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HÆÐARENDI

The calculation of calcium carbonate saturation in geothermal fluids, and the application of a downhole heat exchanger to prevent scaling

Jón Örn Bjarnason

Prepared for ÍSAGA

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Abstract:

The geothermal well at Hæðarendi in the Grímsnes district of southern Iceland produces a fluid rich in carbon dioxide. This fluid has served as a commercial source of liquid carbon dioxide since 1988. The geothermal fluid produces, upon flashing, a large amount of calcium carbonate scale, which will clog surface equipment and even the wellbore itself. This scaling can be prevented, however, by the proper control of fluid temperature and pressure. To this end, cold water is circulated through a 250 m long coaxial double cylinder that has been lowered into the well and serves as a heat exchanger. It prevents scaling by cooling the well fluid and thus reducing the calcium carbonate saturation. This report outlines the method used to determine those conditions of temperature and pressure under which the well should remain free of scale. The chemical composition of the fluid is described, and the calculation of the calcium carbonate saturation index is briefly discussed. This index as a function of temperature and pressure is presented in a diagram for Hæðarendi fluids, and examples of its application to specific cases are given.

The plant is owned and operated by ÍSAGA.

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ABSTRACT

The geothermal well at Hæðarendi in the Grímsnes district of southern Iceland produces a fluid rich in carbon dioxide. This fluid has served as a commercial source of liquid CO_2 since 1988. A plant on the site originally produced about 40 kg of CO_2 per hour, but at the end of 1997 its output was increased to 250 kg per hour, which is sufficient to meet current industrial demand for CO_2 in Iceland. The gas is fairly pure and requires little processing besides the removal of trace amounts of hydrogen sulfide.

The geothermal fluid produces, upon flashing, a large amount of calcium carbonate scale, which will clog surface equipment and even the wellbore itself. This scaling can be prevented, however, by the proper control of fluid temperature and pressure. To this end, cold water is circulated through a 250 m long coaxial double cylinder that has been lowered into the well and serves as a heat exchanger. It prevents scaling by cooling the well fluid and thus reducing the calcium carbonate saturation.

This report outlines the method used to determine those conditions of temperature and pressure under which the well should remain free of scale. The chemical composition of the fluid is described, and the calculation of the calcium carbonate saturation index is briefly discussed. This index as a function of temperature and pressure is presented in a diagram for Hæðarendi fluids, and examples of its application to specific cases are given.

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1 INTRODUCTION

Carbon dioxide has been produced commercially at Hæðarendi in the Grímsnes district of southern Iceland since 1988. The source of the CO_2 is a gas-rich fluid discharged from a geothermal well on the site. The temperature of the fluid, at the point of inflow to the well, has ranged from 153°C to 163°C. The gas is fairly pure and needs little processing before liquefaction, except for the removal of a trace of hydrogen sulfide. The plant at Hæðarendi produced at the outset about 40 kg per hour of CO_2, but in January of 1995 production was increased to 70 kg per hour. In March of 1994, ÍSAGA aquired the plant and the well. The plant was rebuilt, and at the end of 1997 production was expanded to 250 kg per hour, which is sufficient to satisfy current demand for CO_2 in Iceland.

Orkustofnun, the National Energy Authority of Iceland, has from the very beginning served as a scientific and technical consultant on various aspects of the Hæðarendi development. In particular, Orkustofnun carried out virtually all the early exploratory work, including the geological studies, geophysical surveys, and geochemical analyses that led to the siting and drilling of the geothermal well. After the well had been completed, Orkustofnun carried out production tests (Jakobsson et al. 1983). In the process, the rather unusual properties of the fluid were discovered, and Orkustofnun pointed out that the well might serve as a commercial source of CO_2. Over the following decade Orkustofnun continued to provide advice to the previous owners on fluid chemistry and utilization, in particular on the design of the wellhead separation and cooling equipment necessary to prevent calcium carbonate scaling. Since the Hæðarendi operation changed hands in 1994, Orkustofnun has continued as a consultant to the new owners. After they expressed intentions to expand production, Orkustofnun suggested and designed a downhole heat exchanger to suppress scaling in the well.

Calcium carbonate scale has always been a major operational consideration at Hæðarendi. A large volume of such scale is formed if the pressure on the well fluid is reduced so that the fluid flashes and releases gas. This scaling can, however, be prevented if the fluid temperature and pressure are properly controlled. To this end, one must first determine those conditions of temperature and pressure that will keep the calcium and the carbonate in solution. An analysis of this problem, and an approach to its solution, will be the subject of the present report.

The following section provides some background information on the Hæðarendi operation. Section 3 describes the chemical composition of the fluids. The general criteria for evaluating scaling tendency are outlined in Section 4, and Section 5 describes the saturation diagram, which is the basic "road map" for choosing temperature-pressure paths for the fluid so as to avoid scaling. Three specific cases are presented in Section 6, and Section 7 gives some conclusions.

2 THE WELL, THE GAS, AND SCALE

Ever since it was drilled in 1983, well HE-02 at Hæðarendi in Grímsnes has been considered something of a curiosity among geothermal wells in Iceland. There are three reasons for this.

First, its temperature. Geothermal systems in Iceland can, in general, be rather neatly divided into two distinct categories, low-temperature systems and high-temperature systems. The reservoir temperature of the former is usually not much higher than 130°C or so. The fluids in these systems are almost always alkaline, and they generally contain little dissolved gas. Nitrogen normally constitutes the bulk of any gas present. The fluids of the high-temperature systems, on the other hand, are generally acidic. They contain significant amounts of dissolved gases, sometimes large amounts, mostly carbon dioxide. Their reservoir temperature is always above 180°C. Very little geothermal activity in Iceland is found at temperatures between 140°C and 180°C. At roughly 160°C, the fluid in the well at Hæðarendi thus falls into an intermediate range and does not fit into either of the two standard categories.

