CHEMISTRY OF GEOTHERMAL FLUIDS DURING PRODUCTION AND DISPOSAL: CALCITE SCALING IN YANGBAJING, SVARTSENGI AND HVERAGERDI

Yu Heping

Report 17, 1987

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Yu Heping
UNU Geothermal Training Programme
National Energy Authority
Grensásvegur 9
108 Reykjavík
ICELAND

Permanent Address:
Bureau of Industry and Electric Power of
Xizang (Tibet) Autonomous Region
Lhasa, Tibet
PEOPLE'S REPUBLIC OF CHINA

ABSTRACT

Problems associated with the chemical behaviour of geothermal
fluids in production and disposal processes have constituted
technical and economical barriers to the development and
utilization of geothermal energy resources in many countries.
One of these problems is mineral scaling when the fluids
become supersaturated due to changes in physical and chemical
conditions. The thermodynamics of calcite scaling in water-
dominated geothermal wells are reviewed. Two conceptual
mechanisms for calcite deposition are discussed. The handling
methods for calcite scaling in production wells are
summarized. The WATCH computer program which models the
chemical behaviour of geothermal fluids is used for inter-
preting data from the Yangbajing, Svartsengi and Hveragerði
geothermal areas and for predicting their calcite scaling
potential. The results show that calcite deposition is most
severe for the geothermal fluid which has the highest ionic
strength and the lowest reservoir temperature. Sampling
equipment and procedures for geothermal wells and chemical
analysis methods are outlined as used for wells in Svartsengi
and Hveragerði. Finally, the problems related to chemistry
and tracer testing in geothermal injection are reviewed.

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

1. INTRODUCTION

The chemical behaviour of geothermal fluids is an important factor associated with its utilization. One of the most serious problems in exploiting water-dominated geothermal reservoir is the precipitation of various mineral scales due to changes in process chemistry and physics. Scaling in production and injection wells can significantly reduce flow-rates (Figure 1.1) and even block the wells. Flow-tests in Miravalles, Costa Rica, illustrated the time behaviour of wells suffering from wellbore deposition. At early time the decrease in output flow rate and well-head pressure is slow but at late time it becomes rapid (Granados and Gudmundsson, 1985). Deposition of minerals on energy production plant equipments and pipelines can cause costly downtime for removal and affect the heat transfer effectiveness. Scaling in major fissures in wells may result in a irreparable decay in flow.

There are three main types of scales from geothermal fluid that have been recognized. Calcium carbonate (mainly calcite) is encountered when flashing happens within geothermal wells. Siliceous compounds are confined mainly to spent brine discharged to atmosphere. Sulfates and sulfides are observed in the form of many phases usually well crystallized in production processes.

Geothermal reservoir fluids in Yangbajing (Xizang, China), Svartsengi and Hveragerði (Iceland) are invariably just saturated with respect to calcite under reservoir conditions. During the exploiting of those fluids, calcite scale forms in production wellbores. Thus, frequent or periodic cleaning of the wellbore is needed to maintain the output. Knowledge of calcite scaling is very important for managing this problem effectively.

In the literature, the thermodynamic aspects of calcite scaling have been studied extensively and some possible ways

1

to control this scaling have been suggested and tested in geothermal fields in which the problem appears. But information on kinetics is very limited, and so is the economics of handling.

Location and tendency of calcite deposition in a geothermal well can be measured by caliper logging (Figure 1.2) or estimated by computer modelling. This will make it easy for management and operation.

The credibility and usefulness of chemical data for chemical models depends on the sampling and analytical methods and the care taken in the collection and analysis of samples.

After eleven years of development and utilization of geothermal resources in Yangbajing, drawdown in the reservoir and the pollution associated with large scale exploitation are becoming serious problems. Injection of the spent brine can maintain the output of geothermal reservoir and prevent environmental effect. Fluid chemical behaviour and tracer testing can play important roles in successful geothermal injection.

Those all above are the some targets of my project work at UNU Geothermal Training Programme. The training included introduction courses, engineering and geochemical lectures, field excursion and sampling, literature search and data interpretation. This report is the final part of the training.

2. PROCESSES AND PROPERTIES

2.1. Geothermal Power Processes

The practical cycles used for geothermal energy extraction plants are various due to the nature of the resources, utilization purposes, technical and economical considerations etc.

Figure 2.1 shows a conceptual diagram of double flash geothermal power generation cycle in Yangbajing. Figure 2.2 is the flow diagram of combined thermal and electric power production cycle in Svartsengi (Björnsson and Albertsson, 1985).

In a geothermal multi-purpose power cycle, the temperature may vary from as high as 350°C in the reservoir to values approaching 15°C in disposal lines, and the pressure may ranges from 300 to 0.08 bar, while the chemical composition of the geo-fluids varies from almost pure water or steam to hot brine with 360,000 ppm of total dissolved solids. Thus, chemical behaviour of geothermal fluids are very site-specific with its thermodynamic conditions and fluid chemistry (Corsi, 1987).

2.2. Physical Properties

Since geothermal brine are abundant of sodium chloride with smaller amounts of calcium, silica and potassium (Table 2.1), its physical parameters can be predicted from a knowledge of pure water and sodium chloride solutions, modified approximately according to the concentrations of other ions by using the term "equivalent NaCl content" with sufficient accuracy (Wahl, 1977). The "equivalent NaCl content" is the amount of NaCl in solution which gives the same effect on the properties as the amount of all salts combined (Michaelides, 1981). This assumption is supported by "quantity effect of salts" in aquatic solution. Non-condensable gases dissolved

3

in the fluid is an important factor affecting phase change. Release of gases such as CO_2, H_2S, H_2 and NH_3 results in boiling of geothermal brine at a higher pressure, or by lowering the flashing depth in a two phase flowing well.

Calcite scaling is promoted by boiling of geothermal fluid. Among the physical properties, pressure and enthalpy are the two most important factors affecting the boiling.

2.2.1. Pressure in Wellbore

When the vapour pressure of a geothermal fluid is equal to the external pressure acting on the fluid, flashing takes place. Flashing of geothermal brine inside a well leads to two-phase flow, i.e. water and vapor mixture. The salts present in the brine are nonvolatile and hence the produced vapour is free of salts. It contains steam and non-condensable gases such as CO_2, H_2S, NH_3, N_2 and H_2. The vapour pressure can be considered the sum of the saturation pressure of the fluid at a given temperature and gas partial pressures. Since CO_2 is usually the major constituent of the non-condensable gases, it is often assumed for simplicity that the vapor phase is a mixture of steam and CO_2. Based on this assumption, we have

$$P_v = P_s + \Sigma P_{gi} \simeq P_s + P_{CO2} \tag{2.1}$$

The saturation pressure of an aqueous salt solution at temperature, $T(°K)$, can be expressed by Raoult's Law.

$$P_s = P_w*(1-X_{sa}) = P_w - \Delta P \tag{2.2}$$

The pure water saturation pressure, P_w, is given by the following simplified correction (Michaelides, 1981):

$$P_w = \exp(0.21913*10^{-6}*t^3 - 0.17816*10^{-3}*t^2 + 0.653665*10^{-1}*t - 4.96087) \tag{2.3}$$

4

Treating steam as an ideal gas and calibrating this model by experiment, the decrease in steam pressure, ΔP, due to a salt of mole fraction, X_{sa}, can then be derived:

$$\Delta P = 1.8RT/(V_v-V_l)*m_{sa}/55.56*10^{-2} \qquad (2.4)$$

The constant 1.8 is derived empirically and is related to the fact that the salt is ionized in the solution (Michaelides, 1981).

The partial pressure of CO_2 has been studied by Sutton (1976):

$$P_{CO2} = w_{CO2}*x/\alpha(T) \qquad (2.5)$$

where
$$\alpha(T) = [5.4-3.5*(T/100)+1.2*(T/100)^2]*10^{-4} \qquad (2.6)$$

and w_{CO2} is the weight percent in the vapor phase. P_{CO2} can also be expressed in terms of Henry's Law, which is discussed in Part 4.

The pressure at any point in a wellbore has been described by Parlaktuna (1985):

$$P = P_{wf}-dP_t \qquad (2.7)$$

The total pressure drop is made up of frictional, acceleration and potential pressure drops.

$$dP_t = dP_f+dP_a+dP_p \qquad (2.8)$$

$$dP_f = (\rho fv^2/2d)*dZ*10^{-5} \qquad (2.9)$$

$$dP_a = \rho v*dv*10^{-5} \qquad (2.10)$$

$$dP_p = \rho g*dZ*10^{-5} \qquad (2.11)$$

5

The friction factor f is given by modified Colebrook equation as

$$f = \{[-2\log(\varepsilon/3.7d)+(7/Re)^{0.9}]^2\}^{-1} \qquad (2.12)$$

where, the Reynolds Number is given as

$$Re = \rho vd/\mu \qquad (2.13)$$

The density of liquid water is determined by Whal (1977) to follow the correction:

$$\rho_l = \rho_w +$$
$$[(1+1.6E-6*t^2)*5844m_{sa}/(1000+58.44m_{sa})]*10^3 \qquad (2.14)$$

where the pure water density form Keenan and Keyes (1951) was used:

$$\rho_w = [(1+dt'^{1/3}+et)/(v_c+at'^{1/3}+bt'+ct'^4)]*10^3 \qquad (2.15)$$

where $t' = 374.11-t$ for t in °C
$v_c = 3.1975$ cm^3/g
$a = -0.3151548$
$b = -1.203374*10^{-3}$
$c = 7.48908*10^{-13}$
$d = 0.1342489$
$e = -3.946263*10^{-3}$

The density correlation for the vapour phase suggested by Michaelides (1981) is as follows:

$$\rho_v = 100P/(-0.1296*10^{-2}*t^2+0.6325t+121.05) \qquad (2.16)$$

The density of a two phase mixture obeys the ideal mixing rule.

$$\rho = \alpha\rho_v+(1-\alpha)\rho_l \qquad (2.17)$$

The bottom hole flowing pressure for high flow-rate geo-thermal wells can be written as:

$$P_{wf} = P_a - CW^2 \qquad (2.18)$$

when turbulence is the dominant factor in friction loss (Parlaktuna, 1985). In Equation (2.18), reservoir pressure can be measured in a well during shutdown, and C can be obtained by using a wellbore simulator to match the deliver-ability measurements of a well since the wellhead pressure is given by

$$P_{wh} = P_{wf} - \Delta P_t = P_a - CW^2 - \Delta P_t \qquad (2.19)$$

When $P_v = P$, flashing occurs. In water phase region, $dP_c = 0$, so

$$P_v = P_s + P_{CO2} = P =$$
$$P_{wf} - (\rho f v^2/2d*\Delta Z - g\rho\Delta Z)*10^{-5}$$

Then the flashing or boiling depth from wellhead is given

$$D_f = D_a - [(P_{wf} - P_s - P_{CO2})/(\rho f v^2/2d + \rho g)]*10^5 \qquad (2.20)$$

In practice, calcite deposit may occur in the first 20-25 meters above the first boiling point (D_f) (Granados, 1985). The deposition shape may tapper off from this point and become almost zero (Figure 1.2). In Equation (2.20) only the wellhead pressure is a parameter related to operation directly. Therefor deposition can be controlled to occur at a chosen level.

2.2.2. Steam Fraction

In the process of adiabatic flashing in a geothermal well-bore, the following heat balance relationships applies:

$$H_O = H_l + H_v$$

i.e.

$$h_O = h_l*(1-x)+h_v*x \qquad (2.21a)$$

where h_O is the enthalpy of initial liquid prior to flashing, h_l and h_v are the enthalpy of coexisting water and steam after boiling. Based on the salt solution enthalpy equation given by Wahl (1977), and taking $T_O = 0$, the following results:

$$h_l = h_w*[1-58.44m_{sa}/(1000+58.44m_{sa})]$$
$$+T*11.688m_{sa}/(1000+58.44m_{sa}) \qquad (2.22)$$

The correction for the enthalpy of vapor phase recommended by Michaelides (1981) is

$$h_v = -0.81275*10^{-2}*t^2+3.65228t+2388.4 \qquad (2.23)$$

The steam fraction can be given by

$$x = (h_O-h_l)/(h_v-h_l)$$

$$x = (h_O-h_l)/L \qquad (4.21)$$

where L is the evaporative heat.

2.3. Two Phase Flow Regimes

Flowing properties of two phase geothermal fluids can affect geothermal sampling and mineral precipitation. For vertical flow five regimes can be defined as showed in Figure 2.3

(Hetsroni, 1982). The general-flow-pattern map (Figure 2.4) of Hewitt and Roberts (1969) can be recommended for determining the vertical flow regimes. On this map, the plotting coordinates are the superficial momentum fluxes of the respective phase, i.e. $\rho_l v_l^2$ and $\rho_v v_v^2$.

Flow regimes in horizontal flow tend to be somewhat more complex than those in vertical flow. This result from that the gravitational force act normal to the direction of the flow and makes the liquid phase tend to accumulate at the bottom of the channel. The flow patterns are illustrated in Figure 2.5 (Hetsroni, 1982). The best know generalized flow-pattern map for horizontal flow is the Baker Diagram modified by Scott (1963). The coordinates of the Baker Diagram (Figure 2.6) are

$$B_X = 2.105*(1-x)/x*\rho_v^{1/2}/\rho_l^{0.166}*\mu^{1/3}/\sigma \qquad (3.24)$$

$$B_Y = 2.752Wx/(d^2*\sqrt{(\rho_l\rho_v)}) \qquad (3.25)$$

where the correlation equation of viscosity can be developed as (Michaelides, 1981):

$$\log[\mu(t,m)/\mu_w(t)] = A(m)+B(m)*\log[\mu_w(t)/\mu_w(20)] \qquad (2.26)$$

with pure water viscosity, $\mu_w(t)$, is given by the expression:

$$\log[\mu_w(t)/\mu_w(20)] = [(20-t)/(96+t)]*$$
$$[1.2378-1.303*10^{-3}*(20-t)+3.06*10^{-6}*$$
$$(20-t)^2+2.55*10^{-8}*(20-t)^3] \qquad (2.27)$$

with $\mu_w(20)$ =1002 μ Pa s.

A and B are functions of molality.

$$A(m) = 0.3324*10^{-1}*m+0.3624*10^{-2}*m^2-0.1879*10^{-3}*m^3 \quad (2.28)$$

$$B(m) = -0.3961*10^{-1}*m+0.102*10^{-2}*m^2-0.702*10^{-3}*m^3 \quad (2.29)$$

9

The surface tension correction is given by (Wahl, 1977) as:

$$\sigma = \sigma_w * [1 + 22.7916 m_{sa}/(1000 + 58.44 m_{sa})]$$
$$+ 1.4856 * 10^3 * m_{sa}^2/(1000 + 58.44 m_{sa})^2 * 10^{-3} \qquad (2.30)$$

with

$$\sigma_w = 0.0755 * (t_c - t)^{0.776} * 10^{-3} \qquad (2.31)$$

2.4. Chemistry

A hydrothermal or geothermal system is where water currents circulate in the crust of the earth. It may be heated by convection of water from magma. High temperatures at shallow depth are commonly the result of convective flow. Convection may occur because of the heating and consequent thermal expansion of water at depth. Hot water of low density tends to rise and be replaced by cooler water of higher density (Gudmundsson, 1986). As the water circulates through the rock structure by this convection, it dissolves, leaches and precipitates minerals to form a equilibrium hot brine solution with the reservoir rocks at certain temperature and pressure.

The composition of a geothermal reservoir brine is controlled by mineral equilibria. Some of them are listed in Table 2.2. The pH of the brine is determined by acid-base equilibria and reactions involving alumino-silicates. In general, the pH of carbonate-type geothermal waters tends to be between 6.0 and 6.5 or close thereto because of the buffering action of the carbonate reactions (Whal, 1977), which is discussed in Part 4.

It is not known which minerals control carbon dioxide concentrations in high temperature waters (>200°C). Conceivably, the assemblage involved is zoisite (epidote)-prehnite-quartz-calcite (Arnorsson et al., 1982).

10

Calcite is a prominent secondary mineral in reservoir rocks. In geothermal reservoir, the product of carbonate and calcium ion concentrations is a fixed quantity as a function of temperature due to equilibrium with calcite. It is strongly dependant on pH, which in turn is dependent on the equilibria reactions between the alumino-silicates and sodium in the absence of dominating sulfate chemistry. Thus the product of the calcium and carbonate concentrations will be related to the sodium concentration and temperature as shown in Figure 2.7 (Wahl, 1977).

The concentration of potassium in geothermal brine is determined by ion exchange equilibria between sodium and potassium with the alumino-silicates. The molecular ratio of sodium to potassium is fixed at a given temperature (Ellis and Mahon, 1977).

The distribution of major cations and hydrogen ion is governed by temperature dependent ionic exchange equilibria (Table 2.3), so the ratio $\sqrt{(Ca)}/H$ is approximately fixed at a given temperature, variable concentrations of the other major cations, Na, K and Mg, which may cause some scatter in the $\sqrt{(Ca)}/H$ ratio. The absolute concentrations of Ca, H and other major cations are in turn mostly governed by the supply of the incompatible element chlorine (Arnorsson, 1978; Arnorsson et al., 1983).

At high temperature (180°C to 225°C), silica concentration correspond the solubility of quartz. At lower temperatures other silica species such as chalcedony, cristobalite, or amorphous silica may control dissolved silica (Fournier, 1977).

The presence of sulfur deposits and rock through which the hot water is permeating will give rise to the formation of hydrogen sulfide and sulfuric acid:

11

$$4\ S\ +\ 4\ H_2O\ =\ H_2SO_4\ +\ 3\ H_2S \qquad (2.32)$$
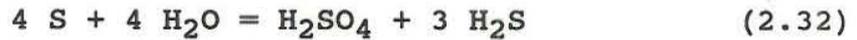
In geologically active volcanic regions, sulfur dioxide if present also gives rise to the formation of sulfuric acid through reaction with warm water as follows:

$$4\ SO_2\ +\ 4\ H_2O\ =\ 3\ H_2SO_4\ +\ H_2S \qquad (2.33)$$
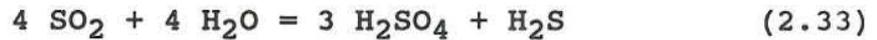
The acid developed from this reaction will override the buffering reactions with the alumino-silicates in controlling the pH (Wahl, 1977).

Ammonia is found in geothermal waters that have come in contact with organic matters.

The concentrations of the various constituents in geothermal brine are shown in Figure 2.8 and in Table 2.1 are shown the chemical compositions for typical wells and hot springs in various geothermal fields.

The measured chemical properties of geothermal fluids at surface temperature and pressure are different from those of deep geothermal brine because of steam loss, gas separation, mineral precipitation and the temperature dependence of homogeneous equilibria. Methods for calculating the geo-thermal reservoir water composition from analysis made under surface condition are discussed in the following parts.

3. SAMPLING AND CHEMICAL ANALYSIS

3.1. Sampling of Water-Dominated Wells

The collection of representative samples from a geothermal well discharging steam and water is a complex procedure. High temperature water (150°C to 350°C) from deep levels can partially flash into steam-water mixture as pressures decrease toward the wellhead, and discharge into the atmosphere at velocities approaching the speed of sound with an explosion of the volume. Thus, special methods and care should be taken for sampling geothermal wells (Ellis and Mahon, 1977). It is necessary to sample each phase separately, at a known pressure, which should be the same as the pressure of the pipe or vessel being sampled. The subsequent combination of the analysis of the separate phases is discussed in Part 5.

The methods used for sampling a geothermal well depend on the surface pipework. Representative sampling of steam, gas and water from wells is made using one or more of the following techniques:

1. Down-hole direct collection.

2. Separator collection, that is, samples of steam, water and gas are collected under pressure from sampling points at the wellhead and on the surface pipes separately.

3. Discharging collection. Steam, water and gas samples are collected from the vertical silencer at atmospheric pressure and boiling point.

The sampling procedure and cautions for separator collection are described in detail by Olafsson (1987). Figure 3.1 shows a small separator for sampling and Figures 3.2, 3.3 and 3.4 are a series of sampling sketches. Figure 3.5 is a flow chart

13

for sampling and analysis. During the sampling, flow through the separator is controlled by the three main valves, i.e. fluid inlet valve, water phase outlet valve and vapor outlet valve.

In order to obtain representative samples, great care has to be taken to select the sampling points and to adjust the three control valves.

Tests have shown that the optimum location of a sampling point is about 1.5 meter from the T-joint on surface discharging piping (Figure 3.6). At this point the flow is free from interference from the T-joint, and the water and steam phases are still in thermodynamic equilibrium (Olafsson, 1987).

Flow patterns in horizontal piping can affect the representativeness of the samples. For slug or plug flow, since the alternating pulses of water and steam exist, the inlet valve of the separator should be adjusted a little closed instead of fully open to create a relative bigger volume of the separator. For stratified and wavy flow, water and steam samples can be taken from the top and bottom sampling points on the horizontal pipe, separately, without using a separator (Arnorsson, 1987a).

Boiling of sampling fluid in the separator should always be avoided. This can be done by adjusting the valves carefully, while looking at the pressure gauge at the top of the separator. The pressure should not fall down more than 0.1 kPa/cm^2 during the collection (Olafsson, 1987).

During the whole sampling, from the preparation until ending, it is necessary to have a check list or a uniform record form for apparatus and samples. And they should be fully used!

3.2. Chemical Analysis Techniques

The analytical techniques (Figure 3.5) for determining the major constituents in geothermal waters can be outlined in the following. For detail on some subjects, please refer to Ellis and Mahon (1977).

1. Atomic Absorption Spectrophotometry

Alkali metals, boron, calcium, magnesium, iron, aluminum, SiO_2 in acid and near neutral pH thermal waters can be determined by this method (Table 3.1).

2. Emission Flame Photometry

It can accurately determine sodium (5893Å, 2000ppm), potassium (7665Å, 250ppm), lithium (6708Å, 25ppm), rubidium (7800Å, 5ppm) and cesium (8521Å, 5ppm).

3. Gas Analyzer and Gas Chromatograph

Residual gases e.g. H_2, N_2, CH_4 and NH3 can be analyzed by standard PVT gas analysis equipments.

4. Ion Chromatograph is used for measuring Cl^- and SO_4^{2-}.

5. Spectrographic Analysis and Spectrophotometry

Many heavy metals and rare earth metals can be extracted by chloroform with mixed solution of diethyl dithiocarbamate, oxine and dithizone at pH 3, 5, 7 and 9. That catchall concentrate is later analyzed spectrographically.

A rapid assessment of the trace metals present in waters can be made by spectrographic analysis of residue obtained by evaporation.

Cu, Pb, Zn, Ag, W, Ni and Cd can be concentrated by one of

two techniques, (1) absorption onto Chelex-100 cation exchange resin and elution with 2N nitric acid; (2) extraction with a benzene solution of mixed diethyl and pyrrolidine dithiocarbamic acid. The concentrate obtained by both methods are evaporate to dryness, and later dissolved for analysis by atomic absorption spectrophotometry.

Sulfate in water is reacted with barium cremate to form insoluble barium sulfate to liberate cremate ions, which are measured photometrically.

Ionic silica formed by digestion with alkali is reacted with an acid solution (pH 1.2-1.5) of ammonium molybdate in the presence of oxalic acid, producing the yellow silicomolybdic acid. The concentration (50-200ppm) can be measured by comparing the absorbance against a standard calibration curve.

6. Ion Selective Electrode

A fluoride specific ion electrode gives a direct reading of fluoride contained in samples buffeted with a citrate-citric acid buffer.

Ammonium concentration can also be read directly on a specific ion meter using calibration curve.

7. Titration

a. Acid-Base Titration. The total carbon dioxide in solution can be determined by titrating this solution from a pH of 8.25 to pH 3.8 with standard acid (0.1N HCl).

b. Redox Titration. In acid solution, total hydrogen sulfide is quantitatively oxidized to sulfur by iodine. Excess iodine is back titrated with sodium thiosulfate, using sodium starchglycollate as indicator.

I^- in a buffered is oxidized to I_2 with Br_2 water. Excess Br_2 is removed by addition of KI. Total I_2 liberated is titrated by $Na_2S_2O_3$ to obtain I^- in original sample. I^- and Br^- in a second aliquot of the sample are oxidized to I_2 and Br_2 with hypochlorite, the excess hypochlorite then being decomposed. I_2 liberated from both I^- and Br^- which produced by addition of KI is titrated with $Na_2S_2O_3$. Br^- is obtained from the difference between the two titration.

c. Direct Titration. F^- in solution at pH 3.5 is titrated with thorium nitrate in the presence of the indicator chromazurol-S.

Cl^- is titrated against standard $AgNO_3$ solution using potassium cremate as indicator (Mohr Method).

Total H_2S is determined by titration with $Hg(CH_3COO)_2$.

d. Potentiometric Method. Cl^- in a supporting sulfuric acid electrolyte is titrated with standard $AgNO_3$, The end point being detected by a silver electrode and a reference mercurous sulfate electrode in association with a standard expanding-scale pH meter.

e. EDTA Titration. Standard EDTA is used to titrate Ca^{2+} at pH 13 with cal-red indicator, and Ca^{2+} plus Mg^{2+} are titrated at pH 10 with solochrome black as indicator. Mg^{2+} is obtained by difference.

8. Distillation. Ammonia is distilled from an alkaline buffeted solution, and an aliquot of the distillate is examined by colorimetry using the Nessler reaction.

9. Dissolved O_2 is measured with a Chemet test kit based on reaction with rhodazine D.

10. A measured volume of geothermal fluid is evaporated and the dry residue is weighted to indicate the total amount of

mineral matter in water.

11. Conductivity and salinity are measured by conductivity
meter.

12. pH is measured by pH meter with a glass electrode.

13. Gonfiantini (1975) reviewed the specialized techniques
required for the analysis of stable isotopes in the samples.

4. THERMODYNAMICS AND KINETICS OF CALCITE SCALING

4.1. System Studied

In order to approach the nature of calcite scaling effectively, the following is assumed for simulating the behaviour of geothermal fluids in the calcite deposition section of a wellbore (from flashing depth to either the end of deposition or until wellhead).

1. Chemical equilibria between the following constituents are considered:

Ca^{2+}, $CaCO_3$
$CO_{2(g)}$, $CO_{2(aq)}$, H_2CO_3, HCO_3^-, CO_3^{2-}
H_2O, H^+ or OH^-
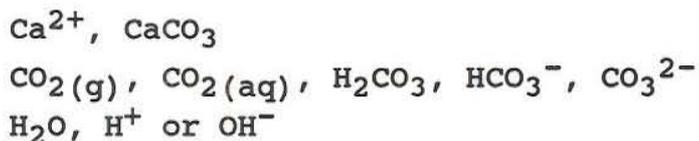
2. Thermodynamic equilibrium of each reaction is approached in the system. From this assumption, some remarks can be derived. (a) The degassing factor of fluid during flashing is unity (=1) because volatile constituents are sufficiently transferred into steam to establish equilibrium. (b) Calcite is the only stable scale of calcium carbonate in high temperature and high pressure geothermal wells. Aragonite and $CaCO_3.6H_2O$ are transferred to calcite (Figure 4.1). Precipitation of $CaSO_4$, $MgCO_3$ and $Mg_xCa_{(1-x)}CO_3$ are omitted.

3. The reservoir and wellbore performances are assumed constant in the period of study. The well is a water-dominated well. The production process is adiabatic and one step flashing take place in the wellbore.

4. The effect of erosion due to flowing on calcite scaling is not considered.

Based on the above assumptions, the maximum calcite precipitation potential or rate can be reached in the wellbore.

4.2. Thermodynamics

4.2.1. Equilibrium Consideration

The geothermal fluid chemistry following flashing can be summarized in the following principle chemical reactions:

Carbon Dioxide in Solution

At interfaces of a vapor-liquid system, carbon dioxide gas is associated with dissolved carbon dioxide.

$$CO_{2(g)} = CO_{2(aq)} \tag{4.1}$$

Taking consideration of a degassing factor, b, according to Henry's Law the fugacity of carbon dioxide is

$$f_{co2} = b*\gamma*K°_H*X \tag{4.2a}$$

where b is a value in the range of 0 to 1, In thermodynamic equilibrium b = 1.

If Henry's Law coefficient for saline solutions is

$$K_H = \gamma*K°_H \tag{4.3}$$

Putting Equation (4.3) into Equation (4.2a) and using b = 1

$$f_{co2} = K_H*X \tag{4.2}$$

Increasing the salinity of a solution increases the Henry's Law coefficient (Fig. 4.3). Since salt out coefficient, k, for carbon dioxide in sodium chloride solution, are generally of the Steshenow type (Fournier, 1985):

$$k = (1/m_{sa})*\log(K_H/K°_H) \tag{4.4}$$

Rearranging Equation (4.4),

20

$$K_H = 10^{(kmsa)} * K°_H \tag{4.4a}$$

Comparing Equation (4.4a) with Equation (4.3),

$$\gamma = 10^{(kmsa)} \tag{4.5}$$

Because the fugacity coefficient for carbon dioxide in dilute aqueous solution at temperature below about 330°C are near unity (Ellis and Golding, 1963), f_{CO2} in Equation (4.2) can be replaced by the partial pressure of carbon dioxide with little error.

$$P_{CO2} \simeq K_H * X \tag{4.2b}$$

In the liquid phase, the total carbon dioxide can be distributed between $CO_{2(aq)}$, H_2CO_3, HCO^-_3 and CO^{2-}_3 with the following equilibrium reactions:

$$CO_{2(aq)} + H_2O = H_2CO_3 \tag{4.6a}$$

$$H_2CO^*_3 = HCO^-_3 + H^+ \tag{4.7}$$
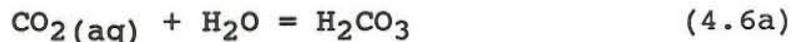
$$HCO^-_3 = CO_3^{2-} + H^+ \tag{4.8}$$

The equilibrium constants are, respectively,

$$K'_o = [H_2CO_3]/[CO_{2(aq)}] \tag{4.9a}$$

$$K_1 = [HCO^-_3] * [H^+]/[H_2CO^*_3] \tag{4.10}$$

$$K_2 = [CO_3^{2-}] * [H^+]/[HCO_3^-] \tag{4.11}$$

Ionization equilibria in dissolved carbonate system are established very rapidly. Somewhat slower is the attainment of the equilibrium of Reaction (4.6a) with the reaction rate constants (Stumm and Morgan, 1970):

$$k+ = 4.37*10^{-2} \quad s^{-1}$$
$$k_- = 19.2 \quad s^{-1}$$

at 298°K and 0.5 ionic strength.

By tradition a distinction is not made between $CO_{2(aq)}$ and H_2CO_3. They are reported as $H_2CO^*_3$.

$$[H_2CO^*_3] = [CO_{2(aq)}]+[H_2CO_3] \qquad (4.12)$$

Combining Reaction (4.6a) with Reaction (4.1), the net reaction is general written:

$$CO2_{(g)} + H_2O = H_2CO^*_3 \qquad (4.6)$$
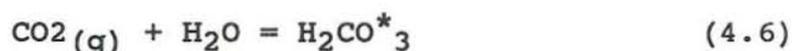
$$K_O = [H_2CO^*_3]/f_{co2} \qquad (4.9)$$

Calcite in Aqueous Solution

The simplest reaction representing the precipitation of calcite in solution can be written,
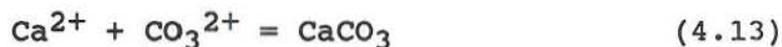
$$Ca^{2+} + CO_3^{2+} = CaCO_3 \qquad (4.13)$$

for which the solubility product is

$$K_C = [Ca_{2+}]*[CO_3^{2-}]/[CaCO_3] \qquad (4.14a)$$

In the above formula, the activity of solid calcite is unity if there is no significant substitution of other cations such as Mg^{2+}, Fe^{3+} or Mn^{2+} for calcium in the solid. Then

$$K_C = [Ca^{2+}]*[CO_3^{2-}] \qquad (4.14)$$

Table 4.1 summaries the equations expressing each coefficient i.e. K_H^O, k, K_O, K_1, K_2 and K_C as a function of temperature (Fournier, 1985).

From Equations (4.9), (4.10), (4.11) and (4.14), we can derive

$$[H_2CO^*_3] = K_o * f_{co2} \qquad (4.15)$$

$$[HCO^-_3] = K_o * K_1 * f_{co2} / [H^+] \qquad (4.16)$$

$$[CO_3^{2-}] = K_o * K_1 * K_2 * f_{co2} / [H^+]^2 \qquad (4.17)$$

$$[Ca^{2+}] = K_c * [H^+]^2 / (K_o * K_1 * K_2 * f_{co2}) \qquad (4.18)$$

In the CO_2-H_2O system, the total carbon species in solution can be expressed in the mass balance equation

$$[CO_{2total}] = [H_2CO^*_3] + [HCO^-_3] + [CO_3^{2-}] \qquad (4.19)$$

This is usually what is given in chemical analysis. Figure 4.5 indicates the fraction of carbonate, bicarbonate, carbonic acid and $CO_{2(aq)}$ present as a function of pH in a solution at 100°C. Since very little CO_3^{2-} presents in most acidic geothermal fluid, precipitation of calcite is commonly expressed in terms of the following reactions with corresponding equilibrium formula (Henry and Brown, 1985):

$$Ca^{2+} + HCO_3^- = CaCO_3 + H^+ \qquad (4.20)$$

$$K_c/K_2 = [Ca^{2+}] * [HCO_3^-] / [H^+] \qquad (4.21)$$

$$2HCO_3^- + Ca^{2+} = CaCO_3 + H_2O + CO_{2(v)} \qquad (4.22)$$
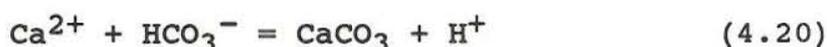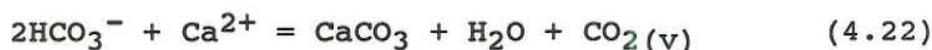
$$K_c K_1 K_o / K_2 = [Ca^{2+}][HCO_3^-]^2 / f_{CO2} \qquad (4.23)$$

or

$$-logK = -226.43 + 6552.81/T + 89.084 * logT - 0.0746 * T \qquad (4.23a)$$

Equation (4.23a) is valid in a temperature range of 100°C-300°C.

23

By using the above equations with equation

$$[H^+]*[OH^-] = K_w = 10^{-14} \qquad (4.24)$$

the mass balance and the charge balance equations we can do the chemical equilibrium calculations in $CaO-H_2O-CO_2$ system. For this system the charge balance is

$$2[Ca^{2+}]+[H^+] = [HCO^-_3]+2[CO_3^{2-}]+[OH^-] \qquad (4.25)$$

Activity Product of Calcite

For a fluid the activity product of calcite is defined as

$$Q = [Ca^{2+}]*[CO_3^{2-}] \qquad (4.26)$$

This equation is useful mainly for testing weather a given solution is under-saturated, saturated or supersaturated in respect to calcite by comparing with Equation (4.14) with definition of supersaturation ratio

$$\Omega = Q/K_C \qquad (4.27)$$

The geothermal fluid chemistry obtained from chemical analysis is usually given by molality. They can be conveniently changed into activity by using following equation.

$$[\ i \ ] = \gamma_i*m_i \qquad (4.28)$$

Taking Equation (4.28) into Equation (4.26), the activity product of calcite can be expressed

$$Q = \gamma_{Ca2+}*\gamma_{CO32-}*m_{Ca2+}*m_{CO32-} \qquad (4.29)$$

Most high-temperature geothermal fluids are closed to calcite saturation (as mentioned in Part 2.4). During flashing, the

fluids rapidly become supersaturated with mineral scales due to following mechanisms leading to increase of the corresponding activity product Q.

a. Loss of steam from the liquid phase increases chemical concentration of remaining solutes and ionic strength.

b. Evaporation in adiabatic process leads to temperature drop of the fluid.

c. Loss of stable gases such as CO_2 and H_2S increases the pH of fluid and reduces the gas contents in the remaining fluid.

4.2.2. Effect of Ion-Strength

The ionic strength of a aqueous solution is defined by the equation

$$I = 1/2 * \Sigma m_i z_i^2 \qquad (4.30)$$

In Table 4.2, the ionic strengths of representative sets of world-wide geothermal systems are shown.

Activity coefficient for solution with ion strength less than 2 molal can be calculated using an extended form of the Debey - Hückel equation.

$$-\log \gamma_i = A z_i^2 I^{1/2} / (1 + \mathring{a}_i B I^{1/2}) + bI \qquad (4.31)$$

The equations for A and B factors are in Table 4.1. For Na^+, HS^-, $H_3SiO_4^-$, $H_2BO_3^-$, SO_4^{2-}, HSO_4^- and OH^-, $\mathring{a}$ is 4.0, in common, NH_4^+, 2.5; K^+, 3.0; HCO_3^- and CO_3^{2-}, 4.5; Li^+ and Ca^{2+}, 6.0; Mg^{2+}, 8.0 and H^+, 9.0 (Fournier, 1985).

For high temperature calculations the following approximate values are quite satisfactory (Henley and Brown, 1985).

25

$$\gamma_{H+} = 0.8,$$
$$\gamma_{Ca2+} = 0.3,$$
$$\gamma_{k+} = \gamma_{Cl-} =$$
$$\gamma_{HCO3-} = \gamma_{H3SiO4-} =$$
$$\gamma_{HS-} = \gamma_{BO2-} =$$
$$\gamma_{Na+} = 0.7.$$

4.2.3. Effect of Steam Loss

Flashing affects the composition of the brine in two ways. One is the simple concentration of the brine as a result of remove of water. The other is change of fluid chemistry resulting from remove of certain constituents such as CO_2, H_2S and NH_3 leading to the increase of pH and reduction of dissolved gases in the brine and reestablishment of the equilibria.

After boiling, the chemistry of the remained liquid phase is expressed by using the steam fraction.

For non-volatile constitutes

$$m_i = m_i^O/(1-x) \qquad (4.33)$$

For volatile constituents

$$m_i = (m^O_i - m_V * x)/(1-x) \qquad (4.34)$$

4.2.4. Calculation of pH of Geothermal Fluid

Since the pH of geothermal brine are determined by acid-base equilibria and reactions involving alumino-silicates (as mentioned in Part 2.4), by taking account of all H^+ species and effects of dissolved gases, Reed and Spycher (1984) calculated in situs pH and distribution of aqueous species in a homogeneous equilibrium system at high temperature, based

26

on chemical analyses and pH/25°C measurement of quenched high temperature water.

The distribution of species, molalities of species whose compositions are described as containing H^+ are summed to obtain total molalities of "ionizable hydrogen",

$$N^+_{H+} = m_{H+} + \Sigma \nu_{H+j} * m_j \qquad (4.35)$$

N^+_{H+} is independent of temperature.

For a geothermal water, Equation (4.35) contains a term for each of the 57 species listed in Table 4.2. The numerical values for the coefficients, ν_{H+j}, of Equation (4.35) are also list in that table.

If the solution under consideration produced a vapor phase, i.e. boiled, it is necessary first to calculate N^+_{H+} in the remaining solute without concerning the gases released, rename the value of N^+_{H+} calculated as N^{aq}_{H+} referring to the remaining aqueous phase alone. Then using the known quantity and composition of gases calculate the moles of components in vapor phase of corresponding steam and add to the moles of aqueous phase components by using steam fraction. For example, for a gas which includes H_2O, CO_2, HCl, H_2S and H_2, we have

$$N^+_{H+} = N^{aq}_{H+} * (1-x) + (2n_{CO2} + n_{HCl} + n_{H2S} - 1/4 * n_{H2}) * x \qquad (4.36)$$

A simplistic calculation provides a useful approximation of pH (Henley and Brown, 1985). Considering the Equation (4.7) and $logK_1$ in Table 4.1. Calculating m_{HCO3-}, m_{H2CO3*} based on water sample analysis at laboratory temperature. Then recalculating those two species in the fluid at reservoir temperature before boiling through Equation (4.34). Since

$$logK_1 = logm_{HCO3-} + log\gamma_{HCO3-} + log[H+] - logm_{H2CO3*} \qquad (4.37)$$

we can substitute values to obtain pH.

