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RESERVOIR STUDIES OF THE SELTJARNARNES GEOTHERMAL FIELD, ICELAND

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ABSTRACT

The Seltjarnarnes geothermal field in Iceland has been exploited for space heating for the last 16 years. A model of the field has been developed that integrates all available data. The model has been calibrated against the flow rate and pressure decline histories of the wells and the temperature and chemical changes of the produced fluids. This has allowed for the estimation of the permeability and porosity distribution of the system, and the volume of the hot reservoir. Predictions of future reservoir behavior using the model suggest small pressure and temperature changes, but a continuous increase in the salinity of the fluids produced.

INTRODUCTION

The Seltjarnarnes geothermal area is located in Seltjarnarnes, a suburb of Reykjavik, the capital city of Iceland (Figure 1). The field has been exploited for the past 16 years to provide hot fluids for the central heating of Seltjarnarnes. In the typical low temperature field, temperatures of about 100 °C at have been encountered at 1000 m depth, and over 140 °C at 2700 m depth. Drilling in the region started in 1965; a total of six wells had been drilled by 1985. Four of these wells are being produced with maximum capacity of 110 l/s, while the remaining two are used for observation.

During the sixteen years of production (1970 to 1986), the salinity within the system has increased. Although the salinity changes were relatively slow initially, an increase in production in 1972 (by 35 l/s), and again in 1981 (by 30 l/s), accelerated the increase. Changes in the average temperature of the produced fluids have been very small (<2 °C) throughout the production period. The pressure changes induced by production have also been small.

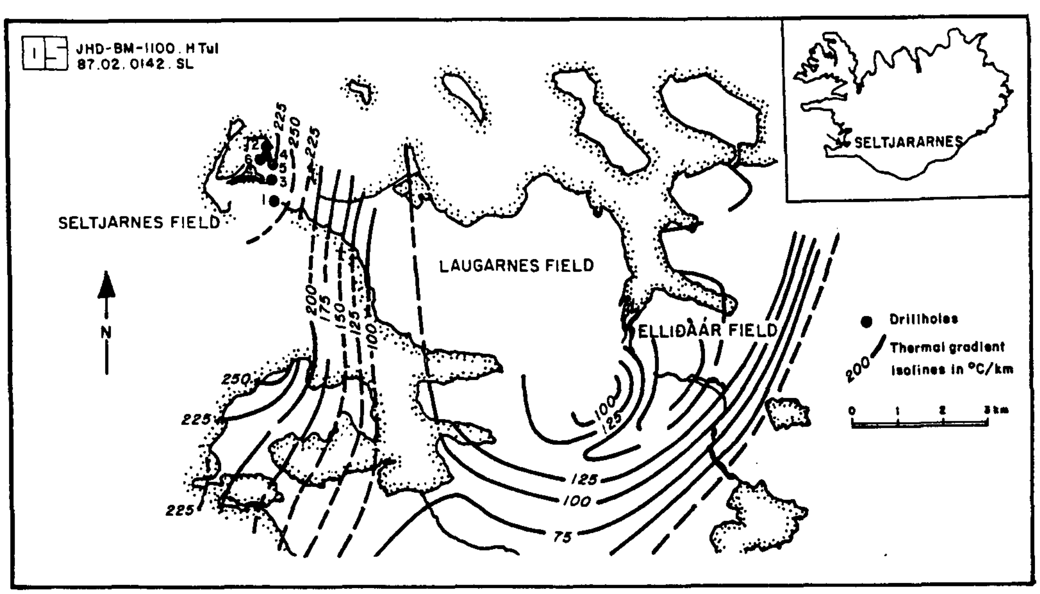

Figure 1. Low-temperature geothermal fields in Reykjavik, showing the locations of the wells in the Seltjarnarnes field. Contours of the thermal gradient in the region are shown on the map.

In the summer of 1986, all available data on the Seltjarnarnes field (geological, geophysical and geochemical) were compiled and integrated, into a conceptual model for reservoir simulation studies. The main objective of this work was to develop a numerical model of the field that was calibrated against the production history, interference test data and observed thermal and chemical changes. The model was then used to predict changes in pressure, temperature, and chemical composition with future production. This paper summerizes the work done; a detailed description is given in Tulinius et al. (1987).

BACKGROUND

Since the drilling of the first well in 1965, considerable amounts of data have been collected and several reports have been published describing the field (Tomasson et al., 1977; Palmason et al., 1983; Sigurdsson et al., 1985 and Kristmannsdottir, 1986). Other, more specific reports on well drilling, fracturing, pressure testing, well tests, fluid chemistry and other aspects of the Seltjarnarnes field include Sveinbjornsdottir et al., 1984a,b; Kristmannsdottir, 1983 and 1984; Kristmannsdottir and Tulinius, 1984; Kristmannsdottir et al., 1984; Tomasson and Saemundsson, 1970; Haraldsdottir, 1984; Thorsteinsson, 1970, 1980 - 1985; Thorsteinsson and Tomasson, 1972; and Thorsteinsson et al., 1985).

