FINAL REPORT

TESTING AND SAMPLING PROCEDURES
FOR
GEOTHERMAL - GEOPRESSURED WELLS

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This is Task 1 of Part 1 "Special Projects Research for Petroleum Engineering Aspects of Geothermal Research" covering the static and dynamic test procedures for use in wells drilled to geopressured formations.

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TESTING AND SAMPLING PROCEDURES FOR GEOTHERMAL-GEOPRESSURED WELLS

Summary and Conclusions

Test wells to tap and sample geothermal-geopressured formations at 15,000-20,000 feet in the Gulf Coast area can be drilled routinely utilizing available equipment and methods. Electrical logs, surveys and fluid samplers can be used to obtain accurate and reliable information as to depths, temperatures, pressures, and fluid content of the geopressed formations before the well is completed. But it will be necessary to set casing and flow the well, at least temporarily, to secure fluid production volume and pressure data to evaluate the producibility of the geopressed resource.

Electric logging and wireline survey methods are fully developed techniques for measuring the parameters needed to assess a geopressed zone before setting casing. Formation subsidence, though it may be slow to develop, can be measured using radioactivity tracer surveys.

Conclusions:

1. Existing well logging and surveying methods and equipment are generally satisfactory for testing and sampling a geothermal-geopressed resource.
2. No significant areas of research are needed to predict, detect, and evaluate geopressed formations for their potential as geothermal resources.
3. Static and dynamic testing procedures using existing technology are satisfactory to test, sample and analyze a geopressed reservoir.

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TESTING AND SAMPLING PROCEDURES

FOR

GEOTHERMAL-GEOPRESSURED WELLS

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INTRODUCTION

Geological assessment studies indicate that commercially attractive geothermal-geopressured resources exist in several "Fairways" in Texas and Louisiana at depths of 12,000 to 20,000 feet near the coast of the Gulf of Mexico. Brines in porous formations at these depths have pressures ranging from 9,000 psig to more than 15,000 psig and temperatures from 250°F to over 350°F. Realistic assumptions may be 13,000 psig and 300°F bottom-hole under static conditions. Wells to tap these resources can be drilled routinely using existing technology. Electrical well logs and surveys taken in those wells will produce reasonably accurate and reliable information of temperatures, pressures, and porosity to estimate the worth of the geopressured resource, but data regarding dissolved solids and gas in the water must be obtained from fluid samples taken out of a well. Producibility of the resource will be an open question. Relative porosity and permeability indices can be estimated from electric logs, but actual reservoir testing is necessary to learn the producing rates that can be maintained and the volumes of gas and fluid that can be obtained.

Seismic survey methods can be used to outline the depths and areas where abnormal formation pressures (geopressures) will be found, but it is necessary to drill a hole to determine the actual depth where high formation pressures will be encountered and whether porous and permeable rocks are present. Seismic surveys can profile the shape and size of an

underground structure and delineate the major faults that may be present.

Wells drilled by cable-tool methods, though slow and tedious, gave prompt, accurate, and quite specific information concerning the kind of rocks and contained fluids as drilling proceeded. If high-pressured fluids were encountered the well would blow out and a production test could be obtained immediately. In fact, many oil and gas wells were allowed to produce while deepening continued; when a satisfactory flow rate was obtained, the drilling tools would be pulled and the well put on production. Fluid samples, of course, could be taken right away and tested as required. These procedures cannot be followed for a rotary-drilled well, particularly to penetrate geopressured formations, because of the great well depths and high pressures involved. The hole must be kept filled with drilling mud heavy enough to contain the geopressured fluids. Well blowouts constitute serious hazards to personnel and equipment, and the unconsolidated rocks where geopressured formations exist would certainly slough into the well and plug the hole unless supported by the hydrostatic pressure developed by a column of heavy mud. Some geopressured formations require drilling fluid weights as high as 18.0 pounds per gallon (2.16 specific gravity) to contain the very high geostatic pressures.

Prior to drilling the well electric logs and other data from nearby wells, plus regional geological studies, can give considerable insight on the pressures and temperatures that will be found in a well at a specific location. But a drilled hole and/or cased well is needed for complete factual data on the porosity and permeability of the reservoir

rocks, their mechanical strengths, and the producing capacity of the well. An accurate estimate of free methane and other hydrocarbons can be obtained from electric logs, but gases in solution must perforce be measured from water samples taken under bottomhole conditions of temperature and pressure. Dissolved solids in the geopressed brines will have a large bearing on the mechanical handling of the geopressed fluids on the surface. Equivalent salinity of the water in the geopressed zones can be determined from resistivity measurements of the underground waters using electric log data. But the kind and amount of dissolved solids in the geopressed fluids will have to be measured by analysis of samples taken under bottomhole conditions. Producibility of underground waters from porous and permeable rocks can be accurately measured only by actual production tests.

Testing and sampling of geopressed formations can be best obtained from a hole drilled and completed specifically for a geothermal test. This will insure that the casing and tubing sizes are large enough for the flow volumes needed to exploit the resource and that the requisite testing-sampling devices can be run through the well bore. A well drilled for oil or gas production but converted to a geothermal test hole will enable considerable information to be obtained from logs and fluid samples, but flowing rates may be limited by the size of the tubing or casing. Minimum information concerning geothermal purposes can be obtained from a hole being drilled for oil or gas. It will have all the limitations of the second case and would not likely be available for geothermal testing after the well was completed. Although considerable information can be obtained from all three types prior to their

completion, actual fluid production tests must be conducted to measure the quality and quantity of heated water, thermal output and geohydraulic power under dynamic conditions, and the quantity of methane that can be obtained on a continuing basis. Short-term production tests may give an indication of fluid pressure and volume relationship, but flowing tests of a year or more may be needed to accurately predict long-term reservoir performance.

Static testing procedures will include techniques and surveys needed to drill into the geopressured zone with safety and to penetrate the sand intervals so that the hole can be logged, cased, and completed as a producing well. This will involve the application of known drilling technology to overbalance formation pressure, thus to avoid well kicks, and to minimize the hazard of lost circulation. Either situation can lead to a blowout, lost hole, and added well expense. Drilling parameters will be monitored by experienced mud loggers on a 24-hour basis to insure safe operations. A conventional core will be taken from an upper sand interval to determine its porosity, permeability, and mechanical properties by laboratory analysis. After the hole is drilled to final depth, a complete "suite" of electric logs will be made to determine lithology, porosity, and other characteristics of the exposed formations. Surveys will be made to measure the angle and direction of formation dip, to plot the course of the hole and its bottomhole location. Temperature and pressure tests will be made and fluid samples obtained from the porous intervals. Casing will then be set and cemented in the well; subsequently tests utilizing wireline equipment will be made to assess the quality of the cement bond between the pipe and wall of the hole. After

assurance of a good bond, the casing will be perforated at the lowest porous zone and produced for dynamic flow tests.

Dynamic testing procedures will involve flowing each productive interval to obtain fluid samples under bottomhole and surface conditions, to determine the maximum rate of flow with negligible sand production, as well as temperatures and pressures. A bridge plug will then be placed between the perforated interval and the next higher porous interval will be perforated and flow tested in the same manner as the first zone. When all porous intervals are tested individually, decision can be made as to which to produce and the well prepared for final completion. It may be necessary to open several of the zones for commingled production to obtain the desired rate of flow, temperature and pressure. If sand movement appears to be a problem, it may be necessary to gravel pack and set screen liners, or perform sand consolidation measures to prevent sand entry under high rates of flow.

TESTING AND SAMPLING TECHNIQUES

A well drilled specifically for geopressured-geothermal tests will be arranged to provide reliable and accurate information for the overall assessment and evaluation of the geopressured resource. To accomplish these objectives, casing sizes and recommended procedures will (1) maximize the quality of the data to be obtained, and (2) utilize existing technology as far as possible to insure the probability of obtaining the desired results. Standard methods will insure reliable tests and safe operations for personnel, the well, and environment.

Within the past five years, ultra-deep drilling technology has resulted in the drilling and completion of wells to depths of 25,000 feet in areas of abnormally high pressures. Bottomhole pressures exceeding 13,000 psig and temperatures more than 300°F in geopressured formations can be reached at nominal depths of 15,000 feet, depending on the geographic location of the well. Casing and tubing sizes, weights, and grades of steel, to satisfactorily handle the required pressures and fluid volumes with safety and reliability are available. The wells can be drilled routinely using the drilling rigs, methods and procedures normally employed for 20,000-foot wells in the oil business.

Testing and sampling methods for a geopressured well are the same as those employed for a deep oil or gas well. Electrical surveying devices lowered into the well on multi-conductor wirelines can be used to define the kind of rocks, contained fluids, temperatures, pressures, and physical characteristics. Resistivity, sonic and radioactivity logs make it possible to estimate porosity, density, and the apparent permeability

of the reservoir rocks, though actual fluid production tests are needed to determine well performance. Actual cores are needed to precisely evaluate porosity and permeability of a reservoir rock, and drill stem tests can evaluate expected well performance and permit some concept of reservoir size. Cores will be needed to predict actual mechanical strength of the rocks penetrated, but electric log data can be used to estimate their apparent mechanical strengths. Prior to setting casing through geopressured strata exposed in a borehole, wireline instruments can be employed to measure the fluid pressures in the permeable formations and to secure samples of the contained fluids. Cored samples from the side-wall of the well can be taken by wireline methods; sidewall samples may be used for laboratory analysis to confirm lithology, porosity and original fluid content of the geopressured formations. After casing is set in a well, acoustic surveys can be used to determine the quality of cement and the bond between the pipe and wall of the hole. Directional survey data, obtained by wireline methods, can be employed to plot the course of the borehole from the surface location and thus to map the bottomhole position of the well. Shaped-charge explosives (jets) will be used to perforate the casing to permit formation fluids to enter the well bore; the perforations will be made at the most porous zones of the reservoir face in the hole, using radioactivity surveys for depth control. Radioactive markers (bullets) will be shot into the well bore at certain levels to be used as references for subsidence observations as the well is produced. Other wireline surveys will be run periodically to observe bottomhole temperature, pressure, to secure fluid samples, and for fluid flow data to evaluate reservoir performance.

Exact subsidence surveys will not be possible in wells drilled for oil and gas, since radioactive markers will not be placed before casing is installed.

Table I lists the parameters measured or derived for geothermal-geopressured tests and sampling procedures, the instruments or techniques employed, and the quality of the information obtained.

Drilling Safeguards

More than 400 wells are being drilled annually for oil or gas to 15,000 feet or greater depth in the United States. About fifty of these reach 20,000 feet or more. Some 6,000 deep wells have been drilled in the U. S. during the past twenty years. Approximately 4,000 were located in the Gulf Coast area of Texas and Louisiana. Drilling machinery, tools and equipment for deep wells have been very much improved during this time and are considered quite satisfactory for the mechanical loads, pressures, and temperatures that will be encountered in 20,000-foot geothermal-geopressured wells. Tubular products, i.e., casing and tubing, in the sizes, weights, and grades of steel needed for 20,000-foot wells are readily available — though delivery time for some sizes and grades may be quite lengthy. Related wellhead equipment, including 10,000 psi working pressure valves and fittings, are available.

Wells are being drilled routinely to 15,000 feet in the Gulf Coast. Drilling time — not including testing and completion work — for making hole in the unconsolidated formations typical of the area may be as little as 25 days but 50 days time is usually required for an exploratory hole in a new area. Drill pipe is quite satisfactory for this work;

Table I
INSTRUMENTS OR TECHNIQUES USED TO DERIVE
INFORMATION ON GEOPRESSURED FORMATIONS

<u>Parameters Measured or Derived</u>	<u>Instrument or Technique</u>	<u>Quality of Information</u>
1. Lithology	Electric Logs Mud Logging Cuttings Analysis Drilling Rate of Penetration Sidewall Samples Conventional Cores	Good Good Fair Fair Good Good
2. Formation Porosity	Resistivity Logs Sonic Logs Density and Pulsed Neutron Logs Sidewall Samples Conventional Cores	Good Good Good Poor Good
3. Formation Permeability	Electric Logs Computer Proc. Logs Sidewall Samples Conventional Cores (1) RFT (2) DST	Porosity Only Indices-Fair Poor Good Fair Good
4. Fluid Identification	Mud Logging Resistivity Logs Density and Pulsed Neutron Logs (1) RFT - Fluid Sample (2) DST - Fluid Sample (3) Fluid Sampler	Fair Good Good Poor-Good Good Good
5. Geopressured Strata	Drilling Rate of Penetration Mud Logging Shale Density (4) Electric Logs (4) Sonic Log (4) Density Log	Fair Fair Fair Good Good Fair
6. Fluid Pressure	Drilling Rate of Penetration Electric Logs (1) RFT - Pressure (2) DST - Pressure (3) Bottomhole Pressure Gauges Amerada** Hewlett Packard** Sperry Sun	Poor Fair Good Good Good Good Good
7. Formation Temperature	Temperature Electric Log (3) Bourdon-Tube Temperature Gauge (3) Electrical Remote Temperature Gauge (3) Maximum Reading Thermometer	Good Good Good Good
8. Formation Mechanical Strength	Electric Logs Sonic Log Density Log Nuclear Log Conventional Cores } Mech. Prop. Log	 Poor Good
9. Formation Subsidence	(3) Radioactivity Tracer Surveys (3) Strain Gauges	Poor Fair
10. Sand Movement	(3) Sonic Detector	?

- (1) Schlumberger Repeat Formation Tester
(2) Drill Stem Test
(3) After the well is completed
(4) After the Fact of Drilling
** Limited to 12,000 psig

common sizes include 3½-inch, 4½-inch, and 5-inch O. D. (nominal outside diameter). Drilling fluid materials are in good supply for the 17-18 ppg (pound per gallon) muds often required to contain the very high pressures found in geopressured formations. Mud expense is considerable for the specially treated, high density fluids needed; cost of mud materials for a 15,000-foot well may be \$200,000 (1976) or more. Blow-out preventer equipment suitable for 5,000-psi working pressure will be installed for protection against the high formation pressures that may be encountered while drilling. The production string of casing that will be set to complete the well will be fitted with 10,000-psi working pressure equipment because of the possibility of high pressure gas at the wellhead. With a given bottomhole formation pressure of, say 12,000 psig, shut-in pressure may be only 5,000 psig with a column of salt water extending to the surface, but with gas in the well could be about 10,000 psig.

Casing and blowout preventers are very important safeguards against "Kicks" and "Blowouts". Casing must be set and cemented to such depths as to provide a solid, pressure-tight, foundation for the wellhead and blowout preventers in case a high-pressured formation is drilled into. Although the drilling fluid normally provides sufficient hydrostatic head to overbalance and contain the formation pressure, high pressure blowout preventers, wellhead and casing are needed to provide a safeguard in case excessive formation pressure is encountered. Blowout preventers, in such case, will make the difference between a "Kick", which is formation fluid or gas that is circulated out of the well under controlled conditions, or a "Blowout", which is an uncontrolled flow of

fluid or gas from a well. In the latter case, flow to the surface becomes uncontrollable and the hazard of an explosion and fire is created.

The "art" of prediction and detection of geopressured formations is a fairly exact procedure today. Many of the parameters that indicate the proximity of high pressure can be measured within the time needed to circulate from the bottom of the well to the surface, about two hours on a deep hole. Table II lists the techniques available to predict and detect geopressured formations. Continuous plots of mud temperature, fluid weight, cuttings density, and normalized drilling rates make it possible to anticipate dangerous high pressures by departures from straightline trends. Electric logs, from which formation conductivity, resistivity and shale density can be obtained, will give after-the-fact evidence that geopressured formations have been penetrated.

Detection of Abnormal Pressure

The scientific principles involved in the process of shale compaction are fairly well defined. Engineers can predict the pressures to be found in abnormally pressured shales and to some extent predict their occurrence with a fair degree of accuracy, using shale-density and electric-log information from nearby wells. High formation pressures can be detected by —

- Drilling rate;
- Sloughing shale;
- Shale density;
- Gas-cut mud;
- Chloride increase in the mud;
- Mud-temperature increase; and
- Electric-log data.