27

4.2.5. Effect of Degassing

When flashing is first initiated, the ratio of CO_2 to steam in the vapor phase tends to be relatively large because most of the carbon dioxide initially dissolved in the liquid passes quickly into the gas phase (Figure 4.7), while only a small amount of water changes to steam. With continued boiling, the mole fraction of CO_2 in the vapor phase steadily decreases because little additional CO_2 is available to partition into the vapor phase, while the fraction of water that is converted to steam increases at a relatively constant rate. As the temperature of the ascending vapor water mixture decreases, the volume of the vapor phase increases due to the decrease in hydrostatic load. The net effect is a drastic decrease in the partial pressure of CO_2 as a boiling fluid ascends toward the earth's surface (Fournier, 1985).

Degassing of CO_2 from the fluid result in changing of total CO_2 content, and increasing pH leading to distribution change of carbon species in fluid. For one step flashing, without calcite precipitation (although fluid is supersaturated) and that thermodynamic equilibrium is reached, the total moles of carbon bearing species is expressed

$$n_{total} = n_{H2CO3*} + n_{HCO3-} + n_{CO32-} + n_{CO2g}$$

(4.38)

Using the distribution coefficient (Table 4.1),

$$K_D = m_{CO2(aq)} / m_{CO2(g)}$$

$$= [n_{CO2(aq)}/(1-x)]/[n_{CO2(g)}/x]$$

$$= n_{CO2(aq)}/n_{CO2(g)} * x/(1-x)$$

(4.39)

and rearranging the above formula

$$n_{CO2(g)} = (n_{H2CO3*}/K_D) * [x/(1-x)]$$

(4.40)

with $n_{CO2(aq)} = n_{H2CO3*}$. Inserting (4.38) into (4.40), for a unit mass fluid changing moles to molality and dividing by m_{HCO3-}

$$m_{total}/m_{HCO3-} = m_{H2CO3*}/m_{HCO3-}*\{1+x/$$

$$[K_D*(1-x)]\}+m_{CO32-}/m_{HCO3-}+1 \qquad (4.41)$$

Combining Equations (4.10) and (4.11) changing the molalities into activities where required through Equation (4.28) and rearranging

$$[HCO_3^-] = m_{total}/([H^+]/K_1*(1+x*(K_D*(1-x)))$$

$$+1/\gamma_{HCO3-}+K_2/([H^+]*\gamma_{CO32-}) \qquad (4.42)$$

In a similar manner, $[CO_3^{2-}]$ and $[H_2CO_3^*]$ can be obtained.

4.2.6. Effect of Temperature and P_{CO2}

Differentiating Equation (4.23a), we have

$$dlogK/dT = -3276.405/T^2-38.689/T+0.0746 \qquad (4.43)$$

Up to T = 573.15°K, $dlogK_1/dT = -2.88*10^{-3} <0$. Therefore, calcite is more soluble at low temperature than at high temperature (see Figures 5.1 to 5.5 and Appendix). So calcite cannot be deposited from solution by simply cooling down of the fluid temperature at constant concentrations of CO_2 and other constituents in the fluid.

By using Equations (4.21) and (4.23), we can draw the solubility product curve for calcite as a function of P_{CO2} at given temperature (Figure 4.7).

4.3. Kinetics

4.3.1. General

Deposition of solids may occur in the bulk of a solution or on a solid surface. It occurs first by nucleation and is then followed by growth. A distinction between those two processes can be made in terms of Figure 4.8 (Berner,1981). The rate of deposition may have a contribution from three terms: the formation of nuclei in the bulk of the solution (homogeneous), the formation of nuclei on the surface (heterogeneous), and the formation of deposited on nuclei already-formed either in the solution or on the solid surface (Whal, 1977).

Nucleation

As a body precipitating from solution begins to increase in size, it encounters a free energy barrier to further growth. Considering a spherical nucleus of radius r, the interfacial energy rate between the phase and solution is $R'cm^{-2}$, and as the degree of the supersaturation is increased, the decrease of free energy ($\Delta G'cm^{-3}$) of nucleation is resulted in by decreasing in the size of the critical nucleus, then the net free energy E_n associated with the nucleus is

$$E_n = 4\pi r^2 R' - (3/4)\pi r^3 \Delta G' \qquad (4.44)$$

setting $dE_n/dr = 0$,

$$E_{no} = 16\pi R'^3/3\Delta G'^2 \qquad (4.44a)$$

Inserting Equation (4.44a) into the Arrhenius equation

$$k = A(T)*exp(-E_a/RT) \qquad (4.45)$$

the rate of nucleation should be

30

$$k = A(T)*\exp[(-16\pi R'^3)/(3\Delta G'^2 RT)] \qquad (4.46)$$

(Drever,1980).

Growth

Once the critical nucleus has formed, further increase in its size can take place spontaneously with a net decrease in free energy. This process is referred to as crystal growth.

Crystal growth involves the transport of dissolved species to the surface of a crystal and various chemical reactions occurring at surface. The latter includes adsorption, ion exchange, dehydration of ions, formation of two-dimensional nuclei on the surface, diffusion along the surface, ion-pair formation etc. The rate of growth is limited by the slowest step with a whole chain of process. It can be characterized as being controlled either by transport of species to the surface (transport-controlled), by reaction at the surface (surface-reaction-controlled), or by a combination of both processes. A comparison of the three mechanisms is shown in Figure 4.9 (Berner,1981).

In case of diffusion limited kinetics, the rate of reaction on the grain surface is so rapidly that migration of species in solution to take their place cannot keep pace. As a result concentrations in solution adjacent to the crystal surface fall until they almost reach the equilibrium or saturation level. So there is a concentration gradients existing in diffusion layer. Further growth is limited by the rate at which additional ions can be transported to the crystal surface and the lowest process is that of molecular or ion diffusion.

In the case where the deposition rate is limited by chemical kinetics, ion attachment to the surface is so slow that replenishment of ions in solution near the surface is easily accomplished by molecular diffusion and other transport

process. Concentrations in the near surface zone are little different than those in the bulk solution, and the growth rate is proportional to the drive force for the chemical reaction and is not affected by the hydrodynamic state of the solution.

4.3.2. Deposition Models

Mechanisms

Nuclei already exist in geothermal fluid or on wellbore surface. The concern of this study therefor, is with the growth kinetics but not the nucleation kinetics of calcite deposition.

Calcite scaling is site-specific. The mechanisms and rates can be influenced by relevant surface property such as surface area, supersaturation ratio (SR), species which can take part in the reaction path to form "intermediaries" temperature, pressure and flowing properties.

Geothermal fluid chemistry is very complicated and different from one well to another, and it is a high temperature, high pressure, high mass flow and flowing system, the data related to kinetics are few in the literature. According to the distinction between ionic reaction taking place in the bulk of solution and that on the mineral surface, the following mechanistic sequences can be assumed for studying the path and rate by which calcite deposit in geothermal production wells.

Mechanism A

Step 1. Ca^{2+} reacts with HCO_3^- or CO_3^{2-} in solution forming a "transfer species" such as $CaCO^*_3$;

Step 2. $CaCO^*_3$ diffuses from boundary interface to mineral grain surface;

32

Step 3. Adsorption, ion exchange, dehydration and precipitation on mineral surface to form scale.

The rate of ionic reaction is instant because there is little or no energy barrier that must be overcome to form products once the ions are in proximity to one another, especially at high temperature. In this case the whole process rate seems to be controlled by the "big" and "heavy" transient constituent diffusion to the surface to form a crystal. Some of the calcite that has not yet diffused to wellbore surface before being carried out by the fluid from the well, can be derived by using this mechanism.

The rate of deposition caused by mass diffusion will be proportional to the concentration difference. Lasaga(1984) has discussed the concentration gradient in the boundary layer during stable mineral dissolution processes. Assuming deposition has a process just opposites to that of dissolution, the diffusion equation (see Figure 4.9) can be written

$$C(r,t) = C_\infty + (C_{eq} - C_\infty) erf[(r/2)(Dt)^{1/2}] \qquad (4.47)$$

The flux of species is obtained from

$$J = -D*(dC/dr)_{r=0}$$

$$= (C_\infty - C_{eq})*D/(\pi Dt)^{1/2} \qquad (4.48)$$

The consequent increase in the concentration of the same species in the boundary layer is then given by

$$dC/dt = J*A/V \qquad (4.49)$$

Assuming $C_{t=0} = 0$, and integrating Equation (4.48)

$$C = [(C_\infty - C_{eq})*D^{1/2}*A]/(2V\pi^{1/2})*t^{1/2} \qquad (4.50)$$

The thickness of boundary layer is relatively insensitive to crystal size, crystal density, flowing properties and diffusion coefficient (Nielsen, 1984). It is usually in range of 1 to 5 nm (Lasaga, 1984). Transport to the surface can be accelerated by bulk flow of solution past the growing crystal or by stirring due to reducing of the thickness of the diffusion layer or concentration gradient. Thus, transport-controlled growth is a strong function of the hydrodynamic state of the solution.

The diffusion coefficient of the species in solution is given as

$$D = \lambda^2 * k'T / [(2\pi wk'T)^{1/2} V_f^{1/3}] * \exp(-E_{vap}/3k'T) \quad (4.51)$$

in Lasaga (1981).

Mechanism B

Step 1. Ca^{2+}, HCO_3^- and CO_3^{2-} diffuse to mineral surface;

Step 2. Ions collide and react on surface to form calcite scale;

The two rate-limited possibilities for this mechanism can be explained as follows.

In case of the rate of deposition is controlled by Step 1, the assertion that diffusion of HCO_3^- or CO_3^{2-} through the boundary layer is the rate-controlling factor can be made. It is supported by

> A. Experimental evidence indicates that the reaction producing scale can be very rapid, occurring in fractions of a second, following the creation of over-saturation condition (Granados, 1983);

> B. Calcium ion diffusion is much faster than that of

34

bicarbonate and carbonate ions owing to (a) the size of un-hydrated calcium ion is much smaller (b) in the early stage of precipitation, concentration ratio of Ca^{2+}/CO_3^{2-} is much higher (see Appendix), though after deposition carbonate ion is more abundant than calcium ion. So no discernable effect of calcium ion concentration on the rate of reaction at earlier stage.

Bicarbonate can effectively increases the rate of diffusion of carbonate through the boundary layer, which can be explained in two terms (Przybylinski, 1987):

A. Bicarbonate combines with calcium on the surface of the crystal to form calcite with Reaction (4.20). As diffusion of hydrogen ion in water is very fast, it can easily diffuse out. This would run in parallel with the referred Reaction (4.14). Although Reaction (4.20) would likely have a rate constant that is lower than Reaction (4.14), but the concentration of bicarbonate is overwhelmingly greater than that of carbonate (see Appendix) in geothermal fluid. The rate of diffusion is proportional to the concentration gradient across the boundary layer. The difference will be proportional to the actual concentrations of each carbonate species. So bicarbonate ion concentration will primarily determine the diffusion rate. Thus, its overall rate may be greater.

B. Bicarbonate ion merely aids the transport of carbonate through the boundary layer. Since hydrogen and hydroxide ions diffuse very rapidly, the surface pH is essentially identical to the bulk pH. Near the surface, carbonate ion is depleted relative to the bulk, whereas calcium is less depleted. The carbonate ion can be replenished by Reaction (4.8) as well as by diffusion. In this case the bicarbonate ion tends to buffer the concentration of carbonate ion.

In the case where the deposition rate is controlled by Step 2, based on a assumption of that the precipitation has the same, but reversed process and reactions as the mechanism of dissolution, for heterogenous kinetics, the precipitation rate of a mineral is given in general by (Lasaga, 1984),

$$dC/dt = A/V*\nu_i*Q^m/K^m{}_{eq}*K*[H^+]^n \qquad (4.52)$$

The Gibbs free energy change of a particular reaction can be

$$\Delta G = \Delta G^\circ + RT\ln Q =$$
$$RT\ln(Q/K_{eq}) = RT\ln\Omega \qquad (4.53)$$

therefore

$$dC/dt = A/V*\nu_i*K*[H^+]^n*\exp(m*\Delta G/RT) \qquad (4.54)$$

The topography of the mineral surface normally includes "step" and "kink", which are imaginative terms for description. Specie at kink, step and plane surface has higher surface energy in order, because kink has three "sides", in common, step two, and planner only one. During growth, new units of the crystal form at the points where they have the maximum surface area in common with the existing crystal. Thus growth normally takes place at kinks, and the rate of growth may be limited by the rate of nucleation of new kinks and steps (Berner,1981).

Dislocation of crystalline structure creates a step which can propagate continuously during growth, so the slow process of nucleating a new step is not required. The rate of growth of a mineral is thus sensitive to the number and type of dislocations present.

Kinks, because they are points of high surface energy, are favoured locations for adsorption of species from solution. The adsorbed species may "block" or immobilize the kink, and so have a large effect on rate of growth. Phosphates can

interrupt the growth of calcite scale by means of being adsorbed at the kinks and steps.

Degassing of CO_2 from geothermal fluid results in the increase of the fluid pH, which leads to an increase in the concentration of carbonate in the CO_2-H_2O system. That means an increase of the calcite deposition rate. But after the affect of pH on the supersaturation ratio and bicarbonate ion concentration are accounted for, there is no discernable effect of pH on the rate (Przybylinski, 1987). Because hydrogen and hydroxide ions are not species which can join forming a transient species in the kinetics of calcite scaling.

Calcite deposition in the wellbore results in the calcium ion concentration change in the solution, i.e. the concentration distribution. Based on the concentration distribution, we can predict the amount of calcite deposited in the well. This purpose can be approached according to the mechanisms, equilibrium relationships and reactions discussed above.

5. THE CHEMICAL EQUILIBRIUM PROGRAM WATCH

5.1. Introduction

The chemical properties of a geothermal brine are strongly affected by the way the brine is manipulated in the energy extraction plant. Therefore, the chemical properties of the fluid need to be taken into account in the designing and operation of the production and disposal processes. Unfortunately, the properties are quite complicated functions of temperature, pressure and concentration variables of the working fluid. Computer models of geothermal fluid behaviour are needed to predict these properties. The WATCH program is one such computer model for this purpose. It can be used for analyzing the scaling potential in various process options and aiding the selection of the optimal extraction process (Arnorsson et al. 1982). This program was developed by Dr. Stefan Arnorsson and co-workers at the National Energy Authority during the period of 1973 to 1978 (Svavarsson, 1981).

5.2. Program Description

There are two parts of the WATCH program: WATCH1 and WATCH3. The WATCH1 program calculates the chemical behaviour of a fluid on the basis of a chemical analysis of the total flow of a two-phase production well (water, gas and condensate collected at wellhead) (Appendix 1). The WATCH3 program is used for calculations exclusively dealing with the aqueous phase. It is a question of two methods. On the one hand it is assumed that there has been no loss of steam in samples, i.e. the water subjected to analysis is the same as the groundwater (SSTEMP =999). In this case, the program is called WATCH2 in printout (Appendix 2.1 and 2.3). This is valid for cold water, water from down-hole and spring water which has not been boiled. On the other hand, it is realized that the water analyzed has boiled before being sampled, the program is printout as WATCH3 (Appendix 2.2). Then "SSTEMP"

is set equal to the temperature at which the water started boiling (Svavarsson, 1981; Arnorsson et al., 1982).

By combination of the WATCH1 and WATCH3 programs, we can also predict the geothermal fluid chemistry in surface equipment systems. For example, the WATCH1 can be used for calculating the composition of liquid phase in separator and the result can then be put into WATCH3 program to study the effect of further processing.

The WATCH programs calculate only the thermodynamic properties of the fluids but not the kinetics of the reactions. Table 5.1 is a summary of the program function. Table 5.2 is the input data needed for the program (Arnorsson, et al., 1982).

5.3. Yangbajing, Svartsengi and Hverageröi Fields

The Yangbajing field is located at an elevation of 4300 m, about 91 km NW of Lhasa. The structure setting of the area is characterized by a narrow, elongated recent asymmetric graben tending NE-SW. The upper portion of the graben is filled by Quaternary lacustrine and fluviolacustrine sediments of variable thickness from about 300 m in the NW to about 100 m in the SE, whose coarse levels represent the shallow reservoir now being exploited. The temperature distribution measured inside the reservoir is quite uniform, ranging between 150°C and 160°C, with a sharp decrease of temperature at the borders. Higher values (172°C) are recorded in the hot water recharging zone. The fluid chemistry is of the type $Na^+-Cl^--HCO^-_3$ with a total dissolved solids of about 2100 mg/l (ENEL-AQUATER, 1985). The calcite scale in the production wells is cleaned by means of daily mechanical removing.

The Svartsengi geothermal field is located in south-west Iceland. It is classified as high-temperature and water-dominated. The reservoir temperature is in the range 235°-

240°C, and the fluids produced are in composition two-thirds seawater and one-third rainwater. The chemical composition of the brine produced from the wells is spatially and temporally uniform, suggesting good fluid mixing with the reservoir (Gudmundsson and Thorhallsson, 1986).

The Hveragerði geothermal field is located about 50 km east of Reykjavik. There are 8 wells of 300-1000 m depth in the area. The maximum temperature measured in those wells is in the range of 180°C-230°C. All the strata are late Quaternary (Zhou, 1980). The hot water is used for direct utilizations. The calcite deposits in the production wells in Svartsengi and Hveragerði areas are reamed by drilling yearly.

5.4. Chemical Data Treatment

In this project work, the chemical analysis results for surface samples from Wells ZK-309, ZK-311 and ZK-324 in Yangbajing, NLFI-1, G-2 and G-4 in Hveragerði, and SG-6, SG-7, SG-8, SG-9 and SG-11 in Svartsengi are interpreted by using the WATCH1 program. The chemical data for down-hole sample of Well ZK-323 in Yangbajing is interpreted by using the WATCH3 program. The temperatures at the bottom of each wells are not known. Based on the statements mentioned in Part 2.4 and general reservoir temperature, the chalcedony geothermometer is selected for the samples from Yangbajing and Hveragerði fields and the quartz geothermometer is used for the samples from the Svartsengi field.

In general, the interpreting procedure used in this project work can be described in the following.

> 1. Creating WATCH program input data file according to Svavarsson (1981). Setting a series of boiling temperatures in the range from the geochemical reservoir temperature to 90°C and giving the degassing factor as 1.

40

2. Running the program for calculation.

3. Checking if the input data accepted by the program or has agreeable result with chemical knowledge to make sure of the credibility.

4. Using the computer output (Appendix) to make the curves of calcite activity product of the samples (Figures 5.2 to 5.5).

5. Comparing the activity product with the solubility product by means of difference and ratio (Figures 5.7 and 5.6).

6. Interpreting the above figures.

For the down-hole sample analysis data from Well ZK-323 in Yangbajing, the computer output (Appendix 2.1) shows that calcite is very supersaturated under the reservoir condition. This result is not possible because it does not agree with the real situation, i.e. thermodynamic equilibrium. As there is no background knowledge on the sampling and analysis of the Yangbajing samples, Arnorsson (1987b) suggested a method on the basis of geothermometers (as mentioned in Part 2.4) to calibrate the data roughly. The procedure can be described as follows.

1. Using the chemical analysis result as the input data for WATCH3 program and assuming the sample of deep water has been boiled at a reasonable guessing temperature such as 135°C with a series of degassing factors or gas solubility multiplying factor (GSMF).

2. Selecting chalcedony temperature as reservoir temperature for the computer calculation of above input files. The calculated result is adapted as Appendix 2.2.

3. Using the temperature dependent functions or

41

geothermometers of $\log(Na^+/H^+)$, $\log(K^+/H^+)$, $\log(\sqrt{Ca^{2+}}/H^+)$, $\log(\sqrt{Mg^{2+}}/H^+)$ and $\log H_2CO_3$ listed in Table 2.3 to calculate out the "function values" at each chalcedony reservoir temperature in the computer outputs.

4. Using the computer output results to calculate the "output values" of the above five ones.

5. Comparing the each "function value" with its corresponding "output value" at each GSMF.

6. Using the differences obtained by the above step to make Figure 5.1.

7. Finding out the GSMF value when the difference is zero in Figure 5.1, which is about 0.1.

8. Using the deep water composition on the computer output sheet when the GSMF is 0.1 to creating a new WATCH3 input data file.

9. Running the WATCH3 program with SSTEMP = 999 to calculating the calibrated data at given boiling temperatures with the degassing factor (GSMF) is 1. The output is as Appendix 2.3.

Since the CO_2 gas geothermometer is not considered to be applicable below 200°C because of the effect of the salinity of the parent water on the concentration of CO_2 in the steam (Arnorsson, 1983), it is understandable that the curve in Figure 5.1 for $\log H_2CO_3$ has a big scatter. But for the others they are suitable quite well.

42

5.5. Result

Figure 5.2 is the activity products of the samples from Yangbajing with one step adiabatic boiling temperature. The calcite deposition potential for separator samples is in the order of ZK-311, ZK-324 and ZK-309. The surface separated sample represents the fluid which has been boiled in the well-bore before sampling, therefor some of the calcite has been deposited out of the fluid during the boiling inside the well. This is why Appendix 1 shows that the activity product of deep waters for calcite is smaller than the solubility products under the reservoir temperature. The sample from ZK-323 is a down-hole collected fluid sample. Calcite has not deposited before sampling. So the scaling potential of this sample is much higher than the others. Figure 5.3 shows the activity product of surface separated samples from wells in Svartsengi. Figure 5.4 is for samples from Hveragerði.

Figure 5.5 is a comparatione of the calcite scaling potential for samples from Wells ZK-311, NLFI-1 and SG-8, which has the highest deposition thermodynamic potentials among the interpreted samples in Yangbajing, Hveragerði and Svartsengi, respectly. It shows that the lower reservoir temperature, the higher calcite scaling potential. This statement can be a factor guiding the setting and drilling geothermal production wells (see Part 6.6).

Figure 5.6 is the ratio of activity product and solubility product. Figure 5.7 is the difference between them. They are showing the degree of supersaturation for calcite reaches maximum by one step adiabatic boiling the geofluid at a temperature below the reservoir temperature in the range of 15°T to 60°C. This result is useful for geothermal project design and operation. From Appendix 1 we can also have another conclusion, which is that the higher ionic strength of the fluid, the higher calcite deposition potential.

43

6. HANDLING OF CALCITE SCALING IN WELLBORE

Effective scale handling in geothermal operation is often
critical to the success of a project. The methods must be
designed and tailored to the site-specific conditions. These
conditions dictate the type of managing method that will be
feasible, since engineer does not take consideration of
technical feasibility only, but also concern economic
feasibility, and easy operation and maintenance. Calcium
carbonate scaling may be handled by following possibilities
based on its thermodynamics and kinetics.

6.1. Mechanical Removal

Mechanical removal of calcite scaling in geothermal wells is
a most practical method used world wide. In Yangbajing,
Xizang, China, a equipment and method shown in Figure 6.1 has
been used for several years with satisfactory results. Since
calcite scaling in the production wells are very heavy (about
0.2 cm/week during the earlier stage of development), the
wells must be cleaned daily by lowering the device down to
wellbore to scrape the deposits in order to keep them fully
producing. During the operation the well is discharging out
of the gathering system through a bi-pass valve to carry the
debris out of the well. The weight of the equipment is mainly
depended on the flowing pressure of the fluid. In case of
Yangbajing, it is normally 80-100 kg. The main problem
recorded in this operation is the loss of the equipment and
blocks of scales into the well bottom to decrease the output
of the well.

In Svartsengi and Hveragerði, Iceland, glands (Figure 6.2)
are used for cleaning the wells. The gland allows drill pipes
to be entered into the well under full pressure, and the
calcite is removed by drilling with a convectional drill bit,
while the well is flowing and discharging the drill-cutting.
The time required to clean the well is only 2-3 days with a
truck-mounted rig. Use of this clean method allows unhindered

operation of the plants and the cost is low (Björnsson and Albertsson, 1985).

6.2. Pressure Manipulation

Calcite scaling is developed by flashing, which is resulted from that the process pressure acting on the fluid drops to be lower than the flashing pressure of the geothermal fluid (as discussed in Part 2.2.1). Pressure manipulation can be achieved quite easily by pumping instead of relaying on its nature flow. Utilizing down-hole pumps such as shaft-deep-well-pump, turbo-pump and submerged-pump will drastically decrease or eliminate the in-hole pressure drop to maintain the producing fluid as water phase. Thus, the formation of "pressure sensitive" scaling, $CaCO_3$, can be eliminated in geothermal wellbore, or at least shifted from the wellbore into the more accessible surface equipment where the handling becomes much easier.

Unfortunately, the use of down-hole pumps is restricted some what by the fluid temperature and well casing structure. At present, no down-hole pump is guarantee to work at wellbore temperature in excess of approximately 190°C (Corsi, 1987).

6.3. Partial Pressure Control

This control is a potential calcite prevention method. By re-injecting some of the produced carbon dioxide back into the producing well according to the scheme of Figure 6.3 can maintain a high CO_2 particle pressure, which in turn maintain the dissolved carbon dioxide content in geothermal fluid artificially to keep the carbonic species equilibria. Experiments on this method were carried out in the USA (Kuwada, 1982), but it appears valid only for fluid with low CO_2 content (as mentioned in Part 2.2).

6.4. pH Manipulation

On-line manipulation of the geothermal fluid pH is another potentially way to avoid scaling. However, the cost of a such process is often overlooked. Adding hydrogen chloride solution to a geothermal fluid in order to decrease the pH below a certain value at which no calcite scaling can form may be technically but not economic feasibility, since excessively large amounts of acid are required to obtain even fairly a small decrease of pH due to many geothermal fluids have an extremely large flow-rate and buffer capacity.

Off-line acidification of geothermal wells within calcite scale has been used in some geothermal fields. But care should be taken, since well casing and other equipments can be corroded by acidic solution when luck of a sufficiently stable inhibitor, which is capable of maintaining its properties at high temperature for a period of time long enough to allow the complete removal of calcite.

6.5. Inhibitors

The utilization of scale inhibitors seems like a promising method of combatting scaling problems. A lot of studies have been carried out on this subject. Inorganic phosphates are able to prevent precipitation of almost insoluble compound if added to the over-saturated $CaCO_3$ solution in small quantities. The proposed mechanism suggests that the phosphate maintain in solution large quantities of $CaCO_3$ while it begins to crystallize. Practically phosphates do not prevent the initial nucleation, but maintain microscopic the size of crystalline nuclei preventing them to grow (as discussed in Part 4.3). The main drawback of that treatment is the possible precipitation of calcium phosphate with the consequence of further encrustation. Therefore, organic phosphorouses has been developed. In organic compounds, phosphorus links to the carbonic atom and hence calcium phosphate can be avoided.

46

6.6. Others

If a sudden increase in diameter of the well (i.e. a liner hanger) is present, calcite scaling may be promoted due to the similar mechanism of pressure drop. Therefore, transitions in the casing diameter should either be avoid or located at a safe distance above or below the predicted flashing zone. It is likely that the scaling rate can be reduced but not eliminated by having a uniform diameter from the bottom to the wellhead. The use of the techniques of cementing through portholes provides a smooth pipe of a single diameter from the reservoir to the wellhead to approach this purpose and also carry the production with less pressure loss (Granados, 1983). Operating the well at a relatively high wellhead pressure, thereby ensuring flashing above the casing-liner joint can also be minimizing deposition of scale.

Increased well casing diameter has reduced frequency of calcite cleaning in Svartsengi field in Iceland, if combining mechanical cleaning and well design improvement with good organization may provide the less costly method that can be applied in the field (Gudmumdsson, 1983).

It is common that wells form scale in the wellbore when they are located peripherically with respect to hotter regions of a reservoir. Since hotter source has a less calcite scaling environment (as discussed in Part 4.2.6 and Part 5), therefore the possibility of sitting wells on and/or deepening wells to hotter region is worth consideration (Granados, 1983).

7. FLUID INJECTION

7.1. Fluid/Formation Compatibility

The successful development of a geothermal reservoir will require injection of heat-depleted brine to improve reservoir longevity and to minimize environmental damage. To maintain injectabilily, the spent brine must be compatible with the receiving formation, i.e. geological strata. Process chemistry of geothermal fluids is one of the very important factor to influence this brine/formation compatibility. It is discussed and reviewed in detail by Kindle et al. (1984).

In general terms, formation/fluid incompatibility can arise from particulate plugging due to precipitation, clay swelling and dispersing, and influencing of rock-solution equilibria in hydrothermal system of the injected fluid. To diagnose injection problems in this area, information on geological and hydrological characteristics of the receiving formation and data on the injection composition, temperature, and suspended solids content of the fluid are required.

Particulate plugging is the most common type of impairment experienced in geothermal injection wells. It can arise from four processes that have been described by Barkman and Davidson (1972) and shown in Figure 7.1.

* Formation of a filter cake on the wellbore face;

* Particle invasion into the rock formation, which reduces available pore space or forms an internal filter cake;

* Well filling;

* Well casing perforation plugging.

Particulate plugging in geothermal systems is often a

48

combination of the mechanisms outlined above. Experiences show that particles less than 0.45 μm in diameter generally pass through the formation without causing impairment, particles greater than 10 μm in diameter generally accumulate in the wellbore or are retained on the surface and form a filter cake, and particles with diameter between those can invade the formation and cause impairment depending on the formation and fluid properties (Kindle et al., 1984).

In order to avoid particulate plugging, a spent geothermal fluid should be treated by means of either or combined following processes before injection.

* Precipitation avoidance or control;

* Liquid/solid separation: chemical coagulation/ flocculation, sedimentation, filtration, gas flotation;

* Purification treatments: reverse osmosis and ion exchange.

Permeability can also be impaired when gas bubbles enter and are entrained in the fluid stream. These bubbles can lodge in pore spaces and plug the formation, but this type of plugging can frequently be remedied by back flushing.

7.2. Precipitation Avoidance and Acceleration

Many brine, particularly those from high-temperature reservoir, undergo severe chemical disequilibrium during the energy extraction process because of temperature and/or pressure changes. As the brine regains equilibrium, precipitates form that can plug the injection process (Table 7.1).

Based on the knowledge of thermodynamics and kinetics of silica, calcite, sulfide and sulfate scales precipitation, process parameters (temperature and pressure) and additives

(acid, inhibitor, carbon dioxide, lime and water) can be used to control scaling before and during the injection process.

When it is uneconomic to prevent precipitation, it may be possible to design a process so that scale formation occurs at all location and in a form that can be manipulated at minimal cost. Among these techniques is the use of crystallizer, crystallizer-separator, reactor clarifier and fluidized bed, and aging the brine in a tank or pond. They control the location of geothermal scaling to surface vessels and keep the injection well usable. They will be most usable for silica, silicate and sulfide scales that have moderate to slow kinetics. Calcite scale, with its rapid kinetics, will probably form in a pipe before reaching a vessel.

During a disposal process, the most universal problem is caused by silica polymerization. Factors that depress the speed of silica precipitation include: decreased temperature, decreased supersaturation ratio, the absence of fluoride ion catalyst, and lowering the pH. Maintaining silica supersaturation ratio below 2 or maintaining high temperature give some opportunity for controlling precipitation at the pH ranges normally. Lowering the pH by one unit slows the kinetics by a factor of 10, and on the other hand, by raising the pH with lime (CaO) addition flocculate the silica (Figures 7.2 and 7.3). As the fluid becomes very acid (pH about 3), the kinetics slows and the presence of fluoride catalyst can maintain the precipitation rate even in the face of further pH drops. Since silica equilibrium solubility increase with temperature, which partially offsets temperature-based kinetic factors, the net effect is that the maximum rate of silica precipitation should occur when the brine is 25°C to 50°C below the temperature for saturation at a given amorphous silica concentration (Table 7.2).

Calcite precipitation is typically a production problem, although it may result from the injection of surface or incompatible waters are involved (as discussed in Part 4).

Sulfide scale frequently occur in conjunction with other scales, although as techniques are used to control these other scales (Figures 7.4 and 7.5), sulfide precipitates become more noticeable as geothermal scales on their own basis. The sulfide chemistry is more complicated and less understood than the silica and calcite chemistry, and it deserves more investigation.

Sulfate scales are a similar problem where incompatible waters are involved.

7.3. Chemical Monitoring and Tracer Testing

Data from sampling and analyzing spent fluid in injection treatment process can be used to identify or understand chemical problems arising from injecting altered or foreign water into a geothermal reservoir by geochemical modeling. The geochemical models can calculated the tendency of the brine to scale in process condition and help in the optimization of critical design of disposal process.

Injection would support reservoir pressure and eliminated surface disposal of spent brine and condensate of geothermal power plant, but it could lead to cold water fingering from injection well to production wells. If large flow-rate of cold water injected into reservoir reaches to production zone rapidly without heated up by heat source to reservoir temperature, it would result from the cooling down of aquifer or even kill the reservoir. Thus, understanding the cold water traveling paths and speed are most important during the whole injection process. Tracer monitoring of well interference is a useful tools for this purpose.

Tracer selection and testing data interpretation are very important two aspects in tracer testing. Factors governing tracer selection are as follows.

* High thermal stability in geothermal reservoir;

* No interference with other chemicals in water-rock interactions in geothermal formation;

* Suitable adsorption-de-adsorption characteristics;

* Low background concentration in original geothermal fluid;

* High sensitivity in analysis;

* Excellent and easy instrument and method for detectability;

* Cheap to use, i.e. low price and high activity at low concentration etc.

A test in Svartsengi, Iceland showed that Iodide seems to be a good choice for use in tracer surveys of high temperature geothermal field, at least much better than rhodamine WT dye (Gudmundsson and Hauksson, 1985). Fluorescent dye has also been used in a few geothermal tracer tests at low-to-moderate temperatures (Gudmundsson et al. 1983).

A tracer breakthrough curve (Figure 7.6) shows the concentration of tracer with time. It provides a record of what happens underground when a fluid flows between two or more geothermal wells. Tracer testing provides three main pieces of information (Gudmundsson and Hauksson, 1985).

The first is the arrival time of the peak concentration. It indicates the mean speed of movement of flow in reservoir. Rapid tracer movement implies a high degree of fracturing or high permeability in the reservoir, and may suggest that the thermally swept volume of reservoir rock will be small.

The second parameter is the total tracer recovery. A production well that receives more of the injected water than others is more likely to suffer temperature decline as a

result. The relative recoveries in several production wells can be useful for comparison between wells.

The third one is to analyze the shape of breakthrough curve. it requires the uses of a tracer flow model between the injection and production wells. This procedure is still under development, but shows possibilities for the estimation of fracture characteristics. An estimate of fracture aperture may be useful for calculating the rate of local thermal depletion along the flow path.

8. CONCLUSIONS

Geothermal fluids are usually just saturated with respect to calcium carbonate under the water-dominated reservoir conditions. During the exploitation of the fluids, large calcite scale is often developed upon boiling in the production wells due to the concentrating and degassing of the liquid phase, which leads to the reestablishment of the chemical equilibrium in $CaO-CO_2-H_2O$ system, and extreme mass flow rate. The lower in reservoir temperature and the higher of ionic strength the fluid, the more severe of the calcite deposition problem.

The degree of calcite supersaturation for a unflashed reservoir fluid reaches a maximum when cooled by 10°C to 60°C through a adiabatic boiling. But simply cooling of the fluid owing to heat losses, i.e. thermal conductivity and/or diffusivity from the fluid to the environment can not cause calcite deposition from the fluid in a general temperature range. Since calcite is formed by ionic reactions in the system, deposition of calcite takes place much faster than the geothermal process operation time. Deposition of calcite in geothermal production well may be mainly controlled by the diffusion mechanism.

Mechanical removal of calcite scale in low enthalpy and high scaling potential production wells as those in Yangbajing and reaming of that in high enthalpy wells as in Svartsengi seem like the practical ways for handling at present. Although the former method is easy for operation, it needs more labor. But that is not a economical problem in Tibet. Using inhibitors is a promising way but it is still under development.

Chemistry can contribute important effects on the successes of geothermal depleted fluid injection. Chemical monitoring and tracer survey can play significant roles in the injection process decision and operation.

The chemical behaviour of geothermal fluids can be estimated by chemical equilibrium process modelling at a certain extent. The usefulness of the input chemical data depends on the sampling and analytical methods and the care taken in the collection and analysis of the sample.

ACKNOWLEDGEMENT

NOMENCLATURE

A: Area in Part 4, m^2

b: Degassing Factor

C: Concentration in Part 4, Mole/kg

C: Turbulence Factor in Part 2, $bar/(kg/s)^2$

D: Depth, m

d: Diameter, m

D: Diffusion Factor in Part 4, cm^2/s

f: Friction factor

G: Gibbs free Energy

g: Acceleration of Gravity, m/s^2

H: Energy, kJ

h: Enthalpy, kJ/kg

I: Ionic Strength

J: Flux of Mass Transfer

K: Coefficient

k: Coefficient

L: Latent heat, kJ/kg

m: Molality, mole/kg

n: Mole Number

P: Pressure, bar

Q: Activity Product

R: Universal gas constant, 8.314 kJ/(kg°K)

r: radial distance

T: Temperature, °K

t: Temperature in Part 2, °C

t: Time in Part 4, s

V: Specific Volume in Part 2, m^3/kg

V_f: Molar Volume, $cm^3/mole$

V: Volume, m^3

v: Velocity, m/s

W: Flow rate, kg/s

w: Weight percent

w: molar weight in Equation (4.51)

X: Mole fraction

x: Mass fraction

Z: Length, m

z_i: Charges of Species i

[i]: activity of species i

μ: Dynamic viscosity, Ns/m^2

σ: Surface Tension, N/m

α: Void Fraction

ρ: density, kg/m^3

ε: Absolute roughness factor, m

γ: correction factor for K_H^o in sanility solution

γ_i: activity coefficient of species i

ν_i: stoichiometric constant

λ: jump distance, cm

erf: error function

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APPENDIX 1 Computer Output for Separated Samples From Wells ZK-309, ZK-311, ZK-324, NLFI-1 and SG-8

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REP.YBJ.001   YANGBAJING ZK-324   TIBET

PROGRAM WATCH1.

WATER SAMPLE (PPM)   STEAM SAMPLE

PH/DEG.C	8.25/20.0	GAS (VOL.%)		REFERENCE TEMP.	DEGREES C	.0 (CHA)
SIO2	254.00	CO2	99.00			
NA	395.00	H2S	.68	SAMPLING PRESSURE	BARS ABS.	3.1
K	46.50	H2	.03	DISCHARGE ENTHALPY	MJOUL/KG	.794 (CALCULATED)
CA	2.00	O2	.00	DISCHARGE	KG/SEC.	.0
MG	.110	CH4	.01			
CO2	196.56	N2	.27	MEASURED TEMPERATURE DEGREES C		.0
SO4	48.00	He	0.006	RESISTIVITY/TEMP.	OHMM/DEG.C	.0/ .0
H2S	12.40			EH/TEMP.	MV/DEG.C	.000/ .0
CL	521.00					
F	10.60	LITERS GAS PER KG				
DISS.SOLIDS	.00	CONDENSATE/DEG.C	5.28/20.0	MEASURED DOWNHOLE TEMP.	FLUID INFLOW	
AL	.2500			DEGREES C/METERS	DEPTH (METERS)	
B	58.8000					
FE	.6100	CONDENSATE (PPM)		.0	.0	.0
NH3	.3200	PH/DEG.C	5.98/20.0	.0	.0	.0
LI	3.4	CO2	17.28	.0	.0	.0
BA	0.15	H2S	14.90	.0	.0	.0
BR	1.7	NA	16.90	.0	.0	.0
				.0	.0	.0
				.0	.0	.0
				.0	.0	.0
		CONDENSATE WITH NAOH (PPM)		.0	.0	.0
		CO2	.00	.0	.0	.0
		H2S	.00	.0	.0	.0

IONIC STRENGTH = .02064   IONIC BALANCE : CATIONS (MOL.EQ.) .01848338
                                            ANIONS (MOL.EQ.) .02161527
                                            DIFFERENCE (%) -15.62

DEEP WATER (PPM)   DEEP STEAM (PPM)   GAS PRESSURES (BARS ABS.)

