PROCEEDINGS

SECOND GEOPRESSURED GEOTHERMAL ENERGY CONFERENCE

VOLUME III

RESERVOIR RESEARCH AND TECHNOLOGY

BY

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INTRODUCTION

Advanced Research And Technology

ADVANCED RESEARCH AND TECHNOLOGY

Within the scope of the Phase 0 Geothermal Project, the Advanced Research and Technology area is concerned with the following aspects.

1. Well Drilling
2. Well Completion
3. Well Performance
4. Reservoir Performance

Within each of these phases, the objective was to identify existing technology, areas of possible research, and to prepare preliminary plans and cost estimates for a geothermal test well.

The overall objective of the project is the meaningful evaluation and prediction of geopressured geothermal reservoir deliverability and performance. Therefore the discussion of each individual phase is focused at two levels:

1. A general discussion related to the Gulf Coast Geopressured resource
2. Specific examples applied to one or more possible test sites

GENERAL CONCLUSIONS

Phase 0 studies have concentrated on research in the following areas: well design, well completion technology, data acquisition, reservoir simulation studies, fluid sampling and analysis, rock mechanics research, and heat transmission in wellbores.

Conclusions of this research are as follow:

1. Available drilling and completion technology and equipment are adequate for successful drilling and completion of a geopressured geothermal well
2. Detailed design of completion, drilling and testing program will require complete definition of the initial test site
3. Certain long lead-time items (pipe, wellheads, data acquisition, etc.) can be ordered based upon approximate site definition.

4. Development of geothermal reservoir simulator is necessary to design proper well test sequence and programs to accurately evaluate reservoir performance
5. Development of the geothermal reservoir simulator will require accurate information on mechanical and flow properties of rocks
6. Initial studies of reservoir simulation in the Kenedy County fairway area indicate that for a single well, a one year test period will be insufficient to establish with certainty the influence of adjacent shale water on the performance of the geopressured geothermal reservoir
7. A single well with a one year test period should be sufficient to allow for determination of compaction effects on reservoir performance, as well as reservoir properties in the vicinity of the well
8. Detailed sampling and analysis of well fluids should be planned as soon as additional information from current test programs in Louisiana is available. Methods of sampling and analysis are available to accurately determine reservoir fluid and dissolved solid components
9. Fluid transmission in wellbore will result in heat losses of only approximately 5^{o} F.

Based upon research to date, it has been determined that well design using a 5½ inch production string of casing will be adequate to produce reservoir fluids at the rate of 40,000 barrels/day. Total costs for drilling, completion, fluid sampling, and installation of the requisite data acquisition system for the first well, to be drilled to a depth of approximately 15,000', will be roughly $2,600,000. However, in order to study the effects of influx of water from adjacent shales, a second well should be drilled near the sand-shale interface, i.e., near a distal portion of the reservoir sand section. This second well should cost approximately $1,900,000. Research into rock mechanics is urgently required in order to study these effects, and it is estimated that such research will cover a two year span and cost approximately $280,000. Development of a reservoir simulator is in progress under a Phase I contract from ERDA to the CES.

RECOMMENDATIONS FOR FUTURE RESEARCH

1. Concurrent with final site selection, final well design is required. However, long lead-time items can be ordered at the time of decision to proceed to site selection.
2. Continue development of geopressured geothermal reservoir simulator (underway).
3. It is necessary to undertake development of equipment and techniques for rock sample testing. Rock mechanics portions of research will cost approximately $280,000.
4. Final plans should be undertaken, and equipment ordered, for reservoir fluid sampling and testing.
5. It is necessary to develop detailed planning for testing and monitoring the initial and development well in the first reservoir.
6. It would be useful to perform additional fluid tests on existing wells in Texas and Louisiana, similar to the test underway presently in Louisiana. Four such tests should be contemplated within the next two years, at a total cost of approximately $2,000,000.

ACKNOWLEDGEMENTS

The following companies have lent assistance in the development of plans and cost estimates for this portion of the Phase 0 project:

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Schlumberger Well Services
Sperry-Sun Company
Systems Science and Software, Inc.

PART 1

Development of Drilling, Completion and Testing Plan for a Geopressured Geothermal Well

The following presents general guidelines, recommendation and cost estimates for drilling, completing and testing a well in a Gulf Coast geopressured geothermal reservoir.

CHAPTER I

WELL DRILLING

Although the ultimate objective of the drilling operation is to provide access to the resource and allow the production of fluids through the wellbore, in this particular case of geothermal geopressured wells the drilling phase should also provide a reliable source of accurate information for the overall evaluation of the gulf coast geopressured resource.

The primary philosophy was that whenever possible existing technology should be used in this project unless reasonable doubt existed that techniques, methods and materials would obscure the true essence of the geopressured resource or might in any way damage or alter the productivity of such formation. As such the following guidelines were adhered to:

1. Minimize possible damage to the producing formation,
2. Maximize quality of data obtained through the drilling operation and subsequent surveys,
3. Simplify procedures to insure maximum reliability and safety,
4. Apply existing technology whenever it insures high probability of satisfying the above objectives.

Within the past five years the deep and ultra-deep well drilling technology has been well established in the oil industry. This has resulted in the successful drilling and completion of wells at depths up to 30,000 feet in areas both of normal and abnormal subsurface pressure. This has been the result of two developments: (1) availability of improved equipment and materials and (2) the application of optimized drilling analysis, well planning and well monitoring during the drilling operation.

PRE-DRILLING ANALYSIS

The objective is to define as accurately as possible the characteristics of the site where the well is to be drilled. Chronologically this takes place after a thorough geologic analysis has been completed.

Following the selection of a general site for the drilling operation is a thorough study of all available offset wells to determine the geologic section to be drilled and any characteristics of the formations to be penetrated. The specific site where the well is to be drilled can be further identified by undertaking a geophysical survey possibly of the seismic reflection type which allows the identification of subsurface features such as faults, which might present a hazard to the drilling operation. Modern techniques of seismic records interpretation allow the determination over relatively broad depth intervals of the velocity of wave propagation in the subsurface strata. This can be further interpreted in terms of formation pressures to be encountered during the drilling operation, besides yielding estimates of the types and strengths of the strata to be drilled. The richest source of information is from drilling records of existing offset wells in the area. This includes not only electric logs but bit records, mud records, recorded drilling data such as torque, pump pressure, penetration rate, etc., casing points, hole size, encountered problems, rig specifications, and correlation of formation tops to the proposed well.

The results of the pre-drilling analysis is therefore a complete definition of a specific site for the drilling operation and a large amount of information upon which the next phase of well planning is to be based.

WELL PLANNING

It is important that in the development of the detailed well plan not only be considered factors that directly affect the drilling operation but remembering that the ultimate objective is to have access to the reservoir in order to satisfy the production requirements, it is imperative that in the drilling plan be considered as well all the completion and production requirements. This is especially important in the case of the geothermal test well since to a large degree the viability of the geopressured geothermal resource will be judged upon the performance of this one test well. As such the completion should in no way mask the true and actual performance of the reservoir. It should also allow and insure the maximum flexibility in terms of methods of well testing, completion, stimulation and formation evaluation. This factor should be included in the formulation of the detailed well plan.

The completed well plan will contain data and instructions on the following:

1. Location
2. Map of location
3. Reference well logs
4. Reference well drilling data
5. Drilling procedures
6. Expected pore pressures as a function of depth
7. Logging procedures
8. Mud program
9. Casing program
10. Well control procedures
11. Well head equipment
12. Blowout prevention equipment
13. Cementing program
14. Casing program
15. Drilling time curves
16. Hydraulics
17. Bit program
18. Testing program.

Equipment to match the hole design and requirements is then selected keeping in mind that in many instances the success of the drilling operation depends on the flexibility and capability of the equipment. Although in practice sometimes the program is modified to fit an available rig in this specific instance it is recommended that the program be utilized to set rig specifications. The primary criteria for rig selection should be (a) hydraulic horsepower available, (b) overall power available (c) adequate drilling fluid handling facilities, (d) adequate selection of drill pipe and drill collars, (e) adequate flexibility of rotary speed, (f) adequate load capacity.

WELL MONITORING

A successful drilling program depends on many factors. None is more important than the quality of data from the drilling operation upon which recommendations are based and modifications of the proposed plan are envisioned. The ideal method for collecting data is via monitoring and recording equipment on the rig with around-the-clock operators and engineers present to insure that the necessary information is obtained.

In particular, in this specific instance of the geothermal test well, where the drilling operation is to yield the main source of direct and indirect information about the resource, it is imperative that the accuracy of the information achieved during the drilling operation be maximized. Techniques for well monitoring are well established and are described in detail in Appendix Ib.

CHAPTER II

WELL COMPLETION

The area of well completion encompasses all operations necessary to allow the controlled flow of reservoir fluids to the surface. This covers all equipment such as casing, tubing, packers, wellheads, etc. as well as specific procedures such as logging cementing, perforating and testing, necessary to achieve this objective.

Well completion should be designed to yield all necessary information for evaluation and predictions of the reservoir performance as well as to achieve the desired objectives with a minimum of disturbance of the productive formation characteristics.

WELL COMPLETION DESIGN CRITERIA

The completion design criteria consists of the following elements:

Rate Requirements. The size of the production tubing should not restrict the flow of fluids from the reservoir. This is illustrated in the accompanying figures 1 through 6 where the frictional and head losses for various sizes of pipe are plotted as a function of flow rate. This is in turn combined with pressure draw-down at the wellbore as a function of rate resulting in a plot of wellhead flowing pressure as a function of rate for the various pipe sizes. The effect of formation deliverability is illustrated by the parameter of permeability thickness product. Knowing a specific rate requirement and a minimum desired wellhead pressure allows the selection of the appropriate size of completion. For example, a specific case of a desired rate of 40,000 bbls/day at a minimum wellhead pressure of 2000 psi indicates that the minimum completion size required is 5 1/2 inch casing for a permeability thickness product of 5000 milidarcy feet. These results have been obtained for a specific reservoir pressure at one specific time in the life of the reservoir and are summarized in Table I.

Pressure loss calculations as well as temperature distribution during steady state flow were performed under the assumptions of single phase flow and for a typical well configuration such as that represented in

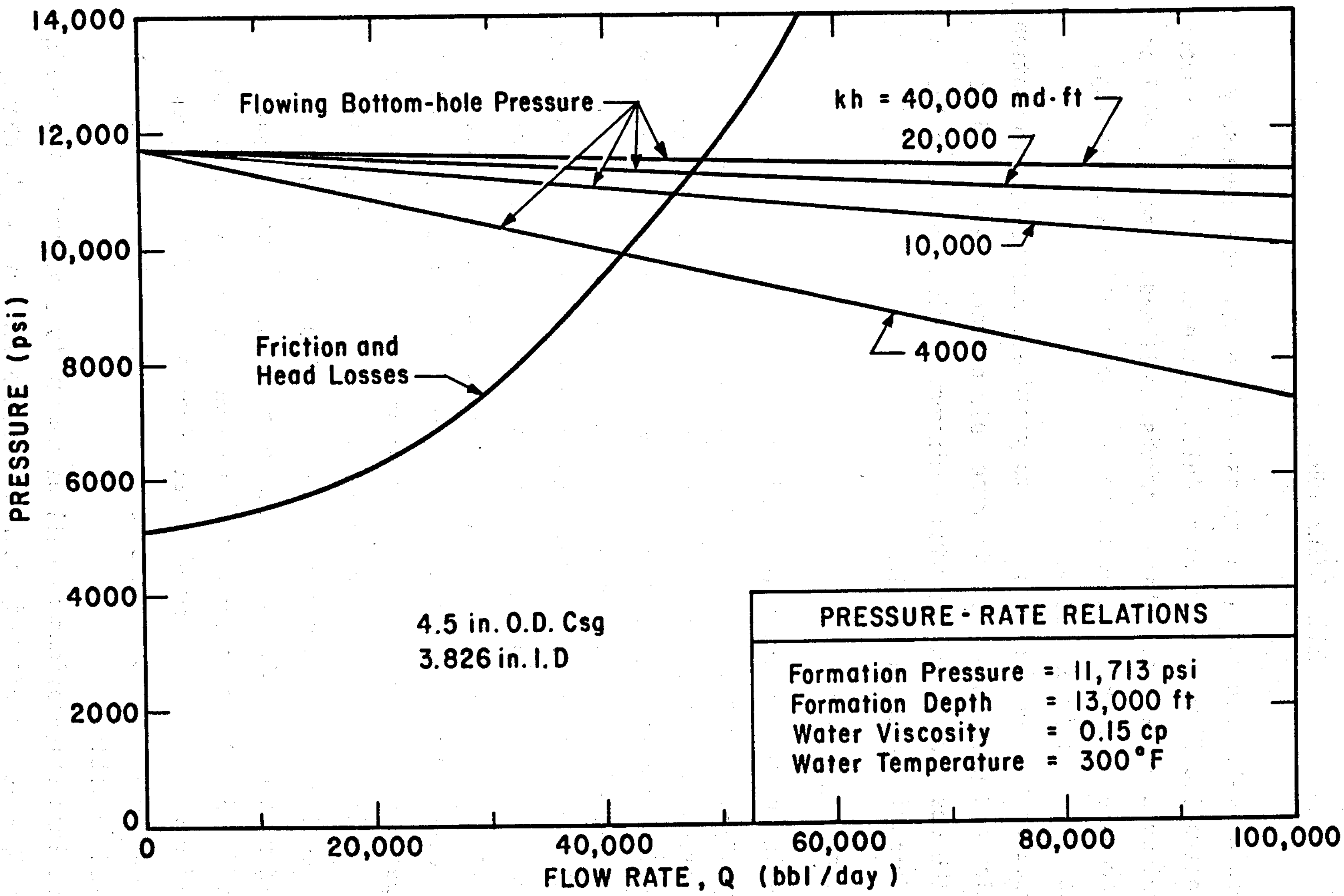

Figure 1. Flowing bottom hole pressure as a function of flow rate for various permeability-thickness conditions. Pressure losses for 4 1/2" tubing.

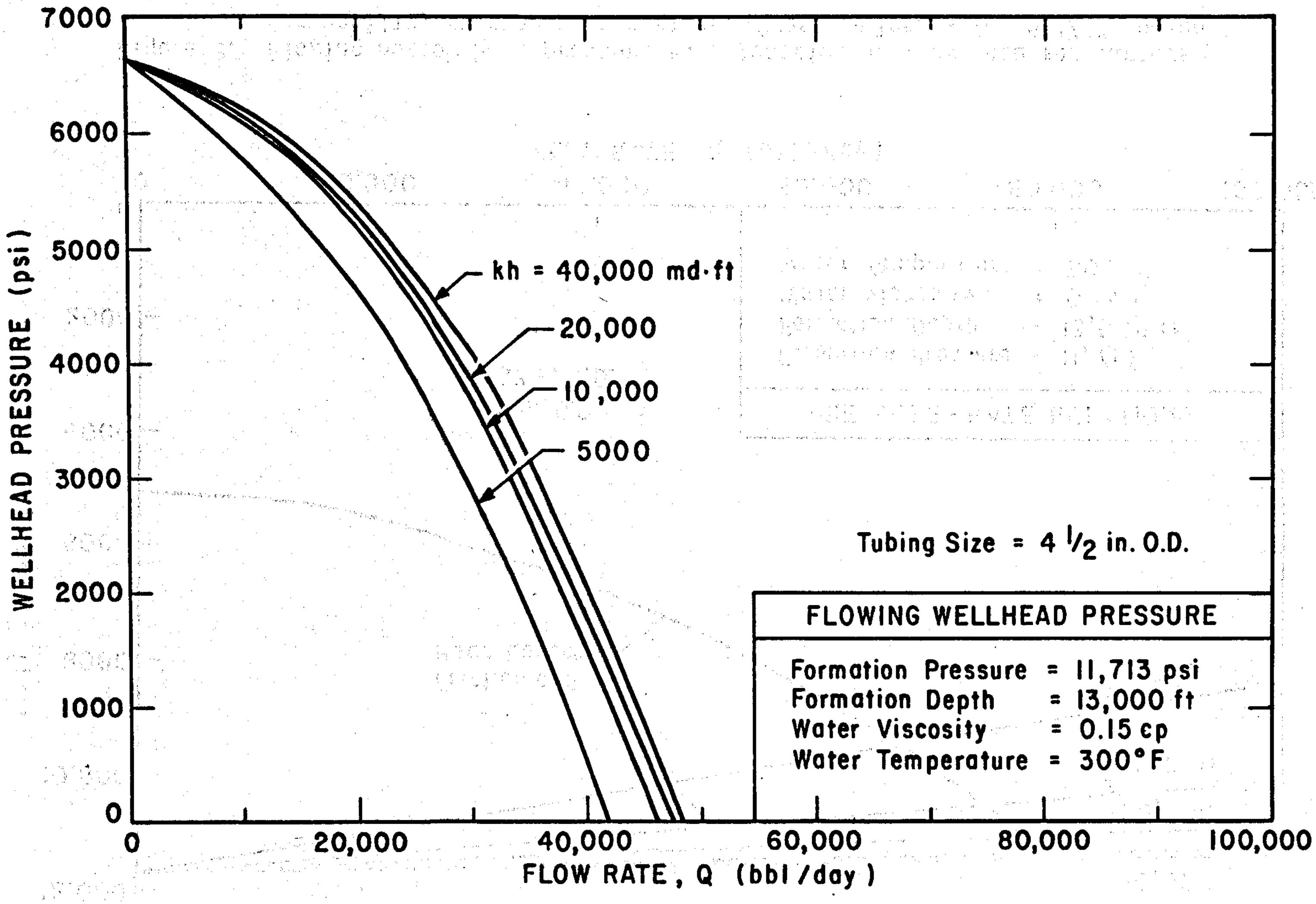

Figure 2. Flowing wellhead pressure as a function of rate for variable permeability-thickness conditions. 4 1/2" tubing.

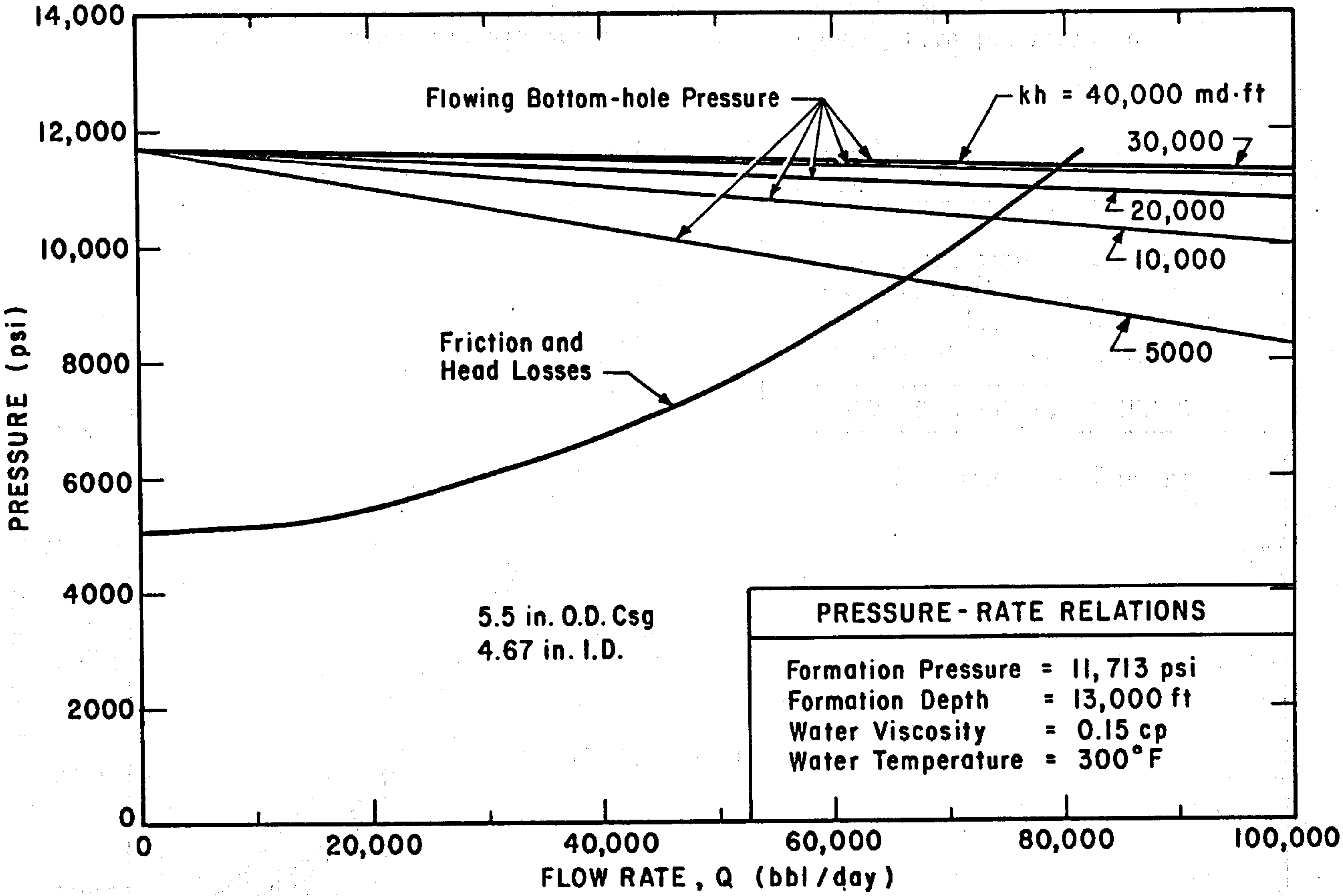

Figure 3. Flowing bottom hole pressure as a function of flow rate for various permeability-thickness conditions. Pressure losses for 5 1/2" tubing.

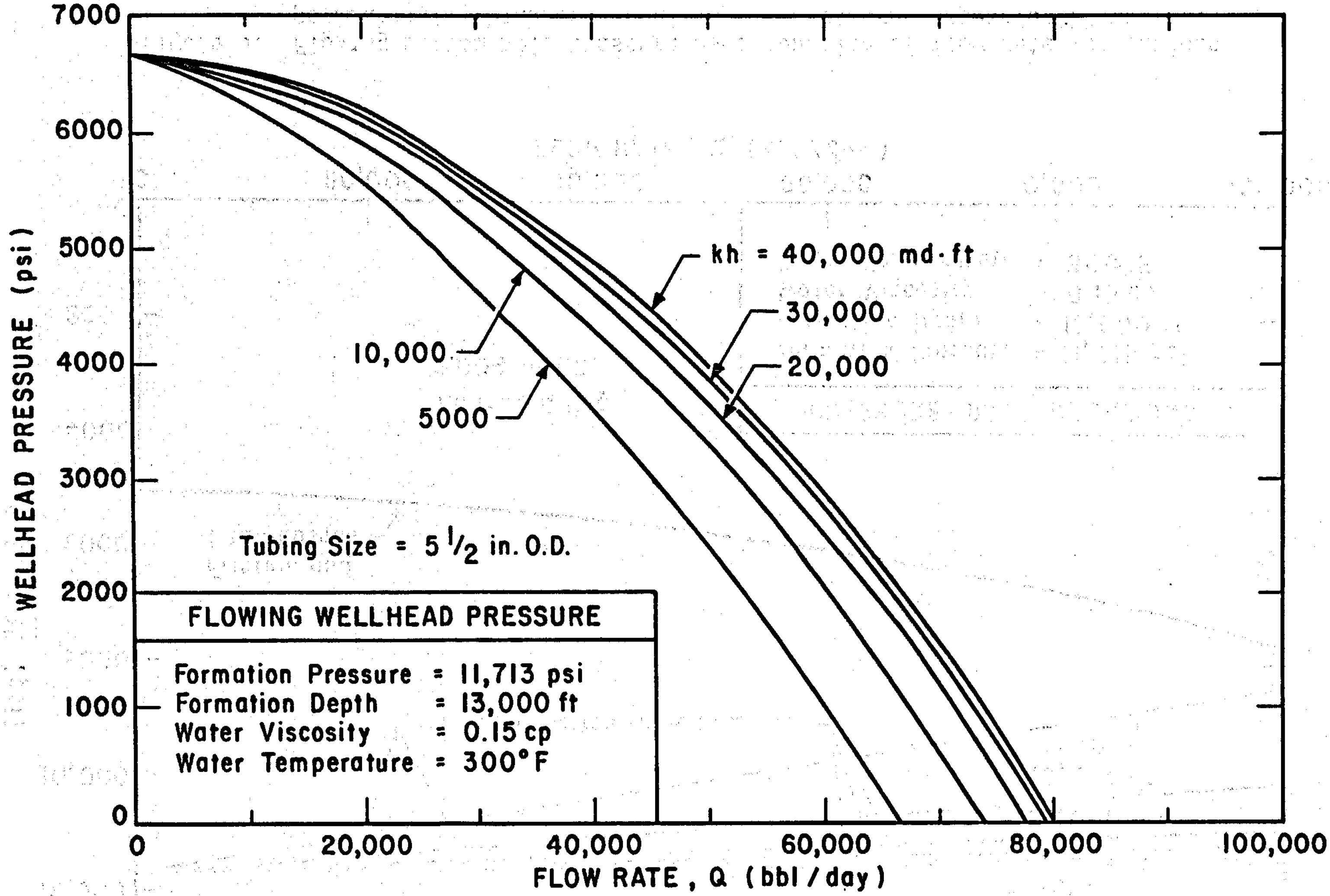

Figure 4. Flowing wellhead pressure as a function of rate for variable permeability-thickness conditions. 5 1/2" tubing.

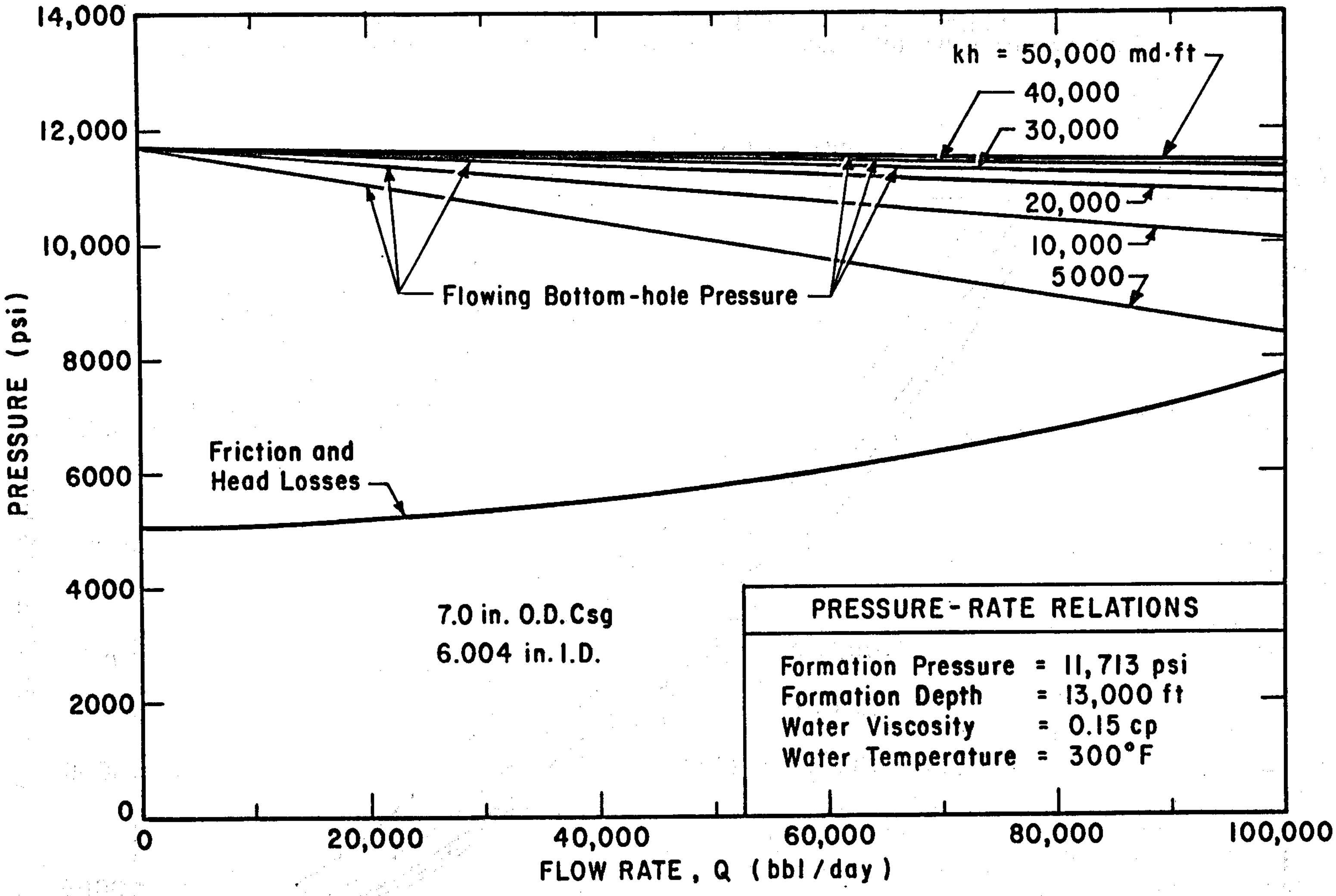

Figure 5. Flowing bottom hole pressure as a function of flow rate for various permeability-thickness conditions. Pressure losses for 7" tubing.

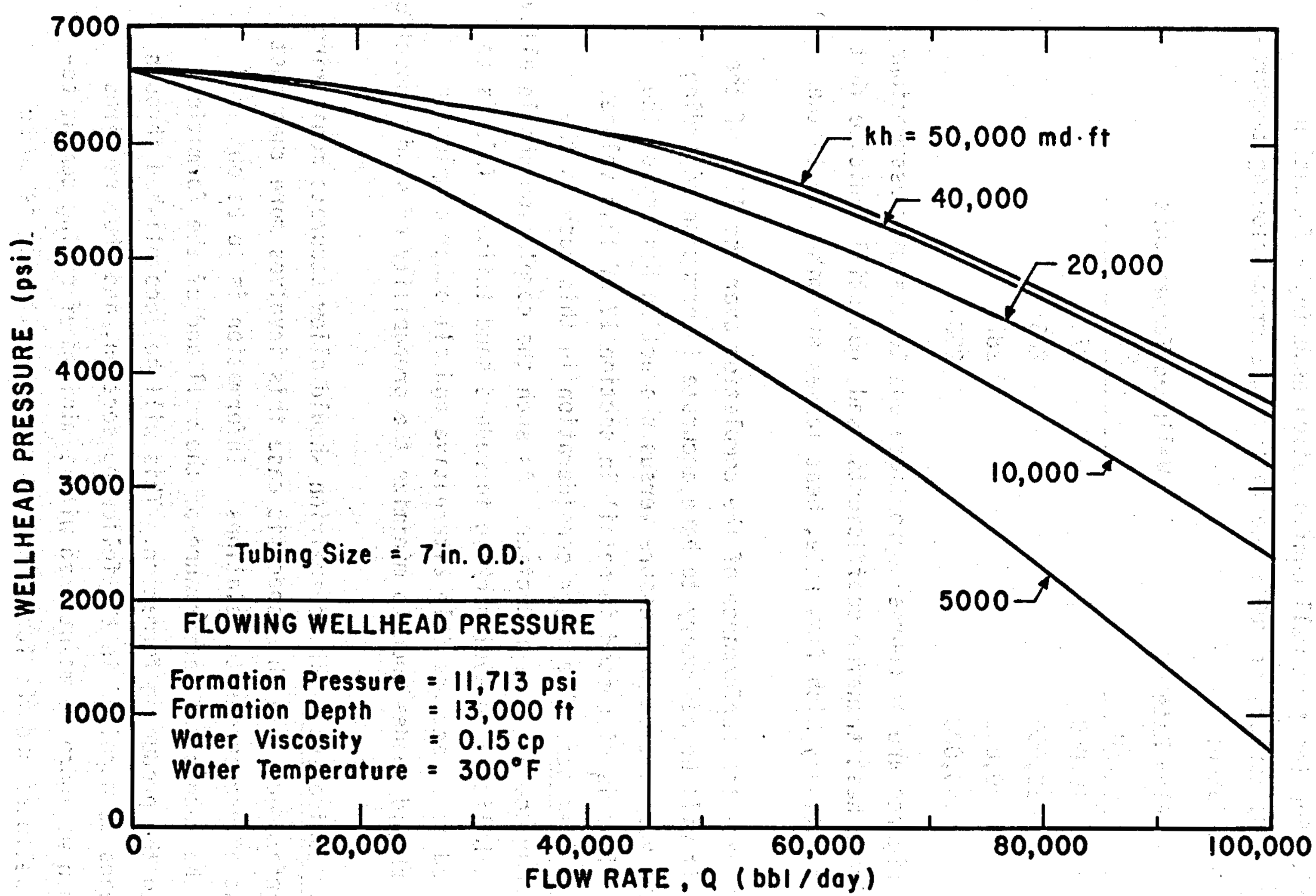

Figure 6. Flowing wellhead pressure as a function of rate for variable permeability-thickness conditions. 7" tubing.

Appendix Ic. A detailed description of the calculations is presented in Appendix III. For the test well configuration assuming a formation temperature (undisturbed) of 300^{o}F the following surface flowing temperatures were calculated:

Flow Rate B/O	Wellhead Temperature ^{o}F
10,000	279
20,000	285
30,000	287
40,000	288

These figures are of course approximate due to the many assumptions and approximate heat transfer coefficients used, but still indicate that due to the relatively high flow rate, heat losses are minor up to the wellhead.

To evaluate the performance of the completion over the life of the reservoir, it will be necessary to have accurate information regarding the pressure versus time or pressure versus production history of the reservoir. This is discussed in detail in section IV of this volume.

Workover Requirements. The major consideration in this case is the possible occurance of sand production. As such the completion should allow for the possibility of gravel packing to reduce sand influx. This is to be considered as a last possible alternative and all other completion procedures should be designed to minimize the probability of sand production occuring.

Monitoring Requirements. The compeltion should allow accurate monitoring of well performance. In this specific case this involves more than just measurement of pressure-rate relations. Information is to be obtained regarding the mechanical performance of the well and of the formation adjacent to the producing formation. This will be accomplished through logging means as detailed in the following section, and thus requires that an open wellbore be maintained with a minimum of casing cement between the wellbore and the formation. Pressure monitoring is to be achieved by permanent installation of the bottom hole pressure sensing device.

<u>Stimulation Requirements</u>. Although the primary consideration in the selection of possible well sites is the formation productivity and as such high permeability thickness sections will be favored, the completion should allow for the possible use of hydraulic fracturing techniques to improve productivity of the well.

<u>Thermal Effects Requirements</u>. Besides thermal effects on the completion materials such as pipe, cement and completion equipment, the effect of temperature variations during transient conditions should be taken into account. In most instances these effects can be accomodated by providing appropriate expansion joints for all tubular sections that are not cemented or including the effect of thermal stresses in the tension design calculations.

TABLE I

Flowing Wellhead Pressure (psi) for 4½" Tubing

Q Bbl/day	Kh md/ft	5000	10000	10000	40000
10000		5800	6100	6150	6200
20000		4640	5100	5300	5400
30000		2900	3700	3900	4100
40000		450	1550	1850	1000
45000		--	340	700	900

Flowing Wellhead Pressure (psi) for 5½" Tubing

10000		6200	6350	6420	6500
20000		5550	5900	6060	6200
30000		4600	5050	5400	5560
40000		3600	4320	4650	4850
50000		2400	3300	3650	3900
60000		1000	2050	2500	2800

Flowing Wellhead Pressure (psi) for 7" Casing

10000		6290	6480	6550	6600
20000		5900	6250	6400	6500
40000		4900	5580	5900	6100
60000		3730	4700	5200	5500
100000		700	2400	3180	3650

Note: Formation Pressure: 11713 psi
Formation Depth: 13000 ft.

Based on the preceding results estimates of drilling and completion costs were obtained for various possible depths and sizes of the producing tubing. These costs are summarized in Table II while the detailed cost breakdown is presented in Appendix II.

From the preceding it can be concluded that the consideration of production rate requirements, with reservoir performance characteristics and completion costs allows the logical initial selection of a well configuration.

TABLE II

ESTIMATED GEOPRESSURED GEOTHERMAL WELL COSTS IN DOLLARS*

Diameter, Inches	Dry Hole	Completed
	Depth 14,000 ft (Nueces Co.)	
4.5	1,067,000	1,681,300
5.5	1,067,000	1,733,300
7.0	1,149,000	1,925,300
	Depth 16,000 ft (Nueces Co.)	
4.5	1,622,700	2,287,700
5.5	1,622,700	2,346,400
7.0	2,220,500	3,077,000
	Depth 18,000 ft (Cameron Co.)	
4.5	1,895,200	2,595,200
5.5	1,895,200	2,662,700
7.0	2,548,700	3,468,200

*See Appendix for detailed breakdown.

CASING DESIGN

Following selection of an appropriate size completion, an overall casing program can be developed. The casing program is dependent on drilling costs, completion requirements and geology and pressures to be encountered. Offset well studies and geologic sections play an important role in supplying the required information.

The well studies provide input for locating the abnormally pressured zones. Location of these zones helps determine the necessity of intermediate casing strings and where the strings should be seated. The number of strings required will vary with the depths of abnormally pressured zones and the target depth of the well. Information on common practices used in the area can also be obtained from the offset well studies.

Knowing the completion requirements and the number of intermediate strings needed, pipe sizes can be chosen and individual string design can begin. In choosing casing and bit sizes attention should be given to adequate clearance and accepted cementing practices. Testing procedures must also be considered to insure the casing design will not interfere.

Choice of casing grades and weights is dependent on the conditions and pressures expected. Any corrosive conditions must be taken into consideration. In all instances, the casing should be designed to protect against the worst possible conditions. Design, or safety factors should be included in all design specifications.

The grade and length conductor pipe to be used is dependent on costs and availability. Previous practices in the area serve as a good indicator.

The surface casing must be seated at a depth sufficient to protect fresh water zones present. Offset well studies will indicate the approximate depth required. Since the surface casing will be the first line of defense in case of blow out, its design is important. The internal yield strength of the casing should not exceed the rating of the blow out preventers. The preventers and casing should be able to handle any kick. The design may be checked by assuming various kick sizes with varying shut-in drill pipe pressures. Calculation of pressures on the casing and preventer stack, as the kick is circulated out, will indicate the reliability of the design. Calculations should be made at the greatest depth to be attained before an intermediate string is run--thus representing the worst possible conditions.

For the longer strings, the collapse, internal yield pressure, and tension requirements must all be explored. Design factors of 1.1 for collapse, 1.1 for internal yield, and 1.8 for tension are recommended. Design factors are variable; they depend on locations and procedures used. For each loading stress the worst conditions should be ascertained and the casing designed to exceed those requirements.

Collapse conditions occur when the external pressure exceeds the internal pressure and the collapse strength of the casing. This condition most often occurs when floating casing into the hole. By assuming an external pressure due to the mud gradient and an internal pressure of zero, the collapse loading on the casing can be calculated. Requirements may be reduced by assuming various mud levels within the casing. While this might better simulate actual conditions, it does not give the extra margin of safety included by assuming zero internal pressure.

Burst conditions occur when the internal pressure exceeds the external pressure and the yield strength of the casing. The worst conditions exist when formation pressure is present throughout the casing. In this instance it is not necessary to assume zero external pressure since the minimum external pressure gradient would be that due to salt water. Designing for this condition should allow any kick to be circulated out safely. Blowout calculations should be made to insure that all requirements are met.

CEMENTING OF HIGH-PRESSURE GEOTHERMAL WATER WELLS

Cementing simply involves securing the pipe from the earth's surface to the productive zone. This is accomplished by filling the annular area between the pipe and the formation with cement by pumping the cement down the inside of the pipe and back up behind the pipe. Cementing the pipe in place may be necessary for a number of reasons, depending to some extent upon the characteristics of the formations through which the pipe is set. The reasons for cementing are to keep the hole from caving in, to protect the pipe from corrosive fluids, to protect the fresh water zones from contamination, to isolate the different productive zones in the well, to support the pipe and to assure that the well pressure can be kept under control.

