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AN INVESTIGATION OF WELLBORE SCALING AT THE MIRAVALLES GEOTHERMAL FIELD, COSTA RICA

by

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INTRODUCTION

Miravalles geothermal field lies in the Guanacaste province of Costa Rica in Central America. At the time of the study (late 1982), three wells (named PGM-1, PGM-2 and PGM-3), had been drilled and periodically tested in this field during 1980-82. During several of these tests scaling of the wellbore appeared to be a serious problem. This paper presents a portion of a study conducted to define the nature and causes of the scaling problem.

No new data were gathered during this study; it was based on the analysis of already existing data as of late 1982. The main limitations in the data as regards this study were:

1. No bottomhole pressure measurements had been made.
2. No temperature or pressure profile under flowing condition was available from any well.
3. A wellhead separator was available at only one well (PGM-1).
4. Although James' lip pressure measurement facilities were available at all wells, in some of the earlier tests (up to May 1981) no measurement of the liquid flow rate was made.

The fact that there was scale deposition in the Miravalles wells was indicated by several observations:

1. Unusually rapid decline had been experienced in both flow rate and wellhead pressure (p_{wh}) except when the wells were flowed at a relatively high p_{wh} level. For example, Figure 1 presents the situation for well PGM-1 during a test (Test 1). This behavior was not due to reservoir depletion because the wells produced a much larger cumulative mass without a serious drop in flow rate or p_{wh} when flowed above a certain p_{wh} level, whereas a much smaller cumulative production was possible if a lower p_{wh} level was maintained. Only a part of the decline in mass flow rate in some of the tests had been caused by increasing steam fraction in the produced fluid.
2. The decline in flow rate became precipitous towards the end of some of the tests. Yet, there had been no precipitous decline in reservoir pressure. For example, on being shut in after several weeks of wide open discharge in 1981, the water level in well PGM-1 returned quickly to the original static level.
3. In May 1981, caliper logging indicated that the borehole diameters in PGM-1 and PGM-3 were reduced sharply after a few months of flow (Figure 2).

Although no sample of the downhole scale had been recovered, the likelihood that the scale being formed was carbonate was indicated by several observations:

1. Calcium carbonate particles have been found in the wellhead separator of PGM-1 and in the silencers of all wells.
2. As concluded in the next section, the principal noncondensable gas in the Miravalles fluid is CO_2 and the weight-% CO_2 in the total fluid is 0.091. Carbonate scaling is encountered in almost all geothermal fields with a significant CO_2 concentration in the fluid.
3. The apparent reduction in the rate of scaling when wellhead pressure was kept high reinforced the belief that the scale being formed was carbonate rather than silica or sulfides.
4. Our geochemical studies have indicated that other types of scaling, such as silica or heavy metal sulfides are not likely under the borehole conditions at Miravalles.

DISCLAIMER

CONCENTRATION OF CO_2 IN RESERVOIR FLUID

NCG percent in steam samples at the wellhead had been measured several times during 1980 to 1982, particularly at PGM-1. Figure 3 is a plot of the weight-% of NCG as a function of separator pressure based on all available data. Numerals on the plot indicate the date of collection of the steam/NCG sample.

Points in Figure 3 show a well-defined trend regardless of the date of sampling. This implies that the overall NCG concentration in the produced steam/water mixture had remained nearly constant during the period September 1980 to August 1982.

To estimate the concentration of NCG in the reservoir fluid, various values were assumed for this variable and the NCG concentration in the steam phase at each of the given separator pressures was calculated from CO_2 vapor-liquid equilibrium relations and the given steam fraction (X). Where the steam fraction value was not available, it was calculated assuming isenthalpic flow between the wellbottom and separator.

Calculated steam fraction values were derived by assuming a constant total downhole fluid enthalpy (235 cal/gm) that gave the minimum root mean square error and the maximum correlation coefficient between the given and calculated X values. Figure 4 shows the root mean square and average percent errors in calculated steam fraction versus assumed total fluid enthalpy. Similarly the NCG concentration in the total fluid was estimated to be 0.091% by minimizing the average percent error and root mean square error in the calculated NCG percent in steam phase as a function of the assumed NCG percent in the total fluid, for a total fluid enthalpy of 235 cal/gm. Figure 5 compares the measured and calculated NCG percent in the steam phase over the entire range of data. This correlation is reasonable, considering the errors inherent in measurement.

The above discussion leads to the following conclusions regarding CO_2 content:

1. NCG consisted predominantly of CO_2, otherwise the match between the given and calculated NCG percent in steam would not have been so reasonable.