SIO2	239.03	CO2	750.33	CO2	.00	CO2	.176E+01
NA	371.69	H2S	15.55	H2S	.00	H2S	.144E-01
K	43.75	H2	.01	H2	.00	H2	.460E-02
CA	1.88	O2	.00	O2	.00	O2	.000E+00
MG	.104	CH4	.03	CH4	.00	CH4	.270E-02
SO4	45.17	N2	.93	N2	.00	N2	.549E-01
CL	490.21	NH3	.30	NH3	.00	NH3	.125E-04
F	9.98					H2O	.702E+01
DISS.S.	.00					TOTAL	.896E+01
AL	.2352						
B	55.3249			H2O (%)	.00		
FE	.5740			BOILING PORTION	.00		

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ACTIVITY COEFFICIENTS IN DEEP WATER

H+	.850	KSO4-	.831	FE++	.469	FECL+	.823
OH-	.819	F-	.819	FE+++	.236	AL+++	.236
H3SIO4-	.823	CL-	.816	FEOH+	.829	ALOH++	.481
H2SIO4--	.481	NA+	.823	FE(OH)3-	.829	AL(OH)2+	.831
H2BO3-	.812	K+	.816	FE(OH)4--	.475	AL(OH)4-	.826
HCO3-	.823	CA++	.489	FEOH++	.475	ALSO4+	.826
CO3--	.468	MG++	.514	FE(OH)2+	.831	AL(SO4)2-	.826
HS-	.819	CAHCO3+	.835	FE(OH)4-	.831	ALF++	.481
S--	.475	MGHCO3+	.823	FESO4+	.829	ALF2+	.831
HSO4-	.826	CAOH+	.835	FECL++	.475	ALF4-	.826
SO4--	.461	MGOH+	.838	FECL2+	.829	ALF5--	.468
NASO4-	.831	NH4+	.812	FECL4-	.823	ALF6---	.182

CHEMICAL COMPONENTS IN DEEP WATER (PPM AND LOG MOLE)

H+ (ACT.)	.00	-6.272	MG++	.07	-5.545	FE(OH)3	.09	-6.099
OH-	.12	-5.141	NACL	4.53	-4.110	FE(OH)4-	.07	-6.249
H4SIO4	380.65	-2.402	KCL	.18	-5.624	FECL+	.08	-6.058
H3SIO4-	1.47	-4.812	NASO4-	3.66	-4.513	FECL2	.00	-14.011
H2SIO4--	.00	-9.278	KSO4-	1.46	-4.967	FECL++	.00	-18.209
NAH3SIO4	.27	-5.640	CASO4	.35	-5.585	FECL2+	.00	-19.642
H3BO3	315.58	-2.292	MGSO4	.14	-5.946	FECL3	.00	-22.038
H2BO3-	.84	-4.857	CACO3	.02	-6.616	FECL4-	.00	-24.893
H2CO3	781.72	-1.900	MGCO3	.00	-8.385	FESO4	.03	-6.639
HCO3-	270.11	-2.354	CAHCO3+	1.95	-4.716	FESO4+	.00	-17.751
CO3--	.03	-6.264	MGHCO3+	.02	-6.581	AL+++	.00	-17.246
H2S	10.84	-3.497	CAOH+	.00	-8.109	ALOH++	.00	-11.969
HS-	4.57	-3.860	MGOH+	.00	-7.971	AL(OH)2+	.00	-7.350
S--	.00	-12.843	NH4OH	.27	-5.108	AL(OH)3	.54	-5.083
H2SO4	.00	-13.601	NH4+	.18	-5.005	AL(OH)4-	.04	-6.394
HSO4-	.11	-5.953	FE++	.28	-5.301	ALSO4+	.00	-17.328
SO4--	40.69	-3.373	FE+++	.00	-20.244	AL(SO4)2-	.00	-18.646
HF	.14	-5.154	FEOH+	.20	-5.563	ALF++	.00	-12.690
F-	9.84	-3.286	FE(OH)2	.01	-7.102	ALF2+	.00	-9.639
CL-	487.35	-1.862	FE(OH)3-	.00	-9.602	ALF3	.00	-8.440
NA+	369.15	-1.794	FE(OH)4--	.00	-15.433	ALF4-	.00	-9.024
K+	43.24	-2.956	FE(OH)++	.00	-13.678	ALF5--	.00	-10.738
CA++	1.00	-4.604	FE(OH)2+	.00	-8.641	ALF6---	.00	-13.635

IONIC STRENGTH = .01895   IONIC BALANCE :   CATIONS (MOL.EQ.) .01725122
                                              ANIONS (MOL.EQ.) .01971595
                                              DIFFERENCE (%)   -13.28

CHEMICAL GEOTHERMOMETERS DEGREES C   1000/T DEGREES KELVIN = 2.28

QUARTZ   185.8
CHALCEDONY 165.1
NAK   218.8

OXIDATION POTENTIAL (VOLTS) :   EH H2S= -.391   EH CH4= -.421   EH H2= -.444   EH NH3= -.415

LOG SOLUBILITY PRODUCTS OF MINERALS IN DEEP WATER

	TEOR.	CALC.		TEOR.	CALC.		TEOR.	CALC.
ADULARIA	-15.333	-15.394	ALBITE LOW	-14.769	-14.229	ANALCIME	-11.963	-11.826
ANHYDRITE	-6.613	-8.625	CALCITE	-10.725	-11.509	CHALCEDONY	-2.402	-2.402
MG-CHLORITE	-80.359	-88.485	FLUORITE	-10.597	-11.660	GOETHITE	-2.002	-1.102
LAUMONTITE	-25.068	-24.610	MICROCLINE	-16.323	-15.394	MAGNETITE	-24.549	-18.271
CA-MONTMOR.	-75.345	-67.031	K-MONTMOR.	-35.935	-34.103	MG-MONTMOR.	-76.727	-67.950
NA-MONTMOR.	-36.112	-32.937	MUSCOVITE	-18.609	-15.224	PREHNITE	-35.793	-37.778
PYRRHOTITE	-66.841	-47.038	PYRITE	-100.948	-54.531	QUARTZ	-2.577	-2.402
WAIRAKITE	-23.824	-24.910	WOLLASTONITE	9.119	5.225	ZOISITE	-35.520	-37.693
EPIDOTE	-38.624	-38.680	MARCASITE	-80.947	-54.531			

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LOG DISTRIBUTION COEFFICIENTS　　CO2 =-3.20　　H2S =-2.71　　GAS SOLUBILITY MULTIPLYING FACTOR 1.00

DEEP WATER (PPM)				DEEP STEAM (PPM)		GAS PRESSURE (BARS ABS.)	
SIO2	246.70	CO2	181.20	CO2	18477.29	CO2	.160E-01
NA	383.62	H2S	9.07	H2S	248.64	H2S	.863E-03
K	45.16	H2	.00	H2	.25	H2	.107E-04
CA	1.94	O2	.00	O2	.00	O2	.0033-09
MG	.107	CH4	.00	CH4	.93	CH4	.499E-05
SO4	45.62	N2	.00	N2	31.44	N2	.951E-04
CL	505.85	NH3	.22	NH3	2.81	NH3	.142E-04
F	10.30					H2O	.476E+01
DISS.S.	.00					TOTAL	.480E+01
AL	.2429						
B	57.1012			HCO (%)	3.11		
FE	.5925			BOILING PORTION	.03		

ACTIVITY COEFFICIENTS IN DEEP WATER

H+	.854	HSO4-	.835	FE++	.500	FECL+	.828
OH-	.834	F-	.824	FE+++	.247	AL+++	.247
H3SIO4-	.828	CL-	.821	FEOH+	.834	ALOH++	.491
H2SIO4--	.492	NA+	.828	FE(OH)3-	.834	AL(OH)2+	.835
H2BO3-	.817	K+	.821	FE(OH)4--	.486	AL(OH)4-	.831
HCO3-	.828	CA++	.500	FEOH++	.486	ALSO4+	.831
CO3--	.479	MG++	.525	FE(OH)2+	.835	AL(SO4)2-	.831
HS-	.824	CAHCO3+	.839	FE(OH)4-	.835	ALF++	.492
S--	.486	MGHCO3+	.828	FESO4+	.834	ALF2+	.836
HSO4-	.831	CAOH+	.839	FECL++	.486	ALF4-	.831
SO4--	.472	MGOH+	.842	FECL2+	.834	ALF6--	.473
NASO4-	.835	NH4+	.817	FECL4-	.828	ALF6---	.192

CHEMICAL COMPONENTS IN DEEP WATER (PPM AND LOG MOLE)

H+ (ACT.)	.00	-7.769	MG++	.07	-5.535	FE(OH)3	.06	-6.261
OH-	2.80	-3.783	NACL	4.36	-4.137	FE(OH)4-	1.14	-5.035
H4SIO4	346.98	-2.443	KCL	.15	-5.694	FECL+	.00	-8.145
H3SIO4-	40.95	-3.368	NASO4-	3.32	-4.554	FECL2	.00	-16.396
H2SIO4--	.05	-6.311	KSO4-	1.30	-5.018	FECL++	.00	-22.250
NAH3SIO4	7.54	-4.189	CASO4	.31	-5.638	FECL2+	.00	-21.678
H3BO3	300.44	-2.312	MGSO4	.12	-6.009	FECL3	.00	-20.112
H2BO3-	25.74	-3.374	CACO3	.55	-5.260	FECL4-	.00	-29.035
H2CO3	16.48	-3.576	MGCO3	.01	-6.981	FESO4	.00	-8.041
HCO3-	232.75	-2.419	CAHCO3+	1.35	-4.874	FESO4+	.00	-21.775
CO3--	1.08	-4.743	MGHCO3+	.02	-6.696	AL+++	.00	-21.325
H2S	.48	-4.850	CAOH+	.01	-6.796	ALOH++	.00	-14.944
HS-	7.36	-3.653	MGOH+	.01	-6.711	AL(OH)2+	.00	-8.188
S--	.00	-11.267	NH4OH	.42	-4.917	AL(OH)3	.20	-5.561
H2SO4	.00	-15.921	NH4+	.02	-6.077	AL(OH)4-	.01	-5.135
HSO4-	.00	-7.649	FE++	.00	-7.269	ALSO4+	.00	-21.517
SO4--	42.70	-3.352	FE+++	.00	-23.989	AL(SO4)2-	.00	-22.675
HF	.00	-6.785	FEOH+	.04	-6.259	ALF++	.00	-16.948
F-	10.29	-3.266	FE(OH)2	.02	-6.576	ALF2+	.00	-14.041
CL-	503.29	-1.848	FE(OH)3-	.00	-7.923	ALF3	.00	-13.825
NA+	379.82	-1.782	FE(OH)4--	.00	-12.348	ALF4-	.00	-13.549
K+	44.70	-2.942	FE(OH)++	.00	-16.234	ALF5--	.00	-15.262
CA++	1.09	-4.568	FE(OH)2+	.00	-10.059	ALF6---	.00	-18.115

IONIC STRENGTH = .01973　　IONIC BALANCE :　CATIONS (MOL.EQ.) .01773389
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SAMPLE = EEP.YB3.001

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OXIDATION POTENTIAL (VOLTS) :   EH H2S= -.511   EH CH4= -.510   EH H2= -.556   EH NH3= -.560

LOG SOLUBILITY PRODUCTS OF MINERALS IN DEEP WATER

	THOR.	CALC.		THOR.	CALC.		THOR.	CALC.
ADULARIA	-15.664	-15.481	ALBITE LOW	-15.067	-14.318	ANALCIME	-12.168	-11.876
ANHYDRITE	-6.366	-6.546	CALCITE	-10.399	-9.930	CHALCEDONY	-2.492	-2.441
MG-CHLORITE	-80.047	-77.594	FLUORITE	-10.561	-11.568	GOETHITE	-2.669	-1.249
LAUMONTITE	-25.402	-24.890	MICROCLINE	-16.731	-15.481	MAGNETITE	-15.789	-17.891
CA-MONTMOR.	-76.836	-83.966	K-MONTMOR.	-36.807	-42.577	MG-MONTMOR.	-78.177	-84.914
NA-MONTMOR.	-36.353	-41.413	MUSCOVITE	-18.391	-18.000	PREHNITE	-35.828	-35.050
PYRRHOTITE	-74.605	-57.694	PYRITE	-111.470	-78.682	QUARTZ	-2.653	-2.449
WAIRAKITE	-23.901	-24.890	WOLLASTONITE	9.469	8.227	ZOISITE	-35.407	-35.393
EPIDOTE	-39.779	-36.298	MARCASITE	-90.765	-78.682			

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LOG DISTRIBUTION COEFFICIENTS   CO2 =-3.41   H2S =-2.93   GAS SOLUBILITY MULTIPLYING FACTOR 1.00

DEEP WATER (PPM)   DEEP STEAM (PPM)   GAS PRESSURES (BARS ABS.)

SIO2	257.02	CO2	158.35	CO2	8617.49	CO2	.958E-02
NA	393.66	H2S	5.65	H2S	133.85	H2S	.131E-03
K	47.05	H2	.00	H2	.11	H2	.270E-05
CA	2.02	O2	.00	O2	.00	O2	.000E+00
MG	.111	CH4	.00	CH4	.42	CH4	.110E-05
SO4	48.57	N2	.00	N2	13.99	N2	.243E-04
CL	527.10	NH3	.16	NH3	2.21	NH3	.034E-05
F	10.73					H2O	.270E+01
DISS.S.	.00					TOTAL	.271E+01
AL	.2523						
B	59.4880			H2O (%)	7.00		
FE	.6172			BOILING PORTION	.07		

ACTIVITY COEFFICIENTS IN DEEP WATER

H+	.860	HSO4-	.842	FE++	.514	FECL+	.834
OH-	.831	F-	.831	FE+++	.262	AL+++	.262
H3SIO4-	.834	CL-	.827	FEOH+	.840	ALOH++	.505
H2SIO4--	.506	NA+	.834	FE(OH)3-	.840	AL(OH)2-	.842
H2BO3-	.824	K+	.827	FE(OH)4--	.501	AL(OH)4-	.827
HCO3-	.834	CA++	.514	FEOH++	.501	ALSO4+	.837
CO3--	.494	MG++	.539	FE(OH)2+	.842	AL(SO4)2-	.837
HS-	.831	CAHCO3+	.845	FE(OH)4-	.842	ALF++	.505
S--	.501	MGHCO3+	.834	FESO4+	.840	ALF2+	.842
HSO4-	.837	CAOH+	.845	FECL++	.501	ALF4-	.837
SO4--	.487	MGOH+	.848	FECL2+	.840	ALF5--	.494
NASO4-	.842	NH4+	.824	FECL4-	.834	ALF6---	.205

CHEMICAL COMPONENTS IN DEEP WATER (PPM AND LOG MOLE)

H+ (ACT.)	.00	-8.135	MG++	.08	-5.500	FE(OH)3	.03	-6.467
OH-	3.95	-3.634	NACL	3.75	-4.193	FE(OH)4-	1.64	-5.076
H4SIO4	319.37	-2.479	KCL	.12	-5.784	FECL+	.00	-7.936
H3SIO4-	78.52	-3.083	NASO4-	2.91	-4.611	FECL2	.00	-18.058
H2SIO4--	.21	-5.660	KSO4-	1.11	-5.087	FECL++	.00	-22.751
NAH3SIO4	14.98	-3.897	CASO4	.27	-5.706	FECL2+	.00	-24.170
H3BO3	282.98	-2.339	MGSO4	.10	-6.085	FECL3	.00	-26.680
H2BO3-	56.15	-3.033	CACO3	.89	-5.050	FECL4-	.00	-23.876
H2CO3	4.73	-4.118	MGCO3	.02	-6.687	FESO4	.00	-8.300
HCO3-	210.90	-2.461	CAHCO3+	.90	-5.049	FESO4+	.00	-21.348
CO3--	2.84	-4.325	MGHCO3+	.01	-6.780	AL+++	.00	-21.873
H2S	.16	-5.337	CAOH+	.01	-6.701	ALOH++	.00	-15.445
HS-	5.30	-3.720	MGOH+	.01	-6.850	AL(OH)2+	.00	-9.800
S--	.00	-11.150	NH4OH	.30	-5.062	AL(OH)3	.07	-6.049
H2SO4	.00	-18.033	NH4+	.01	-6.264	AL(OH)4-	.81	-5.072
HSO4-	.00	-8.278	FE++	.01	-6.886	ALSO4+	.00	-22.001
SO4--	45.16	-3.328	FE+++	.00	-24.108	AL(SO4)2-	.00	-21.410
HF	.00	-7.333	FEOH+	.11	-5.831	ALF++	.00	-17.615
F-	10.73	-3.248	FE(OH)2	.05	-6.168	ALF2-	.00	-14.767
CL-	524.77	-1.820	FE(OH)3-	.00	-7.632	ALF3	.00	-11.774
NA+	394.70	-1.765	FE(OH)4--	.00	-11.847	ALF4-	.00	-14.452
K+	46.66	-2.323	FE(OH)++	.00	-16.389	ALF5--	.00	-15.154
CA++	1.22	-4.516	FE(OH)2-	.00	-10.323	ALF6---	.00	-18.368

IONIC STRENGTH = .02980   IONIC BALANCE :   CATIONS (MOL.EQ.) .01844037
                                              ANIONS (MOL.EQ.) .02205440
                                              DIFFERENCE (%) -17.85

SAMPLE = EEP.YEJ.001

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OXIDATION POTENTIAL (VOLTS) :   EH H2S= -.505   EH CH4= -.499   EH H2= -.501   EH NH3= -.554

LOG SOLUBILITY PRODUCTS OF MINERALS IN DEEP WATER

	TEOR.	CALC.		TEOR.	CALC.		TEOR.	CALC.
ADULARIA	-16.196	-15.546	ALBITE LOW	-15.550	-14.385	ANALCIME	-12.512	-11.907
ANHYDRITE	-6.051	-9.445	CALCITE	-9.992	-9.436	CHALCEDONY	-2.521	-2.479
MG-CHLORITE	-79.901	-76.206	FLUORITE	-10.502	-11.463	GOETHITE	-2.506	-1.430
LAUMONTITE	-25.983	-24.930	MICROCLINE	-17.376	-15.546	MAGNETITE	-27.385	-17.475
CA-MONTMOR.	-79.557	-86.232	K-MONTMOR.	-38.347	-43.719	MG-MONTMOR.	-80.832	-87.137
NA-MONTMOR.	-38.446	-42.558	MUSCOVITE	-19.675	-18.328	PREHNITE	-36.045	-34.895
PYRRHOTITE	-84.760	-63.308	PYRITE	-125.505	-87.754	QUARTZ	-2.807	-2.479
WAIRAKITE	-24.116	-24.930	WOLLASTONITE	9.971	8.987	ZOISITE	-35.495	-36.075
EPIDOTE	-41.227	-36.121	MARCASITE	-103.789	-87.754			

OXIDATION POTENTIAL (VOLTS) :   EH H2S= -.505   EH CH4= -.499   EH H2= -.501   EH NH3= -.554

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LOG DISTRIBUTION COEFFICIENTS   CO2 =-3.63   H2S =-3.16   GAS SOLUBILITY MULTIPLYING FACTOR 1.00

DEEP WATER (PPM)						DEEP STEAM (PPM)		GAS PRESSURES (BARS ABS.)	
SIO2	267.49	CO2	148.78			CO2	5503.60	CO2	.340E-02
NA	415.94	H2S	5.45			H2S	100.43	H2S	.760E-04
K	48.96	H2	.00			H2	.07	H2	.942E-06
CA	2.11	O2	.00			O2	.00	O2	.000E-00
MG	.116	CH4	.00			CH4	.27	CH4	.440E-06
SO4	50.54	N2	.00			N2	9.21	N2	.949E-05
CL	548.57	NH3	.12			NH3	1.84	NH3	.278E-05
F	11.16							H2O	.143E+01
DISS.S.	.00							TOTAL	.144E+01
AL	.2632								
B	61.9109					H2O (%)	10.64		
FE	.6424					BOILING PORTION	.11		

ACTIVITY COEFFICIENTS IN DEEP WATER

H+	.865	KSO4-	.848	FE++	.529	FECL+	.840
OH-	.837	F-	.837	FE+++	.277	AL+++	.277
H3SIO4-	.840	CL-	.834	FEOH+	.846	ALOH++	.521
H2SIO4--	.521	NA+	.840	FE(OH)3-	.846	AL(OH)2+	.848
H2BO3-	.830	K+	.834	FE(OH)4--	.515	AL(OH)4-	.843
HCO3-	.840	CA++	.529	FEOH++	.515	ALSO4+	.843
CO3--	.508	MG++	.553	FE(OH)2+	.848	AL(SO4)2-	.843
HS-	.837	CAHCO3+	.851	FE(OH)4-	.846	ALF++	.521
S--	.515	MGHCO3+	.840	FESO4+	.846	ALF2+	.848
HSO4-	.843	CAOH+	.851	FECL++	.515	ALF4-	.843
SO4--	.501	MGOH+	.854	FECL2+	.848	ALF5--	.505
NASO4-	.848	NH4+	.830	FECL4-	.840	ALF6---	.219

CHEMICAL COMPONENTS IN DEEP WATER (PPM AND LOG MOLE)

H+ (ACT.)	.00	-8.389	MG++	.08	-5.462	FE(OH)3	.03	-6.758
OH-	3.87	-3.643	NACL	3.02	-4.287	FE(OH)4-	.03	-5.295
H4SIO4	301.25	-2.504	KCL	.10	-5.872	FECL+	.00	-7.560
H3SIO4-	107.55	-2.946	NASO4-	2.55	-4.669	FECL2	.00	-13.089
H2SIO4--	.46	-5.308	KSO4-	.95	-5.155	FECL++	.00	-25.929
NAH3SIO4	21.27	-3.744	CASO4	.23	-5.774	FECL2+	.00	-24.337
H3BO3	262.42	-2.372	MGSO4	.08	-6.171	FECL3	.00	-26.887
H2BO3-	90.21	-2.829	CACO3	1.10	-4.960	FECL4-	.00	-30.064
H2CO3	1.93	-4.506	MGCO3	.03	-6.506	FESO4	.00	-7.367
HCO3-	197.71	-2.489	CAHCO3+	.60	-5.225	FESO4+	.00	-22.391
CO3--	5.52	-4.037	MGHCO3+	.01	-6.842	AL+++	.00	-21.560
H2S	.07	-5.687	CAOH+	.01	-6.766	ALOH++	.00	-15.631
HS-	5.22	-3.802	MGOH+	.01	-6.728	AL(OH)2-	.00	-10.201
S--	.00	-11.178	NH4OH	.23	-5.191	AL(OH)3	.03	-6.424
H2SO4	.00	-19.065	NH4+	.01	-6.295	AL(OH)4-	.89	-5.029
HSO4-	.00	-8.789	FE++	.03	-6.317	ALSO4+	.00	-22.016
SO4--	47.59	-3.305	FE+++	.00	-23.911	AL(SO4)2-	.00	-21.478
HF	.00	-7.763	FEOH+	.32	-5.363	ALF++	.00	-17.595
F-	11.16	-3.231	FE(OH)2	.12	-5.866	ALF2+	.00	-15.922
CL-	546.89	-1.812	FE(OH)3-	.00	-7.599	ALF3	.00	-14.098
NA+	410.12	-1.749	FE(OH)4--	.00	-11.763	ALF4-	.00	-14.920
K+	46.64	-2.905	FE(OH)++	.00	-16.340	ALF5--	.00	-16.558
CA++	1.35	-4.471	FE(OH)2+	.00	-10.504	ALF6---	.00	-19.279

IONIC STRENGTH = .02193   IONIC BALANCE :   CATIONS (MOL.EQ.) .01916958
                                          ANIONS (MOL.EQ.) .02344803
                                          DIFFERENCE (%) -20.09

SAMPLE = REP.FBJ.001

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OXIDATION POTENTIAL (VOLTS) :   EH H2S= -.486   EH CH4= -.477   EH H2= -.554   EH NH3= -.504

LOG SOLUBILITY PRODUCTS OF MINERALS IN DEEP WATER

	THOR.	CALC.		THOR.	CALC.		THOR.	CALC.
ADULARIA	-16.847	-15.581	ALBITE LOW	-16.143	-14.421	ANALCIME	-12.545	-11.507
ANHYDRITE	-5.750	-8.353	CALCITE	-9.614	-9.079	CHALCEDONY	-2.764	-2.504
MG-CHLORITE	-80.081	-76.042	FLUORITE	-10.528	-11.365	GOETHITE	-4.397	-1.646
LAUMONTITE	-26.736	-24.933	MICROCLINE	-18.155	-15.581	MAGNETITE	-28.935	-17.327
CA-MONTMOR.	-83.280	-86.377	K-MONTMOR.	-40.404	-43.799	MG-MONTMOR.	-84.474	-87.349
NA-MONTMOR.	-40.447	-42.639	MUSCOVITE	-20.593	-18.310	PREHNITE	-26.476	-34.518
PYRRHOTITE	-94.806	-68.188	PYRITE	-139.758	-94.639	QUARTZ	-3.006	-2.504
WAIRAKITE	-24.474	-24.933	WOLLASTONITE	10.525	9.526	ZOISITE	-15.685	-35.983
EPIDOTE	-42.797	-36.264	MARCASITE	-116.925	-94.639			

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LOG DISTRIBUTION COEFFICIENTS   CO2 =-3.85   H2S =-3.39   GAS SOLUBILITY MULTIPLYING FACTOR 1.00

DEEP WATER (PPM)   DEEP STEAM (PPM)   GAS PRESSURES (BARS ABS.)

SIO2	277.95	CO2	144.00	CO2	4473.30	CO2	.128E-02
NA	432.21	H2S	4.32	H2S	84.50	H2S	.313E-04
K	50.88	H2	.00	H2	.00	H2	.350E-06
CA	2.13	O2	.00	O2	.00	O2	.000E+00
MG	.120	CH4	.00	CH4	.21	CH4	.163E-06
SO4	52.52	N2	.00	N2	7.00	N2	.315E-05
CL	570.04	NH3	.09	NH3	1.58	NH3	.117E-05
F	11.60					H2O	.701E+00
DISS.S.	.00					TOTAL	.702E+00
AL	.2735						
B	64.3338			H2O (%)	14.00		
FE	.6675			BOILING PORTION	.14		

ACTIVITY COEFFICIENTS IN DEEP WATER

H+	.870	KSO4-	.853	FE++	.542	FECL+	.846
OH-	.843	F-	.843	FE+++	.292	AL+++	.292
H3SIO4-	.846	CL-	.839	FEOH+	.851	ALOH++	.534
H2SIO4--	.534	NA+	.846	FE(OH)3-	.851	AL(OH)2+	.853
H2BO3-	.836	K+	.839	FE(OH)4--	.529	AL(OH)4-	.849
HCO3-	.846	CA++	.542	FEOH++	.529	ALSO4+	.849
CO3--	.522	MG++	.566	FE(OH)2+	.853	AL(SO4)2-	.843
HS-	.843	CAHCO3+	.857	FE(OH)4-	.853	ALF++	.534
S--	.529	MGHCO3+	.846	FESO4+	.851	ALF2+	.853
HSO4-	.849	CAOH+	.857	FECL++	.529	ALF4-	.843
SO4--	.515	MGOH+	.859	FECL2+	.851	ALF5--	.522
NASO4-	.853	NH4+	.836	FECL4-	.846	ALF6---	.232

CHEMICAL COMPONENTS IN DEEP WATER (PPM AND LOG MOLE)

H+ (ACT.)	.00	-8.629	MG++	.09	-5.429	FE(OH)3	.01	-7.251
OH-	3.23	-3.721	NACL	2.16	-4.433	FE(OH)4-	.20	-5.731
H4SIO4	290.25	-2.520	KCL	.08	-5.961	FECL+	.00	-7.382
H3SIO4-	130.23	-2.864	NASO4-	2.23	-4.728	FECL2	.00	-20.467
H2SIO4--	.80	-5.072	KSO4-	.80	-5.226	FECL++	.00	-23.249
NAH3SIO4	26.96	-3.842	CASO4	.20	-5.842	FECL2+	.00	-24.645
H3BO3	236.34	-2.418	MGSO4	.06	-6.279	FECL3	.00	-27.259
H2BO3-	129.50	-2.672	CACO3	1.23	-4.911	FECL4-	.00	-30.486
H2CO3	.89	-4.844	MGCO3	.04	-6.364	FESO4	.01	-7.400
HCO3-	187.94	-2.511	CAHCO3+	.39	-5.413	FESO4+	.00	-22.665
CO3--	9.66	-3.793	MGHCO3+	.01	-6.898	AL+++	.00	-21.289
H2S	.03	-5.996	CAOH+	.01	-6.901	ALOH++	.00	-16.639
HS-	4.16	-3.900	MGOH+	.01	-6.866	AL(OH)2+	.00	-10.561
S--	.00	-11.258	NH4OH	.17	-5.311	AL(OH)3	.01	-6.737
H2SO4	.00	-20.017	NH4+	.01	-6.268	AL(OH)4-	.95	-5.002
HSO4-	.00	-9.281	FE++	.07	-5.921	ALSO4+	.00	-21.863
SO4--	49.96	-3.284	FE+++	.00	-23.861	AL(SO4)2-	.00	-23.368
HF	.00	-8.174	FEOH+	.55	-5.121	ALF++	.00	-17.487
F-	11.60	-3.214	FE(OH)2	.13	-5.848	ALF2+	.00	-15.047
CL-	568.69	-1.795	FE(OH)3-	.00	-7.916	ALF3	.00	-14.194
NA+	425.69	-1.732	FE(OH)4--	.00	-12.100	ALF4-	.00	-14.951
K+	50.60	-2.888	FE(OH)++	.00	-16.459	ALF5--	.00	-16.690
CA++	1.48	-4.433	FE(OH)2+	.00	-10.881	ALF6---	.00	-13.345

IONIC STRENGTH =   .02315   IONIC BALANCE :   CATIONS (MOL.EQ.) .01910849
                                                ANIONS (MOL.EQ.) .02493695
                                                DIFFERENCE (%)   -22.44

SAMPLE = REP.YBJ.001

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OXIDATION POTENTIAL (VOLTS) :   EH H2S= -.462   EH CH4= -.452   EH H2= -.549   EH NH3= -.511

LOG SOLUBILITY PRODUCTS OF MINERALS IN DEEP WATER

	TEOR.	CALC.		TEOR.	CALC.		TEOR.	CALC.
ADULARIA	-17.632	-15.589	ALBITE LOW	-16.859	-14.431	ANALCIME	-13.478	-11.911
ANHYDRITE	-6.467	-8.271	CALCITE	-9.272	-8.775	CHALCEDONY	-2.922	-2.520
MG-CHLORITE	-80.616	-76.432	FLUORITE	-10.556	-11.276	GOETHITE	-5.041	-2.064
LAUMONTITE	-27.679	-24.910	MICROCLINE	-19.091	-15.589	MAGNETITE	-30.464	-17.907
CA-MONTMOR.	-88.132	-85.509	K-MONTMOR.	-43.045	-43.369	MG-MONTMOR.	-89.231	-86.495
NA-MONTMOR.	-43.022	-42.210	MUSCOVITE	-21.778	-18.129	PREHNITE	-17.142	-14.683
PYRRHOTITE	-104.804	-74.498	PYRITE	-154.380	-102.437	QUARTZ	-3.195	-1.510
WAIRAKITE	-24.987	-24.910	WOLLASTONITE	11.140	10.037	ZOISITE	-39.166	-35.950
EPIDOTE	-44.416	-36.744	MARCASITE	-130.306	-102.437			

OXIDATION POTENTIAL (VOLTS) :   EH H2S= -.462   EH CH4= -.452   EH H2= -.549   EH NH3= -.511

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REP.YBJ.002   YANGBAJING ZK-311   TIBET

PROGRAM WATCH1.

WATER SAMPLE (PPM)   STEAM SAMPLE

PH/DEG.C	8.43/20.0	GAS (VOL.%)		REFERENCE TEMP.	DEGREES C	.0 (CHA)	
SIO2	255.00	CO2	99.64				
NA	450.00	H2S	.22	SAMPLING PRESSURE	BARS ABS.	1.2	
K	45.50	H2	.02	DISCHARGE ENTHALPY	MJOUL/KG	.705 [CALCULATED]	
CA	2.20	O2	.00	DISCHARGE	KG/SRC.	.0	
MG	.110	CH4	.01				
CO2	311.04	N2	.32	MEASURED TEMPERATURE DEGREES C		.0	
SO4	41.50	He	0.0055	RESISTIVITY/TEMP.	OHMM/DEG.C	.0/ .0	
H2S	26.00			EH/TEMP.	MV/DEG.C	.000/ .0	
CL	522.00						
F	11.20	LITERS GAS PER KG					
DISS.SOLIDS	.00	CONDENSATE/DEG.C	6.01/20.0	MEASURED DOWNHOLE TEMP.		FLUID INFLOW	
AL	.2100			DEGREES C/METERS		DEPTH (METERS)	
B	58.4500						
FE	.0000	CONDENSATE (PPM)		.0	.0	.0	
NH3	.0000	PH/DEG.C	6.65/20.0	.0	.0	.0	
LI	9.2	CO2	8.64	.0	.0	.0	
Ba	0	H2S	26.00	.0	.0	.0	
Br	1.4	NA	1.20	.0	.0	.0	
				.0	.0	.0	
				.0	.0	.0	
				.0	.0	.0	
		CONDENSATE WITH NAOH (PPM)		.0	.0	.0	
		CO2	.00	.0	.0	.0	
		H2S	.00	.0	.0	.0	

IONIC STRENGTH = .02234   IONIC BALANCE : CATIONS (MOL.EQ.) .01863689
                                            ANIONS (MOL.EQ.) .02486035
                                            DIFFERENCE (%)   -28.62

DEEP WATER (PPM)   DEEP STEAM (PPM)   GAS PRESSURES (BARS ABS.)

SIO2	239.67	CO2	952.27	CO2	.00	CO2	.202E+01
NA	375.92	H2S	27.13	H2S	.00	H2S	.123E-01
K	42.76	H2	.01	H2	.00	H2	.295E-02
CA	2.07	O2	.00	O2	.00	O2	.000E+00
MG	.103	CH4	.03	CH4	.00	CH4	.146E-02
SO4	39.00	N2	1.35	N2	.00	N2	.156E-01
CL	490.56	NH3	.00	NH3	.00	NH3	.000E+00
F	10.53					H2O	.793E-01
DISS.S.	.00					TOTAL	.210E+01
AL	.1973						
B	54.9268			H2O (%)	.00		
FE	.0008			BOILING PORTION	.00		

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ACTIVITY COEFFICIENTS IN DEEP WATER

H+	.847	KSO4-	.827	FE++	.479	FECL+	.818
OH-	.814	F-	.814	FE+++	.227	AL+++	.227
H3SIO4-	.818	CL-	.811	FEOH+	.824	ALOH++	.470
H2SIO4--	.470	NA+	.818	FE(OH)3-	.824	AL(OH)2+	.827
H2BO3-	.807	K+	.811	FE(OH)4--	.465	AL(OH)4-	.821
HCO3-	.818	CA++	.479	FEOH++	.465	ALSO4+	.821
CO3--	.457	MG++	.505	FE(OH)2+	.827	AL(SO4)2-	.821
HS-	.814	CAHCO3+	.830	FE(OH)4-	.827	ALF++	.470
S--	.465	MGHCO3+	.818	FESO4+	.824	ALF2+	.827
HSO4-	.821	CAOH+	.830	FECL++	.465	ALF4-	.821
SO4--	.450	MGOH+	.833	FECL2+	.824	ALF5--	.457
NASO4-	.827	NH4+	.807	FECL4-	.818	ALF6---	.173

CHEMICAL COMPONENTS IN DEEP WATER (PPM AND LOG MOLE)

H+ (ACT.)	.00	-6.419	MG++	.07	-5.543	FE(OH)3	.00	.000
OH-	.17	-4.991	NACL	4.53	-4.110	FE(OH)4-	.00	.000
H4SIO4	380.97	-2.402	KCL	.17	-5.639	FECL+	.00	.000
H3SIO4-	2.07	-4.662	NASO4-	3.13	-4.580	FECL2	.00	.000
H2SIO4--	.00	-8.975	KSO4-	1.21	-5.049	FECL++	.00	.000
NAH3SIO4	.38	-5.490	CASO4	.26	-5.717	FECL2+	.00	.000
H3BO3	312.96	-2.296	MGSO4	.11	-6.024	FECL3	.00	.000
H2BO3-	1.18	-4.711	CACO3	.05	-6.323	FECL4-	.00	.000
H2CO3	896.41	-1.840	MGCO3	.00	-8.037	FESO4	.00	.000
HCO3-	436.73	-2.145	CAHCO3+	2.74	-4.567	FESO4+	.00	.000
CO3--	.08	-5.901	MGHCO3+	.04	-6.378	AL+++	.00	-17.758
H2S	16.82	-3.307	CAOH+	.00	-8.019	ALOH++	.00	-12.340
HS-	10.00	-3.519	MGOH+	.00	-7.826	AL(OH)2+	.00	-7.579
S--	.00	-12.348	NH4OH	.00	.000	AL(OH)3	.53	-5.166
H2SO4	.00	-13.967	NH4+	.00	.000	AL(OH)4-	.04	-6.329
HSO4-	.07	-6.169	FE++	.00	.000	ALSO4+	.00	-17.926
SO4--	35.28	-3.435	FE+++	.00	.000	AL(SO4)2-	.00	-19.316
HF	.11	-5.278	FEOH+	.00	.000	ALF++	.00	-13.186
F-	10.43	-3.261	FE(OH)2	.00	.000	ALF2+	.00	-10.120
CL-	487.71	-1.861	FE(OH)3-	.00	.000	ALF3	.00	-8.900
NA+	373.46	-1.789	FE(OH)4--	.00	.000	ALF4-	.00	-9.459
K+	42.32	-2.966	FE(OH)++	.00	.000	ALF5--	.00	-11.143
CA++	.89	-4.656	FE(OH)2+	.00	.000	ALF6---	.00	-14.005

IONIC STRENGTH = .02037   IONIC BALANCE : CATIONS (MOL.EQ.) .01740432
                                          ANIONS (MOL.EQ.) .02255492
                                          DIFFERENCE (%)   -25.78

CHEMICAL GEOTHERMOMETERS DEGREES C   1000/T DEGREES KELVIN = 2.28

QUARTZ   185.9
CHALCEDONY 165.2
NAK   215.2

OXIDATION POTENTIAL (VOLTS) :   EH H2S= -.410   EH CH4= -.432   EH H2= -.448   EH NH3= 99.999

LOG SOLUBILITY PRODUCTS OF MINERALS IN DEEP WATER

	TEOR.	CALC.		TEOR.	CALC.		TEOR.	CALC.
ADULARIA	-15.332	-15.484	ALBITE LOW	-14.768	-14.304	ANALCIME	-11.962	-11.902
ANHYDRITE	-6.614	-8.757	CALCITE	-10.726	-11.217	CHALCEDONY	-2.402	-2.402
MG-CHLORITE	-80.361	-87.488	FLUORITE	-10.598	-11.675	GOETHITE	-2.000	99.999
LAUMONTITE	-25.067	-25.026	MICROCLINE	-16.321	-15.484	MAGNETITE	-24.544	99.999
CA-MONTMOR.	-75.342	-69.958	K-MONTMOR.	-35.933	-35.548	MG-MONTMOR.	-76.723	-70.823
NA-MONTMOR.	-36.110	-34.368	MUSCOVITE	-16.608	-15.767	PREHNITE	-35.793	-37.760
PYRRHOTITE	-66.606	99.999	PYRITE	-100.900	99.999	QUARTZ	-2.576	-2.402
WAIRAKITE	-23.324	-25.026	WOLLASTONITE	3.117	5.450	ZOISITE	-35.520	-37.901
EPIDOTE	-38.618	99.999	MARCASITE	-80.900	99.999			

RHP.YBJ.003　　　　　　　YANGBAJING ZK-309　　　TIBET

PROGRAM WATCH1.