There are approximately fifty different materials used in cementing today's oil, gas, or geothermal wells. These include accelerators for speeding up the setting reaction at low temperatures (80^{o}F-125^{o}F). Retarders are used to delay the setting process at temperatures from 170^{o}F to 600^{o}F. Extenders are used to reduce the cost of the cement slurry and to reduce the weight when encountering weak zones that will not support a cement column of the usual weight. Weighting agents (such as barite and iron oxide) are used to add density to the cement column when additional weight is required to balance the formation pressure and hold the well under control. Fluid-loss additives are used to ensure that the fluid is not squeezed out of the cement slurry leaving a low-water-ratio cement that cannot be pumped into place. Dispersants are used to reduce the viscosity of the cement slurry so it may be placed in turbulent flow for more complete mud removal and a better cement job. These are but a few of the additives that may be used with the cement.

It is necessary to keep the cement and drilling mud separated because they are usually incompatible. There are a number of formulations of materials for use between the cement slurry and the drilling mud. These fluids may be plain water, water with special surfactants or mud thinners, water with scouring materials such as fly ash or perlite, and water with a number of materials added to provide a spacer that has the desired weight and viscosity while being compatible with both the cement and the mud. When using oil-base muds, plain diesel or kerosene is used--with or without special dispersers and surfactants. There are also oil base spacers available which may be weight to 10 ppg or greater while remaining compatible with both the oil-base mud and the cement.

Several different displacement techniques are used for more complete mud displacement and better cement jobs. The most common of these techniques is to design the slurry so that it can be displace in turbulent flow. The slurry in turbulent flow has a lot of internal energy and agitation that has been proven effective for mud displacement in thousands of applications. The Sloflo* technique is also used when conditions warrant--i.e., when the hole and pipe size combinations or slurry properties dictate a pump rate for turbulent flow that is not practical. The Sloflo technique utilizes a displacement rate of 90 ft/min in the annulus, while keeping the density and gel strength of the cement slurry greater than that of the drilling mud.

Mechanical aids are also employed to improve job success. If hole conditions are good, the pipe may be rotated or raised and lowered as the cement is being pumped into place. Research studies and field experience shows this improves the success ratio. However, fear of twisting the pipe apart or getting the pipe stuck off bottom makes this technique unattractive in some instances. Centralizers can be attached to the pipe to hold it in the center of the hole while it is being cemented. Centralizers can normally be run without causing problems and they are very helpful in achieving a good cement job. Other mechanical aids such as rubber cementing plugs are normally used to keep the cement and mud separated as it is being pumped down the casing. A float shoe and a float collar containing check valves are usually attached to the bottom of the casing to assure there is no backflow after the cement has been pumped into place.

The two factors that make geopressured wells different from most oil and gas well cementing operations are the high pressure and high temperature.

The high geopressure makes it necessary to increase the weight of the drilling fluid and cement slurry in order to keep the well under control. It is possible to design and pump cement slurries having weights as great as 18-20 pounds per gallon. The increased weight is attained by either reducing the water:cement ratio, or adding a dense weighting agent or, more frequently, by using both methods. The cement requires only 20-22 percent water by weight to satisfy it chemically--i.e., to complete the reaction. However, in order to keep the cement slurry liquid and pumpable, 40-46 percent mix water is

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*Dowell Service Mark

normally used. By using dispersants or thinners, we can reduce the required mix water to 35 percent or less, and increase the slurry weight from 15.6 to 17.0 pounds per gallon. Weighting agents are then added if needed to further increase the weight. As mentioned earlier these weighting agents are materials of high specific gravity such as barium sulfate, ilmenite and hematite. These materials must also be relatively inert so they won't interfere with the chemistry of the cement or other additives present.

High pressure will reduce the setting time of cement to some extent, but high temperature is a much more serious problem. Tests have been conducted to show that a pressure increase of 10,000 psi will reduce the setting time of a cement slurry by about 50%. However, a change of temperature of 20°F will reduce the setting time of many cement slurries by 50 percent. Therefore, cement pumped into a well with a temperature of 300°F to 400°F would set before getting it pumped into place unless steps are taken to retard it. Retardation is accomplished by dry blending special retarders with the cement at the service company's bulk plant before taking the cement to the well. There are several different retarders available for use, depending upon well temperature and other factors. With today's technology, cement slurries can be formulated to have five hours pumping time in wells with temperatures of 500°F bottom hole temperature. Five hours is adequate time for cementing practically all wells being drilled today.

The other problem that we must contend with because of high temperature is strength retrogression. This loss of strength occurs at temperatures above 120°F due to chemical changes that continue after the normal hydration cycle is complete. The strength loss is accompanied by an increase in permeability. The solution to this problem is the addition of high-purity sand. The optimum quantity of sand is about 35% by weight of the cement. This is added as silica flour or slightly coarser silica sand. Since geothermal wells are produced at high rates, it is necessary to stabilize the cement from the top of the well to the bottom by adding sand.

The cost of cementing a geothermal well depends upon many factors. The cost of a single job may vary from less than $1,000 for the surface or conductor pipe job to $25,000 for the production casing. Factors which determine the cost are the depth, pressure, temperature, annular volume, desired fillup, displacement technique utilized and the formation properties.

Surface and conductor pipe usually require small volumes of materials. Normally, only cement is used with calcium chloride added to accelerate it. The depth of the casing is only a few hundred feet.

The production string job is more critical because it forms the final barrier between the producing formation and the well. The cement slurry will contain dispersants to increase the weight, weighting agents, sand to prevent strength retrogression and retarders necessary to delay the set at elevated temperatures. The drilling muds used under these conditions are oil base or highly treated water-base muds which are very incompatible with the cement. This makes it very important to use spacers or washes between the mud and cement. More mechanical aids are used on the casing to improve job success. All of these factors, and others, combine to make the job more costly.

If a good cement job is not obtained in the initial effort, remedial or squeeze cementing jobs must be done to try and repair the original job. These jobs are also expensive and time consuming, and more difficult to do successfully. This is why every effort should be made to achieve a good job the first time.

LOGGING PROGRAM

Formation evaluation from electrical and radioactive measurements is a well established and developed technology. A survey of existing techniques and available instruments indicates capability to perform measurements in deep wellbores at hydrostatic pressures in excess of 25,000 psig and temperatures in excess of 450^{o}F with standard tools. Special tools can be prepared to exceed these limits if necessary.

Existing logs allow the determination, with reasonable accuracy, of formation properties such as porosity, density and permeability, fluid content and distribution in terms of saturation and lithology in terms of percent clay, matrix composition and porosity. Other parameters such as formation temperature, wellbore geometry, strata orientation and inclination can also be measured. Additional measurements can be performed in the wellbore to determine the movement and distribution of the produced fluids to establish the performance and efficiency of the completion.

It can be therefore concluded that existing techniques can be applied to satisfy requirements of formation evaluation in geopressured geothermal wells.

<u>Proposed Program for Geothermal Test Well.</u>

Similar to the requirement of extensive data collection during the drilling operation, the logging program for the geothermal test well should be designed to provide information to allow the prediction of the overall well performance over the useful life of the project. Information regarding the flow efficiency of perforations, the mechanical stability of the wellbore, presence of corrosion and scaling, compaction of the producing interval, subsidence of overlaying strata, movement of fluids in adjacent formation, etc., will have to be obtained directly when possible or as a minimum should be inferred from interpretation of combinations of logs. The above mentioned effects are directly related to the production of the formation fluids. They will therefore depend on production schedules and are expected to increase in intensity as time progresses. Therefore the philosophy of the logging program is to establish a baseline of conditions at the beginning of the test period, before and soon after the well is completed, and to subsequently repeat the series of measurements to establish changes from the baseline.

Such a logging program will be divided into three phases:

1. Pre-completion
2. Completion
3. Post-completion

Phases (1) and (2) are designed to establish the baseline conditions, while phase (3) will perform the monitoring function.

The following table illustrates these concepts and outlines the principal objectives of each phase.

TABLE III

LOGGING PROGRAM'S OBJECTIVES

<u>Pre-Completion</u>

Formation Properties

- Lithology
- Porosity
- Permeability
- Density
- Fractures

Fluid Properties

Temperature

Temperature Gradient

Borehole Geometry

Dipmeter

<u>Completion</u>

Cement Placement and Bond

Correlation Logs

Perforation Location

Pipe Geometry

Corrositon

Temperature

<u>Post-Completion</u>

Wellbore Performance

- Flow Survey
- Temperature
- Sand Production
- Subsidence
- Collapse
- Corrosion

Reservoir Performance

- Perforation Efficiency
- Inflow from Above or Below
- Subsidence

Pre-Completion Logging Program

The principal objectives of this series of logs are:

1. Provide information about the formations' properties as well as a basis for correlation with adjacent wells and future development wells:
    a. Lithology including identification of shale and/or impervious streaks
    b. Effective porosity
    c. Permeability, including extent of permeability damage
    d. Formation density
    e. Presence of natural fractures
    f. Formation mechanical properties and fracture strength
    g. Formation pressure
2. Definition of the top of overpressure and transition zone
3. Formation dip and azimuth including well deviation
4. Reference logs for subsequent cased hold logs
5. Sampling of formation fluids and direct measurement of pressure and productivity in selected intervals of the producing horizon
6. Establish references for subsequent measurement of subsidence.

Although the type of logs to be used to satisfy these objectives may vary depending on the company performing the service, it has been established that the following combination of measurements, performed in open hole during the drilling phase will satisfy the objectives stated above.

Open hole logging program: A minimum of three runs corresponding to the sequence of wellbore sizes proposed for the test well will produce complete records from surface to total depth:

Induction Electric Log (ISF)
Compensated Neutron Log (CNL)
Formation Density with Gamma Ray (FDC-GR)
Long Spaced Sonic Log (LSS)
High Resolution Dipmeter with Continuous Directional Survey and Borehole Geometry (HDT)

Micro Laterolog (MLL)
Nuclear Magentic Log (NML)
High Resolution Thermometer (HRT)

Combinations of above will allow computation of mechanical properties of formation and formation characteristics through continuous computation of volume of shale, permeability index, porosity analysis, apparent water salinity, and bulk volume analysis of the percent clay, matrix rock, and porosity.

Completion Logging Program

Cased Hole Logging Program: After the production casing string has been run and cemented, a series of logs will be run with the objective of determining the initial wellbore configuration, correlating with the open hole logs, and establishing the formation fluids distribution in the producing and adjacent formations before any fluid is removed from the reservoir. Also logs will be run to establish the relative position between the casing and the formations to establish a baseline for subsidence and compaction studies. The following is a possible suite of logs to accomplish these objectives:

Cement Bond Log, Variable Density, Gamma Ray and Casing Collar Locator (CBL, VOL, GR, CCL)
High Resolution Thermometer (HRT)
Thermal Decay Time Log (TDT)
Multi-CCL (Casing Subsidence Reference)
Multi-gamma Ray (Formation Subsidence Reference)
Compensated Neutron Log (CNL)
Pipe Analysis Log (PAL)

Post-Completion Logging Program.

During the testing period of the geothermal well, which is estimated to last for a period of one year, a series of logs will be run at convenient intervals (2-3 months depending on production rates) to establish what changes have been experienced in the vicinity of the wellbore.

A portion of these logs will be referenced to the baseline logs taken at the time of completion. Others will have as objective the determination of the flow performance of the completion. A possible suite of logs to satisfy these objectives are:

High Resolution Thermometer (HRT)
Thermal Decay Time (TDT)
Compensated Neutron (CNL)
Flow Meter (Fullbore) (FBS)
Fluid Sampler (PFS)

At the end of the test period, or depending upon production data and the results of reservoir simulation and reservoir mechanical behavior indicate that measurable subsidence and/or compaction effect should be measurable a suite of logs will be run to establish if any deformation and/or relative movement has taken place in the vicinity of the wellbore.

Appendix Id presents estimated costs of such a logging program in reference to the Kenedy County test site.

PERFORATING

The objective of perforating is to establish flow communication between the formation and the cased wellbore. Ideally the objective is to establish a communication that allows the same flow through perforations that one could obtain for the uncased open hole wellbore. Such a condition is referred to as a perforated interval with 100% flow efficiency.

Perforating techniques and proceudres can be established that result in such high efficiency completion. The main parameters to be taken into consideration to design a high efficiency perforation are:

1. Type and size of perforating device
2. Strength and flow characteristics of formation
3. Pressure differential between formation and wellbore
4. Type of fluid in wellbore
5. Spacing and orientation of perforation

To properly design the perforating program it is advisable that evaluation tests be performed on actual cores of the reservoir rock to establish the effects of charge size and type on the perforation flow efficiency. Standard API tests can be used for comparison purposes.

Regarding the effect of wellbore fluid on perforation efficiency in the case of the geothermal test well, since the producing interval is relatively thick (several hundred feet) the situation is appropriate for applying a technique known as "trigger completion". This involves initially perforating only a few feet of the producing interval, under underbalanced pressure conditions. This requires that the tubing and christmas tree be installed prior to perforating. After perforating, the reservoir fluid is allowed to displace completely the wellbore fluid, after which the rest of the producing interval is perforated. This procedure insures total compatibility between the reservoir and the wellbore fluid at the time of perforating, thereby minimizing the probability of formation damage.

Since the producing interval is relatively thick and probably will exhibit various degrees of permeability it is advisable that perforations be placed preferentially in the most permeable layers. These can be determined from the open hole Repeat Formation Tester measurements and log interpretation.

Perforating General Recommendations.*

There are many aspects of the perforating operation that deserve careful planning. The perforated interval(s) must be chosen based on production-reservoir considerations. Well completion conditions must be planned to assure best perforation response. A suitably performing gun must be chosen to satisfy well environmental conditions of fluid type, pressure, temperature and mechanical requirements. Pressure control aspects must be considered. A service company must be chosen, one with the necessary modern equipment, techniques and properly trained personnel.

Cost is an important factor in these considerations. In considering cost, it should be borne in mind that the least expensive perforating operation is the one that is conducted properly, according to the design of the completion--on the first attempt.

The following outlines some general recommendations aimed at proper choice of technique and equipment in the interest of balancing cost, perforation performance and mechanical aspects:

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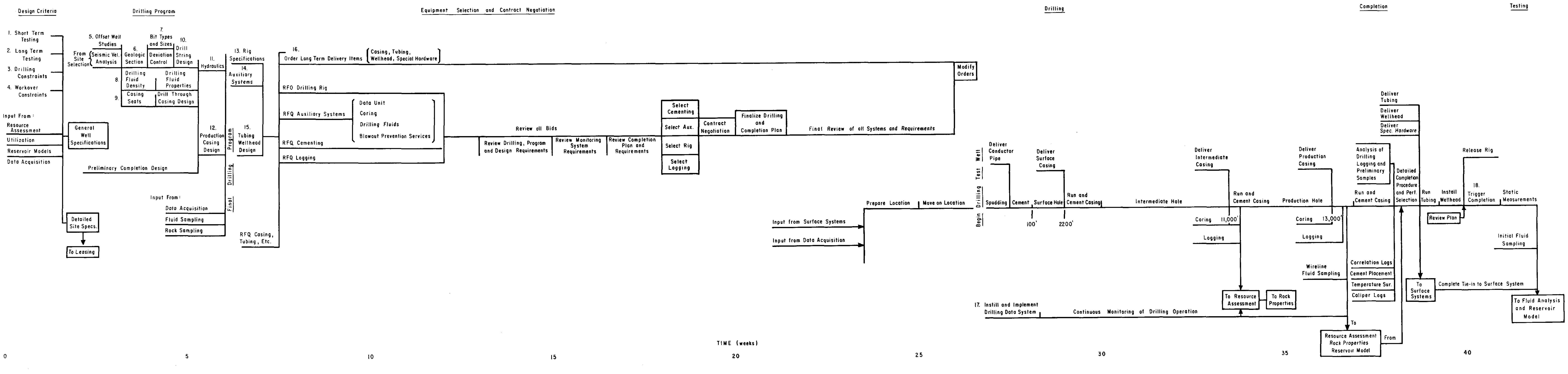
*From "Gun Perforating" by W. T. Bell, Schlumberger Well Services

1. To minimize rig costs, remove the rig from the well and perforate through tubing.
2. For best perforation performance, shoot under reverse pressure conditions to achieve a maximum effective shot density.
3. In perforating through-tubing, utilize a positioning device to assure optimum gun performance.
4. If perforating under positive pressure conditions, avoid mud shooting and substitute salt water, oil or completion fluid. Minimize infiltration time into perforations. If well response is not as expected, reperforate through tubing.
5. Use only charges of more modern design for cleanest perforations.
6. In choosing gun size, use the largest gun available for the particular casing or tubing to achieve maximum performance.
7. Choose a gun type that best satisfies well conditions. Give primary consideration to running the steel retrievable types which leave no debris, produce no casing deformation or damage, are the best in terms of mechanical characteristics (ruggedness) and more often than not result in time savings.
8. Assure that appropriate wellhead pressure control equipment and techniques are employed in the interest of safety.
9. To assure that perforations are properly placed, insist on good depth control techniques and adequate documentation.

SUMMARY

The preceding discussion outlines the general drilling and completion procedure which, at this time seems to satisfy the principal objectives of the project: Obtain accurate information regarding the characteristics and the potential deliverability of geopressured geothermal reservoirs.

The following chart (fig. 7) illustrates the probable time sequence of the various drilling and completion tasks.



1. Short Term Testing
   - Reservoir Characteristics
     - Permeability
     - Bottom Hole Pressure
     - Bottom Hole Temperature
     - Flow Potential
   - Fluid Properties
     - Salinity
     - Viscosity
     - Gas-Liquid Ratio
     - Mineral Content

2. Long Term Testing
   - Reservoir Characteristics
     - Pressure Drawdown
     - Production-Flow Characteristics
     - Life Expectancy
   - Rock Properties
     - Subsidence

3. Drilling Constraints
   - Rig Size
   - Hole Size
   - Temperature
   - Abnormal Pressure

4. Workover Constraints
   - Killing the Well
   - Hole Size, Tool Sizes
   - Formation Consolidation
   - Fracturing

5. Offset Well Studies
   - Projected Properties
     - Temperature
     - Location of Abnormal Pressure
     - Porosity
     - Permeability
   - Drilling Program
     - Casing Seats
     - Target Zone
     - Interval to be Cored
   - Mud Program
     - Density Changes
     - Solids

6. Geologic Section
   - Definition of Target Zones
   - Isopach Analysis
   - Isotherm Analysis
   - Permeability
   - Porosity
   - Reservoir Volume
   - Bit Types-Sizes
   - Rock Types
   - Casing Sizes
   - Jet Sizes
   - Coring

8. Drilling Fluids
   - Density
     - Pressure Control
     - Overbalance
     - Weight-up Points
   - Properties
     - Mud Type
     - Water Loss
     - Viscosity
     - Solids Content
     - Zone Invasion
     - Mud Cake

9. Casing Program
   - Casing Seats
     - Pressure Variation
     - Placement in Consolidated Zones
     - Kick Control
   - Drill-through Design
     - Bit Clearance
     - Blowout Control

10. Drill String Design
    - Weight on Bit
    - Pump Capacity
    - Hole Size
    - Stuck Pipe
    - Fishing
    - Deviation Control

11. Hydraulics
    - Pump Sizes-Capacities
    - System Requirement
    - Time required to weight-up
    - Mud Velocities
    - Lost Circulation
    - Bottom Hole Cleaning
    - Pressure Losses

12. Production Casing Design
    - Kick Control
    - Tension Design
    - Burst Stregth
    - Collapse Resistance
    - Completion Requirements
    - Production Requirements

13. Rig Specifications
    - Capacity
    - Drawworks
    - Prime Mover

14. Auxiliary Systems
    - Drilling Fluids
    - Data Unit
    - Coring
    - Blowout Prevention
    - Logging
    - Cementing
    - Testing Facilities

15. Tubing, Wellhead Design
    - Surface Pressures
    - Workover Requirements
    - Well-Killing
    - Production Requirements
    - Fluid Temperature
    - Pressure Losses
    - Flow Behavior

16. Long Term Delivery
    - 6 months to Delivery from Time of Order

17. Drilling Data
    - Penetration
    - Cuttings
    - Pressure
    - Temperatures
    - Hydraulics

18. Trigger Completion
    - Perforate Bottom 10 feet
    - Static Measurement Period
    - Flow to Clean Out
    - Perforate Remaining Section

Figure 7. Time chart of drilling and completion activities

CHAPTER III

WELL PERFORMANCE

The general concept of well performance encompasses the realtionship between surface flowing conditions (pressure and flow rate) the performance of the wellbore (vertical flow) the bottom hole conditions and the reservoir performance. Generally these relations are expressed in terms of productivity of the well in the case of single phase flow, or in terms of an Inflow Performance relation for two phase flow and other complex flow conditions. These relations allow the establishment of the correspondence between surface flowing pressure and flow rate.

However in the case of the geothermal test well, the concept of performance has to be broadened to include effects of rate of production on compaction, subsurface subsidence, movement of fluids in adjacent formations, production of solids, changes in composition of produced fluids and changes of reservoir flow properties as a function of pressure, changes in formation mechanical properties, and surface effects of compaction.

Therefore it becomes apparent that the solution of the problems of well performance requires interaction of various phases including geothermal reservoir analysis, well testing, formation evaluation, production monitoring, sampling and logging, and surface monitoring and surveying. The necessary steps and plans for the successful solution of this problem can be established with accuracy only after complete definition of the test site and once reservoir parameters have been obtained from cores and well logs at the time of completion.

Nevertheless, preliminary considerations of the general characteristics of the geothermal resource have resulted in the following guidelines for definition of well performance.

WELL TESTING

The concept of well test has been developed to include a specified sequence of flowing and shutin periods designed to establish the flow performance and volume characteristics of a porous reservoir. Various methods and techniques have been devised depending on the nature of the flowing fluids (liquids, gases or both) and the properties of the formation (porosity, permeability, homogeneity, etc.). The various methods can be broadly classed as:

1. Pressure drawdown tests
2. Pressure buildup tests
3. Variable rate tests
4. Pressure pulsing tests

The number and length of tests depends on the accuracy with which one wishes to determine the reservoir parameters as well as the uncertainty of the reservoir mechanism. The larger the number of unknown formation parameter the more complex and lengthy the testing procedure.

Techniques have been developed to establish formation parameters from single well tests by observing the pressure-rate response at the sand face. This requires monitoring or flowing bottom-hole pressure as a function of time for various flow rates (including shut in). From the pressure-time recoridng thus obtained and knowledge of the rate and length of the flow period it is possible to estimate the formation's kh (permeability-thickness) parameter. This however requires a knowledge of the formation's porosity to insure that the test length is sufficient to yield meaningful results.

Other types of tests involve two or more wells, allowing the observation of pressure-time relations at various points of the reservoir as a function of fluid production from the reservoir. These tests naturally yield more information regarding the reservoir properties in between wells and are absolutely a must in the case where reservoir inhomogeneity is an imporant factor, or the adjacent reservoir may contribute to the formation production.

Test interpretation techniques can be enhanced through numerical reservoir models which can simulate the pressure response corresponding to the test flow schedule. The reservoir parameters are adjusted so that the model replicates the observed pressure response.

It is therefore apparent that the accuracy of reservoir parameters obtained from well tests are totally dependent on:

1. Accurate pressure measurements during the tests.
2. Accurate knowledge of basic formation properties (porosity, permeability, saturation, relative permeability, fluid properties).
3. Proper understanding of reservoir mechanisms and geometry
4. Availability of reservoir simulator.

The following sections discuss some of these aspects in detail. Section II describes guidelines for obtaining accurate fluid samples and composition. Section III describes the formation's mechanical behavior and its interaction with fluid flow and production as well as outlining necessary research in this area. Section IV describes aspects of numerical simulation of geothermal geopressured reservoirs. Appendix Ie describes equipment required for continuous monitoring of well performance.

FLUID SAMPLING

Various methods and techniques are available to undertake sampling of reservoir fluids, at various stages of the life of a flowing well. In the proceedings of the First Geothermal Conference was described in detail the drill stem testing technique of formation testing and fluid sampling, and therefore it will not be repeated here.

In the case of the geothermal test well the objective being to evaluate the geothermal resource, wells will be completed (casing run, cemented and perforated) thereby reducing the applicability of drill stem testing which in essence is a temporary well completion. Fluid sampling is therefore expected to take place after installation of the well head and during the testing phase.

However, as mentioned in the completion section of this report, it will be advantageous from the standpoint of optimizing the completion performance, to have preliminary knowledge regarding fluid properties and above all an indication of formation permeability. For this reason it is recommended that prior to the installation of the production casing a number of pressure measurements and preliminary fluid samples be made using a wireline formation tester (Repeat Formation

Tester). The information thus obtained will enhance the planning of subsequent sampling operations. Appendix IV presents a detailed discussion of the operation and application of such an instrument.

PRODUCTION LOGGING

The logging industry has developed a series of tools designed to obtain information regarding the performance of flowing wells. These tools allow the determination of flow rates, flow velocity, entry of fluids into the wellbore, distribution of flowing fluids, location of perforations, temperature distribution, and other parameters that through proper interpretation yield information about the flowing performance of the well.

Two of such tools are particularly indicated for the study of the geothermal geopressured wells: the continuous flowmeter and the high resolution thermometer. A brief description of each, with sample applications follows.

The Continuous Flowmeter.

The continuous flowmeter measures the velocity of the fluid with a spinner velocimeter. The fluid velocity is related to the volumetric flow rate from the well. The flowmeter is calibrated by the *in situ*. technique. This consists of recoridng the tools response in revolutions per second (rps) while moving at several known absolute velocities, both up and down, within the moving column of fluid. From these recordings, exact relationships can be established between the rps of the tool and fluid velocity in ft/min. Thus the logs contain their own calibration data as well as the data needed for analysis.

To corroborate and support the calibration, readings are also normally taken at several points in the well with the tool stopped.

Fig. 8 shows the bottom of a well where water is being produced from three sets of perforations. Stationary flow meter readings are taken between perforations at points A, B, C, and D. Readings taken within perforated sections may be affected by local turbulence.

From the log a table of various spinner speeds and cable velocities is constructed for the four stations (Table IV). Note the negative spin-

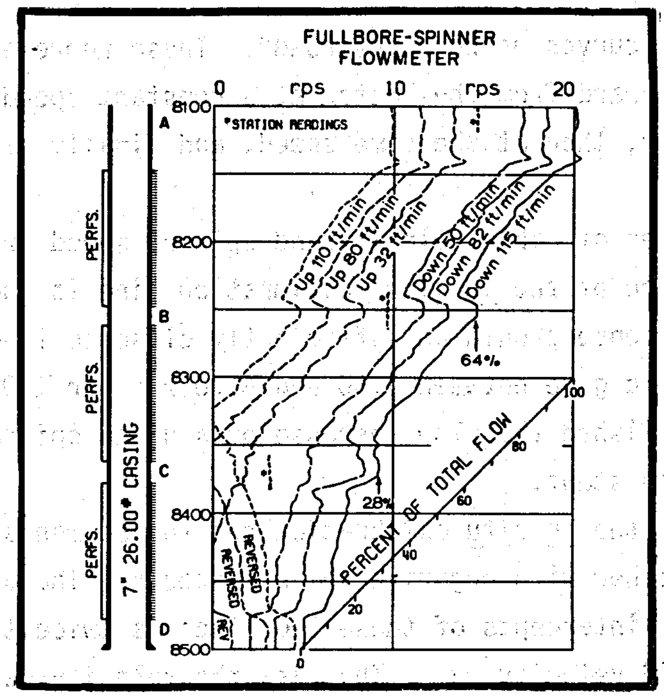


Figure 8. Multiple runs of a Fullbore-Spinner Flowmeter in a dumpflood well. *

Table III*

LOGGING SPEED AND DIRECTION	SPINNER SPEED rps			
	Station A	Station B	Station C	Station D
Down 115 ft/min	20.15	14.60	9.20	5.10
Down 82 ft/min	18.50	13.00	8.35	3.50
Down 50 ft/min	17.20	11.60	5.40	2.10
Station Reading	14.65	9.65	3.15	—
Up 32 ft/min	13.30	8.30	1.85	−1.05
Up 80 ft/min	11,50	6.30	—	−3.05
Up 110 ft/min	9.85	4.75	—	−4.60

*Reproduced from "Production Logging" by Schlumberger.

ner speeds for the curves marked "reversed". These represent runs where the tool travels upward from the bottom at a constant speed. It is at first moving faster, then at the same speed, and finally slower than the water.

Next the values of cable velocity and spinner speed are plotted (fig. 9). The slope of the in situ calibration line is the flow response. The calculated response should be sufficiently close to laboratory values. A new spinner should give between 4.50 and 4.70 rps per 100 ft/min for water. Once established the flow response of a given spinner should remain essentially constant.

For station D the in situ calibration has two segments: one with positive and the other with negative spinner speeds. The difference between the x-axis intercepts of these two lines is twice the value of the threshold fluid velocity, v_x. That is, the velocity necessary to initiate spinner movement. Where in situ calibration is possible this method gives the best value of v_x obtainable from production logs.

Using v_x as the velocity axis intercept, a flow response line is constructed parallel to the line established from the reading at Station A (fig. 10). In some cases it is not feasible to run the tool upward fast enough to establish the linear response for negative spinner speeds. When this happens the volue v_x must be estimated in the range of 6.0 ft/min for water.

Fluid velocities at stations A, B, and C are determined, as shown by the dashed-lines, by starting from the intersection of the in situ calibration line for the station and the y axis (where cable velocity is zero), passing horizontally to the flow response line, and then going vertically downward to the fluid velocity. The measured value is near the maximum fluid velocity, since the measurement is taken near the center of the pipe. The average fluid velocity (which determines flow rate) is some fraction of the maximum fluid velocity, depending on the nature of the fluids and whether the flow is laminar or turbulent. The scale at the bottom of the figure shows correction factors (c_v's) from 0.79 to 0.87. The figure lists flow rates for the commonly used c_v of 0.83.

This type of analysis not only determines flow rates, but is an

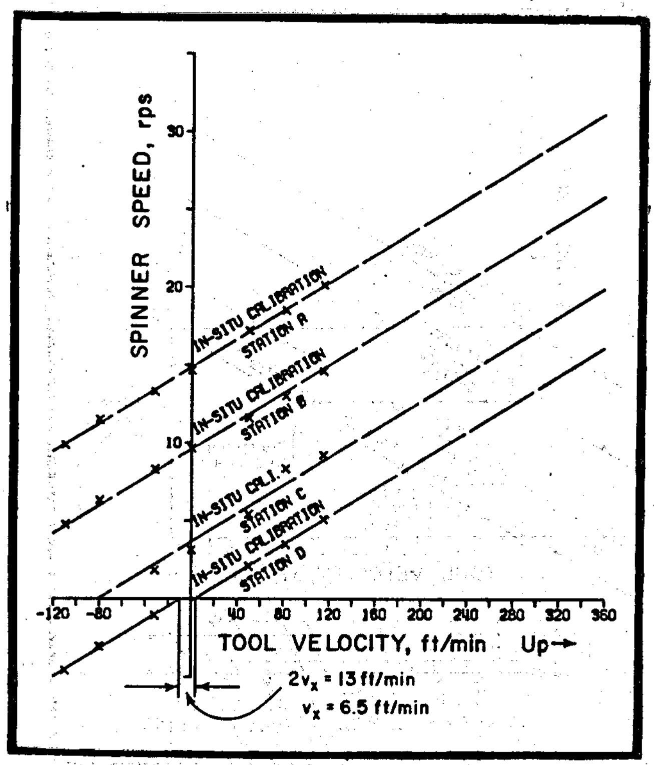


Figure 9. Plot of readings from Stations A, B, C, and D.*

*Reproduced from "Production Logging" by Schlumberger.

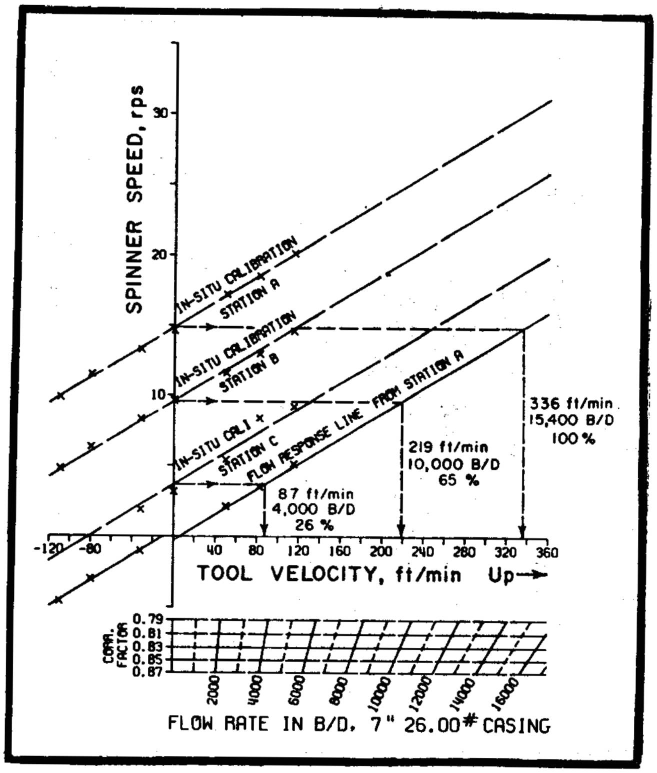


Figure 10. Flow-rate determination for Stations A, B, and C.*

*Reproduced from "Production Logging" by Schlumberger.

excellent check for mechanical failures: tubing leaks, casing leaks, packer failures, etc. Where the surface flow rate, converted to downhole conditions, does not check the downhole flow rate, spurious production or thieving may be occurring.

Production Logs--Temperature Logs.

Temperature logs run while a well is producing at stabilized rates can yield much useful ifnormation. The Thermometer responds to temperature anomalies produced by fluid flow either within the casing or in the casing annulus, and this is very useful for detecting the latter. Temperature log interpretations are also used to determine flow rates and points of fluid entry or exit.

Fig. 11 shows the temperature response for a well making 400 bbl/D for 10, 100, and 1,000 days. Fig. 12 shows the temperature response after 15 days for a well making 200, 400, and 800 bbl/D. In both of these cases the entering fluid has the same temperature as the formation of the zone of entry. In every case the well is initially at geothermal temperatures.

The fluid entering the wellbore can however, be either colder or hotter than the original shut-in formation temperature. Liquids may also be heated as they are produced. Fig. 13 shows the temperature responses of fluids that are cooled, unchanged, or heated as they enter the casing.

Fig.14 shows that the temperature log will respond to downhole flow even though the well is shut in at the surface. In this case the water enters the casing through a leak at 6500 ft. and flows downward to enter the perforations from 8500 to 8700 ft.

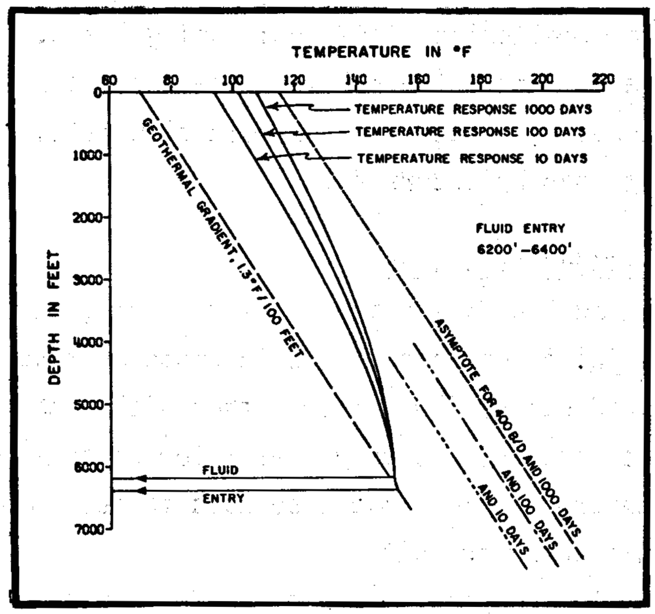


Figure 11. Producing well: Temperature Logs with various times of Production.*

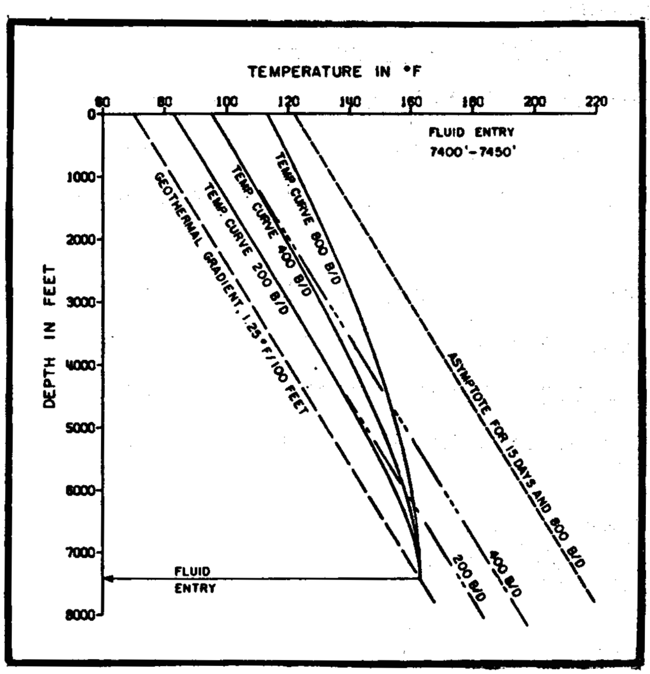


Figure 12. Producing well: Temperature Logs with various flow rates.*

*Reproduced from "Production Logging" by Schlumberger.

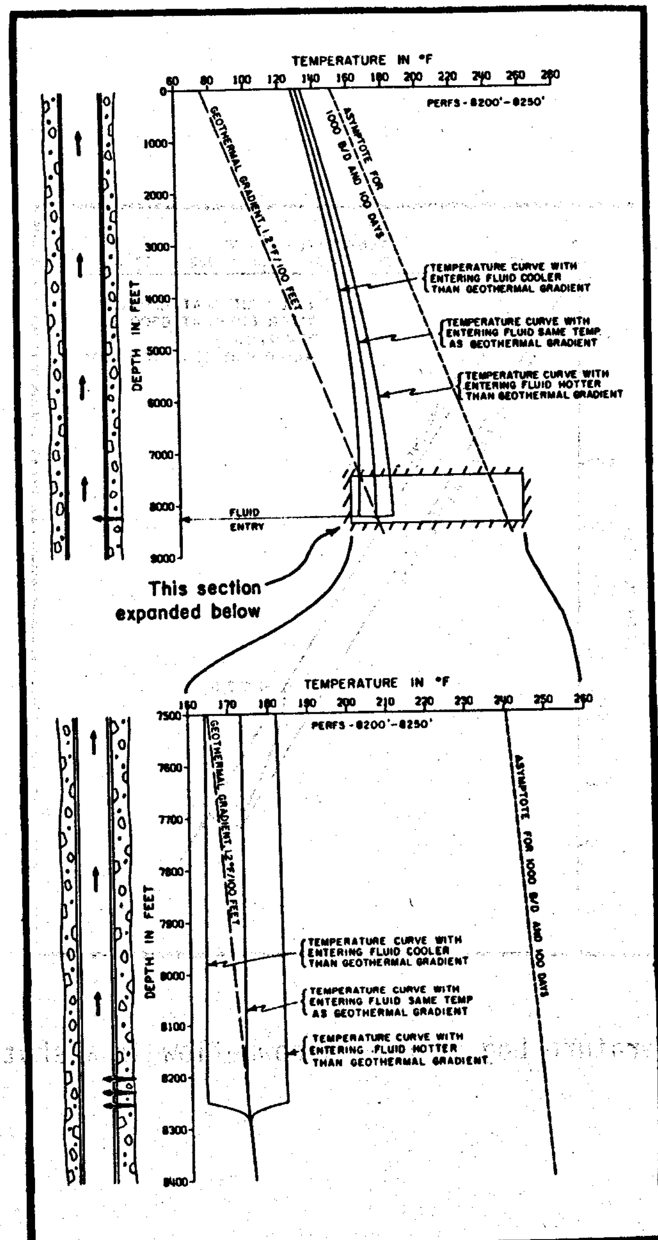


Figure 13. Producing well: Temperature Logs with various entry-fluid temperatures. Top--surface-toTD logs. Bottom--expanded view of the producing interval.*

*Reproduced from "Production Logging" by Schlumberger.

