Chapter 31
Temperature in Wells

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Introduction

Frequently, when working with a wildcat or deepening old production into zones that are relatively unknown, it becomes necessary to know the underground temperatures expected at a predetermined depth. In the 1920's, API Research Project 25 investigated the relationship between geothermal gradients and the geologic structures of oil fields.[1] Initially, interest in subsurface temperatures in oil fields focused on high temperature in deep wells, which caused cement to take initial set before it was placed behind the casing. More recently, cements with low hydration heat have been developed to protect permafrost intervals in northern frontier areas. Temperature surveys in wells were used to determine the top of the column of cement behind the casing.[2] With continual development of temperature devices, the reliability, accuracy, and speed of response have opened new horizons to temperature logging. Temperature logs are used currently to identify fluid entry into the wellbore, fluid migration behind the casing, tubing/casing leaks, and the extent of hydraulic fracturing and to monitor injectivity profiles.

Thermometers

Self-Contained Recording Thermometers

Self-contained recording thermometers, as used in the oil fields, use the same mechanism to record as the bottomhole pressure (BHP) gauge, with a thermometer element substituted for a pressure element. Temperature elements are made for some of the commercially available BHP gauges.

Humble Gauge Temperature Element. The temperature element for the Humble gauge is a container filled with mercury. With an increase in temperature, the mercury expands into a small-diameter cylinder at the end of a piston, which extends through a packing gland against a tense helical spring. A stylus arm attached to the end of the piston extends into the cylindrical chart holder of the recording mechanism. The temperature range may be changed by varying the diameter of the cylinder and piston. To prevent the well pressure from affecting the temperature element, the mercury container is enclosed within an outer tube, which is filled with mercury to reduce thermal lag. With reasonable care in calibration and operation, temperature readings are accurate to 2°F and differential temperatures of 0.5°F can be read.

Amerada Gauge Temperature Element. The temperature element for an Amerada gauge is a pressure element with a bulb attached to the pressure end of the helical Bourdon tube, but thermally insulated from the gauge to reduce thermal lag. The bulb contains a liquid that has a substantial vapor pressure in the temperature range of interest. For various temperature ranges, different liquids and different ranges of helical Bourdon tubes are selected, preferably in such a combination that the maximum temperature range is near the critical temperature of the liquid, which gives maximum defection per degree change in temperature. Ranges of approximately 120 and 200°F are used most frequently, with the minimum or maximum temperature as requested on the order. For maximum chart readability, the span between the minimum and maximum should be no greater than 200°F. Thermometers with a range of 120 to 200°F, as ordinarily calibrated, have a sensitivity of about 0.5°F and temperature changes of 0.1°F can be detected. The absolute accuracy of the Amerada temperature gauges is ±2°F. The time required for thermal equilibrium is 20 minutes, but some 70% of the change in temperature will be recorded in 30 to 45 seconds when the instrument is immersed in liquid. A faster-responding gauge design, which increases the

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temperature sensing area and reduces the heated mass, reaches thermal equilibrium in 8 to 10 minutes. The response of a liquid-vapor element is not a straight line, and therefore the accuracy and sensitivity of the element depend on the temperature to be measured.

Time Response. The time response of a thermometer to a change in temperature is directly related to the rate of movement through fluid, or flow of fluid past the thermometer. When a long section of hole is to be surveyed for a possible anomaly, the thermometer can be run at 50 to 100 ft/min followed by a second run at 2 to 5 ft/min through intervals of interest indicated on the first run.

Thermometers in Gas. The thermal conductivity of a gas is much lower than that of liquid. Therefore, a thermometer in gas has greater thermal lag for a given change in temperature. However, in most wells in which a thermometer is run through gas, any anomaly present is caused by expansion of gas, and the change in temperature is much greater than normally found when the anomaly is caused by migration of liquids. Because of the greater change in temperature, the presence of an anomaly is recorded as quickly in gas as in liquid. If a wellbore contains gas through the interval of interest and no gas expansion is present, such as a survey to determine migration of fluid behind the pipe, it is preferable to fill the well with liquid. If this is not feasible, then the thermometer must be run much slower (one-fifth to one-tenth) than the normal rate in liquid.

Electrical Surface-Recording Thermometers

Electrical surface-recording thermometers have a thermocouple, resistance wire, or thermistor as a temperature element. As normally calibrated for oil well use, electrical surface-recording thermometers have a sensitivity of 0.5°F and a thermal lag of only a few seconds. They are run on armored, insulated cables and the measuring wheel is geared to drive a chart recorder, camera, or computer to record temperature against depth.