The Seltjarnarnes field is located in the Kjalarnes caldera. The main reservoir rocks are Quanternary (1.8 - 2.8 m.y.b.p.), and become younger towards the southeast. A simplified geological cross-section including all six wells is shown in Figure 2. The cross-section, which extends from well SN-01 in the southeast to well SN-02 in the northeast, is based on analyses of drill cuttings. The rocks can be divided into 7 main groups (8 for well SN-06) of Quaternary basalt lavas and hyaloclastites interbedded with a few small sedimentary beds and igneous intrusions that increase in frequency with depth.

Several aquifers have been identified in each of the wells from water losses/gains during drilling, or from temperature logs during the heating period. The main feed zones are shown in Figure 2. All of the wells have at least three feed zones, and some as many as nine (well SN-06). Well SN-01 intersects five aquifers, although it is not productive. The four production wells all encounter an aquifer at around 400 m (see Figure 2). This aquifer probably contains very saline water with an average temperature of 75 °C - 80 °C. The most productive aquifer in all of the wells is located below a depth of 1700 m and has a temperature of approximately 125 °C. About 40% of the water produced from wells SN-03 and SN-05 comes from this aquifer, and up to 80% in wells SN-04 and SN-06.

Several downhole temperature surveys have been obtained for each of the wells. Figure 3 shows the estimated formation temperature profiles for all of the wells. All of the profiles show an increase in temperature with depth with an approximate 300 °C/km gradient in the uppermost 200 m. Below a depth of 600 m, the thermal gradient is about 35 °C/km. The highest measured temperature (>140 °C) is in well SN-06 at 2700 m

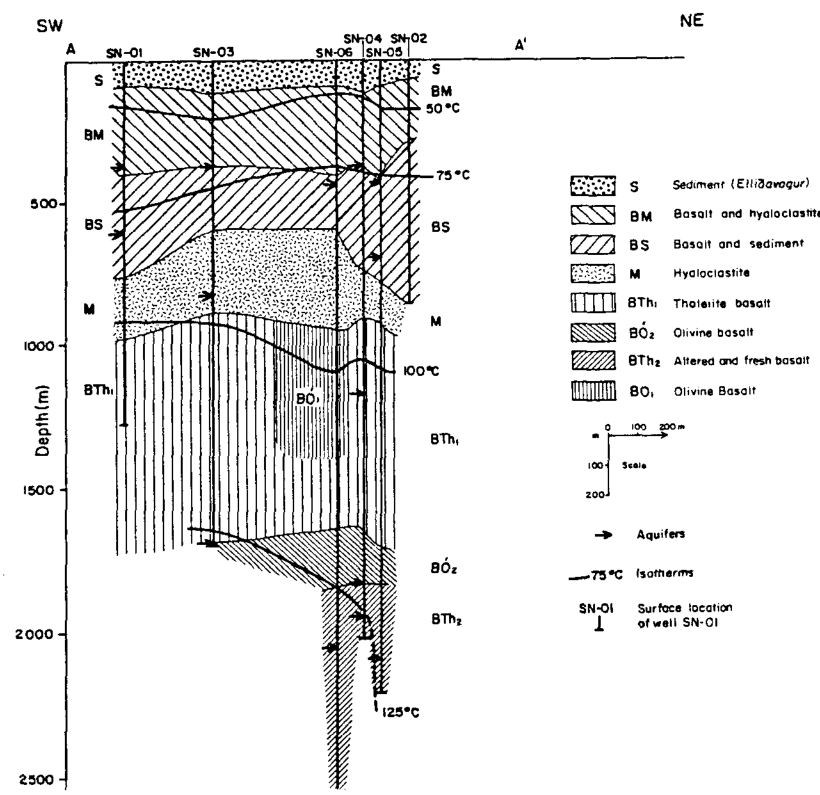

Figure 2. Cross-section A-A' of the Seltjarnarnes field.