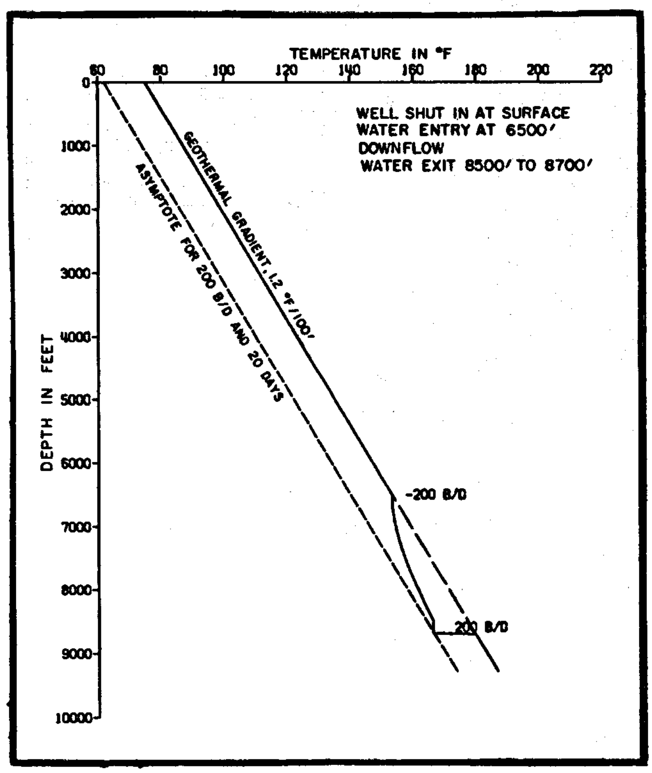


Figure 14. Temperature Log showing a down-flow in a shut-in well.*

*Reproduced from "Production Logging" by Schlumberger.

Production Logging Recommendations.

First, Production Logs should be run on a new well to evaluate its initial productive performance, and to verify the integrity of the completion. The knowledge gained from the Production Logs may lead to different completion techniques on future wells.

Even when no production problems exist, Production Logs run under initial-production conditions are invaluable as a basis for the interpretation of subsequent workover logs.

Second, Production Logs should be run on producing wells at the first sign of performance changes.

Third, Production Logs should be run periodically on a well to monitor production. Even though the well was producing as planned when it was completed, it may not be doing so after a period of months or years.

Fourth, the performance of water-injection wells should be analyzed initially and monitored thereafter by means of Production Logs. This knowledge of where the fluid is going is of the highest importance.

Fifth, Production Logs should be run to confirm or modify the engineering and geological analysis of a field. What was originally visualized as a simple structure may later be analyzed as a complex structure with various producing mechanisms. Production Logs can be instrumental in this analysis.

Well Conditions. At the time of logging, the well should be in a stabilized condition, that is, flowing normally (whether producing or injecting). If it is necessary to change the mechanical arrangement of the well - to remove a constriction in the tubing, for instance - this should be done and the well flowed long enough to restabilize before logging.

Surface Flow Rates. The stabilized surface flow rates of water, and gas, and the gas-water ratio should be established with the best possible accuracy and corrected to downhole conditions. This is necessary in order to be able to compare surface flow rates directly with downhole flow rates.

Reservoir Parameters. In order to make an accurate conversion of surface flow rates to flow rates under downhole well-flowing conditions, the Production Log analyst needs to know the following:

1. Gas gravity

2. Water salinity.

Multiple Runs. Production-Logging operations should be scheduled so as to provide for multiple runs of each service. There are many reasons, varying with the tool and the nature of the problem, why such repeat runs are useful. Multiple runs at different speeds are, of course, essential for the proper in situ calibration of the Continuous Flowmeter and the Full-bore-Spinner Flowmeter. Additional runs with the well shut in are very useful in calibration.

Logging Intervals. As the unexpected often turns out to be the normal, the various runs should be made over extensive lengths of the well below the tubing. In the case where tubing leaks are suspected, the Gradiomanometer and the Temperature Log should be run all the way to surface. In fact, it is advisable to run the Temperature Log to surface in all cases. For convenience it may be recorded on temperature and depth scales of reduced sensitivity.

STIMULATION

The drilling and completion procedures can be designed to minimize damage (impairment of formation flow efficiency) of the formation. However, the probability exists that in spite of all precautions some damage will be affected in the vicinity of the wellbore. Also, in spite of the fact that the geothermal test site will be chosen to satisfy requirements of a certain permeability formation, some uncertainty will exist (until the well will have reached the producing interval) as far as the actual permeability of the formation. The possibility exists therefore that the formation producibility will be too low to satisfy the flow requirements imposed by resource utilization.

If either of the above conditions are encountered it will be necessary to remedy the situation through formation stimulation procedures. One such method is hydraulic fracturing which has been undertaken successfully at depths and in formations similar to those expected in this project.

It is felt that the hydraulic fracturing process may be required, on completion, to remove formation damage created during drilling and cementing operations, to obtain maximum natural productivity. The fracturing process was also studied to determine the degree of production increase that could be realized by removing the formation damage, plus stimulating the in situ producing capacity of the reservoir.

It is generally assumed that when a reservoir rock is subjected to sufficient hydraulic force, it will rupture or fail in a vertical plane. The vertical fracture plane will be of a radial nature and grow radially until confining barriers are reached and then two equal but opposing vertical-linear fractures will be propagated.

The hydraulic fracturing technique increases reservoir productivity by creating deep, highly conductive fracture within the reservoir. These fractures reduce the distance reservoir fluids have to travel to reach the low pressure condition found at the wellbore. In order for the fractures to be effective they must be initiated and propagated in the net producing intervals, and they must have almost infinite flow capacity. The fracture is held open after the hydraulic fracture treatment by the propping agents deposited during the fracturing operation. The earth's forces tend to close the fracture system, and the size and strength of the propping agents determine the resultant fracture flow capacity.

The fracture closing pressure under stabilized producing conditions must be known to determine how to approach reservoir stimulation and to what extent the fracturing process will increase production.

Reservoir hydraulic fracturing pressure is the fracture gradient times the depth of the proposed producing interval. The fracture closure pressure is the reservoir hydraulic fracture pressure less the bottom hole producing pressure. The fracture gradient can be calculated from logs and reservoir data, but is generally determined just prior to the fracture stimulation operation by breaking down the formation with fluid and calculating the pressure required for fracture propagation. Since this is not possible for the proposed location, the hydraulic fracture gradient was calculated using Poisson's ratio of 0.3, bottom hole pressure of 15,300 psi, depth of 18,000 feet. Calculations indicate a minimum gradient of 1.0 psi/foot of depth. The closure pressure would then calculate to be 8,487 psi under a bottom hole producing pressure of 9,513 psi.

The closure pressure of 8,487 psi is an extremely high value and commercially available propping agents are not available that can withstand these forces and still provide high fracture flow capacity. Research within the industry is working to develop high strength propping agents, strong enough to provide high fracture flow capacity under these high load conditions. This research indicates that in the near future propping agents will be available strong enough to withstand these high closure forces, allowing deep penetrating fractures to be effective in increasing reservoir producing capacity by a factor of two and one-half (2.5) to three (3).

At the present time, utilizing present technology and materials, the fracturing process can remove formation damage that remains after perforating and acid clean-up treatments, plus increasing the natural undamaged productivity by a factor of one and one-half (1.5). This will be accomplished by creating hydraulically two equal but opposing vertical fractures and propping the induced fractures a distance of two hundred and sixty four (264) feet from the wellbore (10% of drainage radius). This flow system within the reservoir would provide production rates of 3895.10 bbl/day/100 ft. of producing interval. Assuming that six hundred (600) feet of producing sand is developed in the proposed well, proper completion would indicate a production rate of 23,370.57 bbl/day. This would require only four (4) to five (5) wells instead of seven (7) wells previously mentioned.

The wells will have to be equipped with large diameter tubing (5 1/2" minimum) to reduce producing friction pressure, maintaining maximum pressure differential under bottom hole flowing conditions, to achieve the flow rates desired.

The frac fluids are presently available, to create the required fracture (fracture penetration and fracture width) and prop transport capacity, for major reservoir stimulation. In the near future propping agents will be available to provide high fracture flow capacity, making the deep penetration fracturing technique successful in achieving stimulation increases that are attractive.

PART 2

Reservoir Fluid Sampling and Analysis for a Geopressured Geothermal Well

BY

I. H. Silberberg

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INTRODUCTION

The objective of sampling the geopressured geothermal well is to obtain a representative sample of the reservoir fluid from which the composition and physical properties may be accurately determined. Among the constituents dissolved in the water, of particular interest are the dissolved methane and light hydrocarbons, for this natural gas will be a major factor in determining the economic feasibility of developing such geothermal resources. Of less economic significance, perhaps, but nonetheless important from the standpoint of plant design and ultimate use or disposal of the geothermal reservoir water are the other dissolved gases, salts, silica, and other organic chemicals. Reservoir engineers will need viscosity and compressibility information on the reservoir fluid, as well as the bubble-point pressure and pressure-depletion characteristics at the reservoir temperature. Plant design engineers will need viscosity, thermal conductivity, enthalpy and volumetric behavior data over the range of plant operating conditions. In addition, the phase behavior (both vapor-liquid and solid-liquid) will be important considerations in the plant design.

Results of the Phase 0 work indicate at least three optimum fairways for geothermal development in the Frio trend of the South and Central Texas coastal region. These potential reservoirs lie at depths of 11,000 to 16,000 feet below sea level. Estimated temperatures are in the range of 250^{o} to 375^{o}F, and mean pressure gradients are estimated to be from 0.80 psi/foot to 0.98 psi/foot. More detailed information has been developed for the potential test site in Kenedy County. The estimated depth to the geopressured geothermal reservoir is 13,000 feet. Formation temperature is estimated at 290^{o} F and pressure at 11,700 psia.

EFFECT OF TEMPERATURE AND PRESSURE DECREASES

Regardless of whether the fluid sample is taken at bottom-hole conditions (essentially reservoir temperature and pressure) or at surface conditions, the temperature and pressure of the sample must ultimately be reduced. As a consequence, phase changes will occur such that even an originally single-phase sample will exhibit a vapor phase and very likely solid phases as well. For example, if the pressure is reduced below the bubble-point at a given temperature, natural gas will come out of solution, accompanied by carbon dioxide, hydrogen sulfide and ammonia, if present. Cooling and depressuring may cause supersaturation to develop with respect to silica and certain salts, with resulting precipitation. Subsequent restoration of the sample to reservoir temperature and pressure would return the gases to solution in a reasonable length of time, but the redissolving of precipitates might take a great deal longer and be much more difficult to verify.

Sampling procedures must therefore be designed which will prevent serious errors from arising as a result of gas evolution or solids precipitation. Identification of where these problems might exist and of potential methods for dealing with them is one of the major purposes of this report. It is not intended here to speculate on the probable composition of the geopressured geothermal reservoir fluid, but a review of the behavior with respect to decreasing temperature and pressure of the probable major constituents in the water will provide a basis for the design of a well sampling program.

On Dissolved Salts.

Theories advanced in recent years to explain the existence of abnormally pressured (geopressured) sandstones in the coastal regions of Texas and Louisiana propose a freshening of the saline waters by expulsion of essentially deionized water from adjacent shale beds as a result of the transformation of montmorillonite to illite. In a recent description of the process, Jones[9] stated that resulting salinites are decreased by 50,000 mg/liter or more from values otherwise to be expected at such depths and presented several examples of salinities less than 30,000 ppm in geopressured zones at depths greater than 10,000 feet. Schmidt[14] reported an abrupt decrease in total dissolved solids at 10,000 feet in sandstones in the Manchester Field, Calcasieu Parish, Louisiana, from 170,000 to about 20,000 mg/liter.

If the reservoir fluids in such a situation are simply diluted by fresh water from the shale beds, it can be anticipated that the principal ions in solution will be those of sodium and chlorine. The solubility of sodium chloride in water is so great that its crystallization from a relatively so dilute brine as a result simply of cooling and depressuring is out of the question. The other major cation will probably be calcium, with magnesium and potassium in lesser amounts. Their chlorides are all highly soluble. Other major anions will probably be bicarbonate and sulfate, with iodide and bromide in lesser amounts[8,14]. The solubility of calcium sulfate increases with decreasing temperature and should be little affected by decreasing pressure. The solubility of calcium carbonate similarly increases with decreasing temperature, but the evolution of a vapor phase as a result of decreased pressure would shift the carbonate-bicarbonate equilibrium to favor precipitation of calcium carbonate. If the magnesium and bicarbonate contents of the water are high, a similar tendency to precipitate magnesium carbonate may exist.

Minor constituents may also present problems as the water is cooled and the pressure decreased. Barium sulfate is highly insoluble; the water may be close to saturation even at reservoir temperature. Strontium sulfate, although more soluble than the barium salt, could also exceed its solubility limit at ambient temperatures. With large amounts of carbon dioxide in solution, moderately high barium or strontium concentrations could lead to precipitation of their carbonates as temperature and pressure are reduced. Significant increases in the pH resulting from evolution of dissolved carbon dioxide and hydrogen sulfide might result in the precipitation of other metal ions as the pressure and temperature are lowered.

<u>On Dissolved Silica.</u>

The silica content of the waters to be sampled will almost certainly correspond to saturation with respect to quartz. Not only is quartz the dominant mineral species in the sandstone formation, but, with the possible exception of some silicate minerals, it has the lowest equilibrium silica concentration at all temperatures[12]. In fact, the solubility of quartz is the basis of the "silica geothermometer" with which the source temperatures of geothermal waters have been successfully estimated[6, 7, 10, 11].

Apparently the solubility of quartz in pure water is applicable as well to salt solutions. Fournier and Rowe[6] reported that they were unable to detect any effect of a 2 M solution of sodium chloride on the solubility of quartz. In reporting their study of hot spring waters in Yellowstone

National Park, Fournier and Truesdell[7] stated that, provided the activity of water is not greatly diminished at a given temperature, the solubility of quartz is independent of the local mineral suite, gas partial pressures, and other dissolved constituents commonly found in natural hot spring waters with pH less than about 8.5. In general, it appears that changes in pH in the range of 2 to 9 will have little effect on the solubility of silica in natural waters; above a pH of about 9, dissociation of the silicic acid to silicate anions is probably responsible for the sharp increase in solubility[12].

The most soluble form of silica is amorphous silica. At 25^{o}C and 1 atm., the solubility of quartz in sea water is about 0.1 millimoles/liter, while that of amorphous silica is about 1.8 millimoles/liter[16]. The solubility of quartz increases slightly with increasing pressure. At about 200^{o}C and saturation pressure, the solubility of amorphous silica is approximately three times that of quartz[12]. Fig. 1 provides a comparison over a wide temperature range. When an aqueous solution of silica is cooled, the solid phase which will spontaneously appear is not quartz but amorphous silica. Hot brines saturated with respect to quartz do not precipitate silica when cooled so long as the concentration does not exceed the solubility of amorphous silica. When this limit is exceeded, polymerization of the silicic acid monomer occurs to yield ultimately colloidal-sized silica particles. The rate of polymerization is slow at low temperatures and very slow at both low temperatures and pH less than 7. High temperatures, high pH, and high degrees of supersaturation all favor an increased rate of polymerization to form amorphous silica. Monomeric silica may precipitate directly from solution if active sites (reactive OH groups) are present. Previously deposited silica scale, corroded surfaces, colloidal particles, or any amorphous silica present can provide such a site. In addition, small amounts of polyvalent cations may precipitate colloidal silica if it forms.[12]

However, the process is one commonly characterized by large supersaturations. Wollast[16] stated that, unless a solid phase favorable to the nucleation of quartz is present, it is possible to maintain indefinitely a solution supersaturated with respect to amorphous silica. The process of homogeneous nucleation may require supersaturation of several

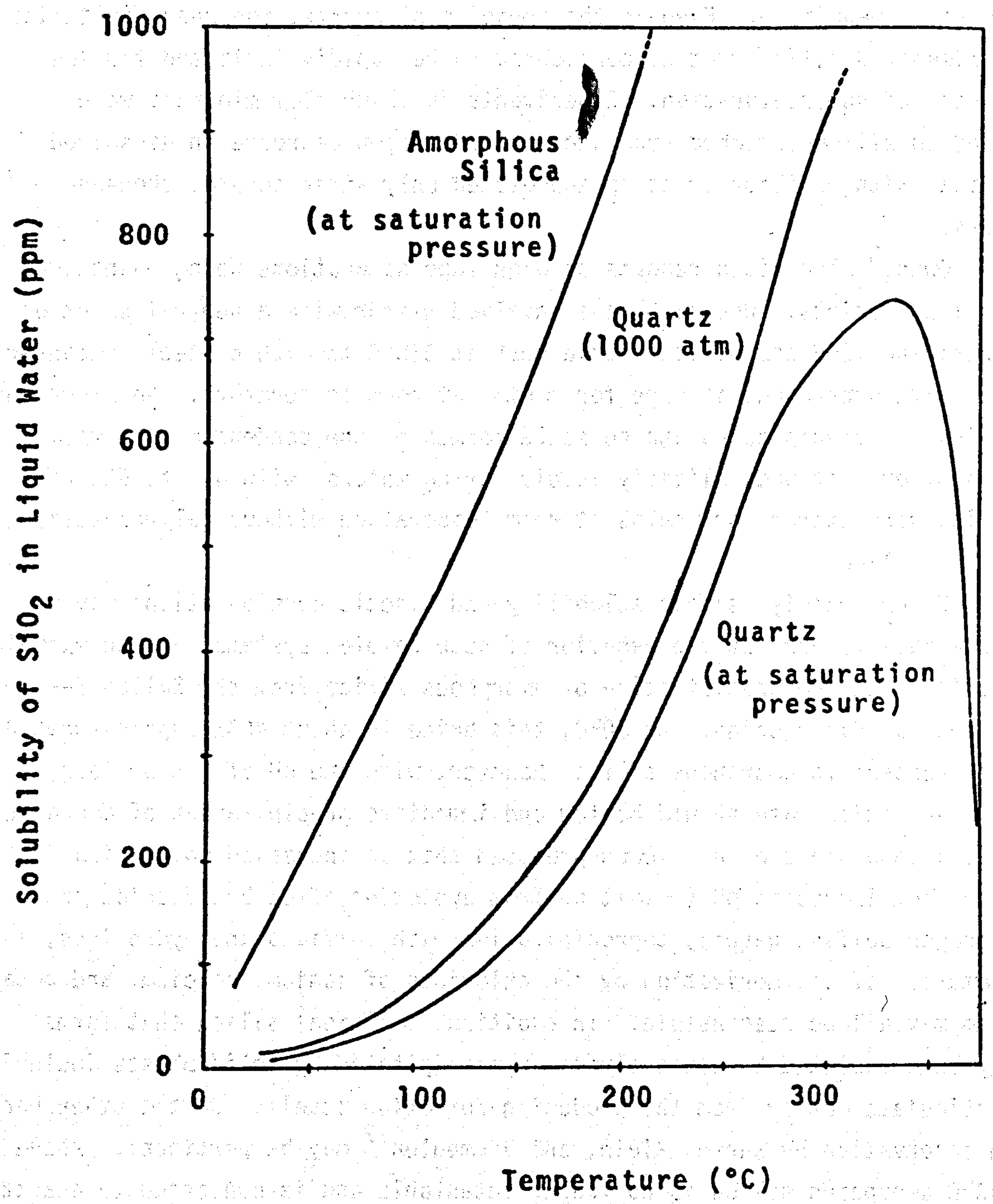

Figure 1. Solubility of quartz and amorphous silica as a function of temperature.*

*Reproduced from Report No. 4415, LBL[12] orders of magnitude. Even in the presence of quartz, the reprecipitation of dissolved silica must be considered to be rapidly inhibited for low degrees of supersaturation. Experiments in which clay minerals were added to silica-enriched sea water showed a slow decrease in dissolved silica, with equilibrium being approached only after several thousand hours.

Owen[13] also cited reports of high supersaturations being maintained for long periods. One such case involved withdrawing a neutral solution containing 1800 ppm silica from a bomb at 310°C through a steel condenser tube with subsequent storage for months at room temperature. No amorphous silica was precipitated and no scale formed on the condenser tube wall. In another instance, slightly acidic spring waters with 400 to 500 ppm silica were stored for months at room temperature without polymerization of the silica.

Unfortunately, simple solubility and kinetic considerations may be inadequate to predict the behavior of such complex systems. As an example, Owen[13] cited the precipitation of amorphous silica from the Salton Sea Geothermal Field brine. At 50°C, this brine is about 400% supersaturated with respect to amorphous silica. However, with the pH of 4.5 or less, polymerization rate should be low and immediate precipitation of amorphous silica should not occur. Owen proposed that an increased polymerization rate from increased pH (resulting from evolution of carbon dioxide and hydrogen sulfide gases), coprecipitation with sulfides and hydroxides, and promotion of polymerization by the chlorides of sodium, calcium, and potassium may all be responsible. In addition, colloidal silica that forms may be coagulated by electrolytes or precipitated by solid phases including particulate matter from the producing formation itself. On the other hand, an observation by Marsh, Klein, and Vermeulen[12] may be pertinent. Above 140°C amorphous silica is no longer metastable and is converted to quartz at an undetermined rate. It is therefore possible that quartz solubility is controlling at 140°C and above.

From the graph of silica solubilities presented in fig. 1, it is possible to estimate a silica content for the Kenedy County well of 150 ppm SiO_2 based on an estimated temperature of 290°F and pressure of 11,700 psia. For this concentration, saturation with respect to amorphous silica will not occur until a temperature of about 95°F (at saturation pressure) is reached. Since only moderate cooling of the fluid will reduce its temperature below 140°C (284°F), amorphous silica should be the solubility-limiting phase as cooling and de-pressuring occurs. For conditions as extreme as 350°F and 15,000 psia, the silica content would be about 250 ppm SiO_2. Saturation with respect to amorphous silica would occur at about 140°F.

On Dissolved Gases

The geopressured geothermal waters can be expected to contain dissolved methane and other light paraffin hydrocarbons, as well as carbon dioxide, possibly hydrogen sulfide, and perhaps ammonia. Although it is impossible to predict the extent of the latter constituents, there is good reason to expect considerable amounts of the hydrocarbons as natural gas in solution. In an extensive investigation involving hundreds of drill-stem tests on water-bearing formations in the Gulf coastal area of the United States, Buckley, Hocott, and Taggart[2] found that substantial amounts of hydrocarbons were dissolved in most of the sampled waters. From 32 drill-stem tests in 25 wells completed in the Frio formation of the upper Gulf Coast of Texas, it was found that the bubble-point pressures of the sampled waters increased linearly with depth and closely paralleled the hydrostatic pressure in the formation. Differences between the median bubble-point pressure and hydrostatic pressure ranged from 300 to 400 psi at depths from about 3500 feet to 8000 feet. The "ethane-plus" (paraffin hydrocarbons heavier than methane) content generally increased with depth, the highest value observed being slightly more than 2% of the total dissolved gas content, observed at a depth of approximately 7000 feet.

The solubility of methane in water was studied by Culberson and McKetta[4] from 77° to 340°F and at pressures up to 10,000 psia. At all temperatures, solubility was found to increase with increasing pressure, but, at a given pressure, solubility was found first to decrease and then to increase with increasing temperature. Results were presented graphically as shown in fig. 2. Also presented was the popular and often-seen graph of methane solubility in cu. ft./bbl. (both volumes at 60°F and 14.7 psia), reproduced here as fig. 3. The methane used in this study

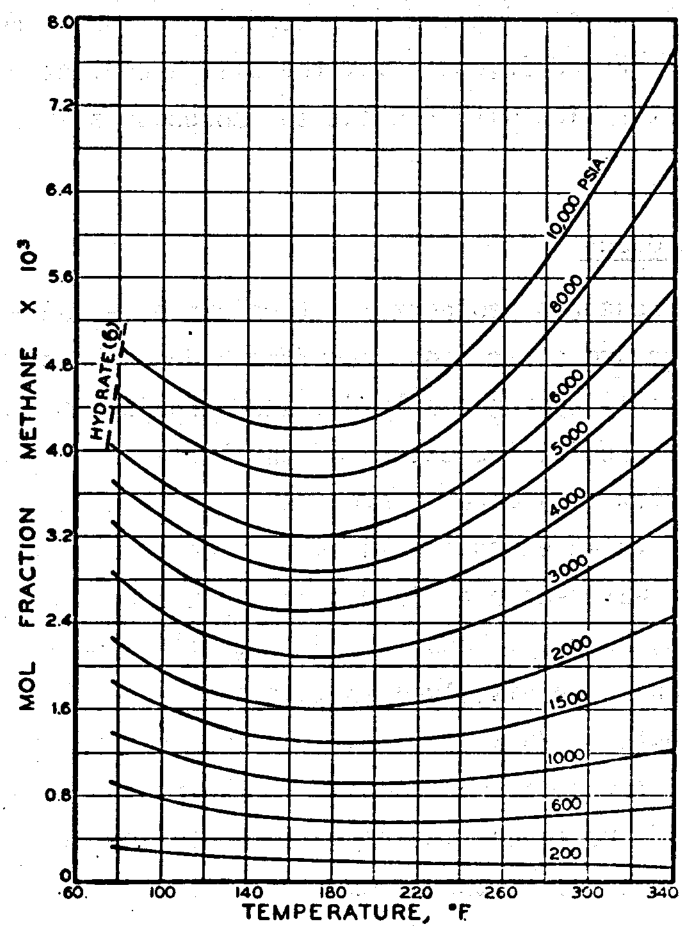

Figure 2. Solubility of methane in water at constant pressure.*

*Reproduced from Trans. AIME v. 192[4]

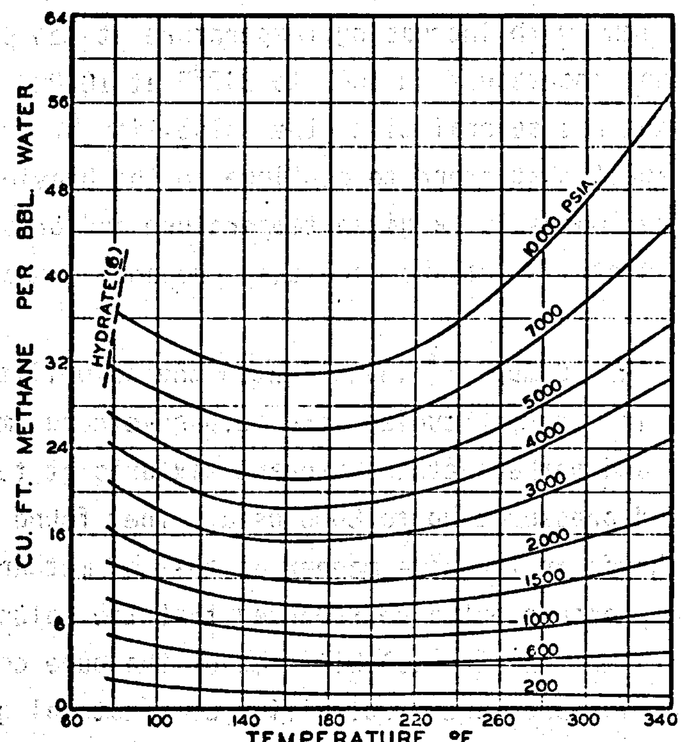

Figure 3. Volumetric solubility of methane in water.*

*Reproduced from Trans. AIME v. 192.[3]

was in reality a very lean natural gas, reported as 98.72% methane, 0.80% ethane-plus, 0.27% nitrogen, and 0.21% carbon dioxide.

Culberson and McKetta[3] also studied the ethane-water system over the same temperature and pressure range. Ethane solubility exhibited a minimum and then maximum with increasing temperature at low pressures but showed a continual increase from 100° to 340°F at 10,000 psia. At high pressures, methane has several times the solubility of ethane, and it is reasonable to expect that trend to continue to the heavier paraffin hydrocarbons. In other words, at a given temperature and pressure, methane is more soluble than ethane, ethane more than propane, propane more than isobutane, etc.

Amirijafari and Campbell[1] investigated the solubility of gaseous hydrocarbon mixtures in water. Studied were methane-ethane, methane-propane, ethane-propane, and methane-ethane-propane mixtures at temperatures from 100° to 220°F and pressures up to 8000 psia. They found that the mixture solubilities behaved in the same manner as that of methane with respect to temperature and pressure but also reported that the solubilities of the mixtures are greater than the solubilities of the pure components at the same temperature and pressure. Solubility of a natural gas (88.5% methane and 11.5% ethane-plus) in pure water was reported by Dodson and Standing[5] at temperatures from 100° to 250°F and pressures to 5000 psia (see fig. 4). When these latter data were compared by Culberson and McKetta[4] with their data on the solubility of methane (actually a leaner natural gas), it was seen that the methane solubilities were somewhat higher at the higher pressures. In view of these two seemingly conflicting pieces of evidence, it is probably best to accept the Culberson and McKetta data on methane solubility as the most reliable predictor for lean natural gases in pure water.

However, it is well-known that dissolved salts can alter the solubility of gases in an aqueous phase. The investigation by Dodson and Standing[5] also included solubility of the natural gas in two brines, one with 8,630 ppm and the other with 34,100 ppm total dissolved solids. (Both brines were primarily sodium chloride solutions.) The temperature range of this study was 100° to 200°F. Based upon their observations, the authors proposed the linear correction factor to the solubility in fresh water shown

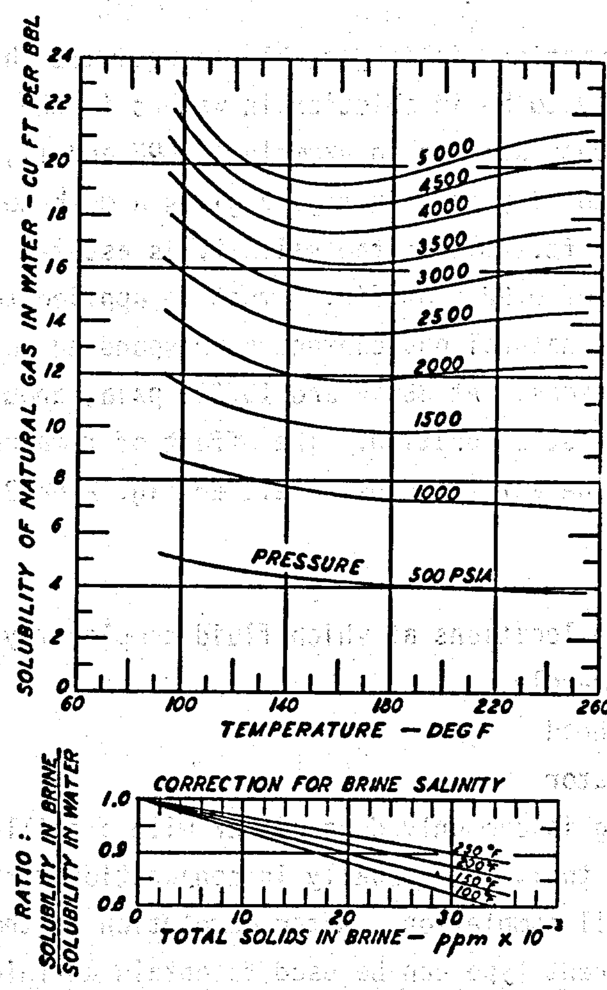

Figure 4. Solubility of natural gas in water.*

*Reproduced from Am. Pet. Inst. Drilling and Prod. Practices, 1944[5] in fig. 4. At 30,000 ppm and 250°F, this correction is 0.90, indicating a 10% reduction in natural gas solubility in this brine from the value in fresh water.

With this information, it is possible to estimate the maximum amount of natural gas likely to be in solution in waters in the geopressured zone. Using the Kenedy County well as an example (290°F and 11,700 psia), extrapolation of the solubility data in fig. 2 gives a methane mole fraction of 0.00660, or 48.6 cu. ft./bbl. If the salinity is assumed to be 30,000 ppm a correction factor of 0.92 from fig. 4 must be applied to give about 45 cu. ft./bbl. as the natural gas content corresponding to saturation under these assumed conditions. At 350°F and 15,000 psia, about 75% more gas would be in solution at saturation. The effect of temperature and pressure reductions can then be estimated using either fig. 2 or 3.

SAMPLING TECHNIQUES

There are three locations at which fluid samples may be obtained:

1. bottom-hole
2. well-head
3. separator

Bottom-hole sampling is commonly done either with a drill-stem sampling tool or a wire-line tool, both usually in conjunction with formation testing and prior to well completion. After completion of the well, wire-line samplers of a different type can be used to obtain a fluid sample from the well at or near the producing formation. Samples can also be withdrawn at the well head (before the choke) and therefore at lower pressures than bottom-hole. The flowing well stream can be sampled indirectly by sampling gas and liquid streams from high- and low-pressure separators and recombining (either physically or by calculation) on the basis of metered flow rates of each stream. Clearly, the three possibilities represent successively greater temperature and pressure changes in the sampled fluids. In addition, further changes must necessarily occur after sampling. The severity of these changes and their impact upon the goal of obtaining representative samples of the reservoir fluid can be tentatively evaluated on the basis of the information developed in this initial study.

Initial Bottom-Hole Sampling

The initial bottom-hole samples can be taken in conjunction with the formation testing conducted before the well is completed. Several excellent drill-stem samplers are available for that purpose, some with two sample chambers and even one with an expandable chamber to reduce sample pressure before bringing to the surface. However, the new repeat formation tester wire-line tool of Schlumberger Well Services[15] appears to have a combination of features quite suitable for this operation. Its pressure rating is 20,000 psi and temperature rating 350^{o}F. The probe of the sampler contains a filter which will exclude sand particles from the sampled fluid. Two sample chambers are provided, with sizes ranging from 1 to 12 gallons. Samples from two different depths may be taken, or the fluid taken last in a single test may be segregated from that produced first. Since these samples will be contaminated by drilling mud filtrate, this last feature may be particularly useful.

By tagging the drilling mud with a suitable tracer, it should be possible to determine the extent of dilution of these first samples with mud filtrate. A tracer must be chosen which is capable of being quantitatively determined at low levels of concentrations. It must of course be unaffected by high temperatures and pressures, be compatible with the drilling mud, and not react with mineral components in the formation nor interfere with logging.

As the sampler is brought to the surface, it will cool and as a result, the sample pressure will decrease. If a pure water sample were taken at 290^{o}F and 11,700 psia in a stainless steel bomb and cooled, by the time the temperature of its contents reached about 200^{o}F, a vapor phase would have evolved. Therefore it is certain that, even though the samples will be diluted with filtrate, a gas phase will evolve upon cooling at the surface. Although bubble-point pressures will be lowered by the dilution, so will the concentrations of silica and salts, so that precipitation may not be a problem. However, because of the phase separation, the entire contents of the sample chambers will have to be transferred quantitatively into other suitable containers or directly into an analytical train, or a combination of both. This transfer should be carried out as quickly as possible to minimize the opportunity for silica or salts to deposit on the walls of the sampler and transfer lines and for corrosion to occur.

Later Bottom-Hole Sampling

After the well has been completed and produced for a sufficient time to flush all filtrate from the formation, a different type of wire-line sampler can be used. This sampler is lowered down the production casing of the well to a point at or near the producing formation, opened by a control from the surface, and allowed to fill with the geothermal water at essentially the reservoir temperature and flowing (or shut-in) bottom-hole pressure. It would be desirable to equip this sampler with a filter to exclude particulate matter from being taken with the sample.

Scientists with the Radian Corporation, Austin, Texas, have suggested that this sampler be partially pre-filled with an alkaline EDTA solution (ethylenediaminetetra-acetic acid). This technique will accomplish three objectives simultaneously:

1. it will dilute the sample initially
2. the increased pH will render the silica more soluble
3. the EDTA will complex all multivalent cations, the sulfates, carbonates, and even silicates of which might otherwise tend to precipitate upon cooling and depressuring the sample.

Of course, the amount of EDTA solution placed in the sampler must be accurately known so that concentrations determined by analysis can be related to the formation fluid.

When this sampler is brought to the surface, its contents are also certain to be in a two-phase (vapor and liquid) state upon cooling. As with the initial bottom-hole sample, it may be desirable to transfer the contents of the sampler quantitatively and rapidly to other suitable containers or an analytical train. However, if corrosion is deemed not to be a problem, this sampler could be transported to the analytical laboratory where the transfer can be made more conveniently and where it may even be feasible to re-pressure the contents and restore the gases to solution. In such a case, aliquot portions of the sampler's homogeneous contents could be withdrawn for analysis.

Well-Head Sampling

At a production rate of 10,000 B/D, it has been estimated that steady-state well-head temperature for the Kenedy County test well will be about 279°F and well-head pressure about 6200 psia (for a 5½" casing). At a 40,000 B/D rate, temperature will rise to about 287° F and pressure decrease to about 3600 psia. At the lower production rate, assuming equilibrium is maintained as gas is evolved, only about 1% by volume of the flowing stream will be vapor. Higher formation pressures would result in higher well-head pressures at the same production rate, so that the 75% more gas potentially in solution at 350°F and 15,000 psia would not necessarily correspond to higher vapor fractions in the flowing stream. In either case, no significant concentration of the dissolved silica or salts should occur, as vaporization of water under these conditions should be negligible. It should, therefore, be possible with a properly designed sampling port to collect a representative sample of the well stream at well-head conditions.

A sample so collected in a stainless steel bomb will undergo a decrease in pressure as cooling to ambient temperatures occurs. By virtue of the evolution of the dissolved gases, appreciable pressures can be expected after cooling, probably higher than 2000 psia if the water is close to saturation at reservoir conditions. At this pressure level, most of the carbon dioxide and hydrogen sulfide should remain in solution, reducing the tendency of the pH to increase and of carbonates to precipitate but unfortunately increasing the rate of corrosion of the wetted steel surfaces. If barium or strontium concentrations are high, their sulfates may precipitate.

According to fig. 1, saturation with respect to amorphous silica will not occur until a temperature of about 95°F is reached for the Kenedy County test well or about 140°F for a reservoir at 350°F and 15,000 psia. Even if cooled below that saturation temperature, homogeneous nucleation of amorphous silica should occur, if at all, very slowly. The presence of sand grains or clay particles could, however, cause a gradual decline of silica in solution, as could also corrosion sites on the inner walls of the sample bomb.

It therefore seems feasible to transport such a sample in its original sampling bomb to a laboratory where it can be restored to reservoir temperature and re-pressured until all gases return to solution. At this point, portions could be transferred to viscometer, P-V-T cell, or other apparatus for needed physical properties measurements. Obviously, the contents could also be sampled for a complete analysis of the geothermal water. For the physical property determinations, this approach may be a preferable alternative to reconstituting the brine from its analysis or using empirical correlations.

The sampling technique described here may require a special sampler to be designed and fabricated. Corrosion resistance requirements may dictate special alloys or perhaps Teflon coatings. The sampler should incorporate a floating piston to reduce tendencies for vapor to "flash" as the stream initially enters the sampler, or a liquid piston such as mercury or even distilled water could be used, with appropriate sampling techniques accordingly devised. A filter (or filters) should be included in the sampling line to exclude particulate matter suspended in the well stream, and provision for line purging must be made. To minimize cooling of the sample, an insulating or even heating jacket may be provided for the bomb during its transport to the laboratory. Since it will remain under pressure, suitable personnel protection should be provided.

