GO TO 650
      IF (GIVNPH .OR. GIVNPS) GO TO 700
      STOP
C
C ----- PRESSURE AND QUALITY GIVEN --------------------------
C
  550 IF (X .LE. 0.99) CSALT= AMIN1(TDS/(1.0-X),SOLBLE)
      IF (X .GT. 0.99) CSALT= SOLBLE
      PPURE = P/A1(CSALT)
      TB     = TSAT(PPURE)
      TEMPER= TSAT(P)
```

```
      TV    = TEMPER + SUPRHT*(TB-TEMPER)
      IF (X .LE. 0.5) T = TB
      IF (X .GT. 0.5) T = TV
      IF (.NOT.FINDHF .AND. .NOT.FINDHG) RETURN
      HG    = HSPT(P,TV)
      IF (CSALT .GT. 0.05) GO TO 560
      HPURE = HFSAT(PPURE)
      HFIVE = 0.637456*(1.8*TB+32.0)**1.20007
      HF    = HFIVE - (HFIVE-HPURE)*(1.0-CSALT/0.05)
      RETURN
  560 HF    = 2.326*A4(CSALT)*(1.8*TB+32.0)**A5(CSALT)
      RETURN
C
C ----- ENTHALPY OF SATURATED LIQUID GIVEN ------------------
C
  600 IF (X .NE. 0.0) STOP
      CSALT = TDS
      IF (CSALT .GT. 0.05) GO TO 610
      TBFIVE= 0.555556*((1.568735*HF)**0.833283 - 32.0)
      PPURE = PSTT(TBFIVE)
      PFIVE = 0.968812*PPURE
      P     = PFIVE - (PFIVE-PSTHF(HF))*(1.0-CSALT/0.05)
      RETURN
  610 TB    = 0.555556*((HF/(2.326*A4(CSALT)))**(1.0/A5(CSALT))
     1        -32.0)
      PPURE = PSTT(TB)
      P     = A1(CSALT)*PPURE
      RETURN
C
C ----- PRESSURE AND TEMPERATURE GIVEN ----------------------
C
  650 CSALT = TDS
      PPURE = P/A1(CSALT)
      TB    = TSAT(PPURE)
      IF (T .LT. TB-1.0) GO TO 670
      CSALT = SOLBLE
      PPURE = P/A1(CSALT)
      TB    = TSAT(PPURE)
      TEMPER= TSAT(P)
      TV    = TEMPER + SUPRHT*(TB-TEMPER)
      PHASUP= 2
      IF (T .GT. TV+1.0) PHASUP= 3
      IF (PHASUP .EQ. 2) GO TO 680
      IF (PHASUP .EQ. 3) GO TO 260
C
  670 IF (.NOT.FINDH .AND. .NOT.FINDX) GO TO 674
      IF (CSALT .GT. 0.05) GO TO 672
      HFIVE = 0.637456*(1.8*TB+32.0)**1.20007
```

```
      HF     = HFIVE - (HFIVE-HFSAT(PPURE))*(1.0-CSALT/0.05)
  672 IF (CSALT .GT. 0.05) HF= 2.326*A4(CSALT)*(1.8*TB+32.0)**
     1    A5(CSALT)
      H      = HF + A7(CSALT)*(T-TB) + 0.5*A8(CSALT)*(T*T-TB*TB+
     1         546.30*(T-TB)) + A9(CSALT)*((T+273.15)**3-(TB+
     1         273.15)**3)/3.0
      IF (.NOT.FINDX) GO TO 674
      TEMPER= TSAT(P)
      TV     = TEMPER + SUPRHT*(TB-TEMPER)
      HG     = HSPT(P,TV)
      X      = (H-HF)/(HG-HF)
  674 IF (.NOT.FINDS) RETURN
      IF (CSALT .GT. 0.05) GO TO 676
      SFIVE = 0.0808975 + 0.0118918*TB - 5.932527E-6*TB*TB
      SF     = SFIVE - (SFIVE-SFSAT(PPURE))*(1.0-CSALT/0.05)
  676 IF (CSALT .GT. 0.05) SF= A2(CSALT) + A3(CSALT)*TB +
     1    A6(CSALT)*TB*TB
      S      = SF + A7(CSALT)*ALOG((T+273.15)/(TB+273.15)) +
     1         A8(CSALT)*(T-TB) + 0.5*A9(CSALT)*(T*T-TB*TB+
     1         546.30*(T-TB))
      RETURN
C
  680 HG     = HSPT(P,TV)
      H      = HG
      X      = 1.0
      IF (.NOT.FINDS) RETURN
      SG     = SSUP(P,H)
      S      = SG
      RETURN
C
C ----- PRESSURE AND ENTHALPY OR ENTROPY GIVEN --------------
C
  700 IF (GIVNPH) X= QUAL(1,TDS,P,H,SUPRHT,TB,TV,HF,HG)
      IF (GIVNPS) X= QUAL(2,TDS,P,S,SUPRHT,TB,TV,HF,HG)
      IF (X .LT. 0.0) GO TO 710
      PHASUP= 2
      IF (GIVNPH) X= QUAL(1,SOLBLE,P,H,SUPRHT,TB,TV,HF,HG)
      IF (GIVNPS) X= QUAL(2,SOLBLE,P,S,SUPRHT,TB,TV,HF,HG)
      IF (X .GT. 1.0) PHASUP= 3
      IF (PHASUP .EQ. 2) GO TO 740
      IF (PHASUP.EQ.3 .AND. GIVNPH) GO TO 300
      IF (PHASUP.EQ.3 .AND. GIVNPS) GO TO 350
C
  710 CSALT = TDS
      ITER  = 0
      T1     = 18.0
      T2     = TB
      IF (GIVNPS) SF= (S-X*SSUP(P,HG))/(1.0-X)
```

```
      IF (GIVNPS) GO TO 720
      IF (CSALT .GT. 0.05) GO TO 715
      SFIVE = 0.0808975 + 0.0118918*TB - 5.932527E-6*TB*TB
      SF    = SFIVE - (SFIVE-SFSAT(P/A1(CSALT)))*(1.0-
     1    CSALT/0.05)
  715 IF (CSALT .GT. 0.05) SF= A2(CSALT) + A3(CSALT)*TB +
     1    A6(CSALT)*TB*TB
  720 TAVG  = 0.5*(T1+T2)
      IF (GIVNPH) B= HF + A7(CSALT)*(TAVG-TB) + 0.5*A8(CSALT)*
     1    (TAVG*TAVG-TB*TB+546.30*(TAVG-TB)) + A9(CSALT)*
     1    ((TAVG+273.15)**3-(TB+273.15)**3)/3.0
      IF (GIVNPS) B= SF + A7(CSALT)*ALOG((TAVG+273.15)/(TB+
     1    273.15)) + A8(CSALT)*(TAVG-TB) + 0.5*A9(CSALT)*
     1    (TAVG*TAVG-TB*TB+546.30*(TAVG-TB))
      IF (GIVNPH) DIFF= H - B
      IF (GIVNPS) DIFF= S - B
      IF ((GIVNPH.AND.ABS(DIFF).LE.0.1) .OR. (GIVNPS.AND.
     1    ABS(DIFF).LE.0.0003)) GO TO 730
      ITER  = ITER + 1
      IF (ITER .GT. 20) WRITE (IOUT,9050) DIFF,TAVG,X,P,H,S
      IF (ITER .GT. 20) STOP
      IF (DIFF .LT. 0.0) T2= TAVG
      IF (DIFF .GE. 0.0) T1= TAVG
      GO TO 720
  730 T     = TAVG
      IF (FINDH) H= HF + A7(CSALT)*(T-TB) + 0.5*A8(CSALT)*
     1    (T*T-TB*TB+546.30*(T-TB)) + A9(CSALT)*((T+273.15)**3
     1    -(TB+273.15)**3)/3.0
      IF (FINDS) S= SF + A7(CSALT)*ALOG((T+273.15)/(TB+273.15))
     1    + A8(CSALT)*(T-TB) + 0.5*A9(CSALT)*(T*T-TB*TB+546.30*
     1    (T-TB))
      RETURN
C
  740 IF (TDS/(1.0-X) .GE. SOLBLE) CAVG= SOLBLE
      IF (TDS/(1.0-X) .GE. SOLBLE) GO TO 790
      ITER  = 0
      CSALT1= TDS
      CSALT2= SOLBLE
  750 CAVG  = 0.5*(CSALT1+CSALT2)
      IF (GIVNPH) X= QUAL(1,CAVG,P,H,SUPRHT,TB,TV,HF,HG)
      IF (GIVNPS) X= QUAL(2,CAVG,P,S,SUPRHT,TB,TV,HF,HG)
      IF (X .GE. 1.0) WRITE (IOUT,9030) CAVG, X, P, H, S
      IF (X .GE. 1.0) GO TO 790
      DIFF  = TDS/(1.0-X) - CAVG
      IF (ABS(DIFF) .LE. 0.003) GO TO 790
      ITER  = ITER + 1
      IF (ITER .GT. 20) WRITE (IOUT,9040) DIFF,CAVG,X,P,H,S
      IF (ITER .GT. 20) STOP
```

```
      IF (DIFF .LT. 0.0) CSALT2= CAVG
      IF (DIFF .GE. 0.0) CSALT1= CAVG
      GO TO 750
  790 IF (X .LE. 0.5) T = TB
      IF (X .GT. 0.5) T = TV
      IF (FINDH) H= X*HG + (1.0-X)*HF
      IF (.NOT.FINDS) RETURN
      SG    = SSUP(P,HG)
      IF (CAVG .GT. 0.05) GO TO 794
      SFIVE = 0.0808975 + 0.0118918*TB - 5.932527E-6*TB*TB
      SF    = SFIVE - (SFIVE-SFSAT(P/A1(CAVG)))*(1.0-CAVG/0.05)
  794 IF (CAVG .GT. 0.05) SF= A2(CAVG) + A3(CAVG)*TB +
     1    A6(CAVG)*TB*TB
      S     = X*SG + (1.0-X)*SF
      RETURN
C
C
 9000 FORMAT (1H0,39HINVALID INPUT PARAMETER CODE IN SUBROUT,
     1 11HINE PROPTY:/1H ,9H  INDEX1=,I3,9H, INDEX2=,I4)
 9010 FORMAT (1H0,40HINVALID OUTPUT PARAMETER CODE IN SUBROUT,
     1 11HINE PROPTY:/1H ,9H  INDEX1=,I3,9H, INDEX2=,I4)
 9020 FORMAT (1H0,40HINVALID DATA IN SUBROUTINE PROPTY:  INDE,
     1 3HX1=,I3/1H ,6H  TDS=,1PE11.4,9H        P=,E11.4/1H ,
     1 6H     T=,E11.4,9H        H=,E11.4/1H ,6H     S=,E11.4)
 9030 FORMAT (1H0,39HQUALITY EQUALS OR EXCEEDS UNITY IN SUBR,
     1 14HOUTINE PROPTY:/1H ,7H  CAVG=,F7.4,4H, X=,F7.4,4H, P=,
     1 F8.4,4H, H=,F8.2,4H, S=,F8.4)
 9040 FORMAT (1H0,40HITERATION FOR CSALT DOES NOT CONVERGE IN,
     1 19H SUBROUTINE PROPTY:/1H ,7H  DIFF=,1PE12.4,7H, CAVG=,
     1 0PF7.4,4H, X=,F7.4,4H, P=,F8.4/1H ,7H      H=,F8.2,
     1 11H          S=,F8.4)
 9050 FORMAT (1H0,40HITERATION FOR TAVG DOES NOT CONVERGE IN ,
     1 18HSUBROUTINE PROPTY:/1H ,7H  DIFF=,1PE12.4,7H, TAVG=,
     1 0PF7.2,4H, X=,F7.4,4H, P=,F8.4/1H ,7H      H=,F8.2,
     1 11H          S=,F8.4)
      END
      FUNCTION QUAL(IND,CSALT,P,B,SUPRHT,TB,TV,HF,HG)
C
      PPURE = P/A1(CSALT)
      TB    = TSAT(PPURE)
      TEMPER= TSAT(P)
      TV    = TEMPER + SUPRHT*(TB-TEMPER)
      HG    = HSPT(P,TV)
      IF (CSALT .GT. 0.05) GO TO 100
      HPURE = HFSAT(PPURE)
      HFIVE = 0.637456*(1.8*TB+32.0)**1.20007
      HF    = HFIVE - (HFIVE-HPURE)*(1.0-CSALT/0.05)
      GO TO 200
```