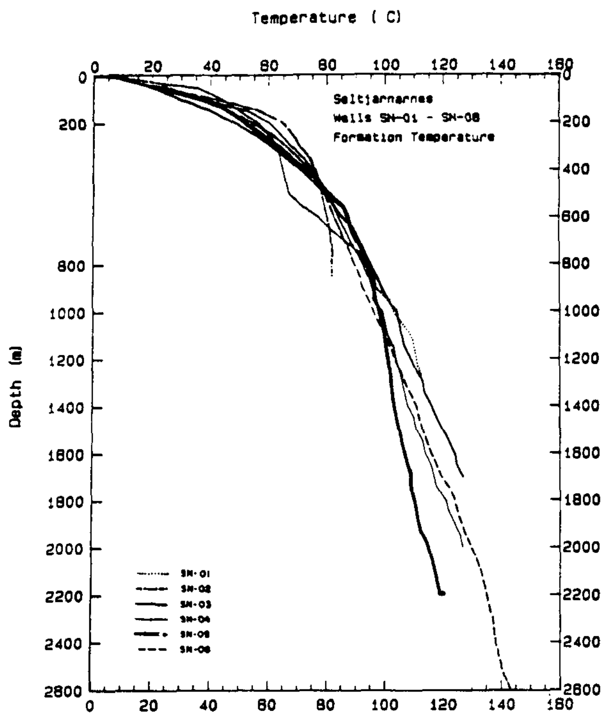

Figure 3. Estimated formation temperature profiles for all six wells.

depth. Temperatures average 110 °C in the 400 - 2200 m interval, where most of the aquifers are encountered. Isotherms plotted along the cross-section AA' (see Figure 2) indicate that temperatures are fairly uniform over the entire wellfield above 1500 m. Well SN-05 is somewhat colder than the other wells below 2000 m depth. This could indicate that hot water recharges the reservoir from the south-east or that colder waters are present close to well SN-05.

Chemical monitoring of the geothermal water has been carried out since 1968. Several downhole samples collected early in the production period indicate that the initial concentrations of the total dissolved solids, chloride, and sodium were fairly uniform throughout the wellfield. The produced water was relatively saline in the beginning of production (1300 ppm total dissolved solids). The salinity increased slowly for the first ten years of production, as the rate of production has increased, so has the rate of increase in salinity. The total dissolved solids has increased from about 1300 ppm in 1966 to 3000 ppm in 1986. The chloride concentration is now 1000 - 1400 ppm, up from around 500 ppm in 1966. Likewise, the concentration of sodium has increased from approximately 300 ppm in 1966 to 600 - 800 ppm in 1986. The stable isotope ratio oxygen-18/oxygen-16 has not changed significantly with time. The near-constant concentration of oxygen-18 suggests recharge of meteoric water, whereas the increase in the chloride and sodium suggests an influx of seawater.

While continuous chemical monitoring of wells SN-02 through SN-06 shows a significant increase in salinity, downhole samples taken from well SN-01 in 1984 show that no changes in the salinity have occurred in the vicinity of this well. This suggests that this well is outside the main reservoir. Samples taken from wells SN-02 through SN-06 at different depths also indicate that the salinity has increased most in the shallow aquifers.

Water level monitoring in the area started in 1966 with the objective of determining if production in the Laugarnes field was causing drawdown in the Seltjarnarnes field 5 - 6 km away (Thorsteinsson and Eliasson, 1970). As no significant changes were observed, it was concluded that these two fields are separated by an impermeable barrier. The water level monitoring continued, using wells SN-01 and SN-02, after production in the field started.

Several interference tests have been performed at the Seltjarnarnes field. A test performed in August - September 1970 involved production of 17 l/s from well SN-03 for 14 days, while water levels were monitored in wells SN-01 and SN-02. The drawdown over the 14 day period was only 4 m in well SN-01 and 6 m in well SN-02. Although well SN-01 is closer than SN-02 to well SN-03, the well experienced less drawdown. This indicates higher permeability between SN-02 and SN-03 than between wells SN-01 and SN-03. It should be noted that well SN-02 was flowing prior to the interference test, which means that part of the drawdown in SN-02 could be due to cooling in the upper part of the well.

CONCEPTUAL MODEL

All available data were integrated to form a conceptual model of the field. The thermal gradient low between Seltjarnarnes and the Laugarnes and Ellidaar fields and the fact that no pressure changes were detected in the Seltjarnarnes field due to production in the Laugarnes field, indicate the presence of low permeability rocks (faults?) between these fields. Tests on shallow wells indicate that the top 100 m of the subsurface rocks are nearly impermeable. Most of the aquifers are located in the interval from about 400 m to 2200 m depth (see Figure 2).

The low oxygen-18 content of the fluid indicates that the water originated from a meteoric source, most likely infiltrating in the highlands tens of kilometers to the north (Arnason, 1976, 1986). The water percolates down to about 3 - 4 km depth, and heats up due to the anomalous thermal conditions in the subsurface rocks. The water flows to the south and ascends under the Seltjarnarnes field through fissures that extend to considerable depths and are more permeable than in the surrounding areas. The small amount of change in the oxygen-18 suggests that a large portion of the fluids recharging the field during exploitation is meteoric. The increase in most of the other chemical components is large, indicating that a portion of the recharge fluids consists of highly saline water. The source is most likely seawater recharging the reservoir at shallow depths (above 400 m). From the observed changes in the chemical composition of individual wells, it appears that the seawater is recharging from the southwest.