WATER SAMPLE (PPM)　　　　STEAM SAMPLE

PH/DEG.C	8.34/20.0	GAS (VOL.%)		REFERENCE TEMP.	DEGREES C	.0 (CHA)

SIO2	254.00	CO2	99.03
NA	395.00	H2S	.53
K	55.50	H2	.02
CA	1.90	O2	.00
MG	.110	CH4	.01
CO2	192.96	N2	.41
SO4	42.50	He	0.005
H2S	13.00		
CL	431.00		
F	11.20	LITERS GAS PER KG	
DISS.SOLIDS	.00	CONDENSATE/DEG.C	6.12/20.0
AL	.2600		
B	58.2750		
FE	.3400	CONDENSATE (PPM)	
NH3	.3500	PH/DEG.C	6.15/20.0
Li	10.5	CO2	10.44
Ba	0.07	H2S	13.50
Br	1.4	NA	8.50

SAMPLING PRESSURE　DBARS ABS.　3.4
DISCHARGE ENTHALPY　MJOUL/KG　.70E (CALCULATED)
DISCHARGE　　　　　　KG/SEC.　.0
MEASURED TEMPERATURE DEGREES C　.0
RESISTIVITY/TEMP.　OHMM/DEG.C　.0/ .0
EH/TEMP.　　　　　　MV/DEG.C　.000/ .0

MEASURED DOWNHOLE TEMP.	FLUID INFLOW
DEGREES C/METERS	DEPTH (METERS)
.0 .0	.0
.0 .0	.0
.0 .0	.0
.0 .0	.0
.0 .0	.0
.0 .0	.0
.0 .0	.0
.0 .0	.0

CONDENSATE WITH NAOH (PPM)
CO2　.00
H2S　.00

IONIC STRENGTH = .02027　　IONIC BALANCE :　CATIONS (MOL.EQ.) .01869829
　　　　　　　　　　　　　　　　　　　　　　　ANIONS (MOL.EQ.) .02076303
　　　　　　　　　　　　　　　　　　　　　　　DIFFERENCE (%) -10.46

DEEP WATER (PPM)　　　　　　　　　　　DEEP STEAM (PPM)　　　GAS PRESSURES (BARS ABS.)

SIO2	240.00	CO2	794.95	CO2	.00	CO2	.190E+01
NA	373.20	H2S	15.55	H2S	.00	H2S	.147E-01
K	52.43	H2	.00	H2	.00	H2	.265E-01
CA	1.80	O2	.00	O2	.00	O2	.600E+00
MG	.104	CH4	.03	CH4	.00	CH4	.250E-02
SO4	40.15	N2	1.61	N2	.00	N2	.900E-01
CL	463.86	NH3	.33	NH3	.00	NH3	.134E-04
F	10.58					H2O	.708E+01
DISS.S.	.00					TOTAL	.933E+01
AL	.2456						
B	55.0531			H2O (%)	.00		
FE	.3212			BOILING PORTION	.00		

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ACTIVITY COEFFICIENTS IN DEEP WATER

H+	.851	HSO4-	.832	FE++	.491	FECL+	.824
OH-	.820	F-	.820	FE+++	.238	AL+++	.238
H3SIO4-	.824	CL-	.817	FEOH+	.830	ALOH++	.483
H2SIO4--	.483	NA+	.824	FE(OH)3-	.830	AL(OH)2+	.832
H2BO3-	.813	K+	.817	FE(OH)4--	.477	AL(OH)4-	.827
HCO3-	.824	CA++	.491	FEOH++	.477	ALSO4+	.827
CO3--	.470	MG++	.516	FE(OH)2+	.832	AL(SO4)2-	.827
HS-	.820	CAHCO3+	.836	FE(OH)4-	.832	ALF++	.483
S--	.477	MGHCO3+	.824	FESO4+	.830	ALF2+	.832
HSO4-	.827	CAOH+	.836	FECL++	.477	ALF4-	.827
SO4--	.463	MGOH+	.838	FECL2+	.830	ALF5--	.470
NASO4-	.832	NH4+	.813	FECL4-	.824	ALF6---	.184

CHEMICAL COMPONENTS IN DEEP WATER (PPM AND LOG MOLE)

H+ (ACT.)	.00	-6.242	MG++	.07	-5.532	FE(OH)3	.05	-6.371
OH-	.12	-5.168	NACL	4.33	-4.130	FE(OH)4-	.04	-6.549
H4SIO4	382.30	-2.400	KCL	.20	-5.566	FECL+	.04	-6.314
H3SIO4-	1.37	-4.840	NASO4-	3.28	-4.560	FECL2	.00	-14.271
H2SIO4--	.00	-9.337	KSO4-	1.56	-4.937	FECL++	.00	-18.432
NAH3SIO4	.26	-5.664	CASO4	.30	-5.652	FECL2+	.00	-19.887
H3BO3	314.09	-2.294	MGSO4	.13	-5.980	FECL3	.00	-22.305
H2BO3-	.78	-4.889	CACO3	.02	-6.660	FECL4-	.00	-25.182
H2CO3	844.00	-1.866	MGCO3	.00	-8.396	FESO4	.02	-6.925
HCO3-	270.74	-2.353	CAHCO3+	1.88	-4.730	FESO4+	.00	-18.001
CO3--	.03	-5.296	MGHCO3+	.02	-6.564	AL+++	.00	-17.162
H2S	11.07	-3.488	CAOH+	.00	-8.152	ALOH++	.00	-11.904
HS-	4.34	-3.882	MGOH+	.00	-7.980	AL(OH)2+	.00	-7.305
S--	.00	-12.893	NH4OH	.29	-5.080	AL(OH)3	.68	-5.063
H2SO4	.00	-13.587	NH4+	.20	-4.954	AL(OH)4-	.04	-6.408
HSO4-	.10	-5.971	FE++	.16	-5.539	ALSO4+	.00	-17.289
SO4--	35.97	-3.427	FE+++	.00	-20.452	AL(SO4)2-	.00	-18.657
HF	.16	-5.096	FEOH+	.11	-5.823	ALF++	.00	-12.574
F-	10.43	-3.260	FE(OH)2	.00	-7.385	ALF2+	.00	-9.493
CL-	461.12	-1.886	FE(OH)3-	.00	-9.908	ALF3	.00	-8.265
NA+	370.81	-1.792	FE(OH)4--	.00	-15.767	ALF4-	.00	-8.822
K+	51.88	-2.877	FE(OH)++	.00	-13.307	ALF5--	.00	-10.511
CA++	.95	-4.625	FE(OH)2+	.00	-8.890	ALF6---	.00	-13.386

IONIC STRENGTH = .01863   IONIC BALANCE :   CATIONS (MOL.EQ.) .01754706
                                            ANIONS (MOL.EQ.) .01890946
                                            DIFFERENCE (%)   -7.47

CHEMICAL GEOTHERMOMETERS DEGREES C   1000/T DEGREES KELVIN = 2.28

QUARTZ   186.1
CHALCEDONY 165.4
NAK   238.3

OXIDATION POTENTIAL (VOLTS) :   EH H2S= -.389   EH CH4= -.418   EH H2= -.431   EH NH3= -.410

LOG SOLUBILITY PRODUCTS OF MINERALS IN DEEP WATER

	TEOR.	CALC.		TEOR.	CALC.		TEOR.	CALC.
ADULARIA	-15.326	-15.290	ALBITE LOW	-14.763	-14.201	ANALCIME	-11.959	-11.801
ANHYDRITE	-6.618	-8.695	CALCITE	-10.732	-11.557	CHALCEDONY	-2.400	-2.400
MG-CHLORITE	-80.368	-88.575	FLUORITE	-10.598	-11.627	GOETHITE	-1.988	-1.374
LAUMONTITE	-25.052	-24.782	MICROCLINE	-16.315	-15.290	MAGNETITE	-24.522	-19.104
CA-MONTMOR.	-75.319	-66.423	K-MONTMOR.	-35.919	-33.709	MG-MONTMOR.	-76.701	-67.308
NA-MONTMOR.	-36.097	-32.621	MUSCOVITE	-18.602	-15.028	PREHNITE	-35.794	-37.524
PYRRHOTITE	-66.671	-49.137	PYRITE	-100.719	-56.573	QUARTZ	-2.575	-2.400
WAIRAKITE	-23.823	-24.782	WOLLASTONITE	9.111	5.151	ZOISITE	-35.523	-37.533
EPIDOTE	-35.803	-39.193	MARCASITE	-80.734	-56.573			

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23001201088706120050   Svartsengi SG-8   GRINDAVIK

PROGRAM WATCH1.

WATER SAMPLE (PPM)   STEAM SAMPLE

```
PH/DEG.C        6.44/23.9   GAS (VOL.%)                REFERENCE TEMP.      DEGREES C      .0 (QTZ)
SIO2          514.80        CO2             96.31
NA           6993.00        H2S              1.23      SAMPLING PRESSURE    BARS ABS.     16.8
K            1099.00        H2                .07      DISCHARGE ENTHALPY   MJOUL/KG      1.057 (CALCULATED)
CA           1053.00        O2                .00      DISCHARGE            KG/SEC.         .0
MG              .811        CH4               .05
CO2            42.20        N2               1.98      MEASURED TEMPERATURE DEGREES C       .0
SO4            31.64        Ar      0.541              RESISTIVITY/TEMP.    OHMM/DEG.C     .0/   .0
H2S              .69                                   EH/TEMP.             MV/DEG.C      .000/  .0
CL          13597.00
F                .14        LITERS GAS PER KG
DISS.SOLIDS 24352.00        CONDENSATE/DEG.C 1.56/13.8    MEASURED DOWNHOLE TEMP.   FLUID INFLOW
AL             .0000                                      DEGREES C/METERS      DEPTH (METERS)
B              .0000
FE             .0400        CONDENSATE (PPM)                .0        .0            .0
NH3            .0000        PH/DEG.C        4.34/24.4       .0        .0            .0
Mn       0.3               CO2            1590.00          .0        .0            .0
                           H2S              40.80          .0        .0            .0
                           NA                9.27          .0        .0            .0
                                                           .0        .0            .0
                                                           .0        .0            .0
                                                           .0        .0            .0
                           CONDENSATE WITH NAOH (PPM)      .0        .0            .0
                           CO2            4220.00          .0        .0            .0
                           H2S              70.00          .0        .0            .0
```

IONIC STRENGTH = .40987   IONIC BALANCE : CATIONS (MOL.EQ.) .38342230
                                            ANIONS (MOL.EQ.) .38332380
                                            DIFFERENCE (%)   .03