The source of the fluid is thought to be a dying high-temperature geothermal system.

Secondly, the concentration of gas in Hæðarendi fluids is very high, nearly 1.4% by mass. Although there are, to be sure, numerous wells with higher gas concentrations found in high-temperature areas in Iceland, those tend to be high-enthalpy wells that discharge primarily steam rather than liquid water. Bubbling carbonate springs occur in various parts of Iceland, most commonly in the Snæfellsnes peninsula, but these are cold. Thus, the high gas concentration is unusual for a well with liquid-saturated (water) inflow, and for a well in this temperature range.

Thirdly, the gas discharged by HE-02 is nearly pure carbon dioxide. Geothermal gas from high-temperature systems in Iceland generally contains fairly high concentrations of hydrogen sulfide, and sometimes hydrogen, along with some nitrogen, methane, and argon. At Hæðarendi, however, the hydrogen sulfide concentration in the gas is only about 300 ppm, i.e. 0.03 per cent by volume. No hydrogen has been detected there. The nitrogen concentration is close to 0.5 per cent, and the methane concentration around 600 ppm. The balance, a little more than 99.4% by volume, is carbon dioxide.

Upon flashing, the fluid from the Hæðarendi well produces large amounts of calcium carbonate scale. This scale will quickly render surface equipment inoperable, and may even clog the well itself should the fluid flash in the bore or in the formation just outside the well. If the fluid is to be put to practical use, this scaling must be controlled, either by keeping the pressure high enough to prevent flashing or by some other means.

At the outset, the fluid from the well was only used for heating the farmhouse at Hæðarendi. The amount of fluid required for this purpose was small, so production from the well was quite limited. Scaling in the wellbore could thus be prevented by maintaining the wellhead pressure sufficiently high to keep the fluid from flashing. The fluid was fed, under pressure, through a heat exchanger, and the heated freshwater was piped to the farmhouse. Since the calcium carbonate solubility rises as the temperature falls, the cooled well fluid could readily be disposed of.

The purity and abundance of the gas, however, suggested that the well might serve as a commercial source of carbon dioxide. To this end, a liquid carbon dioxide plant was constructed on the site. It went on stream in 1988.

The success of the plant over a decade of operation prompted its expansion. Increasing the production of fluid, however, entailed lowering the pressure at depth in the well. In the absence of appropriate countermeasures, this would have lead to scaling in the wellbore.

Scaling in the well was avoided by installing a downhole heat exchanger. Thus, a stainless-steel cylinder made of two coaxial pipes, the inner one open at the bottom end and the outer one closed, was lowered into the well. Cold water was pumped down through the inner pipe and back up on the outside. The fluid in the well was thus cooled, in a concurrent fashion, by the water in the cylinder. Cooling the fluid raises the solubility of calcium carbonate and prevents scale formation. The original heat exchanger, introduced in January of 1995, was about 40 m in length.

This installation permitted an increase in production from from 40 to 70 kg per hour. At the end of 1997, the heat exchanger was extended to 101 m as production was expanded to 250 kg per hour and the flow from the well increased from 2,5 l/s to around 6 l/s. In April of 1998 the cylinder was further extended to 118 m, after scale was detected at depths ranging from 86 to 97 m. In November of 1998 a new heat exchanger was installed, after scaling problems were encountered between 88 and 134 m depth. This new cylinder reaches a depth of 250 m.

3 THE CHEMICAL COMPOSITION OF THE FLUIDS

Samples of geothermal fluids from the Hæðarendi well were collected on April 11, 1995 for chemical analysis. A liquid sample was drawn from the lower part of a tank used to separate the gas from the liquid, and a gas sample was collected from the top of the tank. The temperature of the fluid in the tank was 70°C at the time of sampling, and the separation pressure was only very slightly above atmospheric.

The chemical composition of the liquid phase is shown in Table 1. For comparison, the composition of the most recent previous liquid sample, collected in 1983, has been included. In this table, CO_2 denotes total carbonate, calculated as carbon dioxide, and H_2S denotes total sulfide, calculated as hydrogen sulfide. The total concentration of dissolved solids was determined by evaporating an aliquot of the liquid to dryness at 110°C.

Table 1. Chemical composition of geothermal water from well HE-02.
Concentrations in mg/kg.

Sample no. Date	1983-0196 August 3, 1983	1995-0053 April 11, 1995
pH/°C	6.18 / 22.5	6.71 / 24.7
Silica (SiO_2)	209.2	210.7
Carbonate (CO_2)	1760	1226
Sulfide (H_2S)	1.58	0.54
Sodium (Na)	640	629
Potassium (K)	36.4	35.9
Magnesium (Mg)	3.92	4.05
Calcium (Ca)	32.8	39.5
Fluoride (F)	1.50	1.59
Chloride (Cl)	290.8	273.4
Sulfate (SO_4)	142.7	131.1
Total dissolved solids (TDS)	1914	1816
Conductivity/°C (µS/cm)	2630 / 20.4	2260 / 25.0

These two samples are very similar in composition, though there are some differences, albeit rather insignificant. The more recent sample, in particular, seems slightly more dilute than the old one, as evidenced by the concentrations of chloride, sulfate, calcium, and total dissolved solids. The reason for this may simply be that the two samples were not collected under identical conditions of well flow and wellhead pressure. As a result, the samples may contain contributions from more than one aquifer in different proportions. Significantly, the silica concentration is unchanged, however, suggesting that the mean aquifer temperature has remained stable.