2. NCG content in the total fluid was 0.091 weight-%.

3. During September 1980 to August 1982 the NCG content in the total fluid produced from PGM-1 had remained unchanged even though a total fluid mass of some 1,200 million kg had been produced from the well during this period. Therefore, it was unlikely that the produced CO_2 originated from a gas/steam cap, which would have given rise to a continuously declining CO_2 content in the total fluid.

DEPTH OF FLASHING IN WELLBORE

The depth of flashing was calculated as a function of the total mass flow rate for a range of values of the friction factor for each of the 3 wells. Calculations were based on estimated values of reservoir pressure, transmissivity, drainage radius and CO_2 content in the water. Pseudosteady state in the reserovir, zero skin factor and isenthalpic flow from wellbottom up to the flashing depth were assumed. Reservoir static pressure was estimated from a static pressure profile measured in PGM-2. The transmissivity values around the wells were estimated from transient changes in water level during flow.

A CO_2 weight-% of 0.091 in the total fluid was assumed. The concentration of other NCG and the salinity of the reservoir fluid (about 6,500 ppm) were neglected. Because the friction factor (f) for the casing or liner is unknown, and because f will change as scale forms on borehole wall, calculations were made for a realistic range of f values.

Figure 6 shows the results of calculation for one of the wells, presented as height of the flash level above wellbottom, assuming that the main production zone is at the wellbottom. Also indicated on Figure 6 is the depth of the change in internal diameter of the well, from 17.7 cm (slotted liner) to 22.4 cm (production casing).

PRESSURE-DROP CHARACTERISTICS BETWEEN FLASH DEPTH AND WELLHEAD

Once water flashes in the borehole, there is a strong likelihood of scaling, particularly as there is a further pressure drop as the fluid flows upward from the flash depth to the wellhead. If flashing occurs above the casing-liner joint, scale deposition is spread over the section of casing between the flash depth and the wellhead. However, scaling in these wells did not take place beyond a few hundred m downstream from the flash depth, because the two-phase fluid cooled rapidly as a consequence of pressure drop, and thus there was an increase in $CaCO_3$ solubility.

If flashing took place below the casing-liner joint, scaling might occur on part of the relatively narrow-diameter liner as well as on the casing. Moreover, because there was a sharp pressure drop at the casing-liner joint caused by the sudden expansion of the two-phase mixture as it passed from the liner to the casing, this could cause preferential deposition of calcium carbonate at the casing-liner joint.

PGM-1 and PGM-3 showed scaling at the casing-liner joint, because water flashed to steam below this depth. PGM-2 did not show detectable scaling, presumably because it had a flash depth higher than the casing-liner joint. This argument is discussed further below. In Figure 2, note that scaling had extended only to about 100 m downstream from the casing-liner joint, because further temperature drop increased $CaCO_3$ solubility and prevented further scaling downstream.

This highly localized scaling caused development of a choke in the fluid path. This was in contrast to the situation of flashing above the casing-liner joint, which did not cause serious choking because scaling took place over a large surface area in the casing. Therefore, for the same cumulative withdrawal of fluid, reduction of well productivity due to scaling was much more severe if flashing took place below the casing-liner joint than above it. In the former case, the reduction in well productivity with time was slow at first but became precipitous after a short time, because the rate of reduction in diameter accelerated as the diameter became smaller.

Figure 6 indicates that in PGM-1 the flash level should be above the casing-liner joint so long as the flow rate remained below 39 to 48 kg/sec range (assuming a friction factor range of 0.005 to 0.015). During Test 1 (Figure 1), PGM-1 was flowed at a much higher rate than this, presumably giving rise to flashing below the casing-liner joint and therefore to a precipitous decline in well productivity after a few days. During Test 2 (151 days' duration) this well was flowed at above 39 to 48 kg/sec rate for a very short time during which well productivity dropped rapidly. This initial decline might have been caused by scale buildup. But after the flow rate fell below 39 kg/sec, well productivity remained constant for several months, presumably because flashing took place above the casing-liner joint. There was a sudden increase in well productivity after some 2,000 hours of flow most probably due to breaking off of a part of the scale buildup. After this point, flow rate remained relatively constant at around 45 to 47 kg/sec.

Considering the approximate nature of our flash depth estimate (mainly because we lack a definite knowledge of the friction factor), it is conceivable that the flow rate remained constant at this level because water flashed above the casing-liner joint. It is also conceivable that a break off of scale buildup had reduced the friction factor and therefore increased the threshold flow rate for flashing below casing-liner joint to 48 kg/sec.