Figure 4 shows a topview of the conceptual model for the Seltjarnarnes area. Lines with equal thermal gradient in the uppermost 200 - 300 m are plotted on the figure (Tulinius et al., 1986), along with suggested flow directions for the recharge water (plotted as arrows).

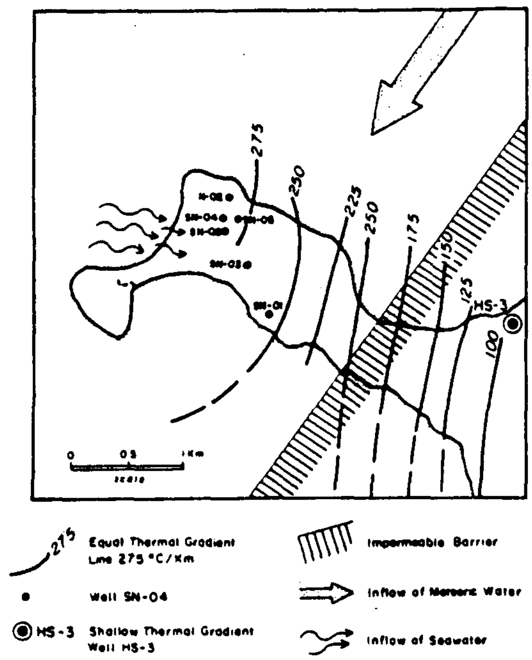

Figure 4. Conceptual model of the Seltjarnarnes geothermal field.

NUMERICAL SIMULATION

The single-phase three-dimensional numerical code PT (Bodvarsson, 1982) was used to simulate the interference tests and the production history. The simulator solves the mass and energy transport equations for liquid-saturated, heterogeneous, porous and/or fractured media using an integrated finite-difference method. The density of the fluid is calculated as a function of pressure and temperature; fluid viscosity is calculated as a function of temperature. A modified version of PT (Spencer, 1986), which allows for chemical transport modeling, was used to model the changes in the chloride, sodium, silica and oxygen-18 concentrations. The modified program is capable of modeling the convective transport of up to ten conservative (non-reactive) chemical species, as well as the kinetic reactions and convective transport of silica and oxygen-18.

In the first attempt to match the interference and production data, a single layer, two-dimensional model was used. Isothermal conditions were assumed initially, with temperature held constant at 110 ° C. This allowed very economical compilations to be achieved, as only the mass balance equation was solved. The model used a 1800 m recharge layer representing the depth interval 400 - 2200 m. The mesh consisted of squares 50 x 50 m in size around the wells and increasing rapidly in size away from the wellfield. The grid extended far enough in all directions so that boundary conditions were not felt during the simulation (infinite reservoir system). The total number of elements was 316. The initial average pressure was estimated to be 123 bars, using the average depth of 1300 m, density of water at 110 ° C, and the initial wellhead pressure in well SN-02 of 13 m.a.s.l. The interference tests from 1970 involving wells SN-01, SN-02 and SN-03 and the production history were simulated. Trial and error simulations were carried out using the permeability (k) and porosity (ϕ) as adjustable parameters. The compressibility of the rock (C) was held constant at 5×10^{-10} Pa^{-1}.

RESULTS

The best model derived from the match using the interference test data consisted of six regions with different porosities and permeabilities. Figure 5 shows the central portion of the grid and the locations of the six regions; the match between the calculated and observed data is shown in Figure 6. The area around all the wells except SN-01 (region 5) was found to have the

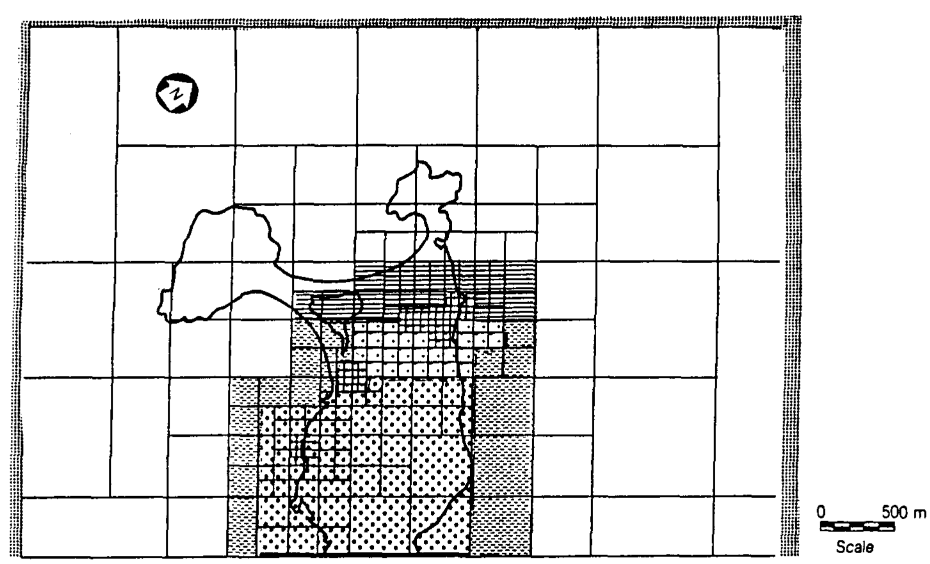

Figure 5. Central part of the mesh showing the location of the six regions of different permeabilities and porosities. Large dots = Region 1; unshaded area = Region 2; dashes = Region 3; small dots = Region 4 (outside mesh region shown); crosses = Region 5; stripes = Reigon 6.