The concentrations in the liquid phase of the volatile components, CO_2 and H_2S, are much lower in the sample from 1995 than previously. The lower concentrations of these components are also reflected in a higher pH. The reason is simply that the separation temperature was less than 20°C when the sample of 1983 was collected, but 70°C when the sample of 1995 was drawn. The decreased solubility of gases with rising temperature accounts for the concentration difference. The bulk of these components, in any case, is in the gas phase at atmospheric pressure.

Table 2 displays the composition of gas phase samples, in 1995 and in 1986.

Table 2. Chemical composition of geothermal gas from well HE-02. Concentrations in volume per cent.

Sample no. Date	1986-0207 October 29, 1986	1995-0053 April 11, 1995
Carbon dioxide (CO_2)	99.33	98.84
Hydrogen sulfide (H_2S)	0.02	0.03
Hydrogen (H_2)	0.00	0.00
Oxygen and Argon ($O_2 + Ar$)	0.02	0.13
Methane (CH_4)	0.05	0.06
Nitrogen (N_2)	0.58	0.94

The oxygen in both samples is almost certainly due to atmospheric contamination during sampling. If we subtract its concentration from the sample, along with an amount of nitrogen that corresponds to the atmospheric ratio of these gases, and renormalize the remaining concentrations to 100 per cent, we obtain the composition of the pure, uncontaminated gas. These concentrations are shown in Table 3.

Table 3. Renormalized composition of geothermal gas from well HE-02. Concentrations in volume per cent.

Sample no. Date	1986-0207 October 29, 1986	1995-0053 April 11, 1995
Carbon dioxide (CO_2)	99.42	99.43
Hydrogen sulfide (H_2S)	0.02	0.03
Methane (CH_4)	0.05	0.06
Nitrogen (N_2)	0.51	0.48

It is clear that the gas composition has remained unchanged since 1986, at least.

The Hæðarendi well is currently the sole source of commercial CO_2 in Iceland. The gas has numerous applications, including some in the food industry. Accordingly, it must be free of hydrogen sulfide, and this contaminant must be completely removed. For this reason, the concentration of hydrogen sulfide in the well gas is a quantity of importance. In the table above, it is given as 0.02 and 0.03 volume per cent (200 and 300 ppm by volume) in 1986 and 1995, respectively. These concentrations were determined by gas chromatography. There is some uncertainty associated with these values, since the concentrations involved are rather low, and other methods of measurement indicate that the H_2S concentration may be slightly higher. It can be stated with reasonable certainty to be in the range of 250 - 400 ppm.

A sample of the final scrubbing fluid displayed a CO_2 concentration of 1180 mg/kg, and an H_2S concentration of 1.3 mg/kg.

4 THE CALCIUM CARBONATE SCALING POTENTIAL

Geothermal fluids rich in carbon dioxide will, upon flashing, generally precipitate calcium carbonate scale, either as calcite or aragonite. As already mentioned, the fluid from the Hæðarendi well is no exception. In fact, the flashing of this fluid, from, say, a wellhead pressure of approximately 9 bar-absolute and a temperature of 120°C to atmospheric pressure and 100°C, quickly produces a large volume of scale. Thus an important consideration in the design and operation of a successful carbon dioxide plant at Hæðarendi is to determine the conditions of fluid temperature and pressure under which calcium carbonate scaling may be avoided.

The primary measure of the tendency of a mineral to precipitate from a given solution is the so-called saturation index, defined by

$$SI = \log(Q/K)\,,$$

where Q is the ionic activity product and K is the solubility product constant. For calcium carbonate the ionic activity product is simply the product of the activities of the calcium and the carbonate ions:

$$Q = (Ca^{++})\cdot(CO_3^{=})\,,$$

whereas K is a function of temperature only. When $Q < K$, so that the saturation index is negative, the solution is undersaturated and no calcium carbonate will precipitate. When $Q > K$, and $SI > 0$, the solution is said to be supersaturated, and scale may form. If $Q = K$, so that $SI = 0$, the solution is exactly saturated, at equilibrium.

Calcium carbonate displays somewhat unusual behavior in that its solubility in water decreases with increasing temperature. Thus, if a geothermal fluid is saturated with respect to calcium carbonate at the reservoir temperature, as is generally the case, it will upon cooling become undersaturated and hence present no danger of scaling, provided the pressure is kept sufficiently high to prevent boiling and the escape of gas from the liquid. If carbon dioxide is released from solution, however, the pH will rise, as will the concentration of carbonate ion, $CO_3^{=}$. This may be expressed as follows:

$$2HCO_3^{-}(aq) = CO_2(g) + CO_3^{=}(aq) + H_2O(l)\,.$$

As a result, the ionic activity product will increase, and calcium carbonate may precipitate.

Gas concentrations in geothermal fluids are generally too low to contribute significantly to the total pressure under two-phase conditions. To a first approximation, the vapor phase of such fluids may be regarded as pure steam. In the language of the Gibbs phase rule, such a one-component, two-phase system possesses one degree of freedom, which means that temperature and pressure cannot be independently specified. In this approximation, the total pressure is simply the steam saturation pressure at the temperature in question, and thermodynamic properties may be regarded as functions of temperature only.

This approximation does not hold for the fluid from the Hæðarendi well, however. In the context of phase equilibrium, this fluid must be treated as a two-component system, since the concentration of carbon dioxide is much too high to neglect. Under two-phase conditions, this system possesses two degrees of freedom. For our purposes, these are most appropriately chosen as temperature and pressure.