During Test 3 (187 day's duration) following a cleanup of scale, PGM-1 was flowed at 30 to 33 kg/sec. Consequently, flashing always occurred above the casing-liner joint, and therefore the well flowed for over 6 months without a significant decline in productivity.

We estimated the flash depth in PGM-2 would be above the casing-liner joint if the flow rate remained below 42 to 50 kg/sec. During a 246 day test, PGM-2 was flowed at 8.4 to 13.2 kg/sec rate. Consequently, the flashing depth was above the casing-liner joint and the well flowed without a major decline in productivity for over 8 months.

We similarly estimated that no matter what the flow rate is, well PGM-3 will flash below the casing-liner joint. Indeed, this well was probably producing a two-phase mixture from the reservoir. Therefore, two tests of PGM-3 of 35 and 29 days' duration showed rapid declines in productivity. Figure 2 indicates that scale deposition in PGM-3 had occurred principally at the casing-liner joint although flashing had occured below this point. We attribute this behavior to the strong influence of the sudden pressure drop at this joint upon nucleation and deposition of scale from water already saturated with calcium carbonate by flashing at a greater depth.

RELATION BETWEEN WELLHEAD PRESSURE AND SCALING

No attempt was made in this study to quantify the pressure drop behavior between the flash depth and wellhead because neither flowing pressure nor temperature profiles nor any bottomhole pressure data were available for any of the wells.

Maintenance of a high wellhead pressure during flow tests at Miravalles appeared to prevent the rapid decline in well productivity experienced otherwise. For example, Test 1 of PGM-1 (Figure 1) showed rapid decline in well productivity with time because the wellhead pressures were low. The same well during Test 3 (187 days' duration) did not show serious decline in productivity for a far longer period than in Test 1, presumably because p_{wh} was maintained at greater than 14 $kg/cm^2(a)$.

An increase in wellhead pressure can reduce the well productivity decline rate due to scaling for several reasons:

1. A reduction in p_{wh} and the corresponding reduction in total mass flow rate may cause flashing above casing-liner joint. This should reduce scaling effect as discussed before.

2. In the extreme case, if it is possible to prevent flashing in the borehole altogether (that is, by allowing flashing only at wellhead), scaling in the borehole can be eliminated totally. However, calculations show that this was not possible for the Miravalles wells drilled to date (see, for example, Figure 6).

3. A reduction in p_{wh} causes reduction in mass flow rate. Therefore, over the same time interval, less $CaCO_3$ is available for deposition. In turn, the potential magnitude of scaling is diminished.

An attempt was made to assess the relation between wellhead pressure and scaling on the basis of available data on flow rate and p_{wh} versus time. However, this proved difficult for several reasons:

1. A decline in mass flow rate does not imply scaling. Flow rate can decline due to declining reservoir pressure or an increase in the apparent skin factor of the well.
2. Changes in flow rate can be caused by changes in p_{wh} and vice versa, whether or not these changes are due to scaling.
3. Without any knowledge of the bottomhole pressures it is difficult to distinguish between a reduction in well productivity due to scaling and that due to reservoir depletion or other causes.
4. Reduction in mass flow rate in some of the tests at Miravalles had been caused by an increase in steam fraction of the fluid entering the borehole, rather than solely by scaling or reservoir pressure decline. Although the mass rate had declined during some tests, the "normalized" volumetric flow rate (Q^*), defined as follows, had shown relatively less decline, and actually had increased in some cases.

$$Q^* = Q_r/M_e \qquad (1)$$

where

Q^* = "normalized" volumetric flow rate (liter·cp/s),
Q_r = downhole volumetric flow rate (liters/s),
M_e = effective mobility (1/cp) given by
$Me = k_{rs}/\mu s + k_{rw}/\mu w$,
k_{rs} = relative permeability to steam,
k_{rw} = relative permeability to water,
μs = viscosity of steam phase (cp),

and

μw = viscosity of water phase (cp).

In calculating Q^*, a straight-line relative-permeability relationship had been assumed, for simplicity.

Considering above problems, it was decided to monitor the mass flow rate obtainable at a fixed wellhead pressure in order to assess the scaling problem. Back pressure (deliverability) tests had been conducted at PGM-1 several times during 1980 and 1981 using a wellhead separator.

Figure 7 shows the flow rate obtainable at 9 kg/cm^2(a) wellhead pressure as a function of time, starting from April 29, 1982, as estimated from the periodic deliverability test data. The points for total mass, water and steam flow rates each show a linear trend if one neglects the first point. Similar linear trend in the decline of water, steam and total flow rates were noted on plots for p_{wh} values of 6.0, 12.0, 13.6, 14.44 and 15.0 kg/cm^2 (a). Separator and/or lip pressure data were utilized in deriving these plots.

