BOREFLOW SIMULATION AND ITS APPLICATIONS (USING HP 41 CV)

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ABSTRACT

This paper deals with the formulation of a calculator program in simulating flowing pressure profiles in geothermal wells and is based from Hagedorn and Brown's Correlation, This program has been tested against measured pressure profiles obtained in some of the geothermal wells in the Palinpinon geothermal field,

The possible applications derived from simulation are also presented and discussed in detail,

INTRODUCTION

In common practice, downhole measurements are conducted with the well discharging at low flow rates (usually not more than 30 kg/s), meaning, the well should be back-pressured to maintain a low flow rate throughout the test such that the downhole instrument can penetrate, Thus, downhole measurements are limited to this rate.

This limitation made simulation important. Flowing pressure profiles at high mass flow can be obtained only by prediction (i.e., simulation).

The ability to predict flowing well pressures is of utmost importance in the following applications:

1. Profile duplication, and hence simulate flowing profiles at any discharge condition.
2. Determination of the necessary conditions for a successful well discharge,
3. To know the effect of elevation on production and discharge.
4. Determination of the minimum feed zone pressure required at which steam supply to the power plant is still possible,
5. To know the effect of flow string sizes on production.

The fluid properties used in this paper are for pure water as obtained from standard steam tables, hence do not include the effects of salinity of the fluid and the presence of non-condensible gases entrained in the discharge, Any deviation of the calculated profile from the measured profile can be attributed to these (salinity and gas),

The limited capacity of the hand-held calculator (HP 41 CV) severely affects the choice of the correlation to be used. Orkiszewski's Correlation which considers flow regimes, introduced numerous parameters in defining the occurence of each regime. Beggs and Brill's Correlation also recognizes the presence of flow regimes and calculation of the liquid hold-up at all pipe angles, In general, the first two-correlations are lengthy and could not be handled by the calculator, whereas, the correlation introduced by Hagedorn and Brown is brief and concise and consider6 slip only. Though this correlation has a simple approach, various computer programs indicated that this correlation is reputed to yield a reasonable fit which is also confirmed by the program used in this paper.

APPLICATIONS

A. Profile Duplication and Simulation

No further simulation can be done unless the measured pressure profile can be duplicated. Oftentimes, however, Some deviations from the measured profiles are observed. These are presumed to be caused by any of the following; presence of multiple feed zones, presence of gas, fluid salinity, others (error in measurements).

To account for heat transfer into the formation, flowing temperature profile was used to determine the fluid properties in the single-phase section (hot water) of the well. The calculation showed that at high flow rates, heat transfer into the formation did not affect the results significantly, Most of the simulations done in this paper are at high flow rates (usually more than 30 kg/s).

1. Okoy-6 KP 24/KT 57 Duplication

The flowing pressure profile (KP 24, Fig. 1), showed that the upper zone (1310-1400m, CHF) well pressure was built-up above the static pressure (KP 23, Fig. 1) indicating no flow from this sone which suggests that the bulk of the discharge came from the lower zone (2300-2600m, CHF) at a temperature of 283°C. This temperature corresponds to an enthalpy of 1252 kJ/kg, whereas, the measured discharge was 1150 kJ/kg, a drop of 102 kJ/kg. The temperature profile (KT 57, Fig. 1 and Table 1) indicated a significant temperature drop from 279°C (1600m, CHF) to 270°C (1400m). This would imply that some cooling had occured at 1400m.

At shut-in condition a low temperature fluid at approximately 224°C entered the well causing a downflou. At flowing conditions this cold fluid ceased to enter the well as the formation pressure (approximately at static condition) was underpressured with respect to the well pressure. The cold fluid outside the well at this depth could have caused the temperature drop, and hence enthalpy drop.

The calculated temperature profile agrees well with the measured profile. In this simulation the enthalpy from 1200m to CHF was made 1120 kJ/kg as an enthalpy of 1150 kJ/kg does not yield a good fit of the measured and calculated profiles.

2. Okoy-6 Full Open Condition (Simulation)

The bore output measurements made for this well at full open conditions are;

WHP = 1.04 MPa.abs
Q = 80 kg/s
H = 1300 kJ/kg

From PCP (Pressure Control Point) vs. Depth plot (Fig. 2), the formation pressure at the main feed zone (1600m) is approximately 14.2 MPa. The object of this simulation is to ably duplicate the measured WHP and hence determine the true injectivity index of the well. The injectivity index was measured to be in the range of 63-196 l/s-MPa.