DEEP WATER (PPM)   DEEP STEAM (PPM)   GAS PRESSURES (BARS ABS.)

```
SIO2      467.10    CO2    429.64    CO2     .00    CO2    .108E+01
NA       6344.48    H2S      7.12    H2S     .00    H2S    .741E-02
K         997.03    H2        .01    H2      .00    H2     .243E-02
CA        955.35    O2        .00    O2      .00    O2     .858E-36
MG          .736    CH4       .05    CH4     .00    CH4    .256E-02
SO4        28.71    N2       3.40    N2      .00    N2     .804E-01
CL      12335.00    NH3       .00    NH3     .00    NH3    .000E+00
F           .13                                     H2O    .348E+02
DISS.S. 22093.65                                    TOTAL  .360E+02
AL         .0000
B          .0000                     H2O (%)         .00
FE         .0363                     BOILING PORTION .00
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SAMPLE = 2300120108870512D050

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ACTIVITY COEFFICIENTS IN DEEP WATER

H+	.635	KSO4-	.544	FE++	.109	FECL+	.495
OH-	.474	F-	.474	FE+++	.021	AL+++	.021
H3SIO4-	.495	CL-	.452	FEOH+	.531	ALOH++	.096
H2SIO4--	.096	NA+	.495	FE(OH)3-	.531	AL(OH)2+	.544
H2BO3-	.428	K+	.452	FE(OH)4--	.087	AL(OH)4-	.514
HCO3-	.495	CA++	.109	FEOH++	.087	ALSO4+	.514
CO3--	.076	MG++	.155	FE(OH)2+	.544	AL(SO4)2-	.514
HS-	.474	CAHCO3+	.562	FE(OH)4-	.544	ALF++	.096
S--	.087	MGHCO3+	.495	FESO4+	.531	ALF2+	.544
HSO4-	.514	CAOH+	.562	FECL++	.087	ALF4-	.514
SO4--	.065	MGOH+	.577	FECL2+	.531	ALF5--	.076
NASO4-	.544	NH4+	.428	FECL4-	.495	ALF6---	.003

CHEMICAL COMPONENTS IN DEEP WATER (PPM AND LOG MOLE)

H+ (ACT.)	.00	-5.375	MG++	.72	-4.528	FE(OH)3	.05	-6.362
OH-	.07	-5.373	NACL	1436.22	-1.609	FE(OH)4-	.02	-6.729
H4SIO4	746.47	-2.110	KCL	108.16	-2.838	FECL+	.00	-7.693
H3SIO4-	.33	-5.455	NASO4-	5.56	-4.331	FECL2	.00	-10.890
H2SIO4--	.00	-10.747	KSO4-	3.80	-4.551	FECL++	.00	-16.975
NAH3SIO4	.45	-5.422	CASO4	14.43	-3.975	FECL2+	.00	-17.723
H3BO3	.00	.000	MGSO4	.05	-6.386	FECL3	.00	-18.915
H2BO3-	.00	.000	CACO3	.04	-6.401	FECL4-	.00	-20.059
H2CO3	570.60	-2.036	MGCO3	.00	-10.403	FESO4	.00	-11.200
HCO3-	7.30	-3.922	CAHCO3+	44.84	-3.353	FESO4+	.00	-19.512
CO3--	.00	-8.847	MGHCO3+	.00	-7.255	AL+++	.00	.000
H2S	6.95	-3.690	CAOH+	.16	-5.562	ALOH++	.00	.000
HS-	.16	-5.320	MGOH+	.00	-6.934	AL(OH)2+	.00	.000
S--	.00	-14.195	NH4OH	.00	.000	AL(OH)3	.00	.000
H2SO4	.00	-11.493	NH4+	.00	.000	AL(OH)4-	.00	.000
HSO4-	.80	-5.083	FE++	.00	-8.234	ALSO4+	.00	.000
SO4--	10.51	-3.961	FE+++	.00	-21.558	AL(SO4)2-	.00	.000
HF	.04	-5.692	FEOH+	.00	-8.846	ALF++	.00	.000
F-	.09	-5.311	FE(OH)2	.00	-10.230	ALF2+	.00	.000
CL-	11412.36	-.492	FE(OH)3-	.00	-11.899	ALF3	.00	.000
NA+	5778.32	-.600	FE(OH)4--	.00	-17.943	ALF4-	.00	.000
K+	939.21	-1.619	FE(OH)++	.00	-14.501	ALF5--	.00	.000
CA++	933.20	-1.633	FE(OH)2+	.00	-9.024	ALF6---	.00	.000

IONIC STRENGTH = .34578   IONIC BALANCE :   CATIONS (MOL.EQ.) .32243390
                                              ANIONS (MOL.EQ.) .32228410
                                              DIFFERENCE   (%)   .05

CHEMICAL GEOTHERMOMETERS DEGREES C   1000/T DEGREES KELVIN = 1.94

QUARTZ   242.2
CHALCEDONY 999.9
NAK   245.8

OXIDATION POTENTIAL (VOLTS) :   EH H2S= -.401   EH CH4= -.463   EH H2= -.416   EH NH3= 99.999

LOG SOLUBILITY PRODUCTS OF MINERALS IN DEEP WATER

	TEOR.	CALC.		TEOR.	CALC.		TEOR.	CALC.
ADULARIA	-14.432	99.999	ALBITE LOW	-13.978	99.999	ANALCIME	-11.524	99.999
ANHYDRITE	-7.963	-7.739	CALCITE	-12.571	-12.560	CHALCEDONY	-2.026	-2.110
MG-CHLORITE	-84.296	99.999	FLUORITE	-10.916	-13.863	GOETHITE	1.846	-1.296
LAUMONTITE	-24.533	99.999	MICROCLINE	-15.125	99.999	MAGNETITE	-17.676	-23.182
CA-MONTMOR.	-72.624	99.999	K-MONTMOR.	-34.033	99.999	MG-MONTMOR.	-74.121	99.999
NA-MONTMOR.	-34.306	99.999	MUSCOVITE	-17.852	99.999	PREHNITE	-37.076	99.999
PYRRHOTITE	-25.401	-49.833	PYRITE	-46.907	-59.476	QUARTZ	-2.139	-2.110
WAIRAKITE	-24.411	99.999	WOLLASTONITE	7.616	6.046	ZOISITE	-37.620	99.999
EPIDOTE	-37.239	99.999	MARCASITE	-29.886	-59.476			

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REP.HRGĐ.001   HVERAGERĐI NLFI-1

PROGRAM WATCH1.

WATER SAMPLE (PPM)   STEAM SAMPLE

PH/DEG.C	8.38/24.5	GAS (VOL.%)		REFERENCE TEMP.	DEGREES C	.0 (CHA)
SIO2	235.90	CO2	83.80			
NA	160.00	H2S	2.97	SAMPLING PRESSURE	BARS ABS.	5.4
K	11.05	H2	3.14	DISCHARGE ENTHALPY	MJOUL/KG	.694 (CALCULATED)
CA	1.62	O2	.16	DISCHARGE	KG/SEC.	.0
MG	.002	CH4	.37			
CO2	87.80	N2	9.40	MEASURED TEMPERATURE DEGREES C		.0
SO4	43.50	Ar	0.17	RESISTIVITY/TEMP.	OHMM/DEG.C	.0/ .0
H2S	15.50			EH/TEMP.	MV/DEG.C	.000/ .0
CL	130.17					
F	1.52	LITERS GAS PER KG				
DISS.SOLIDS	727.30	CONDENSATE/DEG.C 1.00/23.0		MEASURED DOWNHOLE TEMP.	FLUID INFLOW	
AL	.4800			DEGREES C/METERS	DEPTH (METERS)	
B	.0000					
FE	.0000	CONDENSATE (PPM)		.0	.0	.0
NH3	.0000	PH/DEG.C	3.82/23.8	.0	.0	.0
Li	0.08	CO2	989.00	.0	.0	.0
		H2S	173.00	.0	.0	.0
		NA	.71	.0	.0	.0
				.0	.0	.0
				.0	.0	.0
				.0	.0	.0
		CONDENSATE WITH NAOH (PPM)		.0	.0	.0
		CO2	1979.00	.0	.0	.0
		H2S	172.00	.0	.0	.0

IONIC STRENGTH = .00777   IONIC BALANCE :   CATIONS (MOL.EQ.) .00730503
                                             ANIONS (MOL.EQ.) .00722357
                                             DIFFERENCE (%)   1.12

DEEP WATER (PPM)   DEEP STEAM (PPM)   GAS PRESSURES (BARS ABS.)

SIO2	232.94	CO2	111.69	CO2	.00	CO2	.829E-01
NA	157.98	H2S	17.48	H2S	.00	H2S	.475E-02
K	10.91	H2	.03	H2	.00	H2	.199E-01
CA	1.60	O2	.03	O2	.00	O2	.852E-03
MG	.002	CH4	.03	CH4	.00	CH4	.291E-02
SO4	42.95	N2	1.37	N2	.00	N2	.797E-01
CL	128.51	NH3	.00	NH3	.00	NH3	.000E+00
F	1.50					H2O	.632E+01
DISS.S.	718.11					TOTAL	.651E+01
AL	.4739						
B	.0000			H2O (%)	.00		
FE	.0000			BOILING PORTION	.00		

SAMPLE = REP.HRGD.001

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ACTIVITY COEFFICIENTS IN DEEP WATER

H+	.893	KSO4-	.883	FE++	.614	FECL+	.879
OH-	.877	F-	.877	FE+++	.362	AL+++	.362
H3SIO4-	.879	CL-	.876	FEOH+	.882	ALOH++	.610
H2SIO4--	.610	NA+	.879	FE(OH)3-	.882	AL(OH)2+	.883
H2BO3-	.874	K+	.876	FE(OH)4--	.606	AL(OH)4-	.880
HCO3-	.879	CA++	.614	FEOH++	.606	ALSO4+	.880
CO3--	.602	MG++	.629	FE(OH)2+	.883	AL(SO4)2-	.880
HS-	.877	CAHCO3+	.885	FE(OH)4-	.883	ALF++	.610
S--	.606	MGHCO3+	.879	FESO4+	.882	ALF2+	.883
HSO4-	.880	CAOH+	.885	FECL++	.606	ALF4-	.880
SO4--	.598	MGOH+	.886	FECL2+	.882	ALF5--	.602
NASO4-	.883	NH4+	.874	FECL4-	.879	ALF6---	.320

CHEMICAL COMPONENTS IN DEEP WATER (PPM AND LOG MOLE)

H+ (ACT.)	.00	-7.229	MG++	.00	-7.314	FE(OH)3	.00	.000
OH-	.96	-4.249	NACL	.56	-5.017	FE(OH)4-	.00	.000
H4SIO4	359.86	-2.427	KCL	.01	-6.776	FECL+	.00	.000
H3SIO4-	11.77	-3.907	NASO4-	1.92	-4.792	FECL2	.00	.000
H2SIO4--	.00	-7.480	KSO4-	.45	-5.480	FECL++	.00	.000
NAH3SIO4	1.05	-5.052	CASO4	.53	-5.407	FECL2+	.00	.000
H3BO3	.00	.000	MGSO4	.00	-7.545	FECL3	.00	.000
H2BO3-	.00	.000	CACO3	.12	-5.924	FECL4-	.00	.000
H2CO3	37.06	-3.224	MGCO3	.00	-9.454	FESO4	.00	.000
HCO3-	117.61	-2.715	CAHCO3+	.99	-5.011	FESO4+	.00	.000
CO3--	.11	-5.720	MGHCO3+	.00	-8.643	AL+++	.00	-19.889
H2S	3.60	-3.976	CAOH+	.00	-7.137	ALOH++	.00	-13.684
HS-	13.47	-3.390	MGOH+	.00	-8.789	AL(OH)2+	.00	-8.132
S--	.00	-11.525	NH4OH	.00	.000	AL(OH)3	.93	-4.925
H2SO4	.00	-15.503	NH4+	.00	.000	AL(OH)4-	.54	-5.246
HSO4-	.01	-6.889	FE++	.00	.000	ALSO4+	.00	-19.744
SO4--	40.69	-3.373	FE+++	.00	.000	AL(SO4)2-	.00	-20.970
HF	.00	-6.945	FEOH+	.00	.000	ALF++	.00	-16.099
F-	1.49	-4.104	FE(OH)2	.00	.000	ALF2+	.00	-13.810
CL-	128.17	-2.442	FE(OH)3-	.00	.000	ALF3	.00	-13.404
NA+	157.18	-2.165	FE(OH)4--	.00	.000	ALF4-	.00	-14.822
K+	10.77	-3.560	FE(OH)++	.00	.000	ALF5--	.00	-17.412
CA++	1.00	-4.602	FE(OH)2+	.00	.000	ALF6---	.00	-21.223

IONIC STRENGTH = .00757   IONIC BALANCE :   CATIONS (MOL.EQ.) .00717245
                                            ANIONS (MOL.EQ.) .00706562
                                            DIFFERENCE   (%)   1.50

CHEMICAL GEOTHERMOMETERS DEGREES C   1000/T DEGREES KELVIN = 2.30

QUARTZ   181.8
CHALCEDONY 160.9
NAK   163.5

OXIDATION POTENTIAL (VOLTS) :   EH H2S= -.482   EH CH4= -.511   EH H2= -.549   EH NH3= 99.999

LOG SOLUBILITY PRODUCTS OF MINERALS IN DEEP WATER

	TEOR.	CALC.		TEOR.	CALC.		TEOR.	CALC.
ADULARIA	-15.419	-15.708	ALBITE LOW	-14.847	-14.312	ANALCIME	-12.016	-11.885
ANHYDRITE	-6.543	-8.410	CALCITE	-10.533	-10.754	CHALCEDONY	-2.427	-2.427
MG-CHLORITE	-80.256	-88.925	FLUORITE	-10.586	-13.136	GOETHITE	-2.191	99.999
LAUMONTITE	-25.153	-24.142	MICROCLINE	-16.430	-15.708	MAGNETITE	-24.898	99.999
CA-MONTMOR.	-75.717	-73.881	K-MONTMOR.	-36.155	-38.151	MG-MONTMOR.	-77.088	-76.583
NA-MONTMOR.	-36.325	-36.755	MUSCOVITE	-18.705	-16.718	PREHNITE	-35.792	-35.141
PYRRHOTITE	-69.014	99.999	PYRITE	-103.877	99.999	QUARTZ	-2.606	-2.427
WAIRAKITE	-23.838	-24.142	WOLLASTONITE	9.214	7.218	ZOISITE	-35.477	-35.646
EPIDOTE	-39.075	99.999	MARCASITE	-83.685	99.999			

APPENDIX 2.1 Computer Output for Downhole Sample of
Well ZK-323

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REP.YBJ.004   YANGBAJING ZK-323   TIBET

PROGRAM WATCH2.

WATER SAMPLE (PPM)   STEAM SAMPLE

PH/DEG.C	7.85/20.0	GAS (VOL.%)		REFERENCE TEMP.	DEGREES C	.0 (CHA)
SIO2	250.00	CO2				
NA	448.00	H2S		SAMPLING PRESSURE	BARS ABS.	
K	51.75	H2		DISCHARGE ENTHALPY	MJOUL/KG	
CA	14.00	O2		DISCHARGE	KG/SEC.	.0
MG	.400	CH4				
CO2	351.00	N2		MEASURED TEMPERATURE DEGREES C		.0
SO4	34.35			RESISTIVITY/TEMP.	OHMM/DEG.C	.0/ .0
H2S	5.50			EH/TEMP.	MV/DEG.C	.000/ .0
CL	489.00					
F	10.80	LITERS GAS PER KG				

DISS.SOLIDS   .00   CONDENSATE/DEG.C   MEASURED DOWNHOLE TEMP.   FLUID INFLOW

			DEGREES C/METERS		DEPTH (METERS)
AL	1.9800				
B	58.9750				
FE	3.0300	CONDENSATE (PPM)	.0	.0	.0
NH3	.3350	PH/DEG.C	.0	.0	.0
Li	9.93	CO2	.0	.0	.0
Ba	0.415	H2S	.0	.0	.0
Br	1.525	NA	.0	.0	.0
			.0	.0	.0
			.0	.0	.0
			.0	.0	.0

CONDENSATE WITH NAOH (PPM)   .0   .0   .0
CO2   .0   .0   .0
H2S   .0   .0   .0

IONIC STRENGTH = .02317   IONIC BALANCE :   CATIONS (MOL.EQ.) .02161741
                                              ANIONS (MOL.EQ.) .02323177
                                              DIFFERENCE (%)   -7.20

DEEP WATER (PPM)   DEEP STEAM (PPM)   GAS PRESSURES (BARS ABS.)

SIO2	250.02	CO2	351.00	CO2	.00	CO2	.110E+00
NA	448.00	H2S	5.50	H2S	.00	H2S	.630E-03
K	51.75	H2	.00	H2	.00	H2	.000E+00
CA	14.00	O2	.00	O2	.00	O2	.000E+00
MG	.400	CH4	.00	CH4	.00	CH4	.000E+00
SO4	34.35	N2	.00	N2	.00	N2	.000E+00
CL	488.96	NH3	.33	NH3	.00	NH3	.274E-04
F	10.80					H2O	.638E+01
DISS.S.	.00					TOTAL	.649E+01
AL	1.9799						
B	58.9695			H2O (%)	.00		
FE	3.0302			BOILING PORTION	.00		

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ACTIVITY COEFFICIENTS IN DEEP WATER

H+	.843	KSO4-	.822	FE++	.469	FECL+	.813
OH-	.809	F-	.809	FE+++	.220	AL+++	.220
H3SIO4-	.813	CL-	.805	FEOH+	.820	ALOH++	.461
H2SIO4--	.461	NA+	.813	FE(OH)3-	.820	AL(OH)2+	.822
H2BO3-	.801	K+	.805	FE(OH)4--	.455	AL(OH)4-	.816
HCO3-	.813	CA++	.469	FEOH++	.455	ALSO4+	.816
CO3--	.447	MG++	.497	FE(OH)2+	.822	AL(SO4)2-	.816
HS-	.809	CAHCO3+	.826	FE(OH)4-	.822	ALF++	.461
S--	.455	MGHCO3+	.813	FESO4+	.820	ALF2+	.822
HSO4-	.816	CAOH+	.826	FECL++	.455	ALF4-	.816
SO4--	.439	MGOH+	.829	FECL2+	.820	ALF5--	.447
NASO4-	.822	NH4+	.801	FECL4-	.813	ALF6---	.164

CHEMICAL COMPONENTS IN DEEP WATER (PPM AND LOG MOLE)

H+ (ACT.)	.00	-7.632	MG++	.27	-4.962	FE(OH)3	.34	-5.495
OH-	2.65	-3.808	NACL	5.13	-4.057	FE(OH)4-	6.08	-4.309
H4SIO4	361.55	-2.425	KCL	.19	-5.590	FECL+	.00	-7.769
H3SIO4-	32.35	-3.468	NASO4-	2.93	-4.608	FECL2	.00	-15.962
H2SIO4--	.03	-6.551	KSO4-	1.15	-5.072	FECL++	.00	-21.521
NAH3SIO4	6.95	-4.230	CASO4	1.26	-5.032	FECL2+	.00	-22.981
H3BO3	317.04	-2.290	MGSO4	.33	-5.559	FECL3	.00	-25.404
H2BO3-	19.92	-3.485	CACO3	4.41	-4.356	FECL4-	.00	-28.281
H2CO3	49.24	-3.100	MGCO3	.04	-6.277	FESO4	.00	-8.485