Differential thermometers have been developed that record very small changes in temperature, 0.1°F or less, and are useful for identifying an anomaly in a long section when surveying at logging speeds of 100 to 150 ft/min. Once an anomaly is recorded, the thermometer can be run at slower speeds to completely define the anomaly. The differential thermometer is usually run in conjunction with an electrical thermometer to allow the absolute temperature to be measured in conjunction with the differential temperature.

By using electrical surface-recording thermometers, any temperature change noted can be checked by a rerun without returning the instrument to the surface. Very small anomalies under static conditions may be disturbed by the movement of the instrument, and therefore when a check of such condition is run, it should be delayed long enough to reestablish temperature equilibrium in the hole.

Advantages and Disadvantages

Self-contained thermometers and electrical surface-recording thermometers each have advantages and disadvantages. Self-contained thermometers have the advantages of portability and low investment. Disadvantages are much greater thermal lag and the necessity of returning the instrument to surface and reading the charts before the results are known. Electrical surface-recording thermometers have the advantage of quick response to temperature change, which permits running faster, plotting temperature against depth as the survey progresses, and checking any temperature anomaly without having to recover the instrument from the well. Disadvantages include a much greater investment, larger and heavier equipment, and delicate instrumentation.

Thermometry

Introduction

Two types of temperature surveys are used in the oil fields. One determines the true temperature at the depth of interest, and the second determines the depth or interval of a change in temperature. Usually, true temperature is measured with a maximum-recording thermometer. However, the use of electrical surface-recording thermometers is becoming more widespread for measuring true temperatures. Determination of a change in temperature requires a continuous record some distance above and below (as well as through) the interval of interest. In this case, the use of a differential thermometer will show the existence of a change in temperature rather than the true temperature or the actual magnitude of the change.

Actual Temperature

The geothermal gradient is very different in the various sedimentary basins, but within a given basin the change is gradual from one part to another.[3,4] In most oil-producing areas, the gradient is usually within the range of 1 to 2°F increase for each 100 ft of depth. Temperatures just below the seasonal effect, ordinarily 30 ft below the surface, are about 1.5°F higher than the isotherms of the average annual temperature, as shown by climatological data of the U.S. Weather Bureau (Fig. 31.1). An exception to this is in northern latitudes where continuous permafrost exists. A geothermal gradient determined from such surface temperatures and the temperature of the producing formation is sufficiently accurate for most practical uses (Fig. 31.2). The rate of temperature increase in some areas is greater with depth, especially below 10,000 ft, and marked increases have been reported below 18,000 ft. When a precise geothermal gradient is to be determined, the hole selected must not have been disturbed for several months. In any event, the survey must be conducted while the well is in operation, since the passage of the thermometer will alter the static gradient.

The thermal conductivity of geological strata varies. The average heat conductivity of common sediments is given approximately by the figures in Table 31.1.[4]

When fluid movement continues in a borehole for periods of time, such as in drilling operations or a producing well, the temperature effect will be different on each formation. Any effect on a given formation will depend on its thermal conductivity, the difference in temperature between the moving fluid and the formation, and the length of time such movement continues. When fluid movement is stopped, temperature equalization