In order to determine the conditions under which the precipitation of calcium carbonate may be avoided, it is necessary to compute its saturation index in the Hæðarendi fluid at various temperatures and pressures. This will be the subject of the following section.

5 THE SATURATION INDEX DIAGRAM FOR HÆÐARENDI FLUIDS

The calculation of the calcium carbonate saturation index as a function of temperature and pressure is most conveniently carried out on a computer by means of a geochemical speciation program with two-phase capability. A few such are available, and in this study a program called WATCH (Arnórsson et al. 1982; Bjarnason, 1994) was used to calculate the saturation index at almost 900 points. The chemical composition of sample 1995-0053, shown in Tables 1 and 3, and gas production data from the Hæðarendi operation form the basis for these calculations. The total concentration of CO_2 in the unflashed Hæðarendi fluids works out to 1.37% by weight.

The results of these calculations are presented in Figure 1. The saturation index is a function of both temperature and pressure and thus forms a surface over the T-P plane. This surface is represented here much as one would landscape on a geographic map, with color used to designate the degree of saturation. The values of the saturation index range from approximately -1.3, in the upper left hand corner of the figure, to about +2.4, in the bottom right hand part of the red zone. The dark green upper portion of the figure represents the single-phase liquid region, where no bubbles of steam or gas exist. In this region the saturation index is virtually independent of pressure. The lower boundary of this area represents the bubble point. The gray region at the very bottom of the figure lies ouside the scope of our interest; it represents thermodynamic states below the vapor pressure of water, where no liquid can exist.

Four contours, or lines of constant saturation index, have been included in the figure for clarity. The saturation line, SI=0, indicates where the fluid goes from undersaturated states, represented by green, to supersaturated ones, represented by yellow, orange, and red. Although calcium carbonate can precipitate whenever this line is crossed, experience from numerous geothermal areas shows that, in practice, there is little danger of significant scale formation until the saturation index reaches a value of about +0.3.

6 THE APPLICATION OF THE SATURATION INDEX DIAGRAM

A log of the Hæðarendi well in December of 1994 revealed a temperature of 141°C and a pressure of 16.2 bar-absolute at a depth of 100 m. This was roughly the depth reached by the cooling cylinder that was inserted into the well at the end of 1997. This log was obtained at a rather low flow rate, about 1.4 l/s. At 400 m depth, the temperature was found to be 154.5°C, in good agreement with a 1983 measurement of 153°C at 528 m depth, the bottom of the well.

A glance at Figure 1 shows that the saturation index at 141°C and 16.2 bar-absolute lies somewhere between +0.1 and +0.2, in the middle of the yellow region. This suggested that the well would remain scale-free if the fluid were cooled above the 100 m level. These figures were known to be a little optimistic, however, since production from the well had been increasing, and increasing production entails a drop in the well pressure at depth. Furthermore, increasing the flow rate was expected to raise the temperature in the wellbore slightly, because the heat loss from the well to the surrounding rock is nearly constant. A lower pressure and a higher temperature would both tend to increase the supersaturation. Even so, the calcium carbonate saturation index was still thought to be less than +0.3, on the safe side.

The discovery, in April of 1998 and again in September, of scaling at the end of the heat exchanger thus constituted a serious disappointment. The cause of the problem seemed, nonetheless, rather clear. Either the temperature in the well, at the end of the cylinder, was higher than had been thought, or the pressure lower, or both. In any case, the temperature and pressure profiles were insufficiently well known.

The calcium carbonate scale could be removed from the well by a drilling rig, to be sure, but keeping the well clear in this fashion would have entailed such cleaning at intervals of three months or so. This would hardly have proved economical in the long run. Continued operation of the Hæðarendi plant thus called for a more permanent solution.

Only two such solutions presented themselves. More specifically, only two reasonable ways were found that would permit controlling the scale in a thermodynamic fashion. One of these was simply to extend the heat exchanger to a greater depth and thus reduce the supersaturation by cooling the fluid at a high enough pressure. The other suggestion was to effect the cooling by injecting cooled, degassed fluid from the plant directly into the well at depth. Under this plan, chemical scale inhibitor would be mixed with the injection fluid. Both of these possibilities will be discussed below.

Before either of these proposals could be evaluated, however, reliable information about the temperature and pressure profiles under normal production conditons had to be obtained. Downhole measurements of temperature and pressure were thus carried out on November 5, 1998, at flow rates of 4 - 6 l/s. At 100 m depth, the temperature turned out to be 158.5°C, much higher than previously measured. The pressure at this depth was 14.8 bar-absolute. Under these conditions, the calcium carbonate saturation index for the Hæðarendi fluid is close to +0.5, which puts the fluid far into the danger zone and explains the rapid scaling in the well.

The temperature at the bottom of the well turned out to be 162.5°C, some 8°C higher than previously. The reason for this rise in temperature is not entirely clear, but increasing the well flow from 2,5 l/s to 6 l/s may have drawn hotter fluid from the surrounding area, or from a deeper aquifer. In this context it is interesting to note that the chalcedony chemical geothermometer indicates a reservoir temperature of 163°C. This geothermometer, which is based on a relationship between temperature and the concentration of undissociated dissolved silica in geothermal fluids, has in Iceland proven widely applicable to geothermal systems with temperatures below 180°C. It has also been suggested that the temperature rise in the well may be traceable to a seismic episode that occurred in the vicinity during the summer and fall of 1998. This latter explanation, however, must be considered rather speculative.