```
100 HF     = 2.326*A4(CSALT)*(1.8*TB+32.0)**A5(CSALT)
200 IF (IND .EQ. 1) QUAL= (B-HF)/(HG-HF)
    IF (IND .EQ. 1) RETURN
    SG     = SSUP(P,HG)
    IF (CSALT .GT. 0.05) GO TO 300
    SFIVE = 0.0808975 + 0.0118918*TB - 5.932527E-6*TB*TB
    SF     = SFIVE - (SFIVE-SFSAT(PPURE))*(1.0-CSALT/0.05)
300 IF (CSALT .GT. 0.05) SF= A2(CSALT) + A3(CSALT)*TB +
   1    A6(CSALT)*TB*TB
    QUAL  = (B-SF)/(SG-SF)
    RETURN
C
    END
    FUNCTION A1(CSALT)
C
    A1     = 1.0 - 0.617*CSALT + 0.1955*CSALT*CSALT -
   1         7.253*CSALT**3 + 12.73*CSALT**4
C
    RETURN
    END
    FUNCTION A2(CSALT)
C
    A2     = 0.022721568 + 1.8609946*CSALT - 17.556371*CSALT*
   1         CSALT + 78.319422*CSALT**3 - 123.64677*CSALT**4
C
    RETURN
    END
    FUNCTION A3(CSALT)
C
    A3     = 0.0136411 - 0.055155907*CSALT + 0.5069931*CSALT*
   1         CSALT - 2.2488173*CSALT**3 + 3.53276*CSALT**4
C
    RETURN
    END
    FUNCTION A4(CSALT)
C
    A4     = 0.2447 + 0.5337*CSALT + 1.379*CSALT*CSALT -
   1         6.679*CSALT**3 + 9.47*CSALT**4
C
    RETURN
    END
    FUNCTION A5(CSALT)
C
    A5     = 1.225 - 0.4617*CSALT - 1.002*CSALT*CSALT +
   1         5.58*CSALT**3 - 5.371*CSALT**4 - 4.615*CSALT**5
C
    RETURN
    END
```

```
      FUNCTION A6(CSALT)
C
      A6     = -8.5415746E-6 + 1.0078215E-4*CSALT - 1.231346E-3*
     1         CSALT*CSALT + 5.6280648E-3*CSALT**3 -
     1         8.8324747E-3*CSALT**4
C
      RETURN
      END
      FUNCTION A7(CSALT)
C
      A7     = 6.46775648 - 66.27175*CSALT + 178.2585*CSALT*CSALT
C
      RETURN
      END
      FUNCTION A8(CSALT)
C
      A8     = -0.013823412 + 0.3706078*CSALT - 1.021136*CSALT*
     1         CSALT
C
      RETURN
      END
      FUNCTION A9(CSALT)
C
      A9     = 2.055291E-5 - 5.5440741E-4*CSALT + 0.0014887831*
     1         CSALT*CSALT
C
      RETURN
      END
```

1. Steam tables correlation programs

```
      FUNCTION HFSAT(P)
C
C ********* PROGRAM RETURNS ENTHALPY OF SATURATED   ***********
C ********* LIQUID IN KJ/KG GIVEN PRESSURE IN BARS ***********
C
      DIMENSION A(9)
      DATA IN, IOUT/8, 6/
      DATA A/1.26023114E-1, 9.15236473E-2, 2.93525979E-2,
     1       1.42066538E-1, 6.16478510E-2, 4.32617441E-2,
     1       1.76657498E-1, 1.44344866E-2, 5.93803227E-2/
C
      PR    = ALOG10(P*4.52734517)
      K     = 1
      IF (PR .GT. 1.10300) K = 4
      IF (PR .GT. 1.45862) K = 7
      IF (PR.LT.0.08721 .OR. PR.GT.2.22405) WRITE (IOUT,900) P
      HFR   = A(K) + A(K+1)*PR + A(K+2)*PR*PR
      HFSAT = HFR*2099.3
C
      RETURN
  900 FORMAT (1H0,18H----- ARGUMENT P =,F6.2,13H IS OUTSIDE O,
     1 43HF ACCURATE DOMAIN FOR FUNCTION HFSAT ------)
      END
      FUNCTION HGSAT(P)
C
C ********* PROGRAM RETURNS ENTHALPY OF SATURATED ************
C ********* VAPOR IN KJ/KG GIVEN PRESSURE IN BARS ************
C
      DIMENSION A(3)
      DATA IN, IOUT/8, 6/
      DATA A/1.24066734, 5.29195406E-2, -1.79178850E-3/
C
      PR    = ALOG10(P*4.52734517)
      IF (PR.LT.-0.53124 .OR. PR.GT.2.19991) WRITE (IOUT,900) P
      HGR   = A(1) + A(2)*PR + A(3)*PR*PR
      HGSAT = HGR*2099.3
C
      RETURN
  900 FORMAT (1H0,18H----- ARGUMENT P =,F6.2,13H IS OUTSIDE O,
     1 43HF ACCURATE DOMAIN FOR FUNCTION HGSAT ------)
      END
      FUNCTION SFSAT(P)
C
C ********* PROGRAM RETURNS ENTROPY OF SATURATED LIQUID ******
C *********       IN KJ/KG-K GIVEN PRESSURE IN BARS       ******
C
      DIMENSION A(9)
      DATA IN, IOUT/8, 6/
```

```
      DATA A/1.95021570E-1, 1.36982262E-1, 2.11430825E-2,
     1        2.04577565E-1, 1.19308650E-1, 2.93241814E-2,
     1        2.20393658E-1, 9.76922512E-2, 3.67077477E-2/
C
      PR     = ALOG10(P*4.52734517)
      K      = 1
      IF (PR .GT. 1.10300) K = 4
      IF (PR .GT. 1.45862) K = 7
      IF (PR.LT.-0.08888.OR. PR.GT.2.40403) WRITE (IOUT,900) P
      SFR    = A(K) + A(K+1)*PR + A(K+2)*PR*PR
      SFSAT = SFR*4.4298
C
      RETURN
  900 FORMAT (1H0,18H----- ARGUMENT P =,F6.2,13H IS OUTSIDE O,
     1 43HF ACCURATE DOMAIN FOR FUNCTION SFSAT ------)
      END
      FUNCTION SGSAT(P)
C
C ********* PROGRAM RETURNS ENTROPY OF SATURATED VAPOR *******
C *********     IN KJ/KG-K GIVEN PRESSURE IN BARS      *******
C
      DIMENSION A(3)
      DATA IN, IOUT/8, 6/
      DATA A/1.77420044, -1.71066105E-1, -1.48623437E-3/
C
      PR     = ALOG10(P*4.52734517)
      IF (PR.LT.-1.11371 .OR. PR.GT.2.31860) WRITE (IOUT,900) P
      SGR    = A(1) + A(2)*PR + A(3)*PR*PR
      SGSAT = SGR*4.4298
C
      RETURN
  900 FORMAT (1H0,18H----- ARGUMENT P =,F6.2,13H IS OUTSIDE O,
     1 43HF ACCURATE DOMAIN FOR FUNCTION SGSAT ------)
      END
      FUNCTION TSAT(P)
C
C ********* PROGRAM RETURNS SATURATION TEMPERATURE IN ********
C *********  DEGREES CELSIUS GIVEN PRESSURE IN BARS    ********
C
      DIMENSION A(9)
      DATA IN, IOUT/8, 6/
      DATA A/5.19378424E-1, 7.21374154E-2, 2.11544000E-2,
     1        5.29110849E-1, 5.40944226E-2, 2.95313187E-2,
     1        5.45680106E-1, 3.15304175E-2, 3.72182578E-2/
C
      PR    = ALOG10(P*4.52734517)
      K     = 1
      IF (PR .GT. 1.10300) K = 4
```

```
      IF (PR .GT. 1.45862) K = 7                                        TSAT0150
      IF (PR.LT.0.05378 .OR. PR.GT.2.38824) WRITE (IOUT,900) P          TSAT0160
      TR   = A(K) + A(K+1)*PR + A(K+2)*PR*PR                            TSAT0170
      TSAT = 647.29*TR - 273.15                                         TSAT0180
C                                                                       TSAT0190
      RETURN                                                            TSAT0200
  900 FORMAT (1H0,18H----- ARGUMENT P =,F6.2,13H IS OUTSIDE O,          TSAT0210
     1 43HF ACCURATE DOMAIN FOR FUNCTION TSAT -------)                  TSAT0220
      END                                                               TSAT0230
      FUNCTION PSTT(T)                                                  PSTT0010
C                                                                       PSTT0020
C *********  PROGRAM RETURNS SATURATION PRESSURE IN    ********         PSTT0030
C ********* BARS GIVEN TEMPERATURE IN DEGREES CELSIUS ********          PSTT0040
C                                                                       PSTT0050
      DIMENSION A(4)                                                    PSTT0060
      DATA IN, IOUT/8, 6/                                               PSTT0070
      DATA A/7.95640116, -11.9841761, -11.1072210, 6.30109816/          PSTT0080
C                                                                       PSTT0090
      TR   = (T+273.15)/647.29                                          PSTT0100
      IF (TR.LT.0.42201 .OR. TR.GT.0.93335) WRITE (IOUT,900) T          PSTT0110
      PR   = A(1) + A(2)/TR + A(3)*ALOG(TR) + A(4)*TR                   PSTT0120
      PSTT = 22.088*EXP(PR)                                             PSTT0130
C                                                                       PSTT0140
      RETURN                                                            PSTT0150
  900 FORMAT (1H0,18H----- ARGUMENT T =,F6.1,13H IS OUTSIDE O,          PSTT0160
     1 43HF ACCURATE DOMAIN FOR FUNCTION PSTT -------)                  PSTT0170
      END                                                               PSTT0180
      FUNCTION PSTHF(HF)                                                PSHF0010
C                                                                       PSHF0020
C ********* PROGRAM RETURNS SATURATION PRESSURE IN ***********          PSHF0030
C *********  BARS GIVEN LIQUID ENTHALPY IN KJ/KG     ***********        PSHF0040
C                                                                       PSHF0050
      DIMENSION A(9)                                                    PSHF0060
      DATA IN, IOUT/8, 6/                                               PSHF0070
      DATA A/-1.34499168, 1.23549461E1, -1.15588388E1,                  PSHF0080
     1       -1.14790726, 1.08166580E1, -8.55740070,                    PSHF0090
     1       -9.48456764E-1, 9.58110905, -6.64306259/                   PSHF0100
C                                                                       PSHF0110
      HFR   = HF/2099.3                                                 PSHF0120
      K     = 1                                                         PSHF0130
      IF (HFR .GT. 0.26270) K = 4                                       PSHF0140
      IF (HFR .GT. 0.32403) K = 7                                       PSHF0150
      IF (HFR.LT.0.14075 .OR. HFR.GT.0.44559) WRITE (IOUT,900) HF       PSHF0160
      PR    = A(K) + A(K+1)*HFR + A(K+2)*HFR*HFR                        PSHF0170
      PSTHF = (10.0**PR)/4.52734517                                     PSHF0180
C                                                                       PSHF0190
      RETURN                                                            PSHF0200
  900 FORMAT (1H0,18H----- ARGUMENT HF=,F6.1,13H IS OUTSIDE O,          PSHF0210
```