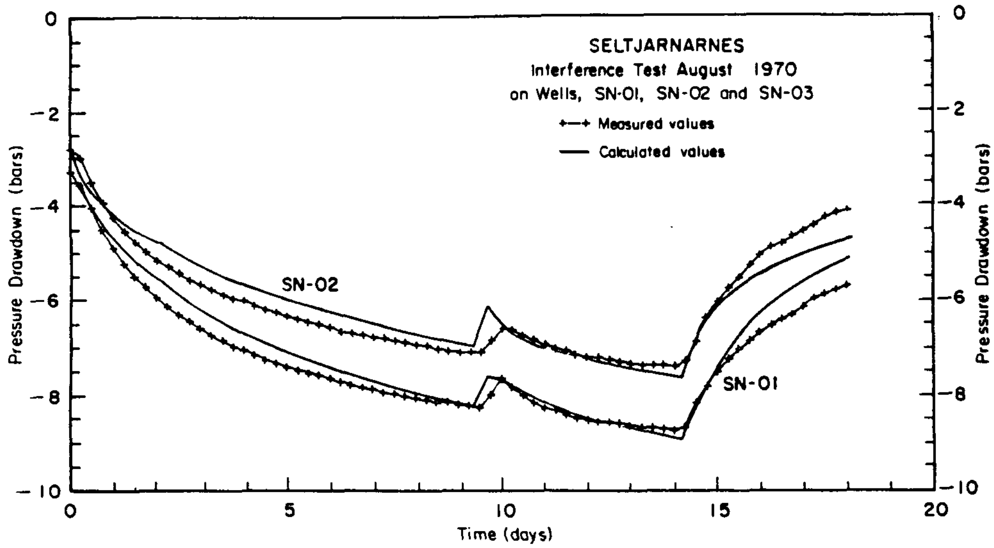

Figure 6. Match between calculated and observed data for the 1970 interference test.

largest permeability (80 md) and a porosity of 2%. The total volume of this region is about 0.8 km^3. The area around well SN-01 (region 1) has the lowest porosity (<0.1%), and a permeability of 7 md. The porosity seems to increase away from the well field with a value of 15% 4 km from the wellfield (region 4); the permeability of this region is about 10 - 15 md. The porosity and permeability near the wellfield are estimated to be 3% and 10 md, respectively (region 2). To achieve a reasonable match with the pressure transients for both wells SN-01 and SN-02, a third region between region 1 (well SN-01) and region 2 with a porosity of 0.3%, and a permeability of 10 md was necessary. Region 6 has a porosity of 4%, and a permeability of 10 md.

After matching the interference data the model had to be modified slightly to get a good match for the production history (Figure 7). The permeability away from the wellfield (regions 2, 4 and 6) had to be increased to 17 md and the porosity in the regions next to the wellfield (region 6) was increased from 3 to 4%. All other parameters remained the same.

The fact that somewhat different models were needed to achieve a good match with both the interference test data and the production history suggest that the effects of fractures may be important. Due to the short duration of the interference test, the overall permeability was most likely dominated by the fracture permeability. However, during the long term production period the matrix permeability becomes more important.

TEMPERATURE AND CHEMISTRY MATCH

After obtaining a match using only the pressure data the temperature was taken into account. The same grid was used, dividing the volume into two regions, a