Table II
PRESSURE DETECTION TECHNIQUES

<u>Source of Data</u>	<u>Parameters</u>	<u>Time of Recording</u>
Seismic Methods	Formation Velocity	Prior to spudding the well
Drilling Parameters	Drilling rate "d" - Exponent Drilling Rate Equations Drill Stem Torque Drill Stem Drag Drilling Porosity Log	While drilling
Drilling Mud	"Kicks" Gas content Flow line mud weight Flow line temperature Chlorides in the mud Drill pipe pressure Pit level, volume Flow rate Hole fill up	While drilling Delayed by the time required for mud return.
Shale Cuttings	Shape and size Bulk density Shale factor Electrical resistivity Volume	While drilling Delayed by the time required for sample return.
Well Logging	Electrical surveys Resistivity Conductivity Shale formation factor Salinity variations Interval transit time Bulk density Hydrogen index Thermal neutron capture cross section	After hole is drilled.
Direct Pressure Measuring Devices	Pressure bombs Drill stem test Wire line formation test	When well is tested or completed.

Other methods more or less direct but generally not as accurate as those indicated above include:

(1) Borehole fluid kicks while drilling caused by formation pressures in excess of hydrostatic mud pressures. Such kicks establish minimum formation pressures.

(2) Surface tubing pressure measurements. The hydrostatic pressure of the fluid in the column must be added to the surface measurements to get the formation pressures.

Drilling rate is a direct means of detecting shale or sand formations containing high pressures. It should be remembered that the rate of penetration is affected by changes in the kind of rocks, bottomhole cleaning by the circulating fluid, bit weight, rotary speed, fluid properties of the mud, and by the type of bit and its condition.

The factors that affect the drilling rate must be held constant if drilling rate is to be used as a means of recognizing a transition from normal pressure to high pressure. A sudden change in the type of rocks cannot be controlled, but a large increase in the rate of penetration, a drilling break, can indicate a change of formation. High pressure may not be present, but the driller should be alert to the possibility of a well flow. Bit weight and rotary speed can be controlled and maintained when it is possible that a high-pressured zone is near. Drilling rate of penetration has been used to predict high formation pressure, particularly in soft formations such as the shales of coastal areas. The procedure used is to determine a normal-rate trend and then, when drilling rate increases above the normal-trend line (other factors being held constant or corrected), to establish the probable high formation pressure.

Maintaining constant bit weight and constant rotary speed is not always possible, but the normalized penetration rate ("d"exponent) can be obtained from the alignment chart in Figure 1. Data required to use the chart include:

1. penetration rate (R) in feet per hour;
2. rotary speed (N) in revolutions per minute;
3. weight on bit (W) in thousands of pounds; and
4. bit size (D) in inches.

Figure 1. Alignment Chart to Determine "d" Exponent from Factors of Drilling Rate. After Jorden and Shirley.

Sloughing shale may be the result of—

1. formation pressure in excess of hydrostatic pressure;
2. hydration or swelling of shale;
3. hole wall erosion caused by fluid circulation, surge pressures, or pipe movement; or
4. fractured or tilted structures.

Sloughing shale is usually the result of formation pressure in excess of hydrostatic pressure, particularly in the softer shales of coastal areas of the United States.

Shale density normally increases with depth because the unit weight of shale is greater when water is squeezed out due to compaction.

Figure 2 shows the normal trend of shale density; when density decreases below the normal-trend line, increased formation pore pressures may be expected. Actual use of this means of detecting formation-pressure increase is difficult because of problems in selecting representative particles of shale and in making precise measurements of density.

Gas-cut mud has always been considered a warning of high formation pressure, but its appearance is not always a serious problem. Gas may enter the mud as a result of the following—

1. gas in shale, the so-called high pressure/low volume shows that are frequently associated with thick shale sections;
2. gas from drilled gas-bearing sands may cause temporary changes in the gas concentration in the mud;

Because gas is compressible, it may give the appearance at the surface of being a more serious problem than it is. Many shales contain gas in

Figure 2. Effect of Shale Compaction on Shale Pore Pressure and Density

the pore space that steadily feeds into the mud of a drilled hole. This feed-in of gas forms a base line on a mud-log chart and is often quite predictable. Gas-bearing sands may considerably increase gas in the mud, particularly if drilled too fast. This is the reason many operators specify that gas sands be drilled at a fairly slow rate, depending on pump capacity, thereby allowing time to circulate out porosity gas and to prevent reduction of equivalent mud weight. A small amount of gas under bottom-hole conditions can appear to be a large amount on the surface.

Chloride increase in the mud is not as easily recognized as changes in gas content. Chloride measurement is usually done by a mud engineer and the information may not be readily available to the driller. This makes it difficult to obtain information on chloride changes. Regular checks should be made of the chloride content of the mud going into and circulated out of the hole. A comparison of the trend levels may confirm that formation fluid is entering the mud due to increasing pore pressure

Mud temperature increase may or may not be an aid in detecting an increase in pore pressure. Mud temperature changes may be caused by a change in the circulation rate, a change in mud weight, a change in rotary speed or bit weight, increased bit torque, addition of caustic soda to the mud, or higher formation temperature. Temperature increase of the mud alone may not indicate that high pore pressure has been encountered. Flow-line temperatures, if correctly plotted against depth, can be used to predict the presence of abnormal formation pressure, as shown in Figure 3.

Electric Log Indications of Geopressures

An induction electric log (I-ES) will indicate the top of a geopressed shale by increased conductivities and lowered resistivities, as clearly indicated on the log illustrated in Figure 4. Conductivity, the irregular curve on the right, increased from approximately 1,000 millimhos/m that had been registered from 12,900 to 13,500 feet to about 3,000 millimhos at 13,700 feet. Note that casing was set in this well just below the top of the geopressed shale. In the same intervals resistivity decreased from about 2.0 ohm-meters to less than 0.5. This is evidence that there is more porosity in the geopressed shales, therefore more water, than would be expected for the depth. Conductivity and resistivity measurements are affected by formation water salinity, temperature, and instrument calibration problems.

Shale conductivity, resistivity, density and acoustic travel time are some of the characteristics measured by electric logs that will confirm that geopressures have been penetrated. Normal compaction of shale with depth as the weight of the overburden increases will result in decreased porosity. For this reason, resistivity should normally increase with depth, sonic travel time should decrease, and shale density should decrease. If deviation from these trends are observed, abnormal pressure (geopressure) will be present.

Formation Fracture Gradients

When wells are drilled in both new or old fields, lost circulation — also termed lost returns — can be a troublesome and expensive drilling problem. It can be troublesome because loss of hydrostatic head in the wellbore can create a situation that will allow formation pressure to

Figure 4. Induction-Electric Survey (I-ES) Will Indicate Geopressured Formations and Distinction Between Sands and Shales.

cause fluid to enter the well, thus the beginning of a blowout, or permit unsupported formations to slough into the well and stick the drill stem. It can be expensive because of the loss of drilling fluid — some muds cost more than \$50.00 per barrel — and drilling delays when rig operating costs may be several hundred dollars per hour.

Formation fractures cause lost circulation; for this reason fracture pressure gradients should be calculated during the planning stage for geopressured wells. The formation fracture pressure is the pressure at which a formation ruptures and drilling fluid feeds into the opening in the rock. Fracture pressure at a given depth is usually expressed as a "gradient" in terms of psi per foot of depth, or the equivalent mud density that would produce the same gradient pressure. Normally formation fracture pressure is greater than the pore pressure of the fluid in porous rock. However, the relationship between formation fracture pressure and pore pressure cannot be generalized and is usually obtained from drilling a number of wells in a given area. Figure 5 is an illustration of a graphical formation fracture gradient prediction for the U. S. Gulf Coast prepared by Matthews and Kelly (1967). Figures at top are mud weight equivalents for pore pressure which are obtained from other wells or electric log calculations. Enter the chart the depth of interest horizontally to the pore pressure curve; read fracture-pressure gradient by dropping to the bottom scale. Other methods are available, notably Eaton (1969), Taylor and Smith (1970), and MacPherson and Berry (1972).

From a plot of formation fracture gradients that will be encountered in a given well, the setting depths for various protective casing strings

Figure 5. Graphical Fracture Gradient Prediction for the U. S. Gulf Coast Area Using the Matthews-Kelly (1967) concept. Figures on Top Represent Mud Weight Equivalents of the Pore Pressure in ppg.

can be established. Casing will allow mud weight sufficient to contain formation pore pressure below the casing setting depth to be employed. Casing will also prevent lost circulation above the casing setting depth.

Problem Areas of Test Data

Although electric logging procedures leave little to be desired in the classification of the formations and the lithological sequence there are many problems when correlating the formations from well to well in the Gulf Coast area, particularly in geopressured shales and sands. This is due to the manner in which these strata were deposited, the amount of compaction that has taken place in geological time, the large number of faults, and the near impossible task of correlating shale formations. Micropaleontology studies, whereby certain micro-fossils were identified in rocks of specific age, have been used with rather indifferent success to correlate shale formations thus to predict geopressured sands. Mud logging techniques, in which gas and cuttings in the mud returns are measured and logged versus well depth, have proven to be fairly reliable, particularly to identify shale and sand strata and the kind of fluids in the pore space. Shale density plots have been found to be good indicators of geopressured rocks, but problems arise (1) to properly identify new cuttings from bottom, (2) properly clean, and (3) shale density determinations. Geopressured shales are more porous, thereby less dense, than the trend of shale densities plotted against depths. A drilling rate log may give valid indication that an over-pressured sand or shale has been entered, but the affects of hydrostatic pressure versus formation pressure, rotary speed, drilling weight and bit size must be considered. These can be normalized, as explained

previously, thus plots of drilling rate versus well depth can be used to indicate that a geopressed formation has been encountered. Sidewall samples, which are short cores taken from the wall of the well using explosive-driven hollow bullets, will give good indications of lithology. The manner in which these samples are obtained disturbs the matrix of the core, thus porosity and permeability measurements are of little value. Conventional cores, properly packaged and analyzed, will enable true porosity and permeability values to be obtained. Bulk compressibility and shear modulus can be measured from core samples loaded in a testing machine.

Electric resistivity logs are valid indicators of average resistivity values for sands and shales, but it is necessary to obtain these readings far enough from the borehole to be true formation fluid, rather than mud filtrate, in the pore space of the rocks. Induction logs will nearly always measure true resistivity because the radius of investigation is some distance from the well. Other focused logs will obtain true formation resistivity at the bottomhole temperature involved. Resistivity values can be converted to apparent porosity and apparent salinity of the formation fluid in clean water sands. Sonic and density logs will indicate total porosity, which can be converted to apparent porosity when the type of fluid in the pore space is known. Conventional cores can be measured precisely for porosity and permeability.

Formation permeability cannot be measured directly by electric log methods, though permeability can be inferred from the displacement of formation fluid by mud filtrate invasion. Porosity measurements will permit some estimate of permeability because permeable rocks must have

porosity. Where porosity is known, the so-called Archie equation, and similar expressions, can be used to calculate the Formation Factor "F" which can be used for saturation determinations. Computer processed logs, when provided with sufficient log data, can calculate permeability indices by taking all log information into account. Conventional cores will permit good assessment of permeability by means of laboratory analytical methods. The Schlumberger RFT formation tester can be reset until intervals of good permeability are located in a porous zone; flow of formation fluid into the tester will permit a fair assessment of the relative permeability of the strata exposed to the borehole. A full-scale test of permeability can be made by a drill stem test, though the need to make the DST through perforations in casing for geopressured formations may effect the result.

Formation fluid identification can be made by resistivity and other electric logs using quantitative interpretation methods. Formation fluid resistivity values, corrected for bottomhole temperature, can be directly related to apparent salinity on the basis of an equivalent sodium chloride solution, but other minerals cannot be identified. Fluid samples obtained by the Schlumberger RFT tool are relatively small, thus the fluid recovered from a permeable zone in the well may contain a large percentage of filtrate that has invaded the zone. Resistivity of the recovered fluid compared to the resistivity of the mud filtrate will enable the percentage of formation water in the sample to be calculated. Formation pressure, temperature, and the amount of dissolved gas in the fluid sample — corrected for dilution by mud filtrate — will be quite valid. Drill stem test fluid samples, particularly

after a lengthy flow test, will be quite valid as to pressure, temperature, dissolved gas and chemical composition. The sample chambers for these devices can be removed for transport to a laboratory for analysis. Several sampler devices that can be run on a wireline are available; these are equivalent to open-end tubes which can be closed by timer, mechanical, or electrical means. These tools can obtain a fluid sample under bottomhole conditions of temperature and pressure, but the sample will cool as it is pulled to the surface and its pressure will be lowered. This will mean precipitation of dissolved gas and silica, etc., unless the samples are quickly diluted when taken from the well.

Geopressured formations have been the bane of rotary drillers for a long time; disastrous and expensive blowouts have taken place when such formations were encountered unexpectedly. Casing strong enough to contain the geopressure must be set before the formation is penetrated and the hole filled with drilling fluid of appropriate density to hold back the geopressured fluids. Drilling parameters such as rate of penetration, shows of gas, oil or saltwater in the mud returns, shale cuttings density, and other indicators are fairly obvious signs that a geopressured formation has been encountered. Gathering this information depends to a great extent on the competence and alertness of the observers. Well kicks, which are incipient blowouts caused when hydrostatic pressure is lower than formation pressure, are usually slow to develop and sometimes are most unobtrusive when they begin. Electric logs can be used to spotlight geopressured formations by indicating lower resistivity than expected for the well depth, increased conductivity, increased porosity, and lower density. But, these are "After-the-Fact" of drilling;

the hole has to be drilled, pipe pulled out, and logs run before electric log information is available.

Formation pressure determinations can be made using electric log data, by drilling rate, and by direct measuring devices such as the Schlumberger RFT tool, drill stem test equipment, or downhole pressure gauges. Electric log data does not permit measurement of formation pressure, but instead a family of curves can be drawn relating depth to resistivity and conductivity values to geostatic pressure gradients in a given area. These curves can be used as an overlay on plots of well depth versus resistivity or conductivity trends; when the values fall between formation pressure gradients, formation pressure at specific well depth can be estimated. Drilling rate of penetration will permit only a poor assessment of formation pressure. Differential between hydrostatic and formation pressures is an important factor affecting drill bit performance; at high differential the bit will drill slower than at low differential, other factors being constant. When negative differential exists, i.e., formation pressure greater than hydrostatic, the bit will make hole with little applied mechanical or hydraulic effort. But a blowout will be underway if the formation is porous and the negative pressure differential is appreciable. The Schlumberger RFT tool will produce valid readings of formation pressure; these values can be monitored on the surface, thus waiting time can be regulated to obtain stabilized pressure readings. Drill stem test equipment includes pressure gauges that are run to or near the depth of the producing formation. Static or dynamic pressure readings will thus be about the same as formation pressure when the well is shut in or flowing. DST pressures

are recorded on 24-72 hour clock-driven charts, thus the record would be limited to 1-3 days time. Several types of bottomhole pressure gauges run on wirelines are available; these are run to the depth desired and pressures recorded on clock-driven charts. Hewlett-Packard makes a quartz crystal bottomhole pressure gauge that is run on an electric cable, thus readings are obtained and recorded on the surface. Sperry-Sun has a remote reading bottomhole gauge which utilizes a downhole chamber connected to a surface monitor by a small diameter tube filled with nitrogen gas. Tube temperature affect must be taken into account.

Formation temperatures can be recorded by electrical logging means, by a mechanical bourdon tube temperature gauge, or by maximum reading mercury thermometers. Electrical-conductor remote reading gauges utilizing downhole temperature sensors are also available.

Formation mechanical strength estimates utilizing electric log data to infer the intrinsic strength from the values of the shear modulus and bulk compressibility are probably of little value. There is some evidence that there is a correlation between intrinsic strength and the dynamic elastic constants, as determined from sonic-velocity and density measurements. Sonic log values may not be correct because the tool is not close enough to the wall of the hole, thus mud will interfere with the acoustic readings obtained. Actual compressibility tests on cored samples will give valid information of rock strength. There is no information on the affects of water flowing through a sandstone formation to break down the matrix of the rock.