```
     1 43HF ACCURATE DOMAIN FOR FUNCTION PSTHF ------)                 PSHF0220
      END                                                              PSHF0230
      FUNCTION PSTHG(HG)                                               PSHG0010
C                                                                      PSHG0020
C ********* PROGRAM RETURNS SATURATION PRESSURE IN ***********         PSHG0030
C *********   BARS GIVEN VAPOR ENTHALPY IN KJ/KG    ***********        PSHG0040
C                                                                      PSHG0050
      DIMENSION A(9)                                                   PSHG0060
      DATA IN, IOUT/8, 6/                                              PSHG0070
      DATA A/-7.31933594E1, 9.50500031E1, -2.91149445E1,               PSHG0080
     1        2.23806915E1, -5.24040222E1, 2.77587738E1,               PSHG0090
     1        3.67976562E2, -5.77664307E2, 2.27340897E2/               PSHG0100
C                                                                      PSHG0110
      HGR   = HG/2099.3                                                PSHG0120
      K     = 1                                                        PSHG0130
      IF (HGR .GT. 1.29667) K = 4                                      PSHG0140
      IF (HGR .GT. 1.31439) K = 7                                      PSHG0150
      IF (HGR.LT.1.25289 .OR. HGR.GT.1.33006) WRITE (IOUT,900) HG      PSHG0160
      PR    = A(K) + A(K+1)*HGR + A(K+2)*HGR*HGR                       PSHG0170
      PSTHG = (10.0**PR)/4.52734517                                    PSHG0180
C                                                                      PSHG0190
      RETURN                                                           PSHG0200
  900 FORMAT (1H0,18H----- ARGUMENT HG=,F7.1,13H IS OUTSIDE O,         PSHG0210
     1 42HF ACCURATE DOMAIN FOR FUNCTION PSTHG -----)                  PSHG0220
      END                                                              PSHG0230
      FUNCTION TSUP(P,H)                                               TSUP
C                                                                      TSUP
C ********* PROGRAM RETURNS TEMPERATURE OF SUPERHEATED *******         TSUP
C *          STEAM IN DEGREES CELSIUS GIVEN PRESSURE IN        *       TSUP
C *********            BARS AND ENTHALPY IN KJ/KG          *******     TSUP
C                                                                      TSUP
      DIMENSION A(36)                                                  TSUP
      DATA IN, IOUT/8, 6/                                              TSUP
      DATA A/-1.45905590E 0, -8.54326189E-1,  1.68955040E 0,           TSUP
     1         1.55361748E 0,  1.14410305E 0, -2.31895447E 0,          TSUP
     1         3.32209468E-2, -3.86246145E-1,  8.01048934E-1,          TSUP
     1        -1.44795799E 0, -1.37720394E 0,  1.04240227E 0,          TSUP
     1         1.56512642E 0,  1.85438728E 0, -1.36987877E 0,          TSUP
     1         1.94339156E-2, -6.27111912E-1,  4.53335404E-1,          TSUP
     1        -3.91609764E 0,  3.21600533E 0,  3.56851220E-2,          TSUP
     1         5.56309605E 0, -5.48186970E 0,  3.71187985E-1,          TSUP
     1        -1.54643345E 0,  2.22234249E 0, -2.58159697E-1,          TSUP
     1        -4.42436790E 0,  1.67020893E 0,  4.97298777E-1,          TSUP
     1         6.03402996E 0, -2.89095306E 0, -4.15853202E-1,          TSUP
     1        -1.62238693E 0,  1.15832043E 0,  6.92373514E-2/          TSUP
C                                                                      TSUP
      PR    = ALOG10(P*4.52734517)                                     TSUP
      HR    = H/2099.3                                                 TSUP
```

```
      K    = 1                                                          TSUP
      IF (PR .GT. 1.27909) K = K+18                                     TSUP
      IF (HR .GT. 1.40019) K = K+9                                      TSUP
      IF (PR.LT.0.35481 .OR. PR.GT.2.02986 .OR.                         TSUP
     1    HR.LT.1.25756 .OR. HR.GT.1.55385) WRITE (IOUT,900) P, H       TSUP
      A0   = A(K  ) + A(K+1)*PR + A(K+2)*PR*PR                          TSUP
      A1   = A(K+3) + A(K+4)*PR + A(K+5)*PR*PR                          TSUP
      A2   = A(K+6) + A(K+7)*PR + A(K+8)*PR*PR                          TSUP
      TR   = A0 + A1*HR + A2*HR*HR                                      TSUP
      TSUP = 647.29*TR - 273.15                                         TSUP
C                                                                       TSUP
      RETURN                                                            TSUP
  900 FORMAT (1H0,18H----- ARGUMENT P =,F6.2,13H OR ARGUMENT ,          TSUP
     1 3HH =,F7.1/1H ,8X,34HIS OUTSIDE OF ACCURATE DOMAIN FOR ,         TSUP
     1 19HFUNCTION TSUP -----)                                          TSUP
      END                                                               TSUP
      FUNCTION SSUP(P,H)                                                SSUP
C                                                                       SSUP
C ********* PROGRAM RETURNS ENTROPY OF SUPERHEATED ***********          SSUP
C *         STEAM IN KJ/KG-K GIVEN PRESSURE IN BARS         *          SSUP
C *********             AND ENTHALPY IN KJ/KG        ***********        SSUP
C                                                                       SSUP
      DIMENSION A(36)                                                   SSUP
      DATA IN, IOUT/8, 6/                                               SSUP
      DATA A/-2.37411499E 0,  4.57980394E-1, -2.45094262E-2,            SSUP
     1        5.28990650E 0, -1.06251621E 0,  7.39890337E-2,            SSUP
     1       -1.56981182E 0,  4.02487874E-1, -3.95627022E-2,            SSUP
     1       -6.95238113E-1, -9.99029696E-1,  4.07750368E-1,            SSUP
     1        2.86507225E 0,  1.04594135E 0, -5.54302752E-1,            SSUP
     1       -6.94033682E-1, -3.60684633E-1,  1.88915133E-1,            SSUP
     1       -7.03521442E 0,  6.21635628E 0, -1.71102619E 0,            SSUP
     1        1.23033962E 1, -9.75796127E 0,  2.63489246E 0,            SSUP
     1       -4.19936180E 0,  3.67173958E 0, -1.00651932E 0,            SSUP
     1       -5.57568645E 0,  5.49639702E 0, -1.71920395E 0,            SSUP
     1        9.73247147E 0, -8.10614109E 0,  2.44793034E 0,            SSUP
     1       -3.10506535E 0,  2.85588837E 0, -8.67748618E-1/            SSUP
C                                                                       SSUP
      PR   = ALOG10(P*4.52734517)                                       SSUP
      HR   = H/2099.3                                                   SSUP
      K    = 1                                                          SSUP
      IF (PR .GT. 1.27909) K = K+18                                     SSUP
      IF (HR .GT. 1.40019) K = K+9                                      SSUP
      IF (PR.LT.0.35481 .OR. PR.GT.2.63421 .OR.                         SSUP
     1    HR.LT.1.25756 .OR. HR.GT.1.64912) WRITE (IOUT,900) P, H       SSUP
      A0   = A(K  ) + A(K+1)*PR + A(K+2)*PR*PR                          SSUP
      A1   = A(K+3) + A(K+4)*PR + A(K+5)*PR*PR                          SSUP
      A2   = A(K+6) + A(K+7)*PR + A(K+8)*PR*PR                          SSUP
      SR   = A0 + A1*HR + A2*HR*HR                                      SSUP
```

```
      SSUP = 4.4298*SR                                                  SSUP
C                                                                       SSUP
      RETURN                                                            SSUP
  900 FORMAT (1H0,18H----- ARGUMENT P =,F6.2,13H OR ARGUMENT ,          SSUP
     1 3HH =,F7.1/1H ,8X,34HIS OUTSIDE OF ACCURATE DOMAIN FOR ,         SSUP
     1 19HFUNCTION SSUP -----)                                          SSUP
      END                                                               SSUP
      FUNCTION HSUP(P,S)                                                HSUP
C                                                                       HSUP
C ********* PROGRAM RETURNS ENTHALPY OF SUPERHEATED **********          HSUP
C *           STEAM IN KJ/KG GIVEN PRESSURE IN BARS          *          HSUP
C *********            AND ENTROPY IN KJ/KG-K         **********        HSUP
C                                                                       HSUP
      DIMENSION A(36)                                                   HSUP
      DATA IN, IOUT/8, 6/                                               HSUP
      DATA A/ 3.10252666E 0, -2.76911438E-1, -2.78082430E-1,            HSUP
     1       -2.77450466E 0, -2.15333477E-2,  3.96500170E-1,            HSUP
     1        9.72972870E-1,  1.52231634E-1, -1.16567492E-1,            HSUP
     1        3.47496891E 0,  8.96547139E-1, -8.99438858E-1,            HSUP
     1       -3.14423084E 0, -1.38792992E 0,  1.05345821E 0,            HSUP
     1        1.06486034E 0,  5.43564141E-1, -2.84795403E-1,            HSUP
     1        7.90833378E 0, -6.86018753E 0,  1.95111370E 0,            HSUP
     1       -9.02869797E 0,  8.52027225E 0, -2.48382759E 0,            HSUP
     1        3.00988674E 0, -2.62252617E 0,  8.15658092E-1,            HSUP
     1        1.33643494E 1, -1.24240036E 1,  3.54003620E 0,            HSUP
     1       -1.50024872E 1,  1.44815683E 1, -4.18934345E 0,            HSUP
     1        4.62117386E 0, -4.18678093E 0,  1.26490974E 0/            HSUP
C                                                                       HSUP
      PR   = ALOG10(P*4.52734517)                                       HSUP
      SR   = S/4.4298                                                   HSUP
      SCUT = 1.9536431 - 0.22158996*PR - 0.014279632*PR*PR              HSUP
      K    = 1                                                          HSUP
      IF (PR .GT. 1.27909) K = K+18                                     HSUP
      IF (SR .GT. SCUT   ) K = K+9                                      HSUP
      SCUT = 2.23637 - 0.24288*PR                                       HSUP
      IF (PR.LT.0.35481 .OR. PR.GT.2.30077 .OR.                         HSUP
     1    SR.LT.1.35893 .OR. SR.GT.SCUT    ) WRITE (IOUT,900) P, S      HSUP
      A0   = A(K   ) + A(K+1)*PR + A(K+2)*PR*PR                         HSUP
      A1   = A(K+3) + A(K+4)*PR + A(K+5)*PR*PR                          HSUP
      A2   = A(K+6) + A(K+7)*PR + A(K+8)*PR*PR                          HSUP
      HR   = A0 + A1*SR + A2*SR*SR                                      HSUP
      HSUP = 2099.3*HR                                                  HSUP
C                                                                       HSUP
      RETURN                                                            HSUP
  900 FORMAT (1H0,18H----- ARGUMENT P =,F6.2,13H OR ARGUMENT ,          HSUP
     1 3HS =,F7.4/1H ,8X,34HIS OUTSIDE OF ACCURATE DOMAIN FOR ,         HSUP
     1 19HFUNCTION HSUP -----)                                          HSUP
      END                                                               HSUP
```

```
      FUNCTION HSPT(P,T)                                                HSPT
C                                                                       HSPT
C ********* PROGRAM RETURNS ENTHALPY OF SUPERHEATED **********          HSPT
C *           STEAM IN KJ/KG GIVEN PRESSURE IN BARS            *        HSPT
C *********     AND TEMPERATURE IN DEGREES CELSIUS      **********      HSPT
C                                                                       HSPT
      DIMENSION A(36)                                                   HSPT
      DATA IN, IOUT/8, 6/                                               HSPT
      DATA A/ 8.93055916E-1,  1.88406944E-1, -2.31952727E-1,            HSPT
     1        6.88367069E-1, -4.35630560E-1,  5.39006412E-1,            HSPT
     1       -5.07310629E-2,  2.59720922E-1, -3.23858857E-1,            HSPT
     1        9.12453294E-1,  1.31719470E-1, -1.06218874E-1,            HSPT
     1        6.29011929E-1, -2.78738797E-1,  2.09811330E-1,            HSPT
     1       -6.68292493E-3,  1.52293026E-1, -1.08514965E-1,            HSPT
     1       -3.68949890E-1,  2.06155396E 0, -9.29848075E-1,            HSPT
     1        3.21899033E 0, -4.15710545E 0,  1.91405392E 0,            HSPT
     1       -1.33034706E 0,  2.11820126E 0, -1.00283051E 0,            HSPT
     1        5.72337151E-1,  7.64949262E-1, -3.95799339E-1,            HSPT
     1        1.08903694E 0, -1.25381660E 0,  6.96024299E-1,            HSPT
     1       -1.41452610E-1,  5.20882249E-1, -3.17029893E-1/            HSPT
C                                                                       HSPT
      PR   = ALOG10(P*4.52734517)                                       HSPT
      TR   = (T+273.15)/647.29                                          HSPT
      K    = 1                                                          HSPT
      IF (PR .GT. 1.27909) K = K+18                                     HSPT
      IF (TR .GT. 0.78504) K = K+9                                      HSPT
      TCUT = 2.86612 - 1.62006*PR + 0.37602*PR*PR                       HSPT
      IF (PR.LT.0.35481 .OR. PR.GT.2.10191 .OR.                         HSPT
     1    TR.LT.0.54713 .OR. TR.GT.TCUT     ) WRITE (IOUT,900) P, T     HSPT
      A0   = A(K   ) + A(K+1)*PR + A(K+2)*PR*PR                         HSPT
      A1   = A(K+3) + A(K+4)*PR + A(K+5)*PR*PR                          HSPT
      A2   = A(K+6) + A(K+7)*PR + A(K+8)*PR*PR                          HSPT
      HR   = A0 + A1*TR + A2*TR*TR                                      HSPT
      HSPT = 2099.3*HR                                                  HSPT
C                                                                       HSPT
      RETURN                                                            HSPT
  900 FORMAT (1H0,18H----- ARGUMENT P =,F6.2,13H OR ARGUMENT ,          HSPT
     1 3HT =,F7.2/1H ,8X,34HIS OUTSIDE OF ACCURATE DOMAIN FOR ,         HSPT
     1 19HFUNCTION HSPT -----)                                          HSPT
      END                                                               HSPT
      FUNCTION TLIQ(P,H)                                                TLIQ
C                                                                       TLIQ
C ********* PROGRAM RETURNS TEMPERATURE OF SUBCOOLED *********          TLIQ
C *          LIQUID IN DEGREES CELSIUS GIVEN PRESSURE          *        TLIQ
C *********         IN BARS AND ENTHALPY IN KJ/KG          *********    TLIQ
C                                                                       TLIQ
      DIMENSION A(12)                                                   TLIQ
      DATA IN, IOUT/8, 6/                                               TLIQ
```

