6-2-77
25 cop. to NTIS

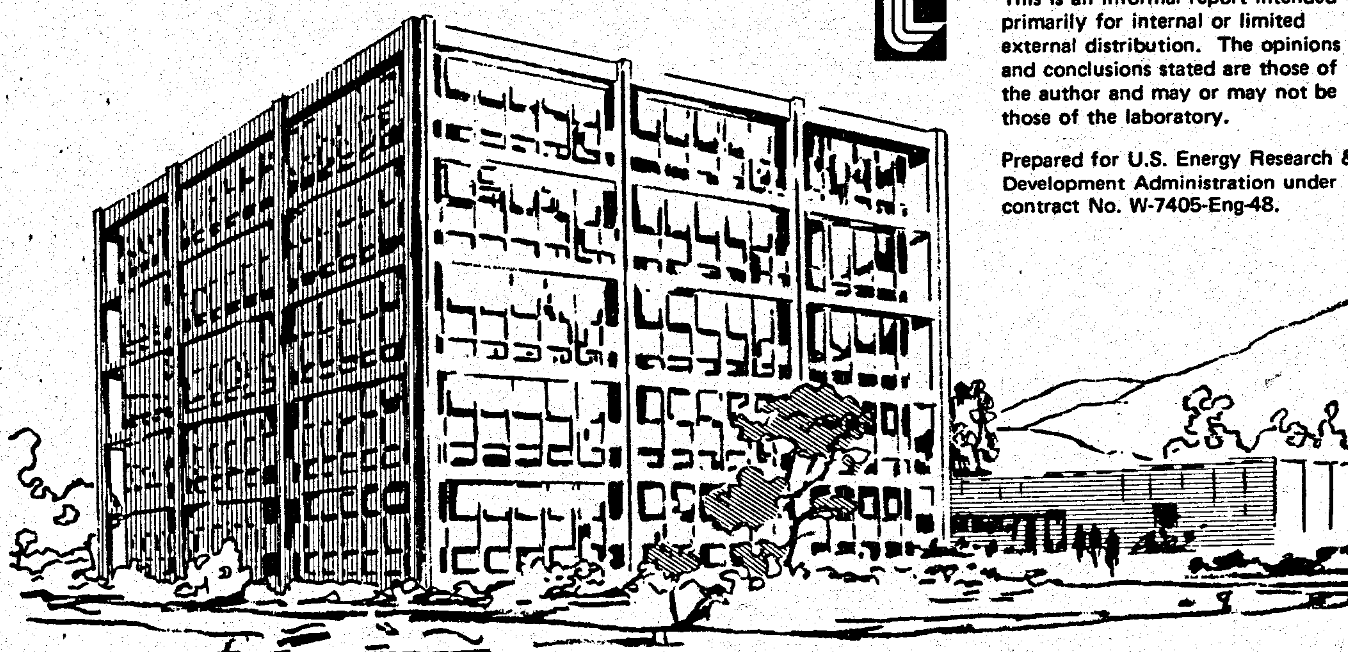
UCID- 17473

Lawrence Livermore Laboratory

WELLFLOW FOR GEOTHERMAL WELLS - DESCRIPTION OF A COMPUTER PROGRAM INCLUDING EFFECTS OF BRINE COMPOSITION

GERALD L. DITTMAN

MAY 13, 1977



This is an informal report intended primarily for internal or limited external distribution. The opinions and conclusions stated are those of the author and may or may not be those of the laboratory.

Prepared for U.S. Energy Research & Development Administration under contract No. W-7405-Eng-48.

MASTER

DISTRIBUTION OF THIS DOCUMENT IS UNLIMITED

DISCLAIMER

WELLFLOW FOR GEOTHERMAL WELLS - DESCRIPTION OF A COMPUTER PROGRAM INCLUDING EFFECTS OF BRINE COMPOSITION

ABSTRACT

A computer program entitled "WELLFLOW" is presented for calculating wellhead flow and fluid conditions for a self-flowing geothermal well of constant diameter. The calculational model was developed by Elliott and has been modified to incorporate a more accurate analytical procedure for calculating brine thermophysical properties. An additional modification establishes the mass flow rate needed to just produce sonic liquid velocity at the wellhead (if the specified flow rate exceeds this value) in order to characterize the entire range of flow conditions for the well geometry and reservoir characteristics.

Reservoir values of temperature, depth, salinity, mass flow rate and drawdown pressure factor must be specified. Wellbore parameters of casing inside diameter, Moody friction factor, gas/liquid velocity ratio and the overall heat transfer coefficient between the casing and ground must also be supplied. The calculated wellhead conditions consist of temperature, pressure, vapor mass fraction, enthalpy and entropy of the two-phase mixture, liquid velocity and vapor and liquid mass flow rates for either pure water or brine.

INTRODUCTION

Assessment of candidate energy conversion processes for use with the high temperature-high salinity (HT/HS) Salton Sea or other geothermal resources and calculation of the corresponding plant operating parameters requires the ability to predict in a reasonably realistic manner, wellhead conditions for the wellbores in question.

Elliott has developed a calculational technique for a self-flowing geothermal well of constant diameter [(1)]. This procedure, with some modification, was employed to produce the Fortran IV computer code, WELLFLOW, that is described below and in Appendix A.

eB

The modification of most significance was incorporation of a different analytical procedure for estimating the thermophysical properties of geothermal brines that is based on more recently published material [2]. Pure water is calculated with the ASME equation-of-state [3]. The option of doubling the casing diameter above the flash level to prevent choking within the wellbore was not incorporated. Instead, the brine flow rate is reduced to a value that will just produce sonic liquid velocity at the wellhead. This allows WELLFLOW to characterize the entire range of wellhead conditions using the assumed constant diameter wellbore geometry. The Darcy-Weisbach equation and Moody friction factor are used to calculate frictional pressure loss in the liquid flow region. Above the flash level, an equivalent friction factor, numerically equal to the value used in the liquid flow region and averaged two-phase flow mixture properties is employed to calculate the pressure loss.

Although the salt concentration of the brine increases as a result of flashing to vapor in the wellbore, the current version of WELLFLOW does not adjust the thermophysical property estimtes for this effect. The model is also based on the brine having zero or a negligible concentration of dissolved non-condensible gases. Therefore, no correction to the predicted wellhead conditions (primarily the vapor partial pressure) is currently made for geothermal fluids that do contain significant quantities of dissolved gases. A reservoir fluid containing 20 weight percent dissolved solids, will experience about a 25 percent increase in salt concentration at the wellhead for a vapor mass fraction of 20 percent. However, this represents only about a 6.5 percent decrease in predicted wellhead pressure and about a 6.5 percent increase in the wellhead mixture enthalpy at approximately 400°F. The predicted wellhead pressure would have to be lowered by about an additional 6 percent, if the wellhead product included non-condensible gases amounting to 3 percent by weight. While these effects can be significant, if additive, their omission seems justified since "typical" wellhead qualities are about 10 percent and dissolved gases are $\sim$1/2 - 1 percent.

The computer program is utilized through a user-operated teletype console that is remotely located from the main computer center, and provides for both visual and printed output in the user's work area. Values must be specified for the reservoir temperature, depth, salinity, mass flow rate and drawdown pressure factor. Wellbore data, including casing inside diameter, Moody friction factor, gas-liquid velocity ratio and the overall heat transfer coefficient between the casing and ground must also be supplied. WELLFOW calculates wellhead (surface) conditions of temperature, pressure, vapor mass fraction (quality), enthalpy and entropy of a two-phase mixture, liquid velocity, and vapor and liquid mass flow rates for a brine of constant composition.

Appendix B contains instructions for using WELLFLOW with a sample problem for illustrative purposes. Appendix C provides examples of the various output formats with a description of the data.

The following pages present the results of calculations for several different wellbore systems. Comparisons are made between these results and other predictions or measured quantities to assess the codes capability.

Results

1. Comparison of Test Case Calculational Results Between Elliott and WELLFLOW Codes.

To verify consistent results with the Elliott code, WELLFLOW was run with the test case used by Elliott, which has the input parameters shown in Table 1.(1) Good agreement between the two sets of calculations up to the flash level is shown by the results in Table 2. The differences in the tabulated values at the flash level are due to the different models used for estimating brine thermophysical properties.

Choking occurs within the wellbore for this case. Surface conditions cannot be compared because the Elliott code doubles the pipe diameter above the flash level to prevent choking while WELLFLOW reduces the flowrate to just produce choking conditions at the wellhead.

TABLE 1

Elliott Test Case Input Parameters

Reservoir Temperature	250°C (482°F)
Well Depth	1500 M (4921.3 ft.)
Pipe Diameter	0.25 M (0.82 ft.)
Salt Content	20 Wt. Percent
Mass Flowrate	110 KG/Sec (242.6 LBM/Sec)
Skin Friction Factor (Elliott)	.008
Moody Friction Factor (WELLFLOW)	.032
Draw-down Factor	25×10^4 Pa/Kg-Sec^{-1} - (1.644 Psi/Lbm-Sec^{-1})
Gas/Liquid Velocity Ratio	1.

TABLE 2

Test Case Calculated Results

		Elliott	WELLFLOW
Reservoir Pressure, MPA (PSIA)		14.68 (2129)	14.70 (2132)
Well Bottom Values	Pressure, MPA (PSIA)	11.93 (1730)	11.95 (1734)
	Temperature, °C (°F)	250 (482)	250 (482)
	Liquid Velocity, M/S (FPS)	2.3 (7.55)	2.3 (7.55)
Flash Level Values	Elevation, M (Ft)	868.9 (2851)	881.1 (2891)
	Pressure, MPA (PSIA)	3.42 (496)	3.23 (468)
	Temperature , °C (°F)	250 (482)	247.5 (477.5)
	Liquid Velocity, M/S (FPS)	2.3 (7.55)	2.3 (7.55)

2. Comparison of Results Between Austin-Johnson[4] and WELLFLOW Calculations for a Hypothetical Well

Austin has proposed a hypothetical well that typifies geothermal wells in the HT/HS portion of the Salton Sea Geothermal Field.[5] The input parameters for the well are listed in Table 3 and a comparison of the calculations are shown in Table 4. The differences between the two sets of calculations are due to Austin-Johnson neglecting frictional effects in the liquid flow region of the wellbore, assuming saturated conditions at the flash level corresponding to the resevoir temperature and neglecting the enthalpy difference of compressed liquid. However, the results are reasonably consistent throughout the wellbore even with these simplifying assumptions.

TABLE 3

"Hypothetical Well" Input Parameters

Reservoir Temperature	572°F
Well Depth	5000 Ft.
Pipe Diameter	0.56 Ft.
Salt Content	0
Mass Flowrate (Areal Flowrate)	125 Lbm/Sec (500 Lbm/Sec-Ft^2)
Moody Friction Factor (Austin/Wellflow)	(∿.040/.041)
Drawdown Factor	1.6 Psi/Lbm-Sec^{-1}
Gas/Liquid Velocity Ratio	1.

TABLE 4

Comparison of Calculated Results

		Austin/Johnson	WELLFLOW
	Reservoir Pressure, PSIA	2,166	2,166
Well Bottom	Pressure, PSIA	1,966	1,966
	Temperature, °F	572	572
	Liquid Enthalpy, BTU/LBM	578.1	575.9
	Liquid Entropy, BTU/LBM-°F	.7771	.7723
Flash Level	Elevation, FT	1,868	2,118
	Pressure, PSIA	1,240	1,212
	Temperautre, °F	572	568.5
	Liquid Enthalpy, BTU/LBM	578.1	573.6
Wellhead	Pressure, PSIA	360	358
	Temperature, °F	434	434
	Quality, (Vapor Mass Fraction)	0.189	0.201
	Mixture Enthalpy, BTU/LBM	562.5	569.5
	Mixture Entropy, BTU/LBM-°R	.7767	.7846
	Liquid Velocity, FT/Sec	∿130	138.6

3. Comparison of Measured and Predicted Wellhead Values for Four Existing Geothermal Wells

Schroeder has suggested as test cases for evaluating wellbore system models and calculational results, four geothermal wells that have reported wellhead measurements.[6]

The methods employed to measure wellhead pressure, temperature and two-phase quality (i.e., steam vapor mass fraction), are not discussed by Schroeder. Therefore, the experimental errors associated with these measurements are not defined. In particular, the uncertainties associated with measurement of two-phase quality are expected to be large because direct measurements cannot be made and the hydrothermal wellhead product actually consists of a liquid phase containing large amounts of dissolved solids and a steam vapor phase that can contain a significant fraction of non-condensible gases. The reported wellhead pressures are probably total pressures that have not been corrected for the partial pressures of the non-condensible gases present. This can lead to significant uncertainty when calculated values of brine saturation pressure are matched with the measured wellhead values.