Formation subsidence measurements can be taken from radioactive markers placed at carefully measured increments of depth in a well

specifically for geothermal testing. These markers can be surveyed at various time intervals and the apparent compaction and/or subsidence measured by comparison with the original depths and measurements between the markers.

Sand movement from the productive zone into the well may be a problem. Sand particles in the water flowing into the well may abrade and wear the mechanical equipment to such an extent that the well cannot be produced; alternatively sand entry into the well bore can plug the casing or tubing thus to shut off fluid flow. Production of minor quantities of solid material is sometimes difficult to measure.

ELECTRIC LOGS AND SURVEYS

Electric well logging is a well-established and highly developed technology. Equipment is routinely available to obtain measurements in deep wells having pressures of 20,000 psig and temperatures of 350°F. Existing logging methods allow the determination, with reasonable accuracy, of lithology, formation porosity, density, fluid content, and distribution in terms of saturation. Other parameters such as temperatures, rock strength, strata inclination (dip) and course of the borehole can be measured. After casing is set in a well other measurements can be performed to determine the movement and distribution of produced fluids, thus to establish well performance and the efficiency of completion measures to drain the underground reservoir. Existing electric logging and surveying techniques can satisfy most of the requirements for formation evaluation in geopressured wells; tool sizes, pressure and temperature limitations are satisfactory for the geopressured well depths expected in the Texas-Louisiana Gulf Coast areas. The program of electric logs and surveys for a proposed geopressured well should be designed to provide all information needed for prediction of well performance during the useful life of the project. Besides information obtained during the drilling operation, electric surveys can be used to determine the flowing efficiency from the perforations, estimated stability of the well bore (rock strength), corrosion and scaling, compaction of the producing interval, subsidence of the overlying strata, etc., most of which will be related to the production of geopressured fluids.

Open Hole Logging Methods

Conventional electric logging is possible because electric current

can pass through earth formations, owing to the presence of mineralized water in the formation. Even so, formations also resist passage of an electric current. In other words, while current does pass through a formation, the formation nevertheless resists current. Because of this resistance to the passage of electric current, the formation is said to have "resistivity." To state this more precisely, the resistivity of a substance is the resistance measured between opposite faces of a unit cube of that substance at a specified temperature. The unit of resistivity in electrical logging is taken as ohm-meter (simplified) which is usually abbreviated, ohm-m.

The resistivity of any formation is a function of the amount of water in that formation and the resistivity of the water itself. Figure 6 depicts an electric current being passed through a container of water. The resistivity offered by this container of water is directly dependent upon the amount of water in the container and the specific resistivity of the water. If the cross-sectional area is doubled, the resistance to the electric current flow will be one-half as much. The graph shown in this figure illustrates that the saltier the water, the lower its resistivity; and the hotter a given brine, the lower its resistivity becomes.

Figure 7 shows an electrical current being passed through another container of water. When sand grains are added to this container, the amount of water is reduced and the resistivity of the entire container is increased. If more sand is packed into the container, more water is displaced and the resistivity increases further. Thus, a formation with a lower porosity — i.e., less water — will have a higher resistivity than a high-porosity formation. Because oil, like sand grains,

Figure 6. Resistivity of a Formation Depends Upon the Apparent Salinity of the Water and its Temperature.

Figure 7. Reduced Porosity and Increased Oil Content in the Pore Space of a Rock Will Increase Resistivity.

is a nonconductor of electricity, adding oil to the container displaces water and increases the resistivity of the contents of the container.

Electric Survey (ES): Figure 8 is a schematic drawing showing the equipment for wireline logging of a well. Drilling is stopped and the drilling string is pulled out of the hole, usually leaving the well full of drilling mud. Electric signals from the sonde are transmitted through insulated conductors in the logging cable to electronic receivers in the truck and recorded, or logged, as the instrument is moved along the borehole of the well. These signals are automatically plotted against depth to produce "curves" as illustrated by Figure 9. Conventional practice is to use Track 1 for the spontaneous potential (SP) curve. The SP curve is a graph that shows the electrical potential, or voltage, that underground formations generate. Tracks 2 and 3 are curves similarly plotted against depth showing the resistivity or conductivity of the formations to the passage of an electric current from a power source on the logging truck. Well depths are shown in the blank space between the SP and other curves.

Spontaneous Potential (SP): The SP log is a record of the electric voltages in the mud opposite the formations at different depths in a borehole. Varying voltages — potentials — will be generated by electrochemical forces that occur naturally in the formations. The measurement is made in uncased, or open, hole containing a water-base fluid between an electrode on the sonde in the borehole and a stationary reference electrode at the surface. SP values are very small, thus are measured as "millivolts."

Usually the SP curve shows two characteristics. It will be a more

Figure 8. Arrangement of Equipment for Electric Logging.

INDUCTION - ELECTRICAL LOG

Figure 9. General Appearance of an Electric Log.

or less straight line opposite impermeable shales. It will show peaks to the left opposite permeable strata. The shapes and amplitudes of the peaks may be different according to the type of formation. However, there is no definite correspondence between the amplitudes of the lines and how porous or permeable the rocks are.

The principal uses of the SP curve are to:

1. Detect permeable beds, e.g., sands vs. shale formations.
2. Locate the boundaries between beds.
3. Permit correlation of equivalent beds from well to well.
4. Obtain good values for formation water resistivity.

The SP deflection is measured with respect to the "shale base line," a reference line which can generally be traced along the extreme positive side of the SP curve. See Figure 10. Usually the shale line is a straight vertical line, but field experience has shown that in certain regions there may be shifts of the shale line. Sometimes these shifts are found systematically at the same places in the geological column and can be used as markers. Also the maximum SP deflections toward the negative side on the log are often the same opposite permeable formations. Thus it is usually possible to draw, parallel to the shale line, a "sand line" on the log.

The resistivity of fluid in the well bore will have a relationship to the resistivity of the fluids in the formation. It is this relation that causes the SP curve to deflect. Figure 11 shows that the SP effect is the greatest for a saltwater sand when the well contains fresh-water mud, as at left. If the drilling fluid is brackish, center, note the SP curve goes to the right in freshwater sand, is straight in a brackish

Figure 10. Sand and Shale Lines on the Self Potential (SP) Curve of an Electric Log.

Figure 11. SP Effect for a Sand Formation Will Vary as Mud Resistivity Relates to Formation Water Resistivity.

water sand, and is less pronounced for the saltwater sand than in the first instance. With saltwater mud, as shown by the right-hand column, these effects are accentuated.

Geological correlation is one of the main uses of the SP curve because the shapes of these curves in different wells for certain geologic horizons will be comparable. They reflect the layering sequence in the process of sedimentation. By observing variations on the SP curve deflections, it is possible to establish corresponding variations in the geologic sequences such as lensing, convergence, shale-out, etc.

Resistivity Curves: In standard electric logging, usually three conventional — i.e., unfocused — resistivity curves are made. These are a short normal (AM = 16 in.), medium normal (AM = 64 in.), and a standard lateral (AO = 18 ft., 8 in.). Generally, all curves are recorded simultaneously and displayed in Tracks 2 and 3 of the log, as shown in Figure 12.

Figure 13 is a schematic drawing of a normal resistivity logging device. A current of known intensity is sent between two electrodes, A and B. A is on the sonde; B may be on the sonde or at the surface. The difference of potential between electrodes A and B is measured by the electrodes, M and N. The apparent formation resistivity is proportional to the measured difference of potential. The sonde must be run in holes containing electrically conductive mud or water. For normal devices, the distance AM is small in comparison with MN, MB, and BN. In practice N or B may be in the hole a large distance above A and M. The voltage measured is practically the potential of M due to current from A referred to an infinitely distant point. The distance AM of a normal device

Figure 12. Tracks 2 and 3 Illustrate Conventional Resistivity Curves on an Electric Survey (ES).

Figure 13. Normal Resistivity Logging Device.

is its "spacing".

For a lateral logging device, shown in Figure 14, measuring electrodes M and N are close to each other and located several feet below the current electrode A. Current electrode B is at a great distance above A, usually at the surface. The voltage measured is approximately equal to the potential gradient at the point of measurement O, which is midway between M and N. The distance AO is the spacing of the lateral logging device.

In either the normal or lateral device the spacing governs the distance of investigation around the borehole — the greater the spacing, the greater the radius of investigation. For example, a very short spacing might investigate only the mud in the borehole. Figure 15 illustrates how filtrate of drilling fluid causes flushing ahead of the bit, thus creating an invaded zone which contains only residual hydrocarbon saturation plus filtrate from the drilling fluid. To avoid the invaded zone and obtain an indication of the true resistivity of a formation, the investigating device must make its observations some distance from the borehole. The short normal device is well adapted for bed definition, boundary determinations, and correlation of formations that have low or moderate resistivities. The lateral device generally shows sharp peaks at the level of thin resistive beds, but the actual thickness of thin beds is often obscured by the presence of blind zones and false peaks. The precision of the normal and lateral curves for bed definition is limited in hard formations and is quite poor when salty muds are used. In those cases, other types of logs must be taken to determine water saturation in the uncontaminated zone. Correction for fluid-filtrate

Figure 14. Lateral Resistivity Logging Device.

Figure 15. Mud Filtrate Will Flush Permeable Zones.

invasion requires reasonable assumptions, based on local experience, as to the depth of invasion. When invasion is very deep, correction for it becomes difficult or impossible.

A normal device has a depth of investigation twice the AM spacing; thus the short normal will investigate a sphere with a radius of 32 inches and the medium normal about 10 feet from the hole. As the length of spacing increases, the curve is flattened; thus, it is necessary that a bed be approximately four times thicker than the AM spacing before the recorded curve can be expected to furnish a proper value of true formation resistivity. Short electrode spacings of the short normal device is necessary even though its sphere of investigation is shallow.

Microcaliper Logs: This device is designed to furnish a means of accurately locating thin, permeable zones in open holes drilled with water-base muds. The SP curve, while useful in this respect, does not furnish adequate definition in many areas. One type of Microlog sonde is shown in Figure 16. Three electrodes spaced 1 inch apart — A, the current electrode, and M_1 and M_2 the pickup electrodes — are placed in a vertical line on an insulated pad which is forced against the wall of the hole. The electric potential differences between M_1 and M_2 and between M_2 and a reference electrode at the surface are measured. Since the pad is pressed tightly against the hole wall, these electrode systems measure the resistivity of a very small volume of material adjacent to the borehole. A second pad is often run opposite the Microlog sonde for recording hole diameter; this will produce the Microcaliper Log. It serves to indicate the presence of caved sections and to verify the

Figure 16. One Type of Microlog Sonde.

presence of mud cake which is indicative of a permeable section. A standard SP is usually taken in conjunction with a Microcaliper Log. Figure 17 shows Microlog and Microcaliper Logs. Note that the Microcaliper shows a reduced hole size — due to wall cake — opposite the permeable zones and an enlarged hole opposite the shale intervals. From the knowledge of the resistivity of the filtrate, which will be about the same as the resistivity of the mud at bottomhole temperature, the porosity of the formation may be calculated; however, these determinations may not be reliable because of mechanical problems with the pad, wall cake, etc.

A focused current device, the Microlaterolog, is similar to the Microlog but has extra electrodes to cause the current to flow horizontally outward from the borehole, thus producing a log representative of the formation at a greater distance from the wellbore than is possible with the regular Microlog. The resistivity of the filtrate flushed zone can be accurately measured by a Microlaterolog. This permits calculation of the effective porosity, instead of total porosity such as measured by neutron and sonic logs. Figure 18 shows (a) the arrangement of electrodes on the insulating pad of a Microlaterolog sonde and (b) the paths of the measuring and focusing currents.

Induction Logs: Induction logging is a method wherein the conductivity, the reciprocal of resistivity, of the formation is measured by means of induced currents without the help of contact electrodes. It is a focused logging method which requires no current flow from the tool into the formation; therefore, it can be used in empty holes or in holes containing oil-base, freshwater, or other type of drilling fluid

Figure 17. Microcaliper and Microlog Surveys.

Figure 18. Electrodes on a Microlaterolog Pad, and the Paths of the Measuring and Focusing Currents.

that is not conductive.

The bottomhole instrument contains a transmitter coil that is activated by a constant alternating current from an oscillator. The receiver coil is connected to an amplifier and a measuring galvanometer on the surface. The alternating magnetic field created by the transmitter coil on the tool induces eddy currents in the formations. These eddy currents have their own magnetic field which induce a voltage in the receiver coil. Accordingly, the voltage induced in the receiver coil and recorded by the galvanometer on the surface depends upon the conductivity of the surrounding earth.

In addition to the two main coils, as described, induction logging sondes also include several additional coils whose characteristics and position on the sonde are chosen to minimize as much as possible the influence on the measurement of the mud column and formations above and below the instrument. The recording equipment includes a reciprocal computer, making it possible to record a resistivity curve as well as the conductivity curve. Along with the induction electrical survey (I-ES) instrument, a 16-inch normal and SP recording devices are also run. The conductivity curve of the induction log device is recorded on a linear scale having its zero at the right side of the chart; deflections to the left correspond to increasing conductivity. The usual type of instrument employed is the 6 FF 40 sonde, comprised of six coils with the main coils 40 inches apart. Figure 19 illustrates an I-ES log taken in conjunction with a Microlog and caliper. The resistive sand sections at "A" and "B" produced gas condensate during a test. Note the hole size reduction of approximately $\frac{1}{2}$ inch at 4166 to 4180 on the caliper log survey.

$R_m = 0.95$, $R_{mf} = 0.61$ AT B.H.T. OF 117°F $d = 7 \frac{7}{8}"$

Figure 19. SP, Induction, 16-In. Normal, and Microlog Curves.

An induction logging tool is particularly useful for measuring high-porosity, thin-bedded formations because a large part of the signal comes from the uninvaded formation away from the well bore. If formation thickness is approximately twice the electrode spacing — e.g., 80 inches or more for 40-inch tools — most of the signal will come from the formation opposite the sonde and be influenced very little by adjacent formations. This gives a better measure of thin bed resistivity than an ES log and reduces the need for correction charts. The induction-log reading can usually be taken as the value of true resistivity with sufficient accuracy for all practical purposes.

Dual Induction-Laterolog (DIL) curves for deep induction, medium induction, and shallow Laterolog investigation can be recorded simultaneously and recorded on logarithmic scales. Wide ranges of resistivity values are obtained by the logarithmic scales that are employed. This will permit quick estimation of the degree of invasion, and vertical focusing makes possible reliable evaluation of beds as thin as about 5 feet. Figure 20 illustrates a Dual Induction-Laterolog presentation.

Acoustic Log: The acoustic, or sonic, log was first recognized in 1954 as a porosity measuring tool. It was originally developed as an aid for interpreting seismic exploration data but proved so effective in determining porosity that it became the standard porosity tool in many areas. It measures the depth versus the time it takes for a sonic impulse to travel through a given length of rock. The rate of travel of the compressional wave through a rock depends on the composition of the formation and the fluids it contains. Since the type of formation can

Figure 20. Dual Induction-Laterolog Presentation.

be ascertained by other logs, and because sonic transit time varies with relative amounts of rock and fluid, porosity can usually be determined with good accuracy.

Table III gives the sonic velocities and corresponding travel times — in microseconds per foot — for various fluids and solid materials. Some of these values are averages and may vary with depth in subsurface formations.

Figure 21 shows diagrammatically one type of sonic logging device. It consists of a sound generator at the top and two receivers positioned some distance below it. The body of the sonde between the generator and receivers must be made of low velocity material; that is, sound energy must travel through the sonde body slower than through the formation being investigated.