```
      DATA A/ 4.21499670E-1, -8.19366658E-4,  7.87100077E-1,          TLIQ
     1        1.03512243E-3, -5.28957956E-2,  1.75578112E-4,          TLIQ
     1        4.15210962E-1, -6.16444647E-3,  8.34903479E-1,          TLIQ
     1        2.88585685E-2, -1.40651643E-1, -3.47168930E-2/          TLIQ
C                                                                     TLIQ
      PR   = P*4.52734517E-2                                          TLIQ
      HR   = H/2099.3                                                 TLIQ
      K    = 1                                                        TLIQ
      IF (HR .GT. 0.32302) K = K+6                                    TLIQ
      IF (PR.LT.0.00106 .OR. PR.GT.5.29699 .OR.                       TLIQ
     1    HR.LT.0.03999 .OR. HR.GT.0.70452) WRITE (IOUT,900) P, H     TLIQ
      A0   = A(K  ) + A(K+1)*PR                                       TLIQ
      A1   = A(K+2) + A(K+3)*PR                                       TLIQ
      A2   = A(K+4) + A(K+5)*PR                                       TLIQ
      TR   = A0 + A1*HR + A2*HR*HR                                    TLIQ
      TLIQ = 647.29*TR - 273.15                                       TLIQ
C                                                                     TLIQ
      RETURN                                                          TLIQ
  900 FORMAT (1H0,18H----- ARGUMENT P =,F6.2,13H OR ARGUMENT ,        TLIQ
     1 3HH =,F7.1/1H ,8X,34HIS OUTSIDE OF ACCURATE DOMAIN FOR ,       TLIQ
     1 19HFUNCTION TLIQ -----)                                        TLIQ
      END                                                             TLIQ
      FUNCTION SLIQ(P,H)                                              SLIQ
C                                                                     SLIQ
C *********   PROGRAM RETURNS ENTROPY OF SUBCOOLED    *********       SLIQ
C *         LIQUID IN KJ/KG-K GIVEN PRESSURE IN BARS          *       SLIQ
C *********            AND ENTHALPY IN KJ/KG          *********       SLIQ
C                                                                     SLIQ
      DIMENSION A(12)                                                 SLIQ
      DATA IN, IOUT/8, 6/                                             SLIQ
      DATA A/ 2.65538692E-3, -1.72114931E-3,  1.64378452E 0,          SLIQ
     1        1.62114436E-3, -8.95615876E-1, -3.94121744E-4,          SLIQ
     1        2.49471068E-2,  6.54318929E-3,  1.47415829E 0,          SLIQ
     1       -4.17630039E-2, -5.83826900E-1,  5.45753837E-2/          SLIQ
C                                                                     SLIQ
      PR   = P*4.52734517E-2                                          SLIQ
      HR   = H/2099.3                                                 SLIQ
      K    = 1                                                        SLIQ
      IF (HR .GT. 0.32302) K = K+6                                    SLIQ
      IF (PR.LT.0.00106 .OR. PR.GT.4.75371 .OR.                       SLIQ
     1    HR.LT.0.03999 .OR. HR.GT.0.68071) WRITE (IOUT,900) P, H     SLIQ
      A0   = A(K  ) + A(K+1)*PR                                       SLIQ
      A1   = A(K+2) + A(K+3)*PR                                       SLIQ
      A2   = A(K+4) + A(K+5)*PR                                       SLIQ
      SR   = A0 + A1*HR + A2*HR*HR                                    SLIQ
      SLIQ = 4.4298*SR                                                SLIQ
C                                                                     SLIQ
      RETURN                                                          SLIQ
```

```
  900 FORMAT (1H0,18H----- ARGUMENT P =,F6.2,13H OR ARGUMENT ,        SLIQ
     1 3HH =,F7.1/1H ,8X,34HIS OUTSIDE OF ACCURATE DOMAIN FOR ,       SLIQ
     1 19HFUNCTION SLIQ -----)                                         SLIQ
      END                                                              SLIQ
      FUNCTION HLIQ(P,S)                                               HLIQ
C                                                                      HLIQ
C ********** PROGRAM RETURNS ENTHALPY OF SUBCOOLED   **********       HLIQ
C *          LIQUID IN KJ/KG GIVEN PRESSURE IN BARS            *       HLIQ
C **********          AND ENTROPY IN KJ/KG-K         **********       HLIQ
C                                                                      HLIQ
      DIMENSION A(12)                                                  HLIQ
      DATA IN, IOUT/8, 6/                                              HLIQ
      DATA A/ 1.11063197E-3,  1.03659043E-3,  5.53658366E-1,           HLIQ
     1        1.86528487E-4,  4.03372109E-1,  1.30917513E-4,           HLIQ
     1        1.77758932E-2,  4.31775115E-4,  4.73831475E-1,           HLIQ
     1        2.27557379E-3,  4.98737633E-1, -1.47053134E-3/           HLIQ
C                                                                      HLIQ
      PR   = P*4.52734517E-2                                           HLIQ
      SR   = S/4.4298                                                  HLIQ
      K    = 1                                                         HLIQ
      IF (SR .GT. 0.43738) K = K+6                                     HLIQ
      IF (PR.LT.0.00106 .OR. PR.GT.9.98280 .OR.                        HLIQ
     1    SR.LT.0.06592 .OR. SR.GT.0.90884) WRITE (IOUT,900) P, S      HLIQ
      A0   = A(K  ) + A(K+1)*PR                                        HLIQ
      A1   = A(K+2) + A(K+3)*PR                                        HLIQ
      A2   = A(K+4) + A(K+5)*PR                                        HLIQ
      HR   = A0 + A1*SR + A2*SR*SR                                     HLIQ
      HLIQ = 2099.3*HR                                                 HLIQ
C                                                                      HLIQ
      RETURN                                                           HLIQ
  900 FORMAT (1H0,18H----- ARGUMENT P =,F6.2,13H OR ARGUMENT ,        HLIQ
     1 3HS =,F7.4/1H ,8X,34HIS OUTSIDE OF ACCURATE DOMAIN FOR ,       HLIQ
     1 19HFUNCTION HLIQ -----)                                         HLIQ
      END                                                              HLIQ
      FUNCTION HLPT(P,T)                                               HLPT
C                                                                      HLPT
C ********** PROGRAM RETURNS ENTHALPY OF SUBCOOLED   **********       HLPT
C *          LIQUID IN KJ/KG GIVEN PRESSURE IN BARS            *       HLPT
C ********** AND TEMPERATURE IN DEGREES CELSIUS      **********       HLPT
C                                                                      HLPT
      DIMENSION A(12)                                                  HLPT
      DATA IN, IOUT/8, 6/                                              HLPT
      DATA A/-5.14242768E-1,  1.50823710E-3,  1.17074490E 0,           HLPT
     1       -7.63387186E-4,  1.17088497E-1, -8.45802948E-4,           HLPT
     1       -4.35137928E-1,  6.95270896E-2,  9.15317714E-1,           HLPT
     1       -1.90349936E-1,  3.22138727E-1,  1.30570829E-1/           HLPT
C                                                                      HLPT
      PR   = P*4.52734517E-2                                           HLPT
```

```
      TR    = (T+273.15)/647.29                                          HLPT
      K     = 1                                                          HLPT
      IF (TR .GT. 0.66917) K = K+6                                       HLPT
      IF (PR.LT.0.00106 .OR. PR.GT.5.02535 .OR.                          HLPT
     1    TR.LT.0.45289 .OR. TR.GT.0.91481) WRITE (IOUT,900) P, T        HLPT
      A0    = A(K  ) + A(K+1)*PR                                         HLPT
      A1    = A(K+2) + A(K+3)*PR                                         HLPT
      A2    = A(K+4) + A(K+5)*PR                                         HLPT
      HR    = A0 + A1*TR + A2*TR*TR                                      HLPT
      HLPT = 2099.3*HR                                                   HLPT
C                                                                        HLPT
      RETURN                                                             HLPT
  900 FORMAT (1H0,18H----- ARGUMENT P =,F6.2,13H OR ARGUMENT ,           HLPT
     1 3HT =,F7.2/1H ,8X,34HIS OUTSIDE OF ACCURATE DOMAIN FOR ,          HLPT
     1 19HFUNCTION HLPT -----)                                           HLPT
      END                                                                HLPT
```

6. Example computer input and output

The complete computer input statements used for the two examples described in Chapter 6 and the corresponding output statements are shown in Figs. D-6 through D-9.

a. Input and output data notes for Example 1

Several points should be noted in relation to the input statements given in Fig. D-6. First, the enthalpy and availability variables XMAT(1) through XMAT(4), ENTOT1, ENTOT2, AVAILS, and AVAIL2 do not affect the calculations in the manual matching mode of operation and so may be set equal to zero. Second, since identical unit process equipment is used in the conventional and the geothermal system, the cost of the equipment is irrelevant to the differential economic analysis and therefore XMAT2(1) and CAREA(1) are set equal to zero. Third, the first requirement for electricity represents the pumping power for the geothermal fluid pipeline. Fourth, since in this case the geothermal fluid user is also the field developer, no fluid is purchased and CFLUID is set equal to zero. Fifth, as was noted above, the variables PROBT, PROBM, and PROBC are not currently used in the program. Sixth, LIFEBD, BONDRT, and DEBTEQ are set equal to zero since project financing considerations are to be omitted from this analysis. Finally, ROIREQ refers to the rate of return on the geothermal investment that is employed in computing the depletion allowance (see Appendix B).

In relation to the output, two points are of interest (Fig. D-7). First, the "First Law error" figures on the second and third pages of the output do not apply to the manual matching mode of operation and so should be ignored. Second, on page 6 of the output the discounted payback period is listed as 100 years despite the fact that the net present value of system savings is negative (which implies an infinite payback period). Since the computer is not capable of generating an expression for infinity, a value of 100 years is used to represent indefinitely long payback periods.

FIGURE D-6 - INPUT FOR EXAMPLE ONE