The method used to calculate wellhead conditions consisted of incorporating the suggested model input parameters and varying only the value of the friction factor until a "match" of wellhead pressure and temperature was produced for the maximum flowrate case. The wellhead conditions for lower flow rates were then calculated and compared to the reported values. Table 5 lists the input values used for calculating the four wells and Table 6 compares the wellhead predictions to the reported values for the highest flow rate case.

TABLE 5

MODEL INPUT DATA FOR FOUR GEOTHERMAL WELLS

	Tres	Pres	PPR	Depth	Dia	WFS	WF	FM	DD	VR	HTC	BETW
	of	PSIA		Ft	Ft	Percent	LBM/Sec		PSI/LBM/SEC		BTU/HR-FT^2-°F	
State No. 1	581.	1958	1.	4600.	.564	25.	112.5	.033	1.28	1.	0	0
11D No. 1	617.	2162.	1.	5000.	.564	25.	147.8	.0263	1.6	1.	0	0
11D No. 2	590.	1581.	1.	3600.	.564	25.	122.2	.0263	6.15	1.	0	0
Sportsman No. 1	572.	1741.	1.	4000.	.408	25.	90.8	.0115	1.6	1.	0	0

TABLE 6

Comparison of Calculated and Measured Wellhead Values
for the Highest Reported Flow Rates

Well Name	Measured Values			WELLFLOW Calculations		
	Press., PSIA	Temp., °F	Quality	Press., PSIA	Temp., °F	Quality
State No. 1	362	450	.200	362	458	.116
IID No. 1	200	405	.200	206	404	.193
IID No. 2	240	418	.180	Not Calculated		
Sportsman No. 1	262	428	.150	268	428	.132

Discussion

The drawdown constant specified (6.15 Psi/Lbm-Sec^{-1}) for the IID No. 2 well would produce a bottom hole flowing pressure that is less than the brine saturation pressure ($\sim$1136 psia) corresponding to the reservoir temperature for any of the flow rates listed. This condition produces flashing within the aquifer and Wellflow cannot calculate this case.

Excellent agreement is shown between measured and calculated values of the wellhead pressure and temperature for the remaining three wells. A large difference is shown in the values for wellhead quality, varying by about 5% for IID No. 1, about 13% for Sportsman No. 1 and about 40% for State No. 1. However, as discussed above, the largest uncertainty is associated with the measurement of two-phase quality and without additional information, the lack of agreement cannot be satisfactorily resolved.

The variation in wellhead parameters for different mass flowrates is shown in Figure 1 for State No. 1, Figure 2 for IID No. 1 and Figure 3 for Sportsman No. 1. The reported wellhead measurements are also shown for comparison.

State No. 1

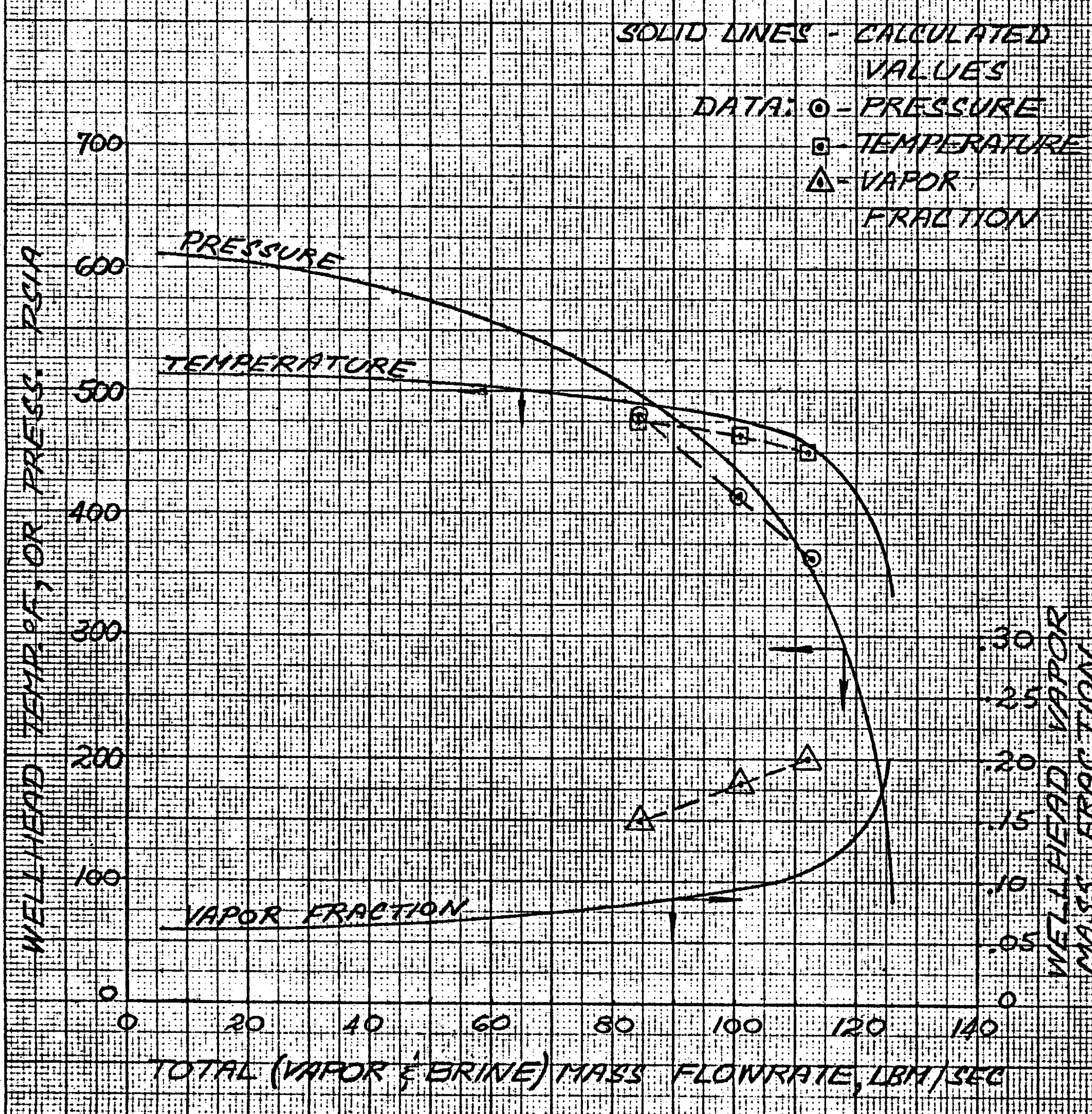
The measured and calculated values for wellhead pressure and temperature are in excellent agreement over the range of reported flowrates. A large discrepancy between measured and calculated wellhead "quality" (vapor mass fraction) is apparent, however, over the same range.

IID No. 1

Calculated wellhead pressures and temperatures deviate from the measured values below the maximum flowrate case that was used to match the wellhead parameters. From a flowrate of about 48 to 139 pounds per second, there is a constant error between calculated and measured values of about 20 percent for pressures and about 6 percent for temperatures, respectively. This type of a discrepancy would occur if the well fluid actually contained a significant concentration of non-condensible gases.

FIGURE 1

COMPARISON OF CALCULATED AND MEASURED WELLHEAD PARAMETERS FOR DIFFERENT MASS FLOWRATES FOR STATE NO. 1 WELL



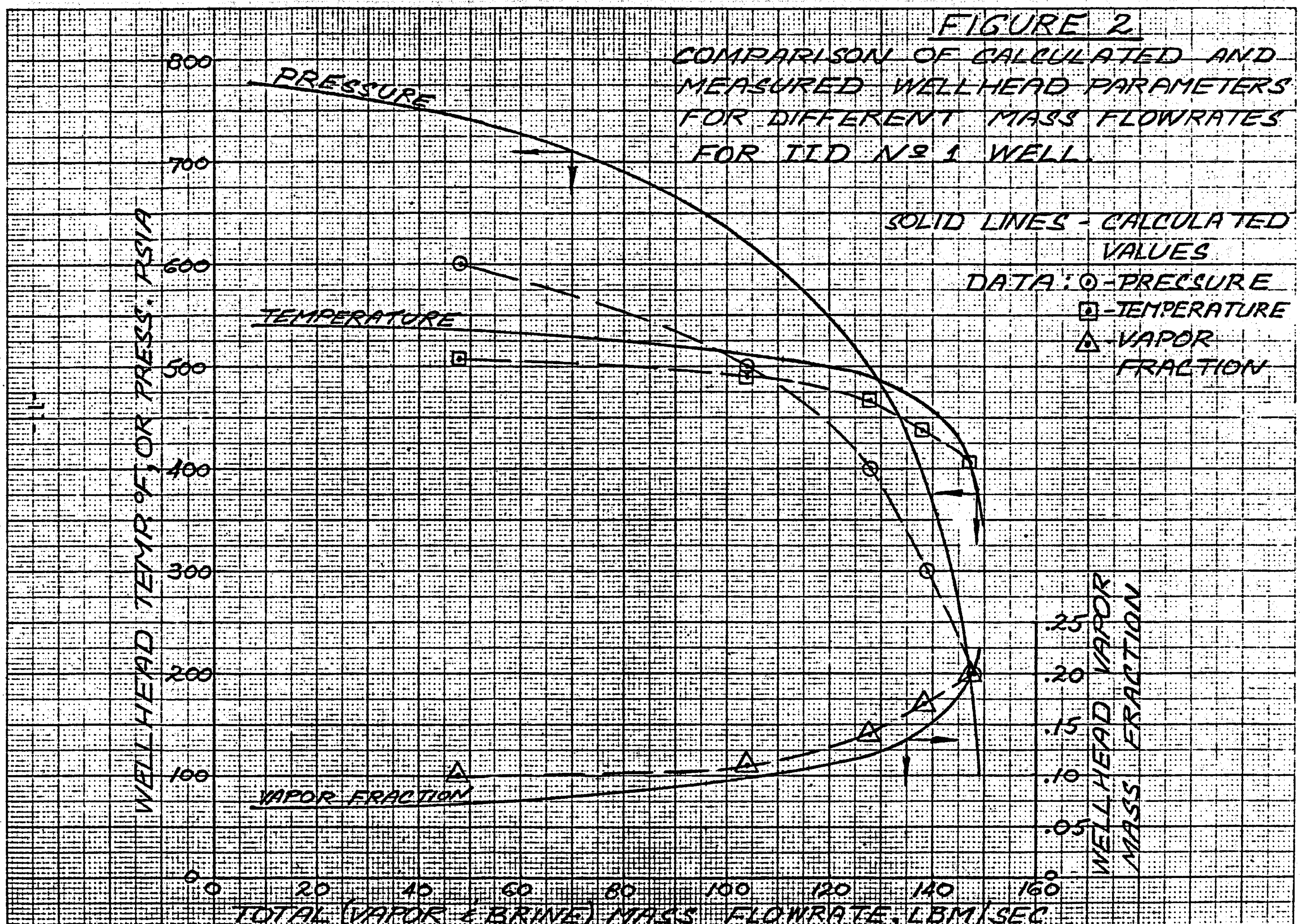


FIGURE 2
COMPARISON OF CALCULATED AND
MEASURED WELLHEAD PARAMETERS
FOR DIFFERENT MASS FLOWRATES
FOR IID Nº 1 WELL.
SOLID LINES - CALCULATED
VALUES
DATA: ⊙-PRESSURE
⊡-TEMPERATURE
△-VAPOR
FRACTION
PRESSURE
TEMPERATURE
VAPOR FRACTION
WELLHEAD TEMP °F, OR PRESS, PSIA
800
700
600
500
400
300
200
100
0
WELLHEAD VAPOR
MASS FRACTION
.25
.20
.15
.10
.05
0
0
20
40
60
80
100
120
140
160
TOTAL (VAPOR & BRINE) MASS FLOWRATE, LBM/SEC

