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DISCHARGE ANALYSIS OF WELL 9 IN REYKJANES FIELD, ICELAND

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ABSTRACT

A discharge analysis method is presented in terms of three key elements: two-phase flow wellbore simulator, reservoir productivity index, and wellbore pivot point based on pressure surveys. The evaluation and production testing of well 9 in the Reykjanes high-temperature field in Iceland, are reported and discussed. The output of this well was measured 180 kg/s at wellhead pressure of 20 bar-g. The main feedzone of the well was found to be in the depth range 1340-1350 m. The temperature of the inflow brine - similar to seawater in composition - was determined in the range 280-290 °C. Calculations showed that the well's deliverability depends greatly on the wellbore diameter, and the enthalpy of the steam-brine mixture.

INTRODUCTION

In many instances, it may not be possible to flowtest a two-phase geothermal well for a long enough period to determine its output curve except for one or two wellhead pressures. The reason for this could be environmental, or simply that it costs too much to operate and monitor the well for a long time. This calls for a method to estimate the well's output curve from the minimum of data.

The high flowrates and temperatures of two-phase geothermal wells, make it difficult to measure downhole under flowing conditions. This means, that in geothermal reservoir and production engineering studies, it is important to be able to calculate the downhole temperature and pressure in flowing wells. It follows, that geothermal wellbore simulators have several potential applications. Such applications have to be tested against field cases to explore their use to geothermal developers. By doing so, the limitations of present methods can be identified, and new applications discovered.

This paper is an example of using a state-of-the-art wellbore simulator to estimate the output curve of a two-phase geothermal well from field data. It concerns the discharge analysis method as proposed by Gudmundsson (1984), and data from well 9 in the Reykjanes high-temperature field in Iceland.

WELLBORE SIMULATOR

Early studies of two-phase flow in geothermal wells were those of Gould (1974) and Nathenson (1974). Both of these studies provide a good introduction to the subject. The Gould (1974) study was based on methods developed in the petroleum industry, and the applications considered were wellbore deposition and output (deliverability) calculations. The Nathenson (1974) study considered no-slip wellbore flow and coupled it to porous media flow in the reservoir. The problems investigated by Nathenson (1974) were deliverability and wellbore deposition. Later investigations of two-phase wellbore flow tend to be variations on the themes first developed in these two studies.

Upadhyay et al. (1977) developed a wellbore simulator and compared calculated and observed pressure drops in two-phase geothermal wells. They concluded that the Orkizsewski (1967) correlation gave satisfactory results, and reported that it had been used with success to predict geothermal well deliverability under different wellbore designs. Similar conclusions were reached by Fandriana et al. (1981).

The problems of wellbore calcite deposition and son et al. (1984). The wellbore simulator used was developed by Ortiz-R (1983) and uses the two-phase correlations of the Orkizsewski (1967) method. This simulator was tested against flowing temperature and pressure surveys in three wells: East Mesa 6-1, Cerro Prieto Y-90 and Roosevelt Hot Springs 14-2. The wellbore simulator accepts either wellhead or downhole data. Up to eight wellbore diameters with different roughness values can be used. This wellbore simulator was used by Gudmundsson (1984), and in the study reported here.

DISCHARGE ANALYSIS METHOD

The discharge analysis method is based on three key elements. The first of these is having a wellbore simulator for two-phase geothermal wells. This makes it possible to calculate down-hole flowing pressures corresponding to measured wellhead conditions. The simulator must have the capability to start the calculations from both the wellhead and well bottom.

The second key element is the concept of productivity index P.I. as discussed by Craft and Hawkins (1959):

$$P.I. = \frac{w}{\bar{p} - p_{wf}}$$

where w represents the total wellbore flowrate and $\bar{p}$ and p_{wf} the average reservoir pressure (static feedzone pressure) and well bottom flowing pressure, respectively. The concept of productivity index is simple and easy to work with. As used in this paper, the productivity index is assumed to stay constant not only with flowrate but also to some extent with time. The wells are assumed to have reached steady flowrate when measured. Also, the analysis refers to the well discharge characteristics at the time of the output measurement used in the calculations.