The blue curve in Figure 2 traces the change in state of the fluid moving up the well under the conditions that obtained in 1998. The temperature and pressure of the inflow to the well were 162.5°C and 48.0 bar-absolute, respectively. By the time the fluid had reached the end of the heat exchanger, its pressure had dropped sharply, to about 14.8 bar-absolute, but the temperature only slightly, to 158.5°C, as indicated by the near-vertical part of the curve, which is just a crossplot of the temperature and pressure logs. At this point there is a sharp break followed by a gentle slope. This lower part of the curve displays the cooling effected by the cylinder in the top 100 m of the well. This part of the curve is concave downwards, as one would expect for concurrent flow. Thus the cooling is most effective at the lower end of the cylinder and becomes less so as the fluid moves upwards. This lower part of the curve along with the corresponding parts of the curves in Figures 3 and 4 were computed by Dr. Árni Ragnarsson of the Energy Statistics and Analysis Division of Orkustofnun.

Figure 3 illustrates the proposal to inject cooled, degassed fluid from the plant directly back into the well at depth, in this case at 250 m. The top part of the blue trace is identical to that in Figure 2. At a depth of 250 m there is a step in the curve, representing the cooling effected by the essentially instantaneous mixing of the injection fluid and the well fluid. The lower part of the curve shows how the fluid in the top part of the well is cooled by the pipe carrying the injection fluid. This part of the curve is convex downwards because the flow is countercurrent. Thus the cooling becomes more and more effective as the fluid rises in the column.

An injection ratio of 50% of the produced fluid was assumed in the example depicted in Figure 3. Under these conditions, the total concentration of CO_2 in the upper part of the well would be reduced to one-half the natural value, and the bubble point pressure to slightly more than one-half. As a result, the single-phase region in Figure 3 is much larger than in Figures 1 and 2. A word of caution is in order here, however. The injected fluid does not have an effect on the saturation index below the level of injection, for obvious reasons. Depicting the entire upper part of the figure as a single-phase zone may therefore be somewhat misleading. Maybe Figure 3 is most accurately described as the saturation diagram representing injection at or below a depth where the pressure equals the bubble point pressure of Figures 1 and 2. If the injection is at a shallower level than this, the fluid will be two-phase in the region between the depth of the bubble point pressure of Figures 1 and 2 and the depth of injection, but single-phase from the point of injection up to a depth corresponding the bubble point pressure of Figure 3. Above that level the fluid will be two-phase, whatever the depth of injection.

It is worth noting in any case that the two-phase part of the diagram in Figure 3 is virtually identical to the corresponding part of the diagram in Figures 1 and 2.

The cooling and the corresponding reduction in the saturation index displayed in Figure 3 were deemed unimpressive and barely sufficient. The question may thus legitimately be raised whether a different injection ratio would yield better results. Reducing the injection to 25% of the produced fluids turned out to afford remarkably limited improvement in the saturation index at the depth of injection. The reason is simply that the injection fluid will, at this flow rate, almost reach the temperature of the well fluid before mixing. Increasing the injection ratio significantly, to e.g. 75%, would reduce the gas lift in the well considerably and might, in effect, reduce the flow unacceptably. An injection ratio of around 50% thus seemed most reasonable.

The improvement in the saturation index that would result from such an injection is smaller, however, than Figure 3 would seem to indicate. The pressure values on which the lower part of the blue trace in the figure is based were obtained from a downhole log at a flow rate of 4 - 6 l/s. Injection of degassed fluid would reduce the gas lift in the upper part of the well considerably, increasing the pressure drop. Thus, the lower part of the blue trace should fall more steeply than is shown in Figure 3. As a result the well fluid would move into the yellow zone of the diagram.

It may be added here that the above scenario could be improved upon by the use of a carbonate scale inhibitor. Thus, an inhibitor substance, such as a polyacrylate, a polymaleic acid, a polycarboxylic acid, or a methylene phosphonic acid, could be mixed into the injection fluid. This would help suppress scaling in the upper part of the well.

Figure 4 shows the expected behavior of the well fluid if the heat exchanger is extended to a depth of 250 m. The background diagram is, of course, identical to that of Figures 1 and 2; only the blue trace is different. We see that the saturation index now never exceeds +0.3, and it is quickly reduced to a negative value by the concurrent flow of cooling water.

This is the proposal that was adopted. In November of 1998, a 250 m cooling cylinder was lowered into the well. At the time of this writing the well has been in operation for a period of five months without incident, at a flow rate of approximately 6 l/s.

7 CONCLUSIONS

The saturation map in Figure 1 represents the basis for any plans to modify or expand the Hæðarendi plant, at least if fluids from well HE-02 are used. Should a new well be drilled in the area, however, it will be necessary to collect and analyze a new fluid sample and to determine the total concentration of CO_2 in the fluid. This information will permit the calculation of a new saturation diagram. The temperature and pressure profiles of a new well must also be determined. Care must be taken, in any case, to maintain the pressure of the fluid high enough, or the temperature low enough, to keep the saturation index at all times from rising above the +0.3 level. It is, of course, desirable to keep it close to zero or below.

Numerous proposals and special cases were evaluated with the help of the saturation diagram during the course of this work. Most of these were rejected, and they will not be treated here. Thus, only three cases have been discussed above: First, the situation obtaining in early 1998, when the rate of production from the well was 6 l/s and the heat exchanger reached a depth of only 101 m; secondly, the proposal to inject degassed, cooled water at 250 m; and thirdly, the solution chosen, namely cooling the well fluid with a 250 m closed cylinder. These examples illustrate the methods involved in the present analysis as well as the actual situation at Hæðarendi before and after the extension of the heat exchanger to 250 m.