The sonic logging device operates in the following manner. First, a sound pulse is emitted by the generator. This pulse then passes through the mud and mud cake into the formation. The pulse proceeds through the rock matrix and pore spaces. Increased porosity decreases the sonic reflectivity. The portion of this pulse which energizes the receivers travels through the formations near the borehole. The pulse travels slower through the mud than through the formation. Its refracted "front" through the formation, mud cake, and mud causes the upper receiver and then the lower receiver to generate a signal. A short time later, which may be tens or hundreds of microseconds later, the energy that has traveled through the mud and the sonde body reaches the receivers. By this time the receivers have been rendered insensitive by appropriate electric circuitry. As a result, this pulse is not recorded. One-foot

Table III

SONIC VELOCITIES AND TRAVEL TIMES
FOR VARIOUS FLUIDS AND SOLID MATERIALS

Material	Sonic Velocity (Feet per second)	Travel Time, ΔT (Micro-seconds/ft)
Air (Standard Temperature and Pressure)	1088	919
Methane	1417	706
Oil	4300	232
Water or mud	5000 - 5300	200
Neoprene	5300	189
Shales	6000 - 16,000	167 - 62.5
Rock Salt	15,000	66.7
Sandstones	up to 18,000	55.6
Anhydrite	20,000	50.0
Limestones	up to 23,000	43.5
Dolomite	24,500	40.8

Figure 21. One Type of Two-Receiver Acoustic Logging Device.

spacing of the receivers is commonly employed, and in practice the difference in time between reception of the energy pulse by the two receivers is recorded. Inspection of the energy paths to the right of the sonde shows that the travel times in the mud and wall cake cancel out, provided the hole is essentially uniform in diameter between the two receivers and provided the sonde is parallel to the hole wall. Only the travel time, ΔT , is recorded; this is the time required for the energy to traverse one foot of formation. The recorded velocity is the average for the material between the receivers. The log is a plot of velocity vs. depth. In practice the acoustic sonde is provided with an SP electrode and caliper arrangement so that three curves may be recorded simultaneously as shown in Figure 22. As stated before, the acoustic log is widely used for determination of formation porosity, which is related to specific travel time, depending on the type of rocks. When the rocks are sandstone, limestone, and the like, porosity values can be marked directly on the log corresponding to the specific acoustic travel time.

Acoustic logging devices respond to fluid-filled porosity and to the specific sound velocity of the fluid contained in the pore space. When oil and water are present in the invaded zone, there is no need to adjust for residual oil saturation since there is very little difference in the elastic velocity of these fluids. When gas is the reservoir fluid, the residual gas saturation in the flushed zone weakens the sonic wave to the extent that cycle skipping becomes a characteristic feature. Cycle skipping occurs when the signal is just strong enough to activate the top receiver but not the bottom one. Skipped cycles occur frequently in clean, unconsolidated sands containing gas because the sand has too

Figure 22. Example of an Acoustic (Sonic) Log.

little rigidity and the signals become weaker. A shaly sand does not exhibit skipped cycles because of the increased bonding between sand grains by clay particles.

It is necessary to run an acoustic log in a fluid-filled open hole. The presence of mud in the hole is required in order to provide an acoustic coupling between the tool and the formation. A gas-cut mud will accordingly reduce the coupling, and it is impossible to acoustic log a gas- or air-filled hole.

Radioactivity Logs: Electric logs must be run in open hole to avoid short circuits through the steel casing. This restriction does not apply to radioactivity logs, which may be run in either open or cased holes. Two curves are commonly logged simultaneously to obtain formation radioactivity characteristics. The Gamma Ray curve will usually appear as the left-hand track and is similar to the SP curve; the Neutron curve which appears on the right-hand track is somewhat analogous to the resistivity curves of an ES log.

Certain elements exhibit nuclear disintegration by emitting energy in the form of alpha, beta, and gamma particles. The first two particles have relatively low penetrating power and may be effectively stopped by thin walls of solid materials. Gamma particles, or rays, on the other hand, are similar to X rays and have the capability of penetrating several inches of rock or steel. Consequently, a properly shielded device can be made to respond only to gamma radiation. All rocks contain traces of radioactive minerals and, as a consequence, will emit measurable radiation. The magnitude of these emissions is highly variable in different geological provinces but is quite uniform over wide areas of a

province. Figure 23 shows the relative intensity of gamma radiation in typical sedimentary rocks.

There is another kind of invisible radiation — neutron — which is not emitted in any natural radioactive process but is produced by nuclear disintegration. This radiation can penetrate several feet of lead and is so difficult to observe directly that it remained undiscovered long after alpha, beta, and gamma rays were well known. Neutrons are applicable to well logging because their reaction with rock material produces effects that can be detected in the borehole. Accumulations of petroleum cannot be observed on the gamma ray curve of a radioactivity log. Likewise, no positive indication of petroleum occurs on the neutron curve since water and oil are nearly alike in their hydrogen content, which is the main element measured by a neutron log.

Gamma Ray Log: A gamma ray logging device of the ionization chamber type carries a chamber containing an inert gas at high pressure that can be penetrated by gamma rays from the formation. Some of the gamma rays collide with the gas atoms in the chamber and liberate electrons from the gas. When electrons are freed from the gas, the gas becomes electrically charged or ionized. The electric current resulting from ionization of the gas is automatically amplified and recorded at the surface. The magnitude of the current is directly related to the intensity of the gamma radiation at any depth. Gamma radiation is not emitted at a constant rate, but the logging speed can be adjusted to obtain a true statistical picture of radiation for a specific locality. Some GR logging devices utilize Geiger or scintillation type counters.

Since the gamma ray curve measures the natural radioactivity of

Figure 23. Relative Intensity of Gamma Radiation in Sedimentary Rocks.

sediments, and because this varies with the rock type, gamma ray logs may be used to define the lithology of a geological section. In sedimentary rocks the gamma ray log will normally reflect the shale content of the formations because radioactive elements tend to concentrate in clays and shales. Clean sand formations usually have a very low level of radioactivity unless contaminants such as volcanic ash or granite wash are present, or when the formation waters contain dissolved potassium salts. The gamma ray log is often substituted for the SP curve where hole conditions make an ES log unsatisfactory, for example, when saltwater or oil-base muds are used.

Neutron Logging: Neutrons exist in the nuclei of all elements except hydrogen. Neutrons have approximately the same mass as a hydrogen atom but have no electron charge. When neutrons are emitted from fissionable, or radioactive, material, they possess very high velocities. However, neutrons are rapidly slowed down by collisions with other atoms. Atoms of nearly the same mass as the neutron are most effective in slowing neutrons down. Therefore, neutrons are greatly slowed by collisions with hydrogen atoms. Almost invariably, there is more hydrogen contained in shale or clay than in fluid-filled limestone or sandstone. Hence, neutrons are affected more by shale or clay than by porous rocks such as limestone or sandstone. This means that the hydrogen content of a formation can be determined with neutron logging devices. The hydrogen content, in turn, is an indication of the type of rock the logging tool is investigating.

A typical neutron logging sonde utilizes a device similar to the gamma ray tool; however, it is modified to include a container of a

highly radioactive source of neutrons which is suitably shielded from the detector chamber. Neutrons from the radioactive source in the tool enter the adjacent formations and collide with various atomic nuclei in the formation. If the rocks entered contain little or no hydrogen, the neutrons emitted from the source will not be immediately slowed and will continue to penetrate the rock until they are captured by some element. When the neutron capture by an element in the formation takes place, gamma rays of capture will be emitted by the capturing element. These gamma rays produced are of much greater intensity than the natural gamma rays already present; thus, the produced gamma rays can be measured separately. When the radioactive neutron source is opposite hydrogen-bearing rocks, the emitted neutrons are slowed by collisions with the hydrogen nuclei and are quickly captured. When quick capture occurs, the detector in the logging tool shows a decrease in radiation (or neutron) intensity. Conversely, when capture is slower, as in the case of rocks with less hydrogen, radiation intensity returned from the formation shows less decrease.

Aside from shale, rock materials vary in their hydrogen content from essentially zero to a maximum depending on chemical composition, porosity, and the nature of the fluid in the pore space. Because the neutron curve is principally affected by the hydrogen in the surrounding space, and because fluids such as water, oil, or gas contain hydrogen, it responds to variation of porosity. As long as the pores are fluid filled, there will be more hydrogen as the porosity increases and consequently the neutron curve will register a lower intensity. Less fluid, corresponding to less porosity, causes an increase in the neutron curve.

Figure 24 illustrates gamma ray and neutron curves logged through a sequence of sands and shales in open hole filled with water-base mud. The interval above 8790' with higher average radioactivity contains mostly shales. The interval below that depth, where the radioactivity is lower and comparatively steady, is mostly sand. In the lower section, the deflections of the neutron curve reflect variations in porosity. The thin beds, as "A" and "B" within the upper interval, correspond to intermediate radioactivity levels and intermediate neutron counting rates, so these beds must be shaly sands.

Density Log: A special type of radioactive log has been developed for open-hole work that responds principally to variations in the specific gravity of the formations. The density logging device is held against one side of the borehole by a spring arrangement to insure close proximity to the formations. Figure 25 illustrates the principle of density logging. The density logging sonde is similar to the gamma ray-neutron instrument but has a small window where the gamma rays may enter the detector, which is pressed tightly against the wall of the hole. It is heavily shielded except for the window on the side adjacent to the formations. In this way the gamma radiation that reaches the detector is effectively limited to that which penetrates into the rock and is then scattered back in the direction of the detector. Since the absorption and scattering of gamma radiation depends largely upon the amount of matter and consequently the electrons in its path, the density logging device will respond according to the variations of specific gravity of the rocks. The density log is recognized as an excellent porosity measuring device, particularly for shaly sands. It is sometimes referred

Figure 24. A Gamma Ray and Neutron (GR-N) Log.

Figure 25. Schematic Drawing of a Dual Spacing Formation Density Logging Device (FDC).

to as Gamma-Gamma Density Log, Formation Density Log, or Densilog.

A radioactivity density log is a continuous record of variations in the density of the lithologic column penetrated by the borehole. This is termed "bulk density" because, in the case of porous rocks, the density measured includes the density of the fluid in the pore spaces as well as the grain density of the rock. There is a relation between the contribution to the bulk density of the fluid in the rock pores and the porosity of the rock. This relation is the basis for the calculation of porosity from a density log. To measure the formation bulk density, a beam of gamma rays is directed into the rock. At a fixed distance from the source a counting system detects changes in the intensity of the gamma ray beam resulting from changes in the bulk density of the formation. The higher the density of the formation, the higher the intensity of gamma radiation measured at the detector, because denser material will deflect more of the emanations from the source of radioactivity.

Most density logging devices record simultaneously a gamma ray log, density log, and caliper log; thus they are sometimes called "GDC" surveys. A standard gamma ray section detects the natural gamma radiation of the formations. A collimated gamma ray source and shielded detector are mounted in a metal shoe which is attached to a retractable arm. A second metal shoe is mounted in a similar fashion parallel to and directly opposite the source-detector assembly. When these plates are extended, they are kept in close contact with the borehole wall by spring pressure. During logging, lateral movement of the two shoes is converted to make a continuous record of the borehole diameter, lithology, and density. A correction is needed where the contacts between the

shoes and the formation are not perfect owing to roughness of the hole wall or because of filter cake. This correction may be fairly large but can be made automatically by most density logging equipment.

Density log information is presented in Figure 26. The formation density curve is recorded in Tracks 2 and 3. The right-hand curve, a dashed line, shows how much compensation has been applied to correct for mud cake and hole wall roughness. The caliper log and gamma ray curve are recorded simultaneously in Track 1.

The density log is applied only in open holes, since the presence of casing and cement would prevent contact with the rock itself. By comparing the density of the various strata it is possible to identify them and also to infer some of their characteristics. Porosity correlates very well with density because the rock matrix must decrease in density as its porosity increases. The density-log variations within a uniform sandstone or limestone body must therefore represent increases and decreases of its porosity. Consideration must be given to the factors which control the response of a density log. For example, the clay minerals which are found in sandstones have nearly the same density as the sand grains of the rock; thus the bulk density observed will be close to the true density of the sample. Also, the mixture of fluids in the pore space will usually have a density of 1, i.e., one gram per cubic centimeter; thus bulk density observed can be converted to porosity values, provided corrections for mud cake, grain density, and fluid density are taken into account.

Figure 26. Formation Density Log Presentation.

Wireline Formation Tester

The Schlumberger Repeat Formation Tester (RFT) generally resembles the earlier wireline formation tester (FT) which was introduced in the mid-1950's. A number of improvements have been made, notably, (1) several tool settings can be made before attempting to take a sample, (2) "pretest" capability that enables the operator to ascertain if the packer seal is holding, and (3) that fluid flow, i.e., permeability, is adequate to obtain a sample in a reasonable time. Two separate fluid sample chambers make it possible to obtain two separate samples on a single run. The RFT tool provides for sampling in both consolidated and unconsolidated formations. Pressure-recording accuracy is within 0.2 percent or better.

The RFT tool consists of a downhole assembly, generally as shown in Figure 27, and control panels in a truck. The downhole device is run on a multi-conductor wireline cable that is used to lower and recover the tester from the well. Figures 28 and 29 show a functional schematic diagram of the RFT tool and pretest pressure indications as they appear on the control panel. Figure 30 is a complete recording of a sample test.

A small pretest chamber (15-cc volume) is located between the packer and the valves leading to the sample chambers. If pressure build-up in this chamber indicates that a satisfactory seal has been made, its rate of fill up will provide an indication of the time needed to fill one of the larger chambers. If all "pretest" indications are satisfactory, one of the seal valves is opened to allow fluid to enter the sample chamber. The seal valves may be closed and opened at any time during a test in order to obtain a pressure build-up measurement.

Figure 27. Setting Section of the Repeat Formation Tester (RFT) Mechanical Unit.

Figure 28. Functional Schematic of the Repeat Formation Sampling System.

Figure 29. Pretest Indication of Pressure of an RFT Test.

Figure 30. Record of a Formation Test Taken by an RFT Tester.

If pretest indications are negative, the probe of the tool is retracted, the pretest chamber is automatically emptied, the equalizing valve is automatically opened as the tester is moved to another place in the well. Fluid sample chambers of one to twelve gallon capacity are available.

Cased Hole Logs and Surveys

Gamma ray and neutron logs make it possible to log lithology and relative porosity, locate gas-liquid contacts through casing, and locate casing collars to check depth measurements. Modern tools are small enough to be run through tubing and are used to correlate precisely perforation depth below the tubing with the formation of interest regardless of the measured hole depth. Neutron devices can be employed to log saltwater outside casing to offer a means of distinguishing hydrocarbon-bearing from nonproducing formation. Significantly better devices, pulsed neutron logs, have been developed for fluid saturation measurements outside cased holes. By use of "through-casing" devices, questionable or unknown accumulations of oil have been discovered. Acoustic or sonic logs, similar to the porosity devices used in open-hole logging, are employed to check cement bonding, isolation or communication of formation fluids, and the level of cement outside casing. Temperature logs, though one of the older tools, find good use in cased holes for locating cement tops and lost circulation zones; more sophisticated uses include gas-fluid entry surveys. Production logging is the descriptive term for the combination of wireline services which are used to investigate and evaluate a well's performance while producing.

Gamma Ray-Neutron Log: As discussed earlier, differences in the natural radioactivity of the rock layers surrounding a well will result in corresponding differences of gamma radiation measured inside casing. By measuring gamma ray intensity and plotting this data as a function of depth, a graph is obtained which depicts the varying underground formations. Broadly speaking, the gamma ray log distinguishes the sandstones, as possible permeable formations, from the clays and shales.

The neutron log, when applied to cased holes, operates the same as in open holes. To reiterate, the log is obtained by moving along the well bore a radioactive source that emits energetic neutrons together with a radiation detector at a fixed distance from the source. The source bombards the rocks with a constant flux of neutrons, and the detector records the varying intensity of gamma radiation which results from the bombardment. The resulting curve is influenced principally by the amount of hydrogen combined in the rocks or by the fluids in the pores of the rocks.

Experience, familiarity with local conditions, and an understanding of the factors which affect radioactivity logs are requisites for the interpreter, particularly if quantitative conclusions are to be drawn from a radioactivity log. Familiarity with the typical gamma ray and neutron curves will permit an interpreter to identify particular rocks or mechanical conditions. It is conventional to record the gamma ray curve on the left and the neutron curve on the right. Each column is appropriately captioned for the type of curve and the direction in which increasing radioactivity intensity is recorded.