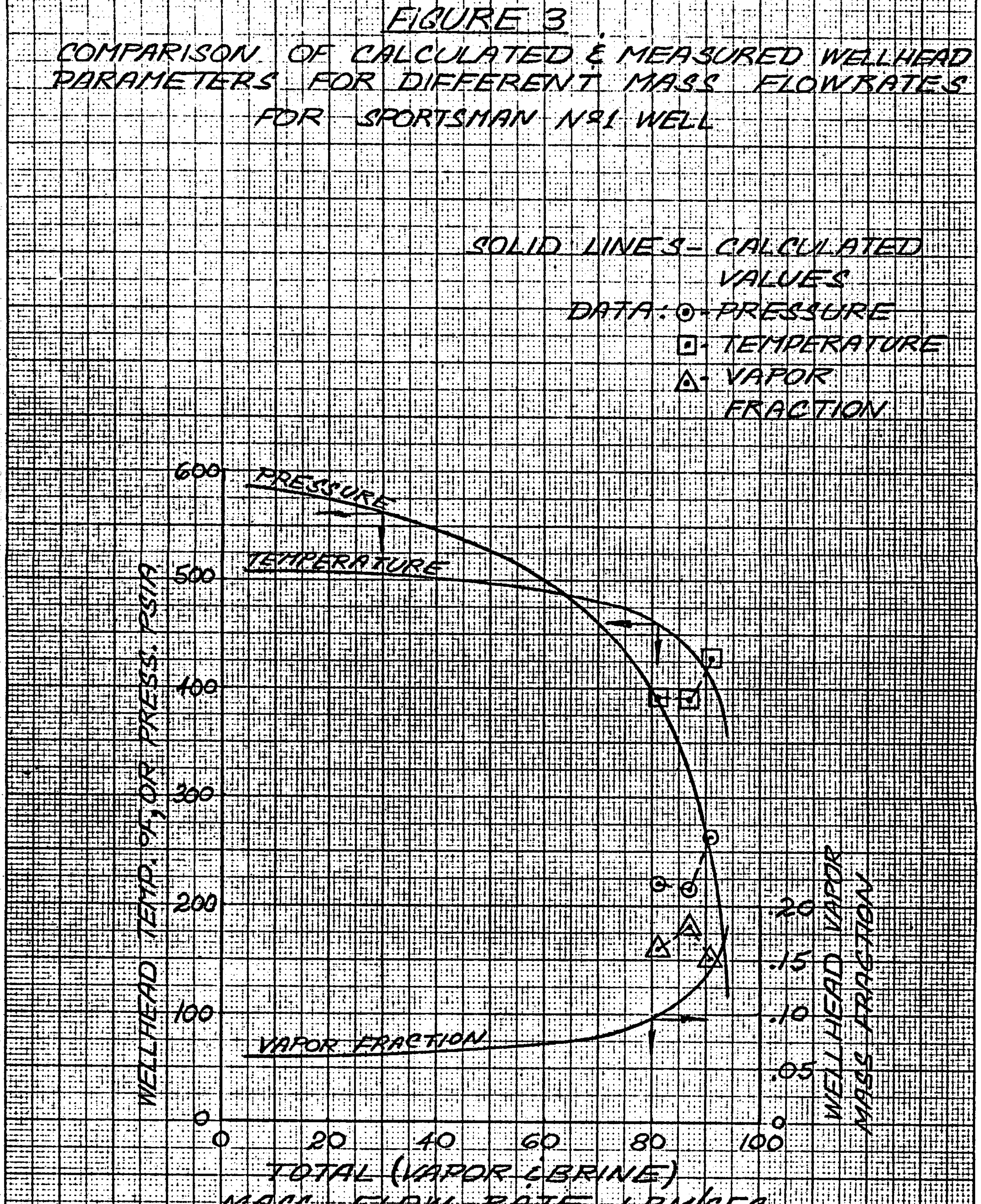


FIGURE 3
COMPARISON OF CALCULATED & MEASURED WELLHEAD PARAMETERS FOR DIFFERENT MASS FLOWRATES FOR SPORTSMAN Nº1 WELL
SOLID LINES - CALCULATED VALUES
DATA: ⊙ - PRESSURE
▣ - TEMPERATURE
△ - VAPOR FRACTION
PRESSURE
TEMPERATURE
VAPOR FRACTION
600
500
400
300
200
100
0
.20
.15
.10
.05
0
0
20
40
60
80
100
WELLHEAD TEMP. °F, OR PRESS. PSIA
WELLHEAD VAPOR MASS FRACTION
TOTAL (VAPOR & BRINE) MASS FLOW RATE, LBM/SEC

If we assume, for simplicity, that the non-condensibles are pure carbon dioxide, then the partial pressure is proportional to the mole fraction of carbon dioxide present and is a constant percentage of the total wellhead pressure if all the dissolved gas were out of solution at this pressure. In addition, a reduced brine vapor partial pressure will result in calculated wellhead temperatures that are lower than shown in Figure 2.

The magnitude of the error is probably too large to be attributable solely to the presence of these gases, however. Another factor that might help explain the discrepancy is that the reported salt content varied from about 26 to 35 percent while 25 percent was used in the calculation. A higher salt content would result in lower predicted wellhead pressures and temperatures.

Sportsman No. 1

The reported wellhead values do not seem to reflect a reliable set of data. The variation in the measured values are probably a reflection of experimental error rather than an indication of trends.

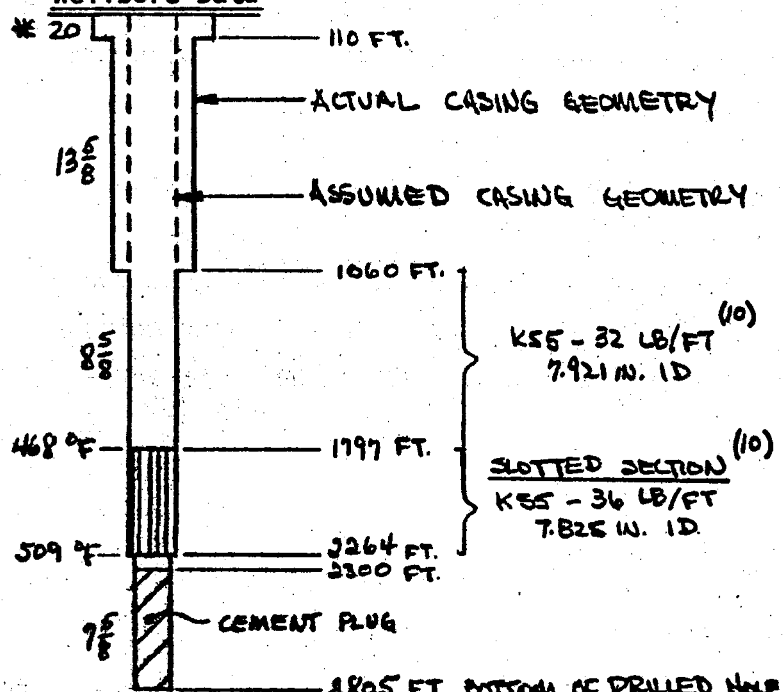
4. Comparison of Measured and Predicted Values for Magmamax No. 1 Geothermal Well[7][8]

Wellbore data, WELLFLOW input parameters, and calculated results are shown in Figure 4. Reported wellhead temperature of about 428°F and pressure of about 300 psia compare very well with the calculated results.[9] Wellhead quality is predicted to be about 8 percent rather than the 10 percent currently estimated.[9] Figure 5 shows the calculated variation in well conditions as a function of wellbore elevation for the input values discussed above. An interesting point to note is that the self-pumping mode of operating this well results in very nearly an isenthalpic process between the wellbottom and wellhead.

FIGURE 4

Magmamax No. 1 Wellbore Data and WELLFLOW Results

Wellbore Data



*Numbers are nominal casing diameters in inches.

WELLFLOW Input Values

Tres = 509. °F
Pres = 0.
PPR = 0.
Depth = 2300 Ft.
Dia. = 0.656 Ft.
WFS = 20 Percent (11)
WF = 111. LB/Sec
FM = .036
DD = 1.6 PSI/LBM-Sec^{-1}
VR = 1.
HTC = 0. BTU/HR-FT^{2}-°F

Calculated Wellhead Conditions

Temp., °F	433.2
Press, PSIA	301.2
"Quality"	.077
Mixture Enthalpy, BTU/LBM	411.5
Mixture Entropy, BTU/LBM-°R	.6224
Vapor Flowrate, LBM/Sec	8.6
Brine Flowrate, LBM/Sec	102.4
Brine Velocity, Ft/Sec	51.4

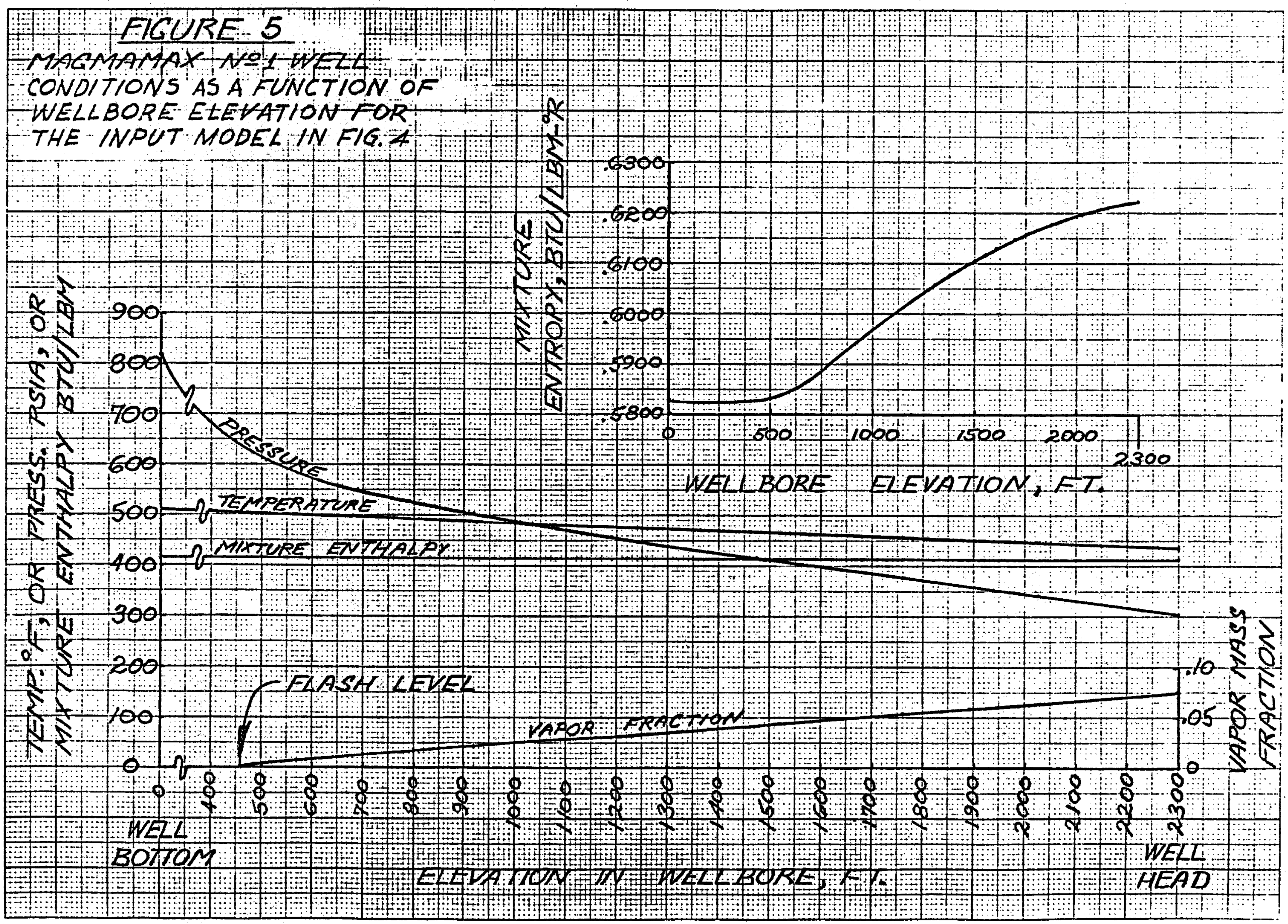


FIGURE 5

~~MAGMAMAX No 1 WELL~~
CONDITIONS AS A FUNCTION OF
WELLBORE ELEVATION FOR
THE INPUT MODEL IN FIG. 4

Summary

Elliott's computational technique for a self-flowing geothermal well of constant diameter has been modified primarily to incorporate a more accurate analytical technique for predicting brine thermophysical properties. A secondary modification allows calculation of wellhead conditions for the assumed geometry if choking occurs within the wellbore. This is accomplished by reducing the mass flow rate just enough to move the attainment of sonic liquid velocity up to the wellhead. The resulting computer program named WELLFLOW appears to reasonably model the geothermal wellbore system. Predicted wellhead flow conditions are in good agreement with measured values of pressure and temperature based on the comparisons that have been made here. Unfortunately, the large uncertainty associated with measurements of two-phase "quality" makes comparison with predicted values of vapor mass friction very difficult at the present time.