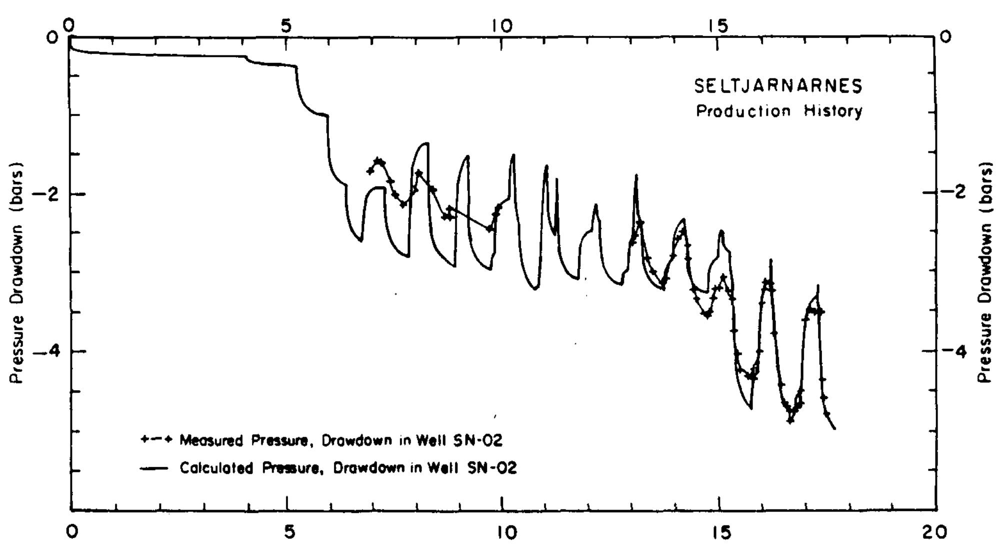

Figure 7. Match between calculated and observed data for the production history.

high temperature region with an initial temperature of 110 °C, and a low temperature region with a temperature of 75 °C. The high temperature region includes the wellfield (region 5) and well SN-01. Using this temperature distribution, very little cooling was detected in the field (<1 °C) over the production history, which is in agreement with the observed data.

To aid in confirming the permeability and porosity of the wellfield, a match with the changes in the fluid chemistry over time was attempted. A very simple two layer model was used, with the entire wellfield contained in one element on the bottom layer. The initial values for temperatures and chemistry were determined from well data. The regions directly above and adjacent to the wellfield were assumed to have fluid of the same composition as that initially present in the field ($Cl^- =$ 500 ppm, $Na^{+2} =$ 300ppm; $\delta O^{18} =$ -10.5 per mil); silica was in equilibrium with the field temperatures (130 ppm at 110 °C in the well field; 80 ppm at 75 °C elsewhere). Seawater ($Cl^- =$ 19,000ppm; $Na^{+2} =$ 10,000ppm; $\delta O^{18} = 0$ per mil) was allowed to infiltrate the system from the top layer, outside the perimeters of the well field region.

Using a trial and error procedure a match for the data was obtained. The results suggest a reservoir volume of 0.75 - 1.0 km^3 and a porosity between 2 and 3%. It must be emphasized that due to the coarseness of the grid, these are only rough estimates of the field parameters and flow patterns. However, they are in close agreement with the values obtained from the match with the pressure history.

The *316 element grid used in modeling the temperature* and pressure was then employed to further study the Seltjarnarnes field by combining the previous results with all available chemical data from the field. The initial chemical concentrations in the wellfield region were the same as those used in the two layer model. Since the results of the pressure and chemistry simulation studies performed on the Seltjarnarnes geothermal field were in close agreement, the chemistry match in this study was not aimed towards verifying field parameters such as the permeabilities, porosities, and reservoir volume. Rather, the purpose of the study was to define the boundaries of the seawater adjacent to the well field.

To achieve the most accurate results for the chemistry match, the calculated and observed data were matched individually for each well. The results for oxygen-18, chloride, sodium and silica are plotted for well SN-03 in Figure 8. For the best match, the seawater boundary follows approximately the land/sea boundary, surrounding the wells on three of four sides, and lying within 350 m of wells SN-02 and SN-05 to the northeast. Figure 9 shows the suggested seawater/meteoric water boundary.