HCO3-	424.78	-2.157	CAHCO3+	15.45	-3.816	FESO4+	.00	-21.225
CO3--	1.30	-4.666	MGHCO3+	.12	-5.834	AL+++	.00	-20.471
H2S	.48	-4.854	CAOH+	.05	-6.061	ALOH++	.00	-13.949
HS-	4.87	-3.831	MGOH+	.03	-6.102	AL(OH)2+	.00	-8.077
S--	.00	-11.471	NH4OH	.65	-4.733	AL(OH)3	2.50	-4.494
H2SO4	.00	-16.567	NH4+	.02	-5.926	AL(OH)4-	3.92	-4.384
HSO4-	.00	-7.521	FE++	.01	-6.957	ALSO4+	.00	-20.773
SO4--	30.01	-3.505	FE+++	.00	-23.454	AL(SO4)2-	.00	-22.264
HF	.01	-6.521	FEOH+	.09	-5.928	ALF++	.00	-15.948
F-	10.80	-3.246	FE(OH)2	.06	-6.181	ALF2+	.00	-12.922
CL-	485.76	-1.863	FE(OH)3-	.00	-7.401	ALF3	.00	-11.722
NA+	444.06	-1.714	FE(OH)4--	.00	-11.876	ALF4-	.00	-12.282
K+	51.32	-2.882	FE(OH)++	.00	-15.621	ALF5--	.00	-13.952
CA++	5.70	-3.847	FE(OH)2+	.00	-9.331	ALF6---	.00	-16.779

IONIC STRENGTH = .02249   IONIC BALANCE : CATIONS (MOL.EQ.) .02109279
                                             ANIONS (MOL.EQ.) .02296164
                                             DIFFERENCE (%)   -8.48

CHEMICAL GEOTHERMOMETERS DEGREES C   1000/T DEGREES KELVIN = 2.30

QUARTZ   182.2
CHALCEDONY 161.2
NAK   217.2

OXIDATION POTENTIAL (VOLTS) :   EH H2S= -.519   EH CH4= 99.999   EH H2= 99.999   EH NH3= 99.999

LOG SOLUBILITY PRODUCTS OF MINERALS IN DEEP WATER

	TEOR.	CALC.		TEOR.	CALC.		TEOR.	CALC.
ADULARIA	-15.412	-14.473	ALBITE LOW	-14.840	-13.301	ANALCIME	-12.011	-10.876
ANHYDRITE	-6.549	-8.038	CALCITE	-10.640	-9.191	CHALCEDONY	-2.425	-2.425
MG-CHLORITE	-80.253	-73.247	FLUORITE	-10.587	-10.851	GOETHITE	-2.176	-.495
LAUMONTITE	-25.146	-22.319	MICROCLINE	-16.421	-14.473	MAGNETITE	-24.870	-16.074
CA-MONTMOR.	-75.687	-69.838	K-MONTMOR.	-36.137	-35.807	MG-MONTMOR.	-77.058	-70.928
NA-MONTMOR.	-36.307	-34.635	MUSCOVITE	-18.697	-15.118	PREHNITE	-35.792	-31.869
PYRRHOTITE	-68.838	-51.584	PYRITE	-103.639	-72.837	QUARTZ	-2.603	-2.425
WAIRAKITE	-23.837	-22.319	WOLLASTONITE	9.206	8.665	ZOISITE	-35.480	-32.192
EPIDOTE	-39.053	-32.364	MARCASITE	-83.463	-72.837			

APPENDIX 2.2 Computer Output for Calibration of the
Downhole Sample from Well ZK-323

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REP.YBJ.004              YANGBAJING ZK-323        TIBET

PROGRAM WATCH3.          TEMPERATURE FIXING STEAM LOSS   135.0 DEGREES C

WATER SAMPLE (PPM)       STEAM SAMPLE
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WATER SAMPLE (PPM)		STEAM SAMPLE			
PH/DEG.C	7.85/20.0	GAS (VOL.%)	REFERENCE TEMP.	DEGREES C	.0 (CHA)
SIO2	250.00	CO2			
NA	448.00	H2S	SAMPLING PRESSURE	BARS ABS.	
K	51.75	H2	DISCHARGE ENTHALPY	MJOUL/KG	
CA	14.00	O2	DISCHARGE	KG/SEC.	.0
MG	.400	CH4			
CO2	351.00	N2	MEASURED TEMPERATURE DEGREES C		.0
SO4	34.35		RESISTIVITY/TEMP.	OHMM/DEG.C	.0/ .0
H2S	5.50		EH/TEMP.	MV/DEG.C	.000/ .0
CL	489.00				
F	10.80	LITERS GAS PER KG			
DISS.SOLIDS	.00	CONDENSATE/DEG.C	MEASURED DOWNHOLE TEMP.	FLUID INFLOW	
AL	1.9800		DEGREES C/METERS	DEPTH (METERS)	
B	58.9750				
FE	3.0300	CONDENSATE (PPM)	.0	.0	.0
NH3	.3350	PH/DEG.C	.0	.0	.0
Li	9.93	CO2	.0	.0	.0
Ba	0.415	H2S	.0	.0	.0
Br	1.525	NA	.0	.0	.0
			.0	.0	.0
			.0	.0	.0
			.0	.0	.0
		CONDENSATE WITH NAOH (PPM)	.0	.0	.0
		CO2	.0	.0	.0
		H2S	.0	.0	.0

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IONIC STRENGTH =  .02317    IONIC BALANCE :  CATIONS (MOL.EQ.) .02161741
                                            ANIONS  (MOL.EQ.) .02323177
                                            DIFFERENCE  (%)    -7.20
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DEEP WATER (PPM)				DEEP STEAM (PPM)		GAS PRESSURES (BARS ABS.)	
SIO2	235.68	CO2	687.43	CO2	.00	CO2	.116E+00
NA	422.30	H2S	7.15	H2S	.00	H2S	.462E-03
K	48.78	H2	.00	H2	.00	H2	.000E+00
CA	13.20	O2	.00	O2	.00	O2	.000E+00
MG	.377	CH4	.00	CH4	.00	CH4	.000E+00
SO4	32.38	N2	.00	N2	.00	N2	.000E+00
CL	460.91	NH3	.34	NH3	.00	NH3	.197E-05
F	10.18					H2O	.676E+01
DISS.S.	.00					TOTAL	.687E+01
AL	1.8663						
B	55.5867			H2O (%)	.00		
FE	2.8563			BOILING PORTION	.00		

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GAS SOLUBILITY MULTIPLYING FACTOR :  .10
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SAMPLE = REP.YBJ.004

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ACTIVITY COEFFICIENTS IN DEEP WATER

H+	.845	KSO4-	.825	FE++	.475	FECL+	.816
OH-	.812	F-	.812	FE+++	.225	AL+++	.225
H3SIO4-	.816	CL-	.808	FEOH+	.823	ALOH++	.467
H2SIO4--	.467	NA+	.816	FE(OH)3-	.823	AL(OH)2+	.825
H2BO3-	.805	K+	.808	FE(OH)4--	.461	AL(OH)4-	.819
HCO3-	.816	CA++	.475	FEOH++	.461	ALSO4+	.819
CO3--	.454	MG++	.502	FE(OH)2+	.825	AL(SO4)2-	.819
HS-	.812	CAHCO3+	.829	FE(OH)4-	.825	ALF++	.467
S--	.461	MGHCO3+	.816	FESO4+	.823	ALF2+	.825
HSO4-	.819	CAOH+	.829	FECL++	.461	ALF4-	.819
SO4--	.446	MGOH+	.832	FECL2+	.823	ALF5--	.454
NASO4-	.825	NH4+	.805	FECL4-	.816	ALF6---	.169

CHEMICAL COMPONENTS IN DEEP WATER (PPM AND LOG MOLE)

H+ (ACT.)	.00	-6.645	MG++	.27	-4.958	FE(OH)3	.81	-5.118
OH-	.28	-4.777	NACL	4.70	-4.095	FE(OH)4-	1.54	-4.904
H4SIO4	372.96	-2.411	KCL	.18	-5.621	FECL+	.18	-5.710
H3SIO4-	3.42	-4.444	NASO4-	2.73	-4.640	FECL2	.00	-13.788
H2SIO4--	.00	-8.524	KSO4-	1.07	-5.103	FECL++	.00	-18.303
NAH3SIO4	.70	-5.225	CASO4	1.30	-5.020	FECL2+	.00	-19.779
H3BO3	315.88	-2.292	MGSO4	.34	-5.555	FECL3	.00	-22.215
H2BO3-	2.02	-4.478	CACO3	.50	-5.299	FECL4-	.00	-25.106
H2CO3	514.79	-2.081	MGCO3	.00	-7.236	FESO4	.06	-6.431
HCO3-	435.82	-2.146	CAHCO3+	17.17	-3.770	FESO4+	.00	-17.999
CO3--	.13	-5.663	MGHCO3+	.13	-5.804	AL+++	.00	-17.376
H2S	3.48	-3.990	CAOH+	.01	-7.003	ALOH++	.00	-11.777
HS-	3.56	-3.968	MGOH+	.00	-7.044	AL(OH)2+	.01	-6.832
S--	.00	-12.581	NH4OH	.44	-4.897	AL(OH)3	4.80	-4.211
H2SO4	.00	-14.558	NH4+	.13	-5.139	AL(OH)4-	.71	-5.124
HSO4-	.03	-6.520	FE++	.70	-4.899	ALSO4+	.00	-17.667
SO4--	28.17	-3.533	FE+++	.00	-20.265	AL(SO4)2-	.00	-19.167
HF	.06	-5.535	FEOH+	1.10	-4.820	ALF++	.00	-12.843
F-	10.13	-3.273	FE(OH)2	.09	-6.017	ALF2+	.00	-9.812
CL-	457.91	-1.889	FE(OH)3-	.00	-8.175	ALF3	.00	-8.619
NA+	419.79	-1.739	FE(OH)4--	.00	-13.631	ALF4-	.00	-9.197
K+	48.38	-2.908	FE(OH)++	.00	-13.367	ALF5--	.00	-10.894
CA++	5.80	-3.839	FE(OH)2+	.00	-8.005	ALF6---	.00	-13.762

IONIC STRENGTH = .02117   IONIC BALANCE :   CATIONS (MOL.EQ.) .02002969
                                              ANIONS (MOL.EQ.) .02139642
                                              DIFFERENCE (%)   -6.60

CHEMICAL GEOTHERMOMETERS DEGREES C   1000/T DEGREES KELVIN = 2.29

QUARTZ   184.4
CHALCEDONY 163.6
NAK   217.0

OXIDATION POTENTIAL (VOLTS) :   EH H2S= -.426   EH CH4= 99.999   EH H2= 99.999   EH NH3= 99.999

LOG SOLUBILITY PRODUCTS OF MINERALS IN DEEP WATER

	TEOR.	CALC.		TEOR.	CALC.		TEOR.	CALC.
ADULARIA	-15.364	-14.480	ALBITE LOW	-14.797	-13.307	ANALCIME	-11.982	-10.896
ANHYDRITE	-6.587	-8.046	CALCITE	-10.691	-10.168	CHALCEDONY	-2.411	-2.411
MG-CHLORITE	-80.320	-80.957	FLUORITE	-10.593	-10.890	GOETHITE	-2.072	-.120
LAUMONTITE	-25.098	-22.300	MICROCLINE	-15.362	-14.480	MAGNETITE	-24.678	-15.198
CA-MONTMOR.	-75.478	-58.249	K-MONTMOR.	-36.014	-30.043	MG-MONTMOR.	-76.855	-59.344
NA-MONTMOR.	-36.188	-28.870	MUSCOVITE	-18.643	-13.238	PREHNITE	-35.792	-33.787
PYRRHOTITE	-67.641	-42.726	PYRITE	-102.025	-54.965	QUARTZ	-2.587	-2.411
WAIRAKITE	-23.829	-22.300	WOLLASTONITE	9.153	6.715	ZOISITE	-35.503	-33.166
EPIDOTE	-38.915	-33.907	MARCASITE	-81.954	-54.965			

**APPENDIX 2.3 Computer Output for the Calibrated
Downhole Sample**

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REP.YBJ.004.A              YANGBAJING ZK-323          TIBET

PROGRAM WATCH2.

WATER SAMPLE (PPM)          STEAM SAMPLE

PH/DEG.C        6.64/****   GAS (VOL.%)           REFERENCE TEMP.      DEGREES C      .0 (CHA)
SIO2           235.68       CO2
NA             422.30       H2S              SAMPLING PRESSURE    BARS ABS.
K               48.78       H2               DISCHARGE ENTHALPY   MJOUL/KG
CA              13.20       O2               DISCHARGE            KG/SEC.         .0
MG                .377      CH4
CO2            687.34       N2               MEASURED TEMPERATURE DEGREES C       .0
SO4             32.38                        RESISTIVITY/TEMP.    OHMM/DEG.C     .0/    .0
H2S              7.15                        EH/TEMP.             MV/DEG.C      .000/   .0
CL             460.91
F               10.18       LITERS GAS PER KG
DISS.SOLIDS       .00       CONDENSATE/DEG.C       MEASURED DOWNHOLE TEMP.    FLUID INFLOW
AL             1.8663                             DEGREES C/METERS    DEPTH (METERS)
B             55.5867
FE             2.8563       CONDENSATE (PPM)          .0        .0              .0
NH3              .3400      PH/DEG.C                  .0        .0              .0
Li             9.36         CO2                       .0        .0              .0
Ba             0.39         H2S                       .0        .0              .0
Br             1.44         NA                        .0        .0              .0
                                                     .0        .0              .0
                                                     .0        .0              .0
                                                     .0        .0              .0
                           CONDENSATE WITH NAOH (PPM) .0        .0              .0
                           CO2                        .0        .0              .0
                           H2S                        .0        .0              .0

   IONIC STRENGTH =   .02117     IONIC BALANCE :  CATIONS (MOL.EQ.) .02002947
                                                  ANIONS  (MOL.EQ.) .02139542
                                                  DIFFERENCE   (%)    -6.59

DEEP WATER (PPM)                              DEEP STEAM (PPM)       GAS PRESSURES (BARS ABS.)

SIO2     235.70      CO2      687.34      CO2      .00      CO2     .116E+01
NA       422.30      H2S        7.15      H2S      .00      H2S     .461E-02
K         48.78      H2         .00       H2       .00      H2      .000E+00
CA        13.20      O2         .00       O2       .00      O2      .000E+00
MG          .377     CH4        .00       CH4      .00      CH4     .000E+00
SO4       32.38      N2         .00       N2       .00      N2      .000E+00
CL       460.87      NH3        .34       NH3      .00      NH3     .198E-04
F         10.18                                             H2O     .676E+01
DISS.S.     .00                                             TOTAL   .792E+01
AL        1.8662
B        55.5816                          H2O (%)        .00
FE        2.8565                          BOILING PORTION .00
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ACTIVITY COEFFICIENTS IN DEEP WATER

H+	.845	KSO4-	.325	FE++	.475	FECL+	.816
OH-	.812	F-	.812	FE+++	.224	AL+++	.224
H3SIO4-	.816	CL-	.808	FEOH+	.823	ALOH++	.467
H2SIO4--	.467	NA+	.816	FE(OH)3-	.823	AL(OH)2+	.825
H2BO3-	.805	K+	.808	FE(OH)4--	.461	AL(OH)4-	.819
HCO3-	.815	CA++	.475	FEOH++	.461	ALSO4+	.819
CO3--	.454	MG++	.502	FE(OH)2+	.825	AL(SO4)2-	.819
HS-	.812	CAHCO3+	.829	FE(OH)4-	.825	ALF++	.467
S--	.461	MGHCO3+	.816	FESO4+	.823	ALF2+	.825
HSO4-	.819	CAOH+	.829	FECL++	.461	ALF4-	.819
SO4--	.446	MGOH+	.832	FECL2+	.823	ALF5--	.454
NASO4-	.825	NH4+	.805	FECL4-	.816	ALF6---	.169

CHEMICAL COMPONENTS IN DEEP WATER (PPM AND LOG MOLE)

H+ (ACT.)	.00	-6.645	MG++	.27	-4.958	FE(OH)3	.82	-5.118
OH-	.28	-4.777	NACL	4.70	-4.095	FE(OH)4-	1.55	-4.903
H4SIO4	372.99	-2.411	KCL	.18	-5.621	FECL+	.18	-5.710
H3SIO4-	3.42	-4.444	NASO4-	2.73	-4.640	FECL2	.00	-13.788
H2SIO4--	.00	-8.524	KSO4-	1.07	-5.103	FECL++	.00	-18.304
NAH3SIO4	.70	-5.225	CASO4	1.30	-5.020	FECL2+	.00	-19.780
H3BO3	315.85	-2.292	MGSO4	.34	-5.555	FECL3	.00	-22.216
H2BO3-	2.02	-4.478	CACO3	.50	-5.299	FECL4-	.00	-25.107
H2CO3	514.65	-2.081	MGCO3	.00	-7.236	FESO4	.06	-6.432