For the fluid at the feed zone to enter the well, a significant pressure differential between the zone and the well should exist. ($P_f > P_{wf}$). In equation form,

$$Q = (PI) \times \Delta P$$

where;

(PI) = Productivity index
$\Delta P = P_f - P_{wf}$, MPa
Q = mass flow, kg/s

Assume that the productivity index = the injectivity index, or (PI) = (I) and that the flow from the feed zone to the wellhead is constant (i.e., B = 1).

$$\therefore P_{wf} = P_f - \frac{Q}{I} + P_{atm.}$$

Several trials had been done, calculating P_{wf} at different values of I. An injectivity index of 180 l/s-MPa gave the best agreement between the WHP (measured and calculated).

$(WHP)_{measured}$ = 1.04 MPa.abs
$(WHP)_{calculated}$ = 1.045 MPa.abs

In this simulation, it was assumed that the process is adiabatic, neglecting heat-losses due to the cooling effect of the cold fluid in the vicinity of the well at the upper zone. The fact that the simulation gave a good agreement in WHP, and in the calculation, it was assumed that in the single-phase section of the well the temperature is constant, would then indicate that at high mass flow rate (full open discharge), the cooling effect from the country rocks (at the upper zone) is minimal.

The simulation indicated that the injectivity index of okay-6 can be 180 l/s-MPa, suggesting high permeability.

B. Determination of Necessary Conditions for a Successful Well Discharge

Initially, discharging of wells in Southern Negros were done by compressed-air stimulation. That is, injecting air into the well and depressing the water column to a point where the temperature is sufficient enough to support fluid flow to the wellhead. However, it was found out that in wells of deep water levels, this method failed. As the fluid started to flash, much of its energy is lost to the casing walls due to the condensation of the 2-phase fluid throughout the cold casing.

To minimize this energy loss external heat from outside source (boiler or another discharging well) was introduced. This method requires injection of steam or 2-phase fluid to the well thereby heating up and depressing the water column to a condition (temperature) sufficient for it to discharge. Unloading the injected fluid would stimulate the well to flow provided the total pressure drop it will encounter during the flowing process can be overcome.

The critical condition that should be attained for the well to sustain is the minimum temperature of the water column which saturation pressure should be more than the total pressure drop the fluid will encounter during the flowing process (i.e., wall friction, elevation change, acceleration). By boreflow simulation these preseure drops can be quantified, and hence determining the minimum temperature required for the water column.

SIMULATION PROCEDURE

The following data should be known be= fore the simulation can be done;

Q_i = Mass injected into the well, kg/s

H_i = Heat injected into the well, kJ/s

T_i = Temperature of the water level before stimulation, °C and wellbore geometry.

The location of the minimum temperature of the water column can be determined by simulation.

Assumed Data:

T_2 = Minimum water column temperature, °C

Z = Location of T_2.

From the known and assumed data the following can be calculated;

Q = Discharge mass flow, kg/s

$= Q_i + Q_w$

Q_w = mass derived from the water column

$= \frac{H_i}{(h_2 - h_1)}$, kg/s (assuming all injected heat were absorbed by the water column).

$h_2 = h_f$ at T_2 = discharge enthalpy

1. SG–1 Discharge Attempt Simulation (EO - 500 Clayton Boiler)

H_i = 6585.5 kJ/s

Q_i = 3.6 kg/s

T_1 = 94°C, h_1 = 394 kJ/kg

Assume T_2 = 212°C, h_2 = 907 kJ/kg

$$Q_w = \frac{6585.5}{(907-394)}$$

$$= 12.84 \text{ kg/s}$$

$$Q = 16.44 \text{ kg/s}$$

The sirnulation showed that the minimum water level temperature of 212°C can be attained during stimulation at approximately 1500m, CHF. This meant that the well could be successfully discharged provided the conditions stated above can be attained. However, the probability of succeseful discharge can also be achieved even if the minimum water level temperature is less than 212°C provided it will occur at depths shallower then 1500m, CHF.

2. Okoy-5 Discharge Attempt Calculation

Okoy-5 was the first well discharged by steam injection in Southern Negros. Prior to steam injection the well was stimulated by compressed-air injection 12 times which all failed. This well was actually attempted to discharge by steam injection twice.

First Discharge Attempt
Min. temperature = 121°C — Failure
Depth = 600m

Second Discharge Attempt
Min. Temperature = 167°C — Successful
Depth = 700m

From Fig. 3, static temperature profile KT 36,

T_i = 100°C

H_i = 1814.5 kJ/s — boiler rating

Q_i = 0.6677 kg/s

For D. A No. 1

$$Q_w = \frac{1814.5}{(508-419)}$$

$$= 20.28 \text{ kg/s}$$

$$\therefore Q = 21.0553 \text{ kg/s}$$

P_{s_2} = 0.2049 MPag = 0.2959 MPa. abs at 121°C

The sirnulation showed that the flow collapsed at 436.9m, CHF, indicating that the minimum temperature attained was below the critical value.