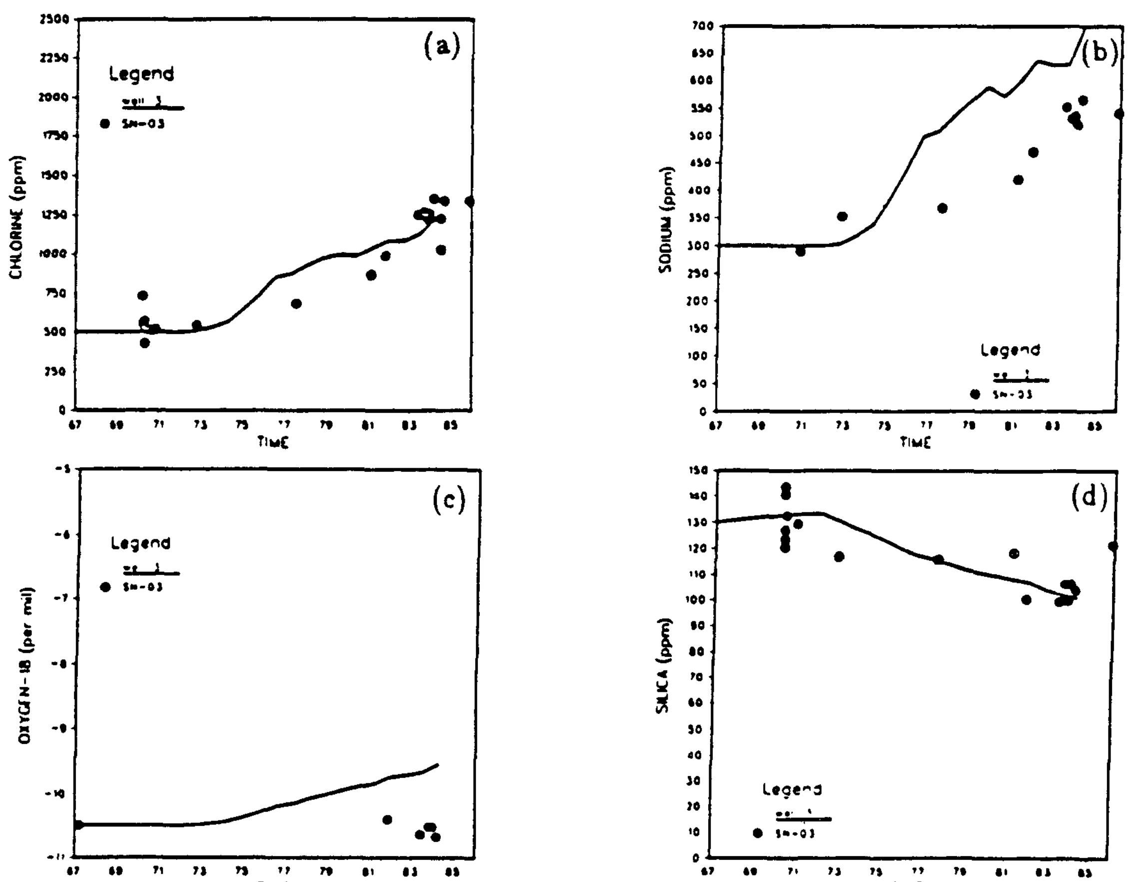

Figure 8. The results of the chemistry matches for well SN-03 for (a) chloride, (b) sodium, (c) oxygen-18 and (d) silica.

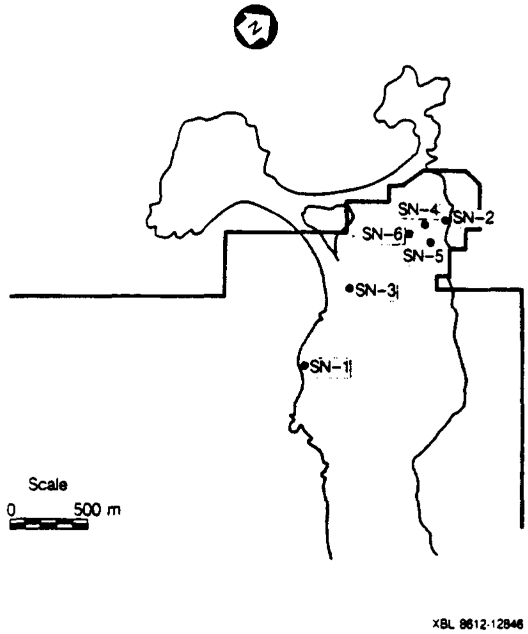

Figure 9. Suggested seawater/meteoric water boundary. The area above the solid line is assumed to contain seawater.

The results also raised several other points. The match with the chloride data was very good (Figure 8a), however, the match with the sodium data was not (Figure 8b). This suggests that the sodium cations in the system sustain significant ionic-exchange reactions, and are not truly conservative as was assumed in the present model. The matches with the oxygen-18 data for the individual wells were not good; the numerical model showed a much more rapid increase in oxygen-18 than the field data (Figure 8c). This could be due to three-dimensional effects, suggesting that fluid having a lower oxygen-18 content than present in the system ($<$-10.5 per mil) is recharging the system from either above or below. Or, it is possible that the fluid infiltrating the system, considered to be seawater, is actually of meteoric origin, but it is flowing through a salty formation before entering the wellfield region. The salts would readily dissolve into fluid, while the oxygen-18 content would remain low.

The results of the silica match (Figure 8d) suggest that kinetic reactions play a strong role in the transport of silica in the Seltjarnarnes system. To achieve the best match for silica, the A/V (surface area open to reaction per volume) value was set at 25.0, indicating fairly rapid kinetic reactions (Spencer, 1986). The kinetic reactions do not appear significant in modeling the oxygen-18, which is probably due to the fractured nature of the reservoir.

Although the chemistry modeling has identified some shortcomings of the two-dimensional model, the model can be used to roughly predict the future influence of the seawater on the system. Thus, an estimate of the amount of influx of seawater into the field in the future could be obtained. The potential corrosion problems may then be evaluated and the necessary steps taken to minimize or alleviate these problems.

PERFORMANCE PREDICTIONS

The main objective of the reservoir simulation studies was to develop a model of the geothermal reservoir to use in predicting changes in pressure and temperature with future production. The model that gave the best match with the production history was used to predict the changes for the next 20 years. Two cases were studied:

(a) Constant production of 70 l/s;

(b) Constant production of 70 l/s for the first five years then 30 l/s increase in production every five years thereafter from two new wells close to well SN-05.