Recommendations for Future Work

There are certain modifications to the computer program that are worthwhile incorporating.

A more refined interpolating scheme should be included to calculate brine properties at any salt content between 5 and 25 weight percent. Consideration should also be given to extrapolating the analytical technique to 30 or 35 weight percent salt content.

The graphical output should be expanded to plot additional wellhead variables as a function of mass flow rate and flow conditions as a function of wellbore elevation.

Correction to the brine property estimates for salt concentration changes as a result of flashing in the wellbore should also be included.

Experiments will be conducted later this year at the LLL Geothermal Test Station at Niland, California, using the Magmamax No. 1 well with the wellhead product separated into its brine and vapor phases. These tests will provide data that can be compared directly to the values predicted by WELLFLOW. This comparison should be made to further verify or normalize the computer program.

Acknowledgements

I would like to gratefully acknowledge the contribution to this effort made by J. Swanson of the Laboratory's Computation Division. His knowledge and capabilities allowed incorporation of several library routines into WELLFLOW in a timely and expenditious manner and he managed to decrease computer running time by internally rearranging the program.

References

1. Elliott, D. G., Comparison of Brine Production Methods and Conversion Processes for Geothermal Electric Power Generation, EQL Report No. 10 Environmental Quality Laboratory, California Institute of Technology, Pasadena, California, July 1975.

2. Dittman, G. L., Calculation of Brine Properties, UCID-17406, February 1977, Lawrence Livermore Laboratory, Livermore, California.

3. McClintock, R. B. and Silvestri, G. J., Calculation of Properties of Steam, American Society of Mechanical Engineers, 1968.

4. Johnson, P., Model to Calculate Flow and Energy from Geothermal Wells, Lawrence Livermore Laboratory Internal Engineering Note ENE 74-9, April 5, 1974.

5. Austin, A. L., Higgins, G. H., Howard, J. H., The Total Flow Concept for Recovery of Energy from Geothermal Hot Brine Deposits, UCRL-51366, April 1973, Lawrence Livermore Laboratory, Livermore, California.

6. Schroeder, R. C., Geothermal Wellbore Test Problems, Lawrence Livermore Laboratory Internal Memorandum GG76-10, March 4, 1976.

7. Palmer, T. D., Characteristics of Geothermal Wells Located in the Salton Sea Geothermal Field, Imperial County, California, UCRL-51976, December 1976, Lawrence Livermore Laboratory, Livermore, California.

8. Schroeder, R. C., Reservoir Engineering Report for the Magma-SDG&E Geothermal Experimental Site Near the Salton Sea, California, UCRL-52094, July 1976, Lawrence Livermore Laboratory, Livermore California.

9. Quong, R., Scaling Characteristics in the Geothermal Loop Experimental Facility at Niland, California, UCRL-52162, November 1976, Lawrence Livermore Laboratory, Livermore, California.

10. Towse, D. F., private communication.

11. Hill, J. and Miller, D., Possible Deposition of Salt From Expanded Magmamax No. 1 Brines, Lawrence Livermore Laboratory Internal Memorandum, February 25, 1977.

APPENDICES

APPENDIX A

A. Nomenclature & Units

AG, vapor flow area, ft^2

AL, liquid flow area, ft^2

AP, casing flow area, ft^2

AVM, average velocity of mixture over the DY interval, ft/sec

AVT, average fluid temperature over the interval Y or DY, °F

DD, drawdown pressure factor, psia/lbm per sec

DEPTH, depth of well, ft

DIA, casing inside diameter, ft

DKE, change in fluid kinetic energy per unit mass of mixture, BTU/lbm

DMOM, change in fluid momentum, lbf

DQ, heat transferred out of the wellbore per unit mass of fluid, BTU/lbm

DY, interval of vertical elevation between T and T-1 in the two-phase flow region, ft

FM, Moody friction factor, dimensionless

g, acceleration of gravity, 32.17 ft/sec^2

gc, conversion constant, 32.17 $\frac{lbm\text{-}ft}{lbf\text{-}sec^2}$

HFP, enthalpy of the liquid at the flash point, BTU/lbm

HGB(T), saturated vapor enthalpy at T, BTU/lbm

HB(T), saturated liquid enthalpy at T, BTU/lbm

HM1, mixture enthalpy at T, BTU/lbm

HM2, mixture enthalpy at T-1, BTU/lbm

HTC, overall heat transfer coefficient, $BTU/hr\text{-}ft^2\text{-}°F$

HWB, liquid enthalpy at the well bottom, BTU/lbm

HYDP, hydrostatic pressure, psia

J, mechanical equivalent of heat, 778.16 ft-lbf/BTU

PRES, reservoir pressure, lbf/in^2 absolute (psia)

PSATB(T), saturated liquid pressure at T, psia

PWB, fluid pressure at the bottom of the wellbore, psia

$\dot{Q}$, rate of heat added to fluid, BTU/sec

RHOB(T), saturated liquid density at T, lbm/ft^3

RHOGB(T), saturated vapor density at T, lbm/ft^3

RHOM, mixture density, lbm/ft^3

RHOMM, average mixture density over the interval DY, lbm/ft^3

SB(T), saturated liquid entropy at T, BTU/lbm-°R

SGB(T), saturated vapor entropy at T, BTU/lbm-°R

SM, entropy of the mixture at start of DY interval, BTU/lbm-°R

T, fluid temperature, °F

Te, temperature of the earth, °F

TRES, reservoir temperature, °F

TSINK, average temperature of earth over the interval Y or DY, °F

TWB, fluid temperature at well bottom, °F

VG, velocity of the vapor phase, ft/sec

VL, velocity of the liquid phase, ft/sec

VLFP, velocity of the liquid at flash point, ft/sec

VLWB, velocity of the liquid at well bottom, ft/sec

VM, equivalent mixture velocity, ft/sec

VR, gas/liquid velocity ratio

WF, total fluid mass flow rate, lbm/sec

WFS, weight fraction of salt dissolved in the brine, percent

WG, vapor mass flow rate, lbm/sec

WL, liquid mass flow rate, lbm/sec

$\dot{W}s$, shaft work done by fluid, ft-lbf/sec

X2, fraction of fluid mass that is vapor at T-1

Y, vertical elevation in wellbore above wellbottom or interval between wellbottom and flash point, ft

YWB, elevation of the wellbottom, ft

YFP, elevation to the flash point, ft

Subscripts

1, statepoint 1 in the two-phase flow region at temperature T

2, statepoint 2 in the two phase flow region at temperature T-1

B. Assumptions

1. The flow is steady.
2. There is no gain or loss in flow rate between the well bottom and wellhead.
3. The liquid is incompressible.
4. In the two-phase region the phases are in equilibrium and the vapor phase does not contain dissolved gases.
5. The phases are homogeneously mixed.
6. The velocity of each phase is constant across the well pipe.
7. The ratio of gas velocity to liquid velocity is constant.
8. The temperature outside the well varies linearly from 70°F at ground level to the reservoir temperature at the bottom.
9. Heat transferred to the earth from the fluid within the wellbore is given by the product of overall heat transfer coeeficient x temperature difference x heat transfer area.
10. Brine salt concentration is constant between well bottom and wellhead.

C. Analysis

The following analysis and the assumptions listed above are essentially the same as reported in Reference 1 except for the modifications explained previously. (This section is included for clarity because there have been nomenclature changes and for the sake of completeness.) Figure A1 is a sketch of the wellbore system.

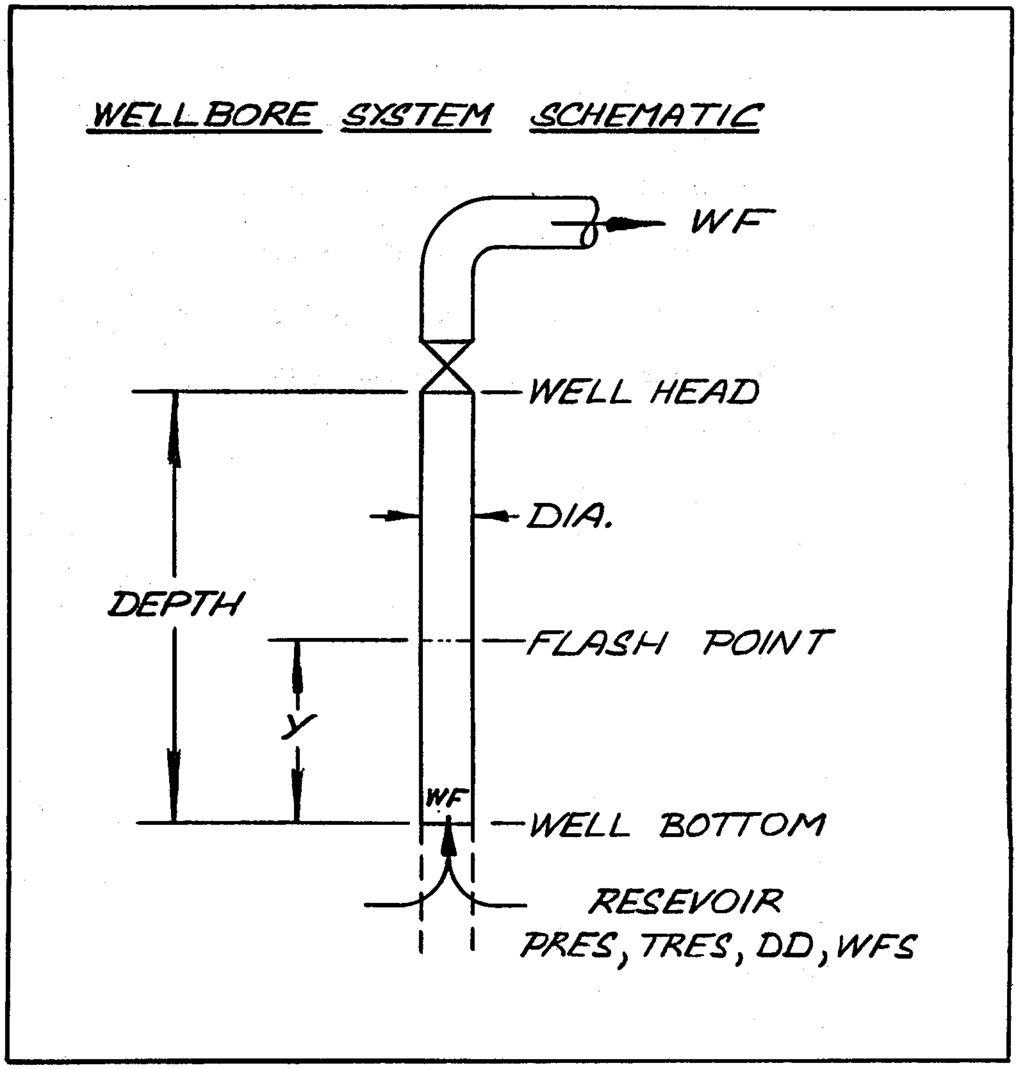

WELLBORE SYSTEM SCHEMATIC
WF
WELL HEAD
DIA.
DEPTH
FLASH POINT
Y
WF
WELL BOTTOM
RESEVOIR
PRES, TRES, DD, WFS

FIGURE A1

Wellbottom

At the wellbottom, the fluid temperature is equal to the reservoir temperature, TWB = TRES, and the wellbottom pressure is determined from the expression, PWB = PRES-DO(WF), where PRES is either specified or calculated from HYDP = 0.433 x DEPTH. The casing cross-sectional flow area is, AP = $\frac{\pi}{4}$ (DIA)^2 and RHOB, PSATB, SWB, HWB at PWB and TRES are determined from the ASME equation of state for pure water [4] or from Reference 2 for brine. Interpolation for brine properties at salt contents different than the specific percentage listed in the reference, is not used in the present version of WELLFLOW. Instead, the following percentages are applied for the indicated range of the WFS parameter.