The fact that at any wellhead pressure, flow rate normalized to a specific p_{wh} declined linearly with time was a useful observation. Figure 8 shows a plot of the rate of decline with time of this normalized flow rate as a function of p_{wh}. Figure 8 was derived from Figure 7 and similar plots at a series of p_{wh} listed above. Figure 8 shows that the rate of decline in well productivity (kg/sec/day) corresponding to a specific p_{wh} becomes smaller with larger p_{wh}. Between the p_{wh} values of 13.6 and 14.44 kg/cm^2(a), a sharp reduction in the decline rate took place. Therefore, if wellhead pressure was maintained above a threshold value (in this case about 14.4 kg/cm^2(a)), well productivity should have declined at a much slower rate.

Figure 8 is based on data during Test 3 of PGM-1. The p_{wh} was higher than 14 kg/cm^2(a) during most of this test. The total flow rate showed a slight decline, presumably because of increasing steam fraction due to gradual heat up of the wellbore. As discussed above, separator tests showed that the well productivity normalized to any specific p_{wh} below 14.4 kg/cm^2(a) had declined steadily during this test. Therefore, although there was apparently no significant decline in well productivity during this test, the true productivity of PGM-1 at wellhead pressures below 14.4 kg/cm^2(a) had suffered significant reduction. The cause of this phenomenon was unclear. One possible explanation is as follows.

Deposition of calcium carbonate scale might have been going on during Test 3, albeit at a very low rate, even though p_{wh} was kept high and the water presumably flashed above the casing-liner joint. This scale did not affect well productivity seriously for p_{wh} above 14.4 kg/cm^2(a), perhaps because at these high values of p_{wh}, the surface valve setting was small enough to effectively control the flow rate and mask the flow-restricting effect of the scale. At low p_{wh}, the valve setting was open wide enough for the scale to act as a choke.

This concept cannot be proven unless there is a detailed simulation of the pressure drop behavior in the well coupled with measurement of flowing pressure and temperature profiles, or caliper logs are run to verify if any scaling had indeed taken place during Test 3. It should be noted that the well was cleaned of scale before Test 3 started.

Considering the results shown in figure 8, the economic life of PGM-1 will be reduced sharply if wellhead pressure is not maintained above 14.4 kg/cm^2(a). If our concept is correct, and a minimum economic limit of 2 MW per well is assumed, maintaining wellhead pressure above 14.4 kg/cm^2(a) will result in a well life of between 1 and 2 years, while maintaining p_{wh} in the 6 kg/cm^2(a) range will give a 5 to 6 month life. Well life here implies the flow period of a well before it has to be cleaned. Increasing p_{wh} from 6 to 14.4 kh/cm^2 (a) will reduce the initial power potential from about 8.6 to 3.6 MW from this well. Therefore, in order to reduce the frequency of scale cleaning by maintaining a high p_{wh}, one has to accept a lower MW production per well.

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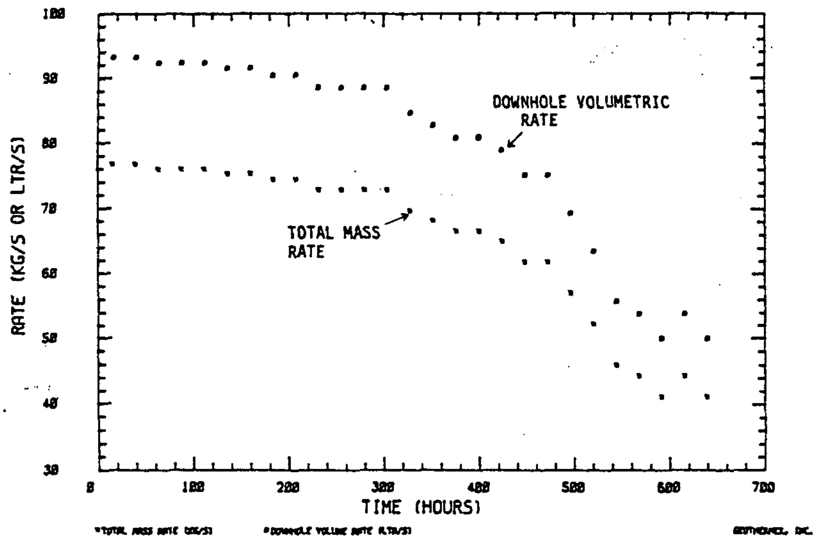