With relatively few exceptions similar rocks throughout the world provide similar response on a radioactivity log. A gamma ray curve will

indicate a zone of great intensity for a limestone that lacks porosity, but even if it were highly porous, the neutron curve would be expected to register a somewhat higher intensity than in the shales. The physical borehole conditions will cause the gamma ray and neutron curves to display more or less intensity. In summary, the neutron curve when logging through casing may be used to evaluate:

1. Lithology.
2. Relative porosity.
3. Location of gas-fluid contacts.
4. Formation depths and thickness.

Collar Locator Logs: The collar locator is used to locate casing collars — usually in conjunction with another cased-hole service, such as a radioactivity log or when perforating. Accurate depth measurement when perforating is absolutely essential because this information must be correlated with a electric log of the formations taken before setting casing. The depth to the bottom of a well is carefully checked when the electric log is run. Also, the height of the formation of interest from bottom is observed. This distance then can be converted to the number of joints of casing from the bottom of the well; thus perforation depth control can be related to the nearest casing collar(s).

Today, depth control for perforating is almost universally obtained by a radioactivity log taken in conjunction with a casing collar survey. See Figure 31, which illustrates a Perforation Depth Control (PDC) Log. A gamma ray survey is generally used for this, though in some cases a neutron run is made. Accurate correlation of radioactive logs with

Figure 31. Perforation Depth Control (PDC) Log.

open-hole logs that were run before casing was set will establish the desired perforating interval in the formation to be perforated. If the depth control log is made on a separate trip in the well, the proper shooting depth is determined on the perforating run by recording a second collar log with the collar locator attached to the perforator. If a combination perforating gun and gamma ray is used, the entire equipment for depth control and perforating is run on a single trip into the well. Various types of collar locators are now in use. Some of them are sensitive enough to locate old perforations in casing. A collar locator can also be used to locate the casing shoe in open-hole completions, or liner overlap inside casing.

Pulsed Neutron Logs: The Neutron Lifetime Log (NLL) of Dresser-Atlas and Schlumberger's Thermal Decay Time (TDT) tool are pulsed neutron logging devices that can be run inside casing to obtain an indication of the presence or absence of hydrocarbons outside the pipe.

Figure 32 illustrates the general parts of an NLL instrument. Tool diameters small enough to run through 2 3/8-inch tubing are available. In these tools a neutron generator irradiates the formations through the casing for a brief time interval. The pulse of radiation is then shut off. A gamma ray detector in the tool is opened a short time later (Gate 1), and a count of the radioactivity from the formation is made. The detector is then shut off and again opened a short time later (Gate 2) to obtain another count of radioactivity. There will be less radioactivity in the second count because some of the radiation will decay. The rate of decay of radioactivity depends upon the porosity,

Figure 32. Neutron Lifetime Logging Device.

water salinity, shale content, and hydrocarbon content of the formation. For example, decay time is faster for a saltwater sand than an oil sand, as shown in Figure 33. From estimates of porosity, water salinity, and shale content available from the log, an estimate of the hydrocarbon content of the formation can be made. Figure 34 shows a TDT Log presentation.

NLL and TDT logs can be used to log through casing to:

1. Determine water saturation, residual oil saturation, and fluid contacts outside casing.
2. Locate hydrocarbons previously overlooked.

Tracer Log: A radioactive tracer is a material such as a gas, liquid, or solid which has a high gamma ray emission. Upon injection of the material to any portion of a well bore, the point of placement or movement may be detected and recorded by a gamma ray instrument. One of the original purposes of tracer surveys was to determine channeling or the travel of cement slurry behind a section of perforated casing. In this case, finely ground radioactive material is mixed with the cement. A gamma ray survey taken after placement of the cement slurry gives an idea of its position behind the pipe. Ground carnotite, is one kind of tracer that has been used in cement. Radioactive liquids can be used to assess relative permeability because they will enter the porous and permeable zones. Radioactive sand tracers can be used for injection, fracture, or gravel packs. Gaseous tracers can be used to detect communications in gas-producing or storage wells. Highly radioactive tracers can be used to obtain indication of fluid movement from one well to another, as when water flooding.

Figure 33. Pulsed Neutron Log Interpretation Chart.

Figure 34. Comparison of an Electric Log and TDT Log.

Figure 35 is a section of a gamma ray log used to precisely identify perforations made in a well. Special charges fired at top and bottom of the perforated sections leave traces of radioactive material in the perforations. These perforations are then identified by sharp pips on the gamma ray curve after perforating. Small size, low activity, and short half-life of the radioactive material prevent significant contamination of produced fluid.

Figure 36 is a similar application used to evaluate the zones that have taken fluid after injection or treatment has taken place. Special charges are used to perforate the zones of interest. These charges leave traces of radioactive material within each perforation which are apparent on a gamma ray log run just after perforating. The treating fluid washes away the radioactive material when injected, thus a second gamma ray log will show which of the perforations took fluid; the radioactive pips will remain at perforations which do not take fluid.

Cement Bond Log: Although a cement bond log is not a reservoir evaluation log, it has received recognition as a useful tool for well completions. The purpose of a cement bond log, which is an acoustic device, is to determine the quality of cement in the annulus, or the degree to which channels may have developed in the cement behind the casing.

The purpose of cement in the annular space between the casing and well bore is to isolate productive zones so they may be selectively produced and controlled. If for some reason fluid communication exists between permeable zones behind cemented casing, it is imperative that

Figure 35. Radioactive Tracers to Identify Perforations.

Figure 36. Treat-Evaluate Radioactivity Tracer Survey.

remedial measures be taken. Usually this involves squeeze-cementing procedures. Until the development of the cement bond log, about the only means to determine the location of the top of the cement behind casing was a temperature or radioactive survey. When acoustic logs became available for open-hole use, this logging tool was also employed to examine the quality of cementation behind casing. Many early attempts did not prove reliable because of errors of interpretation; further, some of the devices developed for cement bond logs were ill-conceived and poorly designed. In many instances, the logging engineer did not know just what part of the acoustic wave train he was measuring. Meanwhile, cementing procedures improved, and cement bond logs now are more complete. When properly interpreted, cement bond logs can be used to determine reliably the quality of the cement bonding between casing and formation.

Figure 37 illustrates the type of downhole instrument, the related signals, and the type of log obtained for a cement bond log. Casing suspended freely, i.e., uncemented, in a well transmits elastic sound energy at a velocity of 17,544 feet per second with relatively little weakening of the vibrations between the transmitter and receiver. However, when the hardened cement is properly bonded to the pipe and formation, the vibrations sent out from the tool to the casing will impart similar motion in the cement but at a lower velocity. Laboratory investigations have shown that there is a relationship between the strength of the vibrations received and the degree of cement bonding. An improvement for interpretation of cement bond logs is a photographic record of an oscilloscope display at the time the cement bond log is made.

CEMENT BOND SONDE

ACOUSTIC SIGNAL

CEMENT BOND LOG

90

Cement Bond Log Acoustic Signals

Figure 37. Cement Bond Log Sonde, Acoustic Signals, and Bond Log.

These displays will produce characteristic patterns — "acoustic signatures" — for various degrees of cement bonding between casing and the borehole. For best control, a recording of the free pipe should be presented on each log as a reference for evaluating the other signals on the log. Examples of cement bond log signals are shown. The lowest amplitude levels correspond to zones of good quality cement and large amplitude readings indicate the absence of a cement bond.

Temperature Log: Temperature in the earth increases with depth. The rate of increase averages about 1°F per 60 feet of depth and is known as the geothermal gradient. Deviation from the average depends on the geographic locality and the heat conductivity of the geologic formations. Temperatures in holes that can be circulated through drill pipe or tubing are dependent, not only on the natural geothermal gradient, but also on the circulation of the fluid in the well. In a well that has been thoroughly circulated, the fluid will tend to have a uniform temperature. If drill pipe or tubing is pulled out of the hole and the well allowed to stand, the fluid will gradually come to the temperature of the formation around it. Most temperature surveys are made during the transition period before the fluid has enough time to reach thermal equilibrium with the adjacent formations. A survey is made by lowering the instrument into the hole slowly in order that the temperature sensing element may have time to reach temperature of the surrounding fluid. Measurements are made going down, thus eliminating the perturbing effect of the logging cable. If another run must be made in the hole, it will be necessary to wait from six to twelve hours so that stabilized temperature conditions may be re-established.

Figure 38 shows a temperature survey taken in a well. A zone of lost circulation is plainly visible on the log. Just below the point of lost circulation, the fluid has been stagnant in the hole for some time and is practically at formation temperature. A noticeable "break" in the temperature gradient curve can be observed at the zone of lost circulation.

During the process of gas flowing into the borehole of a producing well, the temperature at the point of entry will be strongly affected by cooling due to expansion of the gas. The drop of temperature opposite a gas-producing zone may be 20°F or more. With a special, sensitive thermometer, it is sometimes possible to derive an estimate of the amount of gas produced by each horizon.

Production Logs: There are two main categories into which most production logging falls: (1) injection wells and (2) producing wells.

Injection wells are generally receiving water as part of a secondary recovery pressure maintenance, or sometimes simply as a means of water disposal. At times the injection medium may be liquid hydrocarbon, gas, air, or a combination of liquid and gas. Whatever the injection fluid, the main purpose of a production log is to determine the injection profile, i.e., to assign specific volumes or percentages to each of the intervals taking fluid. It is also important to check for casing or packer leaks, bad cement jobs, and fluid migration between zones. A shut-in temperature profile is a recognized means of determining where injected fluids have entered a reservoir, as explained previously.

Figure 38. Temperature Survey to Locate Zone of Lost Circulation.

In many instances, relatively high injection rates — 1000 b/d or more — make the continuous spinner flowmeter a highly suitable tool for obtaining an injection profile. Where the continuous spinner flowmeter is not suitable, the "packer-type" flowmeter can be employed; under certain circumstances, radioactive tracers can be used. Temperature surveys are commonly run in conjunction with spinner flowmeter logs or radioactivity surveys.

Generally, both oil and water are present in a producing well; therefore, a different approach must be made from that used in a single-phase injection well. If well conditions and flow rates permit, spinner flowmeter logs can be used to determine gross flow rates. The use of a water soluble radioactive tracer has proven satisfactory to define the interval or intervals of water entry in the presence of moderate quantities of oil. The radioactive tracer permits measuring the water flow rate at selected depths to obtain a water rate versus depth profile. In addition, the soluble radioactive tracer can be spread over a selected vertical interval, so that the dilution of formation water can provide qualitative assessment of the entry amounts.

The temperature survey is the most common means to evaluate a "static" well. If this does not produce meaningful results, then it may be necessary to run a tracer survey to identify fluid migration from one zone to another, a not uncommon problem in "static" wells. Occasionally, the conventional approach may not give enough information, so special techniques may be required. One example is the use of a single electrode "conductivity" tool to determine an oil-water interface or to identify downward movement of water through an oil column.

The Continuous Flowmeter log is used to determine the contribution of each zone to the total production or injection. These surveys can be used to indicate changes in the flow pattern versus changes in conditions at the surface, time, type of operation, or after stimulation treatments. Depending on the size of the tool employed and the pipe size involved, very high flow rates can be measured, up to 60,000 b/d.

Figure 39 is a schematic diagram of the tool and logging records taken on an example well. The recordings show a profile for either up or down flow, cable speed, tension on the cable, and casing collars.

Figure 39. Continuous Flowmeter Logging Device.

DISCUSSION OF METHODS FOR TESTING GEOPRESSURED FORMATIONS

Lithology

Lithological determinations obtained from electric logs and by mud logging techniques are good. Electric logs are after-the-fact of drilling, thus there is frequently a time delay after a section of hole is drilled before the strata can be classified and identified. Conventional electric logs give sharp distinctions between shales and sandstones, but less clearly define limestone, dolomite, anhydrite and other rocks. Wireline survey depth measurements are good, in terms of corresponding to the measurements of steel pipe used for drill stem and casing, but absolute footage depths are seldom known because of unknown temperature and metal stress corrections. A "suite" of electric logs can usually show good distinction between shales, sands, limestones, etc., but the indications, in some cases, may be subtle and obscure. If the regional geology and lithological sequence are known, electric log markers will be recognized and the lithology can be posted on the log. Gulf Coast sand and shale sequences are clearly delineated on electric logs; resistivity, sonic, and radioactivity values can be correlated to porosity values with good reliability and accuracy.

Mud logging techniques can give good representations of lithology, particularly when alert, experienced, and knowledgeable personnel are employed. Mud logging instruments must be carefully calibrated and adjusted to give representative data by which the various formations and contained fluids are logged. Most of the logged data has a lag-time related to the time required to circulate fluid from the bottom of the

hole to the surface, usually about two hours on a deep hole. In other words, the cuttings, gas, oil, etc., when they appear at the surface were produced by the bit two hours before their arrival. Well depth at that time was shallower by two hours of drilling. When the rate of penetration is relatively constant, lag-time can be converted to depth by a fixed measurement from the existing depth. Cuttings analysis, on which much of mud-logging techniques depends, can vary from fair to good, depending on the sampling procedure, the size of the cuttings, and the instrumentation used by the mud logger. Small cuttings, as generated by a diamond drill bit, will not be as representative of the formation being drilled as will larger cuttings made by a rock bit. Regrinding of cuttings will mask the character of a formation, i.e., the amount of sand in a sandy shale formation or cementation of the matrix.

Rate of penetration may give only a fair indication of lithology. If the hydrostatic pressure of the mud column is constant, and other variables of the drilling process such as weight-on-bit, bit diameter, revolutions per minute, and jet-nozzle velocity are held constant, then rate of penetration may be related to the kind of rocks being penetrated at any given instance. It is for this reason that the drilling equation is utilized to derive the "d" exponent; this factor can then be plotted to observe the normalized trend of the rate of penetration. Variation of the "d" exponent from the established trend will indicate a change in formation or that an overpressured zone has been entered. If hydrostatic pressure developed by the mud column is nearly the same, or only slightly exceeds the formation pressure of an overpressured zone, the

overpressured zone will be drilled faster than a zone under normal pressure. On the other hand, if hydrostatic pressure greatly exceeds formation pressure — 1,000 psig sometimes exists — porous sands will drill much slower than shale formations. This is just the opposite to the usual expectation that sand formations will drill faster than shale sections. For both of these reasons, since hydrostatic overbalance of formation pressure is usually not known, rate of penetration may not always be a good parameter to distinguish shale formations from sand formations.

Instantaneous, (continuous), electric logging has been done on an experimental basis. By this procedure, simple self-potential (SP) and resistivity curves can be logged while drilling ahead. The information is transmitted to the surface by means of a pressure-pulse in the circulating fluid. The necessary equipment includes a self-contained downhole logging device that is battery operated. If a storage battery could be designed that would not shake apart under stress-levels of many "G" forces and would withstand a temperature of 350°F for 100 hours, continuous logging could probably be perfected. Several existing patents have been granted on the procedure. A novel downhole power system employing a mud driven turbo-generator has been developed but not perfected. This system could be used to produce the pressure-pulses necessary for transmission of downhole electric data to the surface but it would not likely have the necessary fine voltage control needed for self-potential values in millivolts or resistivities of 1-2 ohms.

Sidewall samples taken by percussion methods will enable assessment of the rocks at a given depth in a well. The matrix of the formation

material can be visually examined, though the impact of the hollow bullet may pulverize the material, distort its porosity and permeability values, and the presence of mud filtrate in the voids of the rock sample will not be representative of the fluids originally present. The well geologist can usually identify the kind of rock and estimate its porosity within 5-10%. Residual fluid in the void space can give some concept of the fluid in place, i.e., gas, oil, or water, though not the degree of saturation.

Conventional cores, properly cut, recovered and analyzed in a core laboratory will give good information on lithology, porosity, and permeability. It should be understood that one core will represent only a very small percentage of a porous reservoir. Fluid in the pore space of a conventional core will be nearly 100% mud filtrate, though residual fluid can usually be ascertained by color tests and chemical means. Means already exist for continuous coring, but the method would not be feasible for a geopressured formation because of the hazard of lost circulation and/or well kicks when reverse-circulating the well to pump out the cored samples.

Formation Porosity

Porosity from well logs is usually determined from sonic, density, and/or neutron logs, often by means of cross-plot charts to permit confirmation of the values obtained. When none of these are available, porosity may be estimated from a resistivity log in clean water-bearing formations.