$5 \leq$ WFS < 7, brine constants for 5 weight percent are used,
$7 \leq$ WFS < 12, brine constants for 10 weight percent are used,
$12 \leq$ WFS < 17, brine constants for 15 weight percent are used,
$17 \leq$ WFS < 22, brine constants for 20 weight percent are used,
$22 \leq$ WFS < 27, brine constants for 25 weight percent are used.

The velocity of the fluid entering the wellbore is determined from the continuity equation, VLWB = WF/AP(RHOB)

Flash Level

At the flash level, Y feet above wellbottom, the pressure will be the saturation pressure at some temperature T. A free body diagram of the liquid column between the wellbottom and flash point is sketched in Figure A2. The sum of the forces in the vertical direction is set equal to zero in this case since constant velocity is assumed. Therefore,

FB-FT-FF-WT=0
FB = pressure force at bottom = 144 PWB (AP)
FT = pressure force at top = 144 (AP) PSATB (T)
WT = weight of fluid column = AP (Y) RHOP (T) $\frac{g}{g_c}$

FF = friction force = AP (DPF) where
DPF is determined from the Darcy - Weisbach equation for the frictional pressure loss,

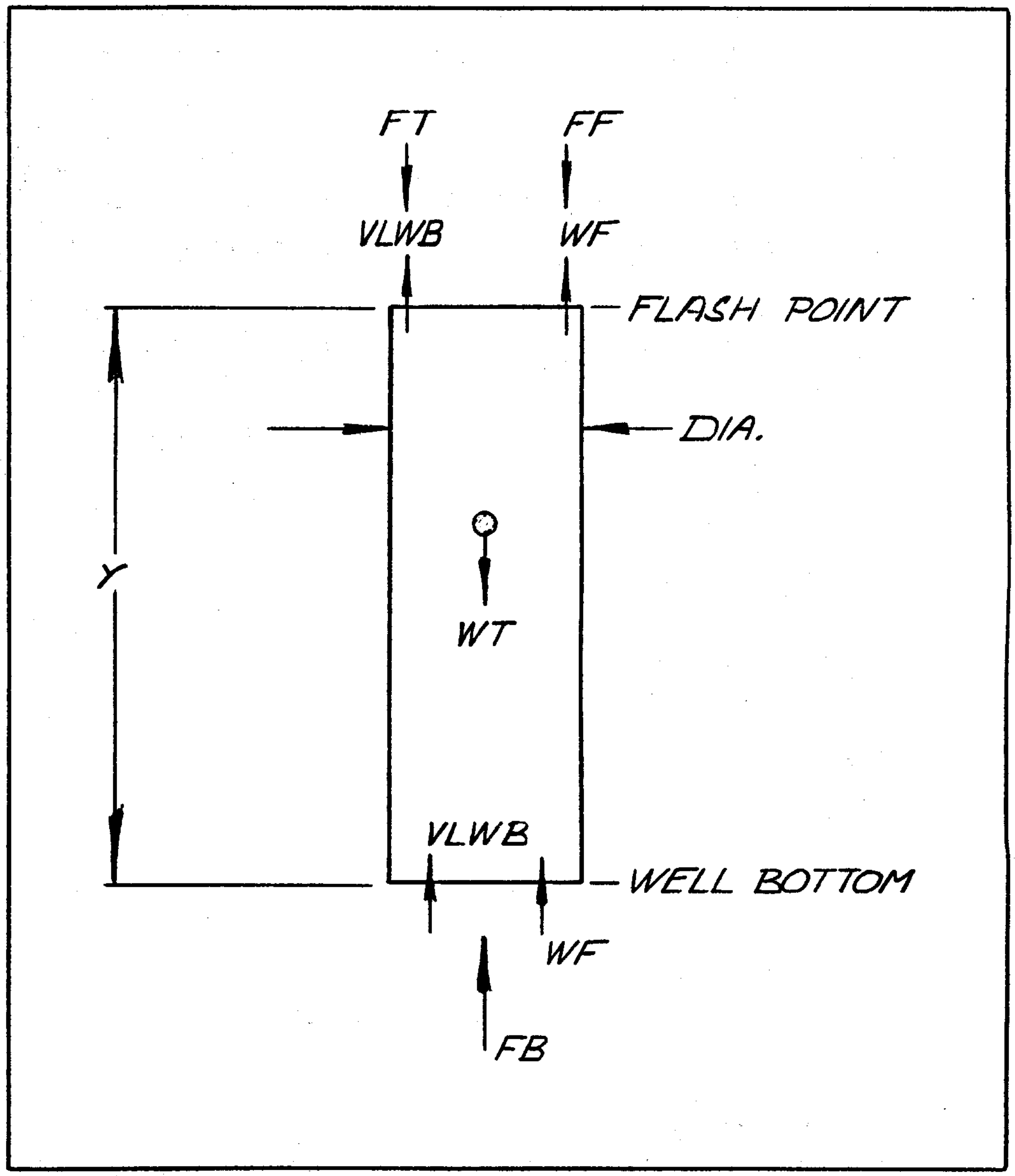


FIGURE A2

$$DPF = RHOB\ (FM)\ (\frac{Y}{DIA})(\frac{VLWB^2}{2g_c}), \text{ and}$$

$$FF = AP\ (RHOB)\ (FM)\ (\frac{Y}{DIA})\ (\frac{VLWB^2}{2g_c})$$

Substituting and simplifying gives,

$$Y = \frac{144\ [PWB-PSATB(T)]}{RHOB(T)[1+ \frac{FM}{DIA} \quad \frac{(VLWB)^2}{2gc}\ ]} \tag{1}$$

The general energy equation written between wellbottom and flash point is,

$$WF\ (HWB + \frac{g}{gc} \quad \frac{YWB}{J} \quad + \frac{VLWB^2}{2g_cJ}) + \dot{Q} = WF\ (HFP + \frac{g}{gc} \quad \frac{YFP}{J} \quad + \frac{VLFP^2}{2gcJ}) + \frac{\dot{W}_s}{J}$$

The velocity difference is neglected, no work is done by the fluid and heat is lost from the wellbore to the earth. Therefore,

$$HFP = HWB - \frac{\dot{Q}}{WF} - \frac{g}{gc} \quad \frac{Y}{J} \tag{2}$$

$$\frac{\dot{Q}}{WF} = DQ = \frac{HTC\ [\pi DIA(Y)]}{WF(3600)}\ (AVT-TSINK) \tag{3}$$

$$AVT = \frac{(TRES+T)}{2}$$

Figure A3 depicts the assumed linear increase of ground temperature from the surface (70°F) to the well bottom (TRES). The ground temperature at any elevation above wellbottom is then,

$Te = TRES - \frac{Y}{DEPTH}\ (TRES-70)$ and the average ground temperature over the Y interval is

$$TSINK = TRES - \frac{Y}{2(DEPTH)}\ (TRES-70)$$

Therefore,

$$HFP = HWB - DQ - \frac{g}{g_c} \quad \frac{Y}{J} \tag{4}$$

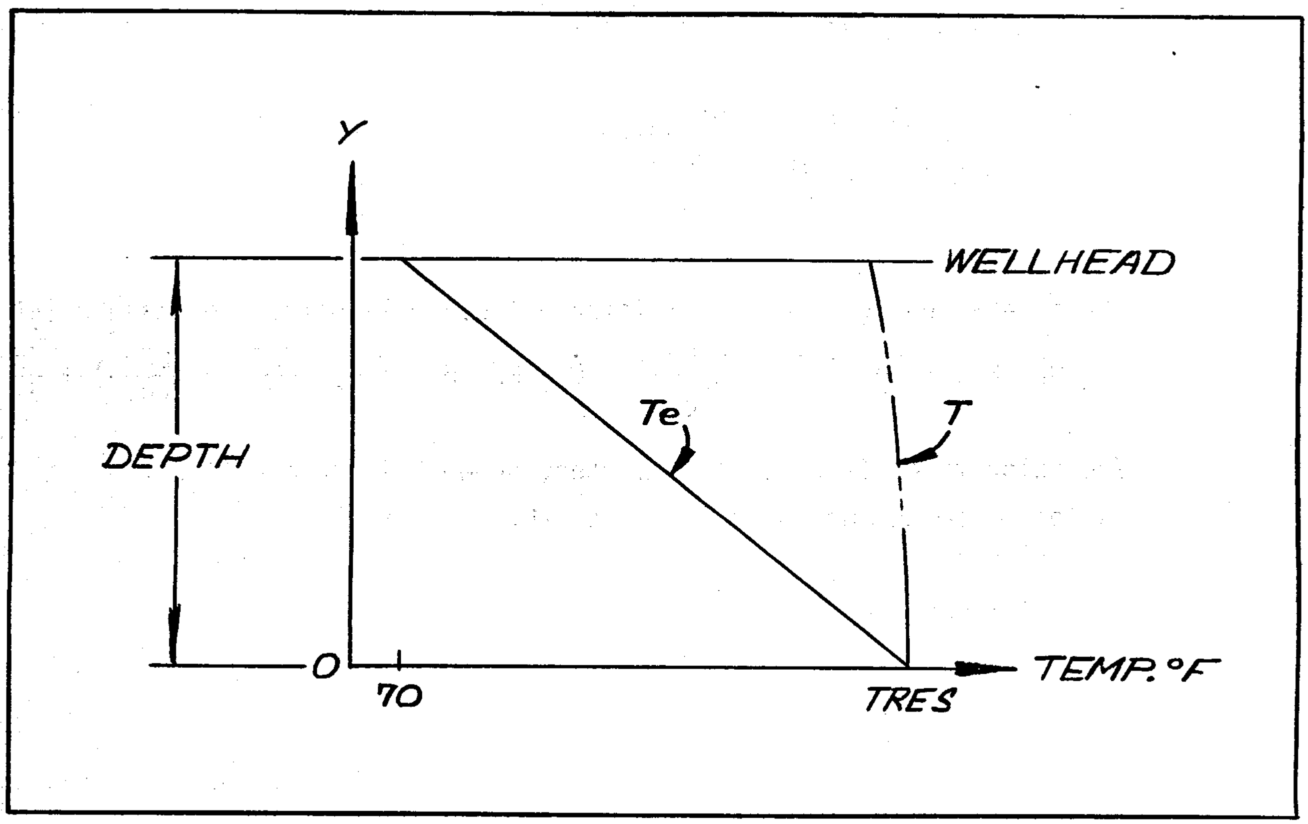


FIGURE A3

The temperature T is decreased in one degree steps from TRES and equations 1 and 4 are solved until the calculated liquid enthalpy, HFP, equals the enthalpy of the saturated liquid corresponding to the temperature T, HB(T). If the value of Y needed to satisfy this conditions exceeds the well-depth, wellhead parameters are determined by interpolation without the occurrence of flashing.