For D. A. No. 2

$$Q_w = \frac{1814.5}{(706-419)}$$

$$= 6.3223 \text{ kg/s}$$

$$Q = 7.00 \text{ kg/s}$$

P_{s_2} = 0.8269 MPa.abs at 167°C

The simulation showed that sufficient pressure was left at the wellhead allowing the the well to discharge, which meant that the critical condition for the well to discharge was attained.

C. Effect of Elevation on Production and Discharge

1. Effect of Elevation on Discharging a Well

Drilling a well at higher elevation would mean additional pressure reduction to be experienced by the fluid during the flowing process as the cold column is (deeper water level) increased. To overcome this, a higher minimum water column temperature is required to support continuous flashing of the fluid to the wellhead.

A simulated discharge curves with depths based on SG-1 were drawn (Fig. 4) for the EO-500 Clayton Boiler (500 HP) at minimum temperatures of 250°C to 230°C, all occuring at 2000m, CHF relative to SG-1. From the depth where these minimum temperature occur, the pressure drop at depth was calculated until the remaining flowing pressure is 0.1 MPa, just enough for the well to discharge.

The depth of occurence of the minimum temperature at any elevation is;

$$Z_m = 2000 + (\text{Elevation}-947.7)\text{m, CHF}$$

The simulation showed that at minimum temperature of 250°C occuring at depth Z_m, wells to be drilled from as high as 2000m, AMSL can still be discharge, At T_{min} = 240°C and T_{min} = 230°C also occuring at depth Z_m, the maximum wellhead elevations required are 1600 and 1200m, AMSL respectively.

Figure 4 can be used as a guide as to whether a well stimulated by 2-phase injection (EO-500 Boiler) will discharge or not if it is drilled at a certain elevation covered by the curve.

2. Effect of Elevation on Production

For future expansion and field assessment of a partially developed field, a simulated output characteristic curves had been drawn at different elevations for Okoy-6, SG-1, and Okoy-7. These wells represent the three areas of the Palinpinon Geothermal field, viz., Nasuji, Sogongon, and Fuhagan respectively,

The simulation showed that the mass flow is inversely proportional to elevation.

This simulated output curves can be helpful in the estimation of the capacity of a partially developed field if the wells are to be drilled at other elevations.

This simulation was made basing on an assumption that the wells to be drilled at other elevations are to obtain production from the same aquifer as that of the base well. Hence, it is expected that wells located in the same elevation may not have the same shape of output curves,

D. Optimization of Wellbore Design From Well Deliverability Conditions

The WHF vs. mass flow curves at different flow string diameters were plotted from calculated data using the existing output measurements and changing the casing/liner diameters.

The curves are drawn in Fig. 6. Curve 1 represents the base data at present flow string diameters, while curves 2 and 3 were obtained by simulation, Curve 2 is somewhat similar to curve 1 but has an almost linear relationship between MF and WHP at higher WHP, whereas curve 3 indicated that at any choke diameter the increase in WHP is not significant but the mass flow decreases rapidly-

The significance of this simulation is for optimization of wellbore design of future wells. It is clearly shown from the graph that the mass flow increases significantly if the flow string diameter is enlarged, However, for future expansion, careful consideration should be taken in comparing the benefit of increased flow rates against the higher cost of drilling (drilling bigger hole diameter) and completing larger diameter wells.

An increase in production rate would also mean large pressure drawdown at the producing aquifer, hence increasing the rate of depletion.

E. Determination of the Minimum-Feed Zone Pressure for a Production Well

The term production well as treated in this paper refers to that well which supplies steam to the power plant through a separator. To maintain two-phase fluid flow from the well to the separator, the wellhead pressure should be greater than the separator pressure, otherwise there will be no flow, The minimum wellhead pressure required should be equal to the separator pressure plus the pressure losses in the piping system connecting the wellhead and the separator, or;

$$\text{WHP} = P_{sep} + \Delta P_{line} \left(\begin{matrix}\text{often}\\ \text{negligible}\end{matrix}\right)$$

Knowing the mass flow, the fluid enthalpy, feed zone tenperature, feed zone location, and wellbore geometry, the minimum feed zone flowing pressure that would correspond to the minimum wellhead pressure required can then be determined by simulation.

This method will be demonstrated for Okoy-6.