The third key element is knowing the pressure at the depth of the pivot point. The pivot point pressure represents the static reservoir pressure at the main feedzone of the well, denoted by $\bar{p}$ in this paper. To obtain the pivot point pressure, at least two pressure surveys must be made in the well during warm-up. The pivot point depth is the only point in the well where the pressure remains constant during warm-up (Grant et al., 1963). In wells with one major feedzone, the pivot point and the feedzone are at the same depth. In wells with two major feedzones, the pivot point will be located between the feedzones according to the lever rule; the point being closer to the higher productivity index feedzone.

The following data are required in the discharge analysis method:

(a) One output (discharge) measurement giving total flowrate, wellhead pressure, and total mixture enthalpy. The fluid chemistry should also be included to obtain the liquid density and the amount of non-condensable gases.

(b) Two pressure profiles in the static well during warm-up to determine the pivot point that represents the average reservoir pressure at that depth.

(c) Well and casing design for depth, diameter, and roughness.

The following calculations are carried out in the discharge analysis method using a wellbore simulator:

sure profile down to the depth of the pivot point. This gives p_{wf}, the flowing wellbore pressure at "well bottom."

(b) Calculate the productivity index using the measured flowrate w and the pressure values $\bar{p}$ and p_{wf} already obtained.

(c) Using the productivity index determined, calculate the flowing wellbore pressure for some new flowrate; higher **or** lower.

(d) Starting from the depth **of** the pivot point and using the new wellbore flowing pressure, calculate the pressure (and temperature) profile to the wellhead. This gives **a** new wellhead pressure.

By repeating steps (c) and (d) of the calculations. it becomes possible to determine the wellhead pressure at different flowrates. and to construct a deliverability curve.

REYKJANES FIELD

The Reykjanes high-temperature, liquid-dominated geothermal Aeld is on the tip **of** the Reykjanes Peninsula in south-west Iceland. **An** extensive exploration effort was mounted at Reykjanes in the years **1968** to **1970** (Bjornsson et al. **1970;** Bjornsson et al. **1972).** This was done in relation to plans to produce salt and various sea-chemicals (Lindal, **1975).** The exploration showed that the fleld would be suitable for development. However, the proposed sea-chemicals scheme did not materialize at that time and further geothermal work at Reykjanes was limited until about ten years later.

The Reykjanes field is thought to be one **of** the smaller high-temperature geothermal fields in Iceland, with a surface area of about 2 km^2. In **1968** and 1969, seven **wells** were drilled in the field. Four of the wells **(2. 3, 4** and **8)** were deep **(301** m, **1165** m, **1036 m** and 1754 m) and encountered both high temperature and permeable zones, while three wells **(5, 8** and **7)** were relatively shallow **(112 m, 572** m and **73** m) and did not penetrate the hot reservoir. In **1963,** well 9 was drilled to a depth of 1445 m. Wells **8** and **9** are the two production wells in Reykjanes. Gudmundsson et **al. (1981)** have discussed the subsurface exploration in Reykjanes and the discharge characteristics of well **8.** Figure **1** shows the geologic details of the Reykjanes **fleld** and the location of wells drilled.

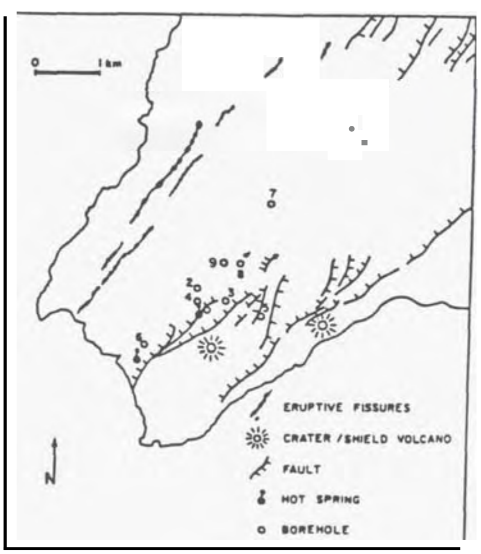

Figure 1. The Reykjanes geothermal field; geologic features and location of wells.