```
    9    0    2
NORTHWESTERN UNITED STATES
LARGE PULP AND PAPER FIRM              ----- EXAMPLE 1 -----
    1    1    1    1
         0.0  151958.0   30372.9        0.0   36867.7   44657.1   44657.1        0.0
         0.0
    253.85      42.383   36867.7
    7  204117.0         1.0
         0.0
    3    2    1    1
  200000.0  187610.0   30372.9       45.9   11667.9   55478.0   55478.0        0.0
         0.0
    253.85      42.382   11667.9
         0.0       0.0      22.1
         0.0       0.0      23.8
    7  204117.0         1.0
    8  200000.0    27886.1
         0.0
    2    2      0.0667     2.0E5      1.8E6     4.5E6     5.0E5     2.5E5        0.0
        0.40      0.80       0.0
         0.0     165.0       0.0      0.0E4     1.0E5     0.0E5
    0.0E-4    0.0E-4    0.0E-4
 1982    3    15
      0.1      0.4      0.5      0.0      0.0      0.0      0.0      0.0      0.0      0.0
      0.0      0.0      0.0      0.0      0.0      0.0      0.0      0.0      0.0      0.0
      0.0      0.0      0.0      0.0      0.0      0.0      0.0      0.0      0.0      0.0
      0.0      0.0      0.0      0.0      0.0      0.0      0.0      0.0      0.0      0.0
 2.5571E-6 1.3699E-6
      0.075     0.112     0.085     0.112     0.070     0.080     0.076     0.080
   13       0.02
    0       0.00        0.0
        0.20     0.022      0.48
    0.0012      0.02      0.75
        0.20      0.20      0.12
```

R U N   N U M B E R: 9.   C A S E   N U M B E R: 1

GEOTHERMAL RESOURCE LOCATION:
  NORTHWESTERN UNITED STATES

INDUSTRIAL PROCESS APPLICATION:
  LARGE PULP AND PAPER FIRM   ----- EXAMPLE 1 -----

FIGURE D-7 - OUTPUT FOR EXAMPLE ONE

RUN NUMBER: 9. CASE NUMBER: 1

CONVENTIONAL SYSTEM MATCH RESULT DATA:

AUXILIARY ENERGY REQUIRED:

TEMP (C)	PRESSURE (BARS)	ENERGY (KW)
253.85	42.383	3.6868E+04

EQUIPMENT SIZE DATA:

EQUIPMENT	DESCRIPTION	SIZE PARAMETER 1	PARAMETER 2
1	PROCESS EQUIPMENT .	204117.0000	1.0000

TOTAL PROCESS ENERGY REQUIREMENT.	= 3.0373E+04	KW
TOTAL PROCESS ELECTRICITY USE	= 0.0000E+00	KW
TOTAL PROCESS AUXILIARY FOSSIL FUEL HEAT. .	= 3.6868E+04	KW
TOTAL GEOTHERMAL SUPPLY MASS FLOW RATE. . .	= 0.0000E+00	KG/HR
TOTAL SUPPLY STREAM ENTHALPY.	= 4.4657E+04	KW
TOTAL SUPPLY STREAM ENTHALPY AT EXIT. . . .	= 4.4657E+04	KW
TOTAL SUPPLY STREAM AVAILABILITY.	= 0.0000E+00	KW
TOTAL SUPPLY STREAM AVAILABILITY AT EXIT. .	= 0.0000E+00	KW
TOTAL MASS FLOW OF WATER REQUIRED	= 1.5196E+05	KG/HR
FIRST LAW ERROR	= 21.3835	%

CURRENT PROCESS EQUIPMENT COSTS:

PROCESS	COST
1	$0.000E+00

RUN NUMBER: 9. CASE NUMBER: 1

GEOTHERMAL SYSTEM MATCH RESULT DATA:

AUXILIARY ENERGY REQUIRED:

TEMP (C)	PRESSURE (BARS)	ENERGY (KW)
253.85	42.382	1.1668E+04
0.00	0.000	2.2100E+01
0.00	0.000	2.3800E+01

EQUIPMENT SIZE DATA:

EQUIPMENT	DESCRIPTION	SIZE PARAMETER 1	PARAMETER 2
1	PROCESS EQUIPMENT .	204117.0000	1.0000
2	HEAT EXCHANGER. . .	200000.0000	27886.0996

TOTAL PROCESS ENERGY REQUIREMENT. . . . . . = 3.0373E+04 KW
TOTAL PROCESS ELECTRICITY USE . . . . = 4.5900E+01 KW
TOTAL PROCESS AUXILIARY FOSSIL FUEL HEAT. . = 1.1668E+04 KW
TOTAL GEOTHERMAL SUPPLY MASS FLOW RATE. . . = 2.0000E+05 KG/HR
TOTAL SUPPLY STREAM ENTHALPY. . . . . = 5.5478E+04 KW
TOTAL SUPPLY STREAM ENTHALPY AT EXIT. . . . = 5.5478E+04 KW
TOTAL SUPPLY STREAM AVAILABILITY. . . . . . = 0.0000E+00 KW
TOTAL SUPPLY STREAM AVAILABILITY AT EXIT. . = 0.0000E+00 KW
TOTAL MASS FLOW OF WATER REQUIRED . . . . . = 1.8761E+05 KG/HR
FIRST LAW ERROR . . . . = -61.4334 %

CURRENT PROCESS EQUIPMENT COSTS: PROCESS COST
1 $0.000E+00

R U N N U M B E R: 9. C A S E N U M B E R: 1

E C O N O M I C D A T A:

NUMBER OF PRODUCING WELLS NEEDED. . . . . . . =	2	
NUMBER OF EXTRA WELLS . . . . =	2	
NEW WELLS PER YEAR PER PRODUCING WELL . . . =	0.067	(YEAR)-1
LAND ACQUISITION COST . . . . =	200000.	1978 $
COST PER WELL . . . . =	1800000.	1978 $
COST OF FLUID TRANSMISSION SYSTEM . . . . . =	4500000.	1978 $
OTHER COSTS (EXPLORATION, ETC.) . . . . =	500000.	1978 $
ANNUAL FIELD MAINTENANCE COST . . . . =	250000.	1978 $
ANNUAL COST FOR REPLACEMENT WELLS . . . . . =	0.	1978 $
FRACTION OF WELL COSTS ATTRIBUTABLE TO TANGIBLE EXPENSE. . . . . =	40.0000	%
FRACTION OF TANGIBLE WELL COSTS ALLOCATABLE TO DEPLETABLE ACCOUNTS. . . . =	80.0000	%
COST OF GEOTHERMAL FLUID. . . . . =	0.0000	CENTS/KG

PROBABILITY DISTRIBUTION FOR STREAM TEMPERATURE:

P(ACTUAL T .LE. GIVEN T)= 25% AT T =	0.00	C
= 50% AT T =	165.00	C
= 75% AT T =	0.00	C

PROBABILITY DISTRIBUTION FOR STREAM FLOW RATE:

P(ACTUAL M .LE. GIVEN M)= 25% AT M =	0.0000E+00	KG/HR
= 50% AT M =	1.0000E+05	KG/HR
= 75% AT M =	0.0000E+00	KG/HR

PROBABILITY DISTRIBUTION FOR COST OF FLUID:

P(ACTUAL C .LE. GIVEN C)= 25% AT C =	0.00000	C/KG
= 50% AT C =	0.00000	C/KG
= 75% AT C =	0.00000	C/KG

PROJECT STARTING DATE . . . . =	1982	
PROJECT CONSTRUCTION TIME . . . . =	3	YEARS
PROJECT OPERATING LIFE. . . . . =	15	YEARS

FRACTION OF TOTAL INVESTMENT MADE EACH YEAR:

0.100	0.400	0.500	0.000	0.000	0.000	0.000	0.000	0.000	0.000
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
0.000	0.000	0.000	0.000	0.000	0.00	0.000	0.000	0.000	0.000

COST OF FOSSIL FUEL IN 1978 . . . . =	2.5571	$/GJ
COST OF ELECTRICITY IN 1978 . . . . =	1.3699	$/GJ

INFLATION FACTORS:	PRICE	FOSSIL	ELECT.	GT FLUID
THROUGH 1986:	7.50%	11.20%	8.50%	11.20%
AFTER 1986:	7.00	8.00	7.60	8.00

DEPRECIATION LIFETIME	=	13	YEARS
SALVAGE VALUE AS PERCENTAGE OF INVESTMENT .	=	2.00	%
BOND LIFETIME TO MATURITY	=	0	YEARS
BOND INTEREST RATE.	=	0.00	%
DEBT/EQUITY RATIO	=	0.00	
INVESTMENT TAX CREDIT	=	20.00	%
PROPERTY TAX RATE	=	2.20	CENTS/$
OVERALL MARGINAL INCOME TAX RATE.	=	48.00	%
INSURANCE PREMIUM RATE.	=	0.12	CENTS/$
OPERATING AND MAINTENANCE COST RATE	=	2.00	CENTS/$
ANNUAL CAPACITY FACTOR.	=	75.00	%
DISCOUNT RATE	=	20.00	%
RATE OF RETURN REQUIRED BY INVESTORS ON DEPLETABLE INVESTMENT	=	20.00	%
ROYALTIES ON GEOTHERMAL FLUID PRODUCTION. . .	=	12.00	%

R U N   N U M B E R: 9.   C A S E   N U M B E R: 1

E C O N O M I C   R E S U L T S: FRAC = 1.0000

TOTAL INVESTMENT IN GEOTHERMAL SYSTEM
  IN CONSTANT DOLLARS . . . . = 1.2701E+07 $
  IN CURRENT DOLLARS. . . . . = 1.8790E+07 $
TOTAL INVESTMENT IN GEOTHERMAL FIELD
  IN CONSTANT DOLLARS . . . . = 1.2400E+07 $
TOTAL INVESTMENT IN CONVENTIONAL SYSTEM
  IN CONSTANT DOLLARS . . . . = 0.0000E+00 $
NET PRESENT VALUE OF GT SYSTEM CASH FLOWS.. =-1.6278E+07 $
NET PRESENT VALUE OF CONVENTIONAL
  SYSTEM CASH FLOWS . . . . =-1.4366E+07 $
NET PRESENT VALUE OF SYSTEM SAVINGS . . . . =-1.9116E+06 $
DISCOUNTED PAYBACK PERIOD . . . . = 100 YEARS
INTERNAL RATE OF RETURN . . . . = 16.6355 %

CASH FLOWS:	YEAR	FOSSIL	GEOTHERMAL	SAVING
1	1982	$ 0.000E+00	$-1.277E+06	$-1.277E+06
2	1983	$ 0.000E+00	$-5.515E+06	$-5.515E+06
3	1984	$ 0.000E+00	$-7.499E+06	$-7.499E+06
4	1985	$-3.047E+06	$-8.280E+05	$ 2.219E+06
5	1986	$-3.389E+06	$-1.015E+06	$ 2.374E+06
6	1987	$-3.660E+06	$-1.179E+06	$ 2.481E+06
7	1988	$-3.952E+06	$-1.353E+06	$ 2.600E+06
8	1989	$-4.269E+06	$-1.536E+06	$ 2.732E+06
9	1990	$-4.610E+06	$-1.731E+06	$ 2.880E+06
10	1991	$-4.979E+06	$-1.936E+06	$ 3.042E+06
11	1992	$-5.377E+06	$-2.155E+06	$ 3.222E+06
12	1993	$-5.807E+06	$-2.386E+06	$ 3.421E+06
13	1994	$-6.272E+06	$-2.633E+06	$ 3.639E+06
14	1995	$-6.774E+06	$-2.894E+06	$ 3.880E+06
15	1996	$-7.316E+06	$-3.173E+06	$ 4.143E+06
16	1997	$-7.901E+06	$-3.469E+06	$ 4.432E+06
17	1998	$-8.533E+06	$-3.785E+06	$ 4.748E+06
18	1999	$-9.216E+06	$-4.077E+06	$ 5.139E+06

R U N   N U M B E R: 9.   C A S E   N U M B E R: 2

ENTER NEXT RUN DATA: INAME= 0 &

NORMAL END OF JOB

b. <u>Input and output data notes for Example 2</u>

The following comments are intended to aid in interpreting the input and output statements for Example 2.

First, the geothermal flow rate loop option described in Chapter 2 is not employed. The variables STARTM and FINALM are therefore both set equal to unity. Second, input fluid streams numbers 3 through 8 represent the exit streams from unit processes numbers 1 through 6. These streams are re-entered as input to allow closure of fluid loops (as was discussed in Chapters 3 and 6). The flow rates are initially set to zero since they are not needed in the conventional system. Third, the unit processes are listed as direct-injection type processes. This restriction is necessary if closed fluid loops are being employed. Fourth, since in this case the process equipment has already been installed and will not be changed, the cost of equipment is irrelevant. The variables CAREA(J) are thus set equal to zero. Fifth, two dummy processes are used to permit interactive operation of the program (as was described in Chapter 2). It should be noted that the second of these represents a requirement for fossil fuel, while the first is left blank at this point.

The eleventh page of the output shows in echo-print form the interactive input to the program mentioned in Chapter 2. In this situation the input is used to alter stream data for the geothermal system. The characteristics of the eighth process (a dummy process) are now altered to establish a requirement for electricity on the part of geothermal reinjection pumps.