WELLHEAD

Above the flash point, the flow is two phase. One degree increments of temperature and corresponding small increments of height, DY, are used so that average values of varying properties can be included in the calculational procedure starting from the flash point. Figure A4 shows an element of the fluid mixture of height DY whose lower statepoint, 1, is at temperature T and whose upper statepoint, 2, is at temperature (T-1). Thermodynamic and physical properties for the vapor and liquid phases, the vapor fraction and height above wellbottom at 1 are known from the previous calculation performed at the flash level or at temperature (T+1). An isentropic expansion of the mixture from T to (T-1) is assumed initially to obtain a new value for the vapor fraction given by

$$X2 = \frac{SM - SB2}{SGB2 - SB2} \tag{5}$$

From continuity,

$$WG2 = X2\ (WF)$$

$$WL2 = WF-WG2$$

The vapor velocity is

$$VG = VR\ (VL),\ \text{and}$$

$$AL2 = WL2/RHOB2\ (VL2)$$

$$AG2 = WG2/RHOGB2(VG2) = WG2/RHOGB2\ (VR)\ VL2$$

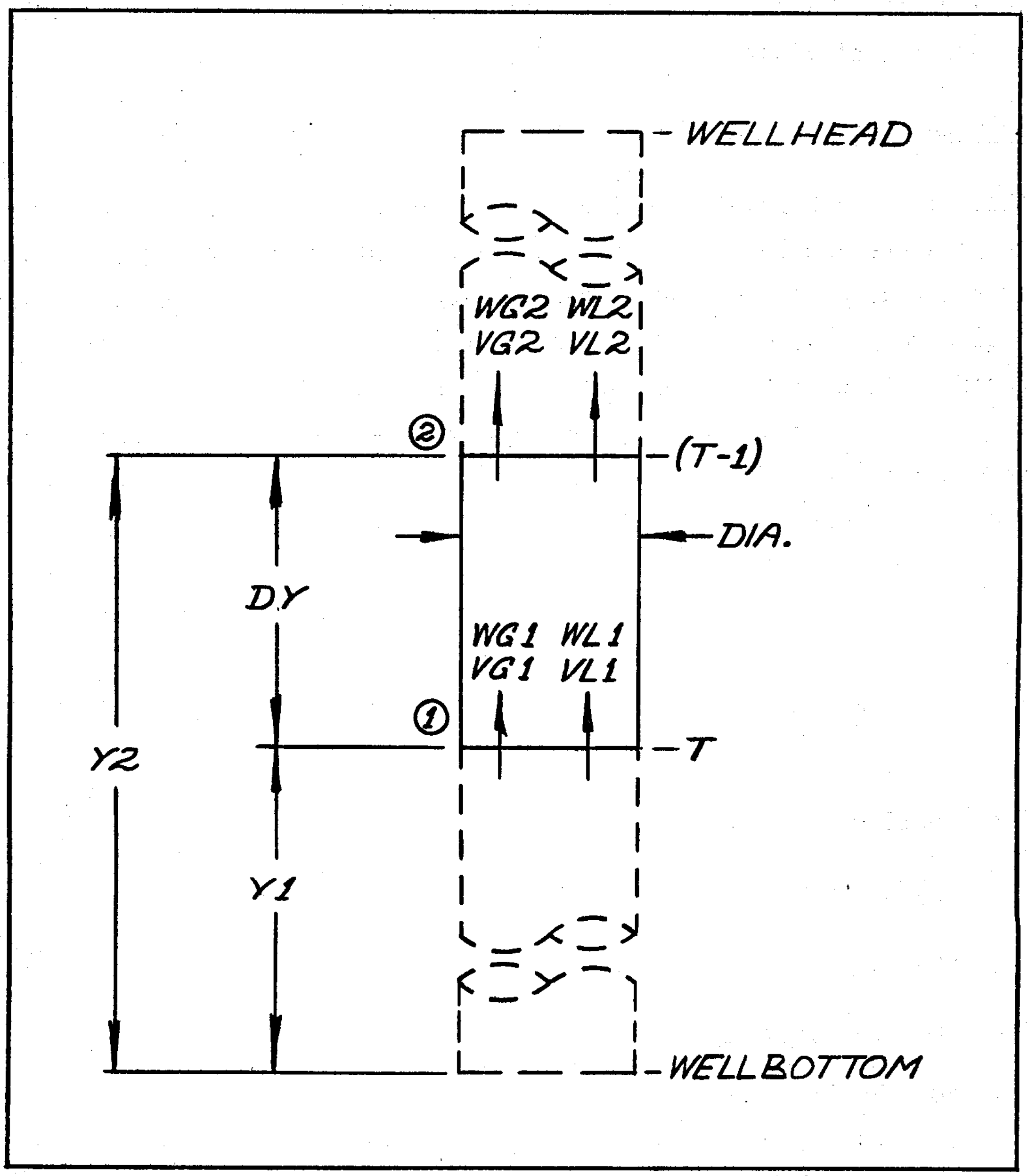

WELLHEAD
WG2 WL2
VG2 VL2
②
(T-1)
DIA.
DY
WG1 WL1
VG1 VL1
①
T
Y2
Y1
WELLBOTTOM

FIGURE A4

The sum of these two areas must equal the casing cross-sectional area.

$$AP = AL2 + AG2$$

$$AP = \frac{WL2}{RHOB2\ (VL2)} + \frac{WG2}{RHOGB2\ (VR)\ (VL2)}$$, which simplifies to

$$VL2 = \frac{1}{AP}\left[\frac{WL2}{RHOB\ 2} + \frac{WG2}{RHOGB\ 2\ \ (VR)}\right] \tag{6}$$

The mass of liquid in unit height of pipe equals $\frac{WL}{VL}$

The mass of gas in unit height of pipe equals $\frac{WG}{VG}$

and the total mass of fluid in unit height of pipe is the sum of these two quantities.

$$RHOM\ (AP) = \frac{WL}{VL} + \frac{WG}{VR\ (VL)}$$

Finally,

$$RHOM = \frac{1}{AP}\left[\frac{WL}{VL} + \frac{WG}{VR\ (VL)}\right] \tag{7}$$

The average mixture density over the DY interval is

$$RHOMM = \frac{1}{2}\ (RHOM1 + RHOM2) \tag{8}$$

Expressing the mass flow in terms of equivalent mixture properties,

$$WF = RHOM1\ (AP)\ VM1 = RHOM2\ (AP)\ VM2$$

$$VM2 = \frac{WF}{\left[\frac{WL2}{VL2} + \frac{WG2}{VR\ (VL2)}\right]}$$

which can be simplified to

$$VM2 = VR\ (VL2)\left[\frac{WF}{WF + WL2\ (VR-1)}\right] \tag{9}$$

Average mixture velocity over the DY interval is

$$AVM = \frac{1}{2}\ (VM1 + VM2) \tag{10}$$

Conservation of momentum requires that the sum of the forces in the vertical direction equal the change in fluid momentum. The momentum of the mixture at 1 is

$$\frac{1}{g_c}\ [WL1\ (VL1) + WG1\ (VR)\ (VL1)]$$

The momentum of the mixture at 2 is $\frac{1}{g_c}$ [WL2 (VL2) + WG2 (VL2)VR].

The change in fluid momentum from 1 to 2 is

$$DMOM = \frac{1}{g_c}\ [WL2\ (VL2) + WG2\ (VR)\ (VL2)]-[WL1\ (VL1) + WG1\ (VR)\ (VL1)].$$

Setting the sum of the forces equal to DMOM,

F1-F2-FF-WT = DMOM, where

F1 = pressure force at 1 = 144 (AP) PSATB1

F2 = pressure force at 2 = 144 (AP) PSATB2

WT = weight of fluid column = $\frac{g}{g_c}$ [RHOMM (AP) DY]

FF = friction force = AP (DPF) where

DPF = frictional pressure loss given by the Darcy-Weisbach formula for the mixture

DPF = FM $\left(\frac{DY}{DIA}\right)$ $\left(\frac{AVM^2}{2\ g_c}\right)$ RHOMM, where FM is an equivalent Moody friction factor numerically equal to the value used in the liquid flow region.

$$FF = AP\ (FM)\ (\frac{DY}{DIA})\ (\frac{AVM^2}{2\ g_c})\ RHOMM$$

Substituting and simplifying yields,

$$DY = \frac{-144\ AP\ (PSATB2-PSATB1) - DMOM}{AP\ (RHOMM)\ [1 + \frac{FM}{DIA}\ \frac{(AVM)^2}{2\ g_c}\ ]} \tag{11}$$

The general energy equation for this case is,

$$WF\ (HM1 + \frac{Y1}{J}\ \frac{g}{g_c} + \frac{(VM1)^2}{2g_cJ}) + \dot{Q} = WF\ (HM2 + \frac{Y2}{J}\ \frac{g}{g_c} + \frac{(VM2)^2}{2g_cJ}) + \frac{\dot{W}s}{J}$$

As before, the shaft work is zero and heat is lost from the fluid.

$$WF\ [(HM1 - HM2) + \frac{g}{g_cJ}\ (Y1 - Y2) + \frac{1}{2g_cJ}\ (VM1^2 - VM2^2)] - \dot{Q} = 0$$

simplifying,

$$(HM2 - HM1) = -\frac{g}{g_cJ}\ (DY) - \frac{1}{2g_cJ}\ (VM2^2 - VM1^2) - \frac{\dot{Q}}{WF} \tag{12}$$

Heat transfer out of well per unit mass of fluid is,

$$\frac{\dot{Q}}{WF} \equiv DQ = \frac{HTC\ (\pi)\ DIA\ (DY)}{WF\ (3600)}\ (AVT - TSINK) \quad \text{where in this} \tag{13}$$

region $AVT = (T - 0.5)$

$$TSINK = TRES - \frac{Y1 + \frac{DY}{2}}{DEPTH}\ (TRES - 70)$$

The kinetic energy per unit mass of mixture at 1 is

$$\frac{WL1\ (VL1)^2 + WG1\ [VR\ (VL1)]^2}{2g_cJ\ (WF)}$$

The kinetic energy per unit mass of mixture at 2 is

$$\frac{WL2\ (VL2)^2 + WG2\ [VR\ (VL2)]^2}{2g_cJ\ (WF)}$$

The change in kinetic energy is

$$DKE = \frac{1}{2g_cJ\ WF} \quad (VL2)^2\ [WL2 + WG2\ (VR)^2] - (VL1)^2\ [WL1 + WG1\ (VR)^2]$$

Equation 12 can be written as,

$$HM2 = HM1 - \frac{g}{g_cJ}\ (DY) - DKE - DQ \tag{14}$$

A corrected value for the vapor fraction can now be determined from

$$X2 = \frac{HM2 - HB2}{HGB2 - HB2} \quad \text{and substituted back into equation 5.} \tag{15}$$

Equations 5 through 15 are solved until the initial and final values of the vapor fraction are equal. At this point the values of the variables at state point 2 are used as the initial values at state point 1 for the new interval, the temperature is lowered one degree and the entire calculational process is repeated. The procedure ends in one of two ways. If the cumulative value of well bore elevation exceeds the well depth, well head conditions are determined by interpolation. If the liquid achieves sonic velocity before the wellhead is reached, a new value for WF that will just result in sonic velocity at the wellhead is found and the program rerun from the reservoir condition with this value of WF.

Sonic liquid velocity is calculated by the expression

$$C = (1+RA)\left[\frac{144(PSATB2)\ g_c}{RHOB2(RA)(1+RM)}\right]^{1/2}$$

where, C = sonic liquid velocity, ft/sec

RA = ratio of gas and liquid flow areas

RM = ratio of gas and liquid mass flow rates

APPENDIX B

HOW TO USE WELLFLOW AND SAMPLE PROBLEM

Instructions

1. Need valid user number.
2. Log on to teletype.
3. Type ELF. Teletype responds with period (.).
4. Read program from storage.
5. Type END to get out of ELF after program read. Teletype responds with ... ALL DONE.
6. Type WELLFLOW to start program.
7. Teletype responds with .... Are you using ENG or SI units?
8. Type ENG for english units, SI for metric units.
9. Teletype responds with .... Please enter your data.
10. Input format: The following variable names and numerical values are to be typed sequentially in decimal format separated by a space.