It is hoped that this extension of the heat exchanger will provide a lasting solution to the problem of scaling in well HE-02.

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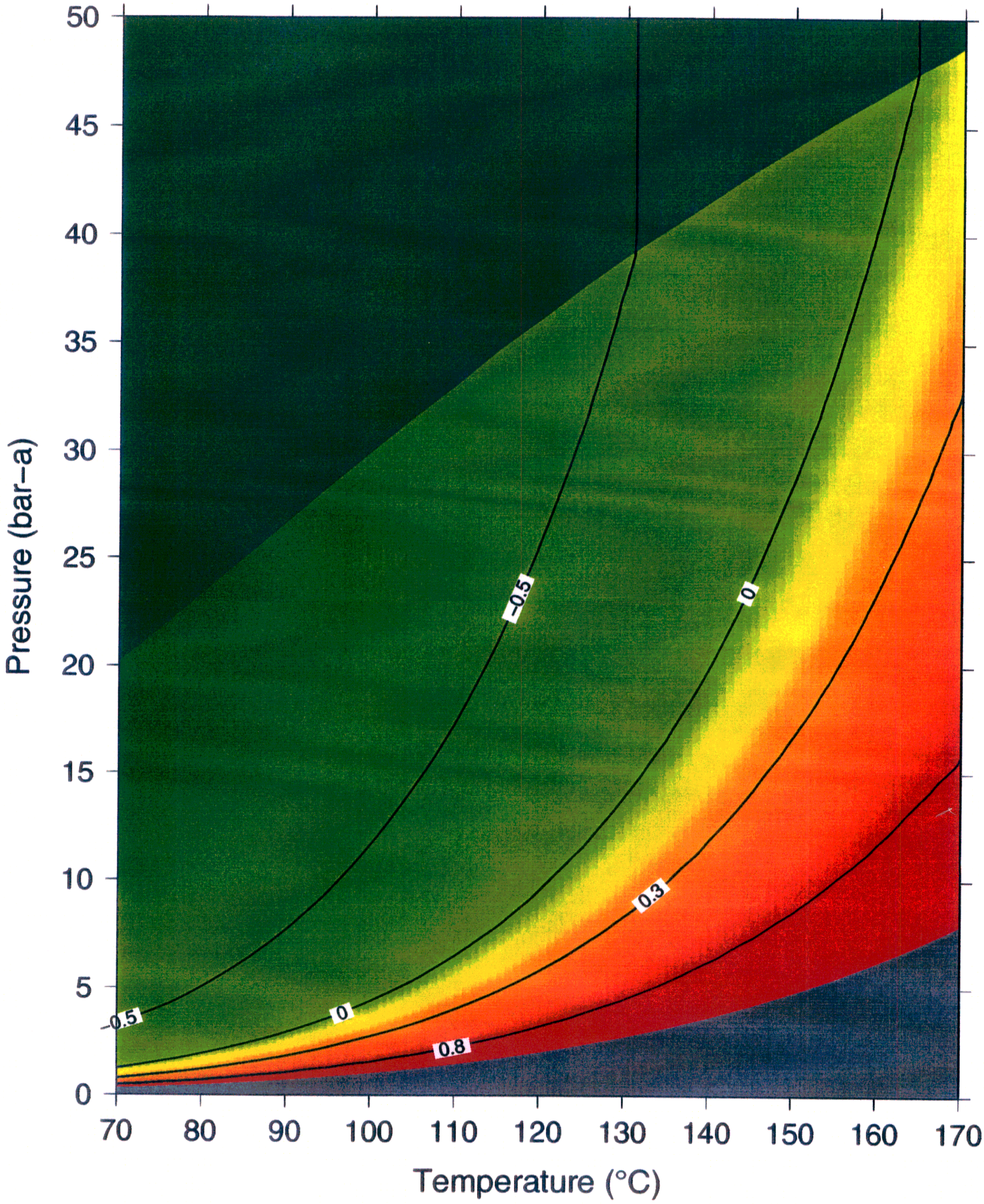

Figure 1. The calcium carbonate saturation index in the fluid from HE−02.

The saturation index ranges from −1.3, in the upper left hand corner, to +2.4 in the lower right hand part of the red zone. The curves represent constant saturation index.