The average concentration of major elements in the deep brines feeding wells *8* and 9 in Reykjanes are shown in Table 1. The table shows that the brines are similar in total dissolved solids (TDS) to that of ordinary seawater. Also shown are the well depths and assumed brine reservoir temperatures. If the inflow temperature of well 9 is taken to be less than 295 "C. the concentrations in Table 1 need to be increased a little, making them **closer** to those reported for **well *8*.**

It has been found that hyaloclastite tuffs, breccias and

of the Reykjanes fleld (Tomasson and Kristrnannsdottir, **1972).** At greater depths, about half the rock is basalt and the rest tuffaceous rocks, mainly sediments. Although the hyaloclastite **is** highly porous, few good aquifers have been encountered in this formation. Numerous aquifers, however. are found in the interbeds of the deeper basaltic formation. Contacts between lava **flows** and interbeds are thought to be highly porous and permeable. Faults and fissures seem **also** to form channels **of** high permeability in **the** Reykjanes fleld.

Table 1: Average concentration (mg/kg) of chemical components in Reykjanes brines. Well 8 and seawater from Haukeson (1981); well 9 from Bjarnason (1984). Also shown are well depth and assumed brine reservoir temperature.

Component	Seawater	Well 8	Well 9
SiO_2	6.0	588	584
Na	10,470	9,520	9,120
K	380	1,380	1.387
Ca	398	1,580	1,475
Mg	1,250	1.43	0.87
SO_4	2,630	40.8	17.8
Cl	18,800	19,200	17,634
F	1.26	0.15	0.15
TDS	33,900	33,300	30,272
CO_2	100	1,930	1,842
H_2S	-	36.5	58.1
H_2	-	0.24	0.14
Depth (m)	-	1,754	1,445
Temp. (°C)	-	270	295

WELL EVALUATION

The drilling of well 9 in Reykjanes has been reported by Franzson et **al. (1983).** The well was drilled and tested from April **11** to May **6, 1983.** It has a **18-5/8"** casing to **63** m depth, **a 13-3/8"** casing to **525** m depth, and a **9-5/8"** slotted liner from **503** m to 1417 m depth. The well **was** drilled to a total depth of **1445 m.** Drilling mud was used in the flrst **525** m -while drilling the casing depth " and then water was used to bottom. The Arst fluid **loss** below casing depth was ***5.5*** kg/s at ***670*** m depth. It was possible to maintain the fluid **loss** to about **10 kg/s** by adding wood-chips to the drilling duid down to **1050** m. **From** that depth and down to about **1300** m. the fluid loss was above **12 kg/s.** At **1316** m depth there was a total **loss** of **37** kg/s that was then stopped by adding wood-chips to the drilling duids. Total **loss** was then again encountered at a depth of **1352 m.** It was not possible to stop this **loss.** The well was then drilled to total depth without further drill-cuttings being returned to the surface.

Total depth was reached on April **30, 1983. Two** days later the well was logged while injecting 17 kg/s and 37 kg/s of cold water. **The** temperature profiles are shown in Figure **2.** They show that there was interzonal flow from the interval **595-715** m and down to hole bottom. To determine the interzonal flowrate, the inflow temperature needs to be known. The minimum flowrate can be estimated by using the reservoir temperature in the inflow interval. Figure **3** shows two temperature profiles measured in well **9.** The measurement on Yay **31, 1983** was taken one month after the injection test. The log shows **250** "C at 600 m depth. Using this as the reservoir temperature, the **flow** estimated to enter the well at 600 m depth was about 4 kg/s when injecting **37** kg/s, and 7 kg/s when injecting **17** kg/s. These flowrates would be higher if the inflow temperature at **600 m** depth was assumed lower. The temperature log from September **10, 1983** shows the temperature at 600 m depth to be 267 °C. The injection tests **show** (Figure **2)** that well **9** has at least two potential feedzones; an upper zone in the depth range 600-700 m and a lower zone near well bottom.