1. Okoy-6 Determination of Minimum Feed Zone Pressure While on Discharge

Consider Okoy-6 at Full Bore Discharge, where;

$$Q = 80 \text{ kg/s}$$
$$H = 1326 \text{ kJ/kg}$$
$$T_f = 296°\text{C}$$

Say that the minimum WHP of 0.55 MPa.abs (Separator Pressure) has been attained.

The procedure is to duplicate the WHP (i.e., the calculated WHP will be approximately equal to the assumed minimum WHP).

Using a P_{wf} of 13.40 MPa.abs at the feed zone, the simulation showed that at the wellhead the WHP is 0.58 MPa.abs.

Roughly, the pressure drawdown in the formation can be calculated considering the case when $r = r_w$ (i.e., at the wellbore), also considering that at the PCP (Pressure Control point, Fig. 2), the pressure measured at static conditions (not yet discharged) is approximately equal to the formation pressure at that depth.

Considering a production life of 25 years the formation pressure drop for the producing aquifer of Okay-6 can be quantified,

Okoy-6

$$\Delta P_f = \frac{P_f - P_{wf}}{25}$$

$$= \frac{14.2 - 13.4}{25}$$

$$= 0.032 \text{ MPa/yr.}$$

However, this rate of drawdown can be exceeded provided the rate of extraction is decreased.

This also showed that in wells where the pressure transient test results do not yield a characteristic curve (can't be interpreted), an alternate method of obtaining the formation pressure at the wellbore at unexploited condition can be made (i.e., making a PCP vs. depth plot of the field).

The pressure control point is the depth in the well where the pressure pivots during heat-up. For multi-zone wells, the YCP should be weighted between the injectivities of the zones and for a single zone well, the PCP is the zone itself.

The objective of this simulation is to show that the pressure drop in the reservoir can be quantified.

CONCLUSIONS

The simulations presented here are just rough representations of the program as applied, and as linited by the capacity of the HP 41 CV,

Basing from the applications of the program done in this paper, the following conclusions have been made;

1. That at back pressured conditions, the enthalpy drop due to the cooling effect of cold fluid at the upper zone is great, whereas, at full discharge conditions, the drop is minimal.

2. That the possibility of a successful well discharge (2-phase injection stimulation) depends on the minimum water column temperature required and the depth at which this temperature occurs,

3. That wells located at higher elevations require a higher minimum water column temperature for a successful well discharge.

4. That the rate of depletion of a producing aquifer can be quantified after calculating the minimum flowing feed zone pressure.

5. That the rate of production is inversely proportional to wellhead elevation,

6. That production can be increased by completing larger diameter wells. However, careful consideration should be taken in comparing the benefits of increased flow rates against tha higher cost of drilling (drilling bigger hole diameter), and the rate of depletion of the producing aquifer.

N.B.

The roughness factors used in this paper were based on the values used by various authors (e.g., Thomas L. Gould, Anthony J. Kenzies, & etc.).

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FIGURES

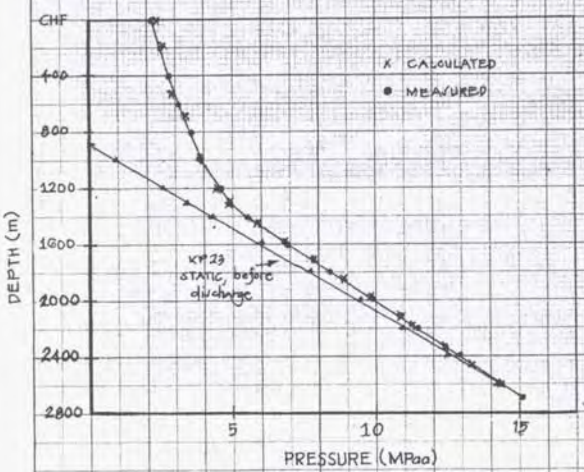
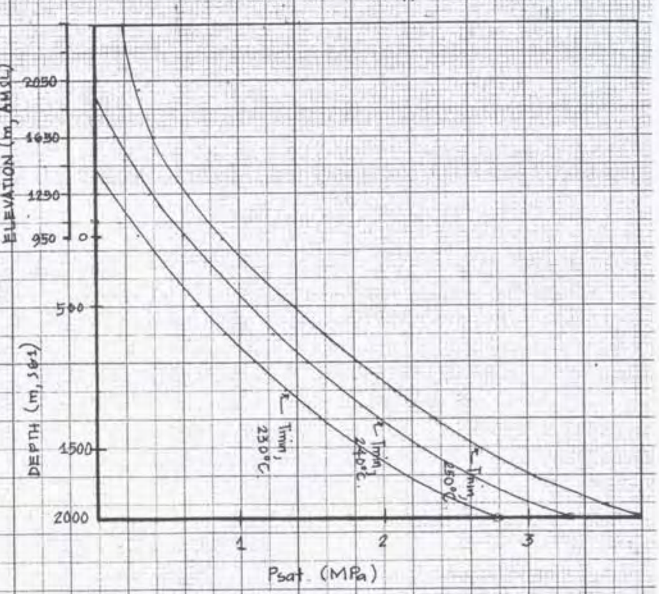


FIG. 1 OKOY 6 CALCULATED and MEASURED PROFILES.