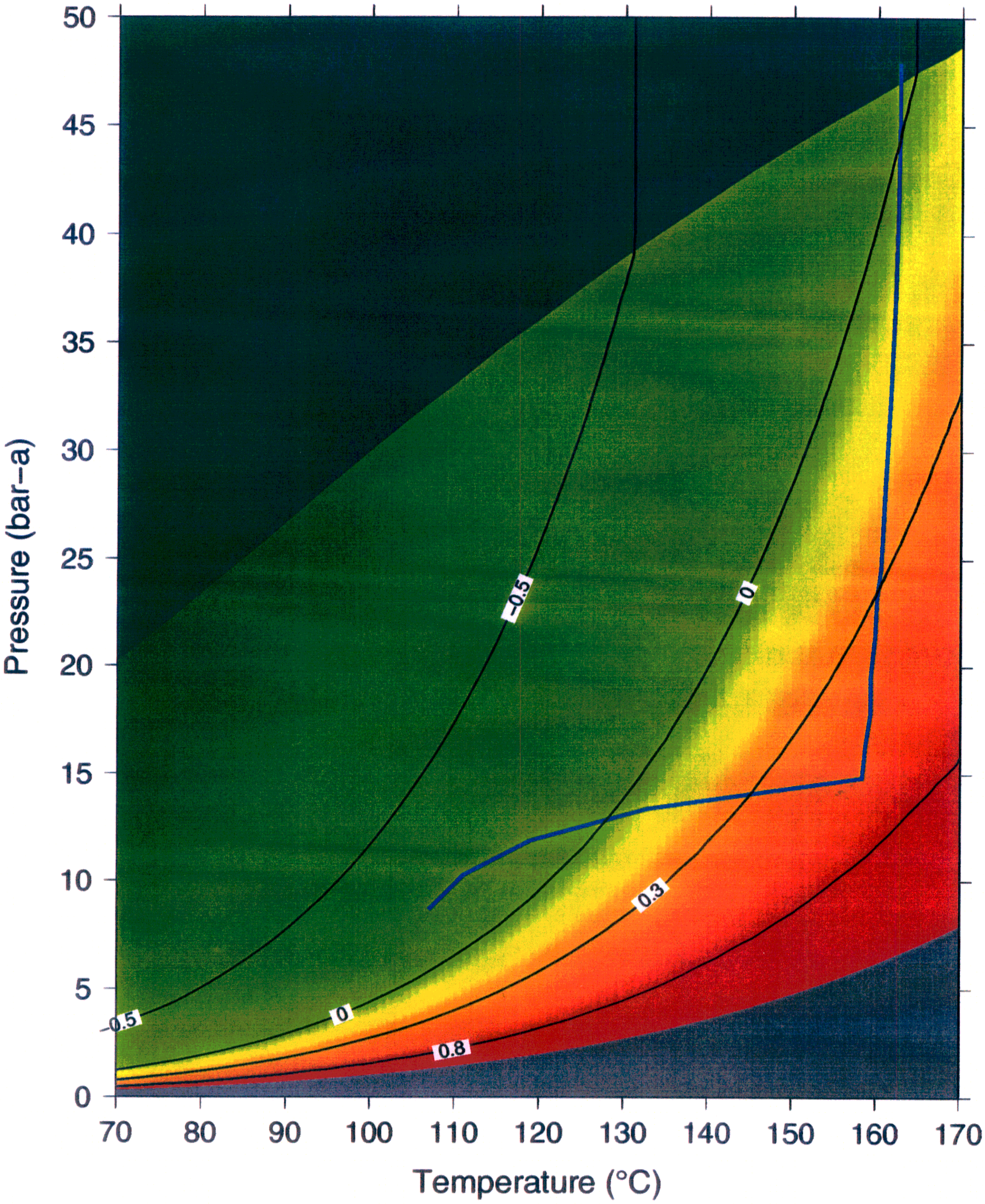

Figure 2. The calcium carbonate saturation index in the fluid from HE–02.

The upper portion of the blue trace represents the temperature–pressure profile in the deeper part of the well. The lower portion of the trace displays the calculated profile above the 101 m level and shows the cooling effected by a cylinder reaching this depth.