Sonic log values can be used for porosity by applying the interval transit time, ΔT , in μ sec/ft to the appropriate formation, i.e.,

sandstone, limestone, or dolomite, and reading porosity directly. This is illustrated in Figure 40.

The Formation Density Log is useful as a porosity-logging tool and will produce good values of porosity directly using charts as shown by Figure 41. Lithology of the rock matrix must be known, as well as whether fresh or salt water mud is in the hole.

Similarly, formation porosity can be determined directly using bulk density, ρ_b , from a compensated Neutron Log, as shown by the chart in Figure 42 for holes filled with fresh water mud. A corresponding chart is available for holes filled with salt water. In either case, using formation density or neutron bulk density values, the type of rocks must be known.

When sonic, density, or neutron logs are not available, formation porosity can be estimated from resistivity values in clean, water-bearing formations, from the formation factor, F , determined from the following equation:

$$F = R_o/R_w$$

where R_o = resistivity of a non-shaly formation that is 100% saturated with brine, ohm-m.

R_w = resistivity of the brine, ohm-m.

Resistivity values can be obtained from conventional ES (Electrical Survey), a focused Laterolog device, or IES (Induction Electrical Survey). The formation factor, F , is used to enter the chart shown in Figure 43 to obtain the porosity value.

Sidewall samples, as already discussed, will not enable reliable

	v_{ma} (ft/sec)	Δt_{ma} ($\mu\text{sec/ft}$)
Sandstones	18,000-19,500	55.5 - 51.2
Limestones	21,000-23,000	47.6 - 43.5
Dolomites	23,000-26,000	43.5 - 38.5

Figure 40. Porosity from Sonic Log.

FRESH WATER

SALT WATER

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Example: $\rho_b = 2.38$ in limestone lithology ($\rho_{ma} = 2.71$), fresh mud ($\rho_f = 1.0$).

Solution: $\phi_D = 19.3$.

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Figure 41. Porosity from Formation Density Logs.

FRESH WATER, LIQUID-FILLED HOLES

Figure 42. Porosity from Formation Density and Neutron Logs.

Figure 43. Formation Factor Versus Porosity.

measurements of porosity because of the shattering effect of the core-bullets on the formation as they enter the wall of the hole.

Conventional cores properly taken, recovered, and examined under laboratory conditions can make it possible to obtain good values of porosity and permeability.

Formation Permeability

Apparent permeability determinations from electric log data cannot be calculated, but since porosity and permeability are related, i.e., a permeable rock must have interconnected porosity, permeability indices can be approximated from porosity values. Some fine-ground rocks have large interconnected porosities, but since the paths available through the pores are quite restricted and tortuous, permeability of such rocks may be quite low, though the relative porosity may be quite high. The permeability of a given rock sample to the flow of a homogeneous fluid is a constant, provided the fluid does not react with the rock and the geometry of the rock passageways is not altered by the way the rock sample is prepared for testing. The permeability of a rock for a homogeneous liquid is called absolute permeability; the unit of permeability is the "darcy"* and since the darcy is quite large, the unit "millidarcy" (md) is commonly used. Accurate determination of permeability must be made using a sample of the rock and air or gas to make the test; these measurements must be corrected for "slippage" effect to obtain equivalent liquid permeability. Permeable beds are usually picked from an electric

*One darcy is permeability that will allow flow of 1 cubic centimeter per second of fluid of 1 centipoise viscosity through a cross-sectional area of 1 square centimeter under a pressure gradient of 1 atmosphere per centimeter.

log by the use of the SP curve, from evidence of invasion as shown by separation of the resistivity curves, and evidence of mud cake as shown by Microlog and Caliper Surveys. These evidences of permeability serve to confirm each other; existence of porosity, as shown by a porosity log gives further confirmation. Clean sands will give good SP values with fresh water mud. Invaded, hence permeable, beds are often evident by the separation between the deep- and shallow-invasion resistivity curves. This is because mud filtrate invasion of the permeable bed alters the resistivity of the zone invaded. Microlog curves can do the same thing, particularly when there is mud cake present. The micro-normal typically will read higher than the micro-inverse curve. If the borehole is reasonably to gauge, mud cake thickness will be recorded on a Microlaterolog, a Proximity Log, or Compensated Sonic Log. Data from these logs can be put into a computer processed interpretation, as Figure 44, to obtain permeability indices.

Sidewall sample cores are poor for the estimation of permeability because of their small size, the fact that the matrix has been shattered, and pulverized material will tend to plug some of the flow channels in the rock. Sidewall coring tools are available, but it is doubtful that they could be effectively employed in geopressured formations because of the high temperatures and pressures.

The Repeat Formation Tester can be used to obtain some concept of formation permeability. It is a wireline tool that can be set and reset as many times as desired. When formation pressure response indicates that the tool has been set in an impermeable section of the hole, it can be released and reset for another pressure reading. When the operator

Figure 44. Schlumberger Computer Processed Interpretation Log. Permeability Index Readings are Shown in Track 1.

is satisfied that the device is seated at a place in the well where there is relatively good permeability, the receiving chambers of the tool can be opened and flow from the well observed. Build-up of pressure in the fluid chambers will permit the operator to make an immediate evaluation of the relative permeability, though not in precise terms. Fluid volume is very small, thus assessment of permeability will be in very general terms.

A drill stem test (DST) taken in a cased hole will permit a fairly good assessment of formation permeability. An actual flow test can be made, the duration of which may be as long as desired, though the usual bottomhole pressure gauges will function only for a few days. This will enable pressure draw-down tests to be made, their accuracy depending on the size of the underground reservoir. If the reservoir is very limited, its size may be apparent in a short time; if it is very large, little can be learned in less than a few weeks or months. Pressure build-up tests, i.e., closing in the well to learn how fast the original pressure can be recovered — if ever — and will thus enable confirmation of formation permeability to the flow of fluid. A fast recovery of original pressure will indicate a fairly good permeability, a slow recovery a low permeability, depending on the length of time needed to draw down the reservoir pressure. An extremely large reservoir might require a year or more for draw-down pressure to stabilize, depending on the producing rate.

Fluid Identification

Mud logging techniques permit only fair assessment of the fluid

in the pore spaces of the rocks penetrated while drilling. Gas in geopressured shales will appear as "background" gas as measured by a gas-detector, usually as so many units per minute. These readings will be mostly methane, rather than heavier hydrocarbons. The relative amount of gas in the stream of drilling fluid being circulated in a well will depend on the flow rate from a geopressured shale exposed to the drilling fluid and the speed of the fluid stream rising in the annulus. If circulation is stopped, as when adding a length of drill pipe to the drilling assembly, gas will percolate from the wall of the hole and enter the drilling fluid. Measured output of gas from the mud stream will thus appear to be greater when that part of the rising mud column reaches the surface. After a trip of the drilling assembly to change the bit or for other purpose, mud that was quiescent opposite the gassy shale will contain more entrained gas than mud opposite other parts of the hole. When a gas-containing formation, as a porous sandstone, is encountered, pore-space gas will be much greater than background gas, depending on how fast the sandstone was drilled and the rate of circulation. Gas readings obtained by a mud logger can be fairly reliable; gas readings from a gas sand will show greater percentages of heavy hydrocarbons than will be indicated for gas from shale. Using somewhat the same procedures, but different instrumentation, mud loggers are able to detect oil shows in the drilling mud stream when a formation containing oil is encountered. Salt water shows from porous rocks cannot be easily detected unless formation fluid actually enters the mud and appreciably dilutes the drilling fluid. If this takes place, tests of the liquid

phase of the mud for chlorides will indicate the degree of salt water contamination.

Resistivity logs, as said previously, will give good indication of the resistivity of any fluid in the pore space of porous rocks. If the fluid has low resistivity, and is in a non-shaly sand, resistivity at the observed temperature will be directly related to the equivalent salinity of the water. Figure 45 shows how salinity can be related to resistivity of NaCl solutions at various temperatures. Resistivity logs do not differentiate between gas and oil in porous formations; both will be shown as high resistivities.

Fluid identification in porous formations using a Repeat Formation Tester (RFT) may vary from poor to good, depending on the permeability of the formation. The relatively small size of the sample taken by an RFT test means, in the usual case, that mud filtrate diluted with varying amounts of formation fluid will be recovered. If the formation is "tight" recovered fluid will be nearly 100% filtrate; if permeability and porosity are high, recovery may be nearly 100% formation fluid. If the fluid samples show electrical resistivity markedly less than the resistivity of the mud filtrate, a calculation of the amount of dilution can be made and the mineral content of the formation estimated. Tracer chemicals used to tag the drilling fluid will appear in the mud filtrate and thus can be used to approximate the percent filtrate and formation water in the recovered samples.

A drill stem test in a cased hole might be practical and feasible for a temporary completion in a well drilled originally for oil or gas, particularly if the geopressured intervals were thin and appeared to be

Example: R_m is 1.2 at 75°F (point A on chart). Follow trend of slanting lines (constant salinities) to find R_m at other temperatures; for example, at Formation Temperature (FT) = 160°F (point B) read $R_m = 0.56$. The conversion shown in this chart is approximated by the Arps formula: $R_{FT} = R_{75} \times (75^\circ + 7)/(FT \text{ (in } ^\circ\text{F)} + 7)$.

Figure 45. Salinity Versus Resistivity at Various Temperatures.

tight. In such case, a normal completion attempt might not be justified because of the apparent problems of deliverability and/or pressure maintenance at high flow rates. A DST tool can be run on drill pipe or tubing, the packer set just above the perforated interval in the well, and formation fluid allowed to flow to the surface until it is clean and free of mud filtrate contamination. The DST tool can then be closed, bottomhole pressures recorded, and fluid samples obtained under downhole conditions of pressure and temperature. These samples can be taken to a laboratory for analysis in the original containers. Bottomhole pressure readings taken during the flowing and shut-in periods can be employed to estimate reservoir limits, thus to allow preliminary calculations of reservoir size and expected performance. Maximum bottomhole temperature — which will approximate reservoir temperature — can be obtained from DST data. A drill stem test made inside casing makes possible a short production test and clean formation fluid samples under bottomhole conditions of pressure and temperature.

Geopressured Strata

Detection of geopressured strata, besides the generalized preview before drilling commences using seismic methods, can be observed by rate of penetration, mud logging techniques, shale density plots, shale resistivity logs, sonic and density logging methods.

Drilling rate of penetration, as previously discussed, can be used to predict that the hole is near or approaching an overpressured stratum. It has been used for many years to distinguish sand from shale formations — the so-called "drilling break" — in that a sand can be drilled

faster than a shale section under normal conditions. With controlled conditions of weight on the bit, rotary speed, bit type, and hydraulic effort at the bit, drilling rate will decrease uniformly with depth. This is due to the compaction increase with depth; excess water is squeezed out of shale formations as they are compacted, thus they become more dense and more difficult to drill. However, in pressure transition zones, the excess water becomes trapped, overpressure develops and the shale can be more easily drilled. Penetration rate increases in such shales are also caused by the fact that differential between hydrostatic pressure and pore pressure within the shale is reduced thus making the chips generated by the bit easier to release from the bottom of the hole, i.e., the bit drills faster. Figure 46 shows how rate of penetration can be used to indicate that an overpressured zone has been entered. Complications can arise due to bit dulling, or other mechanical factors can cause the bit to drill slower. Since it is not always possible to control these conditions, an improved method which describes the normalized penetration rate allows plotting of the "d" exponent, discussed earlier, to accomplish the same end. Basically, "d" exponent plots versus depth should normally show an increasing trend with depth; in a transition zone or an overpressured environment, the calculated "d" exponent values will diverge from the normal trend to lower than normal values. If corrections are made in these values for mud weight changes, in proportion of W_1 to W_2 , overpressures will be more clearly defined. See Figure 47 which utilizes the normalized drilling rate and other mud logging techniques to detect overpressures by plotting mud gas measurements, and other observations.

Figure 46. Effect of Bit-Tooth Dullness on Penetration Rate. After Matthews, 1969.

Figure 47. Mud Logging Parameters to Indicate Geopressured Formations. NDR is the "d" Exponent for Normalized Drilling Rate. Shale Factor is the Methylene Blue Test.

These observations are logged against drilling depth and rate of penetration, as above, to establish trends. Abrupt increase of gas shows in the mud, mud temperature, and weight changes not due to other factors, can indicate that overpressured formations may be near or have already been encountered. Change in the mud flow rate, or a pit level gain not otherwise explained, can mean that high pressured formation fluid is flowing into the wellbore and a kick is underway.

Shale density readings can be employed to detect and/or predict geopressed formations. Bulk density values plotted versus depth can be used to forecast shale density at greater depth by straight line extrapolation. Any decrease in bulk density from the trend line may indicate the presence of an abnormal (geopressed) environment. See Figure 48. The main problem with shale density plots as a geopressed stratum detection method is the selection of representative cuttings, their preparation, and measurement of bulk density. The cuttings method is the same as measurement of shale density by electric logs, but the information is obtained much faster since the only delay is the time needed to circulate from the bottom of the hole.

Shale resistivity increases normally with depth since porosity decreases under compaction; the shape and slope of the normal trend line of shale resistivity plot will vary with the geological age and type of shale involved. In overpressured shales, the short normal curve will show a departure from the normal trend to lower than normal resistivity. This is due to increased porosity and resulting higher water content of these shales. See Figure 49. Formation resistivity measurements are influenced by several factors, including porosity, temperature,

Figure 48. Shale Density Plot to Indicate Geopressures.

Figure 49. Shale Resistivity Plot to Indicate Geopressed Formations.

formation water salinity, mineral composition of the shale, and logging tool problems that may not be recognized. Nevertheless, short normal resistivity and acoustic logs are the tools most valuable for qualitative and quantitative in-situ formation pressure evaluations.

A focused induction-logging device (IES) records formation conductivity (mmhos) and its reciprocal, resistivity (ΩM). Conductivity values in normally-compacted shales decrease with depth, due to lower porosity therefore less water. However, transition to overpressured shales is indicated by greater than normal conductivity, resulting from higher-than-normal water content and porosity. Figure 50 shows an actual field log with a marked conductivity gradient caused by transition into an overpressured zone.

Acoustic (sonic) surveys record the transit time of elastic waves through formations over a predetermined distance. A transducer creates elastic wave pulses which travel through the formation and are picked up by receivers in the logging sonde. The time required for the signal to travel the predetermined distance in the formation is recorded as the travel time. Interval transit time is recorded in microseconds per foot (ΔT in μ sec/ft). In a given formation, ΔT depends upon lithology, degree of compaction (consolidation), porosity and the fluid content of the pore space. For formation pressure evaluation, shale transit travel time is plotted versus depth. In normal-pressure environments, the data points will fall along the normal compaction trend line, that will be characteristic of the well, as shown in Figure 51. Pressure anomalies, as shown at 9,000 ft in the illustration, will appear as increases in the transit time above the normal ΔT value that would otherwise obtain.

Figure 50. Conductivity Curve and Amplified Short Normal Curve Clearly Define Increase of Formation Pressure in the Shale Section Topped at 10,060 Ft.

Figure 51. Shale Transit Travel Plot to Indicate Geopressed Formations. Also Shows Application of Equivalent Depth Method for Estimating Formation Pressure Gradient (FPG). After Hottman and Johnson (1965).

Observed shale travel time, ΔT_{ob} , increased to 107 μ sec/ft at 14850 ft; this was 30 μ sec/ft more than the extrapolated normal ΔT_{sh} at that depth of 77 μ sec/ft. The Hottman-Johnson curve in the lower illustration, which plots $\Delta T_{ob} - \Delta T_{sh}$ versus Formation Pressure Gradient for a Louisiana well indicates an FPG of 0.882 psi/foot should be expected for ΔT difference of 30 μ sec/ft. Formation pressure (BHP) will thus calculate to be 13,100 psi at 14850 ft. Sonic survey transit times in shale produce the best and most reliable indications of formation pressure.