Separator Sampling

The well stream, after passing through an adjustable choke, will enter a separator where dissolved gases and some water vapor will evolve. This high-pressure separator will probably operate in the pressure range from 2000 to 5000 psia. Even at the lower pressure, appreciable amounts of gases will be dissolved in the effluent liquid stream, which will therefore have to be diverted to a low-pressure separator, essentially at atmospheric pressure. If the vapor and liquid streams from both separators are metered and analyzed, the composition of the well stream can be calculated.

Since both cooling and pressure reduction occur prior to the taking of the sample, this method offers the greatest opportunity for solids to be lost, that is, to accumulate within the separators. Periodic shutdowns and visual examination of the separators may serve to verify the presence or absence of this problem, but, if it is present, correction of the resulting errors may be difficult. However, the determination of the dissolved hydrocarbon content from separator stream analyses should be as reliable as from the other sampling methods.

SAMPLE ANALYSIS

The analytical methods described here are those proposed by scientists of the Radian Corporation, Austin, Texas. Liquid samples will be immediately diluted upon collection to prevent precipitation of any solids. Where it was impossible to exclude particulate matter from the sample, liquid samples will be filtered after dilution. Vapor samples will be cooled to condense water vapor, and the condensate will also be analysed for dissolved gases. Analyses will be conducted with a combination of wet methods, gas chromatography, atomic absorption spectrometry, specific ion electrodes, and spark source spectrometry. Application of these methods to vapor and liquid samples is characterized briefly by the following summaries.

Vapor Analysis

Vapor samples will be passed through an absorption train which will be used to collect ammonia, hydrogen sulfide, and carbon dioxide for determination as indicated below.

Component	Scrubber	Determination
NH_3	H_2SO_4	Nessler Reagent
H_2S	$CdAc_2$	Atomic Absorption
CO_2	NaOH	Non-dispersive IR

A polymeric adsorbent will be placed in series with the absorption train to collect trace neutral organics. Any sorbed material will be detected by gas chromatography. In parallel with the absorption train, a corrosion-resistant sample bomb will be used to collect a sample of gas to be analyzed by gas chromatograph to determine light hydrocarbons as well as hydrogen sulfide, ammonia, carbon dioxide, and the rare gases (helium, argon, neon, etc.).

Liquid Sample

Trace hydrocarbons and dissolved gases can be determined by using slight modifications of the procedures described above. Concentration techniques will be employed as needed to enrich trace organics. Spark source mass spectrometry can be used to survey the 60 elements normally detected with slightly better than order-of-magnitude accuracy. For any elements found to be present in significant amounts, an analytical procedure will be recommended at that time. Silica, Cl^-, $CO_3^=$, $SO_4^=$, Na^+, K^+, Ca^{++}, Mg^{++}, Al^{+++}, and iron can be determined quantitatively by such commonly used procedures as atomic absorption spectrometry and specific ion electrodes supported by classical techniques. Dissolved solids, total carbon, and total organic carbon can also be determined.

CONCLUSIONS

1. The Schlumberger repeat formation tester is capable of performing the initial bottom-hole sampling in conjunction with testing. Since samples so taken will be contaminated with drilling mud filtrate, the filtrate should be tagged with a tracer so the extent of dilution can be determined. Information obtained from these samples will be useful in planning for the succeeding types of sampling.
2. After completion of the well, bottom-hole fluid samples can be taken in a wire-line sampler partially filled with alkaline EDTA solution to complex multivalent cations and increase silica solubility. A conventional sampler will probably have to be modified for this purpose. It is expected that this sample will be the most reliable.
3. During production testing, a high-pressure well-head sample can be taken which, through proper handling, should be capable of being restored to its original state at reservoir conditions for physical property measurements as well as analysis. A special sampling port will have to be provided, and a sample bomb will have to be designed and fabricated for this purpose.
4. Measurement of flow rates and compositions of gas and brine streams from high- and low-pressure separators will allow calculation of well-stream composition. An accurate hydrocarbon content can be determined by this method, but some solids may tend to accumulate

in the separators as the brine is cooled and concentrated.

5. Precipitation of dissolved silica will not be a problem until saturation with respect to amorphous silica develops, but care should be taken to exclude clay particles and sand grains from the sample containers or to remove them from the liquid samples promptly. Surfaces in the samplers should be free of corrosion.
6. With the decrease in temperature and pressure, preciptation of calcium carbonate is likely to occur unless samples are sufficiently diluted or the calcium complexed with EDTA.
7. Vapor samples can be analyzed for light hydrocarbons, carbon dioxide, hydrogen sulfide, ammonia, and the rare gases.
8. Brine samples can be analyzed for all major anions and cations. Spark source spectrometry can be used to survey 60 elements to identify which minor constituents are present in sufficient concentrations to warrant detailed analysis.

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PART 3

Rock Mechanics Aspects of Geopressured Geothermal Reservoirs: Subsurface and Surface Behavior

BY

Thomas W. Thompson
AND
Kenneth E. Gray

INTRODUCTION

The controlled exploitation of a geopressured, geothermal reservoir will depend upon the ability to predict the behavior of the reservoir rock under conditions of varying pore pressure and temperature together with the ability to assess the stability of the overlying rocks and the extent of any surface manifestations of the exploitation.

In its most general terms the reduction of pore pressure in a geopressured reservoir will lead to an increase in the effective stress on the rock, and hence a compaction of this material with consequent reduction in permeability. Since the pressure change in the reservoir will not be uniform, and since in general the rock will be neither inhomogeneous nor isotropic, this compaction will be non-uniform. This increase in effective stress and the consequent compaction will induce non-uniform deformation of the immediately overlying strata which may be expected to induce shearing stresses in the rocks and, if the degree of compaction and the depth of the reservoir are of the right order, may induce surface subsidence (fig. 1).

Any variation in the temperature field caused by fluid withdrawal and any changes in pore pressure and temperature distrubiton induced by reintroduction of core fluid will change the stress and deformation fields within the rock mass.

In this context four major critical conditions may be identified:

1. The change in fluid flow behavior caused by compaction may significantly alter the operational capabilities necessary for ecomonic exploitation.
2. The non-uniform deformation of the overburden will induce shear stresses which may, in the extreme case, lead to fracturing of the immediately overlying rocks, the development of shear fractures at the edges of the subsurface subsidence trough, the occurrence of renewed movement on pre-existing faults and the possible loss of stability of the operational well holes.
3. Loss of stability of the well holes may occur within the reservoir rock itself due to deformation within this rock.

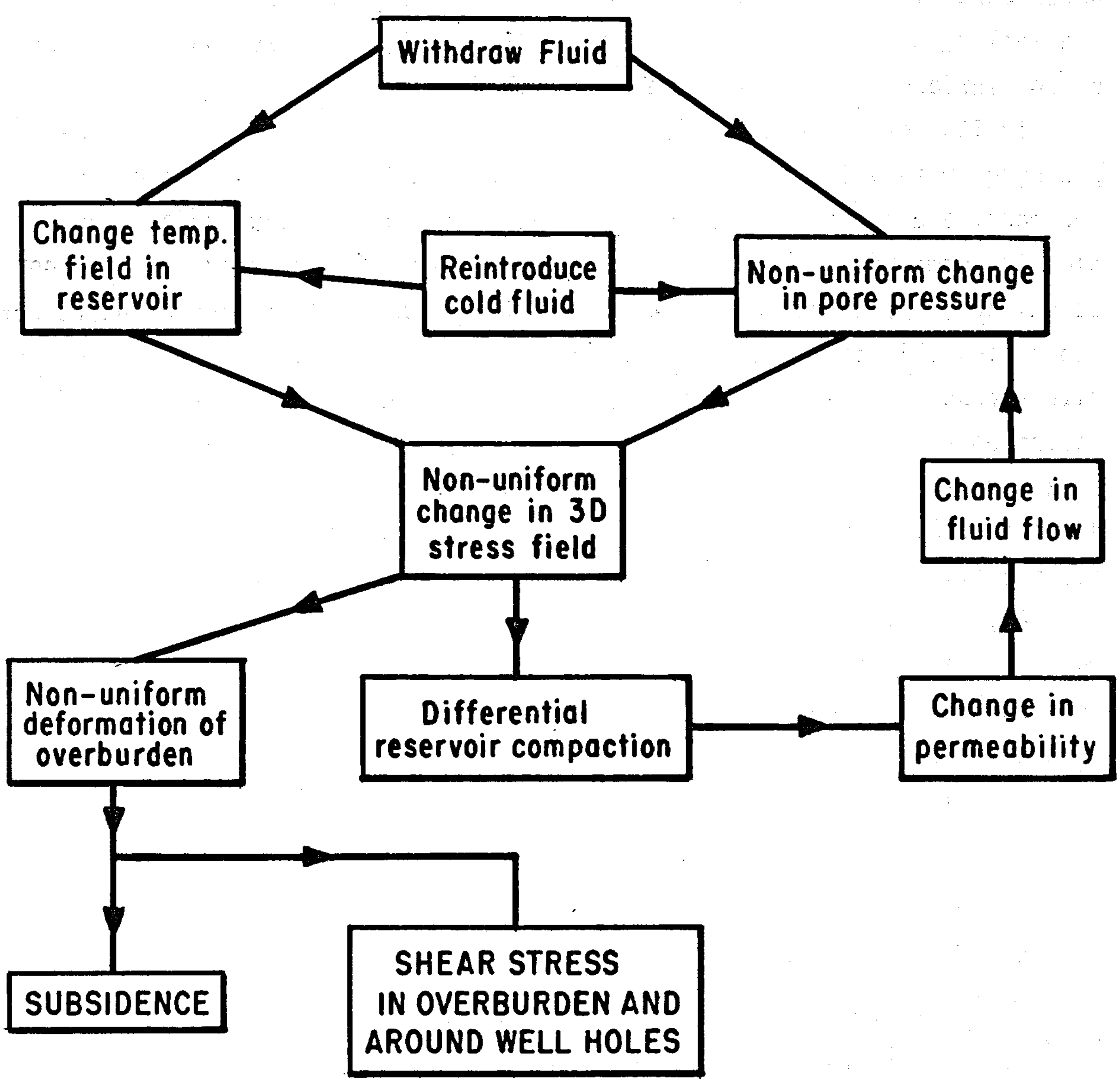


Figure 1. The effects of reservoir exploitation.

4. Surface subsidence may lead to damage of surface installations or features due to differential settlement, lateral strain or surface fracturing.

These conditions can only be fully assessed by a comprehensive study of the relevant rock materials aimed at determining their mechanical properties as functions of stress and temperature, together with the development of a mechanical modelling ability. This section of the report is concerned with a closer examination of the likely rock behavior and an assessment of the most suitable methods for achieving these ends.

THE MECHANICAL EFFECTS OF RESERVOIR EXPLOITATION

The Constitutive Equations for Rocks.

The response of any rock material to change in stress is, in general, complex and is a function of moisture content, history of loading, temperature and time, as well as of stress. Although a relationship involving all of the relevant parameters is preferable from a theoretical standpoint, the complexity of such a relationship precludes its use in all but the simplest cases.

Well compacted and cemented sandstones often show a near linear elastic response to stress, that is the strain at any point is linearly dependent upon the existing stress and temperature[1]. Poorly compacted sandstones, clays, and shales typically exhibit a more complex behavior with strain dependent on time as well as on stress and temperature, and frequently with a non-linear relationship to stress[2]. Moisture content can be important for clays and shales[3].

From the point of view of analytical convenience it is necessary, in the majority of cases, to assume linearity of the stress-strain relationship. In particular the mechanical behavior or rocks is frequently approximated by either a linear elastic, a linear viscoelastic, or a perfect elasto-plastic formulation. For the purposes of this report linear elasticity will be assumed in the main, although conclusions based on this model will carry through to the linear viscoelastic case by operation of the Laplace transformation and use of the well established correspondence principle[4].

Further complexities are added by the facts that rocks, being naturally occurring materials, are likely to be significantly inhomogeneous and frequently will be anisotropic. Large scale inhomogeneities, on the scale of lithological units, can usually be taken into account in solving boundary value problems, but inhomogeneities within lithological units may rarely be included explicitly and must be incorporated implicitly by suitable statistically based sampling techniques. It would, moreover, be meaningless to include such localized inhomogeneities explicitly since the likelihood of their being known over any particular site is extremely small. Anisotropy of the rock material may be included in general for any boundary value problems, particularly when using modern numerical techniques for their solution.

Reservoir Compaction.

The stress and deformation fields induced in elastic porous material by variation in pore pressure have been investigated by several authors, notably Geertsma[5,6], Biot[7], Gassmann[8], and Lubinski[9]. Geertsma has considered briefly the effect of linear time dependance and Van de Knapp[10] the effect of non-linear elasticity. In all cases a uniform pressure drop and simplified geometry has been assumed when applying the results to reservoirs.

The first necessity in formulating an analytical solution to the compaction subsidence problem is to simplify the geometry. A disc-like reservoir is usually assumed since this allows the assumption of axial symmetry which in turn considerably simplifies the solution. Further common assumptions are of homogeneity, isotropy, and linear elasticity for the reservoir rock and overlying strata, though the results may still be applied to a linear viscoelastic material by operation of the correspondece principle.

Geertsma[6] uses these assumptions as a starting point for his solution for the deformation field in and around a disc shaped oil or gas reservoir. Using similar methods to those employed in thermoelasticity he formulates the problem in terms of a potential function and uses the concept of strain nuclei to obtain a solution. He finds that for a reservoir subjected to a uniform change of pressure, Δp, the vertical compaction will be given by:

$w = C_m h \Delta_p$

Where C_m is the "uniaxial compaction coefficient" $= \frac{(1-\beta)\ (1-2\nu)}{2\mu(1-\nu)}$

β is the ratio of the rock matrix to rock bulk compressibilities

μ is the bulk shear modulus

ν is the bulk Poissons ratio

h is the thickness of the reservoir

The solution for a non-linear uniform pressure field, such as would be expected in an operating geopressured reservoir, is more compex and is in any case best obtained using numerical techniques, which would also allow the modelling of non-simple geometries, anisotropy and limited in-homogeneity. However, some indication of the likely form of the stress and deformation fields within a reservoir subjected to a non-uniform pressure field may be obtained by examining the relevant field equations as applied to a simple case.

Regardless of the behavioral characteristics of the material the stress equilibrium equations will apply. If we assume a general radial configuration for the likely pressure temperature and stress fields in a reservoir undergoing compaction, these are most conveniently written in the cylindrical coordinates (r, θ, z) (fig. 2):

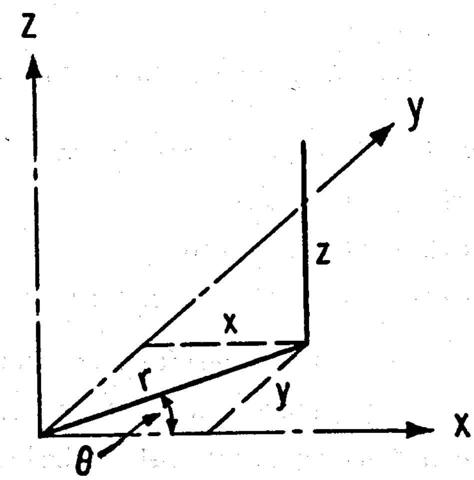
$$\begin{aligned}
&\frac{\partial\sigma_{rr}}{\partial r} + \frac{1}{r}\frac{\partial\sigma_{r\theta}}{\partial\theta} + \frac{\partial\sigma_{rz}}{\partial} + \frac{\sigma_{rr} - \sigma_{\theta\theta}}{r} + R = 0,\\
&\frac{\partial\sigma_{r\theta}}{\partial r} + \frac{1}{r}\frac{\partial\sigma_{\theta\theta}}{\partial\theta} \quad \frac{\partial\sigma_{\theta z}}{\partial z} + \frac{2}{r}\sigma_{r\theta} + \Theta = 0,\\
&\frac{\partial\sigma_{rz}}{\partial r} + \frac{1}{r}\frac{\partial\sigma_{\theta z}}{\partial\theta} + \frac{\partial\sigma_{zz}}{\partial z} + \frac{1}{r}\sigma_{rz} + Z = 0.
\end{aligned} \tag{1}$$

As a first approximation we may consider the pressure and stress fields to be axially symmetrical so that derivatives with respect to Θ will disappear, as will the shear stress components $\sigma_{r\theta}$, $\sigma_{\theta z}$ [11]. Moreover from Lubinski[9] the body force components R, Θ, Z will be given by:

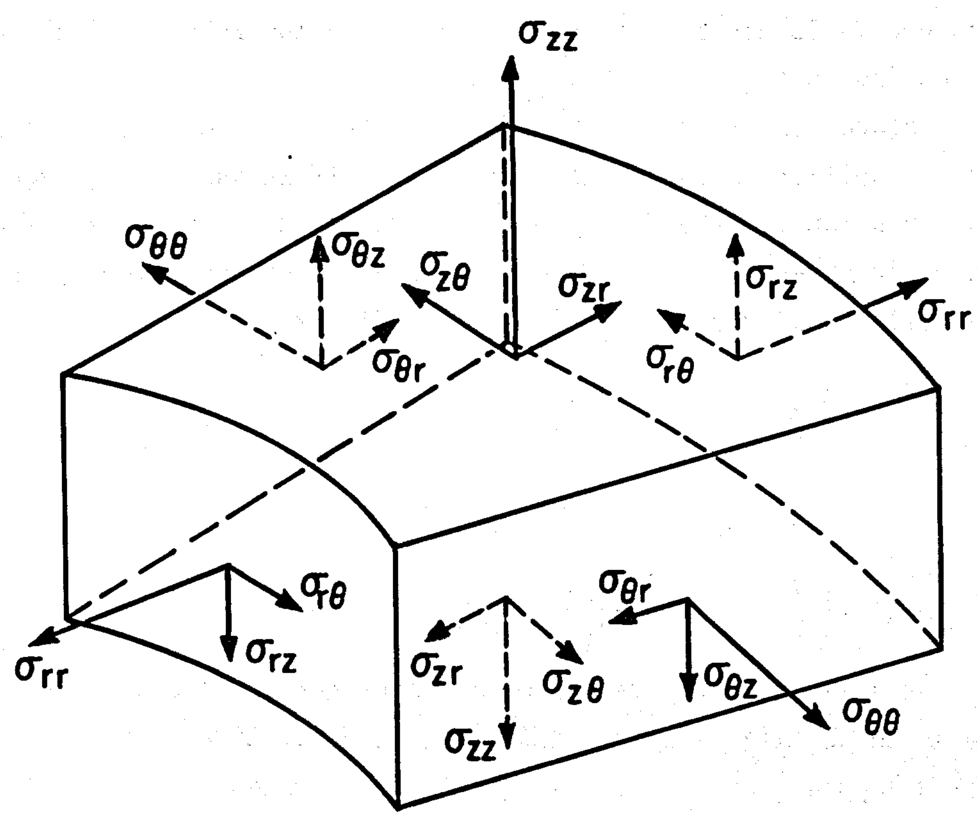
$R = -f\frac{\partial p}{\partial r}$

$\Theta = 0,$

$Z = 0,$



a. Cylindrical coordinates (r, θ, z) related to the orthogonal system (x, y, z)



b. Stress components in cylindrical coordinates

Figure 2. Stress components in cylindrical coordinates.

where f is the porosity,

p is the pore pressure distribution.

With these simplifications the three equilibrium equations reduce to two:

$$\frac{\partial \sigma_{rr}}{\partial r} + \frac{\partial \sigma_{rs}}{\partial \zeta} + \frac{\sigma_{rr} - \sigma_{\theta\theta}}{r} = f \frac{\partial p}{\partial r}$$

$$\frac{\partial \sigma_{rz}}{\partial r} + \frac{\partial \sigma_{zz}}{\partial z} + \frac{1}{r} \sigma_{rz} = 0. \tag{2}$$

If it is further assumed that the vertical stress component σ_{zz} does not vary throughout the thickness of the reservoir so that $\frac{\partial \sigma_{zz}}{\partial \zeta} = 0$-- a reasonable assumption if the pressure distribution is independent of z and the reservoir thickness is small in relation to its areal extent--then the second of equation 2 yields the result:

$$\sigma_{rz} = \frac{A(z)}{r} \tag{3}$$

Where A is a function of Z only.

For a linearly elastic material, assuming isothermal conditions, for the time being, Lubinski has shown that the constitutive relationship has the form:

$$\varepsilon_{ij} = \frac{1 + \nu}{E} \sigma_{ij} - \frac{\nu}{E} \sigma_{kk} \delta_{ij} + \alpha p \delta_{ij} \tag{4}$$

Where i, j = 1, 2, 3

δ_{ij} is the Kroenecker delta function,

α is a function of the moduli of the bulk rock and the interpore material, and of the porosity,

and summation over repeated indices is implied.

Moreover, for the case of infinitesimal strain the various components of the strain tensor $\varepsilon_{i,j}$ are related to the displacement vector u_i by the equations:

$$\varepsilon_{rr} = \frac{\partial u_r}{\partial r};\ \varepsilon_{\theta\theta} = \frac{u_r}{r};\ \varepsilon_{zz} = \frac{\partial uz}{\partial z}$$

$$\varepsilon_{r\theta} = \frac{1}{2}\left(\frac{\partial u\theta}{\partial r} - \frac{u_\theta}{r}\right);\ \varepsilon_{rz} = \frac{1}{2}\left(\frac{\partial u_z}{\partial r} + \frac{\partial u_r}{\partial z}\right);\ \varepsilon_{\theta z} = \frac{1}{2}\left(\frac{\partial u_\theta}{\partial z}\right) \tag{5}$$

where again axial symmetry has been assumed.

From equations 3, 4, and 5 and writing $\mu = \frac{E}{2(1+\nu)}$, it follows that:

$$\frac{\partial u_z}{\partial r} + \frac{\partial u_r}{\partial z} = \frac{A(z)/\mu}{r} \tag{6}$$

Substitution of equations 5 and 6 into the first of equation 2 results in a differential equation involving derivative of u_r with respect to r only, and this is capable of solution. The results are complicated, however, and do not add much to the understanding of the phenomenon at this stage.

Instead assume that $\frac{\partial u_r}{\partial z} = 0$. This assumption requires that $\frac{\partial^2 A(z)}{\partial z^2} = 0$, and imposes restrictions on the form of the radial pressure field, and therefore involves considerable loss in generality. However, it enables a simple deduction of the general form of the vertical deformation component and is useful in this context. With this assumption equation 6 gives immediately:

$$u_z = \frac{A(z)}{\mu} \ln r + C, \tag{7}$$

where C is a constant of integration.

It is therefore apparent that for any particular set of conditions the shear stresses within the reservoir depends upon the radius, r, and will be a maximum at the operational well, and that vertical compaction is also dependent upon the radius and, depending upon the relative values of the function A(z) and the constant C, will be either a maximum or a minimum at the operational well.

This vertical compaction may be expected to be accompanied by some radial deformation, these together leading to volumetric changes. For a pressure withdrawal this volumetric change, and the accompanying porosity change, will be greatest near the operating well, that is the area of maximum pressure drop. Any reduction in porosity will tend to reduce the permeability of the reservoir, and if the maximum permeability change is near the producing well this will have a possibly signficant effect on the overall flow regime.

Overburden Behavior.

Clearly the deformation of the immediate overburden may be expected to be the same as that of the upper boundary of the reservoir. Since this deformation will be a function of the radial distance from an operating well and may be expected to be a maximum or minimum at that well, shear stresses will be induced in the overburden material. Continuing the assumption of axial symmetry and hence of zero tangential shear components, and noting the orientation of the principal stresses, the maximum shear stresses are seen to be on conical surfaces concentric with the operating well. The absolute value of these shear stresses will depend ultimately on the operating conditions and the properties of the rock mass. There is, however, a clear possibility of failure of the rock mass on these planes of maximum shear which requires evaluation.

Subsidence.

Examples of surface subsidence above compacting oil and gas reservoirs are few through sufficient examples have been reported to neccesitate the investigation of this phenomenum, particularly in the high pressure environment of a geopressured explaitation[12,16].

The problem has been examined theoretically by several authors, principally Geertsma[6] who as a further part of the solution described at the start of the section on Reservoir Compaction showed that the vertical subsidence above the axis of a linearly elastic reservoir in a homogeneous, isotropic elastic medium may be given by:

$$u_z = -2(1-\nu)c_m h\Delta_p \left(1 - \frac{D}{\sqrt{1+D^2}}\right)$$

D is the ration of reservoir depth to reservoir radius

The surface subsidence can also be assessed by analogy to conventional mining subsidence. Theories in this field abound and are too numerous to consider in detail here. The most useful of these come from the classic work of Berry and Sales [17] who related the surface subsidence above a mined out panel to the mine roof deformation function, for isotropic and anisotropic elastic media. Use of their two dimensional theory for a transversely isotropic medium could be used to give estimates of surface subsidence profiles.

These theories all assume firstly elastic behavior, and secondly, that the surface subsidence through is continuous, that is that no surface fractures occur. However in the geological environment in which the geopressured reservoirs are found there is no certainty that this continuity will be preserved. A distinctive feature of the Gulf Coast province is the presence of growth faulting, and these faults may be expected to occur in the neighborhood of any commercial reservoir and may, indeed, bound this reservoir. In this case, and bearing in mind the shear stresses likely to occur in the overburden, it would seem likely that a major factor in the development of surface subsidence will be movement along these planes of weakness. There is, indeed, evidence that this influence has occurred in many cases of subsidence above nearer surface depleted aquifers[18]. In such a case, continuous theories may be of little value in assessing surface effects and should be replaced by an assessment of shear stability on planes of weakness.

The Effects of Temperature.

The discussion up to this point has been restricted to the case of isothermal changes in pore pressure. Any significant changes in the temperature field may be expected to alter the deformation and stress fields.

It seems unlikely that temperature changes sufficient to significantly effect the rock response will occur during normal exploitation of a reservoir, such effects that do occur will probably be within the limits of accuracy of the isothermal analysis. However, where reinjection of cool fluid is contemplated this will not be true. In this case, significant cooling of the reservoir may occur which would result in a volume change of the reservoir as a whole--though this will be offset to a greater or lesser extent by the accompanying increase in pore pressure.

Since reservoir compaction is the starting point for all areas of the stability analysis this effect must be investigated. Of further concern is the possibility of thermal gradients in the immediately surrounding material which could appreciably alter the stress regime. In general, a cooling gradient in the surrounding strata will lead to tensile stress components which could worsen the situation with regard to compaction induced shear stresses.

RECOMMENDATIONS FOR FURTHER RESEARCH

In the preceding discussion an attempt has been made to indicate the possible areas where the rock behavior may effect the operation of a geopressured reservoir either because of changes in the flow regime or because of loss of stability in the overlying strata. An attempt has also been made to indicate that these effects cannot be adequately qualified for any particular conditions without a knowledge of the mechanical and thermal properties of the relevant rocks and without a refinement of the techniques for applying these properties to a particular case.

Rock Mass Behavior Prediction.

It has been seen in the section on The Mechanical Effects of Reservoir Exploitation that analytical solutions to the compaction/subsidence problem can be obtained for highly idealized geometries and behavioral characteristics. For any but these ideal conditions, however, the solution of the appropriate field equations becomes increasingly difficult. Since a realistic estimate of the rock mass behavior cannot be expected unless non-ideal geometries and the likely heterogeneity, anisotropy and non-elastic characteristics of the materials are accounted for to a reasonable degree, recourse must be made to numerical techniques. With the current capability and power of those techniques, in particular that of finite elements, a reasonable estimate of the effects of exploitation is possible.

No particular technical problems are foreseen in the adaptation of existing finite element codes to the current investigation, though most will require some modification. All reasonably comprehensive codes can include anisotropy and a reasonable degree of heterogeneity. Most codes are based on linear elasticity, though some are available with extensions to non-linear elasticity and simple plasticity. The adaptation of any code to linear viscoelasticity is not technically difficult, though it could be time consuming. Again most geotechnically oriented codes can handle the effects of simple planes of weakness and gravitational loading. Modification will probably be necessary to solve the poroelastic problem existing in the reservoir. However, there is a strong analogy between the behavior or porous bodies under pressure gradients and solid bodies under thermal gradients[9]. Since many codes are capable of solving thermal stress problems the required modifications should not be overly complex.

Laboratory Data.

Certain areas of the required simulation can probably be best handled using empirical data. This applies particularly to the estimation of permeability variations from porosity values, and to the recognition of shear failure in the immediate overburden. Here there is a close interdependence of the modelling effect and the laboratory investigation of the rock properties. This interpdependence does, in fact, run throughout the whole of the development. Thus the choice of which constitutive relationships to assume, of what degree of anisotropy and heterogeneity to include, and of the geometry of the finite element mesh can only be made in relation to laboratory data.

Much laboratory data are required before any attempt at realistic simulation can be attempted. Initially these data must be of a semiqualatative nature directed towards the identification of the major deformation mechanisms, the degree of anisotropy and the separation of the major mechanical units. Following this, detailed quantitative data will be necessary. This will include the appropriate deformation moduli of the different mechanical units, their strengths and the variation of these with temperature and stress. In the case of the reservoir rock the dependence of porosity and permeability on stress and temperature must be determined. At this horizon, and in the immediate overburden, the thermal expansion coefficients must be determined.

Further data which will be necessary to the overall project, though not essential for the rock mechanism investigation, can be easily determined within the framework of this laboratory program. This will include the thermal conductivity of the reservoir and adjacent rocks and the coefficients of heat transfer between the aquifer rock and its pore fluid. As has already been implied all of these tests must be carried out over the ranges of stress, pore pressure and temperature relevant to the geopressured region. In themselves none of these tests raise any insurmountable problems. Many are fairly standard, though the base temperature and stress conditions required will involve some adaptations to normal techniques, and rather specialized equipment.

However, a great deal of data is required from probably few specimens. This can be partly overcome by using, where possible, similar material from other sites, particularly for the earlier more qualitative tests. Further saving of test material can be made if the equipment and test program are carefully designed to maximize the number of tests to be carried out on any single specimen, although care must also be taken that this maximization does not impair the validity of the final results.

Interdependence With the Fluid Flow Simulation.

There is a strong interdependence between the laboratory and model development program outlined above and the fluid flow simulation described elsewhere in this report. This applies particularly to the dependence of the fluid flow simulation on permeability data, and that of the mechanical behavior simulation on pressure data. Close meshing of the two programs is essential in this area.

Field Verification.

However comprehensive a modelling of the true situation is attempted the behavior of natural rock masses is so complex and varied that perfect simulation is impossible. In view of this an integral and essential part of any development of predictive techniques in this area is the field verification of early predictions and subsequent modification of the simulation to reflect these field data.

In the early stages some of this essential feedback may be obtained from field subsidence data from water producing shallow aquifers in the Gulf region. However, full feedback is essential from early geopressured reservoir developments. Field information on surface subsidence should certainly be obtained from these sites. Where feasible this should be supplemented by information on subsurface deformation, preferably at all levels between the reservoir and the surface, and by porosity and permeability data from the producing reservoir.

Techniques for monitoring surface subsidence are well established and should provide few problems in implementation. Similarly technqiues for monitoring subsurface behavior are available, though adaptation of these will probably be necessary to ensure compatibility with other necessary instrumentation and with well design.

PROJECTED RESEARCH COSTS

Appendix V presents a summary and outline of proposed geothermal geopressured aquifer rock mechanics research.

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PART 4

Aspects of Numerical Simulation Of Future Performance Of Geopressured Geothermal Reservoirs

BY

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ABSTRACT

Differential equations describing momentum and energy conservation in geopressured geothermal reservoirs are developed. Such reservoirs are known to be abundant in the Gulf Coast region of the United States. Effects considered in the development of these equations include heterogeneous and anisotropic porous media, water influx from adjacent compacting shales and clays, and reservoir rock compaction as a result of reservoir fluid withdrawal. The equations describe the behavior of the water and gas phases in the reservoir fluids and the behavior of the rock matrix. Constitutive equations describing the effects of pore pressure changes on reservoir parameters are also presented. The equations can serve as the basis for development of computer models of the geopressured geothermal reservoirs.

One such model is described. This model simulates momentum conservation of the water phase in geopressured reservoirs. Finite difference techniques are used to solve this equation. Simulation studies of a hypothetical geopressured reservoir demonstrate the difficulties of determining reservoir parameters from short term single well tests. However, they do indicate that such reservoirs are capable of sustaining fluid production for a number of years at significant rates.

CHAPTER I

INTRODUCTION

The energy crisis has resulted in an increased interest in the use of alternative energy sources for electric power generation. Geothermal energy is one of the most commonly mentioned supplements to existing and projected major sources of fuel. These sources can aid in bringing about a better balance between energy supply and demand and offer some important environmental advantages.

In addition to known areas of geothermal reserves in the western United States, a unique form of geothermal energy exists at moderate to great depths in geopressured aquifers underlying the United States Gulf Coast (see fig. 1, 2, and 3).

Water from such geopressured aquifers often contains natural gas in solution, which is a very important type of energy resource. The geothermal water itself can be easily converted into electrical energy after lowering the pressure to extract the natural gas content. The geohydraulic energy resulting from the high pressure with which fluid leaves the wellbore can itself be made to run turbines to generate electricity. Moreover, the fact that temperatures in geothermal reservoirs change very little with time makes geothermal geopressured reservoirs an extremely attractive source of geothermal energy, as there exists sufficient pressure in these reservoirs to deliver substantial amounts of fluid.

Preliminary geological studies into these geothermal geopressured aquifers have been in progress at the University of Texas, and results appear very promising.

GEOLOGY

Geopressured reservoirs are deep sedimentary basins filled with sand and clay or shale and are generally undercompacted below depths of 7,000 to 25,000 feet, and, as a result, the interstitial fluid pressure carries a part of the overburden load (see fig. 1, 2, 3, 4).

These reservoirs occur generally in regions where the normal heat flow of the earth is trapped by insulating impermeable clay beds in a rapidly

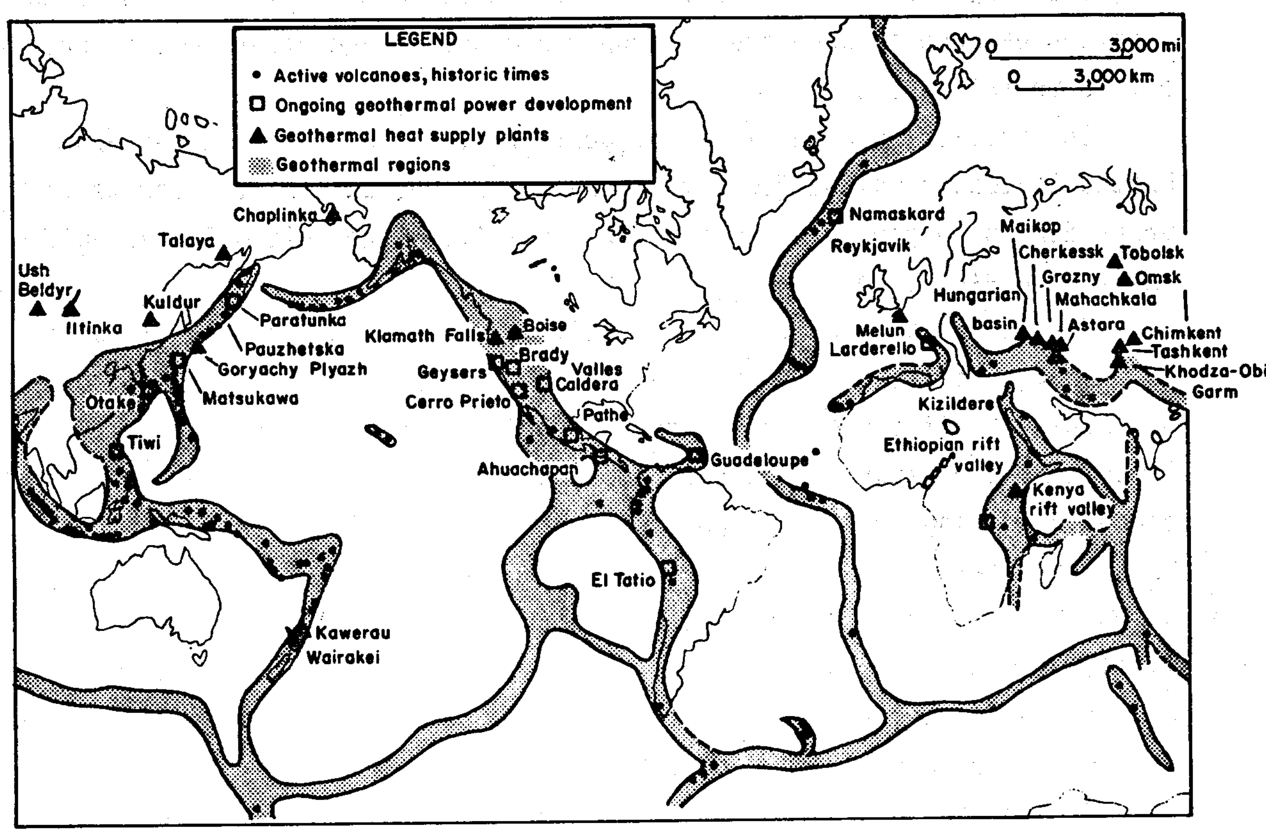


Figure 1 Geothermal regions of the world. After Dorfman,[12] 1974.

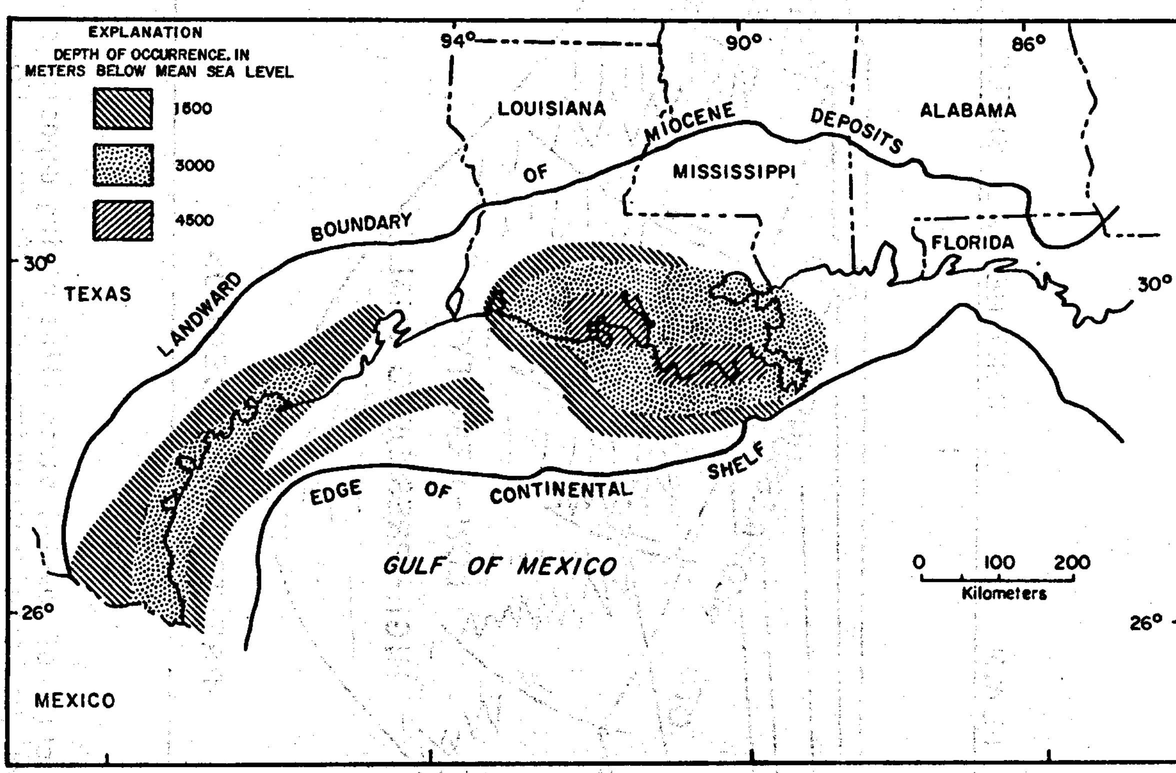


Figure 2 Location and depth of occurrence of the geopressured zone in the northern Gulf of Mexico basin. From Jones, 1969.