HCO3-	435.82	-2.146	CAHCO3+	17.18	-3.770	FESO4+	.00	-18.000
CO3--	.13	-5.662	MGHCO3+	.13	-5.804	AL+++	.00	-17.378
H2S	3.48	-3.991	CAOH+	.01	-7.002	ALOH++	.00	-11.778
HS-	3.56	-3.968	MGOH+	.00	-7.044	AL(OH)2+	.01	-6.832
S--	.00	-12.581	NH4OH	.45	-4.896	AL(OH)3	4.80	-4.211
H2SO4	.00	-14.558	NH4+	.13	-5.139	AL(OH)4-	.71	-5.124
HSO4-	.03	-6.520	FE++	.70	-4.900	ALSO4+	.00	-17.669
SO4--	28.17	-3.533	FE+++	.00	-20.266	AL(SO4)2-	.00	-19.168
HF	.06	-5.535	FEOH+	1.10	-4.820	ALF++	.00	-12.844
F-	10.13	-3.273	FE(OH)2	.09	-6.017	ALF2+	.00	-9.813
CL-	457.87	-1.889	FE(OH)3-	.00	-8.175	ALF3	.00	-8.620
NA+	419.79	-1.739	FE(OH)4--	.00	-13.630	ALF4-	.00	-9.198
K+	48.38	-2.908	FE(OH)++	.00	-13.368	ALF5--	.00	-10.895
CA++	5.80	-3.839	FE(OH)2+	.00	-8.005	ALF6---	.00	-13.763

IONIC STRENGTH = .02117   IONIC BALANCE : CATIONS (MOL.EQ.) .02002972
                                          ANIONS (MOL.EQ.) .02139546
                                          DIFFERENCE (%)   -6.59

CHEMICAL GEOTHERMOMETERS DEGREES C   1000/T DEGREES KELVIN = 2.29

QUARTZ   184.4
CHALCEDONY 163.6
NAK   217.0

OXIDATION POTENTIAL (VOLTS) :   EH H2S= -.426   EH CH4= 99.999   EH H2= 99.999   EH NH3= 99.999

LOG SOLUBILITY PRODUCTS OF MINERALS IN DEEP WATER

	THEOR.	CALC.		THEOR.	CALC.		THEOR.	CALC.
ADULARIA	-15.364	-14.480	ALBITE LOW	-14.797	-13.307	ANALCIME	-11.982	-10.896
ANHYDRITE	-6.587	-8.046	CALCITE	-10.691	-10.168	CHALCEDONY	-2.411	-2.411
MG-CHLORITE	-80.320	-80.955	FLUORITE	-10.593	-10.890	GOETHITE	-2.072	-.120
LAUMONTITE	-25.098	-22.300	MICROCLINE	-16.362	-14.480	MAGNETITE	-24.677	-15.197
CA-MONTMOR.	-75.479	-58.252	K-MONTMOR.	-36.014	-30.045	MG-MONTMOR.	-76.856	-59.348
NA-MONTMOR.	-36.189	-28.872	MUSCOVITE	-18.643	-13.239	PREHNITE	-35.792	-33.785
PYRRHOTITE	-67.634	-42.723	PYRITE	-102.016	-54.964	QUARTZ	-2.587	-2.411
WAIRAKITE	-23.829	-22.300	WOLLASTONITE	9.153	6.716	ZOISITE	-35.503	-33.166
EPIDOTE	-38.912	-33.906	MARCASITE	-81.946	-54.964			

Table 2.1 Chemical Composition of Typical Geothermal Waters

Source and reference[*]	Approx. temp. (°C)	Depth (m)	pH (20°)	Li	Na	K	Rb	Cs	Mg	Ca	Mn	Fe	F	Cl	Br	I
Spring, Reykjavik, Iceland (a)	88	0	9.4	0.00	159	1.4	—	—	0.3	1.9	0.00	0.00	1.0	30	0.9	0.1
Drillhole, Reykjavik, Iceland (b)	100	640	8.6	<0.1	95	1.5	<0.02	0.02	—	0.5	—	—	—	31	—	—
Spring, Hveragerdi, Iceland (b)	100	0	9.3	—	—	—	—	—	0.8	2.5	—	—	1.1	186	—	0.0
Hole G-3, Hveragerdi, Iceland (b)	216	650	9.6	0.3	212	27	0.04	<0.02	0.0	1.5	0.00	0.1	1.9	197	0.45	0.0
Spring, Pauzhetsk, Kamchatka, USSR (c)	100	0	8.4	—	1010	88	—	—	10	64	—	0.0	0.8	1684	3.2	0.0
Pauzhetsk drill holes, Kamchatka, USSR (d)	170–195	300–600	8.9	—	Na + K 940		—	—	7	119	—	—	—	1470	—	—
Jubilee Bath, Ngawha, N.Z. (e)	50	0	6.5	11	870	79	0.3	0.5	2.5 (Ca + Mg 28)	8	—	—	0.3	1336	—	—
Drillhole 1, Ngawha, N.Z. (e)	230	585	7.4	12.2	950	80	0.8	0.4			0.02	0.1	0.8	1625	—	1.3
Ohaki Pool, Broadlands, N.Z. (e)	95	0	7.05	7.4	860	82	0.1	1.2	Ca + Mg 2.6		—	—	5.2	1060	3.0	0.6
Drill hole 2, Broadlands, N.Z. (e)	260	1000	8.3	11.7	1050	210	2.2	1.7	0.1	2.2	0.009	≤0.01	7.3	1743	5.7	0.8
Champagne Pool, Wairakei, N.Z. (e)	99	0	8.0	10.8	1070	102	1.1	2.7	0.4	26	—	—	6.6	1770	4.0	0.7
Drill hole 24, Wairakei, N.Z. (e)	250	800	8.3	13.2	1250	210	2.9	2.5	0.04	12	0.015	≤0.01	8.4	2210	5.5	0.3
Spring 6, Rotokaua, N.Z. (e)	63	0	2.5	7.8	990	102	—	—	11.3	11	—	—	<1	1433	—	0.2
Drill hole 2, Rotokaua, N.Z. (e)	220	880	7.8	10.2	1515	176	—	—	—	50	—	—	6.6	2675	—	—
Spring, Tahuangtsui, Tatun, Taiwan (f)	91	0	—	3.0	611	25.9	—	—	2.6	3.5	2.5	1.1	7.3	387	—	—
Hole E103, Tahuangtsui, Tatun, Taiwan (f)	200	1000	3.2	—	282	54	—	—	8+	0	—	1368	—	1223	—	—
Sheituao Hotel, Matsukawa, Japan (g)	78.5	0	3.1	—	40	9.6	—	—	8.2	31.8	—	8.6	—	3.0	—	—
Hole 1, Matsukawa, Japan (g)	>300	413	4.9	—	264	144	—	—	8.7	22.9	—	508	—	12.4	—	—
Spring 22, Mexicali, Mexico (h)	—	0	—	11.6	4250	535	—	—	21	340	—	—	—	8600	12.3	—
Hole 5, Mexicali, Mexico (h)*	340	1285	—	19	5820	1570	—	—	8	260	—	0.2	—	10,420	14.1	3.1
Water mudpots, Salton Sea, Calif. (i)	21	0	7.1	9.6	6470	466	—	—	325	79	0.9	0.8	14	8480	—	—
Hole 1, IID, Salton Sea, Calif. (i)*	340	1600	4.7	215	50,600	17,500	135	14	54	28,000	1400	2290	15	155,000	120	18
Spring, Makhachkala, Dagestan, USSR	63	0	8.6	0.2	1137	5.4	—	—	2.4	164	—	—	0.4	335	1.6	—

*Reference:
(a) Bodvarsson (1961).
(b) Chemistry Division, DSIR, N.Z. and pers. comm. from Dr. G. Bodvarsson, and Dr. G. E. Sigvaldason. DSIR.
(c) Ivanov (1958).
(f) Y.-C. Liu (personal communication).
(j) Muffler and White (1969).
(d) Averyev et al. (1961).
(g) Nakamura and Sumi (1967).
(j) Ivanov and Nevraev (1964).
(e) Chemistry Division, DSIR.
(h) Mercado (1966).

*Concentrations and pH in deep aquifer.
'Total CO₂, SiO₂, etc. in total CO₂ + HCO₃⁻ + CO₃²⁻ expressed as CO₂, silica + silicate as SiO₂, etc.

Table 2.2   Summary of the Chemical Equilibria Controlling the Composition of Geothermal Fluid

Native copper
$$8Cu + 8H^+ + SO_4^{2-} \rightleftharpoons 8Cu^+ + 4H_2O + S^{2-}$$
Pyrrhotite
$$FeS \rightleftharpoons Fe^{2+} + S^{2-}$$
Sphalerite, Wurzite
$$ZnS \rightleftharpoons Zn^{2+} + S^{2-}$$
Galena
$$PbS \rightleftharpoons Pb^{2+} + S^{2-}$$
Covellite
$$CuS \rightleftharpoons Cu^{2+} + S^{2-}$$
Acanthite
$$Ag_2S \rightleftharpoons 2Ag^{2+} + S^{2-}$$
Chalcocite
$$Cu_2S \rightleftharpoons 2Cu^+ + S^{2-}$$
Pyrite
$$FeS_2 + H_2O \rightleftharpoons Fe^{2+} + 1.75S^{2-} + 0.25SO_4^{2-} + 2H^+$$
Chalcopyrite
$$CuFeS_2 \rightleftharpoons Cu^{2+} + Fe^{2+} + 2S^{2-}$$
Bornite
$$Cu_5FeS_4 \rightleftharpoons 4Cu^+ + Cu^{2+} + Fe^{2+} + 4S^{2-}$$
Cuprite
$$Cu_2O + 2H^+ \rightleftharpoons 2Cu^+ + H_2O$$
Magnetite
$$Fe_3O_4 + 8H^+ \rightleftharpoons Fe^{2+} + 2Fe^{3+} + 4H_2O$$
Hematite
$$Fe_2O_3 + 6H^+ \rightleftharpoons 2Fe^{3+} + 3H_2O$$
Brucite
$$Mg(OH)_2 \rightleftharpoons Mg^{2+} + 2OH^-$$
Gibbsite
$$Al(OH)_3 \rightleftharpoons Al^{3+} + 3OH^-$$
Calcite
$$CaCO_3 \rightleftharpoons Ca^{2+} + CO_3^{2-}$$
Na-Montmorillonite
$$Na_{0.333}Al_{2.333}Si_{3.667}O_{10}(OH)_2 + 7.332H^+ + 2.668H_2O \rightleftharpoons 0.333Na^+ + 2.333Al^{3+} + 3.667H_4SiO_4$$
K-Montmorillonite
$$K_{0.333}Al_{2.333}Si_{3.667}O_{10}(OH)_2 + 7.332H^+ + 2.668H_2O \rightleftharpoons 0.333Na^+ + 2.333Al^{3+} + 3.667H_4SiO_4$$
Ca-Montmorillonite
$$Ca_{0.1665}Al_{2.333}Si_{3.667}O_{10}(OH)_2 + 7.332H^+ + 2.668H_2O \rightleftharpoons 0.1665Ca^{2+} + 2.333Al^{3+} + 3.667H_4SiO_4$$
Mg-Montmorillonite
$$Mg_{0.1665}Al_{2.333}Si_{3.667}O_{10}(OH)_2 + 7.332H^+ + 2.668H_2O \rightleftharpoons 0.1665Mg^{2+} + 2.333Al^{3+} + 3.667H_4SiO_4$$
Muscovite
$$KAl_3Si_3O_{10}(OH)_2 + 10H^+ \rightleftharpoons K^+ + 3Al^{3+} + 3H_4SiO_4$$
Illite
$$K_{0.6}Mg_{0.25}Al_{2.30}Si_{3.50}O_{10}(OH)_2 + 8H^+ + 2H_2O \rightleftharpoons 0.6K^+ + 0.25Mg^{2+} + 2.30Al^{3+} + 3.5H_4SiO_4$$
Biotite (Annite)
$$KFe_3AlSi_3O_{10}(OH)_2 + 10H^+ \rightleftharpoons K^+3Fe^{2+} + Al^{3+} + 3H_4SiO_4$$

Anglesite
$$PbSO_4 \rightleftharpoons Pb^{2+} + SO_4^{2-}$$
Cerrusite
$$PbCO_3 \rightleftharpoons Pb^{2+}CO_3^{2-}$$
Tenorite
$$CuO + 2H^+ \rightleftharpoons Cu^{2+} + H_2O$$
Smithsonite
$$ZnCO_3 \rightleftharpoons Zn^{2+} + CO_3^{2-}$$
Siderite
$$FeCO_3 \rightleftharpoons Fe^{2+} + CO_3^{2-}$$
Dolomite
$$CaMg(CO_3)_2 \rightleftharpoons Ca^{2+} + Mg^{2+} + 2CO_3^{2-}$$
Anhydrite
$$CaSO_4 \rightleftharpoons Ca^{2+} + SO_4^{2-}$$
Gypsum
$$CaSO_4 \cdot 2H_2O \rightleftharpoons Ca^{2+} + SO_4^{2-} + 2H_2O$$
Quartz
$$SiO_2 + 2H_2O \rightleftharpoons H_4SiO_4$$
Microcline
$$KAlSi_3O_8 + 4H^+ + 4H_2O \rightleftharpoons K^+ + 3H_4SiO_4 + Al^{3+}$$
Low Albite
$$NaAlSi_3O_8 + 4H^+ + 4H_2O \rightleftharpoons Na^+ + 3H_4SiO_4 + Al^{3+}$$
Anorthite
$$CaAl_2Si_2O_8 + 8H^+ \rightleftharpoons Ca^{2+} + 2Al^{3+} + 2H_4SiO_4$$
Leucite
$$KAlSi_2O_6 + 2H_2O + 4H^+ \rightleftharpoons K^+ + Al^{3+} + 2H_4SiO_4$$
Nepheline
$$NaAlSiO_4 + 4H^+ \rightleftharpoons Na^+ + Al^{3+} + H_4SiO_4$$
Analcite
$$NaAlSi_2O_6 \cdot H_2O + H_2O + 4H^+ \rightleftharpoons Na^+ + Al^{3+} + 2H_4SiO_4$$
Kaolinite
$$Al_2Si_2O_5(OH)_4 + 6H^+ \rightleftharpoons H_2O + 2Al^{3+} + 2H_4SiO_4$$

Table 2.3 Equations Describing the Temperature Dependence of
Cation/Proton Ratios and Un-dissociated Weak Acid
Concentrations in Geothermal Well Discharge

Weak acid/ ion ratio (moles/kg)	Temperature function	Mean deviation	Standard deviation
$\log H_4SiO_4^0$	$-0.588 -0.00441 \cdot T -1515.21/T +1.3470 \cdot \log T$	0.06	0.05
$\log H_2CO_3^0$	$-1.794 -0.00510 \cdot T -4469.63/T +4.1414 \cdot \log T$	0.30	0.26
$\log H_2S^0$	$-1.678 -0.00355 \cdot T -5071.05/T +3.8889 \cdot \log T$	0.36	0.33
$\log H_2SO_4^0$	$-6.436 -0.03906 \cdot T -13335.68/T +14.7958 \cdot \log T$	0.57	0.48
$\log HF^0$	$-5.262 -0.03511 \cdot T -7964.11/T +12.1022 \cdot \log T$	0.32	0.28
$\log Na^+/H^+$	$2.694 +0.02023 \cdot T +4243.47/T -6.2069 \cdot \log T$	0.14	0.12
$\log K^+/H^+$	$2.505 +0.01971 \cdot T +3325.71/T -5.7814 \cdot \log T$	0.12	0.09
$\log \sqrt{Ca^{+2}}/H^+$	$1.733 +0.01117 \cdot T +3890.51/T -3.9977 \cdot \log T$	0.17	0.12
$\log \sqrt{Mg^{+2}}/H^+$	$1.816 +0.01078 \cdot T +3727.48/T -4.1640 \cdot \log T$	0.34	0.27
$\log \sqrt{Fe^{+2}}/H^+$	$-4.696 -0.04273 \cdot T -1011.46/T +10.8032 \cdot \log T$	0.18	0.17
$\log Al(OH)_4^-/OH^-$	$-3.407 -0.02364 \cdot T -3417.36/T +7.8426 \cdot \log T$	0.21	0.12

Table 3.1   Analysis of Geothermal Waters with AAS

	Conc. Range (ppm)	Dilution[h]	Wavelength (Å)	Monochromator[b]				Lamp		Burner		Flame[c]	Sampling height (mm)
				I	II	III	IV	Type[d]	Current (mA)	Slot length (mm)	Alignment[e]		
Li	0.5–30	(O)	6708	335	vis	in	3	HCL	10	70–100	⊥	C₂H₂–air (fuel lean)	8
	1–150	(D)	6708	335	vis	in	3	HCL	10	70–100	‖	C₂H₂–air (fuel lean)	8
Na	100–1000	(D)	5890 5896	295	vis	in	4	ODL	900	70–100	⊥	C₂H₂–air (fuel lean)	8
K	4–400	(D)	7699	385	vis	in	4	ODL	400	70–100	‖	H₂–air (fuel rich)	8
Rb	0.1–10	(B)	7800	390	vis	in	4[f]	ODL	250	70–100	‖	H₂–air (fuel rich)	8
Cs	0.2–20	(B)	8521	426	vis	in	5[f]	ODL	400	70–100	‖	H₂–air (fuel rich)	8
Mg	0.001–1	(B)	2852	285	uv	out	4	HCL	6	70–100	‖	C₂H₂–air (fuel lean)	8
	0.002–2	(O)	2852	285	uv	out	3	HCL	8	50–70	‖	C₂H₂–N₂O (RZ 3)	8
Ca	2–200	(D)	4227	211	vis	out	3	HCL	15	50–70	‖	C₂H₂–N₂O (RZ 5)	13
Mn	0.005–5	(B)	2795	279[g]	uv	out	3	HCL	20	70–100	‖	C₂H₂–air (fuel lean)	8
Al	0.04–50	(B)	3092.7 3092.8	309	uv	out	3	HCL	25	50–70	‖	C₂H₂–N₂O (RZ 12)	8
Fe	0.01–0.1	(B)	2483	248	uv	out	3	HCL	30	70–100	‖	C₂H₂–air (fuel lean)	8
	0.1–20	(O)	2483	248	uv	out	3	HCL	30	50–70	‖	C₂H₂–N₂O (RZ 3)	8
SiO₂	50–1000	(B)	2507	251	uv	out	3	HCL	40	50–70	‖	C₂H₂–N₂O (RZ 25)	7
B	20–1000	(B)	2497	250	uv	out	4	HCL	30	50–70	‖	C₂H₂–N₂O (RZ 25)	7

[a] Operating conditions are for models 303, 305, and 403; data are from Goguel, (1973).

[b] I, wavelength counter setting; II, grating; III, filter which excludes wavelengths shorter than 550 nm (5500 Å); IV, slit setting: (numbers correspond to spectral bandwidths) for the uv grating, 3 = 2.4 Å, 4 = 7 Å; for the visual grating, 3 = 5 Å, 4 = 14 Å, and 5 = 50 Å.

[c] RZ denotes height of the red zone in millimeters.

[d] HCL, hollow cathode lamp; ODL, Osram discharge lamp.

[e] Of the flame in the light path of the spectrophotometer: perpendicular alignment produces 0.1 or less of the sensitivity of the parallel alignment.

[f] An extra filter must be inserted into the light beam near the window of the spectrophotometer to the left of the flame in order to exclude modulated scattered Na light which reaches the photomultiplier via the reference beam. Filter holder 040-0251 (model 403) or 303-0828 (models 303–305) and a red filter Schott RG 5 or Corning 2-58 (Perkin-Elmer No. 290-1518) are required.

[g] Shortest wavelength of the triplet.