FIGURE 1. Total Mass Flow Rate and Downhole Volumetric Flow Rate versus Time, Test 1 of Well PGM-1 (December, 1980-January, 1981)

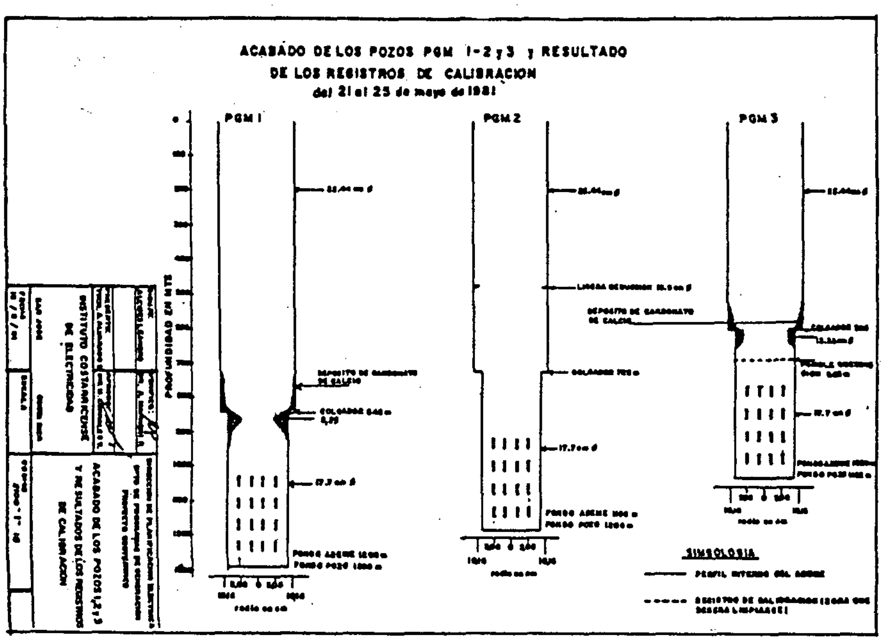

FIGURE 2. Completion of the Wells and Scale Deposition.

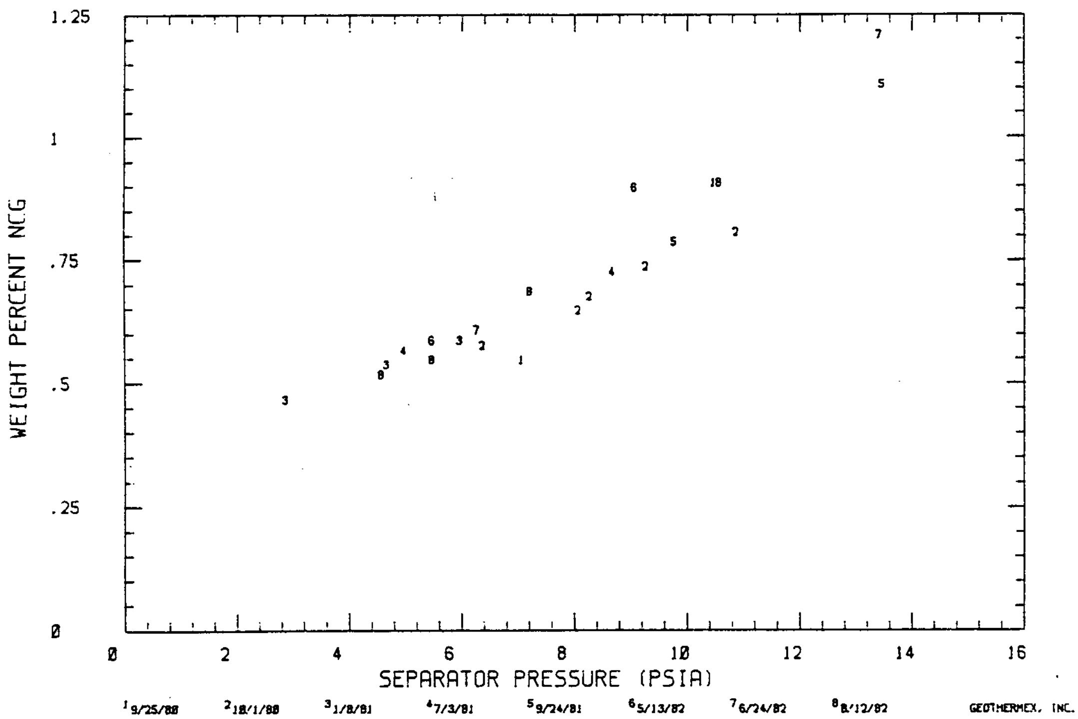

FIGURE 3. Measured Concentration of Non-Condensable Gases in the Steam Phase versus Separator Pressure at Various Times, Well PGM-1