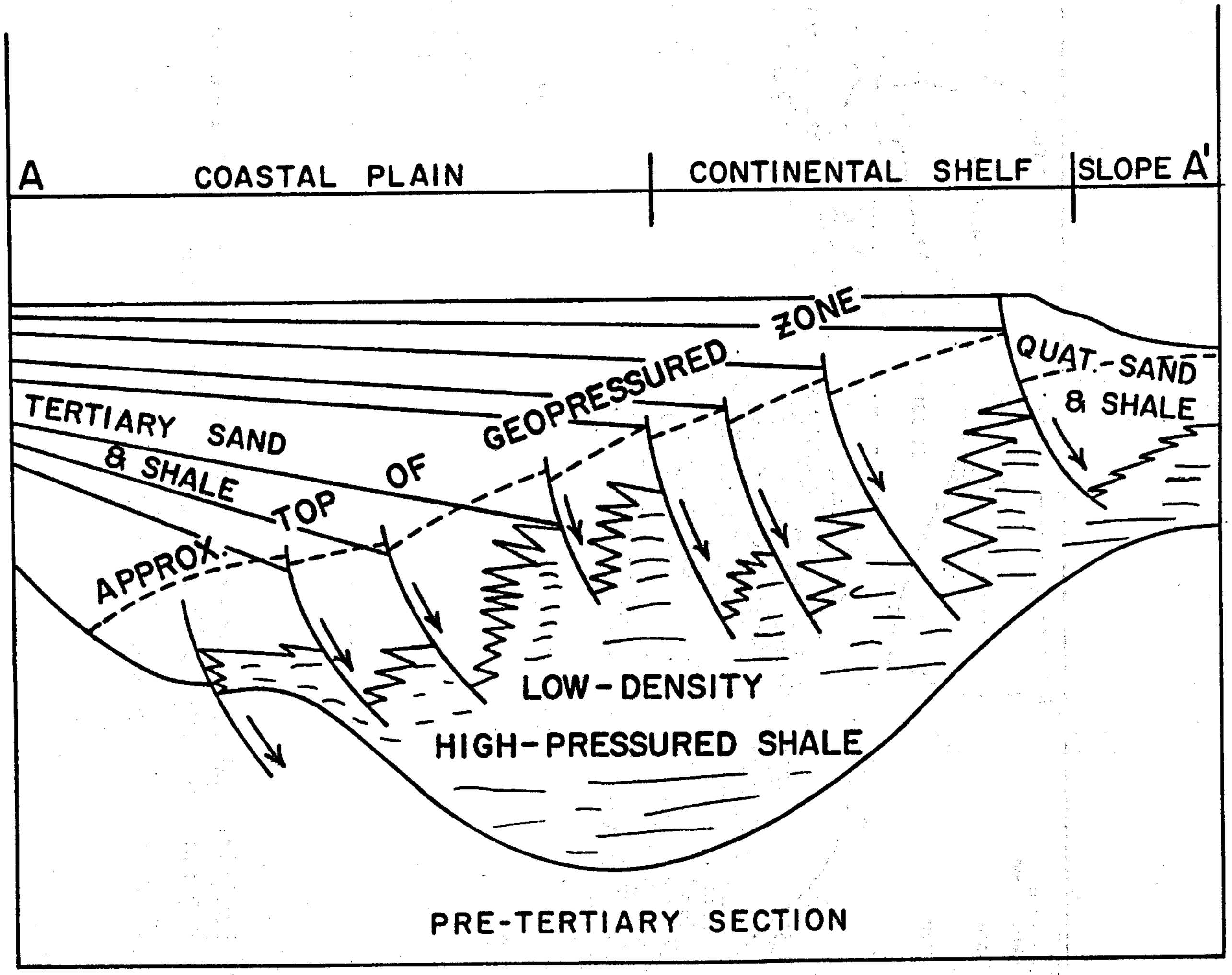


Figure 3 Cross section of coastal plain illustrating deposits of sand that form geothermal reservoirs. After Dorfman, 1974.

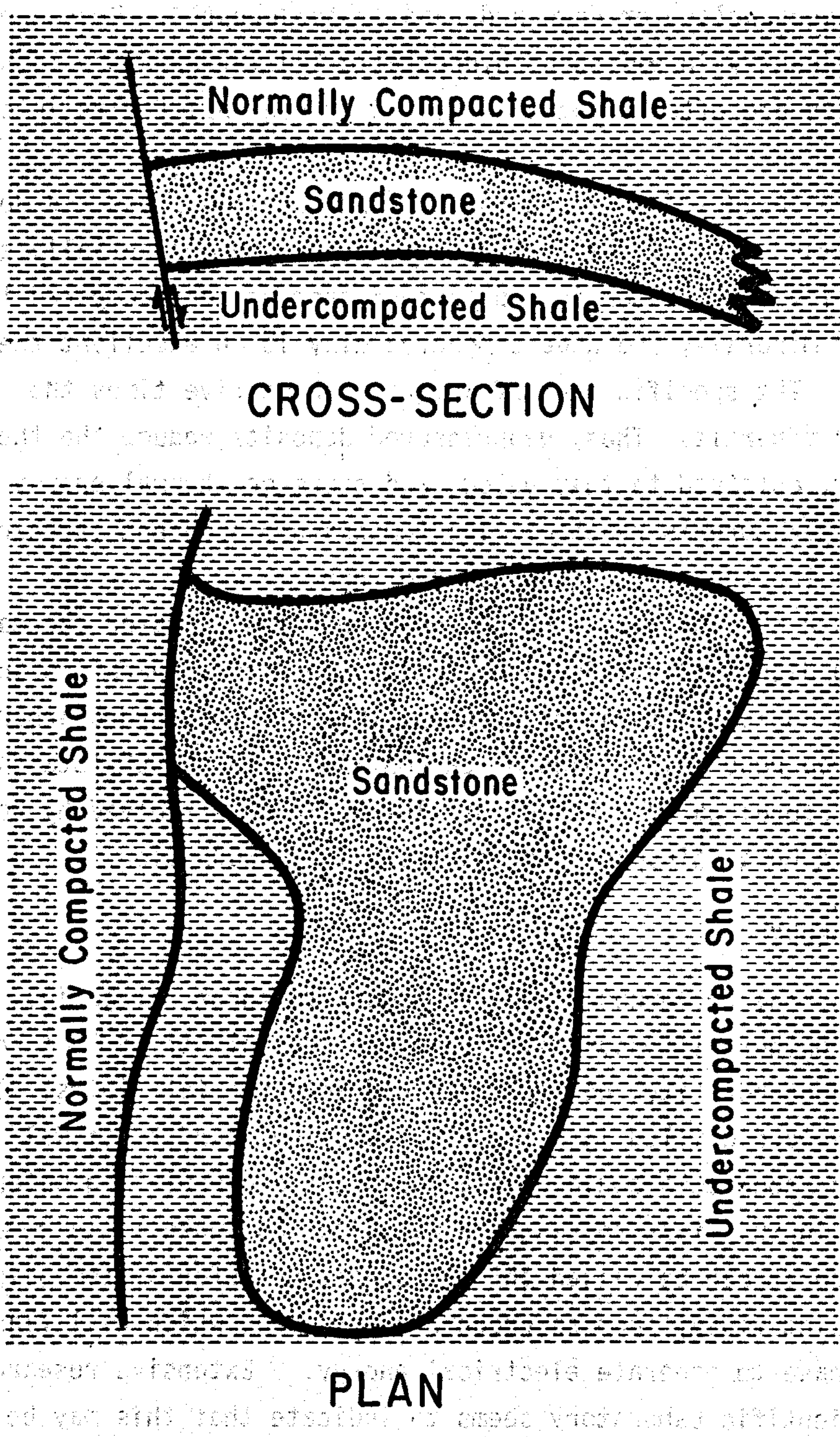


Figure 4. Cross section and plan view of a hypothetical geopressured reservoir.

subsiding geosyncline or downward bend of the crust[22]. Pressures at depth are significantly in excess of hydrostatic and may approach lithostatic. The aquifers are often compartmentalized by regional faults into horizontal blocks.

Geopressured deposits are hotter than normally pressured deposits because upward loss of the included water has been essentially stopped for millions of years. Water is a poor conductor of heat compared to the associated minerals, and undercompacted clay is an excellent thermal insulator. The specific heat of water is about five times that of the associated minerals. Thus, geopressured deposits reduce the thermal flux above them, compared to that below, and store geothermal energy until a steady temperature is reached. The temperature gradient is sharply increased at the top of the geopressured zone.

Because the solubility of hydrocarbon gases in water increases with decreasing dissolved solids, and because the high temperature and pressures have resulted in a natural cracking of the petroleum hydrocarbons, the geopressured reservoir fluids often contain 10 to 40 SCF (Standard Cubic Feet) of natural gas per barrel of fluid. These dissolved hydrocarbon gases would be a valuable by-product of fluid production.

GENERAL THEORY

Geothermal resources can be grouped into three categories; the first, man made geothermal resources. These include solidified "hot rocks" that are devoid of porosity, permeability and interstitial fluids. If, however, holes are drilled into these rocks using standard oilwell drilling techniques, the rocks could be fractured and a circulating water system installed in an effort to heat the water so that when it is returned to the surface it can be passed through a heat transfer system using a low boiling point fluid, such as Freon or isobutane, which will flash it into a vapor phase to generate electrical energy. Extensive research at Los Alamos Scientific Laboratory seems to indicate that this may be technically possible.

Another man made geothermal resource is by pressure drawdown of a natural geothermal resource which is accomplished by the reduction of interstitial fluid pressure in a hydrothermal reservoir and thus converting the water into steam. Examples of such reservoirs are the Larderello in Italy and the Wairakai hydrothermal system. This subgroup may appropriately belong to the second category of geothermal resources.

The second category of geothermal resources is the natural geothermal reservoirs. These include the steam system, an example being the Geysers Field north of San Francisco. Other geothermal resources that fall within this category are the hot brine systems being developed at the Salton Sea and Imperial Valley areas of southern California.

The third category is probably one of the most promising of geothermal resources and is the object of this research project. This is the combination (brine and gas) geothermal geopressured prospect (see fig. 4).

Sedimentary aquifers are generally grouped into two broad classes based on pore fluid pressures: hydropressures and geopressures. Hydropressure aquifers are those wherein the pore fluid pressures are generated by the effective weight of the overlying waters. They may be hydrostatic, hydrodynamic, or artesian. Pressure gradients are 43.3 psi/100 feet for fresh water. However, pressure gradients can significantly exceed this figure as the fluid becomes more saline. In geopressured reservoirs the pore fluid pressures are generated by a pressuring source greater than that for the hydropressures. If the reservoir is static, there is no fluid flowing in the system. The pressure gradient within the static system may still be 43.3 psi/100 feet for a fresh water (greater for saline water). Such reservoirs, however, are overlaid by a seal with a signficantly higher pressure gradient (see fig. 5). If such geopressured reservoirs are not under a static condition but have a small amount of upward flowing water essentially trapped by the seal above, the pressure gradient within the sand system could be significantly higher than that for the static gradient (see fig. 5 and 6).

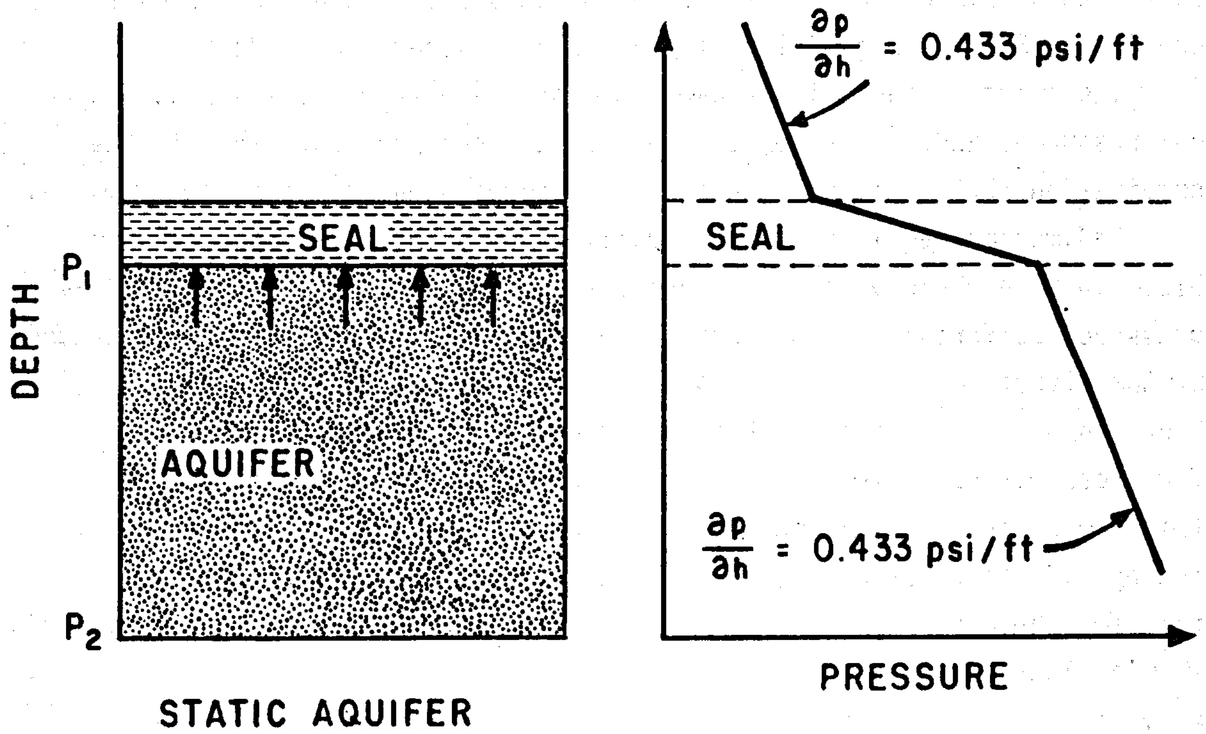


Figure 5. Static pressure representation of hypothetical geopressured reservoirs (schematic).

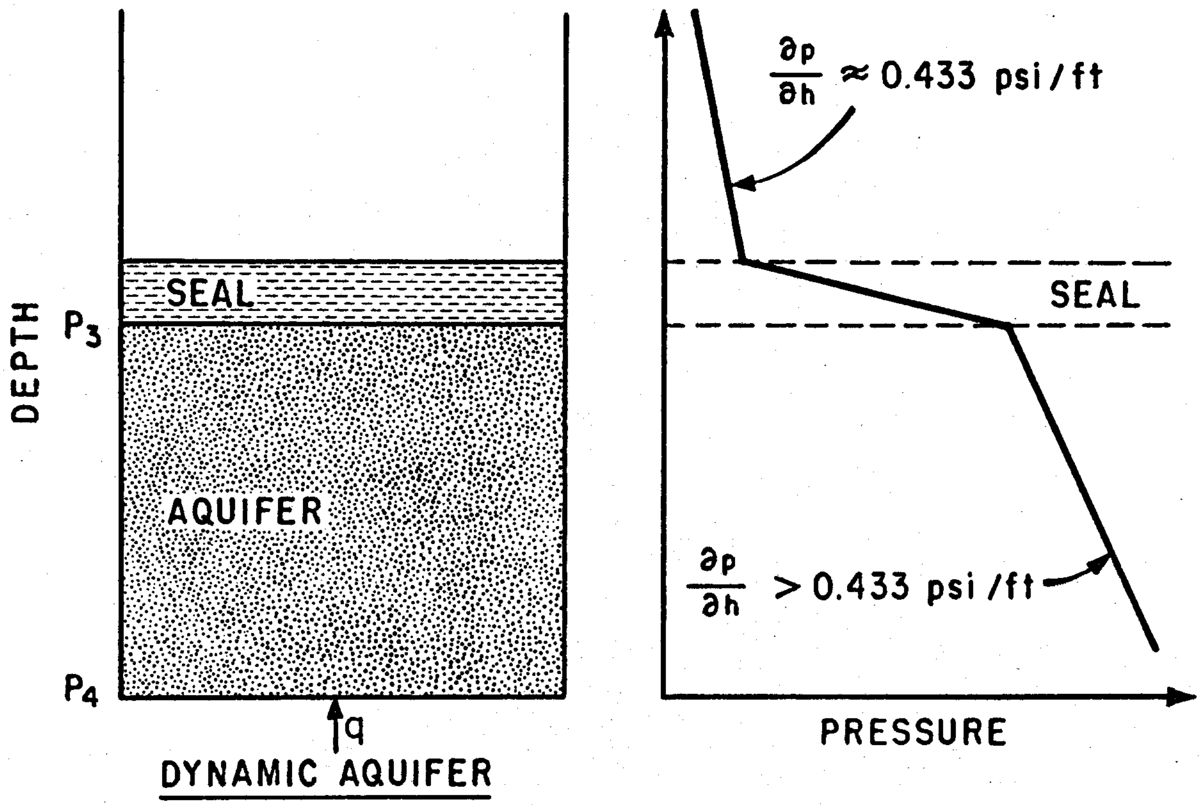


Figure 6. Hydrodynamic pressure representation of hypothetical geopressured reservoirs (schematic).

CHAPTER II

PREVIOUS WORK RELATING TO THE DEVELOPMENT OF NUMERICAL STUDY OF GEOPRESSURED GEOTHERMAL RESERVOIRS

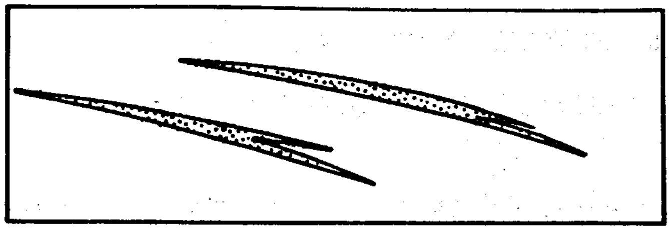
Dickinson[11] studied the geological aspects of abnormal reservoir pressures in the Gulf Coast of Louisiana and found that most of the superpressured reservoirs occur in: (a) sand lenses below the base of the main sand development in or below a major shale series; (b) large reservoirs sealed updip by faulting down against thick shale series and sealed downdip by regional facies change; or (c) relative position of fault seals in upthrown and downthrown blocks (see fig. 7). Timko[35] found that most of these reservoirs do contain gas in solution.

Duggan[13], Wallace[37], and Harvile and Hawkins[21] gave possible explanations for the difference between volumetric calculations of initial gas in place in superpressured reservoirs and extrapolated p/z (or pressure) data. Some of their explanations were: (a) shale dewatering; (b) change in reservoir compressibility; and (c) other possible sources of water influx. Wallace[37] further advanced the theory of shale dewatering. The idea of changes in rock compressibility and porosity during reservoir depletion was first presented by Hall[20].

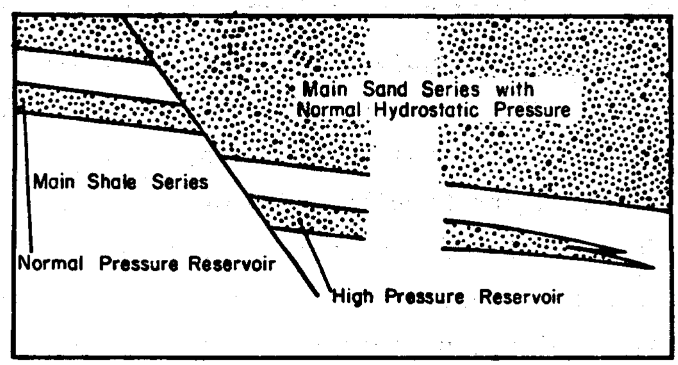
Fatt and Davis[14] found that an increase in overburden pressure results in a reduction of absolute permeability. Young, et al.[39] reported a substantial permeability reduction at only 1595 psi effective overburden pressure.

Dickey[10] and Dorfman and Kehle[12] stated that abnormally high fluid pressures result when interstitial formation waters are trapped during burial and subsequent basin subsidence. Dorfman and Kehle[12] also stated that these abnormally pressured zones are found throughout the world in moderate to high depths. The best documented basin containing these geothermal geopressured zones is the Gulf Coast Basin of the United States and Mexico.

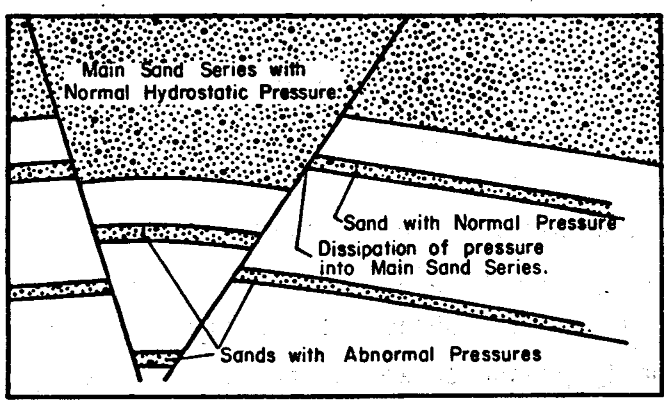
There have been a number of studies that have concentrated on the theoretical analysis of reservoir compaction, which is an important consideration in modelling undercompacted reservoirs.



SMALL RESERVOIR SEALED BY PINCHOUT
(A)



LARGE RESERVOIR SEALED UPDIP BY FAULTING DOWN AGAINST THICK SHALE SERIES, SEALED DOWNDIP BY REGIONAL FACIES CHANGE.
(B)



RELATIVE POSITION OF FAULT SEALS IN UPTHROWN AND DOWNTHROWN BLOCKS
(C)

Figure 7 Types of reservoir seals necessary to preserve abnormal pressure. From Dickinson, 1968.

Biot[3] first presented the general theory of three dimensional consolidation. He later developed a theory of elasticity and consolidation for a porous anisotropic solid.[4] In that study, he presented several deformation constants for reservoir rocks which unfortunately, are impossible to determine experimentally.

Van der Knapp[35] presented an analysis of nonlinear behavior of elastic porous media. This was an experimental as well as theoretical analysis of changes in reservoir volume due to change in pore and overburden pressures. This enables direct calculation of the effect of large increments in stresses on the behavior of porous rocks.

Teeuw[38] presented laboratory testing procedures of compaction, both in cemented and friable rocks. He made an analysis of measuring techniques and concluded that the interpretation of these experimental techniques is complicated by nonlinear compaction behavior of porous rocks. He then derived theoretical expressions that interrelate uniaxial and hydrostatic compaction which enables the prediction of in situ reservoir compaction from hydrostatic cell compaction data. This relation was then verified for various types of rock by comparative measurement in oedometer and hydrostatic cells.

Several studies have been made that are useful for aiding in the development of a numerical model to simulate geopressured geothermal reservoirs. Raats and Klute studied fluid transport in soils and developed mass balance equations[31] and momentum balance equations[32]. Pinder and Bredehoeft[29] presented the application of digital computers for aquifer evaluation. Pinder and Frind[30] later used the Galerkin technique to simulate aquifers.

Mercer[28] used the finite element approach to simulate the Wairakai, New Zealand hydrothermal system. He used partial differential equations describing heat and momentum transport for a single fluid phase in two dimensions. Finol and Ali[16] developed two phase simulators for two dimensional oil and gas flow in a compacting reservoir, utilizing Geertsma's theory. They adapted a rectangular system for predicting ground subsidence.

Bourgoyne et al.[5] presented a one phase, one dimensional fluid equation used in the study of shale water as a pressure support mechanism in superpressured reservoirs.

All the above mentioned studies are useful in aiding the development of geothermal geopressured models. There is, however, no study known that deals with the numerical simulation of geothermal geopressured reservoirs. Such a model should be able to incorporate the hydrologic behavior of the shales and the thermal behavior of the fluids in the geothermal aquifer. Since the geopressured geothermal aquifer is concerned with an undercompacted formation, reservoir properties will vary greatly with pore pressure. Further, models of such systems need to be constructed so that they can be used to estimate the ultimate recovery of useful energy (geothermal, natural gas, and geohydraulic) from the aquifers, to design well tests for pilot wells, to make 'cooled' water reinjection feasibility analyses and to make subsidence studies. This study is aimed at developing the bases for such models.

CHAPTER III

MATHEMATICAL MODEL OF GEOPRESSURED GEOTHERMAL AQUIFERS

The formulation of a reservoir simulator follows a straight forward but sometimes tedious process. First, mass and energy balance equations are written for each phase present. These are combined with momentum balance equations to develop general equations of momentum conservation. Next equations of state describing the pressure, volume, and temperature behavior of the fluids are introduced to reduce the number of primary variables. Similar equations are introduced to describe the effects of pore pressure changes on the rock matrix properties. Finally, equations describing interphase relationships are introduced to couple the resulting partial differential equations. Simplifying assumptions are introduced where appropriate.

ASSUMPTIONS

In developing a mathematical model for geothermal and geopressured reservoirs, a thorough understanding of the geology and reservoir mechanics is important. Some important considerations and assumptions are:

1. The reservoir will be assumed to be saturated with hot high pressured water with gas in solution with or without a free gas cap
2. The reservoir is surrounded everywhere by semipermeable heat conducting, undercompacted shales (except at the top, where shale permeability is negligible, and shales have very low thermal conductivity) (see fig. 4)
3. Reservoir compaction is assumed to be a function of pore pressure
4. Formation porosity, permeability and density, fluid densities and viscosities are assumed to be functions of temperature and pressure
5. Stratification, gravity and capillary pressure effects are included. The pressure and temperature variations of relative permeabilities are considered.

6. A two-phase flow (water, gas/gas in solution) equation is considered, with free gas flowing only if temperature and pressure permit. A heat transport equation is needed to obtain temperature distributions during the productive life of the reservoir.
7. As production continues, there will be a water influx from the surrounding shales into the reservoir. If these shales are saturated with gas which becomes free as pressure declines, shale permeability will be reduced.

BALANCE LAWS FOR DEFORMABLE, ANISOTROPIC RESERVOIRS

Mass

Rock Matrix

$$-\frac{\partial}{\partial z}\left[\bar{V}_{rm}\rho_{rm}(1-\phi)\right] = \frac{\partial}{\partial t}\left[\rho_{rm}(1-\phi)\right] \tag{1}$$

Water

$$-\nabla\cdot\left(\rho_w\bar{V}_w\right)+q_w=\frac{\partial}{\partial t}\left(\rho_w\phi S_w\right)+\nabla\cdot\left(\rho_w\phi S_w\bar{V}_{rm}\right) \tag{2}$$

Gas

$$-\nabla\cdot\left(\rho_g\bar{V}_g+\rho_w\bar{V}_wR_{sw}\right)+q_g=\frac{\partial}{\partial t}\left(\phi\rho_gS_g+\rho_wS_wR_{sw}\phi\right)+$$

$$\left[\left(\nabla\cdot\quad\rho_w\phi S_wR_{sw}+\rho_g\phi S_g\right)\bar{V}_{rm}\right] \tag{3}$$

In the above three equations the mass balance has been transformed from the cartesian coordinate system to the comoving coordinate system of the solid phase.

Where:

$\bar{V}_{rm}$ = Rock matrix microscopic velocity, ft^3/day-ft^2

ρ = Density, lb-mass/ft^3

ϕ = Porosity, fraction

V = Apparent velocity, bbl/day-ft^2, or ft^3/day-ft^2 for gas

q = Injection/production rate, positive for injection bbl/day for water, ft^3/day for gas

S = Saturation, fraction

R_{sw} = Gas solubility in water (lbs/lbs)

t = Time, days

z = z direction, ft.

∇ = Del operator in fixed coordinates.

and the subscripts:

w = Water

g = Gas

rm = Rock matrix

Energy

Rock Matrix

$$\rho_{prm} \frac{DU_{rm}}{Dt} = - \nabla \cdot \bar{\bar{K}}_{rm} + C_{prm} H_{rm} \tag{4}$$

Water

$$\rho_{pw} \frac{DU_w}{Dt} = - \nabla \cdot \bar{\bar{K}}_w + C_{pw} H_w + q_w \left(U_g^* - U_w\right) \tag{5}$$

Gas

$$\rho_{pg} \frac{DU_g}{Dt} = - \nabla \cdot \bar{\bar{K}}_g + C_{pg} H_g + q_g \left(U_g^* - U_g\right) \tag{6}$$

Where:

U = Internal energy per unit mass ($L^2 t^2$)

C_p = Compressibility coefficient, psia^{-1}

H = Heat source strength, BTU/D-ft^3

Constitutive Relations for the Energy Equations:

$$
\begin{aligned}
\rho_p &= \phi S_f \rho_f \\
\rho_{prm} &= (1-\phi)\rho_{rm} \\
U_f &= C_{vf}T_f \\
U_{rm} &= C_{vrm}T_{rm} \qquad (7) \\
\bar{\bar{K}}_{rm} &= -(1-\phi)\ \bar{K}_{rm} \cdot \nabla T_{rm} \\
\bar{\bar{K}}_f &= -\phi S_f K_f \cdot \nabla T_{rm} \\
qU^* &= 0 \text{ (leakage is negligible during production)}
\end{aligned}
$$

Where:

f = Water or gas

$\bar{K}$ = Thermal conductivity, BTU/D-ft-^{o}F

T = Temperature, ^{o}F

C_{vrm}, C_{vf} = Heat capacity of rock matrix and fluid respectively, at constant volume, per unit mass ($L^2t^{-2}T^{-1}$)

DARCY'S LAW FOR ANISOTROPIC POROUS MEDIA

For the water phase

$$\bar{V}_w = -\frac{K_{rw}}{\mu_w}\ K\ \ (\nabla p_w - \rho_w \bar{g} \nabla h) \tag{8}$$

For the gas phase

$$\bar{V}_g = -\frac{K_{rg}}{\mu_g}\ K\ \ (\nabla p_g - \rho_g \bar{g} \nabla h) \tag{9}$$

Where:

- P = Pressure, psia
- $\bar{g}$ = Acceleration due to gravity, ft/sec^2
- h = Depth below a reference datum, ft.
- K_r = Relative permeability, fraction
- K = Absolute permeability tensor, (Darcy x 1.127)
- μ = Viscosity, cp

Using the above assumptions, the balance laws, constitutive relations and Darcy's Law are combined to obtain the equations describing the behavior of geopressured geothermal aquifers. (For detailed mathematical procedures see Isokrari[24].)

FINAL EQUATIONS

The momentum transport equation for the water phase

$$\bar{\nabla} \cdot \rho_w \frac{K_{rw}}{\mu_w} K (\bar{\nabla} \cdot p_w - \rho_w \bar{g} \bar{\nabla} h) + \rho_{wsc} q_w = \left(\phi S_w \left(\frac{\partial \rho_w}{\partial P}\right)_T + (\rho_w S_w) \cdot \left(C_m + C_{rm} (1-\phi)\right)\right) \frac{\partial P_w}{\partial t} + (\phi \rho_w) \frac{\partial S_w}{\partial t} + \left((1-\phi)\rho_{rm} C_{Trm} + \phi S_w \left(\frac{\partial \rho_w}{\partial T}\right)_P\right) \frac{\partial T}{\partial t} \quad (10)$$

And for the gas phase

$$\bar{\nabla} \cdot \left(\rho_g \frac{K_{rg}}{\mu_g} K (\nabla P_g - \rho_g g \bar{\nabla} h) \right) + \bar{\nabla} \left(\rho_w \frac{K_{rw}}{\mu_w} R_{sw} K \left(\bar{\nabla} P_w - \rho_w g \bar{\nabla} \bar{h} \right) \right)$$

$$\rho_{wsc} q_w R_{sw} + \rho_{gsc} q_g = \left[\phi S_g \left(\frac{\partial \rho_g}{\partial p} \right)_T + \phi S_w R_{sw} \left(\frac{\partial \rho_w}{\partial P} \right)_T + \right.$$

$$\left. (\rho_w S_w R_{sw} + \rho_g S_g) \cdot (cm + c_{rm} (1-\phi)) \right] \frac{\partial P}{\partial t} + (\phi \rho_g) \frac{\partial S_g}{\partial t} +$$

$$(\rho_w R_{sw} \phi) \frac{\partial S_w}{\partial t} + (\phi \rho_w S_w) \frac{\partial R_{sw}}{\partial t} + \left((1-\phi) \rho_{rm} C_{Trm} + \right.$$

$$\left. \phi \left(S_w R_{sw} \left(\frac{\partial \rho_w}{\partial T} \right)_P + S_g \left(\frac{\partial \rho_g}{\partial T} \right)_P \right) \right) \frac{\partial T}{\partial t} \qquad (11)$$

Where:

$\bar{\nabla}$ = Del operator in deforming coordinates

The fluid movement in the porous medium is slow and the surface area of the rock matrix is large so the fluids and the rock will be in thermal equilibrium. Therefore, the equation of energy transport is:

Volume III:

1. Page 124, Equation (12) should read:

$$\left((1-\phi) \rho_{rm} C_{vrm} + \left(S_g \rho_g C_{vg} + (1 + R_{sw}) \rho_w S_w C_{vw} \right) \phi \right) \frac{\partial T}{\partial t} +$$

$$\left[(\phi \rho_w S_w C_{vw} \bar{V}_w) + \phi (S_g \rho_g C_{vg} \bar{V}_g + S_w \rho_w R_{sw} C_{vw} \bar{V}_w) \right] \cdot \nabla T =$$

$$\nabla \left[S_g K_g + (1+R_{sw}) \cdot (\phi S_w K_w) + (1-\phi) K_{rm} \right] \cdot \nabla T + q_w C_{vw} T +$$

$$q_g C_{rg} T + \left[S_g \rho_g + (1+R_{sw}) \rho_w S_w + \rho_{rm} (1-\phi) \right] H$$

Equations (10), (11), and (12) are mathematical statements of the processes of heat and momentum transport in a geopressured geothermal reservoir. Several other constitutive relationships of the fluid and rock properties and initial and boundary conditions must be added to complete the mathematical statement of heat and mass transfer in a geopressured geothermal reservoir.

CONSTITUTIVE RELATIONS FOR THE ROCK MATRIX

Porosity

Hubert and Rubey[23] indicate that as geopressured reservoirs are produced, the pressure in the adjacent undercompacted shales decreases and the shales compact to a porosity appropriate for their depth. Undercompacted sandstones and siltstones are known to have similar characteristics. The change in porosity during the depletion of geopressured reservoirs must, therefore, be evalated using the balance law for a deformable rock matrix, equation (1).

$$-\frac{\partial}{\partial z}\left[\bar{V}_{rm}\rho_{rm}(1-\phi)\right] = \frac{\partial}{\partial t}\left[\rho_{rm}(1-\phi)\right] \tag{13}$$

Expanding equation (13), applying the chain rule on $\partial\rho_m/\partial t$ and $\partial\rho_{rm}/\partial_z$, collecting like terms, and dividing by ρ_{rm} gives:

$$\frac{\partial\phi}{\partial t} + (V_{rm})\frac{\partial\phi}{\partial z} = \left[\left((1-\phi)\frac{1}{\rho_{rm}}\left(\frac{\partial\rho_{rm}}{\partial P}\right)_T\left(\frac{\partial P}{\partial t} + V_{rm}\frac{\partial P}{\partial z}\right)\right)\right] + \left[(1-\phi)\frac{1}{\rho_{rm}}\left(\frac{\partial\rho_{rm}}{\partial T}\right)_P\left(\frac{\partial T}{\partial t} + V_{rm}\frac{\partial T}{\partial z}\right)\right] + (1-\phi)\frac{\partial V_{rm}}{\partial z} \tag{14}$$

The application of the chain rule in equation (14) assumes that change in rock matrix density is a function of pressure and temperature.

The application of the chain rule in equation (14) assumes that change in rock matrix density is a function of pressure and temperature.

We can now define:

$$C_{rm} = \frac{1}{\rho_{rm}} \left(\frac{\partial \rho_{rm}}{\partial P}\right)_T \tag{15}$$

$$C_{Trm} = \frac{1}{C_{rm}} \left(\frac{\partial \rho_{rm}}{\partial T}\right)_P \tag{16}$$

Where C_{rm} is the unit change in the density of rock matrix per change in pore pressure (psi^{-1}), and C_{Trm} is the coefficient of thermal volume expansion for the rock matrix (T^{-1}).

Incorporating equations (15) and (16) and taking the material derivative of equation (14) yields:

$$\frac{D\phi}{Dt} = (1-\phi)\, C_{rm}\, \frac{DP}{Dt} + (1-\phi)\, C_{Trm}\, \frac{DT}{Dt} + (1-\phi)\, \frac{\partial V_{rm}}{\partial z} \tag{17}$$

Evaluation of $\frac{\partial V_{rm}}{\partial z}$:

A porous medium containing compressible fluids that is deforming in the vertical plane in response to a change in interstitial fluid pressure has a vertical compressive stress, σ_z, on the medium at a point near the center of the moving element. As the pressure changes, the weight of the solid material above this point remains constant, while the volume and density of the fluid above this point change. The changes in volume and density are so small that the rate of change in compressive stress σ_z is almost equal and opposite to that of the fluid. Thus:

$$\frac{DP}{Dt} = - \frac{D\sigma_z}{Dt} \tag{18}$$

where equation (18) is a material derivative since the rock matrix is moving as a result of the vertical deformation, which can be evaluated using the linear theory of elasticity:

$$e_z = C_m \, dp \tag{19}$$

"dp" is the reduction of pore pressure and C_m is the uniaxial compaction coefficient ($psia^{-1}$) which is defined as the formation compaction per unit change in pore volume. C_m is therefore a function of pressure, but could assume a constant value within a given range of reservoir pressure.

The reduction in reservoir thickness can, therefore, be defined as:[18]

$$\Delta\bar{z} = C_m \, \Delta P L_z \tag{20}$$

where L_z is the height of the productive interval. Accordingly, $\Delta\bar{z}$ varies with stress.

$$\frac{d(\Delta\bar{z})}{\Delta\bar{z}} = -C_m \, d\,\sigma_z \tag{21}$$

Therefore, the relative change in thickness is related to the rate of change of stress, σ_z, and pore pressure, P, by:

$$\frac{1}{\Delta z}\,\frac{D(\Delta\bar{z})}{Dt} = -C_m \frac{D\sigma_z}{Dt} = C_m \frac{DP}{Dt} \tag{22}$$

The grain velocity can, therefore, be defined in terms of pressure by:[7]

$$\nabla \cdot V_{rm} = \frac{\partial V_{rm}}{\partial z} = C_m \frac{DP}{Dt} \tag{23}$$

Substitution of equation (23) into equation (17) yields

$$\frac{D\phi}{Dt} = (1-\phi)\, C_{rm} \frac{DP}{Dt} + (1-\phi)\, C_{Trm} \frac{DT}{Dt} + (1-\phi)\, C_m \frac{DP}{Dt} \tag{24}$$

collecting terms we have

$$\frac{D\phi}{Dt} = (1-\phi)\ (C_{rm} + C_m)\ \frac{DP}{Dt} + (1-\phi)\ C_{Trm}\ \frac{DT}{Dt} \tag{25}$$

In a porous medium, the velocity of the rock matrix is very small and in fact negligible; therefore, the material derivatives can be approximated by the partial time derivative[21] in the above equation and the error introduced will be negligible. Thus equation (25) becomes:

$$\frac{\partial\phi}{\partial t} = (1-\phi)\ (C_{rm} + C_m)\ \frac{\partial P}{\partial t} + (1-\phi)\ C_{Trm}\ \frac{\partial T}{\partial t} \tag{26}$$

If the derivatives of equation (26) are replaced by their standard difference analogies and the result is multiplied by Δt we obtain:

$$\phi^{n+1} = \phi^n + (1-\phi^n)\ (C_{rm} + C_m)\ (P^{n+1} - P^n) +$$
$$+ (1-\phi^n)\ C_{Trm}\ (T^{n+1} - T^n) \tag{27}$$

Permeability

During the depletion of reservoirs, there is a decline in permeability as the pore pressure decreases and the rock matrix supports more of the overburden. Mclatchie, Hemstock, and Young[27] show that there is a significant decrease in sandstone permeability as the effective pressure differential increases. Similar results were obtained by Young et al.[38] with siltsone.