Two pressure profiles were measured in well 9. These are **shown** in Figure **4.** They were measured at the same time as the temperature profiles shown in Figure 3. The measurements on May **31, 1983** were done while the well was open, with the water level at **32.4** m depth. The other measurements were done just before the well was discharged for the flrst time. The well had been closed for a few weeks **and** pressure had built up under the wellhead. The wellhead pressure **was *52*** kg/cm^2, increasing **a** little **down** to 400-600 m depth. Figure **4** indicates that on **May** 31, 1983 there was a column of steam - and perhaps some boiling - down to a depth of 600 m. At greater depths the

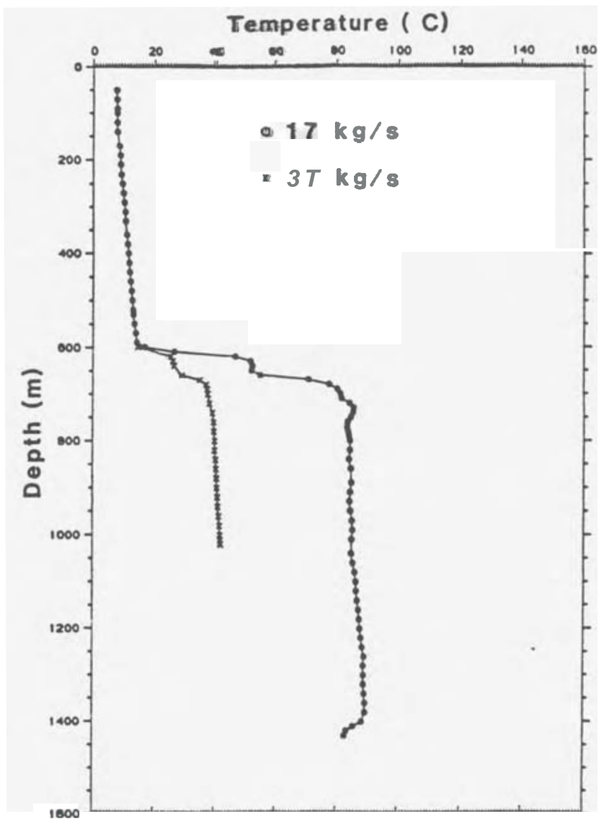

Figure 2. Temperature profiles in well 9. while injecting 17 kg/s and 37 kg/s of cold water on May 2, 1983.

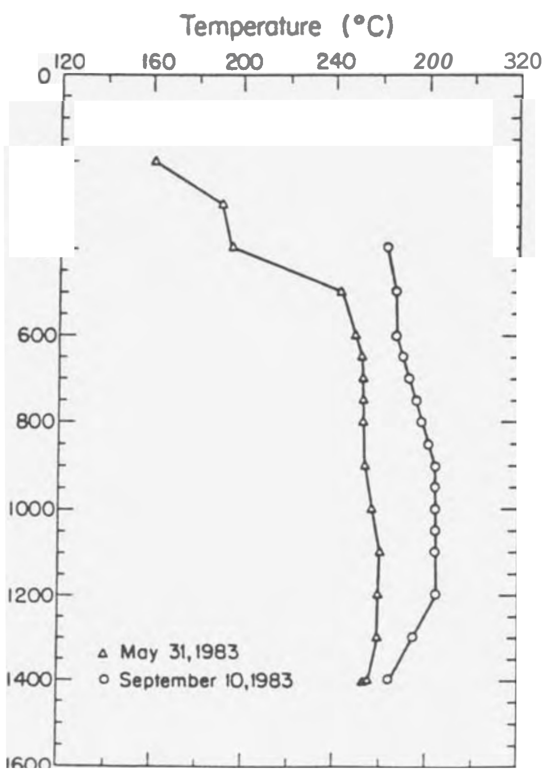

Figure 3. Static temperature profiles in well 9, during warm-up on May 31, 1983, and on September 10, 1983. just before discharge.