```
   18     1     2
ONTARIO, OREGON  (MALHEUR COUNTY). WELLS NE OF INTERSTATE I-80 NEAR SNAKE RIVER
ORE-IDA FOOD PROCESSING FACILITY  (RETROFIT APPLICATION)
    1     1     0     0      1.0      1.0      0.5      1.0      1.0      1.0      1.0
    8
     150.0     6.895     631.96              162532.2
PROBABLY NA, CL, CA                     0.001     4     3      0.001
     6.895
     150.0     4.758     632.23              500000.0
NONE                                      0.0     1     1        0.0
     4.758
      93.0       1.6     389.49                   0.0
NONE                                      0.0     1     1        0.0
       1.6
      66.0   1.01325     275.76                   0.0
NONE                                      0.0     1     1        0.0
   1.01325
      38.0   1.01325     158.77                   0.0
NONE                                      0.0     1     1        0.0
   1.01325
      38.0   1.01325     158.77                   0.0
NONE                                      0.0     1     1        0.0
   1.01325
      38.0   1.01325     158.77                   0.0
NONE                                      0.0     1     1        0.0
   1.01325
      38.0   1.01325     158.77                   0.0
NONE                                      0.0     1     1        0.0
   1.01325
    9
    91.0       1.6    1207.5   31146.8    3     1      1.0     19.0     19.0         0.0
    64.5       1.0    1650.0   51074.5    3     1      1.0     15.0     15.0         0.0
    36.0       1.0    4841.5   74933.5    3     1      1.0     29.5     29.5         0.0
    36.0       1.0    4325.7  133900.5    3     1      1.0     15.6     15.6         0.0
    36.0       1.0    2614.2   80920.9    3     1      1.0     15.6     15.6         0.0
    36.0       1.0    3223.8   99790.3    3     1     20.0     15.6     15.6         0.0
    28.0       1.0     767.8   11884.1    0     1      1.0     10.0     10.0         0.0
     0.0       0.0       0.0       0.0    1     1      0.0      0.0      0.0         0.0
     0.0      -1.0   18630.5       0.0    1     1      0.0      0.0      0.0         0.0
    2    1       0.0       0.0  782000.0  443000.0  731500.0   81000.0              0.0
       1.0       0.0       0.0
     150.0     150.0     150.0  162532.2  162532.2  162532.2
       0.0       0.0       0.0
 1975    2    15
  0.1811  0.8189     0.0      0.0      0.0      0.0      0.0      0.0      0.0      0.0
     0.0     0.0     0.0      0.0      0.0      0.0      0.0      0.0      0.0      0.0
     0.0     0.0     0.0      0.0      0.0      0.0      0.0      0.0      0.0      0.0
     0.0     0.0     0.0      0.0      0.0      0.0      0.0      0.0      0.0      0.0
  2.248E-6  2.810E-6
   0.06000   0.10740   0.07274   0.00000   0.06000   0.07590   0.07274   0.00000
   15      0.0
   15      0.085        0.0
    0.1000     0.026      0.48
    0.0011     0.050      0.60
    0.1000     0.100      0.00
```

FIGURE D-8 - INPUT FOR EXAMPLE TWO

RUN NUMBER: 18. CASE NUMBER: 1

GEOTHERMAL RESOURCE LOCATION:
ONTARIO, OREGON (MALHEUR COUNTY). WELLS NE OF INTERSTATE I-80 NEAR SNAKE RIVER

INDUSTRIAL PROCESS APPLICATION:
ORE-IDA FOOD PROCESSING FACILITY (RETROFIT APPLICATION)

SUPPLY STREAM PHASE SEPARATION ALLOWED

GENERAL STREAM PHASE SEPARATION ALLOWED

SUPPLY STREAM FLASHING NOT ALLOWED

PROCESSES WITH TEMPERATURES ABOVE HOTTEST GT STREAM WILL NOT BE
HEATED SOLELY BY FOSSIL FUEL

GEOTHERMAL SUPPLY FLOW RATE FRACTION: START = 1.000
END = 1.000
STEP SIZE = 0.500

MASS FLOW RATE CUTOFF POINTS:
1.000 1.000 1.000 1.000

FIGURE D-9 - OUTPUT FOR EXAMPLE TWO

R U N   N U M B E R: 18.   C A S E   N U M B E R: 1

S U P P L Y   S T R E A M   D A T A:

```
TEMPERATURE . . . . . . . . . . . . . . . . . . . . . =     150.00  C
PRESSURE. . . . . . . . . . . . . . . . . . . . . . . =      6.895  BARS
ENTHALPY. . . . . . . . . . . . . . . . . . . . . . . =     631.96  J/G
MASS FLOW RATE. . . . . . . . . . . . . . . . . . . . = 1.6253E+05  KG/HR
MINIMUM ALLOWABLE FLASH PRESSURE. . . . . . . =      6.895  BARS
FLUID CHEMISTRY . . . . . . . . . . . . . . . . . . . =  PROBABLY NA, CL, CA
TOTAL DISSOLVED SOLIDS. . . . . . . . . . . . . =    0.00100  KG/KG
SCALING INDEX . . . . . . . . . . . . . . . . . . . . =          4
TOXICITY INDEX. . . . . . . . . . . . . . . . . . . . =          3
AMOUNT OF NON-CONDENSABLE GAS PRESENT . . . =     0.0010  KG/KG
COMPUTED STREAM PURITY PARAMETER. . . . . . . =          0

TEMPERATURE . . . . . . . . . . . . . . . . . . . . . =     150.00  C
PRESSURE. . . . . . . . . . . . . . . . . . . . . . . =      4.758  BARS
ENTHALPY. . . . . . . . . . . . . . . . . . . . . . . =     632.23  J/G
MASS FLOW RATE. . . . . . . . . . . . . . . . . . . . = 5.0000E+05  KG/HR
MINIMUM ALLOWABLE FLASH PRESSURE. . . . . . . =      4.758  BARS
FLUID CHEMISTRY . . . . . . . . . . . . . . . . . . . =  NONE
TOTAL DISSOLVED SOLIDS. . . . . . . . . . . . . =    0.00000  KG/KG
SCALING INDEX . . . . . . . . . . . . . . . . . . . . =          1
TOXICITY INDEX. . . . . . . . . . . . . . . . . . . . =          1
AMOUNT OF NON-CONDENSABLE GAS PRESENT . . . =     0.0000  KG/KG
COMPUTED STREAM PURITY PARAMETER. . . . . . . =          1

TEMPERATURE . . . . . . . . . . . . . . . . . . . . . =      93.00  C
PRESSURE. . . . . . . . . . . . . . . . . . . . . . . =      1.600  BARS
ENTHALPY. . . . . . . . . . . . . . . . . . . . . . . =     389.49  J/G
MASS FLOW RATE. . . . . . . . . . . . . . . . . . . . = 0.0000E+00  KG/HR
MINIMUM ALLOWABLE FLASH PRESSURE. . . . . . . =      1.600  BARS
FLUID CHEMISTRY . . . . . . . . . . . . . . . . . . . =  NONE
TOTAL DISSOLVED SOLIDS. . . . . . . . . . . . . =    0.00000  KG/KG
SCALING INDEX . . . . . . . . . . . . . . . . . . . . =          1
TOXICITY INDEX. . . . . . . . . . . . . . . . . . . . =          1
AMOUNT OF NON-CONDENSABLE GAS PRESENT . . . =     0.0000  KG/KG
COMPUTED STREAM PURITY PARAMETER. . . . . . . =          1

TEMPERATURE . . . . . . . . . . . . . . . . . . . . . =      66.00  C
PRESSURE. . . . . . . . . . . . . . . . . . . . . . . =      1.013  BARS
ENTHALPY. . . . . . . . . . . . . . . . . . . . . . . =     275.76  J/G
MASS FLOW RATE. . . . . . . . . . . . . . . . . . . . = 0.0000E+00  KG/HR
MINIMUM ALLOWABLE FLASH PRESSURE. . . . . . . =      1.013  BARS
FLUID CHEMISTRY . . . . . . . . . . . . . . . . . . . =  NONE
TOTAL DISSOLVED SOLIDS. . . . . . . . . . . . . =    0.00000  KG/KG
SCALING INDEX . . . . . . . . . . . . . . . . . . . . =          1
TOXICITY INDEX. . . . . . . . . . . . . . . . . . . . =          1
AMOUNT OF NON-CONDENSABLE GAS PRESENT . . . =     0.0000  KG/KG
COMPUTED STREAM PURITY PARAMETER. . . . . . . =          1
```

TEMPERATURE	=	38.00	C
PRESSURE.	=	1.013	BARS
ENTHALPY.	=	158.77	J/G
MASS FLOW RATE.	=	0.0000E+00	KG/HR
MINIMUM ALLOWABLE FLASH PRESSURE.	=	1.013	BARS
FLUID CHEMISTRY	=	NONE	
TOTAL DISSOLVED SOLIDS.	=	0.00000	KG/KG
SCALING INDEX	=	1	
TOXICITY INDEX.	=	1	
AMOUNT OF NON-CONDENSABLE GAS PRESENT . . .	=	0.0000	KG/KG
COMPUTED STREAM PURITY PARAMETER.	=	1	

TEMPERATURE	=	38.00	C
PRESSURE.	=	1.013	BARS
ENTHALPY.	=	158.77	J/G
MASS FLOW RATE.	=	0.0000E+00	KG/HR
MINIMUM ALLOWABLE FLASH PRESSURE.	=	1.013	BARS
FLUID CHEMISTRY	=	NONE	
TOTAL DISSOLVED SOLIDS.	=	0.00000	KG/KG
SCALING INDEX	=	1	
TOXICITY INDEX.	=	1	
AMOUNT OF NON-CONDENSABLE GAS PRESENT . . .	=	0.0000	KG/KG
COMPUTED STREAM PURITY PARAMETER.	=	1	

TEMPERATURE	=	38.00	C
PRESSURE.	=	1.013	BARS
ENTHALPY.	=	158.77	J/G
MASS FLOW RATE.	=	0.0000E+00	KG/HR
MINIMUM ALLOWABLE FLASH PRESSURE.	=	1.013	BARS
FLUID CHEMISTRY	=	NONE	
TOTAL DISSOLVED SOLIDS.	=	0.00000	KG/KG
SCALING INDEX	=	1	
TOXICITY INDEX.	=	1	
AMOUNT OF NON-CONDENSABLE GAS PRESENT . . .	=	0.0000	KG/KG
COMPUTED STREAM PURITY PARAMETER.	=	1	

TEMPERATURE	=	38.00	C
PRESSURE.	=	1.013	BARS
ENTHALPY.	=	158.77	J/G
MASS FLOW RATE.	=	0.0000E+00	KG/HR
MINIMUM ALLOWABLE FLASH PRESSURE.	=	1.013	BARS
FLUID CHEMISTRY	=	NONE	
TOTAL DISSOLVED SOLIDS.	=	0.00000	KG/KG
SCALING INDEX	=	1	
TOXICITY INDEX.	=	1	
AMOUNT OF NON-CONDENSABLE GAS PRESENT . . .	=	0.0000	KG/KG
COMPUTED STREAM PURITY PARAMETER.	=	1	

INDUSTRIAL APPLICATION PROCESSES:

PROCESS	TEMP (C)	PRESSURE (BARS)	HEAT (KW)	FLOW RATE (KG/HR)	PURE	PHASE	H.T.C.	DELT1 (C)	DELT2 (C)
1	91.0	1.600	1.208E+03	3.115E+04	3	1	1.00	19.00	19.00
2	64.5	1.000	1.650E+03	5.107E+04	3	1	1.00	15.00	15.00
3	36.0	1.000	4.842E+03	7.493E+04	3	1	1.00	29.50	29.50
4	36.0	1.000	4.326E+03	1.339E+05	3	1	1.00	15.60	15.60
5	36.0	1.000	2.614E+03	8.092E+04	3	1	1.00	15.60	15.60
6	36.0	1.000	3.224E+03	9.979E+04	3	1	20.00	15.60	15.60
7	28.0	1.000	7.678E+02	1.188E+04	0	1	1.00	10.00	10.00
8	0.0	0.000	0.000E+00	0.000E+00	1	1	0.00	0.00	0.00
9	0.0	-1.000	1.863E+04	0.000E+00	1	1	0.00	0.00	0.00

CURRENT PROCESS EQUIPMENT COSTS:

PROCESS	COST
1	$0.000E+00
2	0.000E+00
3	0.000E+00
4	0.000E+00
5	0.000E+00
6	0.000E+00
7	0.000E+00
8	0.000E+00
9	0.000E+00

RUN NUMBER: 18. CASE NUMBER: 1

ECONOMIC DATA:

```
NUMBER OF PRODUCING WELLS NEEDED. . . . . . =          2
NUMBER OF EXTRA WELLS . . . . . . . . . . . =          1
NEW WELLS PER YEAR PER PRODUCING WELL . . . =      0.000  (YEAR)-1
LAND ACQUISITION COST . . . . . . . . . . . =         0.  1978 $
COST PER WELL . . . . . . . . . . . . . . . =    782000.  1978 $
COST OF FLUID TRANSMISSION SYSTEM . . . . . =    443000.  1978 $
OTHER COSTS (EXPLORATION, ETC.) . . . . . . =    731500.  1978 $
ANNUAL FIELD MAINTENANCE COST . . . . . . . =     81000.  1978 $
ANNUAL COST FOR REPLACEMENT WELLS . . . . . =         0.  1978 $
FRACTION OF WELL COSTS ATTRIBUTABLE TO
  TANGIBLE EXPENSE. . . . . . . . . . . . . =   100.0000  %
FRACTION OF TANGIBLE WELL COSTS
  ALLOCATABLE TO DEPLETABLE ACCOUNTS. . . . =     0.0000  %
COST OF GEOTHERMAL FLUID. . . . . . . . . . =     0.0000  CENTS/KG

PROBABILITY DISTRIBUTION FOR STREAM TEMPERATURE:
         P(ACTUAL T .LE. GIVEN T)= 25% AT T =     150.00  C
                                 = 50% AT T =     150.00  C
                                 = 75% AT T =     150.00  C

PROBABILITY DISTRIBUTION FOR STREAM FLOW RATE:
         P(ACTUAL M .LE. GIVEN M)= 25% AT M = 1.6253E+05  KG/HR
                                 = 50% AT M = 1.6253E+05  KG/HR
                                 = 75% AT M = 1.6253E+05  KG/HR

PROBABILITY DISTRIBUTION FOR COST OF FLUID:
         P(ACTUAL C .LE. GIVEN C)= 25% AT C =    0.00000  C/KG
                                 = 50% AT C =    0.00000  C/KG
                                 = 75% AT C =    0.00000  C/KG

PROJECT STARTING DATE . . . . . . . . . . . =       1978
PROJECT CONSTRUCTION TIME . . . . . . . . . =          2  YEARS
PROJECT OPERATING LIFE. . . . . . . . . . . =         15  YEARS

FRACTION OF TOTAL INVESTMENT MADE EACH YEAR:
 0.181 0.819 0.000 0.000 0.000 0.000 0.000 0.000 0.000 0.000
 0.000 0.000 0.000 0.000 0.000 0.000 0.000 0.000 0.000 0.000
 0.000 0.000 0.000 0.000 0.000 0.000 0.000 0.000 0.000 0.000
 0.000 0.000 0.000 0.000 0.000 0.000 0.000 0.000 0.000 0.000

COST OF FOSSIL FUEL IN 1978 . . . . . . . . =     2.2480  $/GJ
COST OF ELECTRICITY IN 1978 . . . . . . . . =     2.8100  $/GJ