This change in permeability must, therefore, be accounted for in simulating a geopressured reservoir. In this study we account for this change using the following empirical relationship:

$$K^{n+1} = K^n \left[1.0 + \left(\frac{C_m + C_{rm}}{1-\phi^n}\right)(P^{n+1} - P^n) + \left(\frac{C_{Trm}}{1-\phi^n}\right)(T^{n+1} - T^n)\right] \quad (28)$$

Thermal Conductivity and Heat Capacity

The rate of heat removal in a geopressured geothermal system depends heavily on the formation permeability, fluid and rock thermal conductivities, and relative permeabilities of the water and gas in the formation. Like most other properties that have been discussed in this chapter, thermal conductivity is a function of temperature and pressure. From published materials in the literature, the effect of temperature on thermal conductivity appears to be more critical than the effect of pressure. Anand et al.[2] present a correlation to determine the thermal conductivity at a given temperature.

$$\lambda_T = \lambda_{68^o} - 0.709 \times 10^{-3}(T-528)(\lambda_{68^o} - 0.800) \cdot \left[\lambda_{68^o}(0.001T)^{0.545\lambda_{68^o}} + 0.738\right] \quad (29)$$

Where:

λ_T = Thermal conductivity of dry rock at temperature; T, BTU/hr-ft-^oF (different from $\bar{K}$ of equation (7) which is in BTU/D-ft-^oF)

λ_{68^o} = Thermal conductivity at 68^o F

T = Temperature, $^oR = ^oF + 460$

For rock saturated with fluid, Anand et al.[2] gave an empirical equation:

$$\frac{\lambda_{rm_T}}{\lambda_T} = 1.0 + 0.299\left[\left(\frac{\lambda_w}{\lambda_{air}}\right)^{0.330} - 1\right] + 4.57\left[\frac{\phi}{(1-\phi)}\frac{\lambda_w}{\lambda_T}\right]^{0.48m}\left(\frac{\rho_B}{\rho_{BD}}\right)^{-4.30} \quad (30)$$

Where:

λ_{rm_T} = Thermal conductivity of fluid saturated rock

λ_w = Thermal conductivity of water

λ_T = Thermal conductivity of dry rock

λ_{air} = Thermal conductivity of air

ρ_B = Bulk density of saturated rock

ρ_{BD} = Bulk density of dry rock

m = Cementation factor

Because water represents almost all of the fluid mass in geopressured reservoirs, equation (30) will be accurate without correcting for the gas phase.

In equation (30), the effect of pressure is shown by the presence of porosity and density terms which are pressure dependent.

Martin and Dew[26] presented a rough approximation of heat capacity as a function of temperature:

$$C_p = \frac{T + 2000}{10,000} \tag{31}$$

Where:

T = Temperature, ^oF

C_p = Heat capacity of reservoir rock, BTU/lb-^oF

Uniaxial Compaction Coefficient

The uniaxial compaction coefficient can be evaluated from laboratory compressibility data[19, 34], using the equation:

$$C_m = \frac{1}{3}\left(\frac{1 + v}{1 - v}\right)(1-B)\ C_b \tag{32}$$

Where:

B = Ratio of rock matrix and rock bulk compressibilities

v = Bulk Poisson's ratio

c_b = Hydrostatically determined bulk compressibilities

Reservoir Compaction

Reservoir compaction during production is computed using Geertsma's equation:[18]

$$\Delta\bar{z} = C_m \Delta P L_z \tag{33}$$

Where:

C_m = Coefficient of uniaxial compaction, psia^{-1}

ΔP = Change in reservoir pressure, psia

L_z = Reservoir thickness, ft.

It may be noted that equation (33) assumes ideal reservoir conditions and is therefore simplified. However, reservoir compaction can represent a significant source of depletion drive energy for the geopressured reservoirs. Geertsma's[18] equation (33) provides a satisfactory method of representing this drive in a fluid flow simulator. The properties of C_m can be varied with pressure, temperature and lithology to increase the applicability of equation (33).

Compressibilities

During the depletion of geopressured reservoirs, the bulk volume of the rock decreases, while the volume of the solid matrix increases. The increase of solid matrix volume results in a decrease of rock matrix density. This fractional change in the density of the solid rock material (without pores) per unit change in uniform pressure is the rock matrix compressibility.

For simplicity we define it in this study as:

$$C_{rm} = \frac{1}{\rho_{rm}} \left(\frac{\partial \rho_{rm}}{\partial P} \right)_T \tag{34}$$

Other kinds of rock compressibility under isothermal conditions should be distinguished:[19]

$$C_f = \frac{1}{V_p} \left(\frac{\partial V_p}{\partial p} \right)_{\sigma,T} \tag{35a}$$

$$C_b = \frac{-1}{V_b} \left(\frac{\partial V_b}{\partial \sigma} \right)_{P,T} \tag{35b}$$

Elsewhere in the literature C_f has been referred to as $\frac{1}{\phi}\frac{d\phi}{dp}$, but it can be readily shown that this expression is equal to $C_f - C_b$.

CONSTITUTIVE RELATIONS FOR FLUID

For a complete mathematical statement we must relate pressures in each phase of equations (10) and (11) by the capillary pressure:

$$P_c = P_g - P_w \tag{36}$$

which is taken to be a function of water saturation alone.

Thus:

$$\frac{\partial P_{cgw}}{\partial x} = \frac{\partial Pg}{\partial x} - \frac{\partial Pw}{\partial x} \tag{37}$$

We also consider the relation that the phase saturations sum to unity; thus:

$$S_w + S_g = 1.0 \tag{38}$$

Velocity

The assumption of Darcy's Law assumes that the fluid velocities are small (Reynolds number <10). Average fluid velocities can be estimated as:

Water Velocity

$$V_w = \frac{-K_{rw}K}{\phi S_w \mu_w} (\nabla P_w - \rho_w g \nabla h) \tag{39}$$

Gas Velocity

$$V_g = \frac{-K_{rg}K}{\phi(1.0-S_w)\mu_g} (\nabla P_g - \rho_g g \nabla h) \tag{40}$$

where P_w and P_g are related by the capillary pressure as defined in equation (36).

Solubility of Hydrocarbon Gas in Water

The solubility of the hydrocarbon gas components in water is inversely proportional to their molecular weights[6]. Thus, methane is more soluble than ethane, ethane than propane, etc. The solubility of methane in water can be used to estimate the solubility of natural gas in geopressured water with an error of less than 2%.

Under conditions of increasing pressure, water will absorb available gas into solution. Conversely, gas will evolve from a saturated water under conditions of decreasing pressure. The composition of the liquid and gas phases is a vapor-liquid equilibrium problem. However, experimental and empirical methods exist by which the solubility of gaseous hydrocarbon in water can be determined[8,9,1](see fig. 8 and 9). Though more detailed study is needed in this area, the available studies can be used in our reservoir model studies.

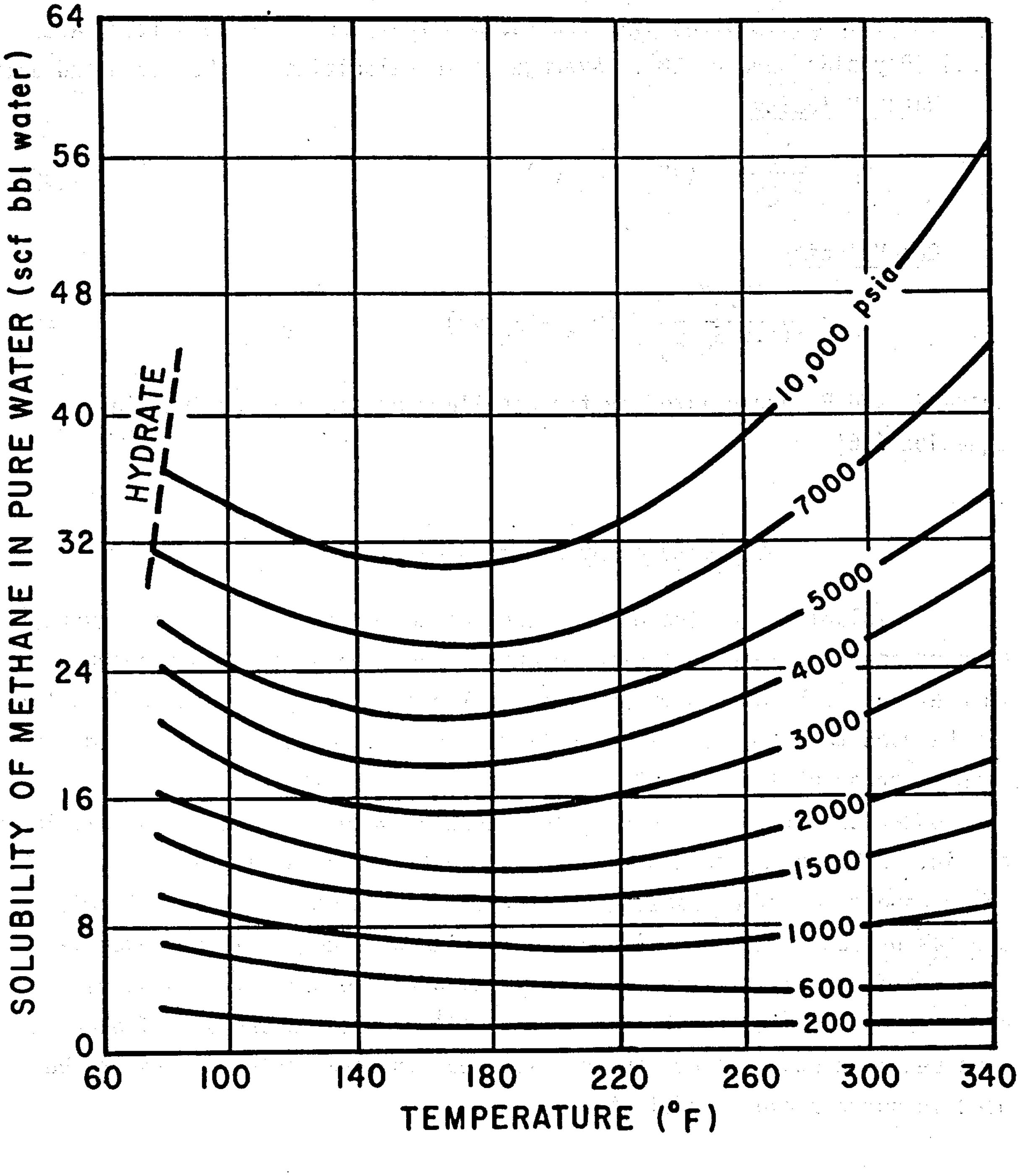


Figure 8. Solubility of methane in pure water. After Culberson and McKetta, 1951.

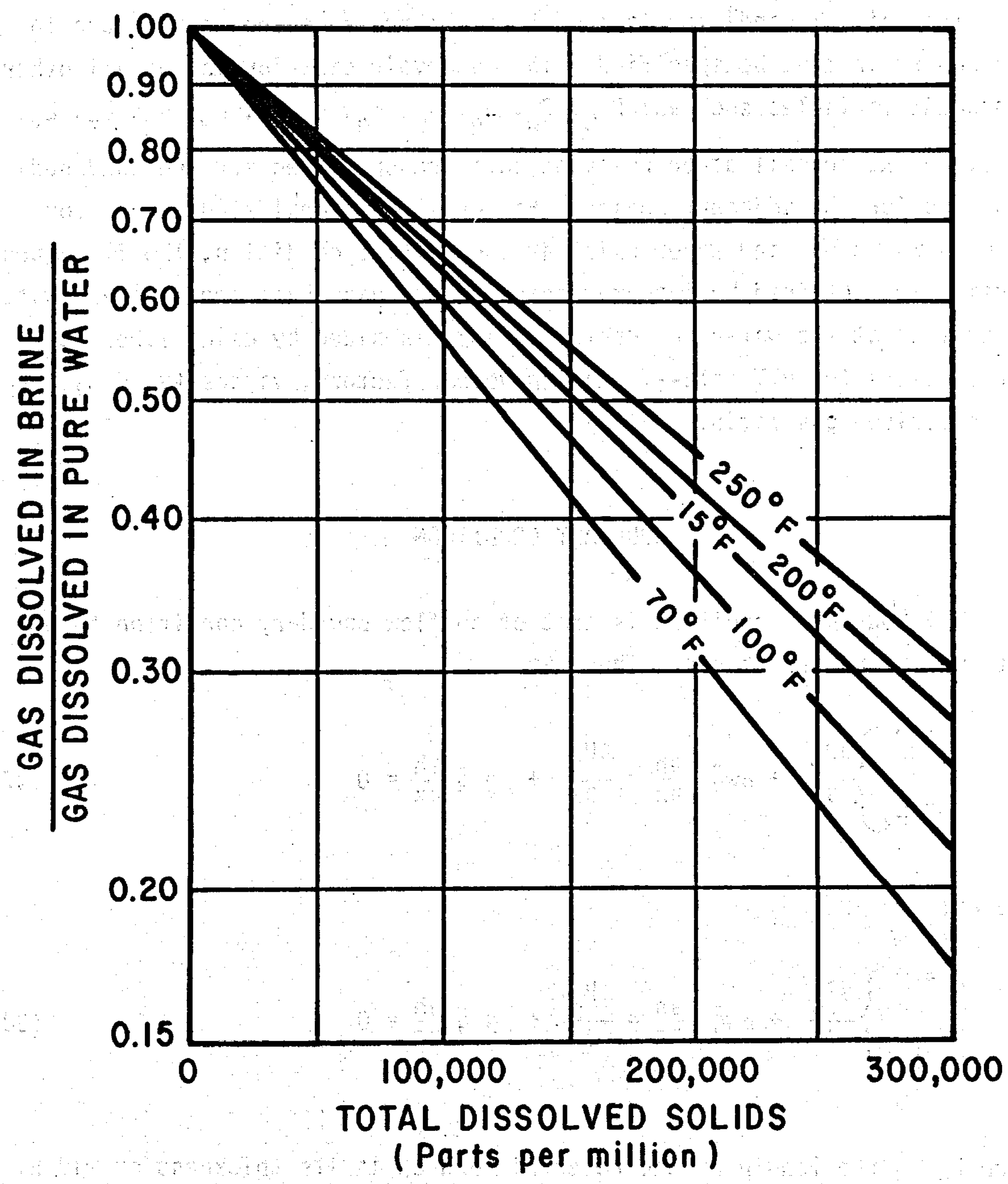


Figure 9. Effect of salinity on the amount of gas in solution when fully saturated with gas. From Brill, 1975.

INITIAL CONDITION

The initial condition is such that the pressure and temperature in the reservoir must be specified. The reservoir distribution of all other dependent variables such as: R_{sw}, S_w, S_g, ρ_w, ρ_g, C_m, C, μ_w, μ_g, L_z, L_x, W, ϕ, and K, and all other relevant data are specified for the sand sediment and for the adjacent shales. For cross sectional studies and for studies where gas and water exist at the initial condition, the fluid properties are obtained by integration using the gas phase pressure and water saturation at the water-gas contact. This is aided by using laboratory correlations for PVT data--formation volume factors, viscosity, density, and dissolved gas ratio.

BOUNDARY CONDITION

The boundary condition is that of no flow boundary condition for both water and gas phases. Thus, at:

$$\left.\begin{matrix} x = 0 \\ \\ x = L_x \end{matrix}\right\} \frac{\partial P_w}{\partial x} + \rho w \bar{g} \ \frac{\partial h}{\partial x} = \frac{\partial P_g}{\partial x} + \rho g \ \bar{g} \ \frac{\partial h}{\partial x} = 0 \tag{37}$$

and at:

$$\left.\begin{matrix} z = 0 \\ \\ z = L_z \end{matrix}\right\} \frac{\partial P_w}{\partial z} + \rho w \bar{g} \ \frac{\partial h}{\partial z} = \frac{\partial P_g}{\partial z} + \rho g \ \bar{g} \ \frac{\partial h}{\partial z} = 0 \tag{38}$$

where L_x is the length of the reservoir and L_z is its thickness or width, depending on if a horizontal or cross-sectional study is being run. The closed boundaries are remote from the sand sediment at positions that will not experience pressure decline. This is reasonable, since in geopressured geothermal reservoirs any interval that experiences pressure reduction, due to fluid production, is regarded as a production interval.

This type of boundary condition will also be helpful in studying variations of shale properties with change in pressure.

The concept of no flow boundary is however not applicable to geopressured reservoirs which initially are in a non-static condition (see fig. 6). Detailed analyses of such reservoirs is beyond the scope of this report.

The height function, h (i,j), may be expressed in terms of the tilt of the reseroir. Let θ be the angle of the x - axis downward from the horizontal. Then:

$$h = - x \sin\theta + z \cos\theta \tag{39}$$

The sign of the first term in the right of equation (39) depends on the direction of the slope.

The boundary condition for the heat transport equation is such that for a vertical study the temperature at the bottom of the reserovir is specified and kept constant, while the derivatives of the other boundaries allow no heat conduction.

Thus:

$$\left.\begin{array}{l} x = 0 \\ x = L_x \end{array}\right\} \frac{\partial T}{\partial x} = 0 \tag{40}$$

$$z = 0 \qquad \frac{\partial T}{\partial z} = 0$$

$$z = L_z \qquad T\ (x,\ z,\ t) = \text{constant} \tag{41}$$

For horizontal study, however, the derivatives at all the boundaries are specified.

The mathematical equations derived in this chapter can be used to make a detailed study of:

1. early production characteristics of geopressured reservoirs
2. effects of rock compressibility
3. effects of uniaxial rock compaction

4. effects of shale water influx

5. effects of changes in reservoir parameters and geometry with reduction of interstitial fluid pressure

6. well test design for pilot well(s)

7. effects of free gas and gas in solution in geopressured reservoirs

8. the production of natural gas from geopressured reservoirs

9. effects of thermal expansion

10. calculation of ultimate energy recovery from geopressured geothermal aquifers

11. "cooled" water reinjection feasibility analysis to determine if the ultimate recovery of useful energy from geothermal reservoirs could be significantly enhanced by reinjection of "cooled waters"

12. analysis of pilot reservoir tests

13. effects of completion techniques on geopressured well deliverability

The equations can also be extended to predict surface subsidence and water reinjection as a means of alleviating possible subsidence and for the disposal of potentially large volumes of water after it has been used for energy conversion at the surface.

This paper will report preliminary results of calculation of the first six types outlined above. This will form the basis for other studies, which are currently in progress and will be reported later.

For these studies solution of equations (10), (27), (28), (33) and (37) through (39) will be sufficient. A single phase (hot water) multidimensional simulator has therefore been developed. The model is two-dimensional, and either areal or cross-sectional studies can be run.

CHAPTER IV

DIFFERENCE APPROXIMATION TO THE MATHEMATICAL MODEL

SOLUTION TECHNIQUE

The reservoir simulation equations developed contain second-order spatial derivatives of type $\frac{\partial}{\partial x} \left(A \frac{\partial P}{\partial x}\right)$ and first-order derivatives in time. The equations are non-linear partial differential equations and are not amenable to analytical solutions. Approximate methods must be used for their solution. There are many such approximate techniques, of which finite differences is probably the most widely used method and is used in this study.

Finite difference technique is used to obtain an approximate solution to the differential equations by replacing the differential equations with a finite number of algebraic equations in an equal number of approximate values of the dependent variables at specified values of the independent variables. As the number of equations or unknowns is increased, the approximate solution at any point will approach the true solution of the differential equation, if the solution is convergent and consistent.

The anisotropic and heterogeneous nature of geothermal, geopressured reservoirs, the frequent existence of natural gas in solution, and the deformable nature of the rock matrix make the simulation of these reservoirs extremely complicated. The compaction of rock matrix predominantly in the vertical direction justifies the development of not only a horizontal model but also a cross-sectional model. If a geopressured reservoir is fully saturated with natural gas and has a gas cap, as production starts there will be gas percolation. Because of the low viscosity of gas, high velocities can be attained as the gas migrates upward. Such high velocities will lead to time step limitations that are often encountered in coning problems. Such time step limitations make it very costly to use an explicit mobility model to make long range depletion studies of these reservoirs. Hence a semi-implicit mobility technique is used.

<u>Selection of Grid Spacing</u>.

To permit variable grid spacing, the reservoir length, L_x, is divided into N-1 intervals. $0 \le x \le L_x$, of arbitrary length, $\Delta x_{i+\frac{1}{2}}$, $0 \le i \le n-1$, such that :

$$x_i = \sum_{v=0}^{v=i-1} \Delta x_{v+\frac{1}{2}} \quad 1 \le i \le N$$

$$x_1 = 0$$

$$x_N = L_x \tag{42a}$$

Similarly, the thickness, L_z, is divided into M-1 intervals, $0 \le z \le Lz$, of arbitrary length, $\Delta z_{j+\frac{1}{2}}$, $0 \le j \le M-1$, such that:

$$z_j = \sum_{v=0}^{v=j-1} \Delta z_{v+\frac{1}{2}} \quad 1 \le j \le M$$

$$z_1 = 0$$

$$z_m = L_z \tag{42b}$$

In deriving difference equations, the grid blocks are selected by placing the block boundaries at half the distance between any two points. Thus:

$$\Delta x_i = \tfrac{1}{2}(\Delta x_{i-\frac{1}{2}} + \Delta x_{i+\frac{1}{2}})$$

$$\Delta z_j = \tfrac{1}{2}(\Delta z_{j-\frac{1}{2}} + \Delta z_{j+\frac{1}{2}}) \tag{43}$$

while the points at the boundary can be handled in the following way:

$$\begin{aligned} \Delta x_{-\frac{1}{2}} &= \Delta x_{\frac{1}{2}} & \Delta x_{M+\frac{1}{2}} &= \Delta x_{M-\frac{1}{2}} \\ \Delta z_{-\frac{1}{2}} &= \Delta z_{\frac{1}{2}} & \Delta z_{N+\frac{1}{2}} &= \Delta z_{N-\frac{1}{2}} \end{aligned} \tag{44}$$

This type of boundary condition is selected to allow grid points to be placed at the well face (see fig.10).

Finite Difference Solution.

The finite difference approximation to equation (10) assuming:

1. An isothermal condition in which changes in temperature during the production period (30 years) are regarded as negligible
2. Natural gas remains in solution or immobile during the production period

is:

$$\bar{\nabla}\left(\frac{\rho_w^{n+1}}{\mu_w^{n+1}} K^n W\Delta x \Delta z \left(\bar{\nabla}\ P_w^{n+1} - \frac{\rho_w^{n+1}}{144}\frac{\bar{g}}{g_c}\ \bar{\nabla}\ h\right)\right) + \rho_{w_{sc}}\ q_{w_{ij}} =$$

$$\frac{W\Delta x\Delta z}{5.6146}\left[\phi^n \left(\frac{\partial\rho}{\partial P}\right)_T + \frac{\rho_w^{n+1}}{\phi^n}\left(C_m + C_{rm}\ (1-\phi^n)\right)\right]$$

$$\frac{P_w^{n+1} - P_w^n}{\Delta t} \tag{45}$$

Where:

sc = Standard condition

n = Old time step

n+1 = New time step

Δt = Incremental time, day

Because geopressured reservoirs have complex geometries, and because both areal and cross-sectional studies are run, the line successive over-relaxation technique (LSOR)[39] is used to solve the set of equations resulting from the application of equation (45) at the M x N grid points in the reservoir. The LSOR method is particularly convenient for cross-sectional water-gas problems. To implement the LSOR, the pressure values on a line are solved simultaneously assuming that those values on the previous lines, i.e., i, j-1 terms, are known since they have just been calculated and the values at i, j+1 are approximated by the old iteration values (see fig. 10). These equations when written for each point on a line for the one phase case produce a diagonally dominant tridiagonal matrix, which is easily

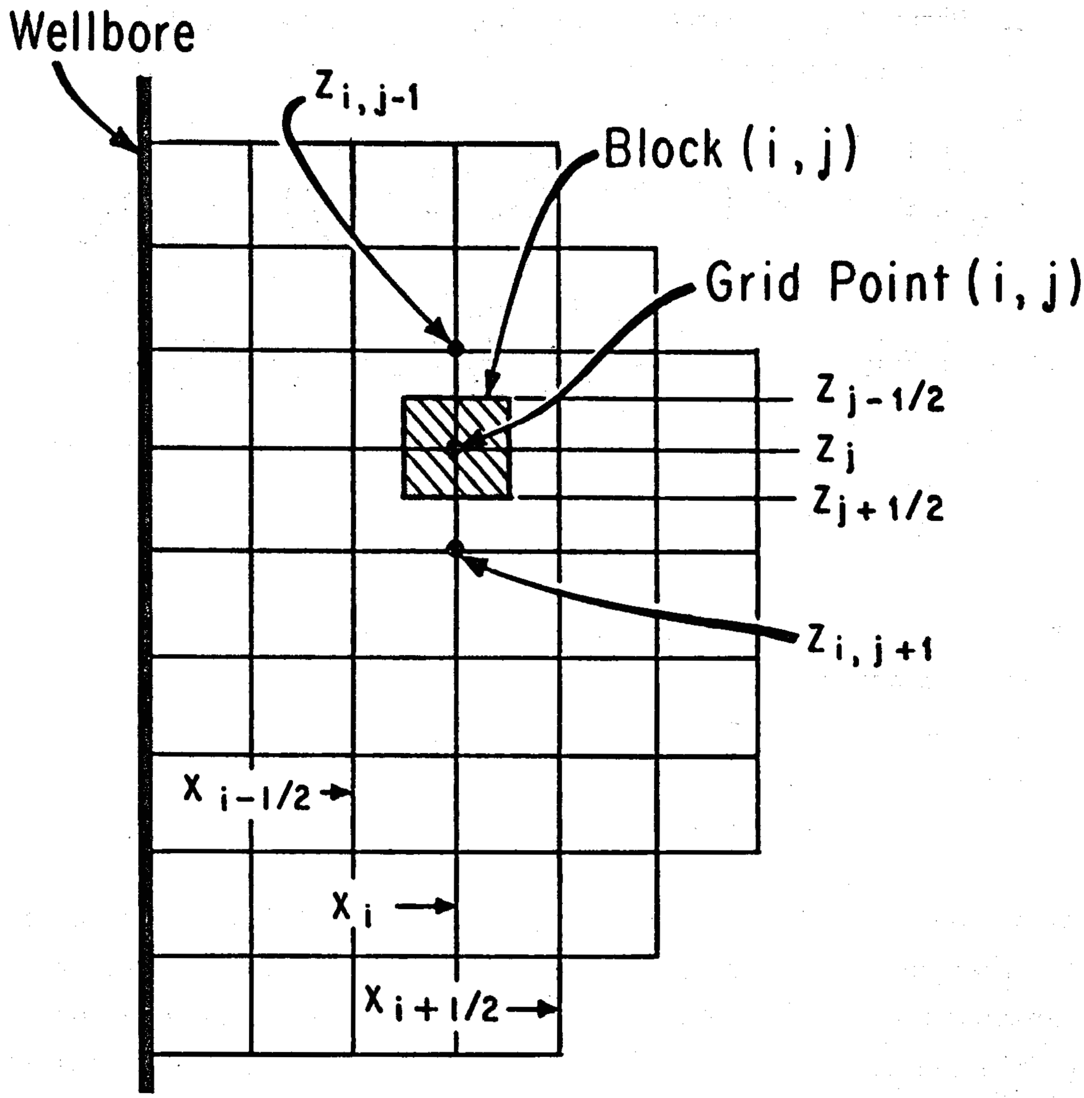


Figure 10. Grid system, with grid points at the well face.

solvable using the Thomas algorithm.[39] The equation can be written summarily as:

2. Page 143, Equation (46) should read:

$$a_{i,j}^{n+1} P_{i-1,j}^{\substack{kk+1\\n+1}} - b_{i,j}^{n+1} P_{i,j}^{\substack{kk+1\\n+1}} + C_{i,j}^{n+1} P_{i+1,j}^{\substack{kk+1\\n+1}} = -P_{i,j-1}^{\substack{kk+1\\n+1}} - P_{i,j+1}^{\substack{kk\\n+1}} + d_{i,j} \qquad 1 \leq i \leq N \qquad (46)$$

Equation (46) is of tridiagonal form since all terms on the right hand side are known at iteration number kk.

To obtain a solution the grid system is swept row by row from top or bottom, depending on the numbering system and the $P_{i,j}^{\substack{kk+1\\n+1}}$ values are solved simultaneously on a line. After the computation of each line, the next approximation to the $P_{i,j}^{\substack{kk+1\\n+1}}$ values are obtained by overrelation as follows:

$$P_{i,j}^{\substack{kk+1\\n+1}} = P_{i,j}^{\substack{kk\\n+1}} + \omega_{opt} \left(P_{i,j}^{\substack{kk+1\\n+1}} - P_{i,j}^{\substack{kk\\n+1}} \right) \qquad (47)$$

Where:

ω_{opt} = Relaxation parameter judiciously selected to assure rapid convergence.

The iterative procedures is continued until a convergence criteria is satisfied, namely:

$$\max \left| \frac{P_{i,j}^{\substack{kk+1\\n+1}} - P_{i,j}^{\substack{kk\\n+1}}}{P_{i,j}^{\substack{kk\\n+1}}} \right| < \varepsilon \qquad (48)$$

for all "i, j". "ε" is selected so that the maximum difference in pressure between $P^{kk+1}_{i,j \; n+1}$ and $P^{kk}_{i,j \; n+1}$ over all active grid points is insignificant. In this study a value of 1.E-7 was found to be appropriate.

The numerical scheme has been incorporated into a finite difference code HVMGR1(Horizontal-vertical model of geopressured reservoirs #1).

The HVMGR1 code possesses considerable flexibility as far as heterogeneous and anisotropic matrix properties, reservoir geometry, regular or irregular grid dimensions and boundary conditions. Formation thickness can vary for two dimensional (2D) areal studies and formation width can vary for 2D cross-sectional studies. The effects of pore pressure reduction on fluid properties and reservoir parameters are included. Reservoir parameters include porosity, permeability and formation thickness. Other rock properties that may vary include rock matrix compressibilities, uniaxial compaction coefficient and rock matrix density.

CHAPTER V

NUMERICAL PERFORMANCE STUDIES OF A HYPOTHETICAL GEOPRESSURED GEOTHERMAL RESERVOIR

Several single phase simulations of a hypothetical geopressured geothermal reservoir were performed to develop an understanding of the productivity of such reservoirs while subjected to a variety of producing conditions. Such studies can establish the importance of various sources of reservoir drive energy and can indicate the range of reservoir responses to early production.

The studies were performed on a hypothetical reservoir. The reservoir represents a simplification of a prospect in the Kenedy County Fairway described in Volume II of this report. The idealization consists of using a regular reservoir geometry and homogeneous properties.

The reservoir consists of a rectangular cube. The long dimension which would be oriented parallel to the coast is 51,865 feet in length. The reservoir width is 23,650 feet and the uniform reservoir thickness is 162 feet. The reason for the unusual choice of length, width, and thickness is that they closely approximate the actual reservoir volume of the Kenedy County prospect while utilizing a much simpler geometry. We used a 9 x 11 computing grid for the studies.

The reservoir temperature was estimated to be 300°F and the initial reservoir pressure was estimated to be 11,000 psia. Since the studies are for a horizontal system this pressure is distributed uniformly throughout the reservoir. The depth of the reservoir is estimated to be 11,000 feet. Initial reservoir permeability was estimated to be 18 md and porosity was estimated to be 0.216.

The reservoir fluid is considered to be only water containing 10,000 ppm of dissolved solids. Table I below gives the water density and viscosity data used in the studies. This data was provided by Systems, Science and Software, Inc., La Jolla, California. No attempt was made to simulate thermal transport and the reservoir process is assumed to be iso-thermal. Solution gas effects were ignored.

TABLE I

Water Properties @ 300^oF

Pressure psia	Density lbs/ft^3	Visc. cp
5000.0000	58.4635	.1926
5500.0000	58.5575	.1933
6000.0000	58.6510	.1939
6500.0000	58.7550	.1946
7000.0000	58.8339	.1952
7500.0000	58.9335	.1959
8000.0000	59.0275	.1966
8500.0000	59.1243	.1972
9000.0000	59.2168	.1978
9500.0000	59.3112	.1986
10000.0000	59.4013	.1993
10500.0000	59.5027	.2001
11000.0000	59.6225	.2008

RESERVOIR DRIVE EFFECTS

To examine the effects of various reservoir drives on the decline of the reservoir pressure four studies were performed. In all of these studies a single well located at the center of the reservoir (block 5, 6) was produced at a constant rate of 40,000 bbl/day. For the purposes of simulation, production was continued for 30 years or until the well-block pressure fell below 5000 psia.

Four separate cases were run. Case I had only one source of reservoir energy, the expansion of the reservoir fluid itself. Case II added the expansion of the rock matrix to the fluid expansion. A rock matrix compressibility coefficient of 7.5×10^{-6} psi^{-1} was estimated to be appropriate for the reservoir. Case III added the effects of reservoir compaction as outlined in Chapter III to the above drives. The uni-axial compaction coefficient was estimated to be 4.6×10^{-6} psi^{-1}. For Case IV the basic geometry of the system was changed. The reservoir width was increased by adding 7,920 feet along the entire length of the reservoir. This extra reservoir volume was assumed to be shale with a permeability of 10^{-4} md at 11,000 psia, compressibility and uni-axial compaction coefficients of 7.5×10^{-4} psi^{-1} and 4.6×10^{-5} psi^{-1}, respectively. The shale's porosity was assumed to be the same as the sandstone. The well is produced at the same rate and in the same location in the sandstone reservoir. This case was designed to estimate the influence of shale water influx.

The results of the four cases are summarized in fig. 11. If water expansion is the only source of reservoir energy (Case I), the reservoir would be depleted in about 8 years. A drawdown test could be expected to yield considerable amounts of information about reservoir volume and properties within one year. When the formation compressibility is included (Case II), the reservoir is able to produce for the entire 30 year production history. At that time the well pressure has dropped to 8,000 psia. However, a single well drawdown test could not be expected to provide information on reservoir pore volume in less than 5.5 years. It should be possible to identify the presence of formation compressibility much sooner. But it will not be possible to estimate the compressibility coefficient from such limited data.

When formation compaction is added as a source of energy (Case III), the pressure levels are generally raised throughout the producing life. The final well pressure at the end of 30 years has declined to approximately 8,800 psia. During the early transient for this production, the well pressure parallels that of Case II but is displaced to a higher pressure level. It will probably not be possible to estimate reservoir volume from single well drawdown test data in less than 10 years.

Case IV shows that it will be very difficult to either identify the presence of shale water influx or estimate its influence in less than 10 years. Even though the shale volume added to the simulated reservoir appeared to be small, it was apparently adequate for the simulation because the pressure at the outside boundary of the shale had not decreased from the initial pressure even after 30 years of production. In face, most of the shale water influx has come from the first half mile of the shale.

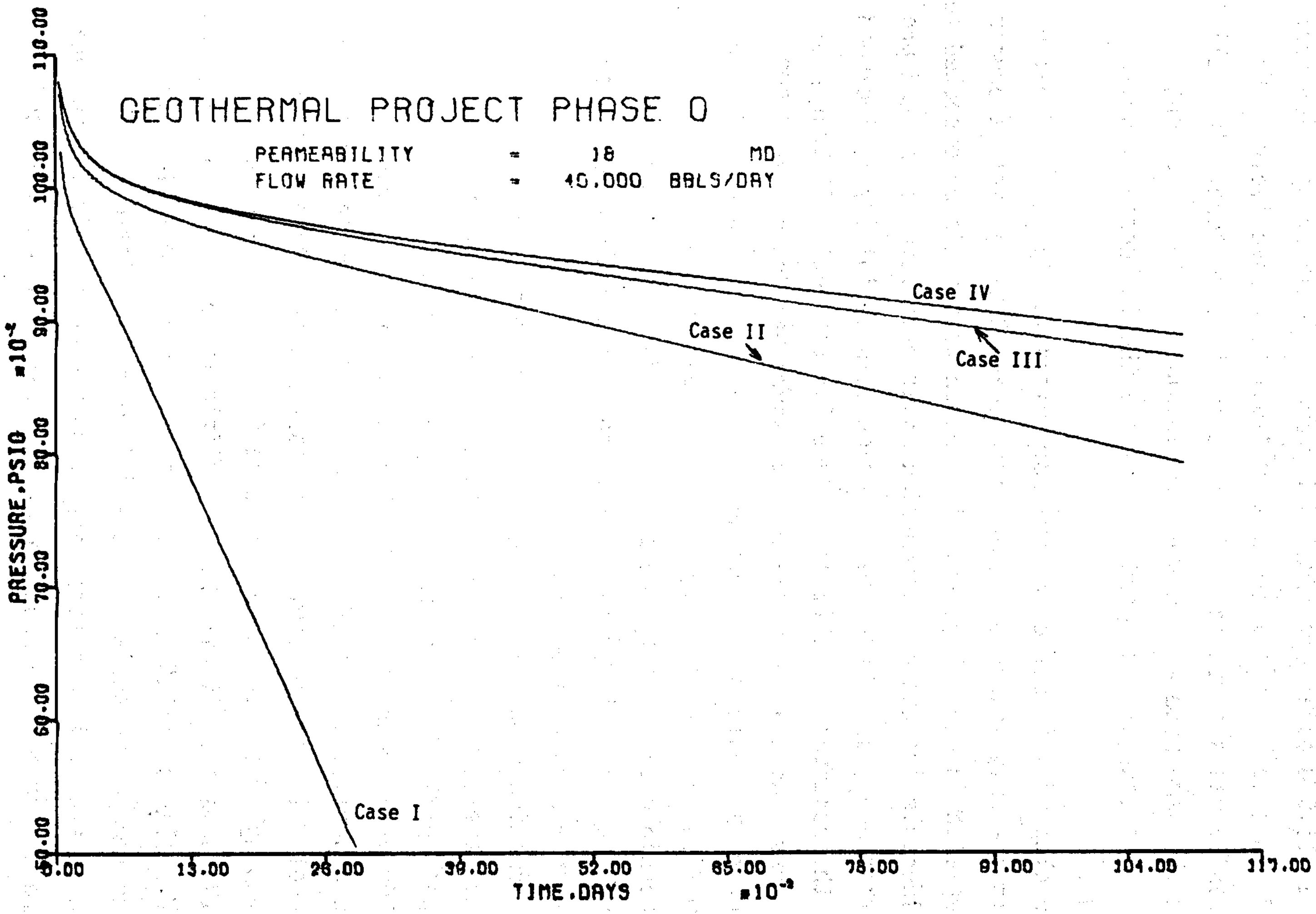


Figure 11. Well block pore pressure of various reservoir drives with time.