Variable Name	Eng. Units	SI Units	Default Values(1)
TRES =	°F	°C	572. °F
PRES =	PSIA	Pascals	0
PPR = 0 or 1 (2)			0
DEPTH =	Feet	Meters	5,000. Ft.
DIA =	Feet	Meters	0.56 Ft.
WFS =	Percent		0
WF =	Lbm/Sec	Kg/Sec	125. Lbm/Sec
FM =			.04
DD =	Psia/Lbm Per Sec	Pa/Kg Per Sec	1.6 Psia/Lbm Per Sec
VR =			1.0
HTC =	BTU/Hr-Ft^2-°F	Watts/M^2-°C	0
BETW = 0 or 1 (3)			0

Graphics Input Data [4]

WN Points =[5]	20
FPLOTS (1) =	0
FPLOTS (2) =	.005
FPLOTS (3) =	.02
FPLOTS (4) =	.03
FPLOTS (5) =	.04
FPLOTS (6) =	.05
FPLOTS (7) =	.06
FPLOTS (8) =	.10
NPLOTS =	8

Notes

(1) Default values will be used if variable name and numerical value is not supplied first time through program. Current calculation will use values from preceeding calculation if new input not specified.

(2) PPR = 1., if PRES is specified, PPR= 0. if PRES is not specified.

(3) BETW = 1., if calculated output is desired for each temperature increment in the two-phase flow region in the wellbore between the flash point and wellhead.

(4) A reduced graphics output can be obtained by specifying the friction factor values to be used in FPLOTS ( ) and the corresponding number of curves this represents by NPLOTS (which is not parenthesized).

(5) The number of points to be calculated for defining the curve of flow rate versus wellhead pressure for each value of FPLOTS ( ) specified. Fifty points is the maximum number that can be specified.

11. Type GO to start calculation.

12. Teletype responds with .... Do you want the graphics package?

13. If user types NO, program jumps to step 16. If user types YES, teletype responds with ... Monitor No.?

14. User types the 3 digit monitor number and the program proceeds to calculate mass flowrate versus wellhead pressure for the values of the variables and the friction factors specified. Teletype types the numbers 1 through 8 (if 8 curves specified) to indicate progress through the calculation. At the end of the calculation, the results are displayed on the monitor in graphical form. Teletype responds with ... Do you want the hardcopy?

15. Type NO if no print is wanted and program will proceed to next step. Type YES for print of graphs and teletype will respond with ... RJET, DD80 or BOTH? Hardcopy will be available immediately at RJET terminal 43 or in Box R69, Building 113 in 4-6 hours. After choice is made, teletype responds with ... Given, to close out graphics.

16. Teletype next responds with ... Do you want the output now?

17. If user types NO, no further calculations are performed and the program will go to the next step. If user types YES, an output file named VALUES will be filled with the calculational results corresponding to the variable input data.

18. The teletype responds to either a yes or no answer to step 16 with ... Do you wish to do another problem? The output file can be inspected at this time by bying into a new channel and typing U to enable this library program.

19. Teletype responds with ... an open cross symbol and a TV monitor display.

20. Type T followed immediately by the number corresponding to the VALUES file to observe calculated data in VALUES.

21. System responds by displaying file contents on monitor screen and types some additional information.

22. If output looks acceptable, user types END to return to previous U-program display.

23. To print output file contents on RJET, user types ... AR-RJET terminal number - VALUES file number.

24. Teletype responds with ... an open cross symbol and the print is available immediately at the designated RJET terminal with the name Box R69. User types END to close out U.

25. System responds with ... ALL DONE, and removes display from screen.

26. User byes back into original channel. Teletype responds with ... RCV + FLOW.

27. If user now types YES, (response to step 18) the program recycles to step 7.

28. If user types NO, teletype responds with ... ALL DONE.

29. User logs off machine by depressing CTRL and D keys simultaneously. Teletype responds with ... BYE.

Calculations of the Magmamax No. 1 geothermal well are used as an example problem to illustrate operation of the code.

Sample Problem - Magmamax No. #1

The user - teletype sequence for this calculation is shown in Table B1. The graphical output is shown in Figure B1 and the output file VALUES is shown in Table B2.

TABLE B1

USER - TELETYPE SEQUENCE FOR MAGMAMAX NO. 1 CALCULATION

```
WELLFLOW
ARE YOU USING 'ENG' OR 'SI' UNITS?
ENG
PLEASE ENTER YOUR DATA
TRES=509. DEPTH=2300. DIA=.656 WFS=20. WF=111. FM=.036 FPLOTS(1)=0.
FPLOTS(2)=.03 FPLOTS(3)=.04 FPLOTS(4)=.036 NPLOTS=4 GO
DO YOU WANT THE GRAPHICS PACKAGE
YES
MONITOR NO.?561
   1
   2
   3
   4
DO YOU WANT THE HARD COPY?
YES
RJET,DD80, OR BOTH
RJET
GIVEN
DO YOU WANT THE OUTPUT NOW
YES
DO YOU WISH TO DO ANOTHER PROBLEM
%B
BYE B
NIL
U
#T5
48 LINES. (120A)
CHANNEL 053
.END
#AR43 5
#END

 ALL DONE
%A
BYE A
RCV       +FLOW
NO

 ALL DONE
BYE
```

FIGURE B1

MAGMAMAX NO. 1 GRAPHICAL OUTPUT

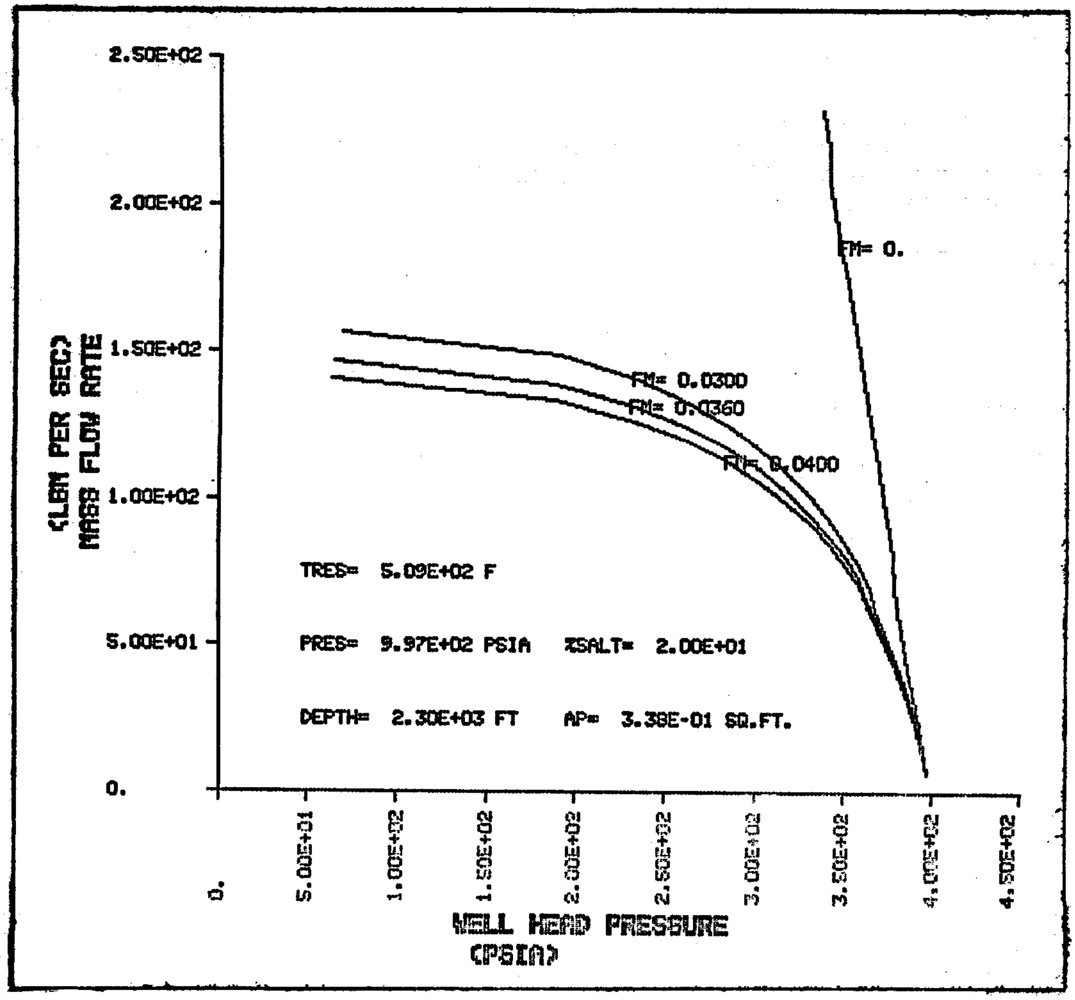


TABLE B2

MAGMAMAX NO. 1 VALUES OUTPUT FILE

```
1  CONSTANT DIAMETER WELLBORE CALCULATIONS BASED ON COMPUTATIONAL METHOD FOR SELF FLOWING GEOTHERMAL WELLS
     IN 'COMPARISON OF BRINE PRODUCTION METHODS AND CONVERSION PROCESSES FOR GEOTHERMAL
    ELECTRIC POWER GENERATION'. D. G. ELLIOT. EQL REPORT NO. 10. ENVIRONMENTAL QUALITY
    LABORATORY. CALIFORNIA INSTITUTE OF TECHNOLOGY. PASADENA. CALIFORNIA. JULY 1975.

          TIME:  09:51:48  DATE:  03/23/77

                    ****INPUT VALUES****
                         TRES   =  5.0900E+02 DEG F
                         PRES   =  0.          PSIA
                         PPR    =  0.          ONE WITH PRES INPUT    ZERO WITHOUT
                         DEPTH  =  2.3000E+03 FEET
                         DIA    =  6.5600E-01 FEET
                         WFS    =  2.0000E+01 WEIGHT PERCENT
                         WF     =  1.1100E+02 LBM PER SEC
                         FM     =  3.6000E-02 MOODY FRICTION FACTOR
                         DD     =  1.6000E+00 PSIA/LBM PER SEC. DRAWDOWN
                         VR     =  1.0000E+00 GAS/LIQ VELOCITY RATIO
                         HTC    =  0.          BTU/HR-SQ FT-DEG F
                         BETW   =  0.          1 FOR VALUES THRU 2 PHASE REGION

                    NORMAL HYDROSTATIC PRESSURE =   9.966E+02 PSIA

                    ****BRINE CONSTANTS****
                         A1  =  8.4700E-01
                         A2  = -3.2000E-02
                         A3  =  7.6210E+01
                         A4  =  3.6800E-01
                         A5  =  1.1274E+00
                         SB1 =  4.7610E-01 BTU/LBM-DEG R AT 400 F

                    ****WELL BOTTOM CONDITIONS****
  5.090E+02   6.250E+02   8.190E+02   4.144E+02   3.380E-01   5.481E+00   5.827E-01

                    ****FLASH POINT CONDITIONS****
  5.085E+02   6.222E+02   5.994E+01   4.609E+02   4.139E+02   5.479E+00   5.822E-01

                    ****INTERPOLATED WELLHEAD CONDITIONS****
                         TWH   =  4.3325E+02 DEG F
                         PWH   =  3.0124E+02 PSIA
                         XWH   =  7.7119E-02 QUALITY
                         HWH   =  4.1151E+02 BTU/LBM
                         SWH   =  6.2235E-01 BTU/LBM-DEG R
                         WGWH  =  8.5602E+00 LBM/SEC   VAPOR
                         WLWH  =  1.0244E+02 LBM/SEC   LIQ
                         VLWH  =  5.1434E+01 LIQ VELOCITY. FEET PER SEC
                         YWH   =  2.3000E+03 FT ABOVE WELLBOTTOM
```

APPENDIX C

EXAMPLES OF WELLFLOW OUTPUT

Several types of calculated outputs are possible. Examples of the formats with a description of the output data are discussed below.