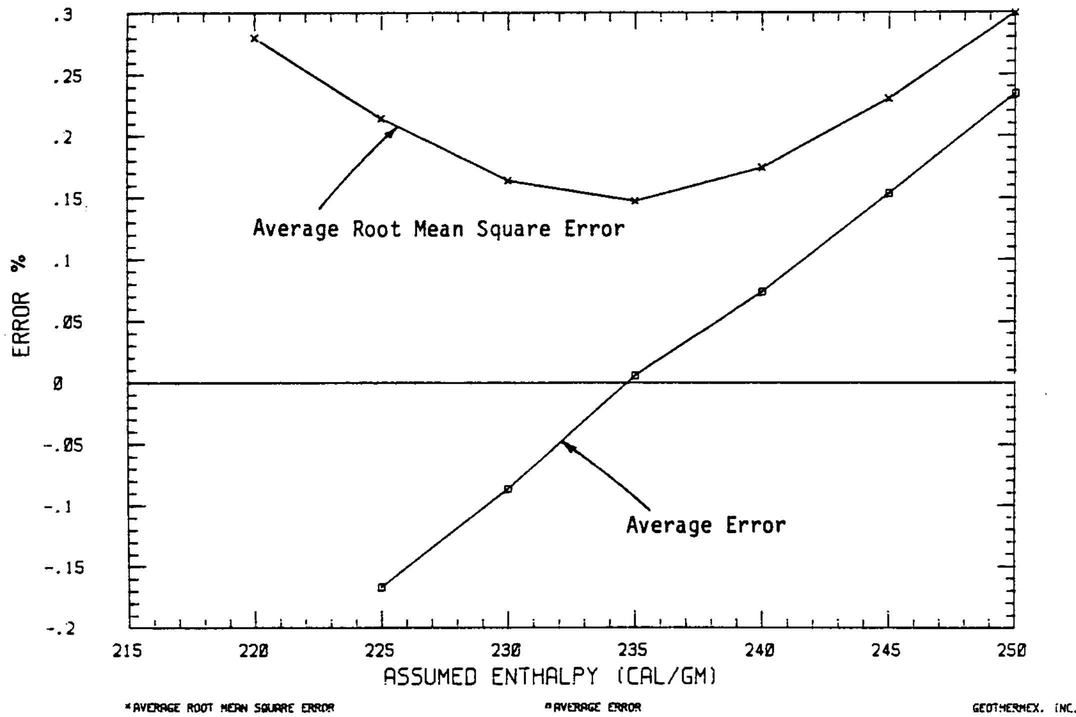

FIGURE 4. Root Mean Square Error and Average Error in Calculated Steam Fraction versus Assumed Enthalpy of Total Fluid, Well PGM-1