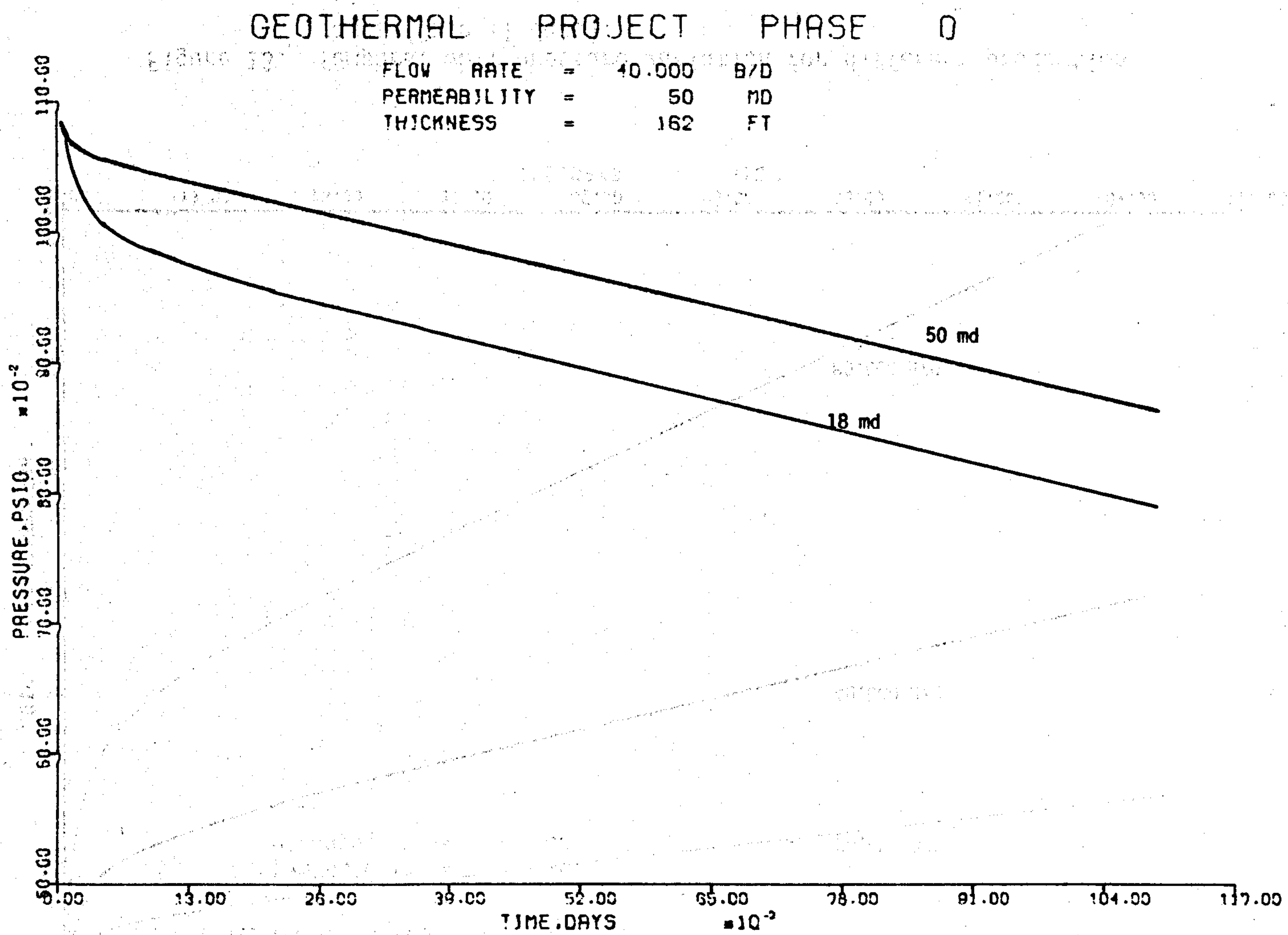


Figure 12. Temporal variation of well pressure for different permeabilities (Case II data).

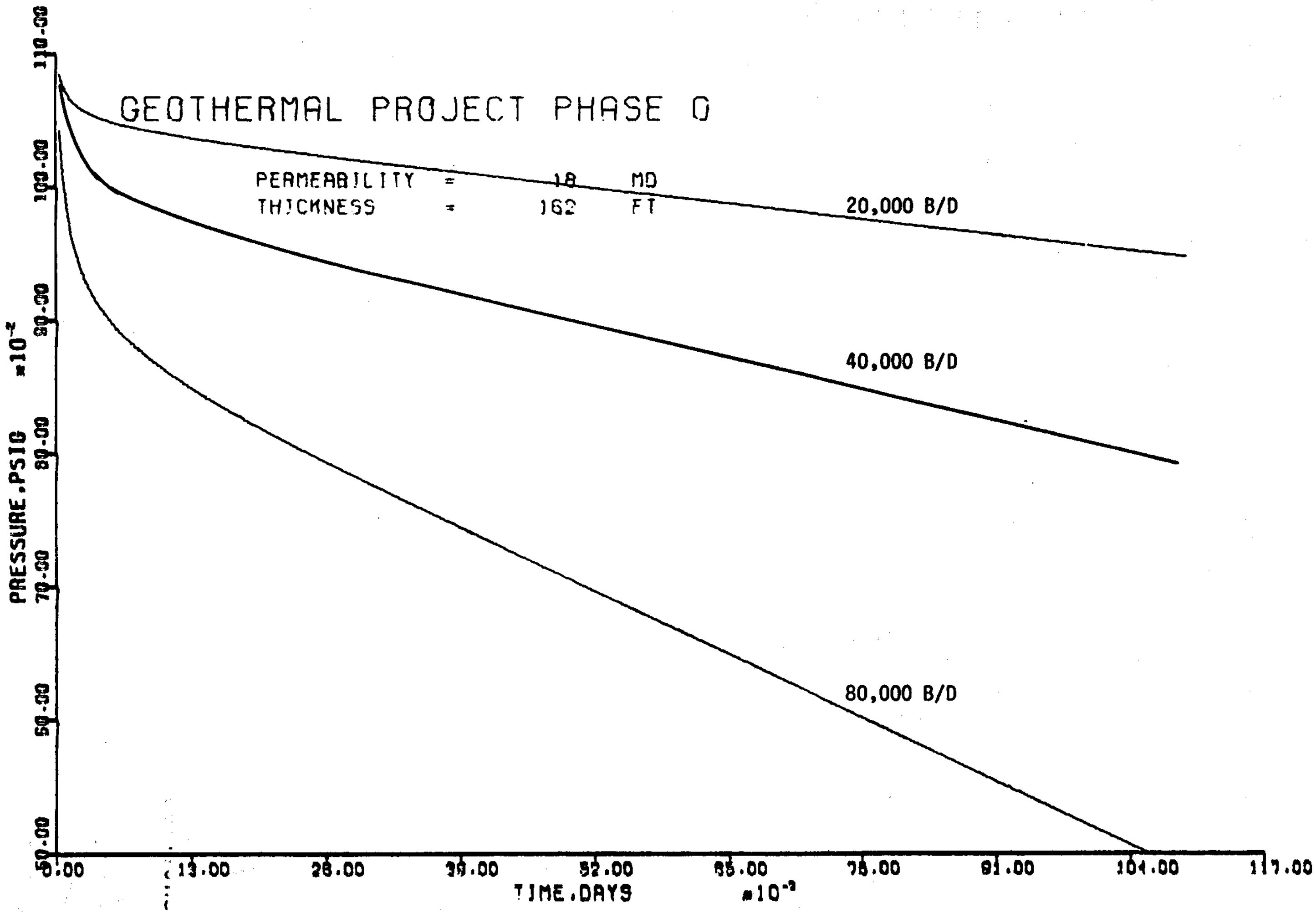


Figure 13. Temporal well pressure variation for different production rates (Case II data).

It should be noted that the effects of water expansion, formation, and compressibility and formation compaction affect the same terms in the differential equation (10). Therefore, early well pressure response will be identical for many different possible combinations of values for these parameters. In addition, porosity and permeability effects strongly interact during early production from reservoirs. It would not be wise to rely solely on well test information to provide estimates of these properties. Instead all possible efforts to obtain reliable independent estimates of formation parameters from other data including core analyses of actual formation samples should be exercised.

PERMEABILITY AND RATE SENSITIVITY

To examine the sensitivity of the well pressure to formation permeability, a reservoir identical to Case II in all respects except formation permeability was simulated. Formation permeability was set at 50 md as shown in fig. 12. The observable effect is to displace the pressure decline curve upward about 750 psia. This is expected because the higher pèrmeability requires lower flowing pressure gradients within the reservoir to sustain the constant flowrates. In addition, the time required to obtain reservoir volume and formation property estimates from production data is reduced. If a permeability lower than 18 md should be encountered, the effect would be to displace the pressure decline unfavorably downward. It would also extend the time required to obtain reservoir volume and formation property data from a single well drawdown test.

The effects caused by a change in production rates are shown in fig.13. These runs all used Case II data. However, the flowrates were changed as labelled on the pressure histories. Clearly, the main effect caused by the change of flowrate is to increase or decrease the rate of pressure decline. This is identifiable during all stages of reservoir depletion. The 80,000 bbl/D depletion rate results in the depletion of the reservoir after approximately 29 years of production.

MULTIWELL DEPLETION

A single well producing 40,000 bbl/D would not produce a large amount of useful energy. It is expected that a power generating plant utilizing geopressured geothermal fluids would require eleven such wells. The Case IV data was utilized with a complex of eleven wells distributed throughout the reservoir to simulate such a production history. The average reservoir pressure was calculated as a function of time for this system. This is shown in fig. 14. The reservoir is depleted after 13 years of production. At that time well pressures would fall below 5000 psia. For an eleven well producing complex, it would be necessary to either have a larger reservoir, complete some of the wells in another formation, or introduce some form of enhanced recovery. In the area where the hypothetical data were obtained, there are two additional formations similar to the one simulated that are also prospective geopressured geothermal reservoirs. Enhanced recovery of geopressured geothermal reservoirs is possible through the reinjection of the produced water after surface utilization. Since no attempt was made to simulate the influence of thermal energy transport it is not possible to tell at this time if that would result in an increase of recoverable energy.

SHALE WATER INFLUX

Since the case studies of fundamental reservoir drive mechanisms demonstrated the difficulty of identifying the presence and influence of shale water influx, two additional runs were made to see if a different well location might produce more information on the source of reservoir energy. The results are shown in fig. 15. For these runs, the producing well location was changed until it was only one-half mile from the sand-shale boundary. The no influx run utilized the Case III data with a no flow boundary at the sand-shale boundary. In the influx study, the reservoir properties of Case IV were used. It is clear that the influence of the shale water is identifiable at a much earlier time and is clearly distinguishable at the end of two years of production. ~~A well located~~

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3. Page 152, Paragraph 2, Last sentence should read:

"A well located near the sand-shale boundary would help to evaluate the importance of this potential source of reservoir energy."

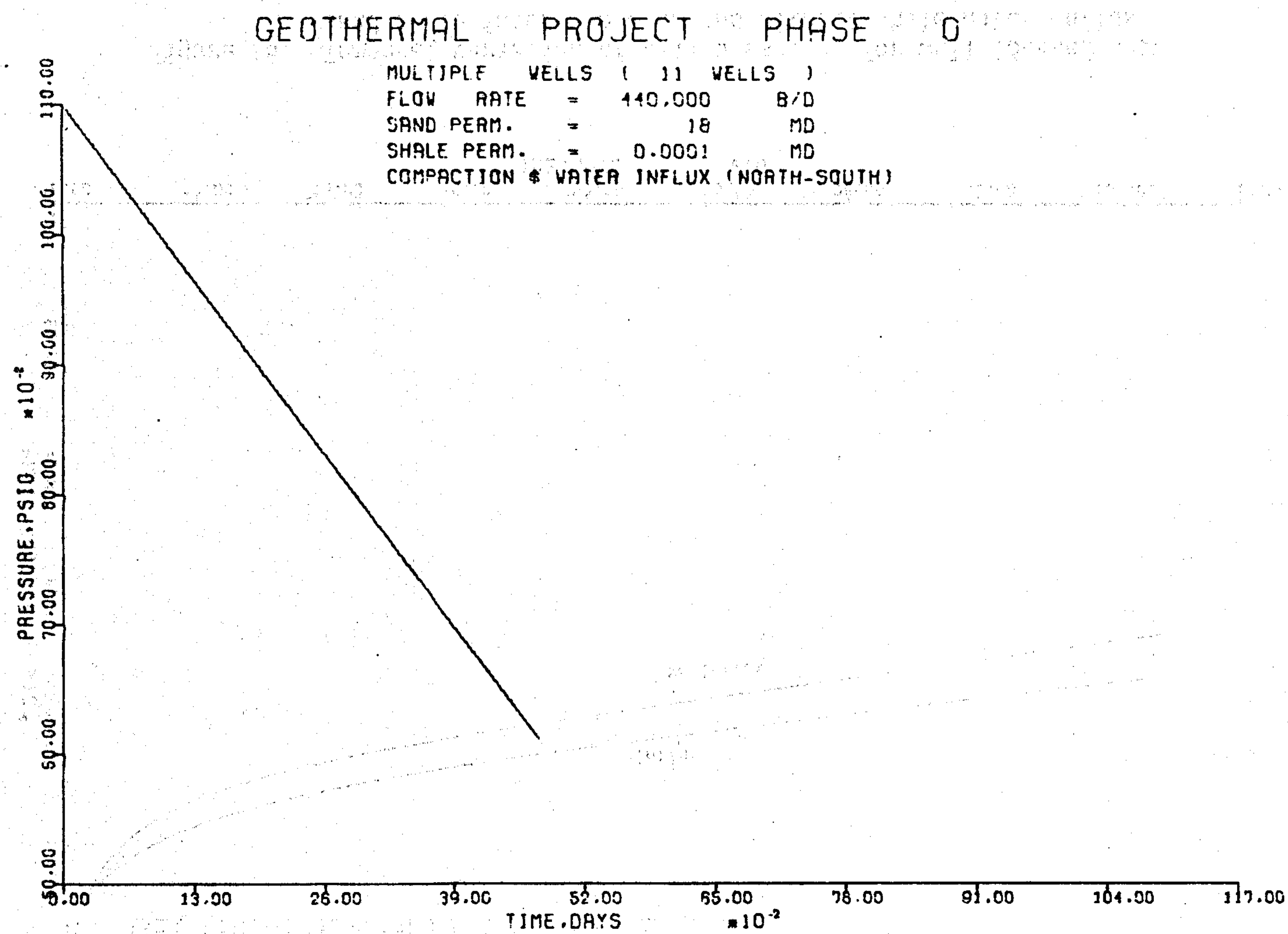

Figure 14. Temporal variation of average reservoir pressures for an Eleven Well Producing Complex (Case IV data).

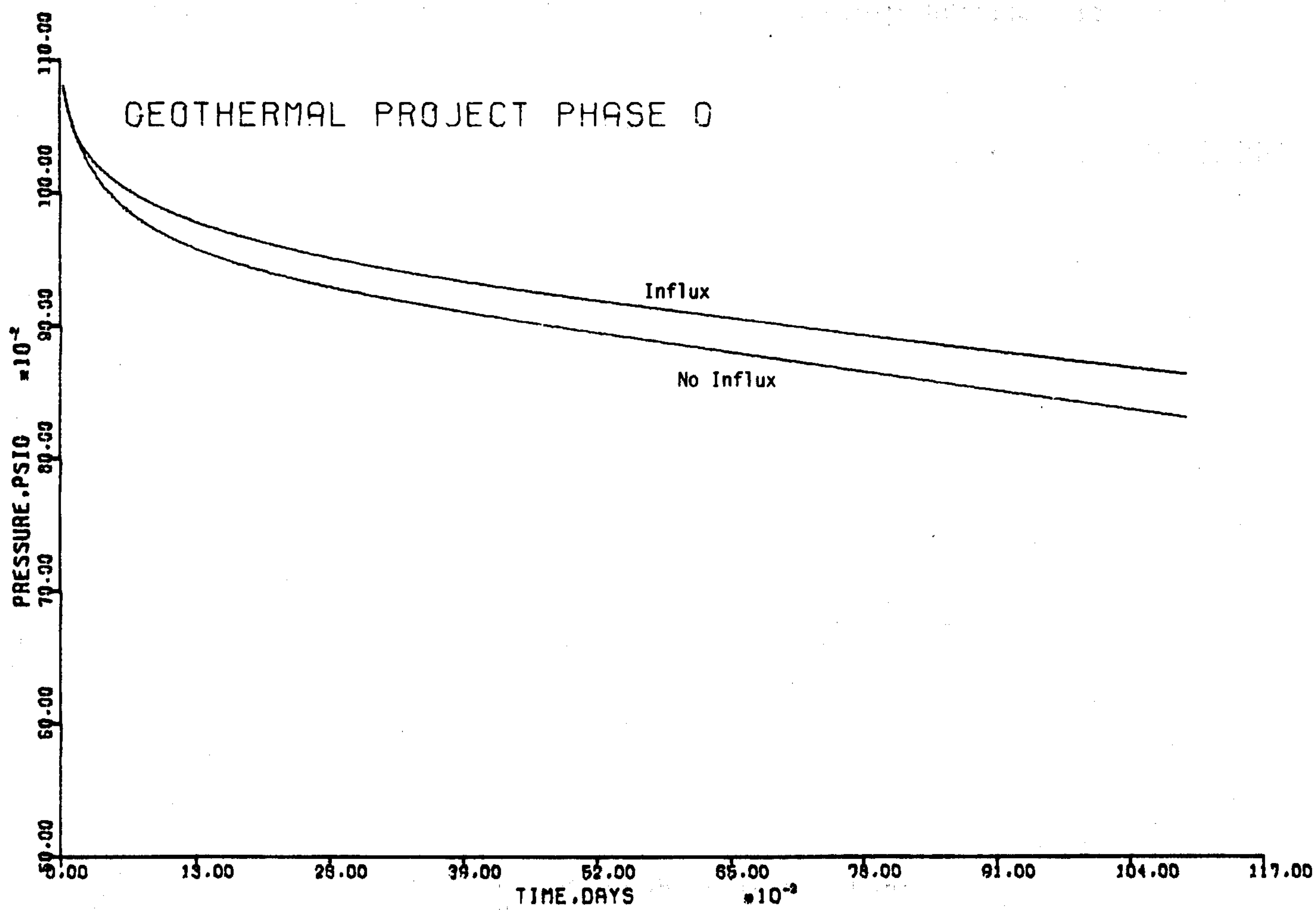

Figure 15. Temporal variation of well pressures for well located near sand-shale interface with and without shale water influx.

GENERAL CONCLUSIONS OF STUDIES

The four case studies of reservoir drive sources show that long term single well drawdown flow tests will be required to estimate reservoir volume and formation properties on a reservoir as large as the hypothetical reservoir studied. Since the well producing rate is at the design capacity of the wells described elsewhere in this report, it is not likely that a single well could produce at rates high enough to appreciably shorten this time.

The presence of additional wells would make it possible to obtain information at a faster rate. Since many formation parameters affect well response in nearly identical ways, all attempts to obtain independent estimates of formation properties from laboratory data should be made. Well test information could then be used to confirm the laboratory estimates of formation properties.

To identify or estimate the influence of shale water influx in a short period of time, it will be necessary to locate a well close to the sand-shale reservoir boundary.

CHAPTER VI

RECOMMENDATIONS

In the previous chapters several recommendations have been made and implied as a part of the discussion. These are summarized as follows.

SIMULATOR DEVELOPMENT

The development of multidimensional two-phase computer models simulating the response of geopressured geothermal models should be continued. These models should consist of two separate types. The first type should be based on the solution of the momentum conservation equations presented in Chapter III. The second type of simulator should include the effects of thermal and kinetic energy transport within the geopressured reservoir. Computer model development and other related research should include the refinement of the constitutive relations presented in Chapter III describing the stress-strain relations of the reservoir material, the pressure, volume and temperature behavior of reservoir materials and fluids, and the effects of formation compaction on thermal and fluid flow properties of the fluids and porous media.

The numerical performance studies described in Chapter V show that flow tests will not be able to provide reliable estimates of many formation parameters unless the reservoir has been produced for a long period of time. Therefore, it is desirable to obtain formation samples for extensive laboratory testing to provide additional sources of estimates of formation properties such as thermal expansion coefficients, thermal conductivities, coefficients of surface heat transfer between reservoir rocks and reservoir fluids, absolute permeability, relative permeabilities, porosity, rock compressibility, and uniaxial compaction coefficients. These properties should be analyzed to determine their pressure and temperature dependence.

SIMULATION STUDIES

After development of the above simulators they may be used in conjunction with estimates of reservoir parameters to estimate the response of geopressured geothermal reservoirs to production. The simulator based on the solution of the momentum conservation equations may be used to estimate the early production characteristics of geopressured reservoirs. This would include the effects of rock compressibility, uniaxial rock compaction, shale water influx, changes in reservoir parameters and geometry with the reduction of interstitial fluid pressure, and the effects of free gas and gas in solution on the recovery of useful energy from geopressured geothermal aquifers. The depletion simulator may be used to estimate the production of natural gas from geopressured reservoirs. This simulator may also be used to design well tests for geopressured reservoirs and to evaluate the effects of well completion techniques on the production from geopressured reservoirs.

Simulators including the effects of energy transport may be used to estimate the effects of thermal expansion, shale dewatering, and the feasibility of "cooled" water reinjection to increase the recovery of both natural gas and useful energy as well as to reduce the subsidence associated with reservoir compaction.

The design of well tests for pilot well(s) should be initiated as soon as possible. The program HVMGR1 can be used to initiate this process. This should be done to establish the requirements for well logging and core analyses for the pilot well(s) before drilling and completion. As soon as available, the more sophisticated reservoir models should be introduced to include the effects of the gas phase and thermal energy transport where applicable.

SHALE WATER INFLUX

The studies of Chapter V show that the behavior of shales will be extremely difficult to evaluate from wells completed within the sand body of the geopressured aquifers. Therefore, special efforts will need to be exerted to define the reservoir properties associated with shales. It should be pointed out that no attempt was made in this project to consider fluid movement from shales above or below the sand body of the aquifer.

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APPENDIX I

SAMPLE APPLICATION TO TEST SITE NO. 1
(KENEDY CO.)

General description of drilling operation.

SAMPLE APPLICATION

In order to satisfy the objective of outlining the preliminary plan and schedules as well as obtaining representative costs the guidelines set out in the preceding section have been applied to one of the possible test sites identified by the Resource Assessment Phase I of the project. The specific site is the Armstrong lease in the Candelaria Field in Kenedy County, Texas. The following sections contain offset well information including bit records, drilling fluid programs, formation pressure encountered and casing programs for the Armstrong #20 and #22 wells. Based on this information a preliminary drilling program has been prepared. Well completion and production considerations were taken into account in the preparation of the drilling program. These considerations are detailed in the next section of the report. A brief description of drilling operations has also been included to clarify the terminology used.

LAYMAN'S DESCRIPTION OF A DEEP DRILLING OPERATION

The first step in drilling a deep geopressured geothermal well is the selection of a specific drill site. Once a site has been selected, a drilling program is prepared, the well is "staked" by a surveyor, and a location is prepared for the drilling rig and other equipment necessary for the operation. If the location is remote, it may also be necessary to build access roads.

In accessible areas, such as Texas Gulf Coast Onshore, the rig and other bulky equipment are brought to the drillsite by trucks. The well will be drilled with a rotary drilling rig which is a highly portable piece of equipment that will be dismantled at some previous location, transported to the present drill site and reassembled by experienced oilfield personnel. The entire operation from site preparation through drilling and completion of the well will be carried out by an assemblage of specialized contract firms and oilfield service companies under the supervision of the Dow Chemcial Company, Oil and Gas Division personnel.

Various equipment necessary for the drilling operation includes

1. the rotary drilling rig, which includes large diesel engines to rotate a heavy string of drill pipe during the drilling operation
2. rotary drill bits, to grind through the various layers of rock to be penetrated
3. drill pipe, comprised of 30' joints with threaded ends that are connected to form a "drill string" as the well is drilled.

The commencing of actual drilling operations follows a procedure as described below.

Conductor casing is driven to a depth of about 100'. Actual rotary drilling now begins with a hole being drilled to a depth of about 2500'. This hole is started by drilling out the inside of the conductor casing. This is accomplished by rotating drill pipe with a bit and gradually lowering the pipe as the bit grinds up the rock below. As the hole becomes deeper, the drilling crew adds additional joints of drill pipe to the drill string.

During the drilling operation, a fluid mixture of water, clay, chemical and weight additives known as "drilling-mud" is pumped down the inside of the drill pipe. This fluid passes through openings in the bit at the bottom of the hole and returns to the surface outside the drill pipe. This fluid is almost constantly circulated down the drill pipe and up the open area outside the pipe and serves to cool the rotating drill bit, bring rock cuttings to the surface (thus keeping the hole clean), and seals off the rock formations already penetrated by the hole. The drilling mud is necessary to prevent hole cave-ins and, by its density, controls subsurface pressures, thus preventing entry of subsurface rock fluids into the hole which could result in a "blow-out" at the surface.

The characteristics of the drilling fluid are constantly monitored at the surface. Rock cuttings are removed by a screening device and those cuttings are examined by wellsite geologists. Other equipment measures the gas content, if any, in the returning drilling mud. After the mud has been decontaminated at the surface, it is recirculated down the drill pipe and the "mud circulation cycle" is repeated.

When the hole reaches a depth of about 2500', another string of casing called "surface-casing" is set inside the conductor casing. The surface casing serves to protect fresh water sands from contamination by the drilling fluid and provides additional protection from higher pressures to be encountered at greater depths. The space between the inside of the hole and the surface casing is filled with cement to anchor the casing and to prevent fluids from escaping to the surface. This is done by displacing cement down the casing and forcing it out the bottom of the casing and back to the surface much the same as the drilling mud is circulated. After the cement has been allowed to harden, drilling is resumed using a smaller diameter rotary bit. This size hole will be drilled to about 10,000' at which depth a string of casing, called "protection-casing," will be run and cemented, utilizing essentially the same procedure as described for the surface casing.

During the drilling operations, many rotary drilling bits will be used. Whenever a bit becomes worn and must be replaced, the entire string of drill pipe must be removed from the hole. The pipe is disconnected and racked in the derrick. After the bit has been replaced, the drill string is reassembled as it is returned to the hole and drilling is resumed. This process is called "round-trip" and is repeated many times in the drilling of a deep hole such as we are now considering.

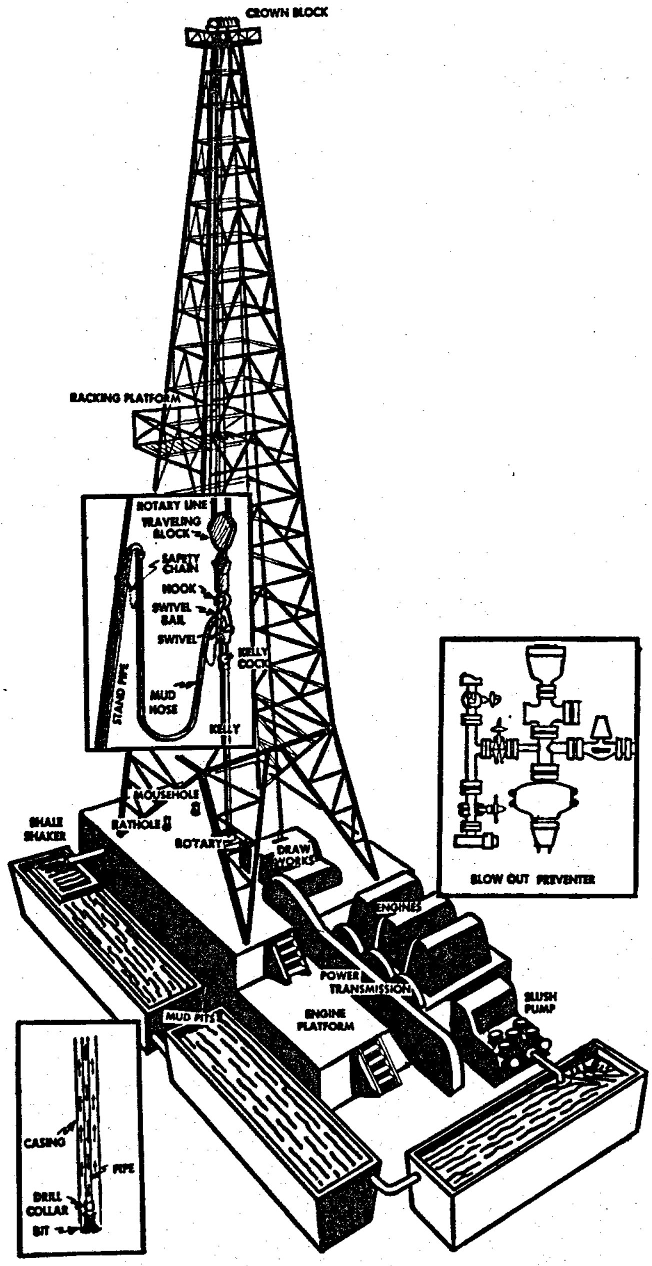
At various stages during drilling, prior to running casing and at total depth, the drill pipe is removed from the open hole and evaluation logs are run. These logs consist of the measurement of a number of parameters including spontaneous potential, resistivity, conductivity, sonic response, response to radioactivity, etc. of the various layers of rock and fluids penetrated. To measure these parameters, tools are run to the bottom of the open hole by wireline and slowly pulled back to the surface while the various responses are recorded by instruments at the surface. Data from these logs are essential to the evaluation of the types of rocks and formation fluids penetrated by drilling. Temperature data is also recorded during this operation.

If the hole is determined to be worthy of a completion attempt after total depth has been reached, another string of smaller diameter casing will be run. This will consist of a "liner" run from the bottom of the hole and overlapping a portion of the protection casing and a connecting "tie-back string" run from the top of the liner to the surface. The liner will be cemented into the open hole and to the protection casing.

If a completion is to be attempted, the casing will be penetrated at various selected intervals and fluid will enter the casing and flow through a tubing string to the surface. In our geothermal wells, the last string of casing will serve as a tubing string. Pressures will be controlled at the surface by a set of high pressure valves attached to the casing, commonly called a christmas tree. A more detailed description of the completion procedure will be submitted later.

The entire operation described above could require as much as six months time to complete, depending on the total depth of the well and the overall drilling conditions encountered.

The following figure represents a schematic of a particular drilling rig.

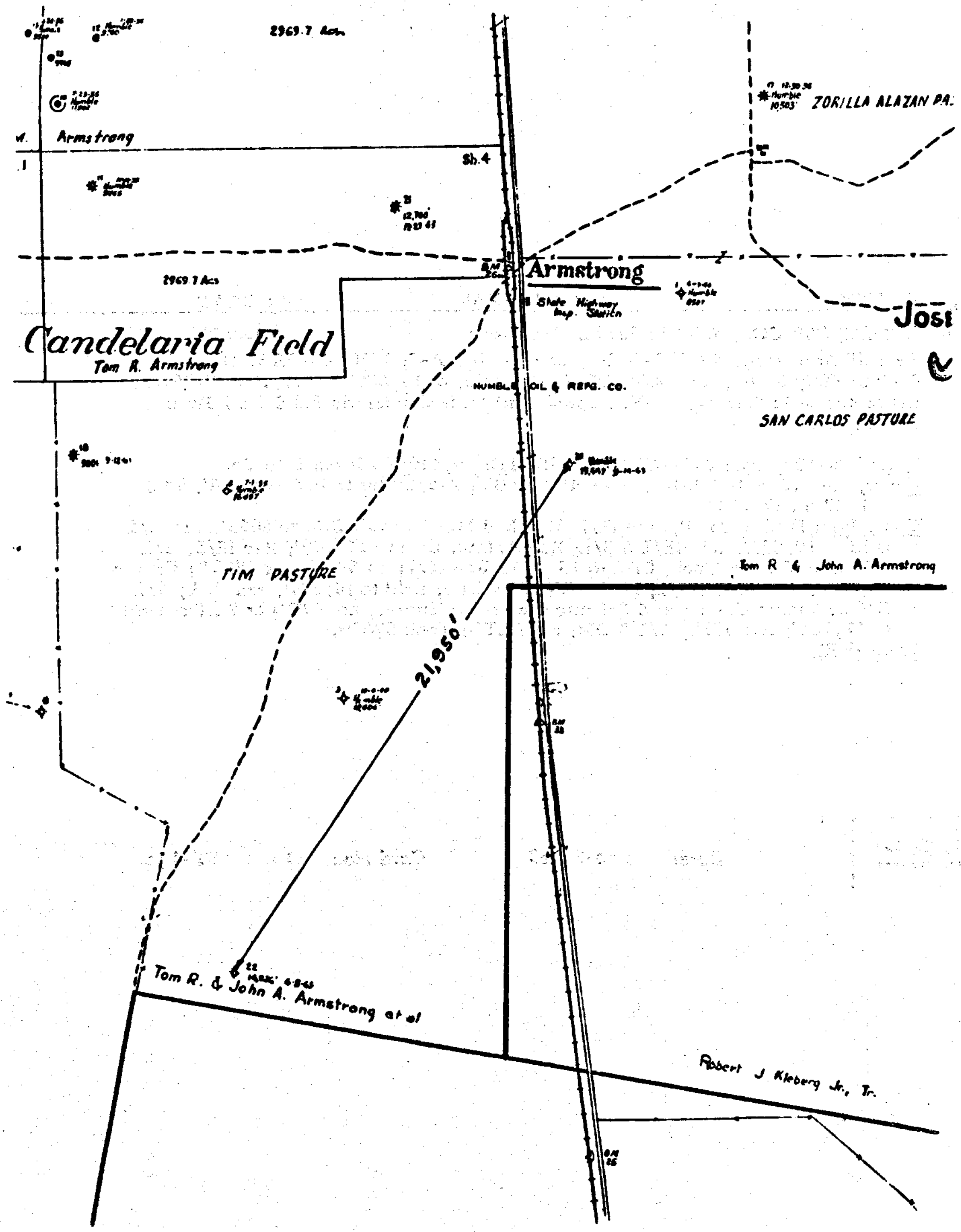


Drilling rigs vary in size and in capacity, although the component parts remain the same and in about the same position. This rig illustrates the principal parts. The blowout preventer, out of its normal position beneath the rotary table, is shown with its many valves and rams necessary for protection against excessive formation pressures and unexpected well flows. The lower inset indicates the circulating fluid coming from the slush pump down through the drill pipe, out the bit and back up the hole. This fluid is returned to the surface, cleaned of sand and cuttings in the shale shaker, is allowed to settle until it reenters the cycle at the slush pump.

APPENDIX IA

OFFSET WELL INFORMATION

The following presents information regarding drilling history for Wells #20 and #22 in the Armstrong Ranch lease, in the vicinity of Test Site No. 1.


2969.7 Acs.
ZORILLA ALAZAN PA.
Armstrong
Sh.4
Armstrong
2969.7 Acs
State Highway Insp. Station
Jose
Candelaria Field
Tom R. Armstrong
HUMBLE OIL & REFG. CO.
SAN CARLOS PASTURE
TIM PASTURE
Tom R & John A. Armstrong
21,950'
Tom R. & John A. Armstrong et al
Robert J Kleberg Jr., Tr.

KENEDY	SOUTH TEXAS	WILDCAT

Well: HUMBLE O&R CO., #20 Charles M. Armstrong **Result:** J&A

Loc'n: 2 mi SE Armstrong, 49. 396-ac lse, Barreta Grt, A-3; 1320' E fr U. S. Hwy #77 & 4400' FE'ly SL lse; sc: 8000' SW #1, dry hole; or 14,600' S & 21,100' W-FSW/c Las Motas de la Barreta, A-77; Approx 4 mi SE fr Candelaria Fld & 4 mi SW fr Barreta Fld.

Spud: 7-5-62 Comp: 2-17-63 Elev: (NR) TD: 19,449' C/Strom Drlg Co.
Casing: 24" 106'; 16" 2516'; 10-3/4" 10,003'; 7-5/8" lnr fr 9697-11,998'; 5" & 5-1/2" lnr 17,774'.
Comp Info: Drld to 2545'; Ran IE/L Attached ML @ 2545'; Drld to 8058', ran A/L Drld to 10,029'; Ran IE/L & S/L; Ran A/L to; Drld to 12,000'; Ran IE/L, S/L & DM; no SWC's; Took; Drld to 15,000'; Ran IE/L; no SWC's, no WLT's; Drld to 16,000'; Ran IE/L & S/L; No S WC's or WLT's; Drld to 16,884', ran IE/L, S/L DM w/Analog Computer & Seismic Reference Survey; no SWC's or WLT's; Drld to 17,766'; Ran IE/L, S/L & DM; No WLT's; Took SWC's.
Tops: (NR).

PRESSURE PLOT

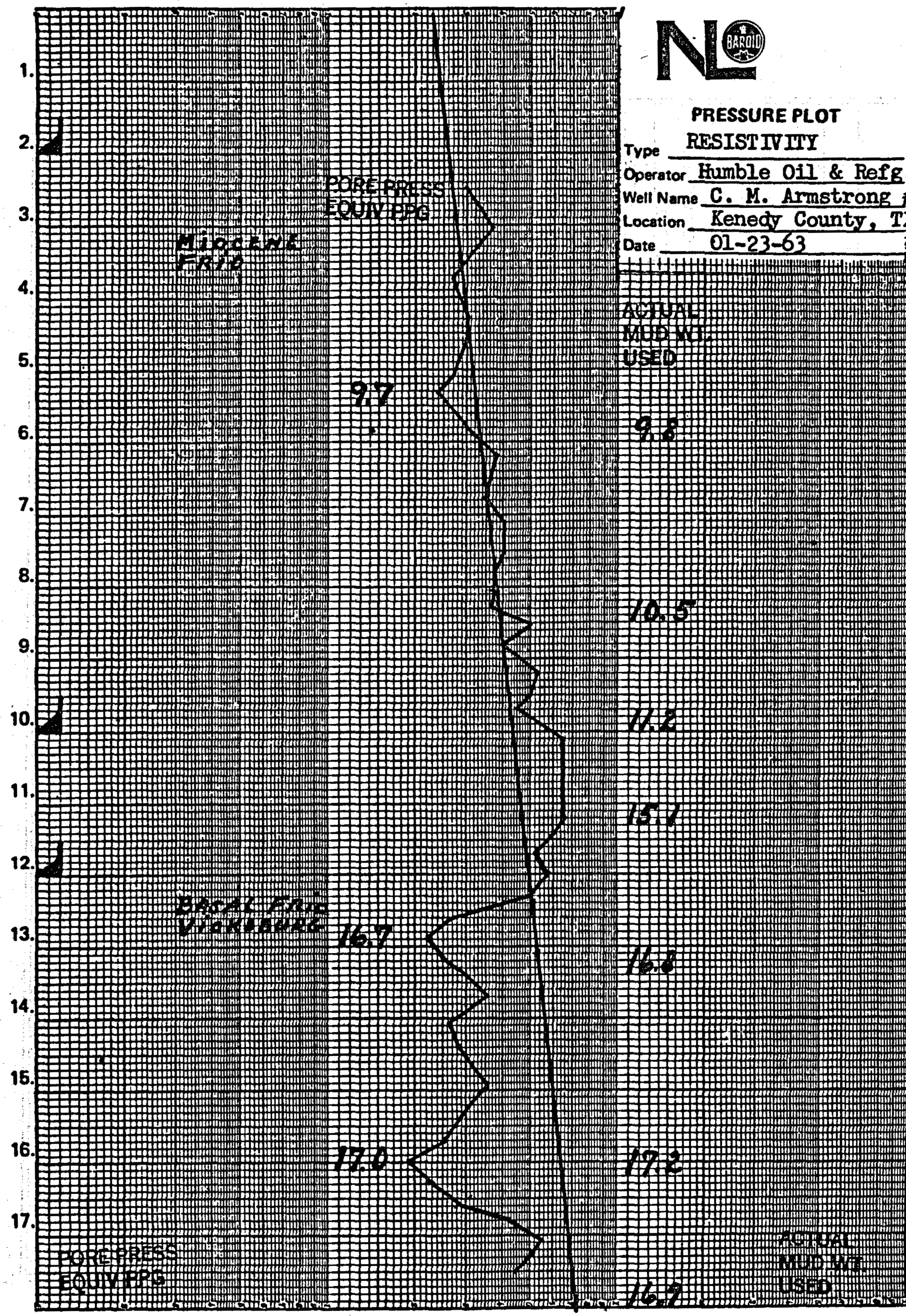
Type: RESISTIVITY

Operator: Humble Oil & Refg. Co.