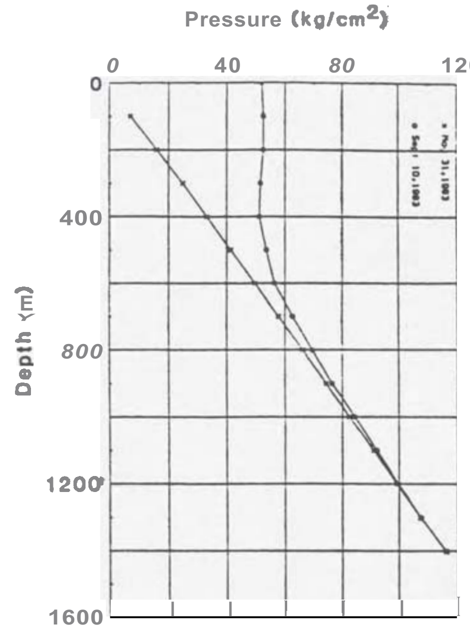

Figure 4. Static pressure profiles in well 9. during warm-up on May 31, 1983. and on September 10, 1983, just before discharge.

An examination of Figure 4 shows that the two pressure profiles cross near well bottom The cross-over occurs at a depth of about 1345 m and shows the pivot point of the well. In wells with one major feedzone the pivot point represents the true reservoir pressure at that same depth. In wells with two feedzones the pivot point will be Located closer to the zone that dominates the well flow under production. Figure 4 indicates that the major feedzone of well 9 is near well bottom. A pivot point depth of 1345 m correlates well with 1352 m as the major loss zone during drilling. These two depths agree better than apparent here, because the loss of circulation depth refers to the drillrig's rotary while the pivot point refers to the wellhead flange 5 m below.

PRODUCTION TESTING

Discharge of well 9 was initiated on September 14, 1983. Prior to that time the wellhead valve had been closed and pressure allowed to build-up to the value shown on Figure 4. The wellbore temperature profile before discharge is shown on Figure 3. The well was opened through a vertical 2" valve at 14:00. A few minutes later the horizontal leg was opened through a critical flow nozzle, and a telescopic silencer, into an open circular tank. The steam escaped into the atmosphere and the water was metered in a V-notch weir. An orifice plate was positioned between the wellhead and critical flow nozzle to maintain wellhead pressure. The first flowrate measurement was made at 14:05 when the 2" vertical valve had been closed. The critical flow nozzle used was 80 mm in diameter. Six output measurements were made during the first day of discharge. The total flowrate and wellhead pressure are shown in Figure 5. At the end of the day the output values were 36 kg/s at a wellhead pressure 39 bar-g and with a total mixture enthalpy of 1230 kJ/kg.

After about ten days of discharge. the well had to be shut-in to clean silica deposits from the pressure line to the critical flow nozzle. Figure 6 shows the output measurements taken during the first ten days of discharge. The flowrate. wellhead pressure and enthalpy were in the range 33-36 kg/s, 39-42 bar-g and 1190-1340 kJ/kg, respectively. On September 28, 1983 the well was again put on discharge but silica deposition continued to be a problem. The well was again shut-in on November 2, 1983. The diameter of the critical flow nozzle had decreased from 80 mm to about 73 mm. Therefore, the nozzle flow area had been reduced by about 20 percent. This means that the output values taken after the first week or so cannot be used.