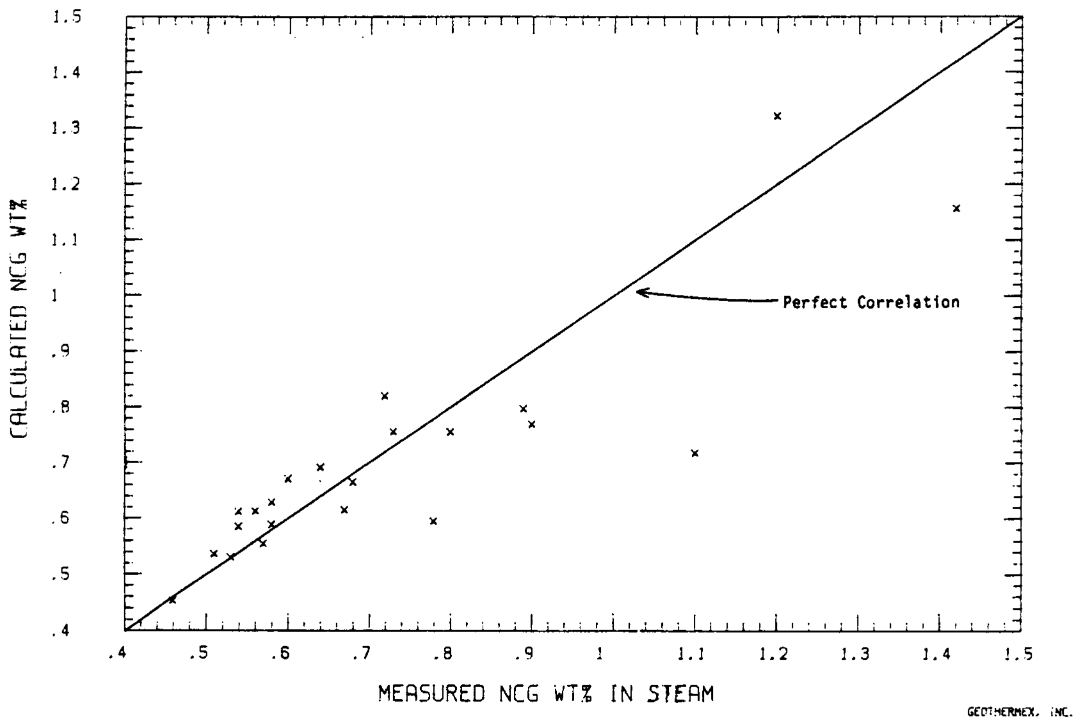

FIGURE 5. Calculated versus Measured Weight Percent of Non-Condensible Gases in the Steam Phase, Well PGM-1