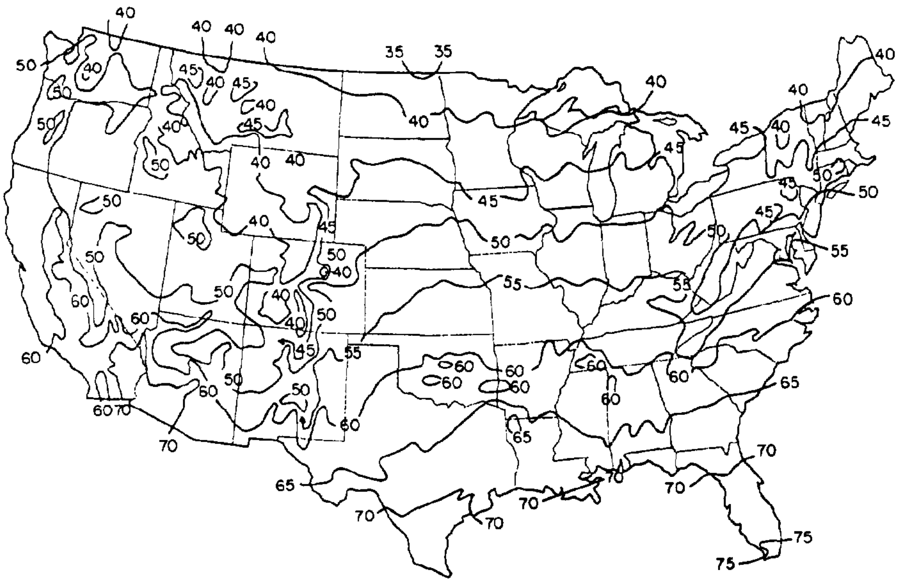


Fig. 31.1—Average annual temperature, °F, for the period 1899 to 1938. Isolines are drawn through points of approximate equal values.

begins, but considerable time, usually several months, is required to approach temperature equilibrium. In temperature surveys of wells, such temperature irregularities can be confused with an anomaly caused by some operating condition. Normally, however, the irregularities in the gradient resulting from normal operating conditions are small and the abnormal condition being investigated, such as a hole in the casing, fluid migration behind the pipe, or cement top, is of such size or character that there is no uncertainty as to cause.

The actual temperature at depth is very important in many problems in drilling, production, and reservoir work. Drilling mud is often adversely affected by high temperature. The type of cement and additives are determined by the temperature at the casing seat or zone of interest. In oil reservoirs, the amount of gas in solution, the bubblepoint, and the viscosity are all related to the temperature, as is the amount of condensate formed and

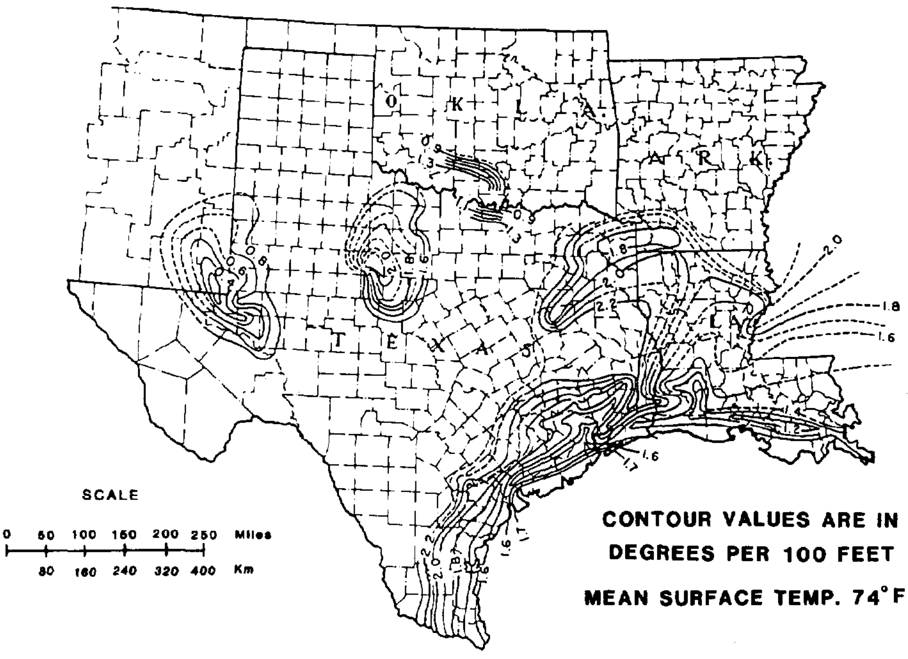


Fig. 31.2—Contour map of geothermal gradients in southwest U.S.

TABLE 31.1—AVERAGE HEAT CONDUCTIVITY OF COMMON SEDIMENTS (Btu/hr-sq ft-°F)

Rock salt	36
Anhydrite	32
Dense lime	20
Sand	16
Shale	12

the amount that remains as a liquid wetting the reservoir rock. The volume of gas per unit of reservoir rock and the supercompressibility of the gas are also related to the actual temperature.