FIG. 4 (EO-500 CLAYTON BOILER) WELL DISCHARGE CURVES
BASE DEPTH: SG-1 @ approx. 950 m, AMSL



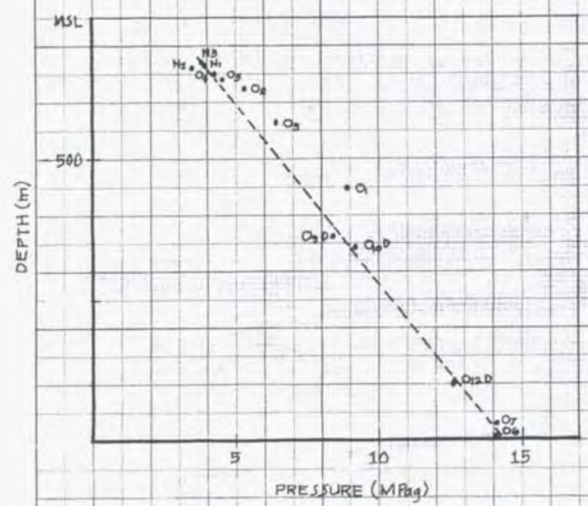


FIG. 2 PRESSURE CONTROL POINT VS. DEPTH PLOT OF THE SOUTHERN NEGROS GEOTHERMAL FIELD.

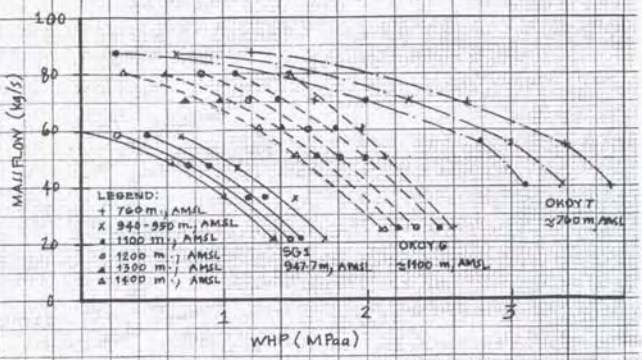


FIG. 5 OKOY 6, OKOY 7, SG1 SIMULATED DISCHARGE CURVES (OUTPUT)

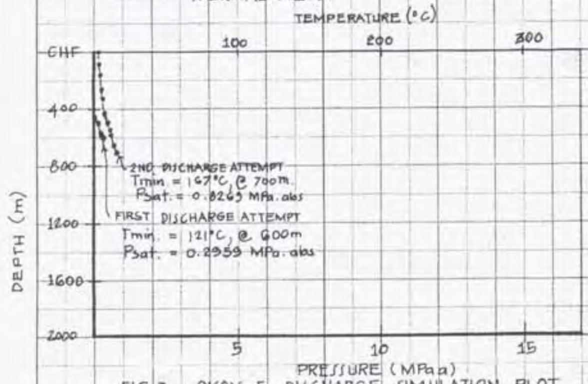


FIG. 3 OKOY 5 DISCHARGE SIMULATION PLOT

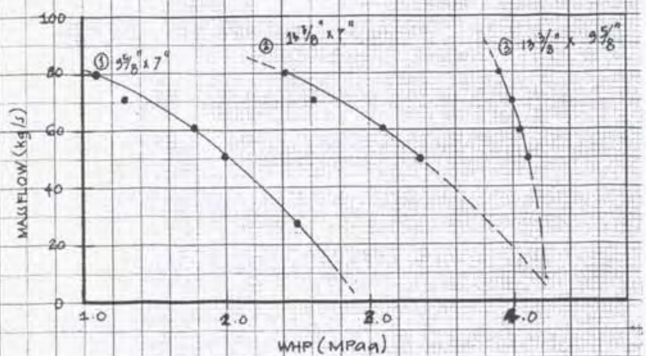


FIG. 6 OKOY 6 SIMULATED OUTPUT CURVES AT DIFFERENT FLOW STRING DIAMETERS.