1. Time when the calculation was performed in hours, minutes and seconds; date (All examples).

2. Tabulation of the input values used. (All examples).

3. Calculated hydrostatic pressure at well depth if the reservoir pressure was not specified. (See Table B2).

4. If a value had been entered for WFS, the coefficients used to calculate brine properties would now be listed followed by the calculated value of saturated brine entropy at 400°F. (See Table B2).

5. Wellbottom conditions of temperature and the corresponding saturation pressure, flowing bottom pressure, liquid enthalpy, pipe cross-sectional area in square feet or meters, liquid velocity and liquid entropy in a sequential line format. (All examples).

6. Flash point conditions of temperautre and the corresponding saturation pressure, liquid density, elevation from well bottom to flash point, saturated liquid enthalpy, liquid velocity and saturated liquid entropy in a sequential format (All examples).

7. If BETW had been set equal to one, each temperature increment from the flash level to the wellhead would produce two lines of output at this point under the title, "Traverse Well Conditions" (See example C2). The first line would consist of the current values of temperature, corresponding saturation pressure, cumulative elevation in the wellbore, elevation change as a result of the temperature increment, mixture quality and the quality at the start of the current calculation, respectively. The second line consists of the current values of mixture entropy, liquid velocity, vapor velocity, saturated brine enthalpy, sonic liquid velocity and mach number, respectively.

8. If the calculation has proceeded to the wellhead without producing a choking condition, the labeled wellhead parameters are tabulated under the title "Interpolated Wellhead Conditions". (See example C1).

9. If the mixture chokes below the wellhead, an appropriate value of WF is selected to just produce sonic liquid velocity at the wellhead and the problem is automatically rerun starting at the wellbottom. An output statement is made indicating this condition and listing the value of WF selected. The labeled wellhead parameters are tabulated under the title, "Flow is Choked". (See example C3).

10. Graphical output is shown in Figure B1.

EXAMPLE C1 - PURE WATER

```
1  CONSTANT DIAMETER WELLBORE CALCULATIONS BASED ON COMPUTATIONAL METHOD FOR SELF FLOWING GEOTHERMAL WELLS
     IN 'COMPARISON OF BRINE PRODUCTION METHODS AND CONVERSION PROCESSES FOR GEOTHERMAL
     ELECTRIC POWER GENERATION', D. G. ELLIOT, EQL REPORT NO. 10, ENVIRONMENTAL QUALITY
     LABORATORY, CALIFORNIA INSTITUTE OF TECHNOLOGY, PASADENA, CALIFORNIA, JULY 1975.

          TIME:  08:49:46  DATE:  03/24/77

                    ****INPUT VALUES****
                         TRES   =  5.7200E+02 DEG F
                         PRES   =  0.         PSIA
                         PPR    =  0.         ONE WITH PRES INPUT    ZERO WITHOUT
                         DEPTH  =  5.0000E+03 FEET
                         DIA    =  5.6000E-01 FEET
                         WFS    =  0.         WEIGHT PERCENT
                         WF     =  1.2500E+02 LBM PER SEC
                         FM     =  4.1000E-02 MOODY FRICTION FACTOR
                         DD     =  1.6000E+00 PSIA/LBM PER SEC, DRAWDOWN
                         VR     =  1.0000E+00 GAS/LIQ VELOCITY RATIO
                         HTC    =  0.         BTU/HR-SQ FT-DEG F
                         BETW   =  0.         1 FOR VALUES THRU 2 PHASE REGION

                    NORMAL HYDROSTATIC PRESSURE =   2.166E+03 PSIA

                    ****WELL BOTTOM CONDITIONS****
  5.720E+02   1.246E+03   1.966E+03   5.759E+02   2.463E-01   1.125E+01   7.723E-01

                    ****FLASH POINT CONDITIONS****
  5.685E+02   1.212E+03   4.471E+01   2.118E+03   5.736E+02   1.135E+01   7.731E-01

                    ****INTERPOLATED WELLHEAD CONDITIONS****
                         TWH    =  4.3381E+02 DEG F
                         PWH    =  3.5773E+02 PSIA
                         XWH    =  2.0073E-01 QUALITY
                         HWH    =  5.6953E+02 BTU/LBM
                         SWH    =  7.8464E-01 BTU/LBM-DEG R
                         WGWH   =  2.5091E+01 LBM/SEC   VAPOR
                         WLWH   =  9.9909E+01 LBM/SEC   LIQ
                         VLWH   =  1.3859E+02 LIQ VELOCITY, FEET PER SEC
                         YWH    =  5.0000E+03 FT ABOVE WELLBOTTOM
```

EXAMPLE C2 - CALCULATIONAL OUTPUT THROUGH TWO-PHASE REGION

```
1  CONSTANT DIAMETER WELLBORE CALCULATIONS BASED ON COMPUTATIONAL METHOD FOR SELF FLOWING GEOTHERMAL WELLS
     IN 'COMPARISON OF BRINE PRODUCTION METHODS AND CONVERSION PROCESSES FOR GEOTHERMAL
     ELECTRIC POWER GENERATION', D. G. ELLIOT, EQL REPORT NO. 10, ENVIRONMENTAL QUALITY
     LABORATORY, CALIFORNIA INSTITUTE OF TECHNOLOGY, PASADENA, CALIFORNIA, JULY 1975.

          TIME:  08:52:14  DATE:  03/24/77

                    *****INPUT VALUES*****
                        TRES   =  5.7200E+02 DEG F
                        PRES   =  0.         PSIA
                        PPR    =  0.         ONE WITH PRES INPUT    ZERO WITHOUT
                        DEPTH  =  5.0000E+03 FEET
                        DIA    =  5.6000E-01 FEET
                        WFS    =  0.         WEIGHT PERCENT
                        WF     =  1.2500E+02 LBM PER SEC
                        FM     =  4.1000E-02 MOODY FRICTION FACTOR
                        DD     =  1.6000E+00 PSIA/LBM PER SEC, DRAWDOWN
                        VR     =  1.0000E+00 GAS/LIQ VELOCITY RATIO
                        HTC    =  0.         BTU/HR-SQ FT-DEG F
                        BETW   =  1.0000E+00 1 FOR VALUES THRU 2 PHASE REGION

                    NORMAL HYDROSTATIC PRESSURE =   2.166E+03 PSIA

                    *****WELL BOTTOM CONDITIONS*****
  5.720E+02   1.246E+03   1.966E+03   5.759E+02   2.463E-01   1.125E+01   7.723E-01

                    *****FLASH POINT CONDITIONS*****
  5.685E+02   1.212E+03   4.471E+01   2.118E+03   5.736E+02   1.135E+01   7.731E-01

                    *****TRAVERSE WELL CONDITIONS*****                K=   2
  5.6700000E+02  1.1902321E+03  2.1584395E+03  4.0542222E+01  3.1622030E-03  3.1622090E-03
  7.7309343E-01  1.1870928E+01  1.1870928E+01  5.7356291E+02  1.6263974E+03  7.2989099E-03

                    *****TRAVERSE WELL CONDITIONS*****                K=   2
  5.6600000E+02  1.1887981E+03  2.1859967E+03  2.7557261E+01  5.2484932E-03  5.2484961E-03
  7.7309919E-01  1.2223084E+01  1.2223084E+01  5.7352732E+02  1.2880189E+03  9.4839418E-03

                    *****TRAVERSE WELL CONDITIONS*****                K=   2
  5.6500000E+02  1.1794211E+03  2.2139549E+03  2.7958107E+01  7.3176867E-03  7.3176898E-03
  7.7310530E-01  1.2579629E+01  1.2579629E+01  5.7349122E+02  1.1137760E+03  1.1294577E-02

                    *****TRAVERSE WELL CONDITIONS*****                K=   2
  5.6400000E+02  1.1701008E+03  2.2422981E+03  2.0343196E+01  9.3700938E-03  9.3700970E-03
  7.7311203E-01  1.2940624E+01  1.2940624E+01  5.7345461E+02  1.0038893E+03  1.2890490E-02
```

EXAMPLE C3 - CHOKED FLOW

```
1  CONSTANT DIAMETER WELLBORE CALCULATIONS BASED ON COMPUTATIONAL METHOD FOR SELF FLOWING GEOTHERMAL WELLS
     IN 'COMPARISON OF BRINE PRODUCTION METHODS AND CONVERSION PROCESSES FOR GEOTHERMAL
     ELECTRIC POWER GENERATION', D. G. ELLIOT, EQL REPORT NO. 10, ENVIRONMENTAL QUALITY
     LABORATORY, CALIFORNIA INSTITUTE OF TECHNOLOGY, PASADENA, CALIFORNIA, JULY 1975.

        TIME:  08:58:03  DATE:  03/24/77

                    *****INPUT VALUES*****
                        TRES   =  5.7200E+02 DEG F
                        PRES   =  0.         PSIA
                        PPR    =  0.         ONE WITH PRES INPUT    ZERO WITHOUT
                        DEPTH  =  5.0000E+03 FEET
                        DIA    =  5.6000E-01 FEET
                        WFS    =  0.         WEIGHT PERCENT
                        WF     =  1.2500E+02 LBM PER SEC
                        FM     =  8.0000E-02 MOODY FRICTION FACTOR
                        DD     =  1.6000E+00 PSIA/LBM PER SEC, DRAWDOWN
                        VR     =  1.0000E+00 GAS/LIQ VELOCITY RATIO
                        HTC    =  0.         BTU/HR-SQ FT-DEG F
                        BETW   =  0.         1 FOR VALUES THRU 2 PHASE REGION

                    NORMAL HYDROSTATIC PRESSURE =   2.166E+03 PSIA

                    *****WELL BOTTOM CONDITIONS*****
  5.720E+02   1.246E+03   1.966E+03   5.759E+02   2.463E-01   1.125E+01   7.723E-01

                    *****FLASH POINT CONDITIONS*****
  5.685E+02   1.212E+03   4.471E+01   1.888E+03   5.736E+02   1.135E+01   7.731E-01

        *****FLOW WOULD CHOKE BELOW WELLHEAD, RESTARTING USING     9.7833E+01 FOR THE WF VALUE*****

                    *****WELL BOTTOM CONDITIONS*****
  5.720E+02   1.246E+03   2.010E+03   5.759E+02   2.463E-01   8.795E+00   7.720E-01

                    *****FLASH POINT CONDITIONS*****
  5.685E+02   1.212E+03   4.471E+01   2.185E+03   5.736E+02   8.884E+00   7.731E-01

                    *****FLOW IS CHOKED*****
                        T      =  3.0100E+02 DEG F
                        P      =  6.8015E+01 PSIA
                        X      =  3.1497E-01 QUALITY
                        HMX    =  5.5714E+02 BTU/LBM
                        SMX    =  8.1503E-01 BTU/LBM-DEG R
                        Y      =  5.0000E+03 FT ABOVE WELLBOTTOM
                        WG2    =  3.0815E+01 LBM/SEC   VAPOR
                        WL2    =  6.7018E+01 LBM/SEC   LIQ
                        VEL    =  8.0237E+02 LIQ VELOCITY FT/SEC
                        M      =  1.0028E+00 MACH NO
```

Printed in the United States of America
Available from
National Technical Information Service
U.S. Department of Commerce
5285 Port Royal Road
Springfield, VA 22161
Price: Printed Copy $; Microfiche $3.00

Page Range	Domestic Price	Page Range	Domestic Price
001–025	$ 3.50	326–350	10.00
026–050	4.00	351–375	10.50
051–075	4.50	376–400	10.75
076–100	5.00	401–425	11.00
101–125	5.50	426–450	11.75
126–150	6.00	451–475	12.00
151–175	6.75	476–500	12.50
176–200	7.50	501–525	12.75
201–225	7.75	526–550	13.00
226–250	8.00	551–575	13.50
251–275	9.00	576–600	13.75
276–300	9.25	601–up	*
301–325	9.75		

*Add $2.50 for each additional 100 page increment from 601 to 1,000 pages; add $4.50 for each additional 100 page increment over 1,000 pages.

Technical Information Department
LAWRENCE LIVERMORE LABORATORY
University of California | Livermore, California | 94550