Temperature Surveys

A temperature survey of a well is made either by running the thermometer continuously at a slow speed or by stopping it for a short time at regular intervals. For a survey through a long interval of hole, a continuous run is often preferred, while for a short interval numerous stops of 1 to 2 minutes are made. Temperature readings should be taken through the interval of interest, while running the thermometer in and while pulling up. Both runs should be at the same speed or at the same stops to determine more accurately the depth of any anomaly. On runs made very slowly, 2 to 5 ft/min, the actual thermal lag may be too small to warrant surveying the opposite direction. When a survey is started at a given rate, that rate should not be changed during the survey. To do so will cause a change in gradient or anomaly on the chart that may mask an actual anomaly or change in gradient in the well. Since the temperature chart is not available until the survey is completed and the thermometer is removed from the well, thorough notes that record time and depth of the instrument are required to correlate temperature and depth.

The location of a temperature change on a temperature survey is, in most cases, much more significant than the actual temperature or the amount of change in temperature. Normally, the temperature gradient in a well is reasonably uniform, and any deviation is indicative of an abnormal condition at that depth. The deviation may be an irregularity or anomaly in an otherwise uniform gradient, or it may be merely a change in the gradient. The primary causes of temperature change in a wellbore are expansion of gas, hydration of cement, and migration of fluid. Expansion of liquids in producing wells and heat of solution and chemical reaction are often present, especially in drilling wells, but the net effect on the temperature in the borehole is normally too small to be recognized. Gas expansion will cause an anomaly on the gradient, and migration of fluid will cause a change in gradient.

Gas expanding as it enters the borehole from the reservoir formation is much cooler than the adjacent formations, and therefore the particular intervals from which the gas is flowing can be identified by a temperature survey (Fig. 31.3A). A typical temperature survey conducted in a well producing minimal or no gas can be identified by a temperature survey (Fig. 31.3B). Greater detail will be recorded if the thermometer is run across the open hole or perforated sections while the well is producing. When the tubing tail is below the producing interval, any gas produced that travels downward to the bottom of the tubing, then up the tubing past the thermometer, mixed with any other fluid that may be flowing into the wellbore, will mask anomalies that exist at the producing interval. With this type of completion, the tubing must be shut in and the annulus allowed to produce with the thermometer being run in the tubing. If a packer is set or, for other reasons, the well cannot be produced through the annulus, the survey can be run after the well is shut in. A temperature survey on a shut-in well relies on gas cooling by expansion to lower the temperature of that part of the formation producing gas below that of the formation not producing gas. Some time is required for the temperature to equalize, and a temperature survey run long enough after shut-in to complete afterflow will record lower temperatures in the principal intervals of gas production. A sequence of runs through the interval will permit a more reliable interpretation.

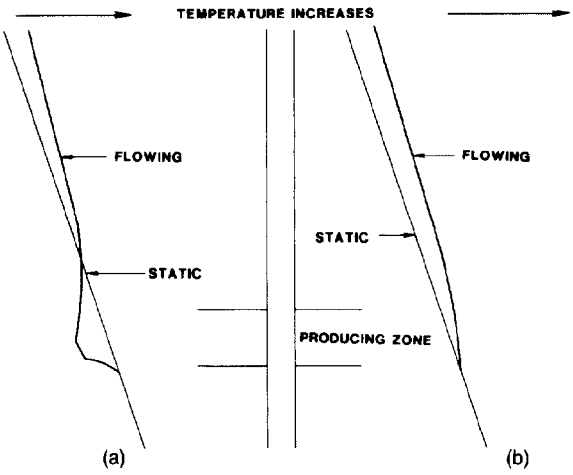


Fig. 31.3—(a) Example gradient gas flow. (b) Example gradient fluid flow.

The lowest interval producing gas can be identified from a temperature survey by the cooling effect through the intervals producing the free gas and the return to the normal gradient below. Water-producing intervals can be determined only if enough free gas is produced with the oil to give a change in gradient at the lowest interval producing oil.

A hole in the casing through which fluid is moving can usually be found by running a temperature survey. In addition to the depth of the hole in the casing, the depth of the formation, which is the source of the migrating fluid, and the depth of the formation into which the fluid is moving must be determined when a hole is known or suspected to exist.