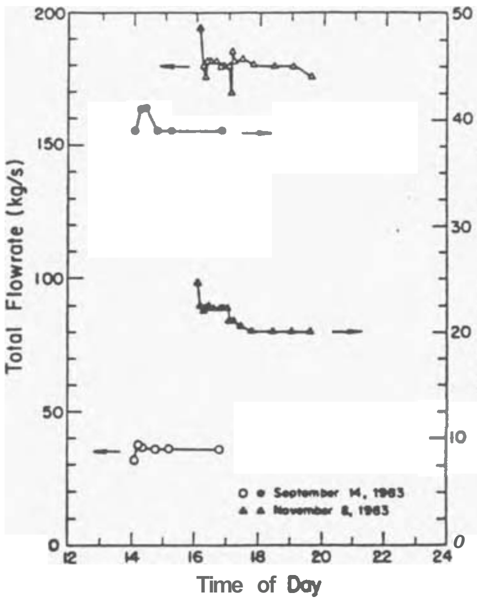

Figure 5. Flowrate and wellhead pressure of well 9, on September 14, 1983 and November 8, 1993.

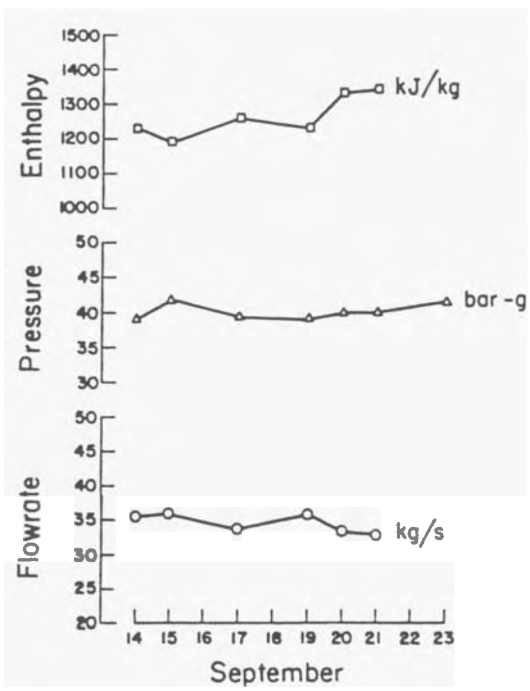

Figure 6. Flowrate, wellhead pressure, and mixture enthalpy of well 9, during first ten days of flow testing in September 1983.

higher flowrates. two critical flow nozzles discharging into the atmosphere had to be used. Well 9 was flow tested on November 8, 1983 using two nozzles. The total mixture enthalpy had to be assumed to determine the flowrate when using this method. The well was opened at 16:00 into a 209 mm flow nozzle, and one hour later into a 105 mm nozzle; one vertical and the other horizontal. The output measurements taken that day are shown in Figure 5. The wellhead pressure approached 22 bar-g the first hour and 20 bar-g the second. The flowrate. however, was about 180 kg/s at both wellhead pressures. The total mixture enthalpy was assumed 1320 kJ/kg.

Seven chemical samples were taken from September 14 and November 30, 1903 of the mixture produced by well 9 (Bjnrnason. 1964). The analysis of these samples show that the chemical composition was constant during the period. The average of these analyses is shown in Table 1.

et al. (1983) were in the range 267 to 288 °C with 273 ° as the average of the seven samples. The enthalpy of water at this average temperature is 1200 kJ/kg. The pressure sensitive silica geothermometer of Ragnarsdottir and Walther (1983) gives a higher average temperature of 297 °C. This temperature corresponds to water with enthalpy of almost 1330 kJ/kg.