The density logging device consists of a radioactivity source which irradiates the formation with medium-energy gamma rays. Collision with electrons in sedimentary rocks cause gamma rays to lose energy; the number of collisions is directly related to electron density, or numbers, surrounding the borehole. Electron density is related to true bulk density, which in turn depends on the density of the rock-matrix material, formation porosity and density of fluids in the pore space. Thus the density logging device produces a record of bulk densities that appears somewhat like ΔT transit times of an acoustic log, but are actually measured bulk density values. If the values of shale bulk density are plotted against depth, as Figure 52, it will be found that they will fall on a straight line in normal-pressured shales. Generally, a marked decrease of shale density from the normal compaction trend will indicate the presence of excess water, therefore greater porosity, and lower density than would be normally expected. In cases of severe hole enlargement, the reliability of bulk density plots decreases drastically. Washouts cause the density log to read too low; further complications may arise from the high barite content of weighted drilling fluids.

Figure 52. Shale Bulk Density Plots to Indicate Geopressures.

Experience indicates that a density log is not as accurate or as reliable for formation pressure evaluation as acoustic or resistivity logs.

Fluid Pressures

Geopressures when drilling a well can be evaluated by several methods, as listed previously, including well kicks and drill pipe pressure, by drilling rate, electrical surveys, sonic surveys, and bulk density logs. Direct reading devices include Schlumberger RFT tester, drill stem test (DST) and bottomhole pressure gauges.

Perhaps the most direct manner to obtain measured formation pressure while drilling is to make hole with mud weight deliberately lower than expected formation pressure. When a geopressed formation is encountered fluid or gas will enter the borehole, displace some of the mud in the well and start up the annulus between the drill stem and wall of the hole, in other words a well kick. An alert driller will stop the pump, observe the flow of mud from the well, shut the blowout preventer, and close in the well. Figure 53 illustrates that closed in drill pipe pressure plus the hydrostatic pressure of the mud column inside the drill stem will equal static formation pressure. It is not recommended that this procedure be followed routinely, because of the hazard of a blowout and subsequent damage to the well, the chance of personnel injuries, and ruined drilling equipment. It will obtain a true reading of formation pressure.

Drilling rate of penetration, as discussed previously, may enable qualitative assessment of formation pressure when geopressed strata are encountered. If hydrostatic pressure of the mud column is less than

Figure 53. Drill Pipe Pressure Plus Mud Column Pressure Inside the Drill Pipe, When a Well is Shut In, Equals Formation Pressure.

formation pressure, as above, the bit will drill relatively fast because of negative chip hold-down effect. In fact, drillers in such cases have been known to report "The bottom fell out of the hole"; of course the well would kick and a blowout would be underway unless the blowout preventer was promptly closed. On the other hand, rate of penetration will be relatively slow if the mud column pressure greatly exceeds formation pressure. Positive chip hold down will prevent effective bit action, bit cuttings will be small, and drilling progress will be slow. The driller may not be aware the bit had penetrated a porous formation; there would be no indications at the surface until cuttings, and/or shows of gas, oil or salt water were circulated up in the drilling fluid. Drilling rate of penetration is not a very satisfactory means of detecting high formation pressure.

Electrical surveys, including resistivity, conductivity, acoustic, and formation density logs can be used to estimate formation pressure. Quantitative evaluations of formation pressure can be made by plotting shale resistivity versus well depth to establish a normal trend due to compaction. The top of the geopressured zone will be the depth where the plotted values start to diverge from the normal trend. To determine formation pressure at a specific depth, calculate the ratio of normally-pressured resistivity to the observed shale resistivity at the depth of interest. This ratio can then be entered in a chart such as depicted in Figure 54 to find the corresponding FPG (fluid pressure gradient). Fluid pressure gradient times the depth will equal formation pressure. Shale resistivity ratio charts are produced from empirical data for a given area and are valid only for the geological setting of that area;

Figure 54. Relationship Between Shale Resistivity Ratio and Reservoir Fluid Pressure Gradient (FPG) in Geopressed Formation, U. S. Gulf Coast. After Hottman and Johnson, 1965.

this method of evaluating geopressures should be restricted to areas where overpressures are due to compaction. Similar methods can be used for pressure determinations using sonic transit times, ΔT in microseconds per foot, or bulk densities obtained in clean shales by a formation density log. It should be recognized that formation resistivities can be influenced by several factors, including porosity, temperature, water salinity, etc. Both acoustic and density logs are affected by hole enlargement and other mechanical factors. Acoustic and resistivity parameters for shale are the best surveys for evaluating formation pressure.

The Schlumberger Repeat Formation Tester, previously described, can obtain valid indications of formation pressure prior to setting casing. Its pretest capability, whereby the tool can be set by the operator at a given depth and opened for a preliminary pressure reading, makes it particularly useful where tight streaks may prevent fluid flow and/or the pressure seal may fail and only mud pressure register. If either situation is indicated, the probe may be withdrawn, the tool moved to a new place in the hole and the pressure test repeated. Any number of tests may be repeated without pulling the tool from the well. Pressure accuracy is within 0.2%.

Drill stem test (DST) pressure readings can be valid when properly taken and read using micrometer-type chart readers. The pressure instruments are bourdon-tube or bellows-type devices that are fairly small size, due to their design for small diameter holes; service ratings of 20,000 psi and 400°F are readily available. Temperature compensated calibration curves can be obtained for each instrument.

Pressure accuracy is in the order of 0.25% of full scale readings.

Downhole pressure records are made on clock-driven charts; clocks are available for 24 to 192 hours or more running time. Maximum reading thermometers are usually run in conjunction with DST bottomhole pressure gauges.

Several proprietary bottomhole pressure gauges are available; these are run on small-diameter solid wires, or electrical cables. The Amerada gauge is a bourdon-tube gauge that is run into the well on a solid wireline. It is a self-contained device that incorporates a clock-driven chart to obtain a record of bottomhole pressures. Accuracy is within 0.2% of full scale readings; service ratings are 25,000 psi pressure and 650°F temperature. The Amerada gauge can also be obtained in an electrical surface readout configuration that is run into the well on a single conductor armored cable. Electric power from the surface operates the downhole instrument to obtain a signal to record bottomhole pressure on the surface. The Hewlett-Packard gauge is run on an electrical conductor cable to the desired depth in the well; a quartz crystal sensor transmits a frequency signal to a surface indicator/recorder that is proportional to the bottomhole pressure. Service limitations are 12,000 psi pressure and 300°F temperature. Pressure accuracy is stated to be 0.075% the full scale reading. The Sperry-Sun "Permagauge" utilizes a small diameter stainless steel tube to transmit nitrogen pressure from the desired depth to the surface for continuous readout.

Formation Temperature

Formation temperatures can be obtained by means of an electrical

temperature survey, by use of a bottomhole temperature instrument, or by means of an electrical-remote reading temperature gauge that will permit surface readout. Most downhole pressure recording devices include a maximum reading thermometer to obtain a temperature reading for instrument calibration purpose.

An Electrical Temperature survey is run by conventional logging methods; the temperature sensor is a temperature sensitive resistor which can detect anomalies as small as 0.5°F . The survey will record a temperature profile of the well from which a geothermal gradient can be defined; other temperature variations can also be noted. Maximum service ratings are 15,000 psi and 350°F .

Bourdon-tube bottomhole temperature gauges are available from Amerada; temperature ratings are for ranges of 200°F to 400°F , or higher and accuracy is within 2°F . This gauge can be run on a solid wireline to obtain a bottomhole temperature chart as described for bottomhole pressure; a similar instrument can be run on a single conductor electric cable to obtain readout and record bottomhole temperatures on the surface.

Maximum reading thermometers will give an accurate indication of bottomhole temperature when left in the hole long enough to obtain a stabilized reading.

Formation Mechanical Strength

Formation strength characteristics can be estimated from a Mechanical Properties Log, which is a display of computed elastic constants of a porous interval in a well that may be used for production. The Mechanical

Properties Log can be used to determine whether or not a sandstone formation is strong enough to be produced at a high rate without breakdown due to sand movement. There is good correlation between the ability of a formation to produce at high rates and the dynamic elastic constants that can be derived from acoustic and density logs. These constants are shear modulus and bulk compressibility. Techniques have been devised which relate dynamic elastic constants to the compressional-wave transit time, the bulk density, and Poisson's ratio. According to Tixier, et al (1), the relationship between the elastic moduli and permissible production rates for a sand formation from which water is produced have yet to be established. Also, additional log and test data are needed to fully predict the behavior of geopressured formations.

Mechanical strength tests of cores in a laboratory will be the best way to determine formation strength as well as permeability. Sand cores will be needed to check the maximum flow rates that may be employed without breaking down the matrix of the rock. Shale cores will be needed for laboratory testing of pore water content in order to predict compaction performance.

Formation Subsidence

Surface subsidence takes place as the underlying formations become more compact when water is expelled from the clays and shales due to the weight of the overburden. This means that the measured thickness of a geopressured formation will lessen as the water is withdrawn, thus the

(1) M. P. Tixier, G. W. Loveless, R. A. Anderson "Estimation of Formation Strength from the Mechanical Properties Log". Society of Petroleum Engineers, AIME, 1973.

overlying rocks will slump in relation to the "normal" surface of the ground. Geopressured sand formations, when permeability barriers such as faults or shaleouts exist, will assume fluid pressures approaching geostatic pressure. The generally accepted theory is that the weight of the overburden above a geopressured sand is partially supported by fluid pressure within the sand. When fluid is withdrawn from a geopressured sand, the formation will become thinner due to compaction and the sand grains take on the geostatic load. Land subsidence above a pressure-depleted reservoir will relate to the thinning of the reservoir formation itself, plus the slumping of the overlying rocks above the reservoir. Radioactive bullets implanted at the bottom and top of the geopressured reservoir before production begins can be used to measure the thinning of the formation after pressure depletion takes place. This will involve careful measurements by an electrical survey using a radioactivity detector to locate the exact depths of the bullets. Similar measurements from the bottom of the well to radioactive bullets placed at intermediate points above the geopressured formation will detect footage changes due to slumping of the overlying clays and shales above the pressure depleted reservoir. This will require very precise depth measurements to detect the subtle changes that take place. Land subsidence, at worst, will be a very slow process, requiring a year or more for a few hundredths of a foot. The process of land subsidence due to expulsion of water from geopressured clays and shales is non-reversible.

Sand Movement

Sand influx into the wellbore from the producing formation will pose serious problems in the exploitation of a geopressured resource.

A very minor sand content in the produced water can wear and abrade well control and surface equipment so badly as to make them useless. Sand abrasion of the perforations and/or screen liner can cut out the screen, thus to allow uncontrolled entry of sand into the wellbore. Sand-fill in the well or surface equipment can shut off well flow. Finally, removal of sand from outside the well casing can leave shale stringers unsupported; subsequent slumping of shale around the perforated casing can cut off fluid entry into the wellbore. Sand particles, in small quantities, are difficult to detect in a well stream, but it is a truism that early detection and prompt remedial measures to correct the condition are most important to successfully treat the situation.

The usual procedure is to increase flow from a well slowly to minimize the entry of sand and to carefully observe all equipment for evidence of abrasion and/or accumulations in the surface vessels. Otherwise the screen liner might cut out, the wellbore would plug, and flow would cease.

A new device, patented by Mobil Oil Corp., "Sonic Sand Detector" offers promise to monitor sand production from a producing well. A probe inserted in the flowline from the well converts the acoustical "pinging" of impinging sand into an electrical signal which is processed by electronics to produce a chart recording of the signals. Alarms can be triggered to indicate that solids are being produced in the well stream in excess of tolerable levels.

TEST AND SAMPLING PROCEDURES WELL DRILLED TO TEST GEOPRESSURED ZONE

After the well has reached the depth required to top the geopressured shale, protective casing set and cemented, high pressure blowout preventers (5,000 psi working pressure) will be installed, pressure tested, and other preparations made to drill ahead into the geopressured zone.

STATIC PROCEDURES

1. Drill out the cement inside the casing, the casing shoe and make a few feet of hole.
2. Pressure test the casing seat and open hole to an equivalent bottom hole pressure of 1 psi per foot of depth. If lost circulation takes place due to failure of the casing seat or because of formation fracture, cement the open hole, drill out and retest. Repeat until the desired pressure can be obtained.
3. Drill ahead with a drill bit of maximum diameter for the size and weight casing in the well.
4. Drilling fluid density will be closely monitored while drilling. Mud weight will be increased as required to allow safe balanced-pressure drilling operations as the well is deepened. Applied drilling technology will provide a pressure profile and mud weight schedule to follow for the minimum mud density needed to balance formation pressure, thus to avoid well kicks or formation fracture.
5. Drilling parameter observations will be made continuously, including well depth, rate of penetration, weight on bit, rotary speed and revolutions, torque, mud circulating pressure, mud density in and

out, mud temperature in and out, mud flow rate in and out, and mud pit level totalized with an indication of gain or loss. Entrained gas and chlorides in the mud will be monitored and recorded. Shale cuttings will be cleaned and measured manually for bulk density. Much of this information will be recorded for future use and/or computer input for immediate analysis.

6. When drilling data indicates a sand interval has been penetrated, the drilling assembly will be pulled and a diamond core barrel run to cut a core. A 50-foot core for reservoir and rock strength measurements will be taken. Laboratory measurements will be made on sand sections for porosity and permeability determinations. Rock strength characteristics, i.e., bulk density, bulk compressibility, bulk and shear moduli measurements, will be made on both sand and shale sections of the core.
7. Ream the cored hole to full diameter and drill ahead. Maintain careful observations of all drilling parameters in order to promptly detect well kicks, to detect lost circulation, and to prevent stuck pipe.
8. It may be desirable to stop drilling and run an electric log for geological correlation before reaching final depth. This could be at 500-1,000 ft. intervals depending on the stratigraphy and decision of the well site geologist.
9. When final depth is reached, run a full suite of electrical logs and surveys, including:

Induction Electric Log

Compensated Neutron Log

Formation Density and Gamma Ray

Dipmeter, Directional and Caliper Surveys

Micro Laterolog

Temperature Survey

Computerized processed logs will be made of the geopressured sand intervals for (1) reservoir and (2) mechanical properties presentations.

10. Run the Schlumberger Repeat Formation Tester (RFT). Depending on the number of permeable zones, enough runs will be made to obtain multiple pressure tests and fluid samples from each sand interval. Fluid samples will probably contain large amounts of filtrate. If less than 100% filtrate, fluid analyses can be corrected for dilution using resistivity measurements and/or chemical analysis for comparison with similar measurements of the mud filtrate. Characteristics that can be measured using RFT measurements include:

Formation Pressure

Formation Permeability Estimate

Formation Productivity Estimate

Gas-Liquid Ratio

Water Salinity Estimate

Chemical Analysis of Fluid Sample

11. Take sidewall samples as specified by the well-site geologist for lithological identification, etc.
12. Run Radioactive Bullet Gun. Shoot radioactive bullets into the wall of the hole at measured intervals above and below the permeable zones for reference at later dates to assess compaction that may

effect subsidence of shallow formations.

13. Underream the hole below the protective casing in order to run and properly cement the production casing. If clearances are sufficient this step may not be required.
14. Run lower part of the production casing string as a liner and suspend on a liner hanger set about 200 feet overlapping the intermediate casing. Depending on well depth and the depth of the intermediate casing, this liner may be about 5,000 feet long. Cement the casing with API Class H cement mixed with sand and silica, salt, and retarder chemical to prevent premature set. A polished-bore "tie-back" receptacle will be run on top of the liner above the liner hanger.
15. Run balance of the production casing string with a seal nipple on bottom to match the bore of the receptacle on the liner. Cement this string back to the surface with Class H cement and admixtures as above appropriate for the expected bottomhole temperature. Hang full weight of the production string on the casing hanger and pressure test the casing-hanger to 10,000 psig.
16. Assemble 10,000 psig working pressure wellhead and blowout preventers above the production casing hanger. Pressure test this equipment to 10,000 psig.
17. Run cleanout bit on drill pipe inside the production casing to drill out the cement above the liner hanger. Clean out hardened cement inside the liner hanger. Pressure test the tie-back to the equivalent of 1 psi/foot of depth bottomhole pressure. If tie-back receptacle leaks, squeeze cement until a satisfactory pressure test

is obtained.