A permeability or injectivity profile of a water-injection well can be determined from a temperature survey. A typical temperature survey of a water-injection well with a homogeneous formation shows a cooling across the injection interval (Fig. 31.4). Two procedures are used to obtain injection-well temperature surveys. After injecting water for a period of time, injection is discontinued and, after a few hours, the survey is run. A more reliable answer would be expected from a series of

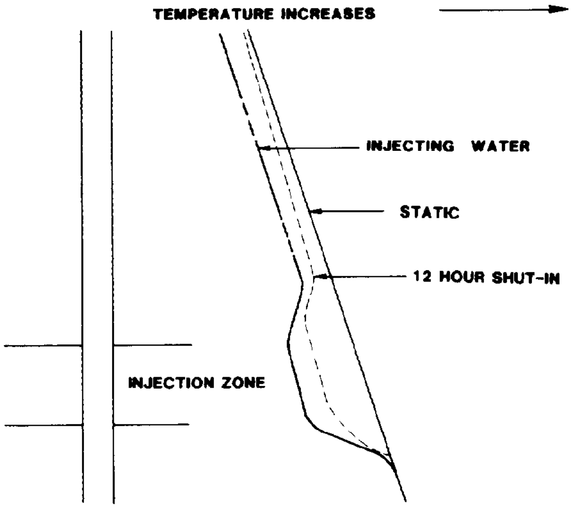


Fig. 31.4—Water-injection gradient.

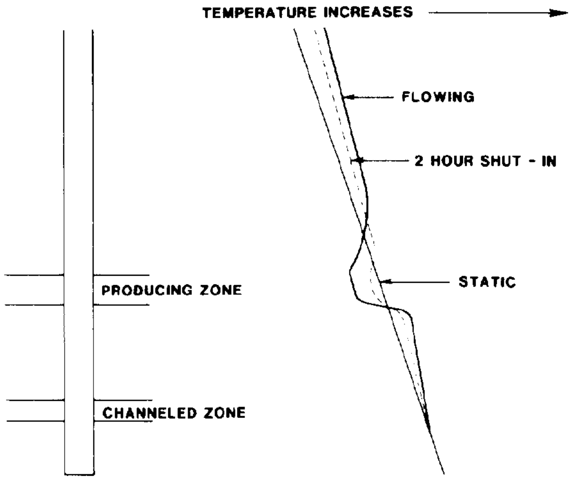


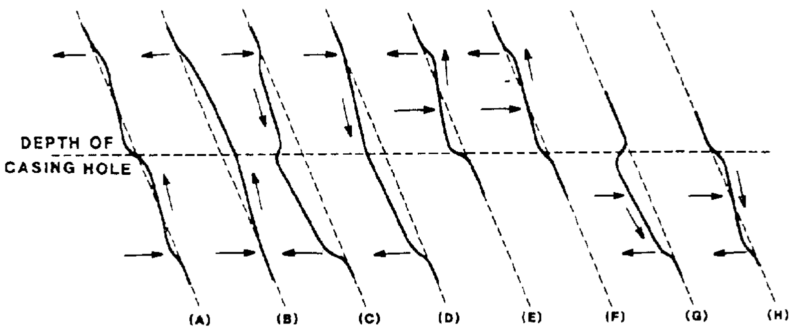
Fig. 31.5—Fluid channel gradient.

surveys at intervals of a few hours. Continued injection for many months can cool the entire formation and make it difficult to identify the relative injection capacity of the different parts. Under some conditions, another method that may give more detail is to discontinue injection for a day or more, then run a survey while injecting water at a very low rate, such as 1 to 5 bbl/hr. Because of the residual variations of temperature from normal water-injection operations, a survey before injection is recommended for comparison.

If water were channeling from below, the temperature survey would show a warmer anomaly at the base of the producing interval (Fig. 31.5). Fig. 31.6 shows ideal-temperature curves for various conditions of migration of fluid through a hole in the casing. Certain assumptions were made in drawing these ideal curves. Where gas is migrating, some expansion and, therefore, cooling is presumed as the gas leaves the formation. Also, it is assumed there will be a drop in pressure and, therefore, expansion and cooling at the depth of the hole in the casing. If there is no expansion at either point, the curves for gas would have the same appearance as the curves for liquid. In cases where both formations are either above or below the casing hole, the movement of fluid from the hole to the farthest formation will mask any gradient between the hole and the nearest formation.

There are times when the volume of migrating fluids is not sufficient to affect the temperature. Gas leaking through a small hole in the casing will cause a very sharp temperature drop, but the volume may be too small to affect the gradient. Migration of fluids behind the casing will create a lower rate of temperature change than the normal gradient. If the flow is upward the gradient temperature will be higher than the normal gradient, and for downward flow the gradient temperature will be lower.

Preparation of the well is essential for a successful and reliable interpretation of the survey results. Usually the maximum anomaly is of the order of 2°F, and under less than optimal conditions the anomaly may be so small or so masked that a reliable interpretation is impossible. In these instances, the use of an electrical surface-recording differential thermometer may be the only method of obtaining a successful survey.