[h] Dilutions: (B) 1.1 fold. Add 5 ml of a buffer solution (2.5% recrystallized Sr (NO₃)₂, 4% KC1, 1 N HNO₃) to 50 ml of each sample of standard. (D) 51 fold. Deliver 2 ml of sample or standard into 100 ml of a buffer solution (0.1% CsCl, 0.1N HNO₃).(O) Undiluted water sample. Note: Sr(NO₃)₂, KCL, and CsCl are reagents of high purity (e.g., Merck "Suprapur").

Table 4.1 Equations Expressing the Temperature Dependence of Equilibrium Constants in $CaO-CO_2-H_2O$ System

$$K_H{}^\circ = -7656970-3122.11449T+1.092229T^2+1.880778E8*T^{-1}+3.1771246E6*logT$$

$$k = 108.875+0.174114604T-1.9845113E(-4)*T^2+1.0131668E(-7)*T^3-58.867703*logT$$

$$logK_1 = 124.4478+0.0056623T-5.86972601E3*T^{-1}-45.589821*logT$$

$$logK_2 = 143.4475+0.034559T-1.9732326E(-5)T^2-6.16187137E3*T^{-1}-57.248899*logT$$

$$logK_0 = -130.5593-0.0517898T+2.6766438E(-5)T_2+4.4176248E3*T^{-1}+51.47548*logT$$

$$logK_c = 30.8131-0.1728295T+3.271501E(-4)T^2-2.5529153E(-7)T^{-1}+2.95989303*logT$$

$$A = -11092.1143+11.562984T+0.01454757T^2-1.2064489E(-5)*T^3+4.4598806E(-9)*T^4+1.76312033E5*T^{-1}+5229.515*logT$$

$$B = 3.8096+0.01846467T+4.8075571E(-5)T^2-6.0838461E(-8)*T^3+3.0473184E(-11)*T^4-2.617130669E2*T^{-1}$$

$$logK_D = -1823.663+3.9000818T-0.00412503T^2+1.75503E(-6)*T^3+4.2179661E5*T^{-1}-3.9002725E7*T^{-2}$$

96

Table 4.2 Ionic Strength of Typical Geothermal Waters

Geothermal source	Ionic strength (molality)	Res. temp. (°C)	pH
Reykjaból, Iceland	0.005	152	7.23
Nâmafjall, Iceland	0.007	252	7.48
Hveragerdi, Iceland	0.009	184	6.99
Leira, Iceland	0.014	127	6.73
Broadlands, N.Z. well 2	0.052	260	8.3
Wairakei, N.Z. hole No.24	0.062	250	8.3
Matsukawa, Japan hole No. 1	0.065	300	4.9
Sulphur Bank, CA Geyser spring	0.094	230	6.8
El Tatio, Chile geyser 238	0.230	220	7.32
Ahuachapan, El Salvador, ave.	0.312	230	6.3
Cerro Prieto, Mex. ave. 12 wells	0.431	388*	8.2
Matsao, Taiwan well 205	0.429	245	2.4
Sea water Std. Cl = 19‰	0.709	20	8.0
Halls Bayou, TX. FF No. 1	1.111	150	6.8
Chocolate Bayou, TX. Angle No. 3	1.348	118	5.9
Salton Sea Woolsey	3.434	176†	5.8
Salton Sea Magmamax No.1	4.203	196†	5.5
Salton Sea hole I IID	6.931	340	4.7

*Max temp.
†Well head temp.

Table 4.3 Aqueous Species for Proton Mass Balance and Alkalinity Equations

Hydrogen ion mass balance species						Alkalinity species	
Coefficient		Coefficient		Coefficient		Coefficient	
1	H^+	-1	$AlOH^{2+}$	-2.875	$Fe(OH)_4^-$	1	OH^-
-1	OH^-	-2	$Al(OH)_2^+$	1	PbH_2S_3	2	$H_2SiO_4^{2-}$
-2	$H_2SiO_4^{2-}$	-4	$Al(OH)_4^-$	1.125	Cu^{2+}	1	$H_3SiO_4^-$
-1	$H_3SiO_4^-$	-1	$Mg(OH)^+$	1.125	$CuCl^+$	1	HCO_3^-
1	HF	1	$MgHCO_3$	1.125	$CuCl_2$	2	CO_3^{2-}
1	HF_2^-	-1	$FeOH^+$	1.125	$CuCl_3^-$	1	HS^-
1	HCl	-3	$Fe(OH)_2$	1.125	$CuCl_4^-$	2	S^{2-}
.5	O_2aq	.25	$Fe(OH)_3$	1.125	$CuOH^+$	2	$NaCO_3^-$
.25	H_2aq	1.125	Fe^{3+}	1.125	$CuSO_4$	2	$CaCO_3$
1	CH_4aq	.125	$FeOH^{2+}$	1.125	CuF^+	1	$CaOH$
1	HCO_3^-	1.125	$FeCl_2^+$	-1	$MnOH^+$	1	$CaHCO_3$
2	H_2CO_3	1.125	$FeCl^{2+}$	-2	HgS_2^-	2	$MgCO_3$
1	H_2S	1.125	$FeCl_2$	1	HgH_2S_3	1	$MgOH^+$
-1	S^{2-}	1.125	$FeCl_3$	-2.25	Hg_2^{2+}	1	$MgHCO_3^+$
1	HSO_4^-	1.125	FeF^{2+}	-1	$HgClOH$	1	$BaOH$
-1	$MnOH$	1.125	FeF_2^+	-1	$HgOH^+$		
1	$KHSO_4$	1.125	$FeSO_4^+$	-2	$Hg(OH)_2$		
-1	$CaOH^+$	.875	$Fe(OH)_2^+$	2.25	$AuCl_2^-$		
-1	$CaHCO_3^+$	-1.875	$Fe(OH)_3$	-1	$Au_2H_2S_3^-$		

Table 5.1   Schematic Layout of the Function of WATCH Program

GEOCHEMICAL MATERIAL	SELECTED PARAMETERS	COMPUTED PARAMETERS
1 Wet-steam well discharges (steam and water phases)	1 Reference temperature	1 Deep water composition
2 Boiling hot springs	a. measured	2 Species concentrations
3 Hot-water wells and non-boiled hot spring waters	b. chalcedony equilibrium	3 Activity coefficients
	c. quartz equilibrium	4 H^+ activity
	d. Na-K feldspar equilibrium	5 Redox potential
	e. arbitrary	6 Gas partial pressures
	2 Degassing factor (only for geochemical material 1 and 2)	7 Mineral solubilities
	3 Discharge enthalpy (only for wet-steam wells)	

SPECIAL COMPUTATIONS

1 Speciation of variably boiled and cooled water

Table 5.2   Input Data for WATCH Program

CHEMICAL DATA
Water samples: pH/°C[1], SiO_2, B, Na, K, Ca, Mg, Fe, Al,
NH_3, CO_2, SO_4, H_2S, Cl, F, dissolved
solids, electric conductance[2].
Steam samples: (only for wet-steam wells) CO_2, H_2S,
NH_3, N_2, O_2, H_2, CH_4, and Na or Cl to
check dryness of steam.

PHYSICAL DATA
Wet-steam wells: Sampling pressure, enthalpy of well
discharge.
Hot springs and hot water wells: Discharge temperature.

DATA WHICH ARE DESIRABLE
Downhole temperature of wells.
Aquifer inflows of wells.
Discharge rates of wells and hot springs.

[1] Temperature at which the pH is measured.   [2] These data are
not necessary for the programme calculations.

Table 7.1 Effect of Process Parameters on Scale Formation

Process Parameter	Equilibrium Effect on Potential Scale Species[a]			
	SiO_2	$CaCO_3$	Sulfide	Sulfate
Temperature decrease (as in plant cycle)	●	o	●	o Ca ● Ba
Temperature increase (reheat during injection)	o	●	o	● Ca o Ba
Increased pH (as CO_2 is flashed)	● o pH >9	●	●	●
Decreased pH (acid addition)	o	o	o	o
Increased salinity (flashing; mixing)	●	o	o	o

(a) ● aggravates problem
    o alleviates problem.

Table 7.2 Factors affecting Silica Deposition Kinetics

Factor	Impact	Comments
pH	Lowering pH slows kinetics by a factor of ~10 for every pH unit.	
Supersaturation ratio	Precipitation becomes rapid as the ratio exceeds 2.	Reduce pH and temperature
Temperature	Kinetics slows dramatically as temperature drops, which counteracts the increase in supersaturation ratio as a saturated solution cools.	The maximum silica deposition rate may occur 25 to 50°C below the temperature at which the cooled solution reaches amorphous silica solubility limits.
Salinity	Increased salinity increases kinetics of deposition	
F catalyst	This equilibrium (precipitation) accelerator may become the dominant controller of deposition in lower pH brines (pH 3?) where the normal precipitation mechanism is pH inhibited.	
Chemical inhibitors	Retards growth of silica particulates	Limited testing described in the Inhibitor Treatment section.
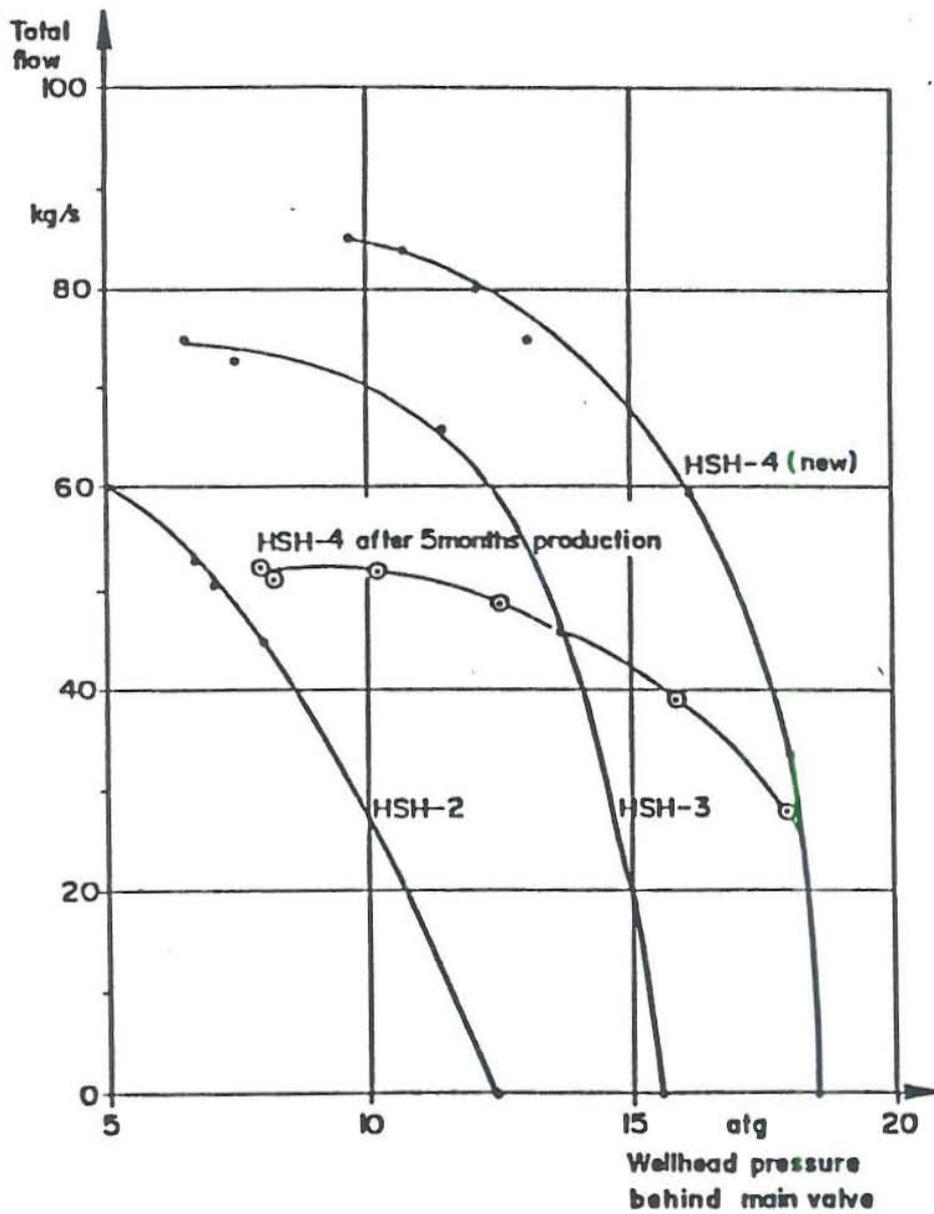
Figure 1.1 Output Decay due to Scaling in Well, Svartsengi
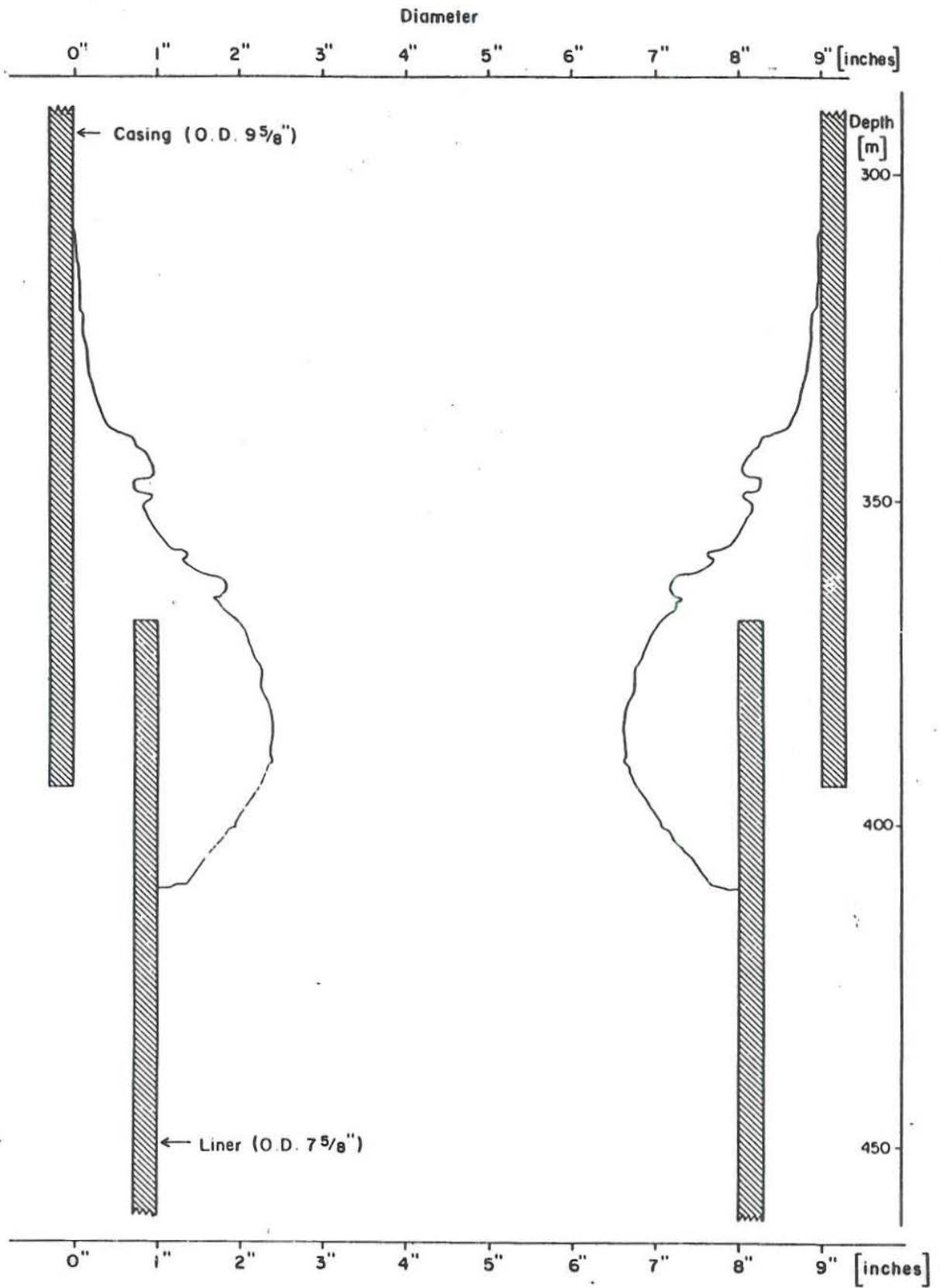
Figure 1.2   Formation of Calcite Deposition in Well 4 in
Svartsengi

1. Production Well
2. Wellhead Separator
3. First Flasher
4. Second Flasher
5. Turbogenerator
6. Condenser
7. Ejector
8. To Greenhouse
9. Cooling Water Pump
10. Disposal Line
11. Pump
12. Injection Well
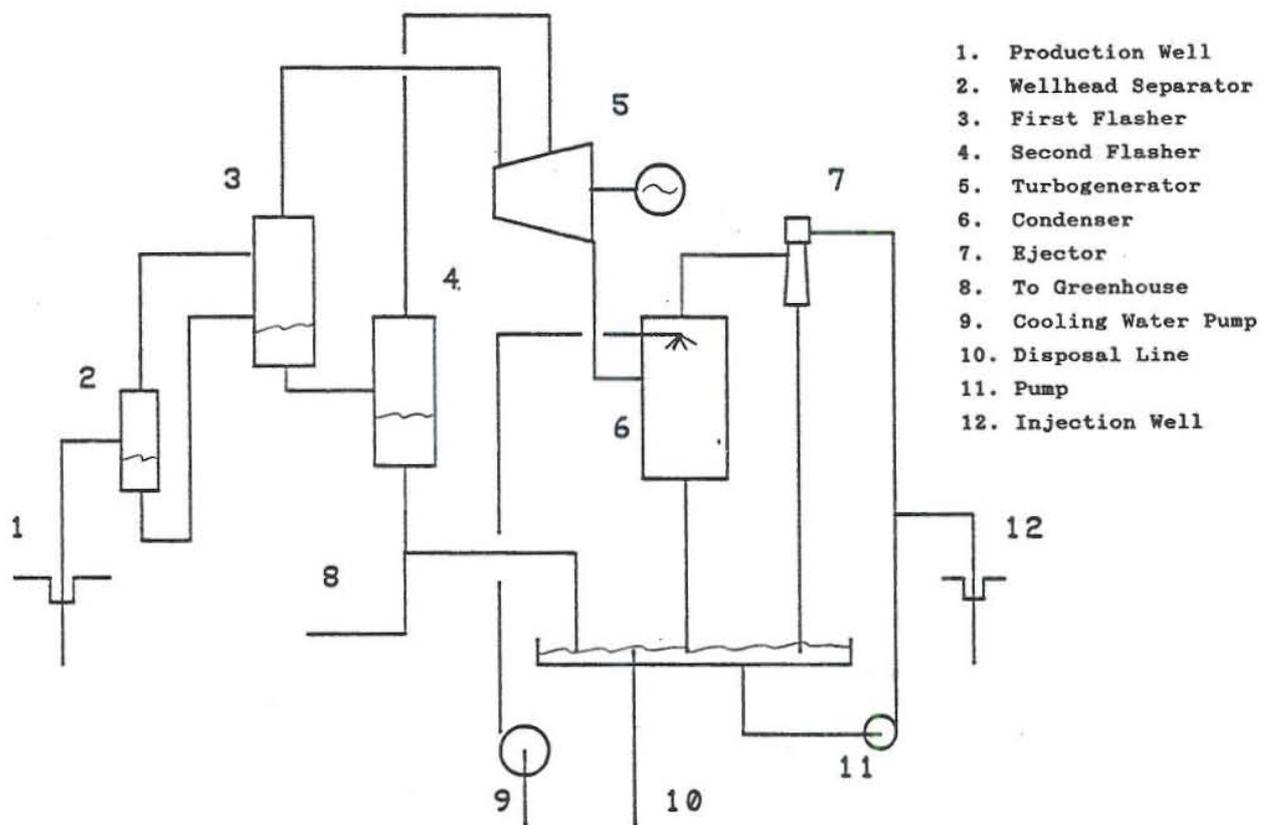
Figure 2.1   Schematic Flow Diagram of Double Flashing System in Yangbajing Power Plant
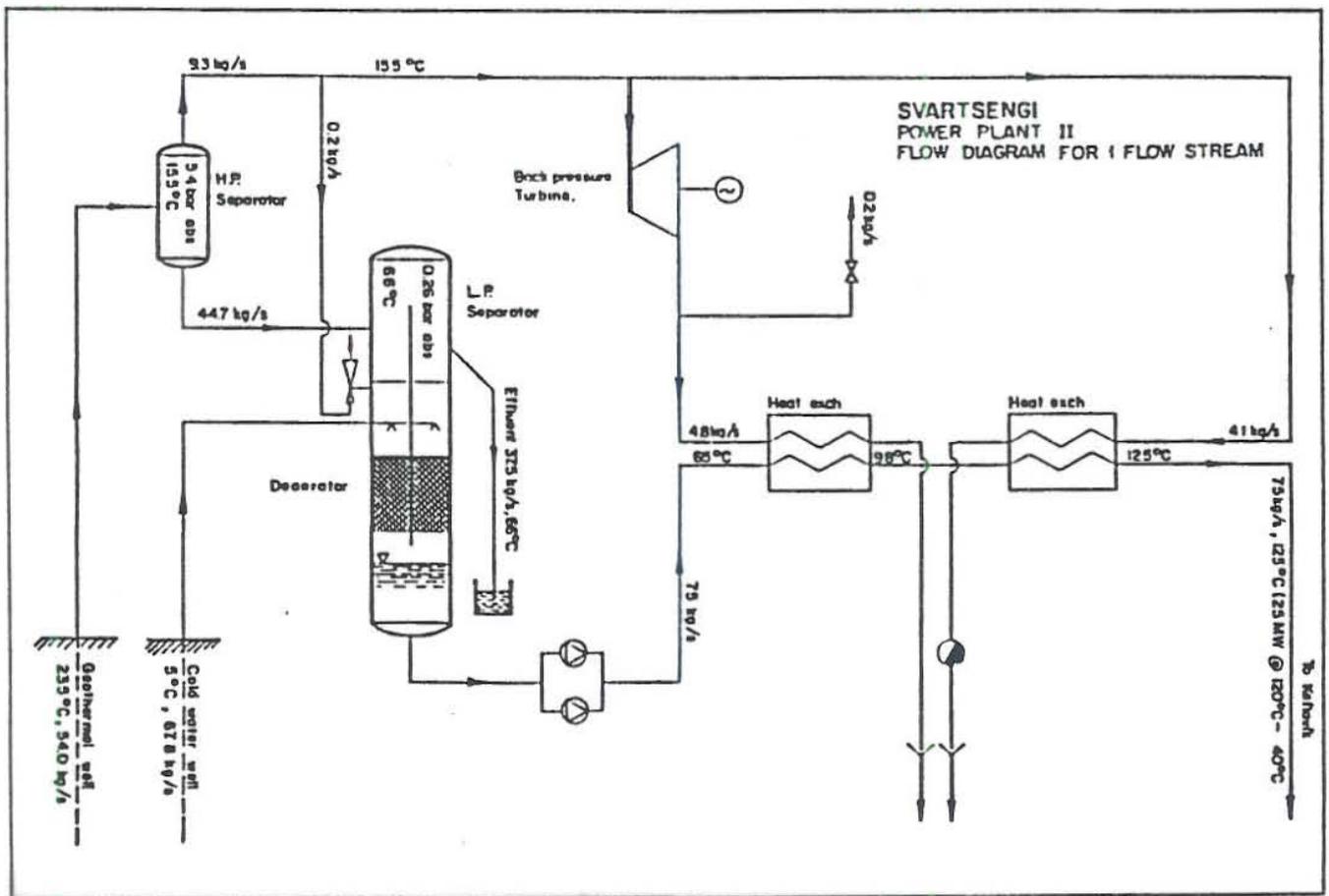
Figure 2.2 Flow Diagram of Svartsengi Power Plant
(Björnsson and Albertsson, 1985)

Bubble Flow   Slug or Plug Flow   Churn Flow   Annular Flow   Wispy Annular Flow
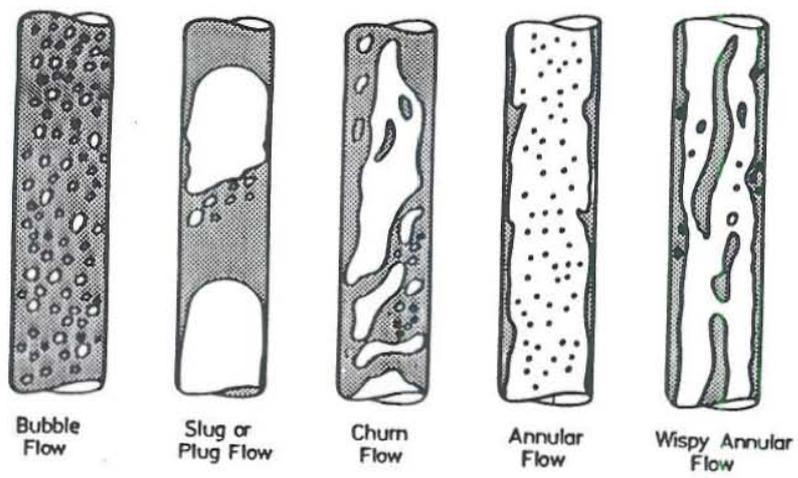
Figure 2.3 Flow Patterns of Vertical Two Phase Flow
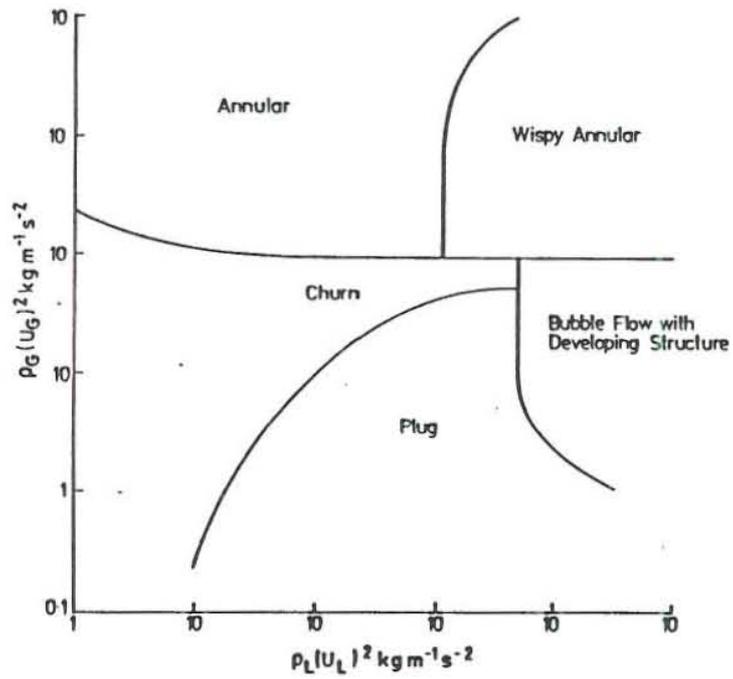
Figure 2.4 Flow Pattern Map for Vertical Two Phase Flow
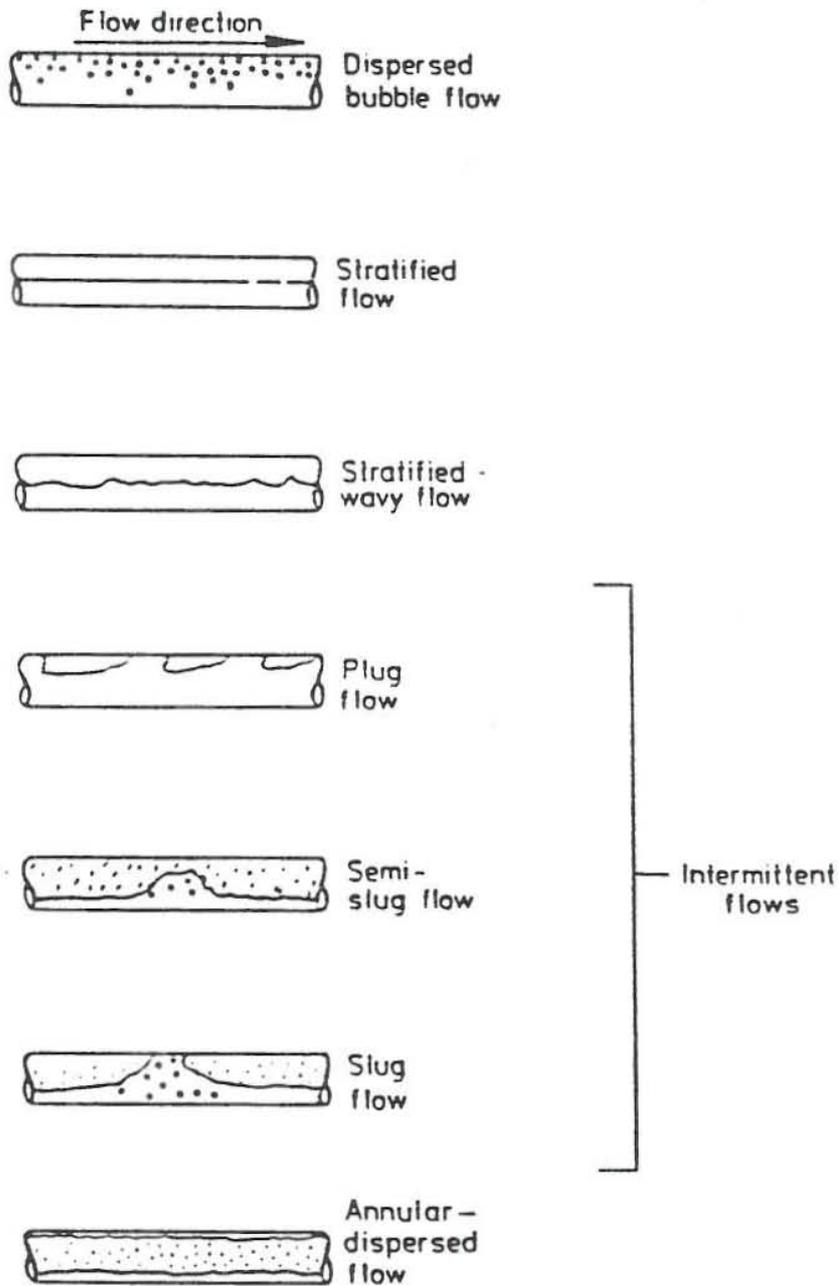
Figure 2.5   Flow Regimes in Horizontal Two Phase Flow
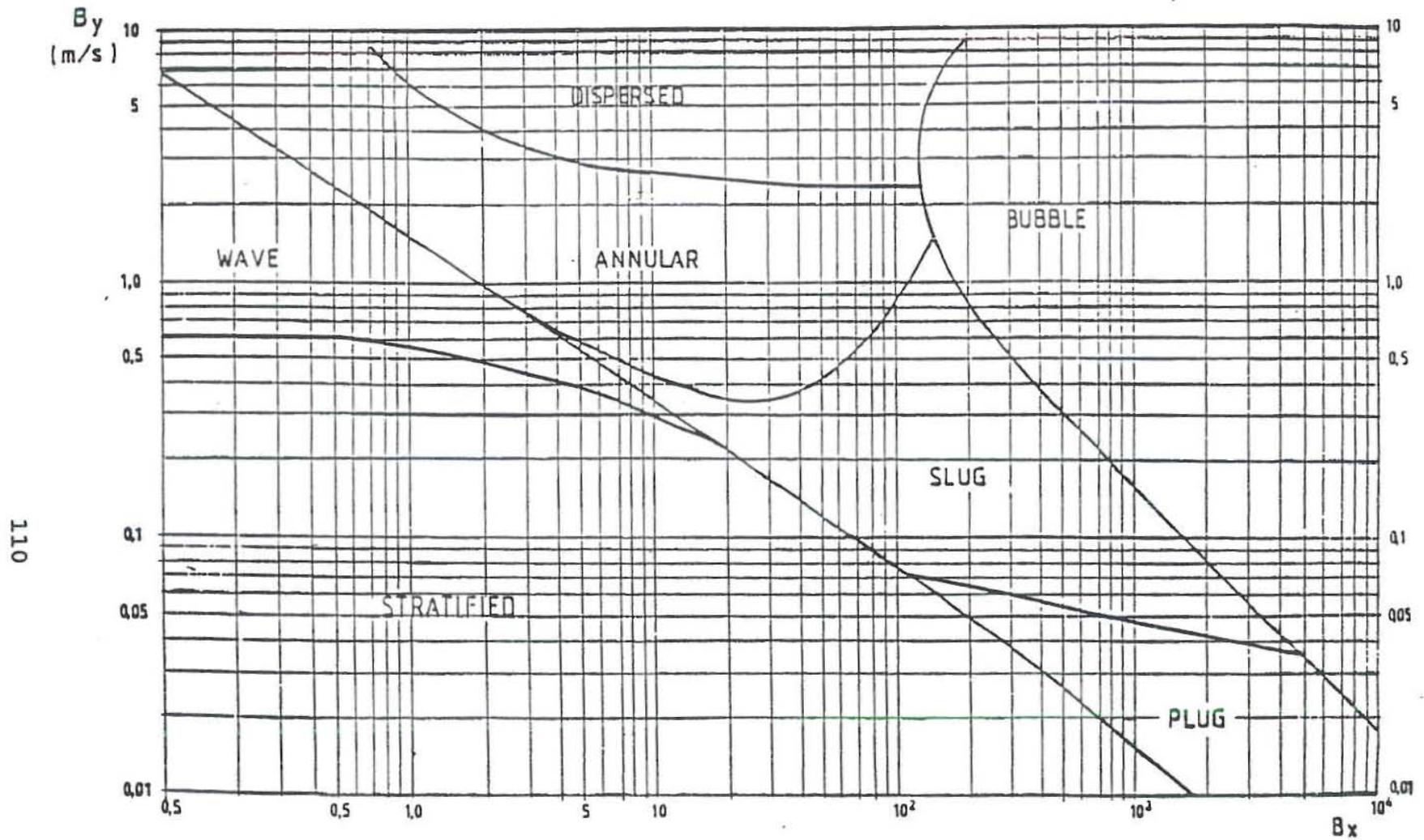
Figure 2.6 Flow Pattern Map of Baker as Modified by Scott
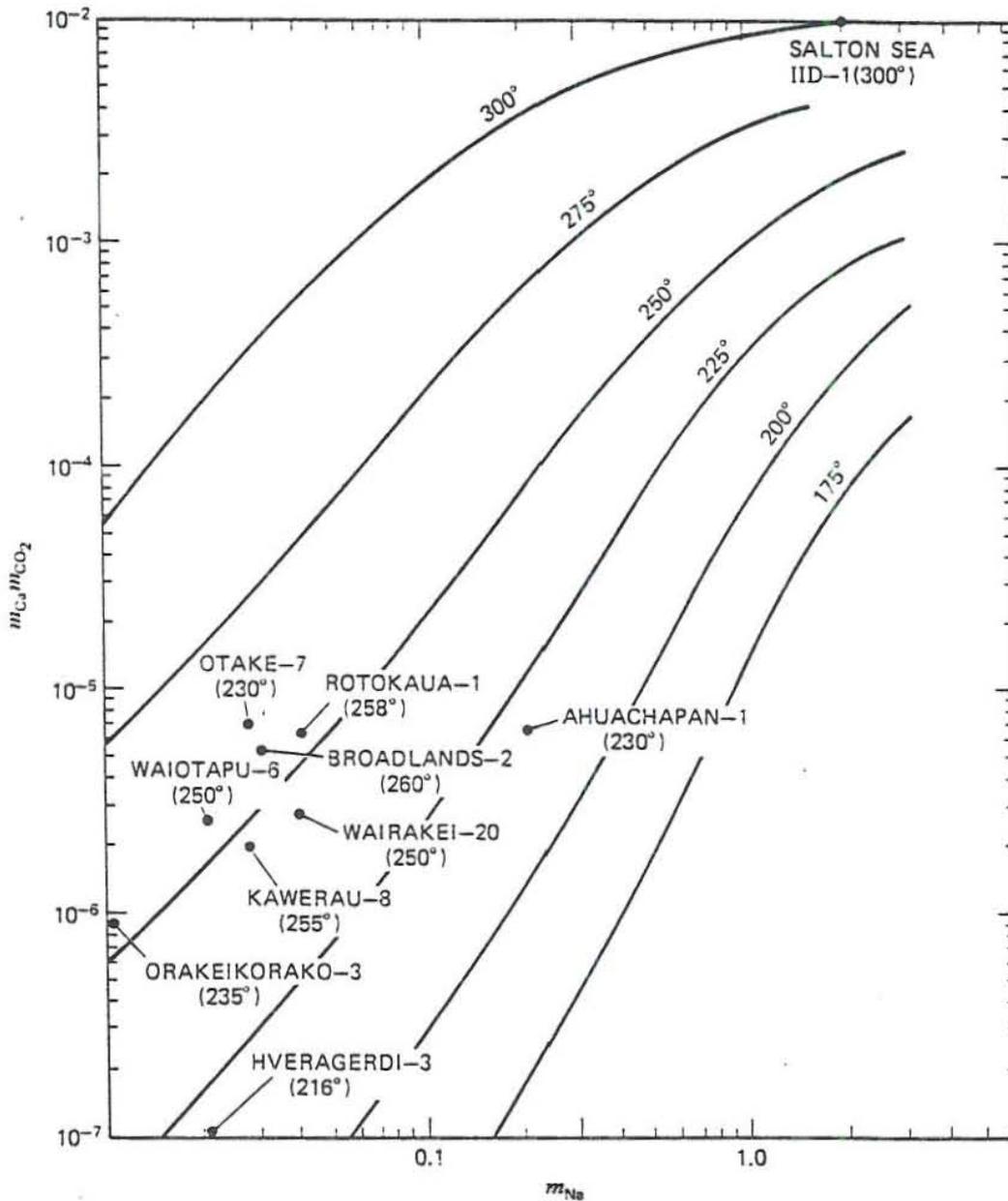
Figure 2.7 Relationship of the Product of Calcium and Carbonate Ion Concentrations with Temperature and Sodium Concentration in Equilibrium Reservoir Conditions
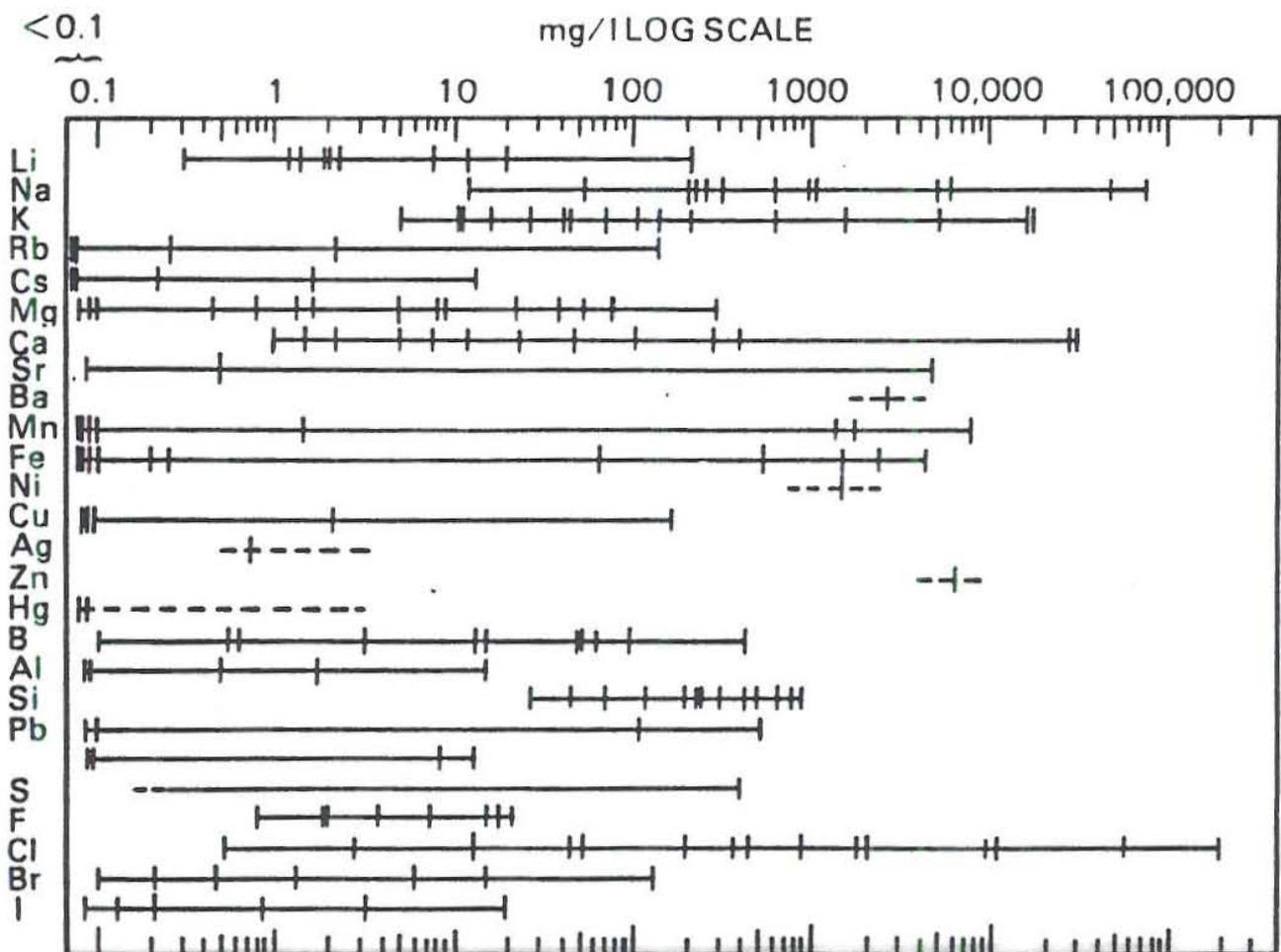
Figure 2.8   Concentration Ranges for Elements in Geothermal Water

Pressure Gauge

Thermometer Hole

Connection to Well

Water Valve

Vapour Valve

Vapour Tap
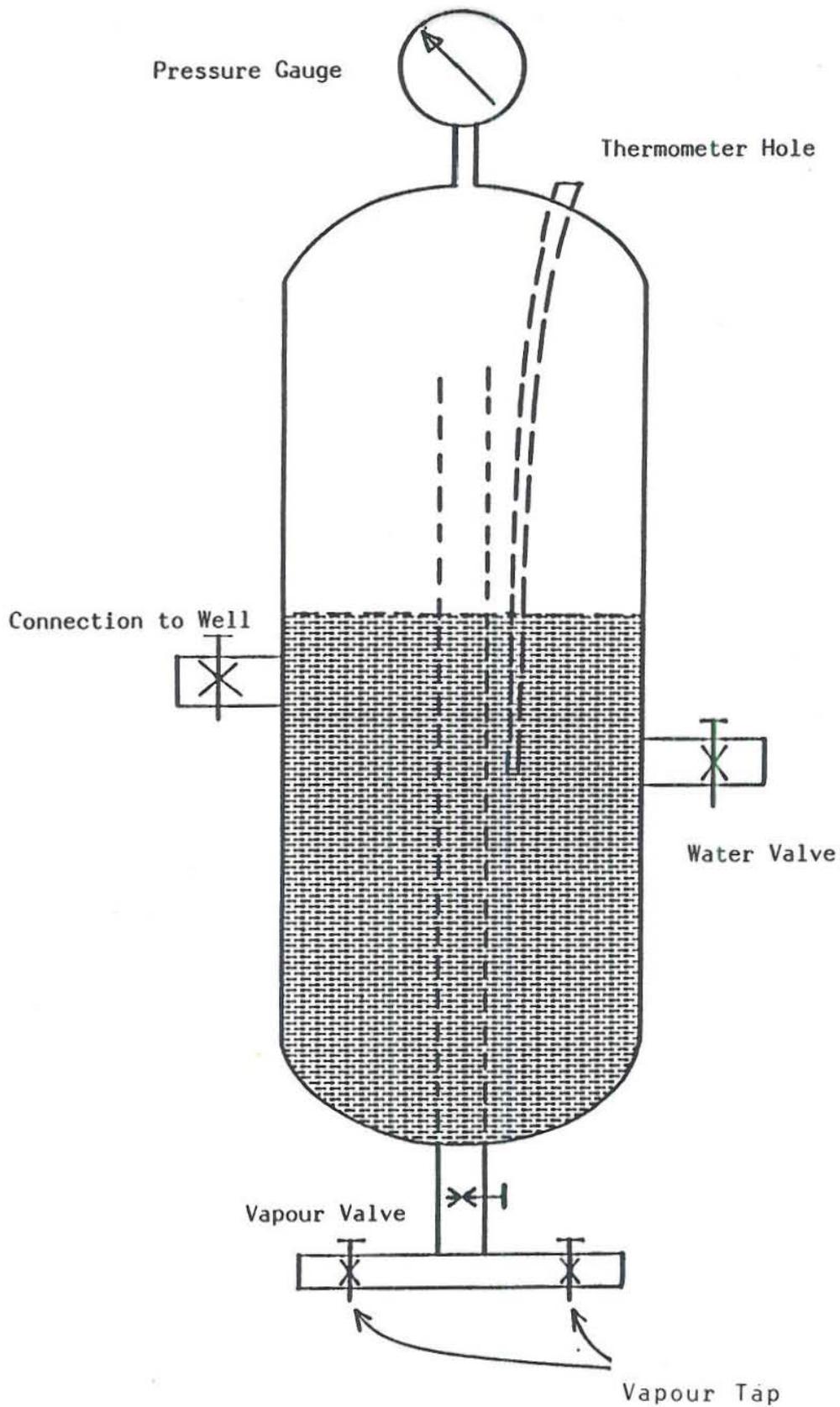
Figure 3.1 Small Separator for Sampling of Geothermal Well
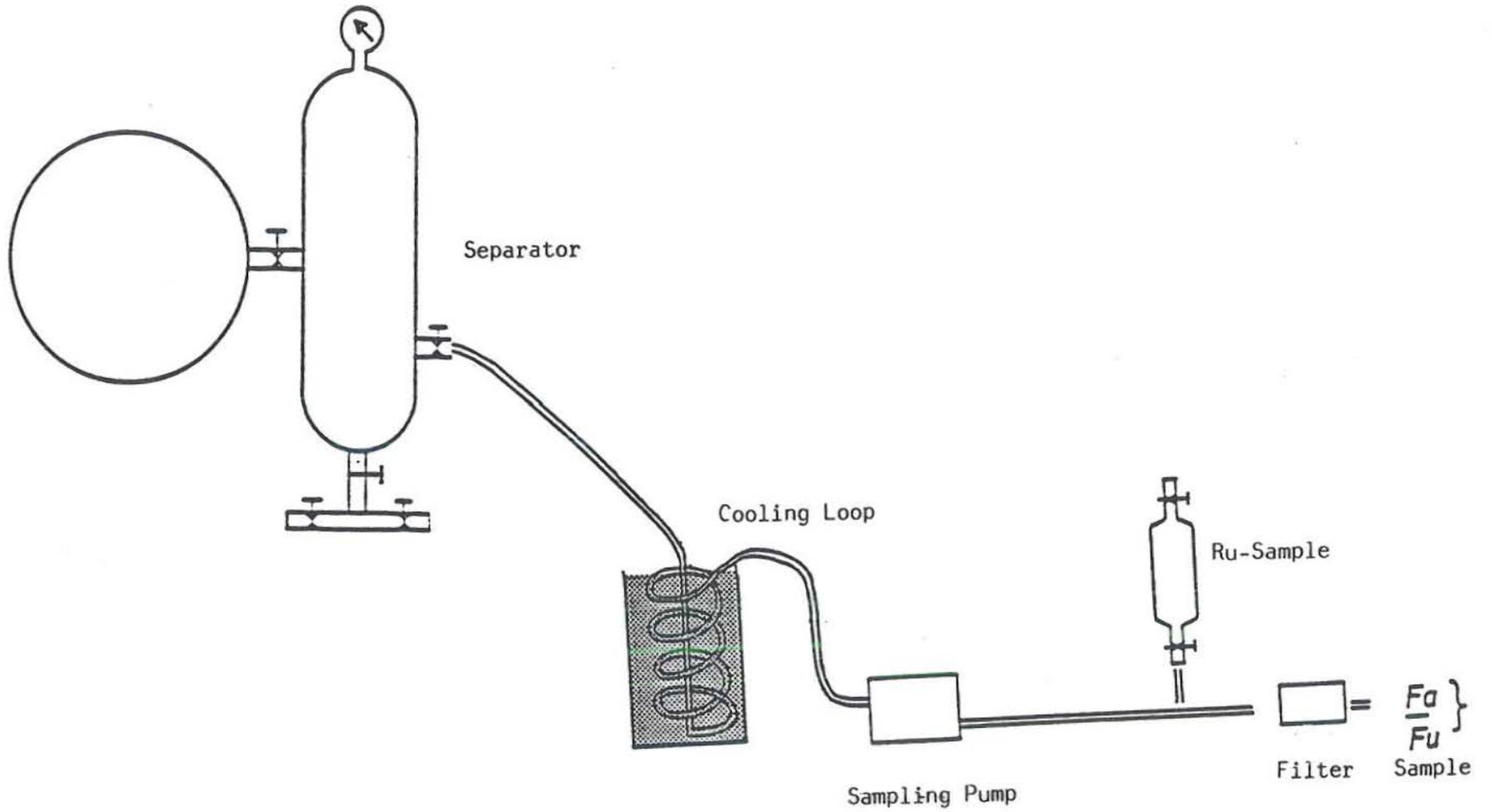
Figure 3.2 Collection of Water Phase

Separator

① Conllection of
Condensate A

Conllection
of Gas A

② Conllection of
Condensate B

Cooling Loop
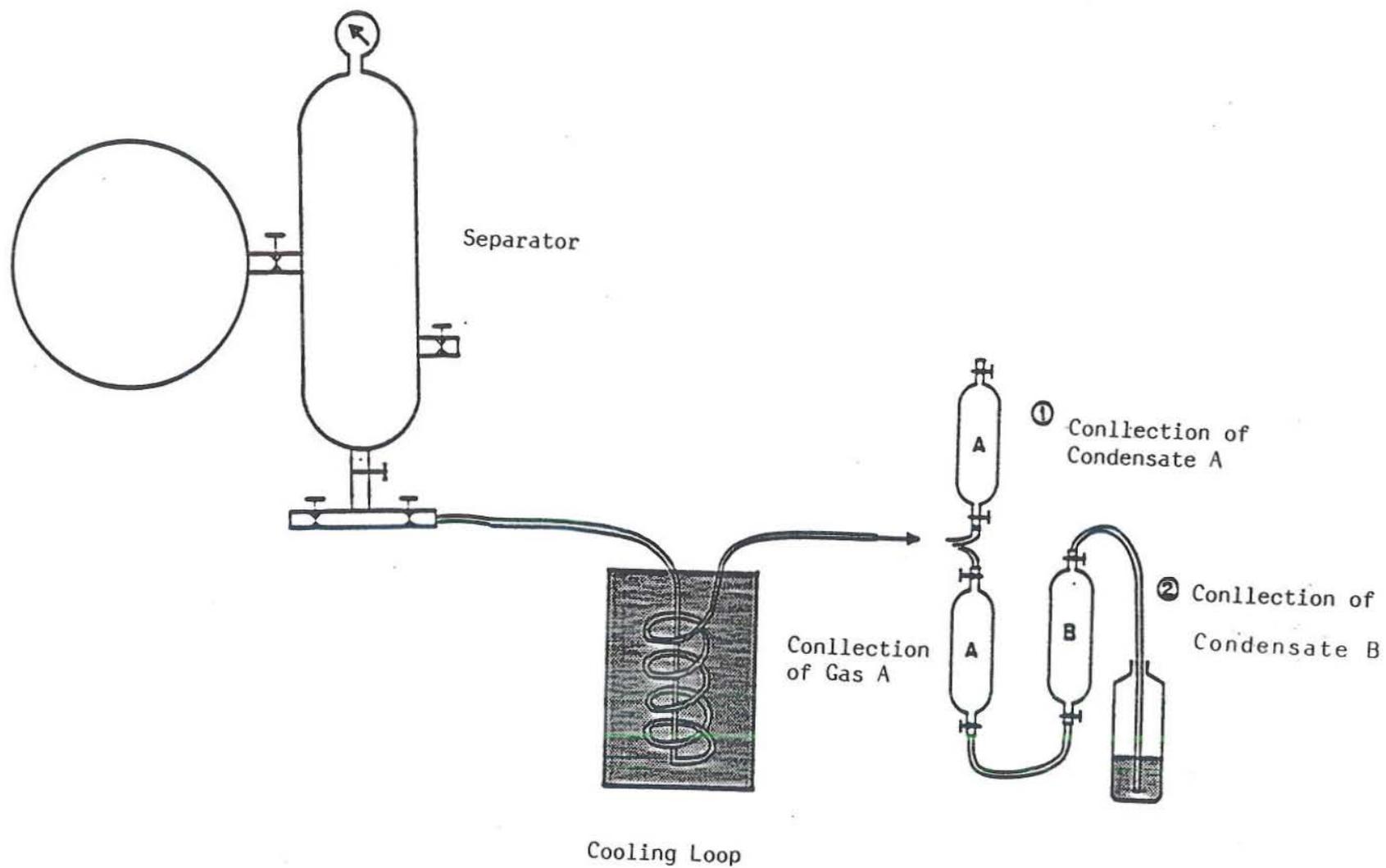
Figure 3.3 Collection of Condensate and Gases

Figure 3.4   Collection of Vapor Phase into NaOH Solution

116
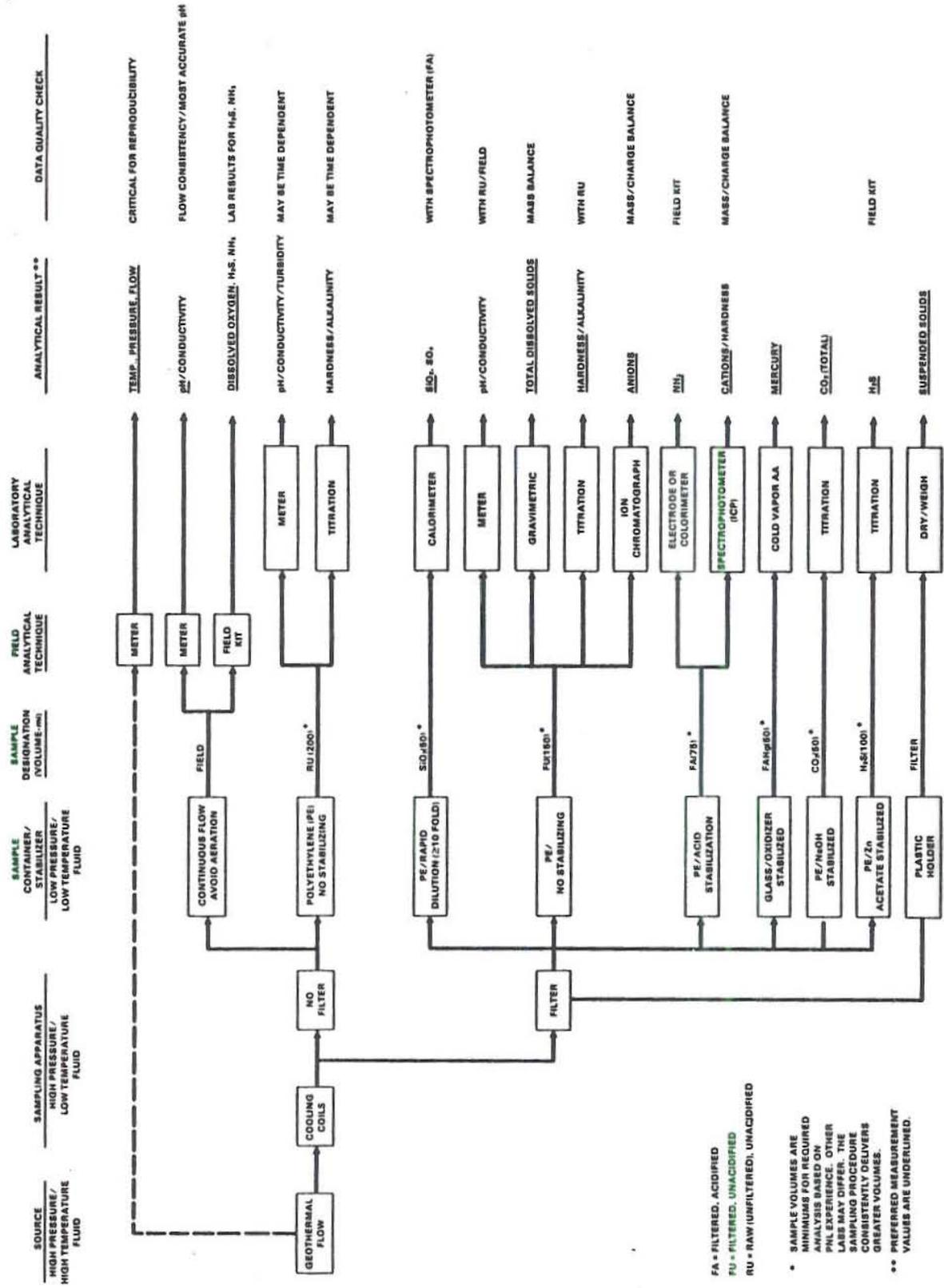
Figure 3.5   Flow Chart for Comprehensive Sampling and Analysis of Geothermal Fluid
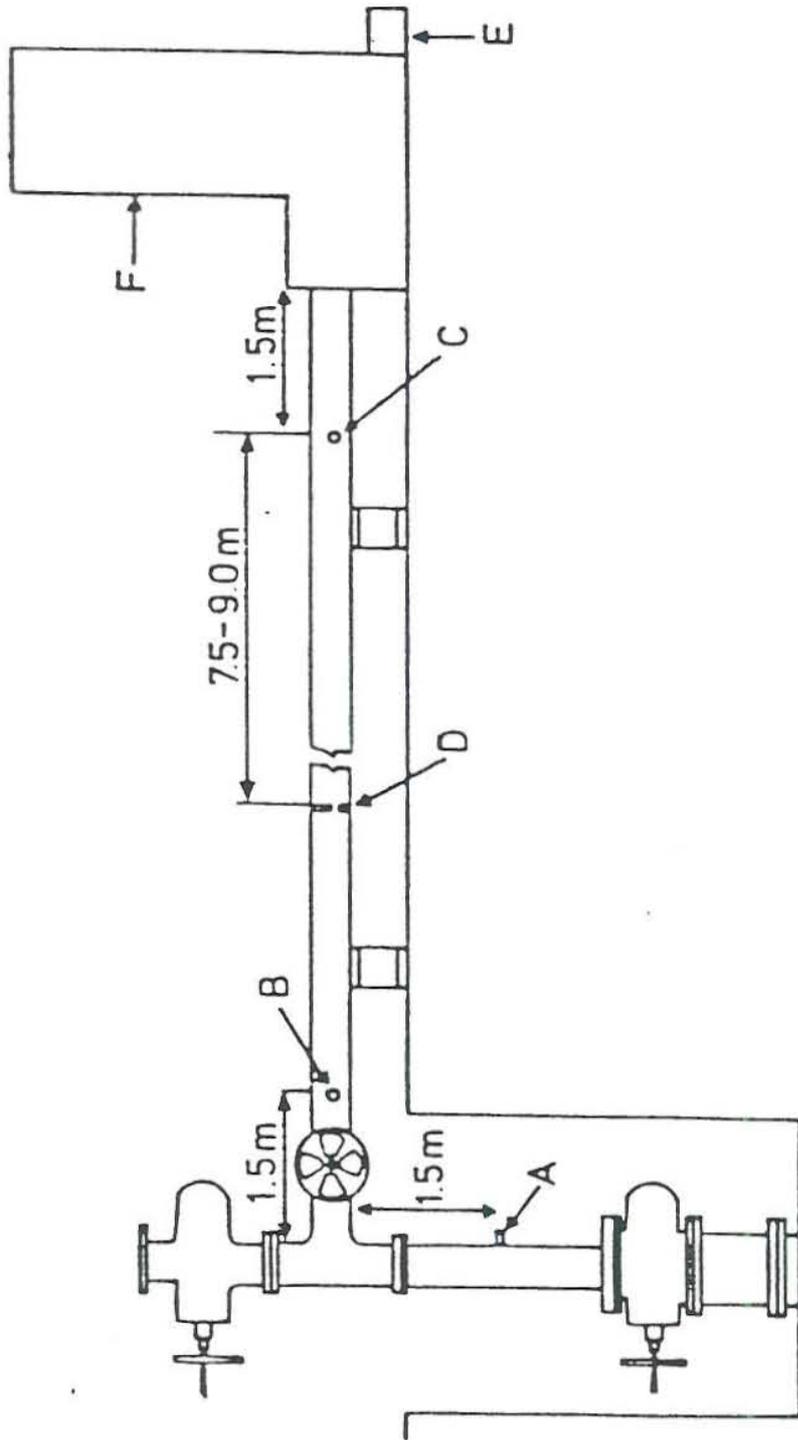
Figure 3.6   Positions of Sampling Points on Surface Piping

118
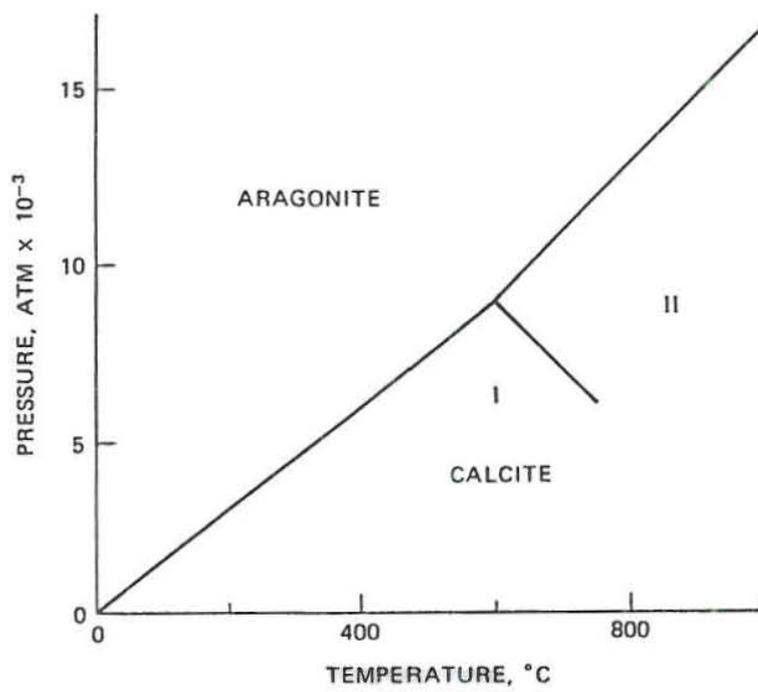
Figure 4.1 Aragonite-Calcite Phase Transition Diagram

119
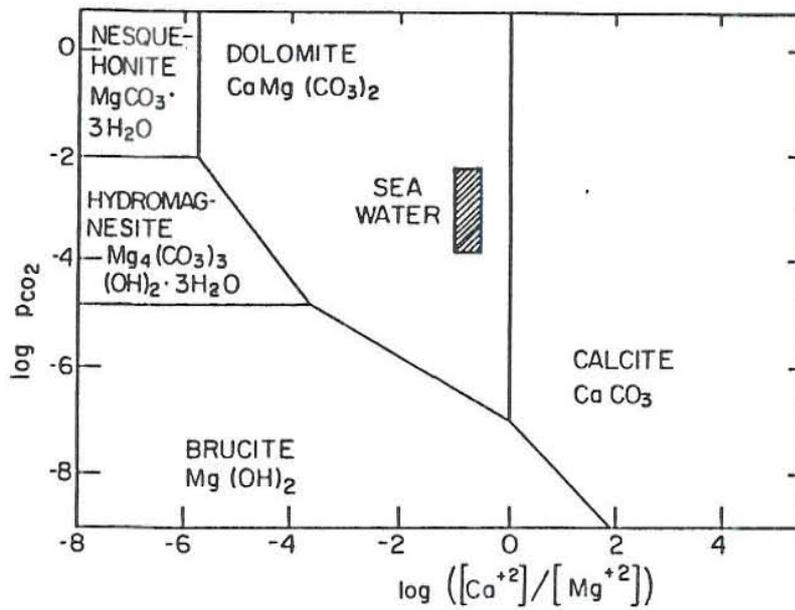
Figure 4.2 Stability Relations in Ca^{2+}-Mg^{2+}-CO_2-H_2O System
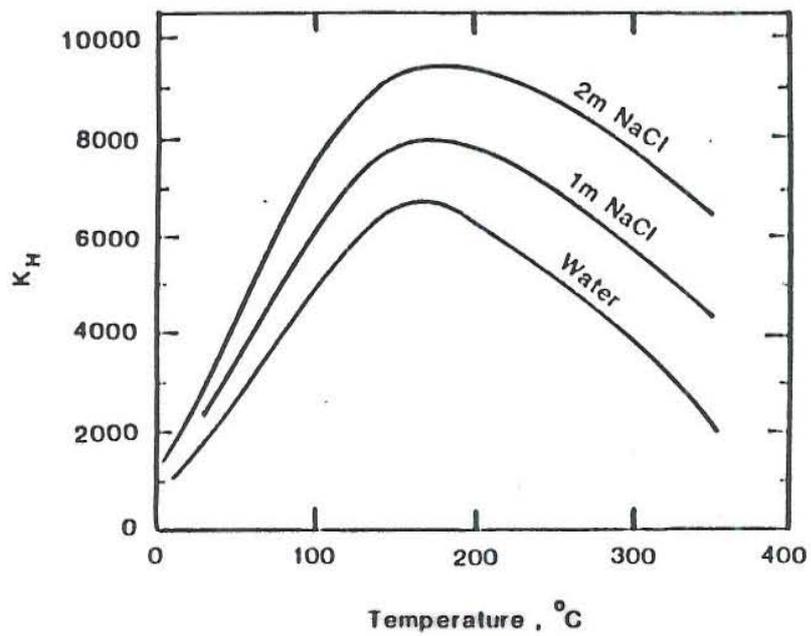
Figure 4.3 Effect of Salt Concentration on Henry's Law Constant
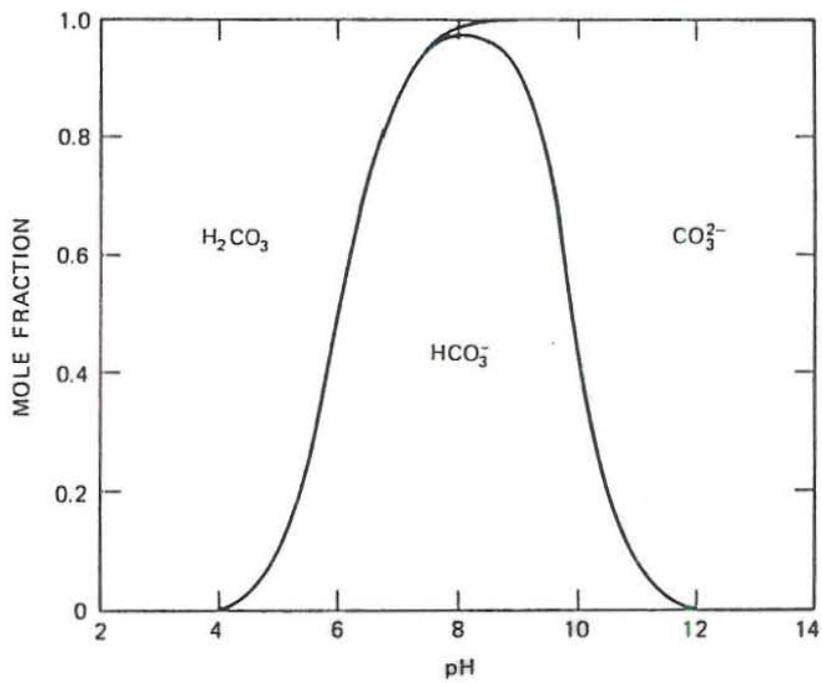
Figure 4.4 Fraction of Carbonate, Bicarbonate, Carbonic Acid and CO_2 Present as a Function of pH at 100°C
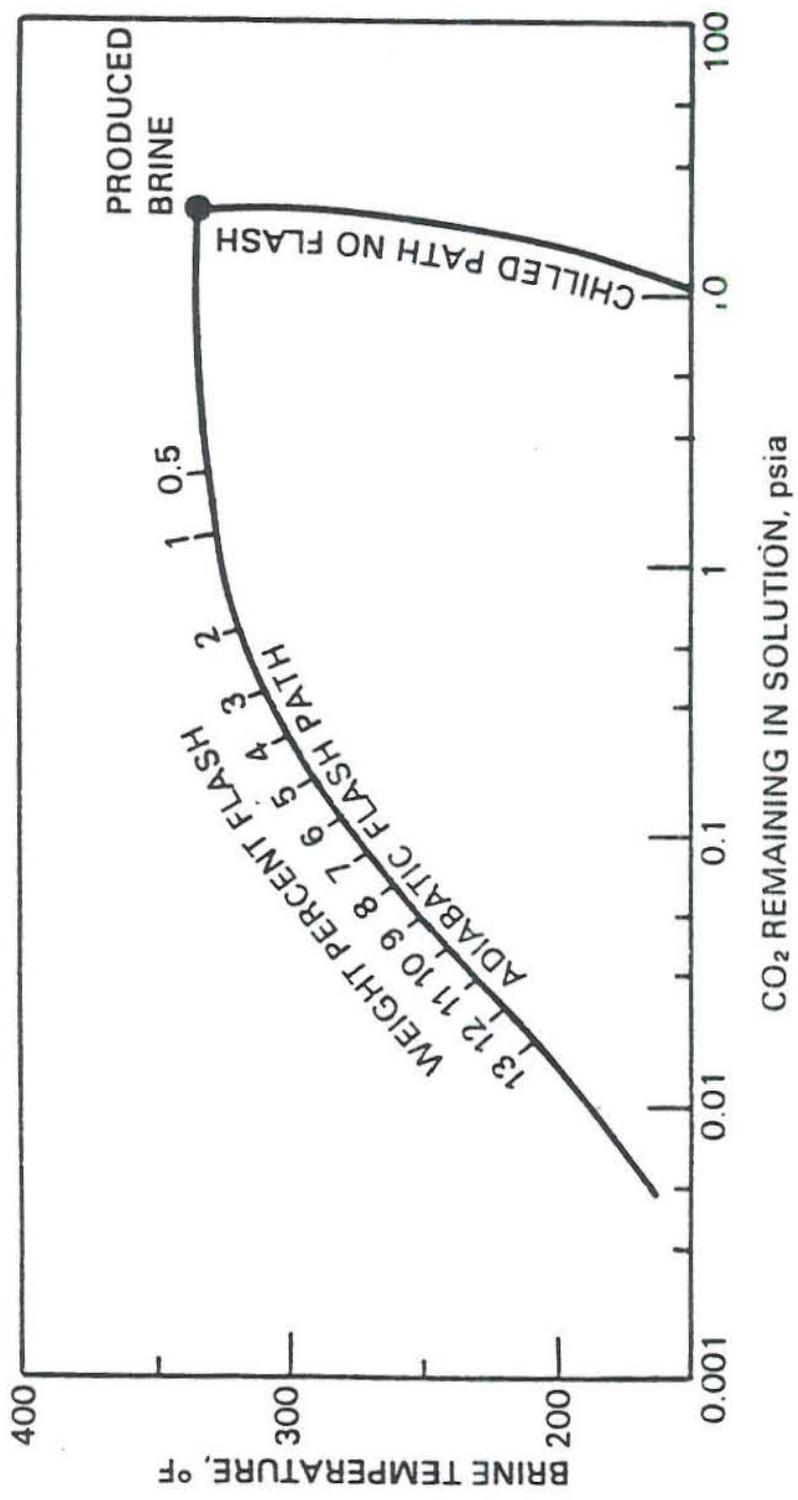
Figure 4.5 Loss of Carbon Dioxide as Flash Progresses

123
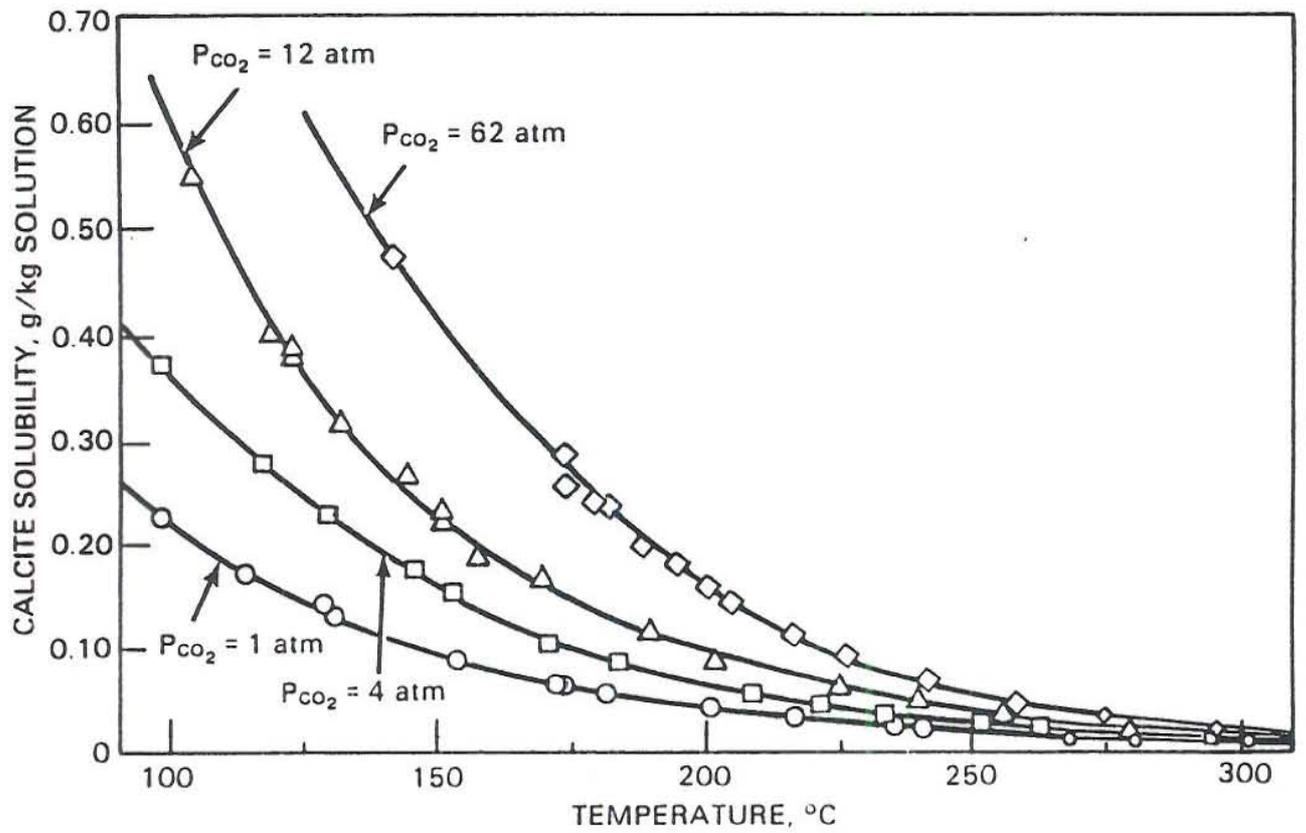
Figure 4.6   Solubility of Calcite in Water up to 300°C at
Various Partial Pressures of Carbon Dioxide

124
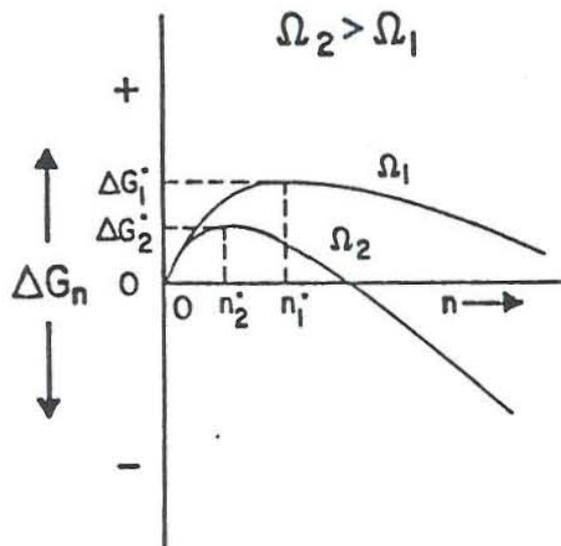
Figure 4.7 Plot of Free Energy of Precipitation vs Crystal Size Illustrating Nucleation and Growth

(a) Transport control
(b) Surface reaction control
(c) Mixed transport and surface reaction control
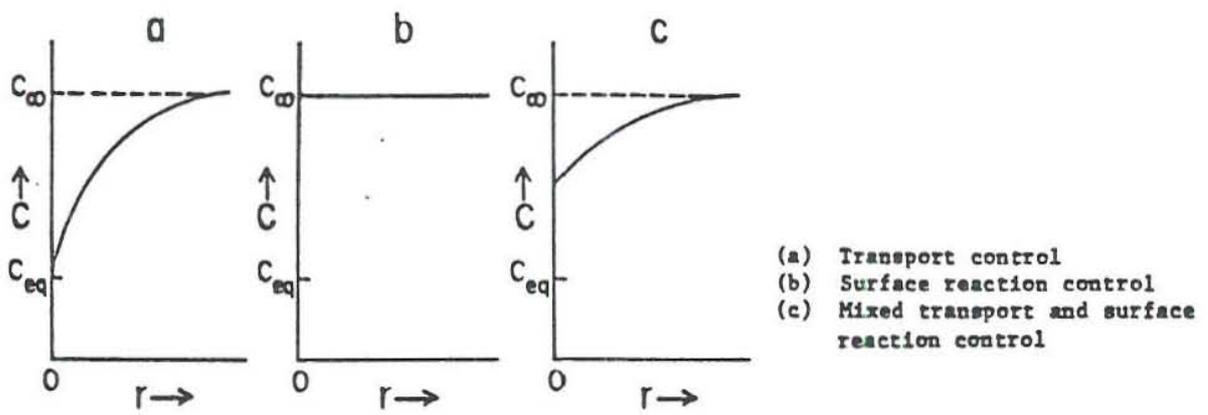
Figure 4.8 Schematic Representation of Concentration in Solution as a Function of Radial Distance

126
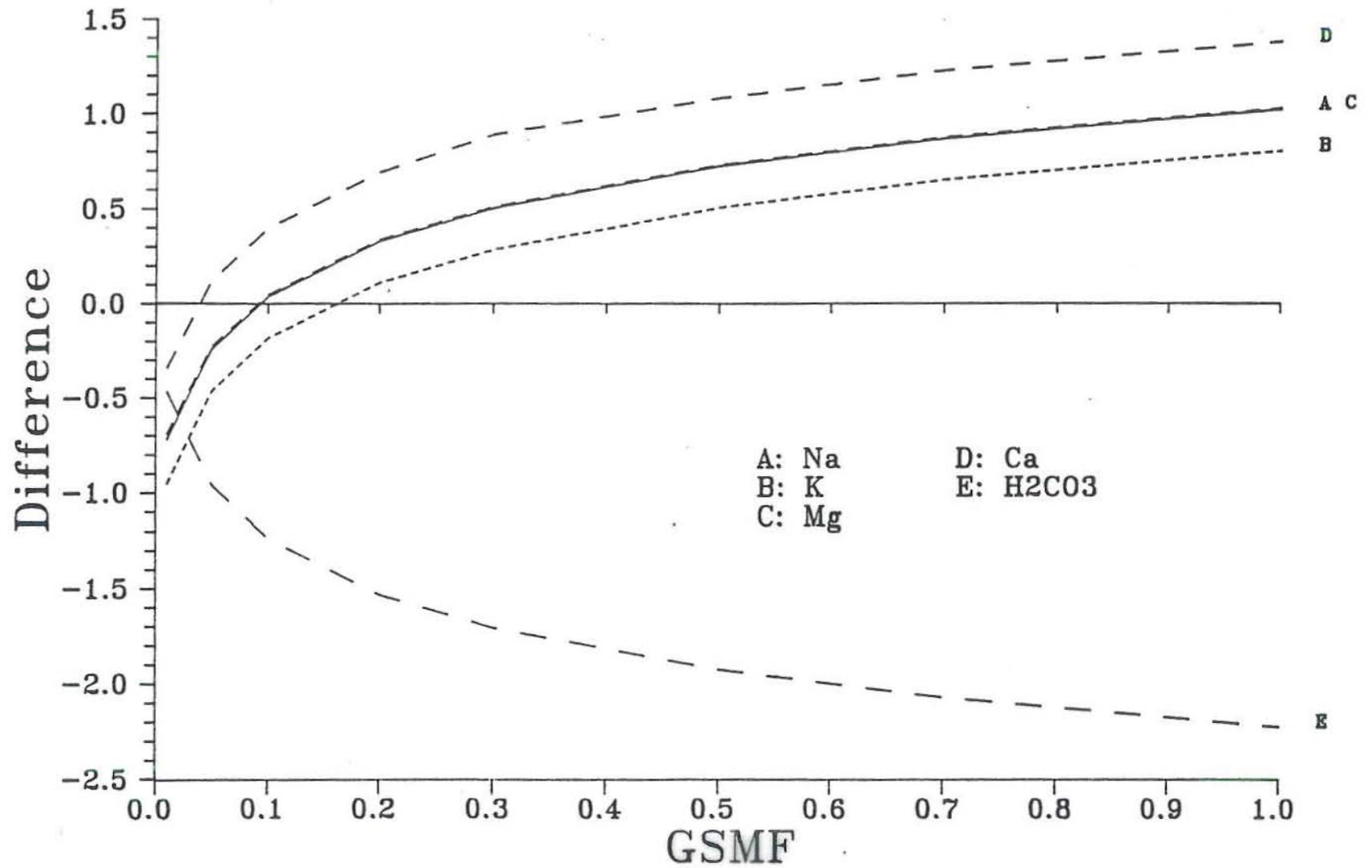
Figure 5.1 Difference Between Function and Output Values
vs Gas Solubility Mutilplication Factor
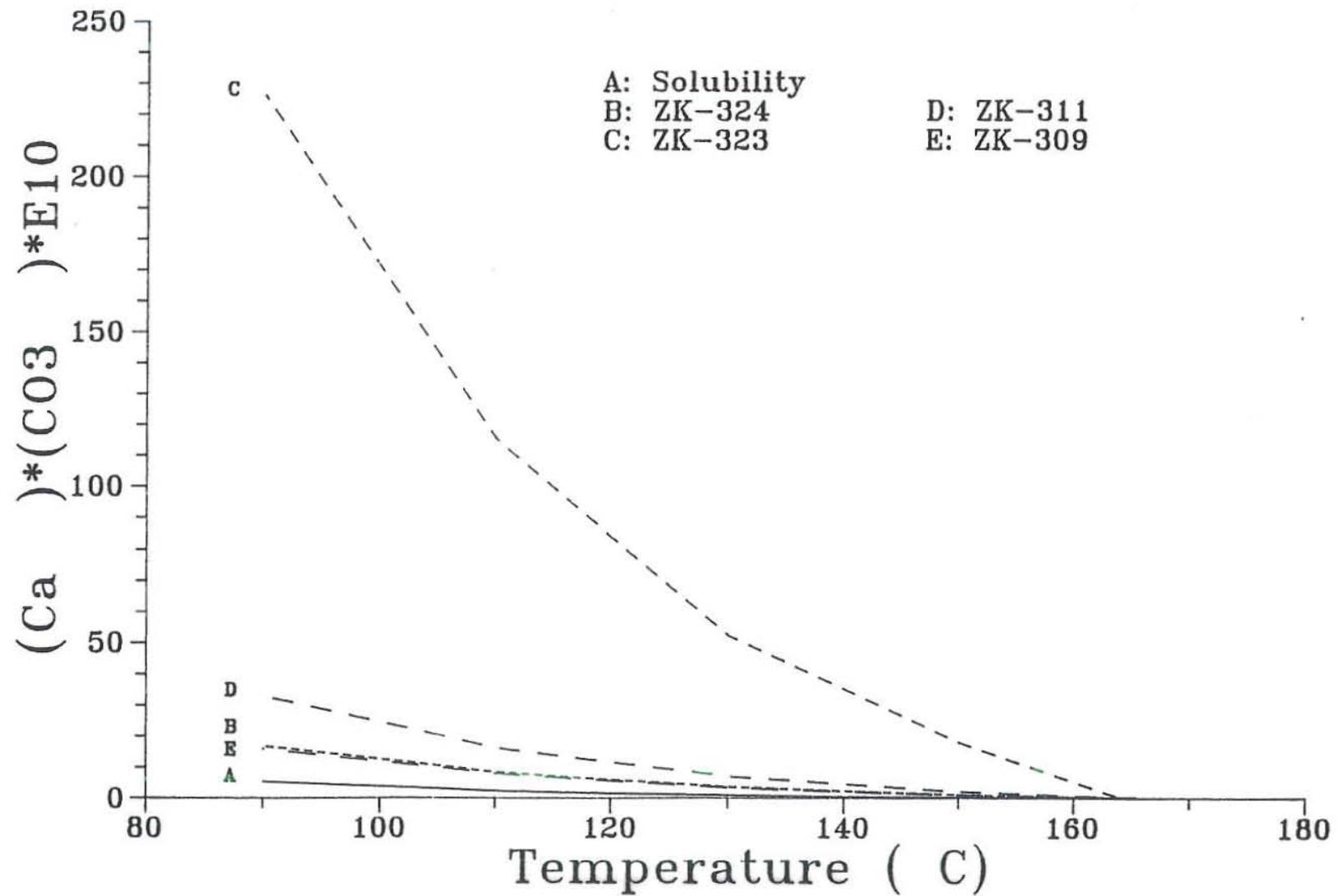
Figure 5.2 Calcite Activity Product for Samples from
Yangbajing Geothermal Field
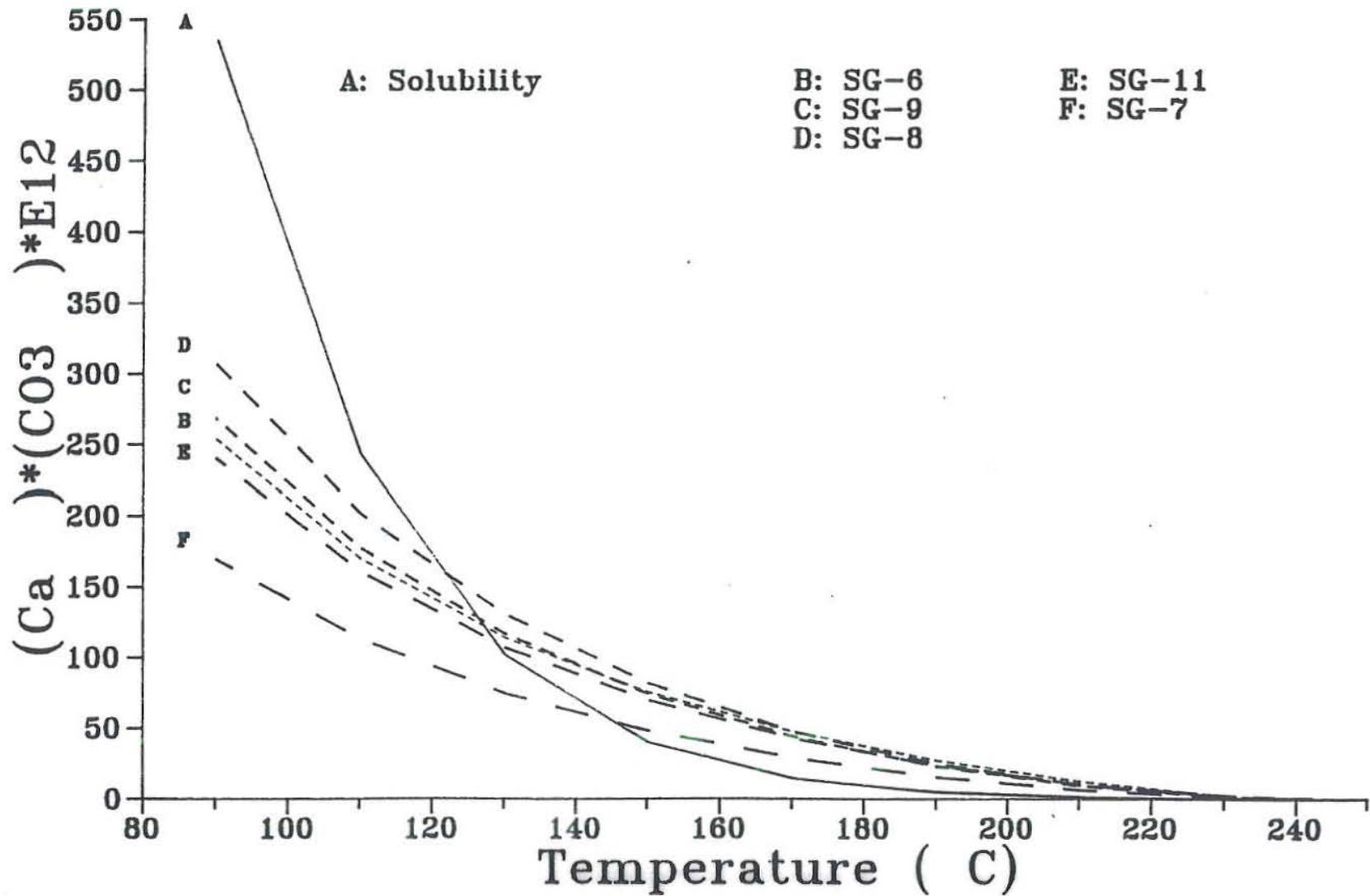
Figure 5.3   Calcite Activity Product for Samples from
Svartsengi Geothermal Field
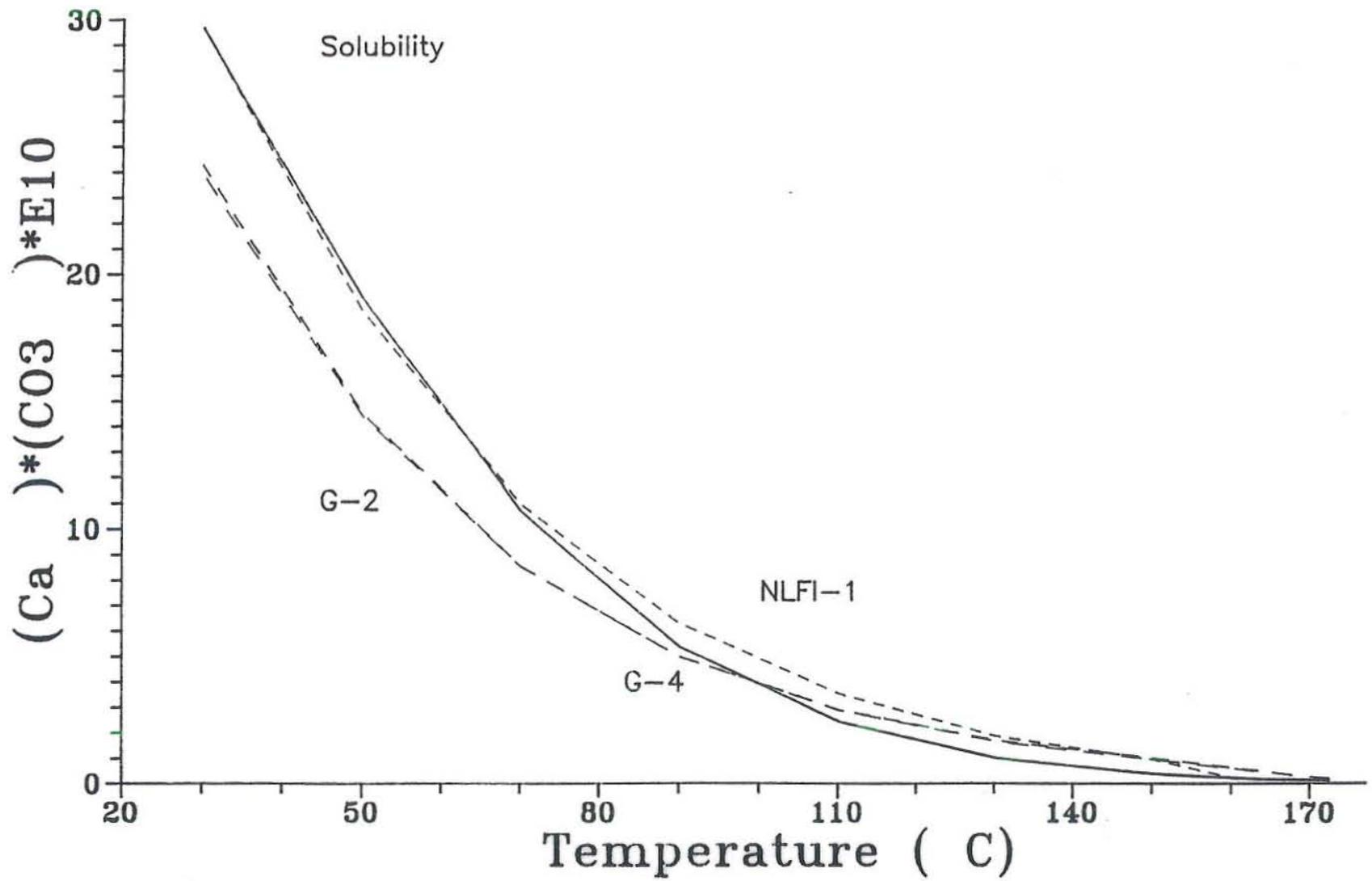
Figure 5.4 Calcite Activity Product for Samples from
Hverageröi Geothermal Field
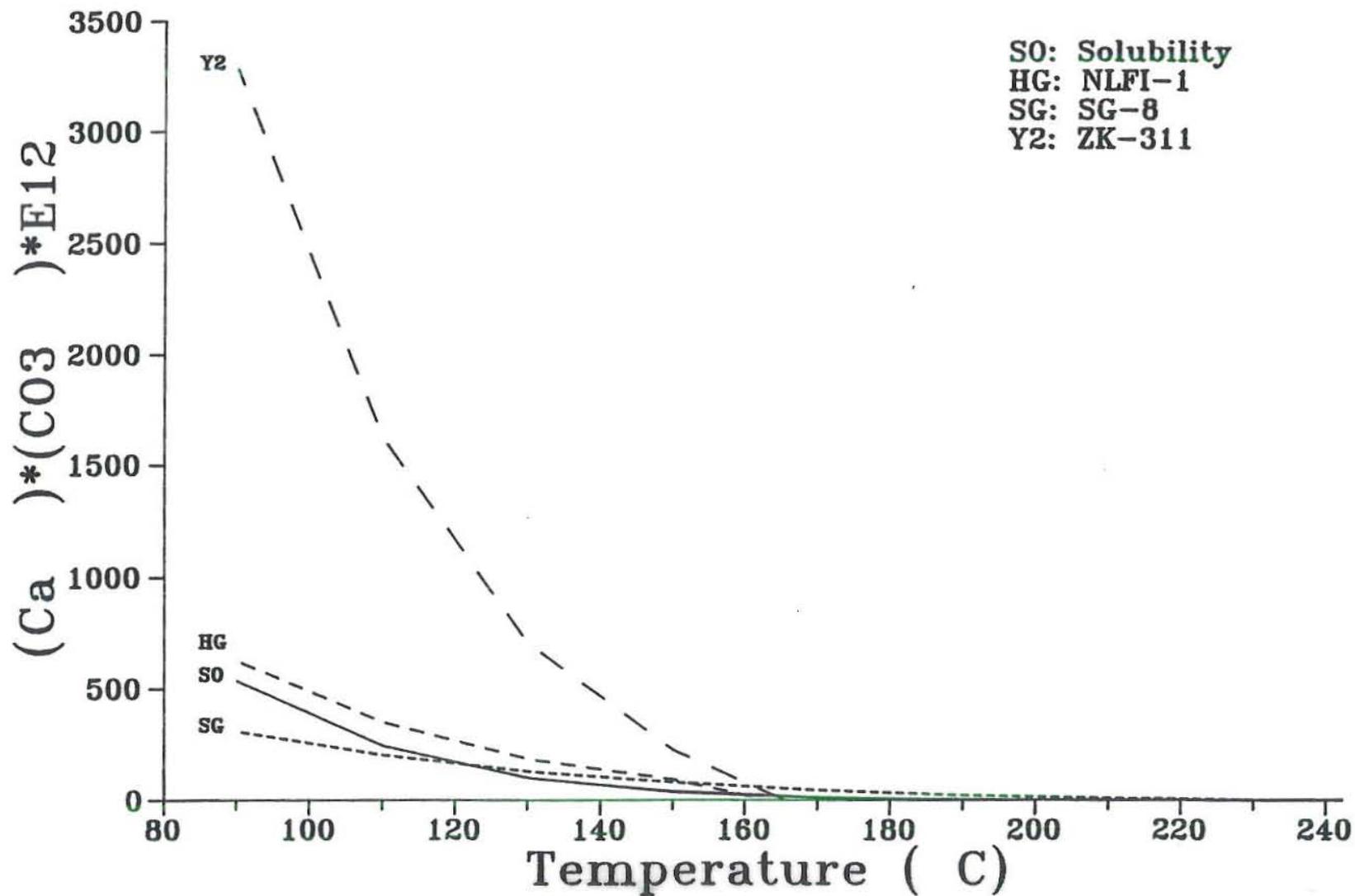
Figure 5.5   Comparison of Calcite Activity Product for
Samples from Yangbajing, Svartsengi and Hveragerði Geothermal
Fields
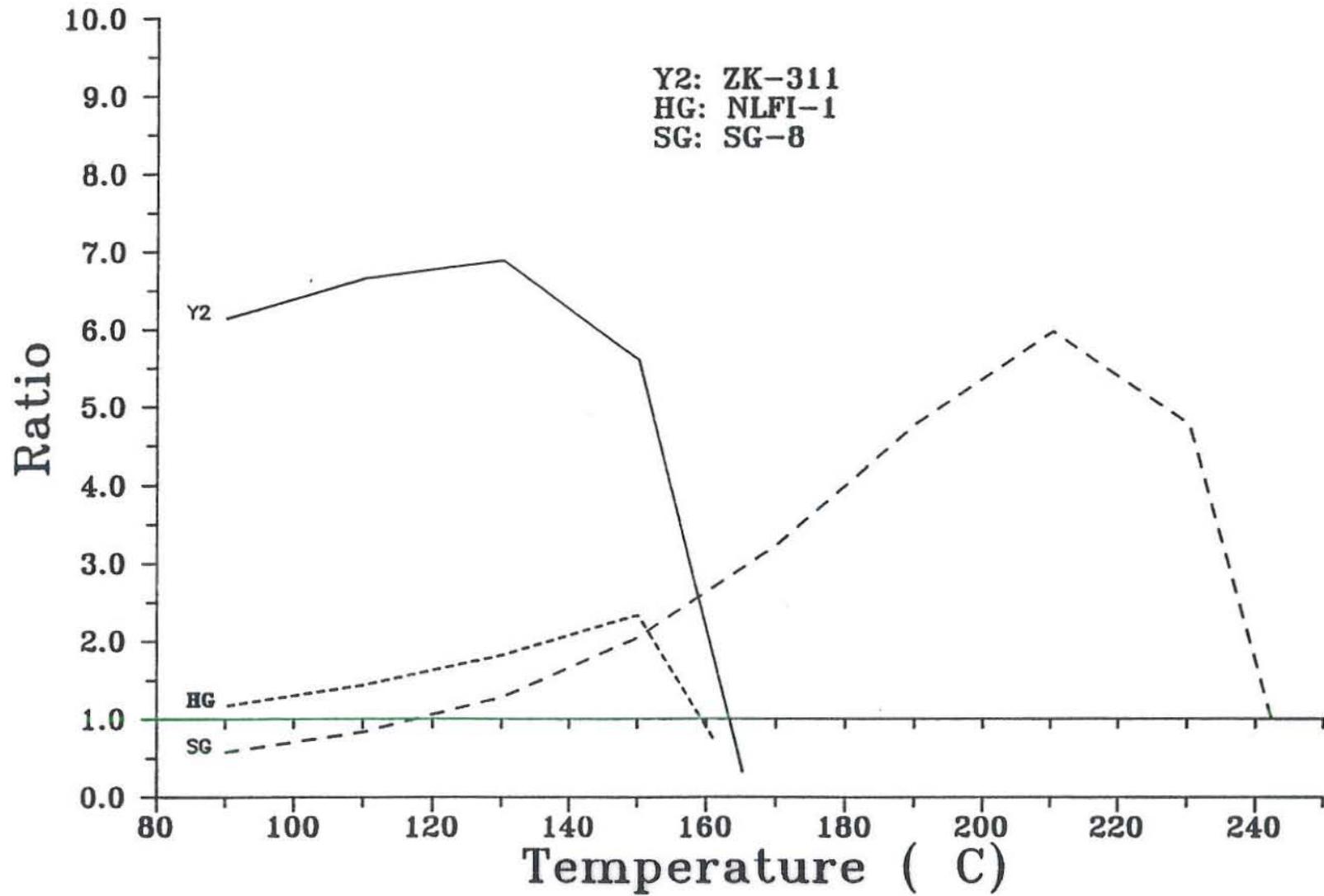
Figure 5.6   Ratio of Calcite Activity and Solubility
Products for Samples from Yangbajing, Svartsengi and
Hveragerði Geothermal Fields
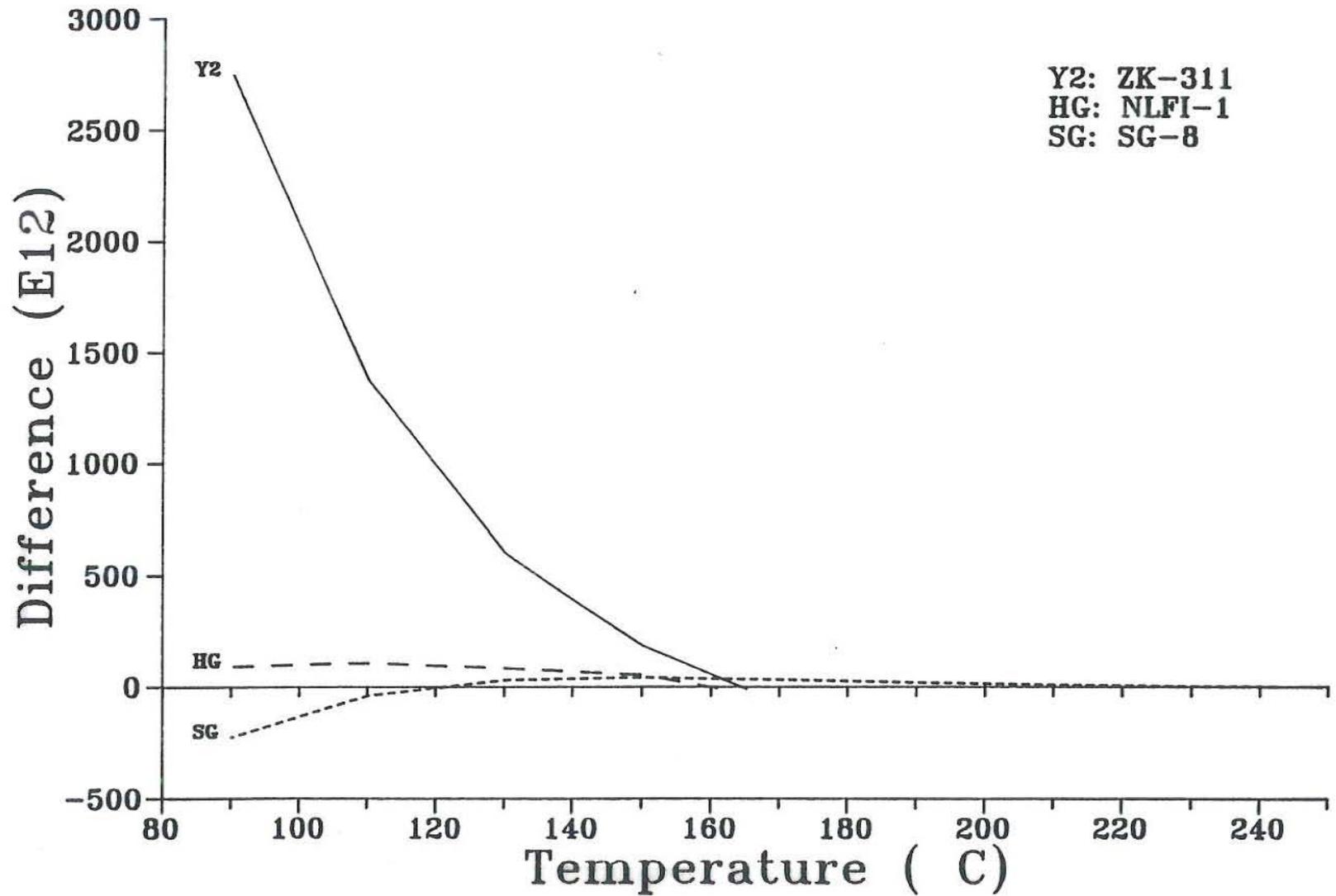
Figure 5.7 Difference of Calcite Solubility and Activity
Products for Samples from Yangbajing, Svartsengi and
Hveragerði Geothermal Fields
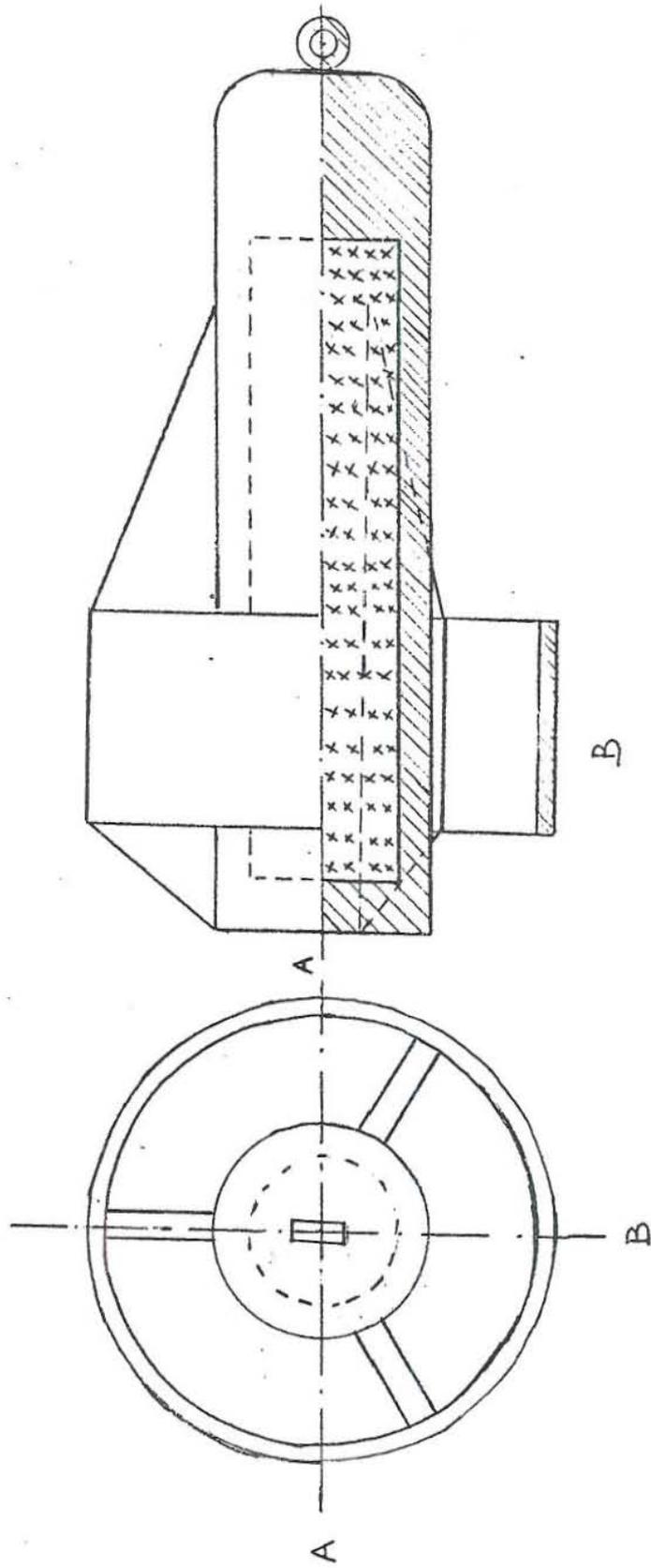
Figure 6.1 Mechanical Cleaning Equipment in Yangbajing

134

COOLINGWATER INLET

COOLINGWATER OUTLET

COOLINGWATER INLET

COOLINGWATER OUTLET

(1) EXTERNAL FLUSH DRILLPIPE

(2) HYDRAULIE JACKS

(3) STUFFING BOX

(4) TWO ORIFICE PLATES

(5) BLOWOUT PREVENTER

(6) TWO ORIFICE PLATES

(7) FLOW OLIVERTER

(8) MASTERVALVE
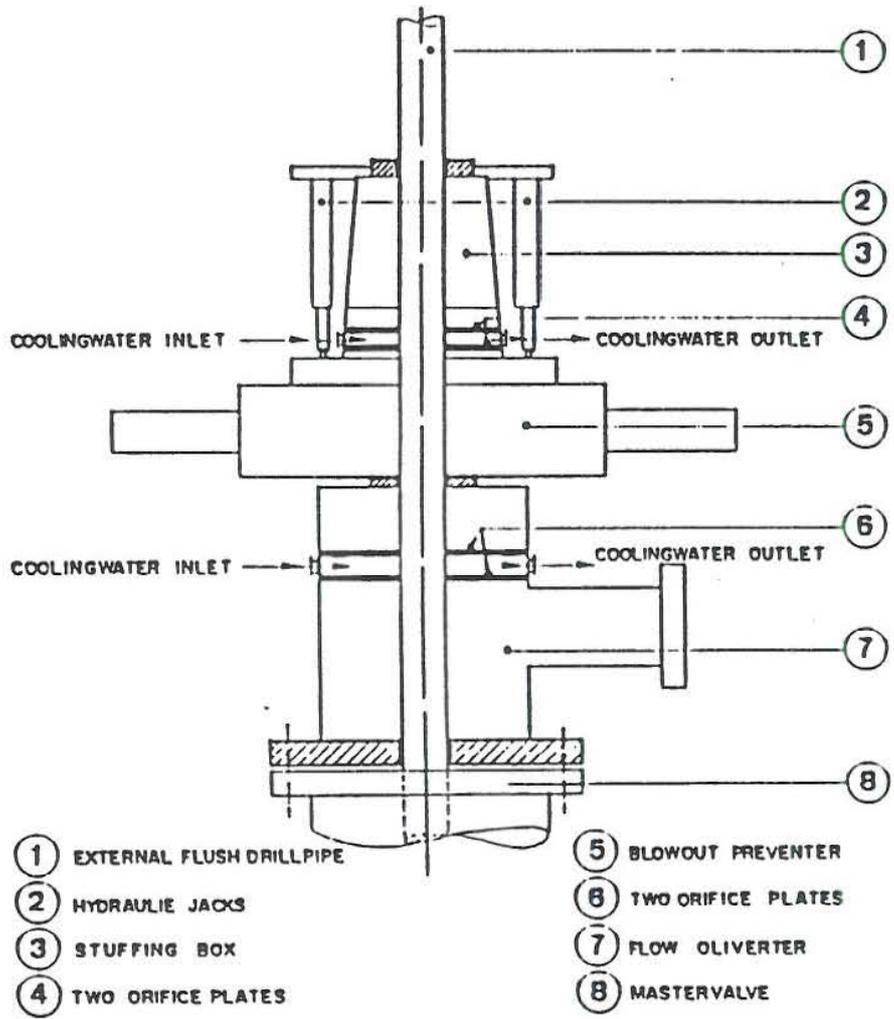
Figure 6.2   Reaming of Scale in Svartsengi

135
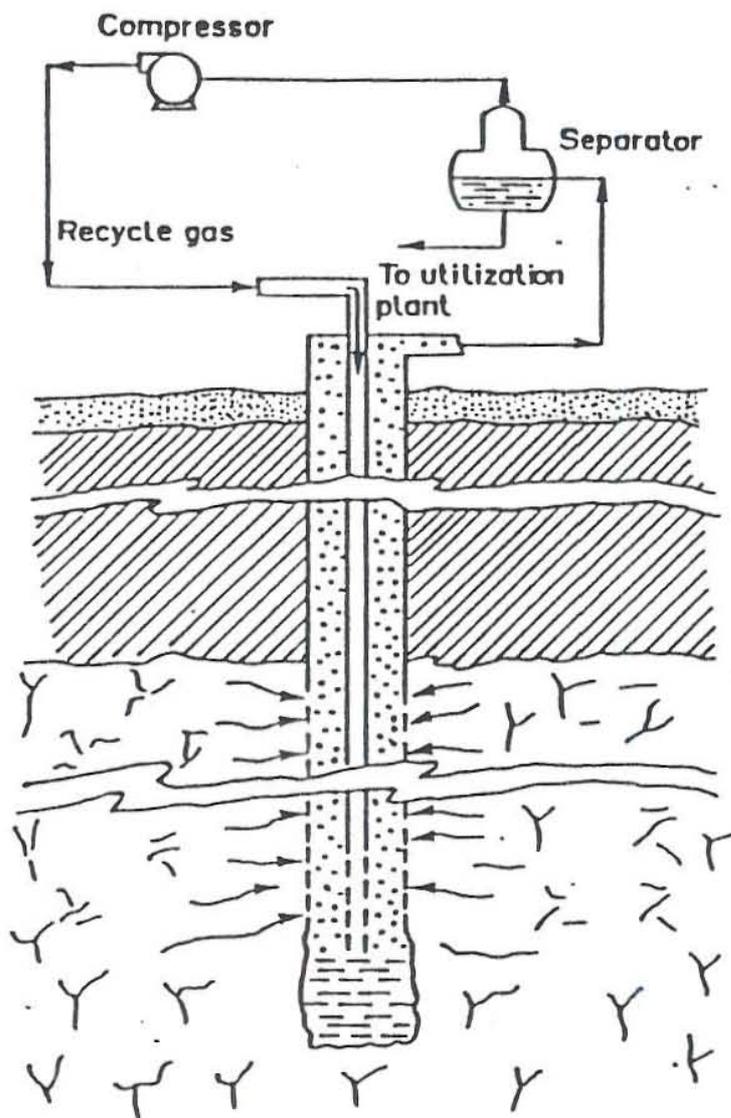
Figure 6.3   Sketch of a Plant for P_{CO_2} Control

WELLBORE NARROWING
(FILTER CAKE)
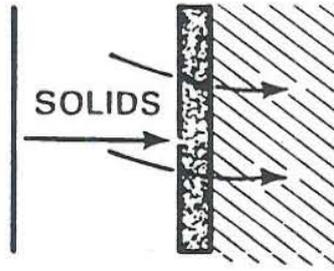
SOLIDS

SOLIDS

INVASION
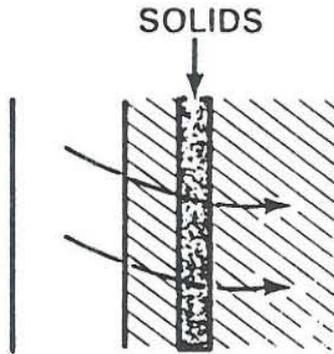
WELLBORE FILLING
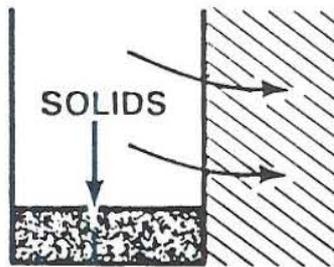
SOLIDS

PERFORATION PLUGGING
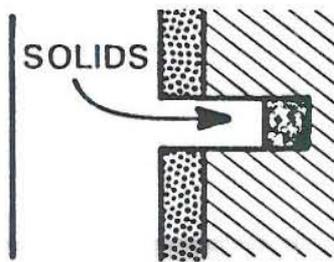
SOLIDS

Figure 7.1 Types of Wellbore Impairment Caused by Suspended Solids

137
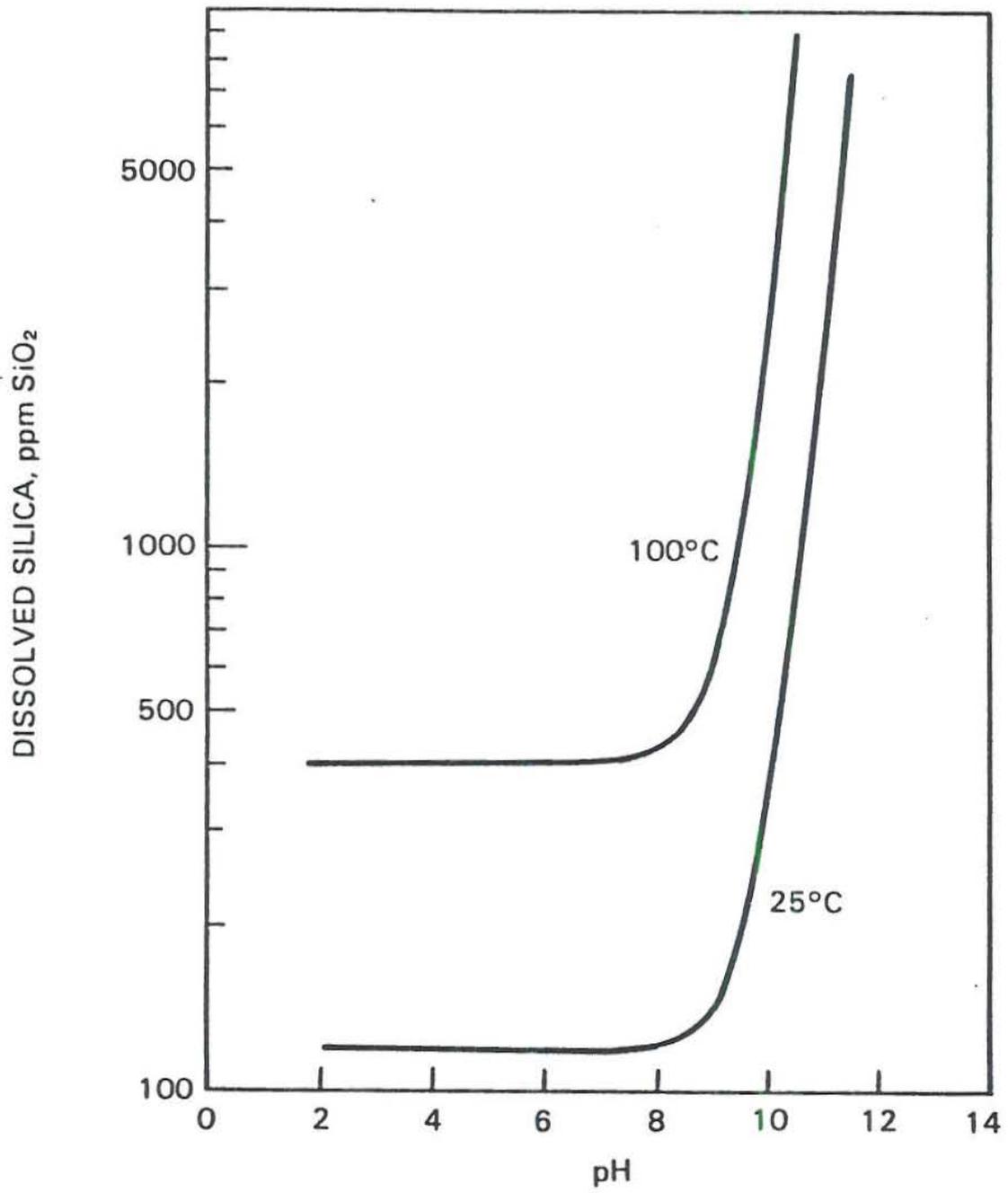
Figure 7.2   Silica Solubility as a Function of pH
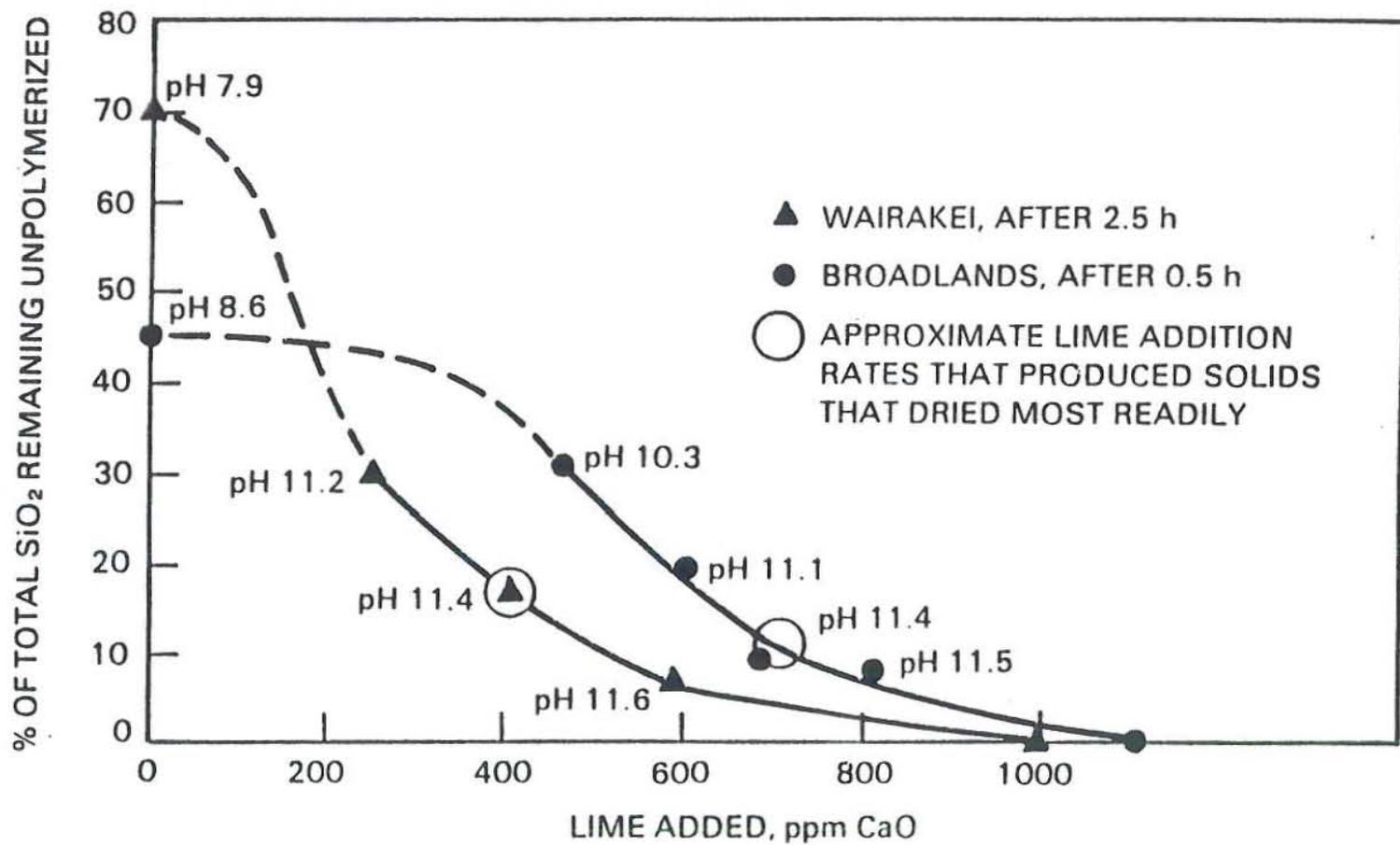
Figure 7.3 Effect of Lime Treatment on Silica
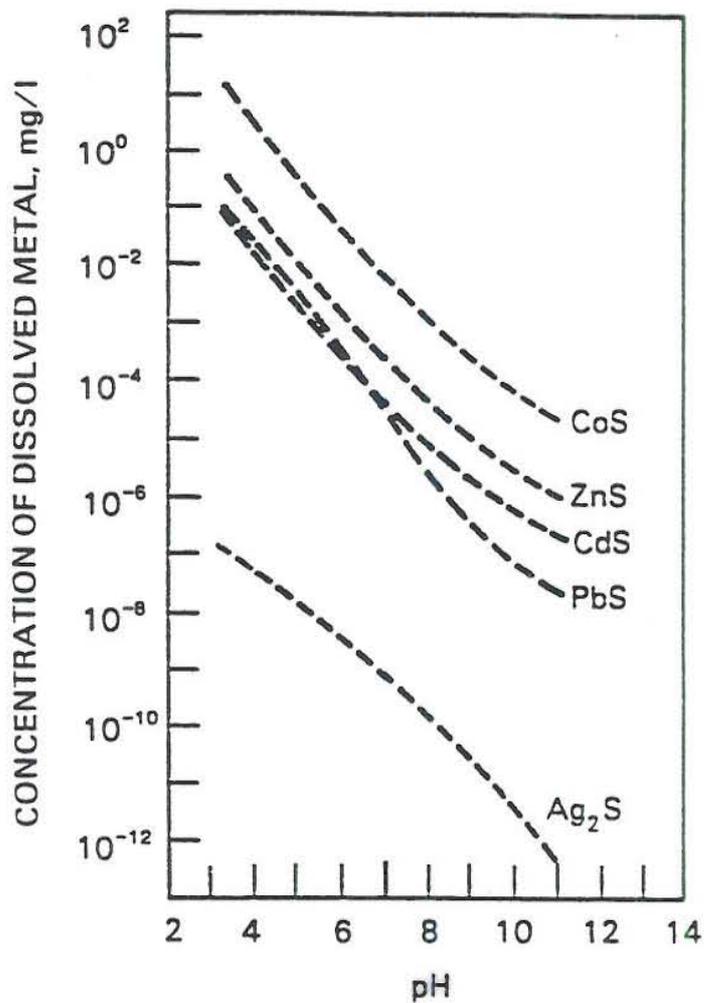
Figure 7.4 Metal Sulfides Solubility in Water as a Function of pH
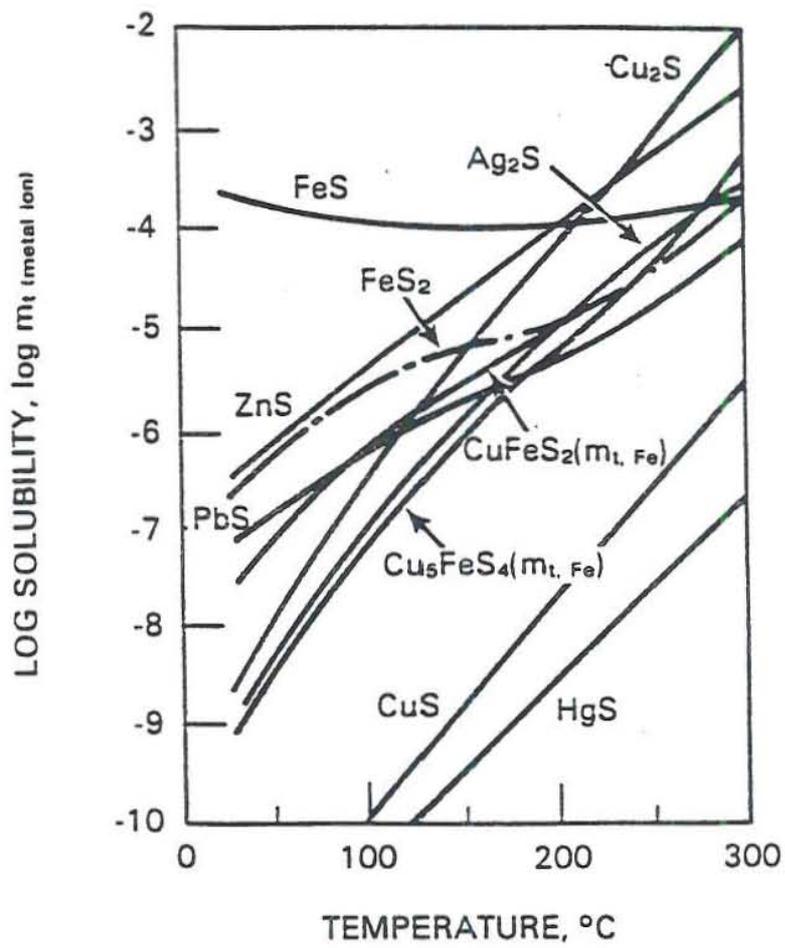
Figure 7.5 Solubility of Sulfides in Solution as a Function of Temperature
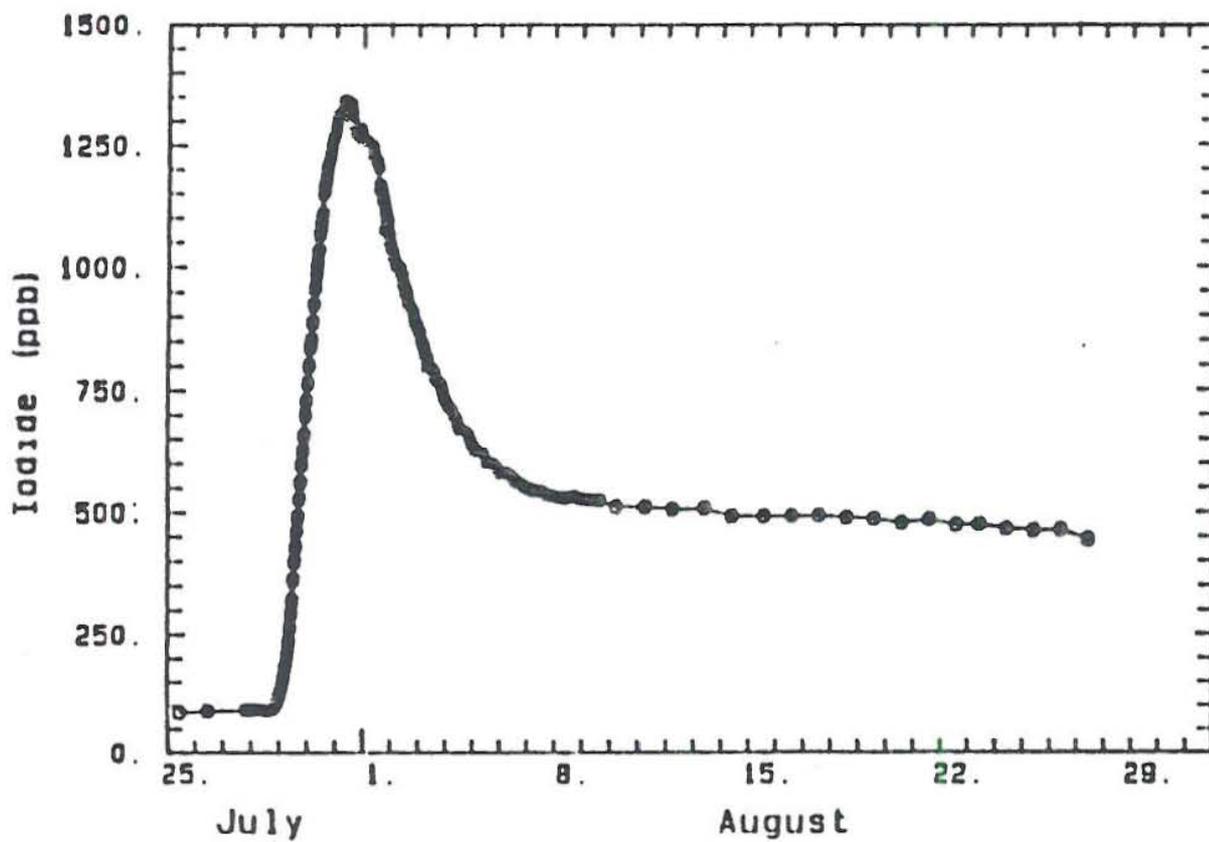
Figure 7.6   Iodide Breakthrough Curve in Well 6, Svartsengi