Figures 10a and b show the calculated and measured drawdown in well SN-02 for the two cases. For the simulation, the production period from August 1966 to October 1984 was used. The maximum pressure drawdown after 20 years with no increase in production (case a) is estimated to be 7.4 bars; the maximum temperature decrease would be 3 °C. The maximum pressure drawdown for case b was calculated to be 15.5 bars, with a 7 °C decline in temperature.

CONCLUSIONS

A two-dimensional model for the Seltjarnarnes geothermal field in Iceland has been developed, incorporating thermal, chemical and pressure transient data. Results of matching the model with the observed drawdown data revealed six regions of different permeabilities and porosities. The wellfield lies within a region of high permeability (80 md) and low porosity (2%). The porosities increase away from the field, up to 15% at a distance of 4 km. The model shows no thermal decline, in agreement with observed data. The fluid chemistry modeling indicates that the seawater is very near the wellfield to northwest. The performance predictions showed a maximum drawdown of 15.5 bars over 20 years and a maximum temperature decline of 9 °C, if the production of the field were to increase by 30 l/s every five years beginning in 1991. From the pattern of the observed chemical data, the salinity could increase greatly under this production scheme.

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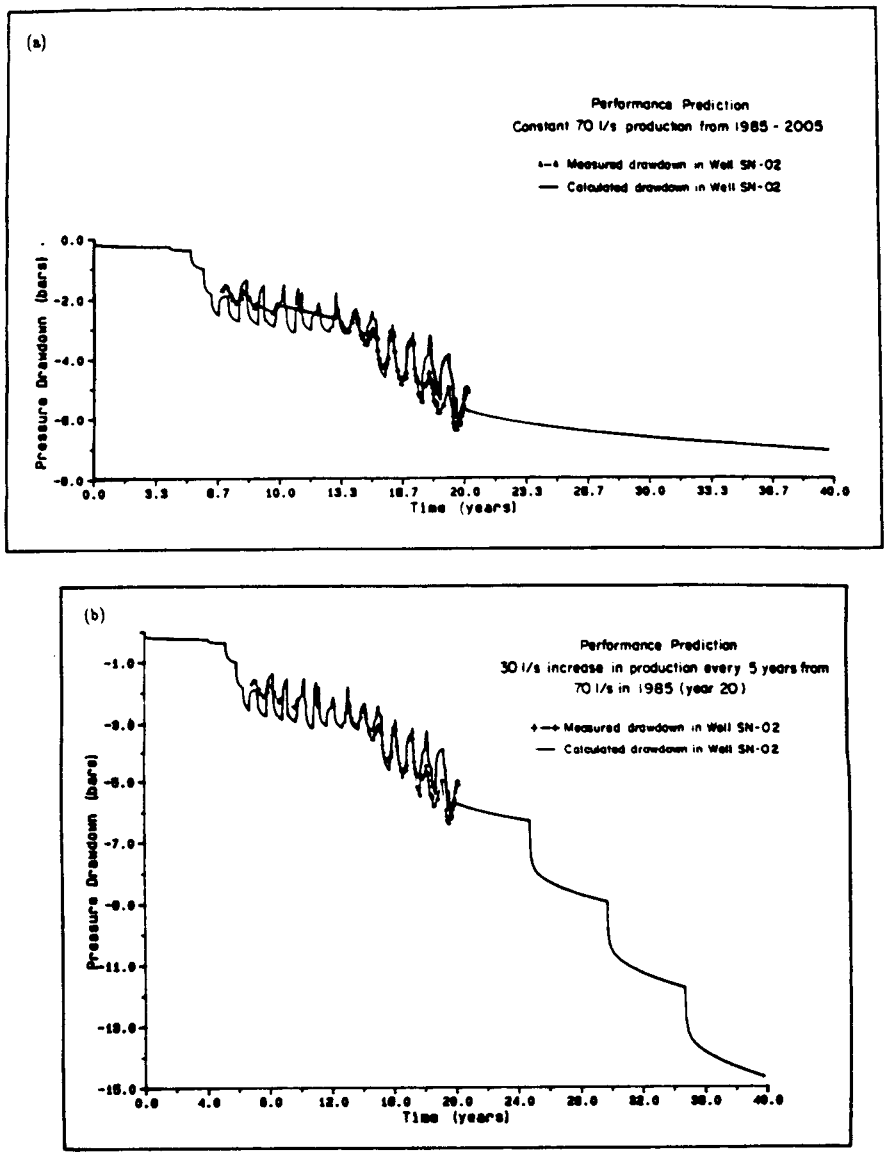

Figure 10. Performance predictions: (a) Constant production of 70 l/s; (b) Base production of 70 l/s, increasing every five years.

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