WELLBORE CALCULATIONS

The discharge analysis method was used to calculate the output curve of well 9 in Reykjanes. The details of the wellbore simulator are given by Ortiz-R. (1983). 'An important reason for calculating the discharge behavior of well 9. as reported here, was to investigate how the simulator performs for large diameter wells. The following data were first used as input in the discharge analysis method wellhead pressure 39 bar-g, mixture flowrate 37 kg/s and enthalpy 1180 kJ/kg. The pivot point pressure (reservoir pressure) was determined as 111 bar-g at 1345 m depth. The casing internal diameters (ID's) used in the calculations were 12.415" from surface to 503 m depth and 9.835" to bottom. The pipe roughness was assumed 0.0003 ft for both casing and liner. The flowing pressure at 1345 m depth was calculated as 134 bar-g, or 23 bar higher than the pivot point pressure. Taking the flowrate as 34 kg/s, changed the calculated flowing pressure by less than one bar. It was decided to investigate the effect of mixture enthalpy on the wellbore pressure profile.

For a mixture flowrate of 37 kg/s and wellhead pressure of 39 bar-g, the wellbore simulator was used to calculate the flowing profiles for well 9. Heat transfer between the wellbore and reservoir was assumed zero; adiabatic flow up the well. The results are shown in Figure 7 for several mixture enthalpy values. The figure shows the flowing pressure at 1345 m depth and the depth to first Bashing in the wellbore. The pivot point pressure in the static well is shown for reference. Also shown is the range of mixture enthalpy measured during the first ten days of discharge. An examination of Figure 7 shows that the pressure profile in well 9 is very sensitive to the mixture enthalpy. The accuracy of normal enthalpy measurements is reported more or less 50 kJ/kg (Grant et al. 1982). Figure 7 shows that for enthalpy values in the range 1200-1300 kJ/kg - as would be the case if the true enthalpy was 1250 kJ/kg - result in flashing occurring in the depth range 450-1450 m; that is, one kilometer range.

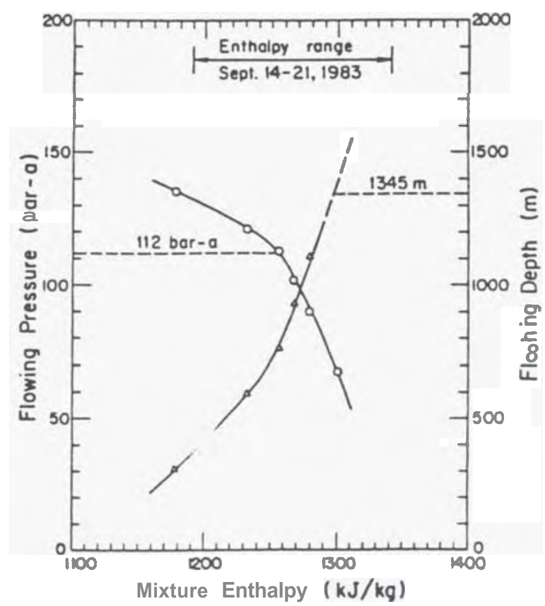

Figure 7. Calculated flowing pressure at depth of pivot point (1345 m), and calculated depth of flashing, at diderent mixture enthalpy values. Also, range of enthalpy values measured during first ten days of testing.

The calculations were continued using the same flowrate and 1268 kJ/kg as the mixvalues shown in Figure 7, for the period September 14-21. 1983. Using this mixture enthalpy, the flowing pressure at 1345 m depth was calculated as 101 bar-g, so the productivity index becomes 3.7 kg/s.bar. This compares to 2.7 kg/s.bar, as determined by the same method for well 12 in the Svartsengi field. also on the Reykjanes Peninsula (Gudmundsson. 1984).

Two calculated deliverability curves are shown on Figure 8. Also shown are the two output measurements determined on September 14, and November 8, 1983. The two deliverability curves result from different assumptions about the roughness of the wellbore. Taking the roughness as 0.0003 ft, which would be typical for commercial pipes, the calculated flowrate fell short of the 180 kg/s measured. Assuming a smooth wellbore. but still taking friction into consideration, the calculated dowrate was greater and closer to that measured.