18. Drill out any hardened cement remaining in the liner at the liner hanger. Cleanout to the cement plug left above the liner shoe.
19. Run Cement Bond, Gamma Ray, Neutron Porosity, and Collar Locator log from total depth up to the depth of the intermediate casing. Determine condition of cement bond between the casing and wall of the hole.
20. If cement bond is missing or is not effective, perform remedial cement squeeze jobs, after perforating as required, to obtain good bond between the casing and wall of the hole. Cleanout to the bottom of the liner as in Step 18.
21. Run drill pipe and full-bore packer with 90-foot tailpipe below packer. Place packer above lowermost porous zone as indicated by Gamma Ray-Neutron survey and other logs. Circulate clean drilling mud of sufficient density to balance expected formation pressure of the lowermost productive zone.
22. Displace weighted drilling mud in the drill pipe using saltwater with tailpipe located below the top of the porous zone. Pull tailpipe above the porous zone and set packer. This should leave an effective pressure at the casing shoe of about 0.5 psi/foot of depth. Observe if casing shoe appears to be leaking or holding pressure. If holding, proceed to perforate.
23. Rig up 15,000-psi test perforating and wellhead control equipment on drill pipe including blowout preventer, lubricator, and grease seal packing gland for wireline to run and pull perforating tools under pressure. Run large-diameter, hollow-carrier, jet perforating gun to the depth of the lowermost permeable zone in the well.

Apply hydraulic pressure to the drill pipe to obtain a bottomhole hydraulic pressure 300 psig less than formation pressure. Perforate the casing using one shot per foot over a 5 ft. interval in the porous zone. Record tubing pressure and indicated bottomhole pressure. Recover perforating tools.

24. Open drill pipe production manifold on small choke and allow well to flow slowly until clean formation fluid reaches the surface. Record drill pipe pressure and temperature of flow stream ahead of choke.
25. Close well in, record drill pipe pressure and estimated bottomhole pressure.
26. Run hollow-carrier jet perforating gun and perforate the lowermost permeable zone with a shot density of 2 holes per foot. Rig down perforating lubricator and prepare to flow-test lowermost permeable zone using surface facilities to measure water producing rate, pressure, temperature, and the flow rate at which a significant amount of sand is produced.

DYNAMIC PROCEDURES

The dynamic testing program is designed to accomplish several objectives:

- (1) Obtain fluid samples under both bottomhole and surface conditions of pressure and temperature. These samples will be tested for methane gas and chemical solids in solution.
- (2) Establish the flow rate from a given footage of perforations at which significant sand production occurs. Each permeable zone in the geopressured interval will be tested.

- (3) Determine the total footage of perforations needed to obtain the optimum flow rate from the well with negligible sand production, maximum temperature and pressure.
 - (4) Collect data for reservoir analysis. This will include tubing pressures, wellhead temperatures, bottomhole pressures, fluid volume per day and cumulative, pressure drawdown versus fluid production, and pressure buildup after the well is shut in.
- 27. Flow well on small size choke until pressure and temperature are reasonably stable. Record well head pressure, bottomhole pressure, and well head temperature. Record flow rate. Shut in well.
 - 28. Run bottomhole sampler to maximum feasible depth with sampler. Secure fluid sample for laboratory analysis. Run bottomhole pressure gauge with maximum reading thermometer.
 - 29. Open well on small size choke and divert flow to surface test equipment when pressure and temperature stabilize. Monitor and record vessel pressure(s), temperature(s), gas and fluid flow rates. Collect fluid sample at the separator for laboratory analysis. Check sand detector every hour. Flow well for 24 hours and go to Item 30.
 - 30. Open well on 50% larger choke size, allow time to obtain stabilized flow. Make 24-hour test as Item 29 and go to Item 31.
 - 31. Open well on 100% larger choke size than Item 29. Make 24-hour test as Item 29 and go on to Item 32.
 - 32. Continue increasing flow rates, as above, until wellhead pressure is reduced to 1,000 psig or until noticeable amounts of sand appear in the sand detector. Monitor surface equipment and record

data as Item 29. Close in well.

33. Run bottomhole pressure gauge to observe pressure buildup while well is closed in. Leave well closed in until surface pressure returns to pressure observed in Item 27, or until shut-in time equals flow-testing time. Unseat packer and circulate mud to kill well. Pull out of hole.
34. Set wireline bridge plug above perforations and place 10 sacks of Class H cement with dump bailer. Set second wireline plug on top of cement.
35. Run drill pipe and full-bore packer with 90-foot tailpipe below packer. Place packer above second porous zone from bottom as indicated by Gamma Ray-Neutron survey and other logs. Circulate clean drilling fluid of sufficient density to balance formation pressure of the porous zone.
36. Displace weighted drilling fluid in the drill pipe using saltwater with tailpipe located below the top of the porous zone to be perforated. Pull tailpipe above the porous interval and set packer. This should leave an effective pressure on the bridge plugs of about 0.5 psi per foot of depth. Observe if bridge plugs are leaking or holding pressure.
37. If bridge plugs appear to be leaking, perform cement squeeze on the plugs to obtain pressure integrity. (If Halliburton RTTC packer is used this operation can be performed immediately). If plugs appear to be holding proceed to perforate.
38. Rig up perforating equipment including 15,000 psi lubricator as Item 23, and perforate the second porous interval following

procedures outlined previously.

39. Open drill pipe production manifold on small choke and allow well to flow slowly until clean formation fluid reaches the surface. Record pressure and temperature of the flow stream ahead of choke.
40. Close well in, record drill pipe pressure and estimated bottomhole pressure.
41. Run hollow-carrier jet perforating gun and perforate the second porous zone using procedures as outlined in Item 26.
- 42-47. Make production test of second zone following procedures outlined Items 27-33. At end of test, close in well.
48. Run bottomhole pressure gauge to observe pressure buildup while well is closed in. Leave well closed in until surface pressure returns to the pressure observed Item 40 or until shut-in time equals flow testing time.
49. Set wireline bridge plug above perforations in the second porous zone and place 10 sacks API Class H cement on the plug using a dump bailer. Set second wireline bridge plug on top of cement.
- 50-56. Repeat procedures outlined in Items 22-26 to test bridge plugs and perforate the third porous zone in the well.
- 57-62. Perform production test of third zone following procedures outlined in Items 27-33. At end of test, close in well.

Continue testing zones of porosity and permeability until the uppermost zone is tested. Set bridge plugs between zones. When all zones have been tested, or the sum of flow rates from the individual zones totals 40,000 barrels per day, discontinue testing schedule.

TEST AND SAMPLING PROCEDURES
FOR A CASED HOLE
GEOPRESSURED TEST WELL

An existing well untested in geopressured aquifers must be repaired and reconditioned for geothermal purposes before static and dynamic tests can be made. The casing and casing head must be pressure tested to assure that neither will leak under pressures as high as 10,000 psig at the surface. The well bottom and any old perforations in the production casing must be plugged in such fashion as to hold about 5,000 psig differential pressure without leaking.

STATIC PROCEDURES

1. Install 10,000 psi working pressure blowout preventers on the wellhead. Test to maximum safe pressure of the wellhead fittings and casing hanger.
2. Pick up and run internal flush drill pipe to check integrity of the casing plugs and any old perforations. Drill pipe should be the largest size compatible with the production casing. Run cleanout bit to plug-back depth in the well. Check depth measurement of plug, and drill out plug(s) to desired depth inside the casing.
3. Run full-bore packer on drill pipe to pressure test the plug and squeeze perforations in the casing. Place packer above plug, displace mud in drill pipe with salt water to lower the static head on the plug to about 0.5 psi per foot of depth. Set packer, close valve on drill pipe at the surface and check for pressure build up on drill pipe. If plug leaks, squeeze cement through the plug to obtain plug integrity. Pull up the packer, cement squeeze perforations, drill out, and pressure test to assure shut off. Clean out

to plug back depth.

4. Run Cement Bond Log, Gamma Ray and Neutron Porosity Log, and Collar Locator Log. It may be desirable to run a Pulsed Neutron Log to ascertain if there is any free oil or gas behind the casing.
5. If the cement bond between the production string and wall of the hole does not appear to be satisfactory, a squeeze cement job will be performed where lack of bond appears. It will be necessary to perforate the casing above and below the zone to perform block squeezes. Drill out cement to plug-back depth.
6. Run open-end drill pipe with full-bore packer to pressure test the casing. Set packer and apply pressure to the drill pipe to obtain 1.0 psi per foot of depth below the packer. If pressure drops off, lower packer, reset and pressure test until leak is located. Cement hole in casing. Drill out cement.
7. Run drill pipe and full-bore packer with 90-foot tailpipe below the packer. Place the packer near the top of the lowermost porous zone as indicated by the Gamma Ray-Neutron survey and other logs. Circulate clean drilling fluid of sufficient density to balance expected formation pressure.
8. Displace weighted drilling fluid in the drill pipe using saltwater with tailpipe located below the top of the porous zone. Pull tailpipe above the porous zone and set packer. Close blowout preventers and prepare to perforate.
9. Rig up 15,000 test pressure control equipment on the drill pipe, including wireline blowout preventer, lubricator and grease-seal packing gland for wireline, to run and pull perforating tools under

pressure. Run large diameter, hollow-carrier jet perforating gun to perforate the casing. Apply hydraulic pressure to the drill pipe to obtain bottomhole hydrostatic pressure 300 psig less than the estimated formation pressure. Perforate the casing, using 1 shot per foot over an interval of five feet near the top of the lowermost zone of porosity. Record drill pipe pressure and indicated bottomhole pressure. Recover perforating tools.

10. Open well on small choke and allow well to flow slowly until clean formation fluid reaches the surface.
11. Close in well, record drill pipe pressure and estimated bottomhole pressure.
12. Run hollow-carrier jet perforating gun, as in Item 9, and perforate the lowermost porous zone completely for total shot density of 2 holes per foot. Rig down lubricator and prepare to make extended dynamic flow tests using surface utilities.

DYNAMIC SAMPLING PROCEDURES

The dynamic testing program is designed to accomplish several objectives:

- (1) Obtain fluid samples under both bottomhole and surface conditions. These samples will be tested for the amount of methane gas and chemicals dissolved in the water.
- (2) Determine the flow rates at which significant quantities of sand are produced from each zone.
- (3) Determine the footage of perforations needed to obtain optimum flow rate with minimum sand production, maximum temperatures and pressures.

- (4) Collect data for reservoir analysis from each zone.
13. Flow the well on small size choke until pressure and temperature are reasonably stable. Record wellhead pressure, bottomhole pressure, and wellhead temperature. Record flow rate. Shut in well.
 14. Run bottomhole sampler to maximum feasible depth. Secure fluid sample for laboratory analysis. Run bottomhole pressure gauge with maximum reading thermometer.
 15. Open well on small size choke and divert flow to surface test equipment when pressure and temperature are stabilized. Monitor and record vessel pressure, temperature, and gas and fluid flow rates. Collect fluid sample at the separator for laboratory analysis. Check sand detector every hour. Flow well 24 hours and go to Item 16.
 16. Open well on 50% larger choke size, allow time to obtain stabilized flow. Make 24-hour test as Item 15 and go to Item 17.
 17. Open well on 100% larger choke size referring to Item 15, allow time to obtain stabilized flow. Make 24-hour test as Item 15 and go to Item 18.
 18. Continue increasing flow rate, as above, until wellhead pressure declines to 1,000 psig, or until significant amount of sand appears in the sand detector. Monitor surface equipment and record data as in Item 15. Close-in well.
 19. Run bottomhole pressure gauge to observe pressure buildup while well is closed in. Leave well closed in until surface pressure returns to pressure observed Item 13, or until shut-in time equals

flow testing time. Unseat packer and circulate mud to kill well. Pull out of hole.

20. Set wireline bridge plug above perforations and dump 10 sacks Class H cement on plug using bailer. Set second wireline bridge plug on top of cement.
21. Run drill pipe and full-bore packer with 90-foot tailpipe below packer. Place packer above second porous zone. Circulate clean drilling fluid of sufficient density to balance formation pressure of the porous zone.
22. Lower drill pipe to place tailpipe below the top of the porous zone. Displace weighted drilling fluid in the drill pipe using saltwater. Pull tailpipe above the porous zone interval and set packer. This should leave an effective pressure on the bridge plugs of about 0.5 psi per foot of depth. Observe if bridge plugs appear to be leaking or holding pressure.
23. If bridge plugs appear to be leaking, perform squeeze operation on the plugs to obtain pressure integrity. (If Halliburton RTTS packer is used this operation can be performed immediately). If plugs appear to be holding proceed to perforate.
24. Rig up perforating equipment, including 15,000 psi lubricator, as Item 9, and perforate the second porous interval using 1 jet shot per foot for five-foot interval in the porous zone.
25. Open drill pipe production manifold on small choke and allow well to flow slowly until clean formation fluid reaches the surface. Record flowing pressure and temperature ahead of the choke.
26. Close in well, record drill pipe pressure and estimated bottomhole pressure.

27. Run hollow-carrier jet perforating gun and perforate the balance of the porous interval for total of 2 shots per foot as outlined in Item 12.
- 28-33. Make production test of second zone following procedures outlined in Items 13-18. At end of test close in well.
34. Run bottomhole pressure gauge to observe pressure buildup while well is closed in. Leave well closed in until surface pressure returns to pressure observed in Item 26 or until shut-in time equals flow-testing time. Recover bottomhole pressure gauge. Unseat packer, circulate mud to kill well. Pull drill pipe out of hole.
35. Set wireline bridge plug above perforations in the second porous zone and place 10 sacks Class H cement on the plug using a dump bailer. Set second wireline bridge plug on top of cement.
- 36-42. Repeat procedures outlined in Items 21-27 to test bridge plugs and perforate the third porous zone in the well.
- 43-48. Perform production test of third zone following procedures outlined in Items 13-18. At the end of test close in the well.
49. Run bottomhole pressure gauge to observe pressure buildup while well closed in. Leave well closed in until surface pressure returns to the pressure observed in Item 43, or until shut-in time equals flow-testing time. Recover bottomhole pressure gauge. Unseat packer, circulate mud to kill well. Pull drill pipe out of hole.

Continue testing zones of porosity and permeability until the uppermost zone is tested. Set bridge plugs between zones. When all zones have been tested, or the sum of flow rates from the individual zones totals 40,000 barrels per day, discontinue the testing schedule.

TEST AND SAMPLING PROCEDURES
FOR GEOTHERMAL PURPOSES
A WELL BEING DRILLED FOR OIL OR GAS

An operator of a well being drilled for oil or gas might be willing to obtain extra electric logs, perhaps a core to be taken, and permit wireline tests to assess the geothermal-geopressured formations in the well. But it is extremely unlikely that the operator of such a well would turn it over for long-term testing to fully evaluate the geothermal capabilities before he had exhausted the possibility of oil and gas production. It is thus anticipated that, if such a well was obtained for geothermal purposes, testing and sampling procedures would consist of electric surveys, and formation tests to determine lithology, porosity, formation fluid characteristics, pressure, temperature, and apparent salinity. In such case, the following electric logs would be needed:

- Induction-Electric Survey
- Borehole Compensated Sonic
- Formation Density and Gamma Ray
- Dipmeter and Caliper Survey
- Microlaterolog
- Temperature Survey

Taped data from the above logs would be used to prepare Computerized Process Logs of the geopressured sand intervals for reservoir analysis and mechanical properties logs.

The Schlumberger Repeat Formation Tester (RFT) would be run on the permeable zones to obtain pressures and fluid samples from the most permeable sections.

If an operator of a well being drilled for oil and gas permitted his well to be logged for geothermal assessment and subsequently released the hole for long-term testing, test and sampling procedures would be as discussed previously. In the situation that no oil or gas zones were found, production casing would not be set, thus procedures would be as listed for a well specifically drilled for a geothermal well. In the second situation, where non-commercial shows of oil or gas may have been encountered, production casing would have been set into the geopressured zone. It is extremely unlikely a well such as the second case would be made available for geothermal testing purposes prior to being abandoned by the operator. In that situation, test and sampling procedures for geothermal purposes would proceed as outlined for a cased hole. In essence, this means the well must be cleaned out, repaired, and the casing checked for pressure integrity. This would be the same as the procedures for a cased hole that has already been discussed.