INFLATION FACTORS:  PRICE  FOSSIL  ELECT.  GT FLUID
  THROUGH 1986:     6.00%  10.74%   7.27%   0.00%
  AFTER 1986:       6.00    7.59    7.27    0.00
```

DEPRECIATION LIFETIME	=	15	YEARS
SALVAGE VALUE AS PERCENTAGE OF INVESTMENT .	=	0.00	%
BOND LIFETIME TO MATURITY	=	15	YEARS
BOND INTEREST RATE.	=	8.50	%
DEBT/EQUITY RATIO	=	0.00	
INVESTMENT TAX CREDIT	=	10.00	%
PROPERTY TAX RATE	=	2.60	CENTS/$
OVERALL MARGINAL INCOME TAX RATE.	=	48.00	%
INSURANCE PREMIUM RATE.	=	0.11	CENTS/$
OPERATING AND MAINTENANCE COST RATE	=	5.00	CENTS/$
ANNUAL CAPACITY FACTOR.	=	60.00	%
DISCOUNT RATE	=	10.00	%
RATE OF RETURN REQUIRED BY INVESTORS ON DEPLETABLE INVESTMENT	=	10.00	%
ROYALTIES ON GEOTHERMAL FLUID PRODUCTION. .	=	0.00	%

R U N N U M B E R: 18. C A S E N U M B E R: 1

M A T C H I N G S U B R O U T I N E R U N: FRAC = 0.0000

F L U I D S T R E A M S A F T E R P R O C E S S 1 :

SUPPLY	TEMPERATURE (DEGREES C)	PRESSURE (BARS)	ENTHALPY (J/G)	FLOW RATE (KG/HR)	PURE	NON-COND.	TDS
9	150.0	4.758	632.23	4.6885E+05	1	0.0000	0.00000
2	117.3	4.758	492.67	3.1147E+04	3	0.0000	0.00000

F L U I D S T R E A M S A F T E R P R O C E S S 2 :

SUPPLY	TEMPERATURE (DEGREES C)	PRESSURE (BARS)	ENTHALPY (J/G)	FLOW RATE (KG/HR)	PURE	NON-COND.	TDS
10	150.0	4.758	632.23	4.1778E+05	1	0.0000	0.00000
9	122.7	4.758	515.93	5.1075E+04	3	0.0000	0.00000
2	117.3	4.758	492.67	3.1147E+04	3	0.0000	0.00000

F L U I D S T R E A M S A F T E R P R O C E S S 3 :

SUPPLY	TEMPERATURE (DEGREES C)	PRESSURE (BARS)	ENTHALPY (J/G)	FLOW RATE (KG/HR)	PURE	NON-COND.	TDS
11	150.0	4.758	632.23	3.4285E+05	1	0.0000	0.00000
9	122.7	4.758	515.93	5.1075E+04	3	0.0000	0.00000
2	117.3	4.758	492.67	3.1147E+04	3	0.0000	0.00000
10	95.3	4.758	399.63	7.4934E+04	3	0.0000	0.00000

F L U I D S T R E A M S A F T E R P R O C E S S 4 :

SUPPLY	TEMPERATURE (DEGREES C)	PRESSURE (BARS)	ENTHALPY (J/G)	FLOW RATE (KG/HR)	PURE	NON-COND.	TDS
12	150.0	4.758	632.23	2.0894E+05	1	0.0000	0.00000
9	122.7	4.758	515.93	5.1075E+04	3	0.0000	0.00000
11	122.7	4.758	515.93	1.3390E+05	3	0.0000	0.00000
2	117.3	4.758	492.67	3.1147E+04	3	0.0000	0.00000
10	95.3	4.758	399.63	7.4934E+04	3	0.0000	0.00000

FLUID STREAMS AFTER PROCESS 6:

SUPPLY	TEMPERATURE (DEGREES C)	PRESSURE (BARS)	ENTHALPY (J/G)	FLOW RATE (KG/HR)	PURE	NON-COND.	TDS
13	150.0	4.758	632.23	1.0915E+05	1	0.0000	0.00000
9	122.7	4.758	515.93	5.1075E+04	3	0.0000	0.00000
12	122.7	4.758	515.93	9.9790E+04	3	0.0000	0.00000
11	122.7	4.758	515.93	1.3390E+05	3	0.0000	0.00000
2	117.3	4.758	492.67	3.1147E+04	3	0.0000	0.00000
10	95.3	4.758	399.63	7.4934E+04	3	0.0000	0.00000

FLUID STREAMS AFTER PROCESS 5:

SUPPLY	TEMPERATURE (DEGREES C)	PRESSURE (BARS)	ENTHALPY (J/G)	FLOW RATE (KG/HR)	PURE	NON-COND.	TDS
14	150.0	4.758	632.23	2.8233E+04	1	0.0000	0.00000
9	122.7	4.758	515.93	5.1075E+04	3	0.0000	0.00000
13	122.7	4.758	515.93	8.0921E+04	3	0.0000	0.00000
12	122.7	4.758	515.93	9.9790E+04	3	0.0000	0.00000
11	122.7	4.758	515.93	1.3390E+05	3	0.0000	0.00000
2	117.3	4.758	492.67	3.1147E+04	3	0.0000	0.00000
10	95.3	4.758	399.63	7.4934E+04	3	0.0000	0.00000

FLUID STREAMS AFTER PROCESS 7:

SUPPLY	TEMPERATURE (DEGREES C)	PRESSURE (BARS)	ENTHALPY (J/G)	FLOW RATE (KG/HR)	PURE	NON-COND.	TDS
15	150.0	4.758	632.23	1.6349E+04	1	0.0000	0.00000
9	122.7	4.758	515.93	5.1075E+04	3	0.0000	0.00000
13	122.7	4.758	515.93	8.0921E+04	3	0.0000	0.00000
12	122.7	4.758	515.93	9.9790E+04	3	0.0000	0.00000
11	122.7	4.758	515.93	1.3390E+05	3	0.0000	0.00000
2	117.3	4.758	492.67	3.1147E+04	3	0.0000	0.00000
14	95.3	4.758	399.64	1.1884E+04	1	0.0000	0.00000
10	95.3	4.758	399.63	7.4934E+04	3	0.0000	0.00000

R U N N U M B E R: 18. C A S E N U M B E R: 1

E N E R G Y P R O F I L E M A T C H R E S U L T S: FRAC = 0.0000

AUXILIARY ENERGY REQUIRED:

TEMP (C)	PRESSURE (BARS)	ENERGY (KW)
0.00	0.000	0.0000E+00
0.00	-1.000	1.8631E+04

EQUIPMENT SIZE DATA:

EQUIPMENT	DESCRIPTION	SIZE PARAMETER 1	PARAMETER 2
1	PROCESS EQUIPMENT .	31146.8008	0.9055
2	PROCESS EQUIPMENT .	51074.5000	0.8334
3	PROCESS EQUIPMENT .	74933.5000	0.8556
4	PROCESS EQUIPMENT .	133900.5000	0.7675
5	PROCESS EQUIPMENT .	80920.8984	0.7675
6	PROCESS EQUIPMENT .	99790.2969	0.7675
7	PROCESS EQUIPMENT .	11884.0996	0.1056
8	PROCESS EQUIPMENT .	0.0000	1.0000
9	PROCESS EQUIPMENT .	0.0000	1.0000

TOTAL PROCESS ENERGY REQUIREMENT.	=	3.7261E+04	KW
TOTAL PROCESS ELECTRICITY USE	=	0.0000E+00	KW
TOTAL PROCESS AUXILIARY FOSSIL FUEL HEAT. .	=	1.8631E+04	KW
TOTAL GEOTHERMAL SUPPLY MASS FLOW RATE. . .	=	0.0000E+00	KG/HR
TOTAL SUPPLY STREAM ENTHALPY.	=	8.7810E+04	KW
TOTAL SUPPLY STREAM ENTHALPY AT EXIT. . . .	=	6.9179E+04	KW
TOTAL SUPPLY STREAM AVAILABILITY.	=	1.3223E+04	KW
TOTAL SUPPLY STREAM AVAILABILITY AT EXIT. .	=	8.0004E+03	KW
TOTAL MASS FLOW OF WATER REQUIRED	=	0.0000E+00	KG/HR
FIRST LAW ERROR	=	0.0000	%

RUN NUMBER: 18. CASE NUMBER: 2

ENTER NEXT RUN DATA: MSI(2)= 0.0

ENTER NEXT RUN DATA: MSI(3)= 31147.0

ENTER NEXT RUN DATA: MSI(4)= 51075.0

ENTER NEXT RUN DATA: MSI(5)= 74934.0

ENTER NEXT RUN DATA: MSI(6)= 133901.0

ENTER NEXT RUN DATA: MSI(7)= 80921.0

ENTER NEXT RUN DATA: MSI(8)= 99791.0

ENTER NEXT RUN DATA: QPI(8)= 223.74

ENTER NEXT RUN DATA: QPI(9)= 0.0

ENTER NEXT RUN DATA: INAME = 1

ENTER NEXT RUN DATA: &

R U N N U M B E R: 18. C A S E N U M B E R: 2

M A T C H I N G S U B R O U T I N E R U N: FRAC = 1.0000

FLUID STREAMS AFTER PROCESS 1:

SUPPLY	TEMPERATURE (DEGREES C)	PRESSURE (BARS)	ENTHALPY (J/G)	FLOW RATE (KG/HR)	PURE	NON-COND.	TDS
9	150.0	6.895	631.96	1.3139E+05	0	0.0010	0.00100
1	117.1	6.895	492.40	3.1147E+04	0	0.0010	0.00100
3	93.0	1.600	389.49	3.1147E+04	3	0.0000	0.00000
4	66.0	1.013	275.76	5.1075E+04	1	0.0000	0.00000
5	38.0	1.013	158.77	3.8955E+05	1	0.0000	0.00000

FLUID STREAMS AFTER PROCESS 2:

SUPPLY	TEMPERATURE (DEGREES C)	PRESSURE (BARS)	ENTHALPY (J/G)	FLOW RATE (KG/HR)	PURE	NON-COND.	TDS
11	150.0	6.895	631.96	8.0311E+04	0	0.0010	0.00100
9	122.6	6.895	515.66	5.1075E+04	0	0.0010	0.00100
1	117.1	6.895	492.40	3.1147E+04	0	0.0010	0.00100
3	93.0	1.600	389.49	3.1147E+04	3	0.0000	0.00000
4	66.0	1.013	275.76	5.1075E+04	3	0.0000	0.00000
5	38.0	1.013	158.77	3.8955E+05	1	0.0000	0.00000

FLUID STREAMS AFTER PROCESS 3:

SUPPLY	TEMPERATURE (DEGREES C)	PRESSURE (BARS)	ENTHALPY (J/G)	FLOW RATE (KG/HR)	PURE	NON-COND.	TDS
13	150.0	6.895	631.96	5.3774E+03	0	0.0010	0.00100
9	122.6	6.895	515.66	5.1075E+04	0	0.0010	0.00100
1	117.1	6.895	492.40	3.1147E+04	0	0.0010	0.00100
11	94.8	6.895	399.36	7.4934E+04	0	0.0010	0.00100
3	93.0	1.600	389.49	3.1147E+04	3	0.0000	0.00000
4	66.0	1.013	275.76	5.1075E+04	3	0.0000	0.00000
5	38.0	1.013	158.77	7.4934E+04	3	0.0000	0.00000
14	38.0	1.013	158.77	3.1461E+05	1	0.0000	0.00000

FLUID STREAMS AFTER PROCESS 4:

SUPPLY	TEMPERATURE (DEGREES C)	PRESSURE (BARS)	ENTHALPY (J/G)	FLOW RATE (KG/HR)	PURE	NON-COND.	TDS
13	150.0	6.895	631.96	5.3774E+03	0	0.0010	0.00100
1	117.1	6.895	492.40	3.1147E+04	0	0.0010	0.00100
11	94.8	6.895	399.36	7.4934E+04	0	0.0010	0.00100
3	93.0	1.600	389.49	3.1147E+04	3	0.0000	0.00000
4	66.0	1.013	275.76	5.1075E+04	3	0.0000	0.00000
9	50.7	6.895	216.67	5.1075E+04	0	0.0010	0.00100
5	38.0	1.013	158.77	7.4934E+04	3	0.0000	0.00000
15	38.0	1.013	158.77	1.8071E+05	1	0.0000	0.00000
14	37.5	1.013	156.52	1.3390E+05	3	0.0000	0.00000

FLUID STREAMS AFTER PROCESS 6:

SUPPLY	TEMPERATURE (DEGREES C)	PRESSURE (BARS)	ENTHALPY (J/G)	FLOW RATE (KG/HR)	PURE	NON-COND.	TDS
13	150.0	6.895	631.96	5.3774E+03	0	0.0010	0.00100
1	117.1	6.895	492.40	3.1147E+04	0	0.0010	0.00100
3	93.0	1.600	389.49	3.1147E+04	3	0.0000	0.00000
4	66.0	1.013	275.76	5.1075E+04	3	0.0000	0.00000
11	57.5	6.895	244.48	7.4934E+04	0	0.0010	0.00100
9	50.7	6.895	216.67	5.1075E+04	0	0.0010	0.00100
5	38.0	1.013	158.77	7.4934E+04	3	0.0000	0.00000
16	38.0	1.013	158.77	8.0923E+04	1	0.0000	0.00000
15	38.0	1.013	158.77	9.9790E+04	3	0.0000	0.00000
14	37.5	1.013	156.52	1.3390E+05	3	0.0000	0.00000

FLUID STREAMS AFTER PROCESS 5:

SUPPLY	TEMPERATURE (DEGREES C)	PRESSURE (BARS)	ENTHALPY (J/G)	FLOW RATE (KG/HR)	PURE	NON-COND.	TDS
13	150.0	6.895	631.96	5.3774E+03	0	0.0010	0.00100
3	93.0	1.600	389.49	3.1147E+04	3	0.0000	0.00000
4	66.0	1.013	275.76	5.1075E+04	3	0.0000	0.00000
11	57.5	6.895	244.48	7.4934E+04	0	0.0010	0.00100
1	50.4	6.895	215.35	8.2221E+04	0	0.0010	0.00100
16	39.9	1.013	166.70	8.0921E+04	3	0.0000	0.00000
5	38.0	1.013	158.77	7.4934E+04	3	0.0000	0.00000
15	38.0	1.013	158.77	9.9790E+04	3	0.0000	0.00000
14	37.5	1.013	156.52	1.3390E+05	3	0.0000	0.00000

F L U I D   S T R E A M S   A F T E R   P R O C E S S   7 :

SUPPLY	TEMPERATURE (DEGREES C)	PRESSURE (BARS)	ENTHALPY (J/G)	FLOW RATE (KG/HR)	PURE	NON-COND.	TDS
3	93.0	1.600	389.49	3.1147E+04	3	0.0000	0.00000
4	66.0	1.013	275.76	5.1075E+04	3	0.0000	0.00000
13	65.5	6.895	277.76	5.3774E+03	0	0.0010	0.00100
11	57.5	6.895	244.48	7.4934E+04	0	0.0010	0.00100
18	50.4	6.895	215.35	7.0337E+04	0	0.0010	0.00100
16	39.9	1.013	166.70	8.0921E+04	3	0.0000	0.00000
5	38.0	1.013	158.77	7.4934E+04	3	0.0000	0.00000
15	38.0	1.013	158.77	9.9790E+04	3	0.0000	0.00000
14	37.5	1.013	156.52	1.3390E+05	3	0.0000	0.00000
1	33.0	6.895	143.03	1.1884E+04	0	0.0010	0.00100

R U N   N U M B E R: 18.   C A S E   N U M B E R: 2

E N E R G Y   P R O F I L E   M A T C H   R E S U L T S: FRAC = 1.0000

AUXILIARY ENERGY REQUIRED:

TEMP (C)	PRESSURE (BARS)	ENERGY (KW)
67.73	1.013	3.7671E+02
0.00	0.000	2.2374E+02
0.00	-1.000	0.0000E+00

EQUIPMENT SIZE DATA:

EQUIPMENT	DESCRIPTION	SIZE PARAMETER 1	PARAMETER 2
1	PROCESS EQUIPMENT .	31146.8008	0.9914
2	PROCESS EQUIPMENT .	51074.5000	0.9453
3	PROCESS EQUIPMENT .	74933.5000	0.9993
4	PROCESS EQUIPMENT .	133900.5000	1.0007
5	PROCESS EQUIPMENT .	80920.8984	0.9932
6	PROCESS EQUIPMENT .	99790.2969	0.9990
7	PROCESS EQUIPMENT .	11884.0996	0.3028
8	PROCESS EQUIPMENT .	0.0000	1.0000
9	PROCESS EQUIPMENT .	0.0000	1.0000
10	HEAT EXCHANGER. . .	31146.8008	1207.5000
11	HEAT EXCHANGER. . .	51074.5000	1650.0000
12	HEAT EXCHANGER. . .	74933.5000	4841.5000
13	HEAT EXCHANGER. . .	133900.5000	4241.9121
14	HEAT EXCHANGER. . .	99790.2969	3223.8000
15	HEAT EXCHANGER. . .	80920.8984	2415.7615
16	FOSSIL FUEL HEATER.	80920.8984	376.7134
17	HEAT EXCHANGER. . .	11884.0996	529.0834

TOTAL PROCESS ENERGY REQUIREMENT. . . . . . . =	1.8854E+04	KW
TOTAL PROCESS ELECTRICITY USE . . . . =	2.2374E+02	KW
TOTAL PROCESS AUXILIARY FOSSIL FUEL HEAT. . =	3.7671E+02	KW
TOTAL GEOTHERMAL SUPPLY MASS FLOW RATE. . . =	1.6253E+05	KG/HR
TOTAL SUPPLY STREAM ENTHALPY. . . . . =	5.2994E+04	KW
TOTAL SUPPLY STREAM ENTHALPY AT EXIT. . . . =	3.4740E+04	KW
TOTAL SUPPLY STREAM AVAILABILITY. . . . . . =	5.1891E+03	KW
TOTAL SUPPLY STREAM AVAILABILITY AT EXIT. . =	1.2928E+03	KW
TOTAL MASS FLOW OF WATER REQUIRED . . . . . =	0.0000E+00	KG/HR
FIRST LAW ERROR . . . . =	0.0007	%

R U N N U M B E R: 18. C A S E N U M B E R: 2

E C O N O M I C R E S U L T S: FRAC = 1.0000

TOTAL INVESTMENT IN GEOTHERMAL SYSTEM		
IN CONSTANT DOLLARS	= 4.6063E+06	$
IN CURRENT DOLLARS.	= 4.8326E+06	$
TOTAL INVESTMENT IN GEOTHERMAL FIELD		
IN CONSTANT DOLLARS	= 3.5205E+06	$
TOTAL INVESTMENT IN CONVENTIONAL SYSTEM		
IN CONSTANT DOLLARS	= 0.0000E+00	$
NET PRESENT VALUE OF GT SYSTEM CASH FLOWS..	=-4.4991E+06	$
NET PRESENT VALUE OF CONVENTIONAL		
SYSTEM CASH FLOWS	=-7.6694E+06	$
NET PRESENT VALUE OF SYSTEM SAVINGS	= 3.1702E+06	$
DISCOUNTED PAYBACK PERIOD	= 10	YEARS
INTERNAL RATE OF RETURN	= 19.7205	%

CASH FLOWS:	YEAR	FOSSIL	GEOTHERMAL	SAVING
1	1978	$ 0.000E+00	$-7.625E+05	$-7.625E+05
2	1979	$ 0.000E+00	$-3.667E+06	$-3.667E+06
3	1980	$-6.317E+05	$ 1.181E+05	$ 7.498E+05
4	1981	$-6.995E+05	$ 8.775E+04	$ 7.873E+05
5	1982	$-7.747E+05	$ 5.667E+04	$ 8.313E+05
6	1983	$-8.579E+05	$ 2.482E+04	$ 8.827E+05
7	1984	$-9.500E+05	$-7.873E+03	$ 9.421E+05
8	1985	$-1.052E+06	$-4.146E+04	$ 1.011E+06
9	1986	$-1.165E+06	$-7.602E+04	$ 1.089E+06
10	1987	$-1.253E+06	$-1.109E+05	$ 1.143E+06
11	1988	$-1.349E+06	$-1.467E+05	$ 1.202E+06
12	1989	$-1.451E+06	$-1.835E+05	$ 1.267E+06
13	1990	$-1.561E+06	$-2.215E+05	$ 1.340E+06
14	1991	$-1.680E+06	$-2.606E+05	$ 1.419E+06
15	1992	$-1.807E+06	$-3.009E+05	$ 1.506E+06
16	1993	$-1.944E+06	$-3.425E+05	$ 1.602E+06
17	1994	$-2.092E+06	$-3.856E+05	$ 1.706E+06

R U N N U M B E R: 18. C A S E N U M B E R: 3

ENTER NEXT RUN DATA: INAME= 0 &

NORMAL END OF JOB