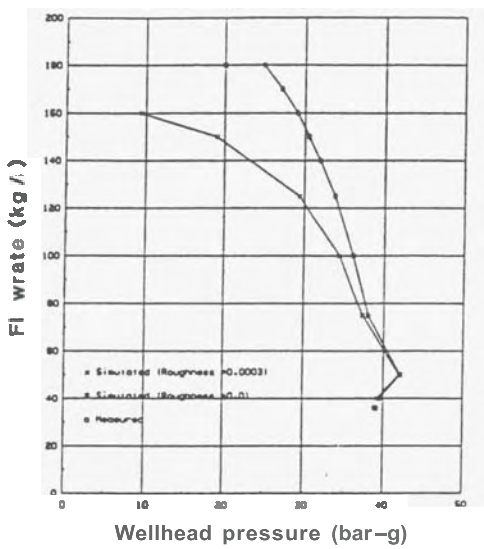

Figure 8. Calculated deliverability curves for well 9. The two curves refer to differentwellbore roughness. *Also* shown are the two output measurements.

DISCUSSION

Large diameter wells have been drilled in two high-temperature fields in Iceland. First in Svartsengi - wells 7 to 12 - and now in Reykjanes. *An* important incentive for drilling the 13-3/8" wells in Svartsengi. was to lessen the effectof wellbore deposition on output. The wells suffer from calcium carbonate deposition, and have to be cleaned by drilling every year or two. It was argued, that by increasing the cross-sectional flow area, the wells would not fail as rapidly. The high flowrates in the large diameter Svartsengi wells was an added bonus.

The wellbore simulator calculations have shown how very sensitive the discharge analysts method is to mixture enthalpy. The same would hold true for any other wellbore flow calculations. The other parameter of great importance is wellbore diameter. When both of these parameters are large, the wellbore output also becomes large. At these conditions the calculation methods used in wellbore simulator are most likely to fail. The reason for this is that the methods have been developed from data obtained in small diameter pipes and at much lower flowrates than found in geothermal wells. Another difference is that the experimental data are almost all from non-flashing situations. The wellbore simulator used in this paper is based on the Orkizsewski (1967)method. It seems to give reasonable results. Nevertheless. there appears to be scope for developing better wellbore simulators for geothermal wells. Better data on the roughness of casing and slotted liners used in geothermal wells appear also to be needed.

Applications of state-of-the-art wellbore simulators to geothermal well production problems, are likely to show some limitations of the methods used At the same time. such uses *may* also point the way to new developments *and* applications The following items appear to deserve some attention (1) measure the wellbore flowing pressure at the pivot point depth, (2) use well testing data of permeability thickness instead of productivity index, (3) consider the effect of turbulent flow (non-Darcy) in the feedzone. and (4) estimate the decrease in wellbore output with time using a reservoir draw-down model.

CONCLUSIONS

The output of well 9 in Reykjanes has been measured 180 kg/s at a wellhead pressure of 20 bar-g, and 36 kg/s at a wellhead pressure of 39 bar-g. The inflow brine temperature is likely to be 280-290 °C. This makes well 9 the most prolific geothermal production well in Iceland, if not the world.

The main feedzone of well 9 is in the depth range 1340-1350 m. It was located - independently - by a total circulation loss during drilling, and the wellbore pivot point determined from two pressure surveys made during warm-up. The pivot point analysis showed that a loss of circulation zone in *the* depth range *600-700* m, is unlikely to contribute much to the well flow.

Wellbore diameter and mixture enthalpy are the two most important parameters to determine the output of geothermal wells. The diameter effect affects decisions about drilling and wellbore design. The enthalpy effect concerns accurate measurements of wellbore discharge. Wellbore roughness is an important parameter at high flowrates.

The discharge analysis method provides the necessary boundary conditions to construct a deliverability curve of two-phase geothermal wells from only one output measurement. The method would benefit from improvements in state-of-the-art wellbore simulators. Pressure profiles should be measured in all geothermal wells during warm-up because of their several uses in production and reservoir engineering studies.

ACKNOWLEDGMENTS

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