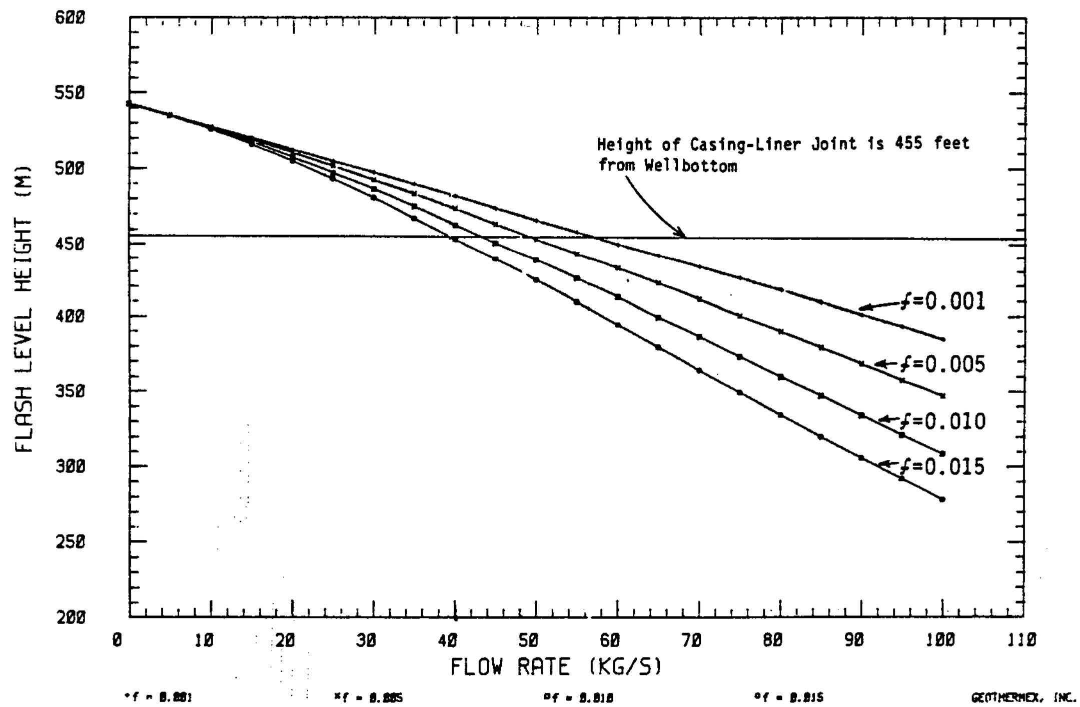

FIGURE 6. Flash Level Height versus Total Mass Flow Rate, Well PGM-1

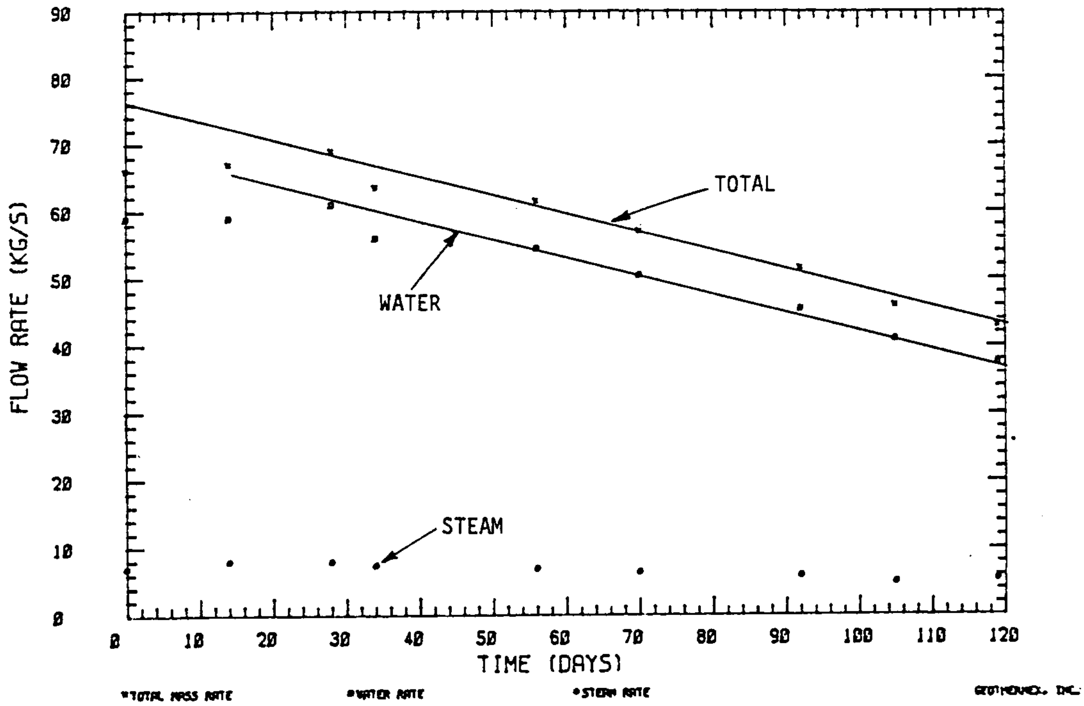

FIGURE 7. Flow Rate at 9 Kg/Cm^2 Wellhead Pressure versus Time, Well PGM-1

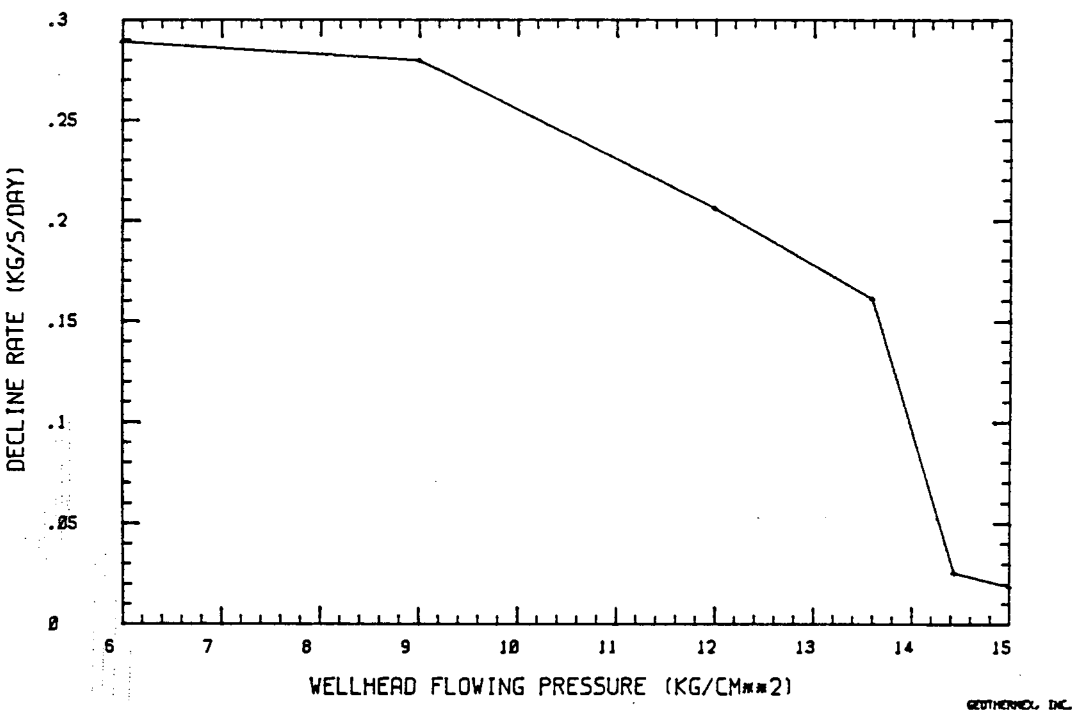

FIGURE 8. Productivity Decline Rate versus Flowing Wellhead Pressure, Well PGM-1