Normal Temperature Gradient

→Formation from which fluid is migrating

←Formation into which fluid is migrating

(A) Gas migrating upward

(B) Liquid migrating upward

(C) Gas migrating downward

(D) Liquid migrating downward

(E) Gas migrating downward to casing hole, then up

(F) Liquid migrating downward to casing hole, then up

(G) Gas migrating up to casing hole, then down

(H) Liquid migrating up to casing hole, then down

Fig. 31.6—Ideal-temperature curves of fluid migrating through casing hole.

Casing-leak and channeling-of-fluid temperature surveys are run with the well shut in. The shut-in time must be long enough for the entire wellbore to approach an even temperature gradient. A minimum of 24 hours should be allowed. However, the shut-in time required should be determined from past experience, type of problem to be identified, and location. Gas production and water production intervals are located with the well flowing at the maximum practical rate. If the survey cannot be run while flowing the well, the time interval between shutting in the well and running the survey may be critical. All afterflow must have ceased, but not so long as to allow the temperature to approach the normal gradient, which would mask any anomaly.

A temperature anomaly can be created by injection of fluid, usually oil or water, when normal conditions will not give a temperature change. Examples of this are identifying a channel below the producing interval and locating a packer or tubing leak by pumping cool fluids.

Drilling Wells

In drilling deep wells or wells that encounter high temperatures, especially in excess of 250°F, a representative bottomhole temperature (BHT) is required for selection of a proper mud program, cement, and additives to ensure proper cementing of the casing. In development drilling, temperature data from neighboring wells can be used in estimating the BHT of a new well. In exploration drilling, an estimation of the BHT may be all that is available. Unless offset data are available a geothermal gradient must be assumed that will permit estimation of the BHT.

A technique exists for determining static BHT's by plotting on semilog paper T_{ws} vs. $(t_k+\Delta t)/\Delta t$ where

T_{ws} = bottomhole shut-in temperature measured at Δt, °F,
t_k = circulation time, hours, and
Δt = time after circulation ceases or shut-in time, hours.

The data required for this graph usually are obtained on successive openhole logging runs and allow an approximation of static BHT.[5] Although this Horner-type analysis is not mathematically correct, when assuming short circulating times the technique provides reliable estimates of static temperature. This technique is most applicable in regions of high geothermal gradient, where log-recorded temperatures can be significantly lower than the static temperature.

The hydration of cement is an exothermic reaction, and sufficient heat is generated that the presence of cement behind a string of casing can be determined by a temperature survey for up to several days after cementing. The character of the anomaly at the top of cement in a particular field is fairly uniform but varies greatly in different fluids. The anomaly may be a large, sharp increase (Fig. 31.7A) in some cases 35 to 45°F, or it may be a very slight increase in gradient (Fig. 31.7B).

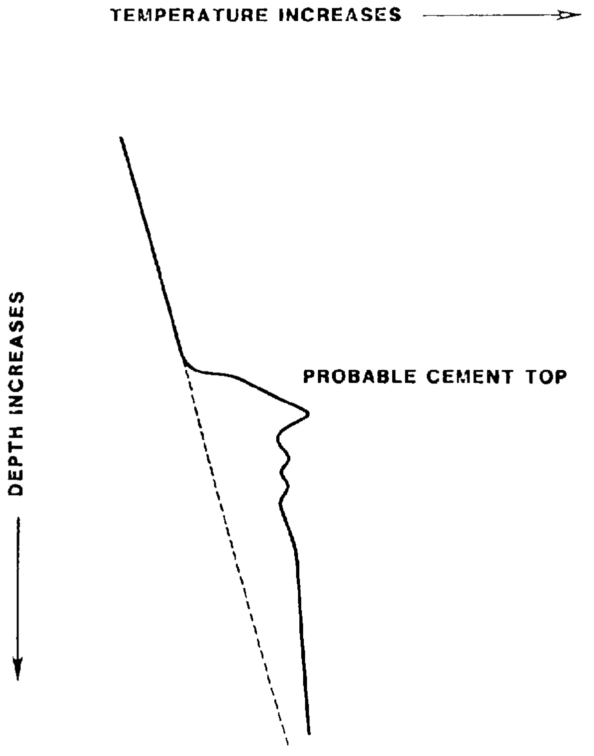


Fig. 31.7A—Effect of cement behind casing on temperature gradient.