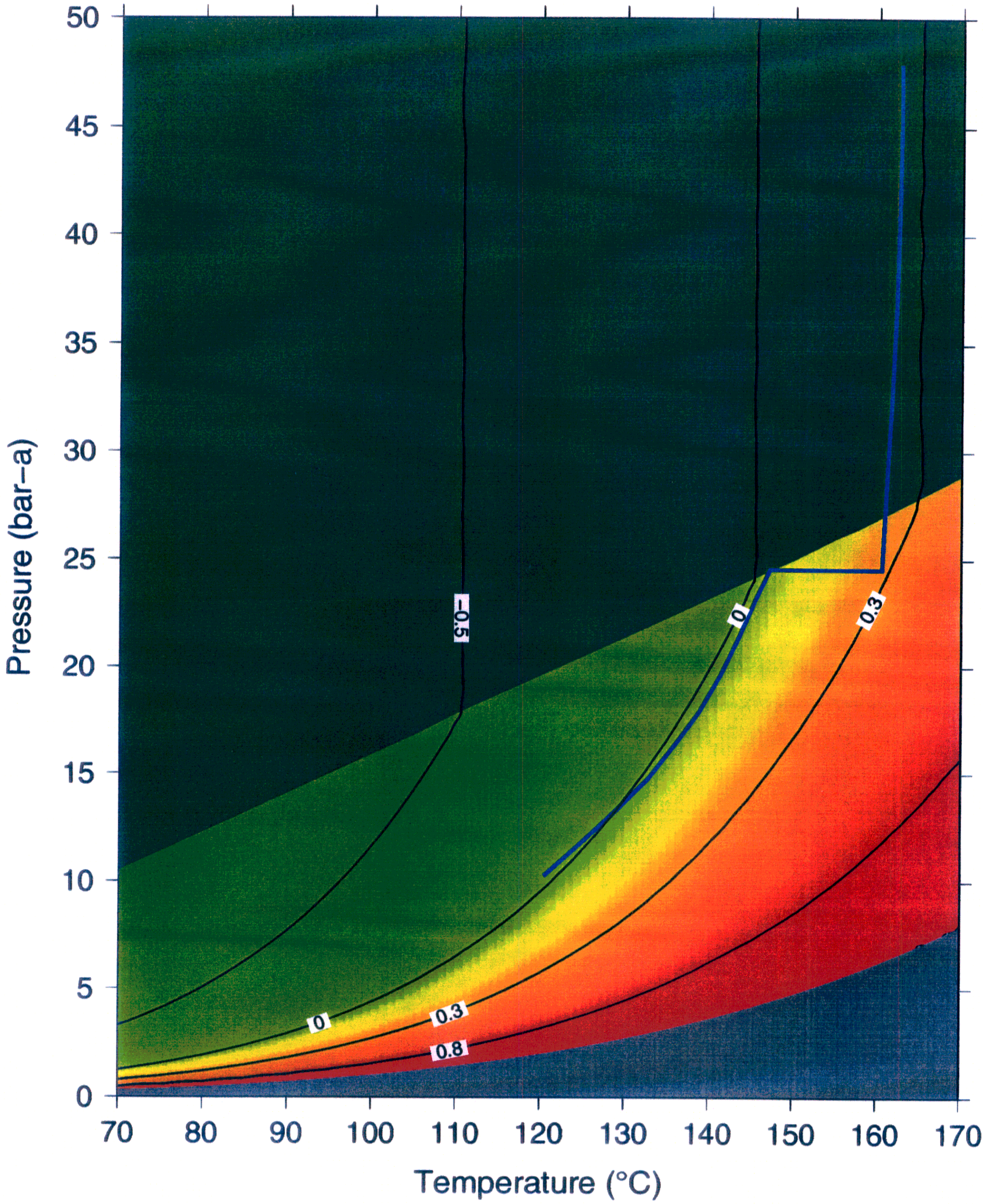

Figure 3. The calcium carbonate saturation index in the fluid from HE–02.

The upper portion of the blue trace represents the temperature–pressure profile in the deeper part of the well. The lower portion of the trace was calculated from a model based on the reinjection of one–half of the produced fluid at a depth of 250 m.

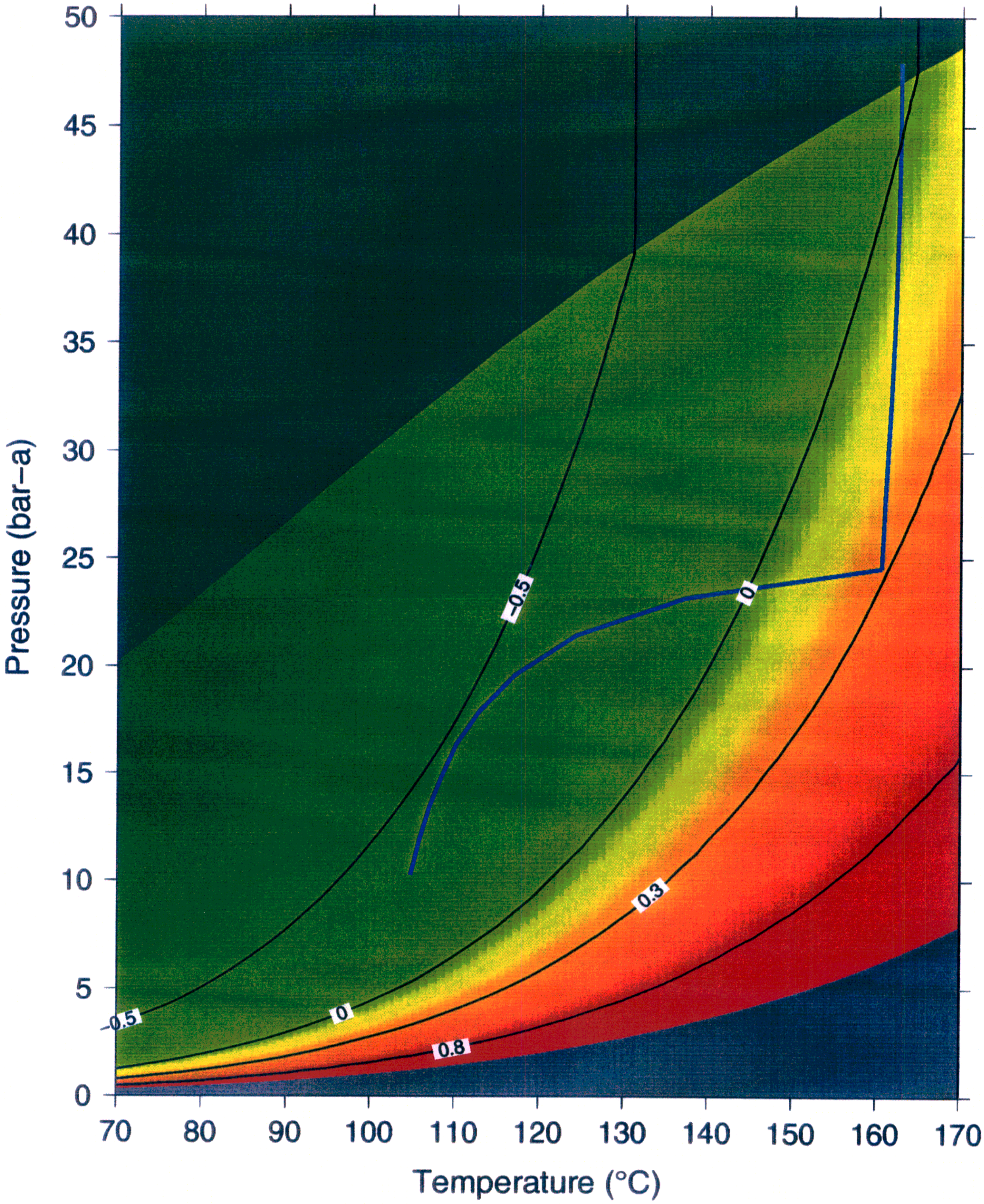

Figure 4. The calcium carbonate saturation index in the fluid from HE–02. The upper portion of the blue trace represents the temperature–pressure profile in the deeper part of the well. The lower portion of the trace displays the calculated profile above the 250 m level and shows the cooling effected by a cylinder reaching this depth.