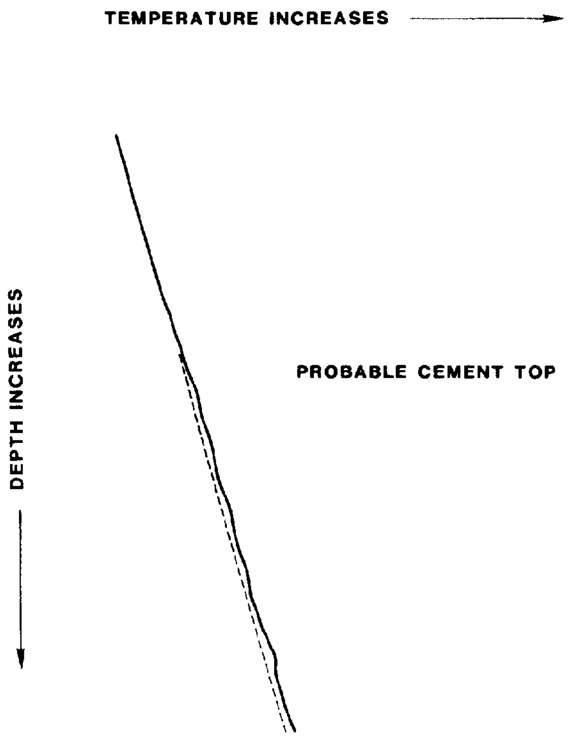


Fig. 31.7B—Effect of cement behind casing on temperature gradient.

The principal influence on the survey is the time elapsed between placement of the cement and running the survey. Other influential conditions include fineness of cement, chemical composition, rate of hydration, mass of cement in place, and the thermal conductivity of the adjacent formation. The maximum temperature usually occurs 4 to 9 hours after cementing, but reliable data can be determined in most areas after 48 hours. Any temperature change is affected more by the rate of hydration than by the total amount of heat liberated. Although hydration continues indefinitely, the rate decreases rapidly from the peak. A washed-out section of hole may be responsible for a large, sharp increase in temperature and can indicate a false cement top. A small temperature change or slight change in gradient could be caused by a small annular area or dilution of the cement with drilling mud. These factors, which influence the size of the temperature anomaly at the top of the cement in a given well, vary widely in their effect. However, even under an unfavorable combination enough heat is generated to permit a determination of the cement top.

A new cased-hole logging method exists for detecting vertical flow outside the casing resulting from faulty cement. The radial differential temperature (RDT) log measures variations in temperature in the plane of the casing radius on the inside of the casing.[6] Normally, two sensors are used, placed 180° apart; one sensor may be used at the wall of the casing and the other sensor in the body of the tool. An anchor spring at the top of the logging tools prevents the entire tool from turning as the sensors rotate. A motor rotates the tool at a speed of one revolution every 4 minutes. The RDT logging tools are designed to allow attachment of a perforating gun, which can be adjusted to perforate into the suspected channel or abnormality located by logging.

If a channel is suspected in a perforated well, the well should be produced long enough to ensure that channel fluid is being produced before running the RDT log. The RDT sonde is placed at depths in the well where the channel is suspected. The arms are extended and the instrument revolves once or twice. Before moving to another depth the arms are retracted. As many measurements as required to delineate the channel can be made on one run. In some cases better results are obtained by injecting fluids at the surface to cool the channel.

Temperature surveys can be used to locate depth of lost circulation in an area where formations above the depth of drilling are known to have taken fluid. The temperature survey will show a sharp increase in temperature immediately below the point of loss of fluid. The temperature break will be even greater if slow losses are occurring while running the survey. At times when the hole is considered dangerous, the survey can be run through open-ended drillpipe over the suspected interval.

Summary

Wellbore temperature surveys are an inexpensive method to determine problem well conditions. The data obtained from a temperature survey are often the only data available and usually are accurate and reliable. When an anomaly occurs, one of these conditions must exist: (1) expansion of gas, (2) migration of fluid, or (3) some type of chemical reaction. With the exception of measuring the actual temperature at a point in a wellbore, temperature surveying is highly qualitative. In the majority of surveys, consistency of procedures, past experience, and the engineer's ingenuity allow reliable information to be collected and unique analyses to be performed. Since no quantitative relationship between temperature and depth exists that covers all areas and sedimentary basins, an assumed gradient of 1 to 2°F/100 ft depth is appropriate.

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