Well Name: C. M. Armstrong #20

Location: Kenedy County, TX

Date: 01-23-63



Compiled by Ed Cain

FORM 5-11 (REV. 8-62) Magcobar

MAGNET COVE BARIUM CORPORATION
WELL DATA SHEET 23 dro

Magcobar

COMPANY: Humble Oil & Refining	WELL: #20 Armstrong	LOCATION: Armstrong	COUNTY: Kenedy	STATE: Texas
CONTRACTOR: Storm Drilling Co.	TOTAL DEPTH: 19,449	DATE SPUD: 7-4-62	DATE T.D.: 1-23-63	DAYS TO T.D.: 235

CASING PROGRAM	GEOLOGICAL OR COMPLETION DATA
SURFACE: 16" @ 1,959	PROD. FMTN:
INTERMEDIATE: 10 3/4 10,003	PERF. INTVL: TO:
INTERMEDIATE: 7 5/8" 9,847-11,998	PACKER SET @ 17,145
PRODUCTION: 5" 5½" Surface-17,776	
Liner 3½ @ 17,145-19,025	
TOTAL BITS: 44 Rock Bits 9 Diamond	TOTAL ROTATING HOURS: 1507
MUD TYPE: XP-20 Spersene	COST:
COMPLETION FLUID TYPE: Salt Water	COST:
PACKER MUD TYPE: Salt Water	COST:
TOTAL MUD COST: $167,060.52	COST/FOOT: $6.88

MUD PROPERTIES

DEPTH	5800	6800	7285	7990	8366	8940	9290	9290	9800
WEIGHT	9.8	10.3	10.5	10.6	10.5	10.7	10/9	11.0	11.1
VISCOSITY	35	44	54	54	48	49	55	48	.52
WATER LOSS	4.6	4.0	3.6	3.2	3.2	3.3	3.3	3.2	3.4
CHLORIDE	2300	2800	3100	3100	2900	2450	2700	2800	2600
OIL	8.0	12.0	10.0	10.0	10.0	10.0	9.5	10.0	10.0
Alk.	.2	.2	.3	.4	.2	.4	.4	.6	.6
DEPTH	10024	10075	10150	10307	10425	10740	10940	11120	11185
WEIGHT	11.2	11.6	12.7	13.8	14.2	15.0	15.1	15.2	15.1
VISCOSITY	46	47	52	55	52	51	54	65	68
WATER LOSS	2.6	2.6	2.5	2.4	2.3	2.0	1.8	1.8	1.8
CHLORIDE	2750	2800	2800	2900	2950	3000	3100	3100	3100
OIL add5%	13.0	13.0	13.0	12.0	11.0	12.0	12.0	12.0	11.0
SDE Alk.	.5	.8	.8	.5	.4	.5	.3	.2	.2
DEPTH	11356	11610	11895	12000	12225	12340	12550	12750	13040
WEIGHT	15.3	15.5	15.9	16.2	16.1	16.3	16.5	16.4	16.5
VISCOSITY	72	70	58	65	54	54	57	62	65
WATER LOSS	1.4	1.0	1.0	1.8	1.2	1.2	1.4	2.2	2.8
CHLORIDE	3100	3100	3300	3500	3500	3500	3600	3600	3600
OIL	11.0	11.0	11.5	11.0	12.0	11.5	11.0	11.0	10.5
Alk	.4	.3	.4	2.0	2.0	1.8	1.5	1.0	.7
DEPTH	13177	13400	13610	13773	13990	14170	14635	14754	14960
WEIGHT	16.5	16.8	17.0	17.0	17.2	17.5	17.5	16.9	17.2
VISCOSITY	62	58	63	62	70	75	90	77	73
WATER LOSS	2.0	2.4	2.4	2.4	2.2	2.4	2.6	2.5	1.7
CHLORIDE	3600	3700	3800	3900	4100	4100	4200	7200	7200
OIL	11.0	11.0	11.5	11.0	11.0	10.0	10.0	8.0	8.0
Alk	.6	.4	.5	.5	.6	.5	.2	.2	.5

REMARKS AND ADDITIONAL DATA:

0-120 Set 108' of 24" Conductor.

120-2545 Lost Circulation @ 1,016'. Tried to cure with Loss Circulation Material, but failed to hold. Set Cement Plug and drilled to 2545. Set 16" @ 1,959'. Total 22" bits-3. Rotation Hrs. 46. Approximate Mud cost $16,000.00

2545-10024' Broke Mud over @ 5,800' to Spersene - XP-20 Drilled ahead with no trouble. Set 10 3/4" Casing @ 10,003'. Total 14 3/4" Bits 20. Total Rotating Hrs. 344. Approximate Mud Cost $16,002.95

10024'-12000' Lost Returns @ 11,161' while weighting up to 15.3#/gal. Cut Wt. back to 15.0 #/gal. Added 20 #/bbl. Loss Circulation material and regained circulation. Bipassed shake and added 10 #/bbl more loss cerculation material and drilled to 12,000' with wt. 16.2 #/gal. Set 7 5/8" Liner from 9,847 to 11,998. Total 9 5/8" bits 18. Rotating Hrs. 202. Approximate Cost $27,898.37.

12000'-17776' Lost returns @ 14,648' with 17.5 #/gal. cut wt. back to 17.0 #/gal and added 25 #/bbl loss circulation material. Regained circulation and drilled to 17,776' with 17.2 #/gal. Set 17,764' of 5" casing. Total rock bits 3 to 12,263. Total hrs. 30. Diamond Bits 4 Total Hrs. 608 Approximate cost $60,031.19

SIGNIFICANCE OF WELL:

Tested zones from 17,300' to Bottom of Casing.

BOTTOM HOLE TEMPERATURE FROM WELL LOG:

REPORT PREPARED BY: ______________________

FORM 9-11 (REV. 8-62) Magcobar

MAGNET COVE BARIUM CORPORATION

WELL DATA SHEET

Magcobar

COMPANY: Humble Oil & Ref. Co.	WELL: Armstrong # 20	LOCATION: Armstrong	COUNTY: Kenedy	STATE: Texas
CONTRACTOR: Storm Drilling Co.	TOTAL DEPTH: 19,449'	DATE SPUD:	DATE T.D.:	DAYS TO T.D.:

CASING PROGRAM	
SURFACE:	@
INTERMEDIATE:	@
INTERMEDIATE:	@
PRODUCTION:	@

GEOLOGICAL OR COMPLETION DATA	
PROD. FMTN:	
PERF. INTVL:	TO:
PACKER SET @	

TOTAL BITS:		TOTAL ROTATING HOURS:	
MUD TYPE:		COST:	
COMPLETION FLUID TYPE:		COST:	
PACKER MUD TYPE:		COST:	
TOTAL MUD COST:		COST/FOOT:	

MUD PROPERTIES

DEPTH	15190	15370	15535	15705	15865	16148	16320	16485	16680
WEIGHT	17.2	17.2	17.2	17.1	17.2	17.2	17.0	17.2	17.2
VISCOSITY	77	72	75	65	62	65	72	65	75
WATER LOSS	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.6	1.4
CHLORIDE	7500	7700	7700	7800	7700	7700	7900	8000	8000
OIL	8.0	8.00	9.5	10.0	10.0	10.5	10.5	11.0	11.0
Alk	.6	.4	.4	.4	.5	.2	.2	.4	.6
DEPTH	16884	16970	17130	17270	17500	17692	17776	17783	17850
WEIGHT	17.2	17.2	17.2	17.2	17.3	17.3	17.2	17.2	16.9
VISCOSITY	72	60	62	62	62	60	66	65	64
WATER LOSS	1.3	1.3	1.5	1.5	1.6	1.6	1.7	2.2	2.0
CHLORIDE	8300	7800	7900	8000	7900	7700	7500	8500	8500
OIL	10.5	10.5	11.0	11.5	11.5	11.5	11.0	8.5	9.0
Alk	.6	.5	.5	.4	.5	.3	.3	.25	.15
DEPTH	17922	18035	18135	18276	13375	18500	18665	18776	18854
WEIGHT	17.2	17.2	17.2	17.0	17.2	17.2	17.2	17.2	17.2
VISCOSITY	65	68	66	67	64	80	74	67	62
WATER LOSS	1.8	1.8	1.6	1.8	1.4	1.2	1.2	1.3	1.4
CHLORIDE	8600	8800	8800	8500	8500	8500	8000	7800	7500
OIL	9.5	10.0	10.0	8.0	10.0	10.0	10.0	9.5	9.0
Alk	.3	.3	.4	.16	.4	.6	.2	.4	.3
DEPTH	19010	19090	19140	19276	19287	19330	19430		
WEIGHT	17.4	17.4	17.4	17.4	17.4	17.4	17.4		
VISCOSITY	67	62	68	68	70	70	64		
WATER LOSS	1.4	1.3	1.3	1.2	1.2	1.2	1.2		
CHLORIDE	7200	6800	6500	6200	6000	6500	6000		
OIL	9.5	9.5	9.5	9.0	9.0	9.2	9.4		
Alk	.2	.3	.3	.3	.25	.15	.3		

REMARKS AND ADDITIONAL DATA:

17,776-19,449' Drilled to 18,440 with 17.2#/gal. Gas cut from sand @ 18,440. Raised wt. 17.4 #/gal and drilled to to 19,287' and cut 10' core. Twisted off while drilling @ 19,449'. Left 14 Drill Collors in hole. Set 3½' liner from 17,145-19,025'. Tried to complete in sand @ 18,440. Twisted off 1¼" D.P. inside 3½" liner while drilling frac sand. Three fishing attempts failed. Well was plugged and abandoned 3-15-63.

Total 4 1/8" diamond bits-5

Total Hrs. 297

Approximate cost $14,036.03

Total Mud cost for Drilling $133,968.54

Total Mud cost for Testing & completing $33,091.98

SIGNIFICANCE OF WELL:

BOTTOM HOLE TEMPERATURE FROM WELL LOG: 430°F.

REPORT PREPARED BY: Ken Beeman

I-14

HUGHES BIT RECORD

(OVER) SHEET 1 OF 3

FILE NUMBER: 1728

- COUNTY: KENEDY
- FIELD: ARMSTRONG
- STATE: TEXAS
- SECTION:
- TOWNSHIP:
- RANGE:
- OPERATOR: HUMBLE
- RIG NO.: 1
- CONTRACTOR: STORM DRLG.
- LOCATION: ARMSTRONG #20
- SPUD: 7-5-62
- US:
- INTER:
- TOTAL DEPTH DATE:
- TOOL PUSHER: SPUD MEIDER
- TOOL JOINTS — GIVE SIZE & TYPE: 1. 4½ X HOLE O.D. 2. O.D.
- DRILL COLLARS: NO. O.D. I.D.
- PUMPS: 1. GD-GXR 18" 2. NAT E 500 14"
- DRAWWORKS & POWER: NAT. 110
- FUEL:
- WATER: WELL ON LOCATION
- NO. OF DULL:
- SALESMAN: Dick Weddell
- DIVISION: Corpus Christi
- STOCKPOINT: 4131
- DO NOT USE: STATE / ZONE / FIELD / CONTRACTOR / OPERATOR / DATE / PURCHASER

LOCATION 2 mi SE Armstrong, 49,396-ac tr, La Barreta Grt, A-3; 1320' E of EL St Hwy 77 & 4400' N of E'ly SL; sc: approx 7500' SW #1 dry hole; 4 mi SE Candelaria Fld; 4 mi SW Barreta Fld. (WHICO Coord:

DO NOT USE TYPE	WC	NO.	SIZE	MAKE	TYPE	REG	JET 32nd IN.	SERIAL	DEPTH OUT	FEET	HOURS	WT. 1000 LBS.	RPM	VERT. DEV.	PUMP PRESS.	NO. 1 SPM	NO. 1 LINER	NO. 2 SPM	NO. 2 LINER	MUD WT.	MUD VIS.	MUD W.L.	DULL. COND. T	DULL. COND. B	DULL. COND. OTHER	DULLS	FORMATION CALL DATES REMARKS
		A	30"	HTC	OSQ-R	✓		Re Run	(NOTE: 26" HTC OSQ-R BUILT up TO 30")																		
		"	"	"	"			Ran 22" Pilot Bit	And Reamed with 30" Bit to 114 Ft																		
		"	"	"	"			"	114	114	8	5	150	1/4°	700	65	6½	66	6	WTR	•				Good		
		B	22"	HTC	OSC3AJ	SR	3-18	Re Run	(Note: 17½ HTC OSC3AJ Built up to 22")																		
		"	"	"	"		Lost"	Returns	completely			Pumping	Gel + Lost Circ. Material														
		"	"	"	"		"	"	1940	1839	1	20	180	2½°	1600	Pulled up Conductor pipe											
		C	22"	HTC	OSC3AJ		3-18	Re Run	2545	605		25	220	2½°	1800	65	6½		5¾	9.4	37				Good		
		D	22"	Sec	HOLE		OPENER		Ream + washing hole to 2545"																		
		1	14¾	HTC	OSC3AJ		2-14 1-16	98761	3270	725	21	45	120	2½°	2100	60	6			9.7	63						(Dev. outlook
		2	14¾	HTC	OSC3A-J		2-14 1-16	98757	4600	1330	29	25	180	½°	2200	60	6			9.6	38						(Constant ligeons in hole)
		3	14¾	HTC	OSC3A-J		3-16	99531	5526	926	19	25	180	3/4°	2200	60	6			9.8	38						
		4	14¾	HTC	OSC3A-J		3-16	98758	5862	336	19	25	180	3/4°	2200	60	6			9.9	40						7-25-62
		5	14¾	Reed	YT3AJ		2-16 1-18	New	6438	574	17	40	180		2300	50	6			9.8	45						
		6	14¾	Reed	YT3AJ		2-16 1-18	New	6775	337	14	35	180		2300	50	6			10.1	50						
		7	14¾	HTC	OSC3A-J		3-14	98756	7079	304	16	30	180		2300	50	6			10.5	45						
		8	14¾	Reed	YT3A-J		3-14	New	7382	303	16	55	220		2000	58	6½			10.5	54						
		9	14¾	HTC	OSC3A-J		3-14	98762	7744	362	15	45	220		2300	58	6½			10.8	48						
		10	14¾	HTC	OSC3A-J		3-14	98763	8058	314	16	65	220		2110	58	6½			10.6	55						
		11	14¾	HTC	OSC3A-J		3-14	98759	8253	195	11	65	220		2250	60	6½			10.7	54						
		12	14¾	HTC	OSC3AJ		3-14	98760	8524	271	16	65	220		2300	60	6½			10.5	49						
		13	14¾	Sec	S3-J		3-16	New	8717	193	14	60	220		2300	60	6½			10.7	48						

Armstrong #20

HUGHES BIT RECORD

SHEET 2 OF 3

FILE NUMBER 1728

CITY	FIELD	STATE	SECTION	TWNSHIP	RANGE	OPERATOR	X(1)

NO.	CONTRACTOR	X(2)	LOCATION	SPUD	US	INTER	TOTAL DEPTH DATE	TOOL PUSHER
	Storm Dlg Co							

TOOL JOINTS	GIVE SIZE & TYPE	1. / 2.	O.D. / O.D.	DRILL COLLARS	NO.	O.D.	I.D.	PUMPS 1. / 2.	DRAWWORKS & POWER	FUEL	WATER	NO. OF DULLS

SALESMAN	DIVISION	STOCKPOINT	DO NOT USE	STATE	ZONE	FIELD	CONTRACTOR	OPERATOR	DATE	PURCHASER

DO NOT USE TYPE	WC	NO.	SIZE	MAKE	TYPE	✓ REG	JET 32nd IN.	SERIAL	DEPTH OUT	FEET	HOURS	WT. 1000 LBS.	RPM	VERT. DEV.	PUMP PRESS.	NO. 1 SPM	NO. 1 LINER	NO. 2 SPM	NO. 2 LINER	MUD WT.	MUD VIS.	MUD W.L.	DULL. COND. T	DULL. COND. B	DULL. COND. OTHER	✓ DULLS	FORMATION CALL DATES REMARKS
		14	14 3/4	Reed	YT3-AJ		3-14	New	8940	223	13	60	220		2200	58	6 1/2			10.7	48						
		15	14 3/4	Reed	YT3-AJ		3-14	New	9158	218	15	55	220		2300	58	6 1/2			10.7	55						
		16	14 3/4	HTC	OSC3AJ		3-16	98755	9291	133	10	55	220		2100	63	6 1/2			10.8	55						
		17	14 3/4	HTC	OSC3J		3-16	68877	9424	133	9	55	220		2100	63	6 1/2			11.9	55						
		18	14 3/4	HTC	OSC3J		3-16	68882	9593	169	9	55	220		2100	63	6 1/2			11.0	53						
		19	14 3/4	Reed	YT3AJ		3-16	New	9723	130	15	55	180		2200	58	6 1/2			11.0	55						
		20	14 3/4	Reed	YT3AJ		2-14 1-16	New	9864	141	16	55	180		2200	58	6 1/2			11.1	53						
		21	14 3/4	Reed	YT3AJ		3-16	New	10,029	165	14	55	180		2200	58	6 1/2			11.3	58						
									8-10-62		Reached				10,029	FT.											
		22	9 5/8	Reed	YT3-J		2-14 1-16	New	10,034	5	6	30/40	140		2300	56	6						Half of [illegible] off				
		23	9 5/8	HTC	OWV-J		3-20	301	10,100	64	7	35/50	140		2300	56	6						[illegible] on junk				
		24	9 5/8	HTC	OSC3-J		3-14	55365	10,150	50	6	35/50	140		1800	66	6										
		25	9 5/8	HTC	OSC3-J		3-14	53871	10,307	157	13	35/50	140		2000	66	6										
		26	9 5/8	Reed	YT3-J		2-14 1-16	New	10,341	34	6	35/50	140		2000	66	6										
		27	9 5/8	HTC	OSC3-J		2-16 1-14	55366	10,491	150	16	35/50	130		2000	65	6										
		28	9 5/8	Reed	YT3-J		2-16 1-14	New	10,630	140	13	35/50	130		2000	64	6										
		29	9 5/8	HTC	OSC3-J		2-16 1-14	54037	10,741	111	12	35/50	130		2000	64	6										
		30	9 5/8	HTC	OSC3-J		2-16 1-14	53874	10,841	100	13	35/50	130		2000	63	6										
		31	9 5/8	HTC	OSC3-J		2-16 1-14	53870	10,927	84	12	35/50	130		2000	63	6			15.2	55						8-25
		32	9 5/8	Reed	YT1-J		2-16 1-14	New	11,000	73	6	30	120		2000	63	6			15.2	59						
		33	9 5/8	HTC	OSC1GJ		2-16 1-14	25413	11,112	112	13	35	120		2000	63	6			15.2	55						
		34	9 5/8	HT	OSC1GJ		2-16 1-14	25411	11,206	94	13	30	85		1000	62	6			15.1	65						
		35	9 5/8	HT	OSC1GJ		2-16 1-14	72322	11,345	139	13	30	85		1500	62	6			15.3	62						
		36	9 5/8	Reed	YT1AJ		2-16 1-14	New	11,457	112	16	35	85		1600	62	6			15.4	100						

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L. ARMSTRONG #20 CONT'D. HUGHES BIT RECORD

SHEET 3 OF 3 FILE NUMBER 1728

COUNTY	FIELD	STATE	SECTION	TOWNSHIP	RANGE	OPERATOR	X(1)

RIG NO.	CONTRACTOR	X(2)	LOCATION	SPUD	US	INTER	TOTAL DEPTH DATE	TOOL PUSHER
	STORM DRLG CO							

TOOL JOINTS GIVE SIZE & TYPE	1.	O.D.	DRILL COLLARS NO.	O.D.	I.D.	PUMPS 1.	DRAWWORKS & POWER	FUEL	WATER	NO. OF DULLS
	2.	O.D.				2.				

SALESMAN	DIVISION	STOCKPOINT	DO NOT USE	STATE	ZONE	FIELD	CONTRACTOR	OPERATOR	DATE	PURCHASER

DO NOT USE MFR.	TYPE	WC	NO.	SIZE	MAKE	TYPE	√ REG	JET 32nd IN.	SERIAL	DEPTH OUT	FEET	HOURS	WT. 1000 LBS.	RPM	VERT. DEV.	PUMP PRESS.	NO. 1 SPM	NO. 1 LINER	NO. 2 SPM	NO. 2 LINER	MUD WT.	MUD VIS.	MUD W.L.	DULL. COND. T	B	OTHER	√DULLS	FORMATION CALL DATE REMARKS
			37	9 5/8	HT	OSC1GJ		2-16 1-14	36574	11,682	225	16	30	84		1600	60	6			15.5	70						
			38	9 5/8	HT	OSC1GJ		2-16 1-14	25410	11,823	141	15	30	84		1600	60	6			15.7	74						
			39	9 5/8	Reed	YT1 J		2-16 1-14	New	12,000	177	16	30	84		1600	60	6			15.7	74						
									Rocked		12,000 FT			9-3-67			Set				7 5/8 Csg.							
			40	6 3/4	Sec	S4-J		0																				
			41	6 3/4	Sec	S4-J		5/8	New	12,017	17		30	80		2000	40	6										
			42	6 3/4	HTC	OSC1GJ		5/8	8171	12,180	163	15	30	85		2000	40	6			16.4	63						
			43	6 1/16	HYCALOG	◇				12,273	93	15	30	85		2000	40	5 1/2			16.6	62						
			44	7	Williams	◇				13,177	904	88	14	120		2300	43	5 3/4			17.2	77						
			45	6 1/16	HYCALOG	◇				14,646	1469	163	14	120		2300	43	"			17.2	64						
			46	6 1/16	"	" ◇				16,000	1354	151	14	120		2300	43	"			17.3	61						
					→			→		17,776	1766	176	14	120		2300	43	5"			17.3	61						
			47	4 1/8	HTC	OW	Reg		28517	17,763	Plug + Float Collar + Cement Drilled																	
			48	4 1/8	HTC	OW	Reg		35387	17763																		
			49	4 1/8	Htc	W7	Reg		28466	17763																		
			50	4 1/8	Htc	OSC	✓	✓	48652	17763																		
			51	4 1/8	Htc	W7	✓		71194	17768		Drlg Cement & Shoe																Lost 3 Cone
				4 1/8	H	◇		DD	NEW	19276	1493	265																
				4 1/8	H.	◇	DD			19291	15	3																
			52	4 1/8	H	◇		DD	NEW	19449			T.	Set 3 1/2 Liner at 19025														14 DC
			53	4 1/8	Htc	OW	✓		28522							Drlg Cement To Top of Liner												
			54	2 7/8	D&W	Four Way			NEW							Drlg Cement in Liner												
			55	4 1/8	Htc	OW			28516	16852	Drill Plug & Cement																	
								T.	D																			

TC-308

SCHLUMBERGER INDUCTION-ELECTRICAL LOG

SCHLUMBERGER WELL SURVEYING CORPORATION

COUNTY KENEDY
FIELD or LOCATION WILDCAT (EAST CANDELARIA AREA)
WELL CHARLES M. ARMSTRONG #20
COMPANY HUMBLE OIL AND REFINING COMPANY

COMPANY HUMBLE OIL AND REFINING COMPANY

WELL CHARLES M. ARMSTRONG #20

FIELD WILDCAT (EAST CANDELARIA AREA)

LOCATION

COUNTY KENEDY

STATE TEXAS

Other Surveys: SLC

Location of Well: LA BARRETA GRANT. 1320' E OF EL OF STATE HIGHWAY #77 & 4400' N OF EASTERLY SL OF LEASE, ALSO APPROXIMATELY 7300' SW OF #1.

Elevation: K.B. *
D.F.
or G.L.

FILING No.

RUN No.	ONE	TWO	THREE	FOUR	FIVE
Date	7-31-62	8-11-62	8-25-62	9-1-62	9-17-62
First Reading	8052	10027	10997	11998	14007
Last Reading	1959	8052	10027	10997	12001
Feet Measured	6093	1975	970	1001	2006
Csg. Schlum.	1959	-----	9986	9988	12001
Csg. Driller	1959	1959	9993	9993	11998
Depth Reached	8053	10028	10998	11999	14008
Bottom Driller	8058	10029	11000	12000	14000
Depth Datum	RKB, 20'	ABOVE GROUND LEVEL	RKB=21.50'/G.L.	CSG-HD	
Mud Nat.	XP-20		XP-20	XP-20	XP-20
Dens. | Visc.	10.6 | 54	11.2 | 52	15.2 | 66	16.0 | 68	17.2 | 80
Mud Resist.	.56 @ 100°F	.8 @ 85°F	.97 @ 80°F	.88 @ 85°F	.81 @ 83°F
" Res. BHT	.31 @ 180°F	.38 @ 182°F	.35 @ 220°F	.31 @ 224°F	.25 @ 274°F
Rmf	.40 @ 82°F	.6 @ 100°F	.41 @ 75°F	.28 @ 75°F	.29 @ 79°F
Rmc	-- @ --°F	1.1 @ 100°F	.91 @ 75°F	.62 @ 224°F	--- @ --°F
" pH	9.0 @ --°F	9 @ °F	9.8 @ --°F	9.8 @ --°F	10.0 @ --°F
" Wtr. Loss	4.0 CC 30 min.	2.4 CC 30 min.	1.8 CC 30 min.	1.0 CC 30 min.	2.2 CC 30 min.
Bit Size	14-3/4"	14 3/4"	9 5/8"	9 5/8"	6 3/4"
Spcgs.—AM	16"	16"	16"	16"	16"
MN	34'6"	34'6"	34'6"	34'6"	34'6"
IND.	6FF40	6FF40	6FF40	6FF40	6FF40
Opr. Rig Time	2 HOURS	1.5 HOURS	2 HOURS	2 HOURS	2 HOURS
Truck No.	3533-CC	1556-ALICE	3533-C.C.	4514-C.C.	4514-C.C.
Recorded By	SHORT	ELLIS	SHORT	BOND	COMPTON
Witness MR.	LOWE	LOWE	LOWE	WYNNE	WYNNE

SCHLUMBERGER INDUCTION-ELECTRICAL LOG

SCHLUMBERGER WELL SURVEYING CORPORATION

COUNTY
FIELD or LOCATION
WELL
COMPANY

COMPANY

WELL

FIELD

LOCATION

COUNTY

STATE

Other Surveys

Location of Well

Elevation: K.B.
D.F.
or G.L.

FILING No.

RUN No.	SIX	SEVEN	EIGHT	NINE	TEN
Date	9-27-62	10-3-62	10-8-62	10-15-62	10-17-62
First Reading	15008	16009	16891	17511	17773
Last Reading	14007	14900	16009	16892	17511
Feet Measured	1001	1109	882	619	262
Csg. Schlum.	12001	12001	12001	12001	12001
Csg. Driller	11998	11998	11998	11998	11998
Depth Reached	15009	16010	16892	17512	17774
Bottom Driller	15000	16000	16884	17502	17766
Depth Datum	KB=21.5'	ABOVE CASING HEAD			
Mud Nat.	XP-20	OIL EMULSION 10%		SPERSENE	XP-20
Dens. | Visc.	17.2 | 72	17.2 | 62	17.3 | 74	17.3 | 69	17.3 | 80
Mud Resist.	.49 @ 105°F	.56 @ 90°F	.54 @ 91°F	.65 @ 85°F	.67 @ 80°F
" Res. BHT	.17 @ 300°F	.16 @ 317°F	.15 @ 320°F	.167 @ 310°F	.16 @ 343°F
Rmf	.05 @ 300°F	.32 @ 72°F	.042 @ 320°F	.22 @ 80°F	.25 @ 80°F
Rmc	.40 @ 300°F	... @ ..°F	.31 @ 320°F	.35 @ 310°F	1.14 @ 80°F
" pH	9.89 @ --°F	9.9 @ ..°F	10.0 @ --°F	9.8 @ --°F	9.8 @ --°F
" Wtr. Loss	1.2 CC 30 min.	1.8 CC 30 min.	1.[illegible] CC 30 min.	1.6 CC 30 min.	1.6 CC 30 min.
Bit Size	6 11/16"	6 11/16"	6 [illegible]	6 11/16"	6 11/16"
Spcgs.—AM	16"	16"	16"	16"	16"
MN	34'6"	34'6"	34'[illegible]	34'6"	34'6"
IND.	6FF40	6FF40	6FF40	6FF40	6FF40
Opr. Rig Time	2 HOURS	2 HOURS	2 HOURS	3 HOURS	3 HOURS
Truck No.	4514-C.C.	3533-C.C.	4514-CC	4516-HEBB	2582-HEBB
Recorded By	PORTER	BLUMBERG	PORTER	HAMMAR	ROBBINS
Witness MR.	WYNNE	WYNNE	WYNNE	WYNNE	WYNNE

SCHLUMBERGER ELECTRICAL LOG

SCHLUMBERGER WELL SURVEYING CORPORATION

COUNTY
FIELD or LOCATION
WELL
COMPANY

COMPANY

WELL

FIELD

LOCATION

COUNTY

STATE

Other Surveys

Location of Well

Elevation: D.F.
K.B.
or G.L.

FILING No.

RUN No.	ELEVEN	TWELVE **	THIRTEEN		
Date	1-10-63	1-15-63	1-20-63		
First Reading	18273	18777	19269		
Last Reading	17772	17776	18777		
Feet Measured	501	1001	492		
Csg. Schlum.	17772	17772	17772		
Csg. Driller	17776	17776	17776		
Depth Reached	18274	18778	19270		
Bottom Driller	18276	18776	19276		
Depth Datum	KB, 21.5'	ABOVE GROUND LEVEL			
Mud Nat.	XP-20	SPERSENE	XP-20		
Dens. | Visc.	17.2 | 65	17.2 | 67	17.4 | 68	|	|
Mud Resist.	0.54 @ 77°F	.52 @ 75°F	.54 @ 68°F	@ °F	@ °F
" Res. BHT	.15 @ 361°F	.105 @ 368°F	.11 @ 378°F	@ °F	@ °F
Rmf	.19 @ 68°F	.21 @ 70°F	.20 @ 71°F	@ °F	@ °F
Rmc	1.41 @ 77°F	1.50 @ 70°F	1.27 @ 71°F	@ °F	@ °F
" pH	9.1 @ --°F	9.8 @ --°F	9.8 @ --°F	@ °F	@ °F
" Wtr. Loss	1.8 CC 30 min.	1.3 CC 30 min.	1.3 CC 30 min.	CC 30 min.	CC 30 min.
Bit Size	4 1/8"	4 1/8"	4 1/8"		
Spcgs.—AM	16"	16"	16"		
AH	64"	64"	64"		
AO	18'8"	18'8"	18'8"		
Opr. Rig Time	3 HOURS	3 HOURS	3 HOURS		
Truck No.	4516-HEBB	4516-HEBB	2582-HEBB.		
Recorded By	HAMMAR	ROBBINS	JOHNSTON		
Witness MR.	WYNNE	WYNNE	WYNNE		

REMARKS

NOTE: RUNS #11, #12, AND #13 ARE ELECTRICAL LOGS.

**RUN #11 RERUN WITH RUN #12.

NOTE: SP SCALE CHANGE:
CSG. - 17772 = 10 MVS.
17772 - T.D. = 4 MVS.

REMARKS CP

C.D. USED   I.S.O. = 1.5"   * UNAVAILABLE

RUN NO.	ONE	TWO	THREE	
Cartridge No.	G-407	IRC-D-485	IRC-E-407	RM FROM MUD PIT SAMPLE
Panel No.	F-1	IRP-F-78	IRP-F-1	RMF FROM FILTER PRESS
Sonde No.	K-43	IRS-K-184	IRS-K-43	RUN #2-RM FROM CIRCULATED, F-117
IAP	D-141	IAP-D-98	IAP-D-43	D-141
	SBR-1	SBR-1	SBR-1	

E218 HIGH TEMP HIGH TEMP

I-17

KENEDY	SOUTH TEXAS	WILDCAT

Well: HUMBLE O&R CO., #22 Charles M. Armstrong Result: DRY

Loc'n:
5 mi SW Armstrong, 49,396-ac lse, La Barreta Grt, A-3; 9943' NE of #3, dry hole & 11,031' SE of #6, dry hole; also being 1320' NE-FN'ly SWL of Grt & 17,472' S of #8, dry hole; sc: FNW/cor of San Juan de Carricitos Grt, A-8, go SE alg NEL 3300', th NE@RA 1320' to loc; 8 mi NE Julian Fld.

Spud: 4-16-65 Comp: 6-8-65 Elev: 32' Grd/DF 47' TD: 14,226' C/ Monte Christo Drlg Co.
Casing: 20" 60'; 13 3/8" 2005'; 9 5/8" 10,199'; 7" lnr @ 11,916' (T/Lnr @ 9877')
Comp Info: installed ML @ 7250'; drld to 7254' & lost partial returns (lost 40 bbls mud in 40 mins); cond mud & regained lost circ; drld to 10,202'; ran IE/L, S/L & DM; took SWCs; ran WLT; drld to 11,928'; ran IE/L, S/L & DM; no SWCs & no WLTs; drld to 13,610'; ran IE/L, S/L & DM; no SWCs & no WLTs; drld to TD 14,226'; ran IE/L & S/L; no SWCs & no WLTs; set BP @ 9821'; D&A 6-8-65.

NL BAROID

Tullidos Area

PRESSURE PLOT

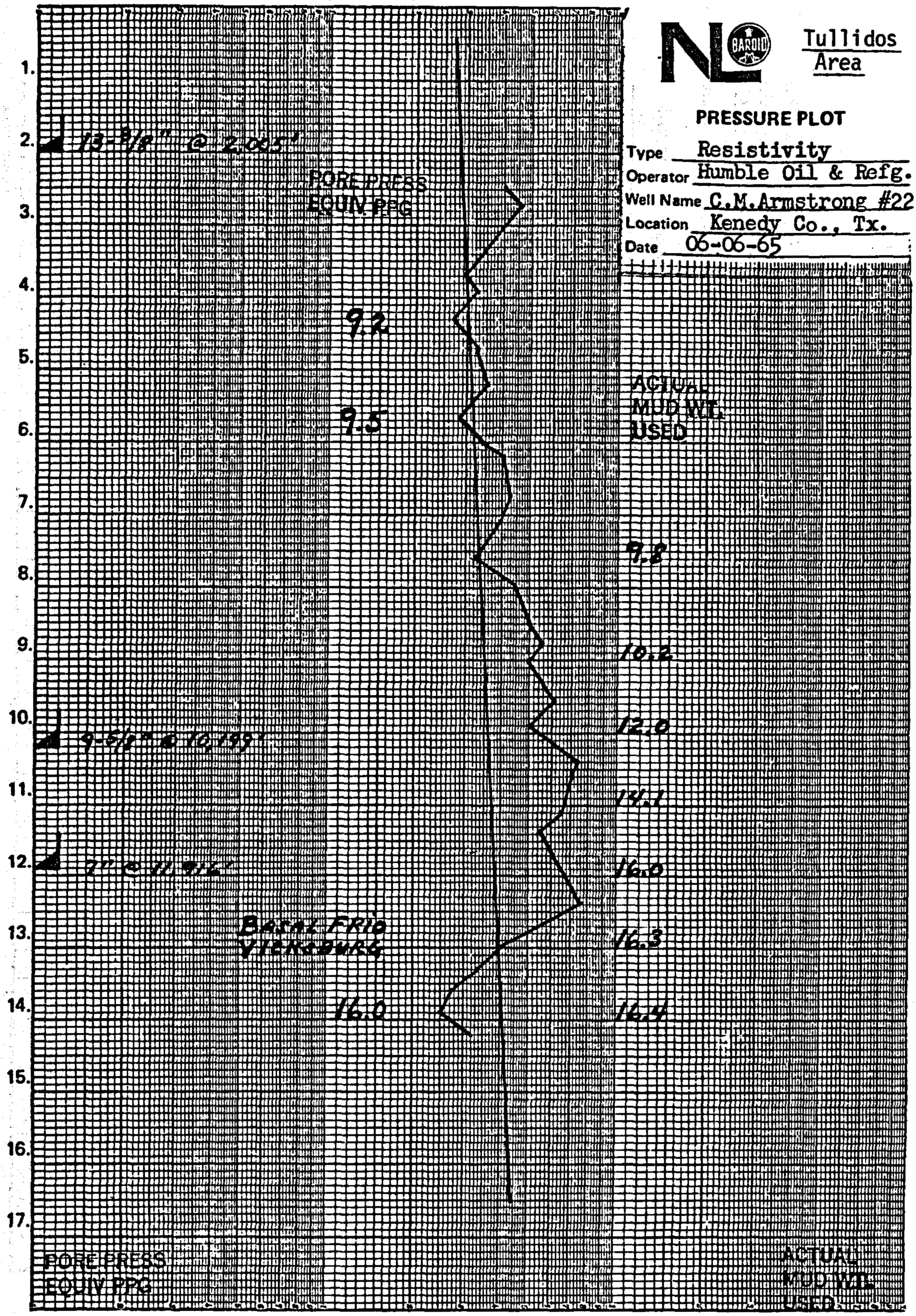
Type: Resistivity

Operator: Humble Oil & Refg.

Well Name: C.M.Armstrong #22

Location: Kenedy Co., Tx.

Date: 06-06-65



Compiled by Ed Cain

BAROID DIVISION
NATIONAL LEAD COMPANY

DRILLING MUD RECORD

COMPANY Humble Oil & Ref. Co. STATE Texas CASING PROGRAM: 13 3/8 inch at 2050

WELL Armstrong #22 COUNTY Kenedy 9 5/8 inch at 10,200

DATE 1965 CONTRACTOR Monte Christo Drlg. Co. LOCATION 7 inch at 11,916

STOCKPOINT Falfurrias BAROID ENGINEER John Cubine SEC TWP RNG TOTAL DEPTH

DATE	DEPTH feet	WEIGHT lb/gal	VISCOSITY Sec	FILTRATION cc	FILTRATION Cake 32nd	SAND %	SALT NaCl ppm	SALT Cl ppm	pH	VISCOSITY cp	VISCOSITY Pv	VISCOSITY Yp	GELS in	GELS 10 min	FILTRATE ANALYSIS Cl ppm	FILTRATE ANALYSIS Ca ppm	FILTRATE ANALYSIS SO_4 ppm	FILTRATE ANALYSIS Alk Pf	RETORT ANALYSIS Oil %	RETORT ANALYSIS Water %	RETORT ANALYSIS Solids %	REMARKS AND TREATMENT
4-17	2050	Water																				wt 8.5 - 9.0.
4-19	5913	9.3	51			1 1/2																wt 8.5 - 9.5
4-20	6907	9.9	30	72.0	4	4		1100	7.5	15	5	5	3	7	280			0	–	–	–	
4-21	7254	9.4	32	62.0	3	2		1050	7.5	16	6	4	2	6	280			0	–	–	–	
4-22	7554	9.9	32	60.0	3	5 1/2		1160	7.5	15/10	5	5	5	8	240			0	–	–	–	12 AM. wt 9.0 - 10.0
4-22	7554	9.8	30	30.8	2	1/2		1100	8.0	12/7	5	2	0	3	160			.1	–	–	–	6:00 PM.
4-23	7761	10.0	32	19.2	2	1/2		1200	9.0	15/9	6	3	0	3	120			.2	2	86	12	Hole Taking a small
																						amount of fluids.
4-24	8598	10.4	36	20.0	2	2 1/2		1300	8.0	27/17	10	7	1	5	100			.1	4	82	14	
4-25	8606	10.1	37	22.4	2	2		1100	8.0	29/18	11	7	2	9	100			.1	4	84	12	
4-26	8768	10.2	37	18.8	2	3.0		1160	8.0	27/16	11	5	0	9	100			.1	3	84	13	Hole Still Taking
4-27		10.2	36	15.2	2	2 1/2		1100	8.0	28/17	11	6	0	8	120			.1	3	84	13	Mud. wt. 10.0 - 10.5.
4-28	9523	10.3	40	16.6	2	2 1/2		1160	8.5	32/20	12	8	0	12	100			.15	4	82	14	Hole Taking fluid
																						in smaller amt than
																						previously. wt 10.5 - 11.0
4-29	9672	11.0	51	14.0	2	2 1/2		1200	9.0	40/24	16	8	0	18	160			.2	6	80	14	wt 11.0 9/1
4-30	9901	11.7	58	10.0	2	2		1200	8.5	60/35	25	10	0	15	100			.15	8	74	18	wt 12.0
5-1	9945	12.0	52	9.2	2	2		1300	9.0	62/35	27	8	0	8	–			.2	8	74	18	
5-2	10,175	12.0	40	8.0	2	2		1400	9.0	37/22	15	7	0	4	100			.25	8	74	18	
5-6	10,220	12.1	45	9.2	2	1/2		1500	9.8	52/30	22	8	0	8	200			.5	6	74	20	
5-7	10,255	12.7	43	8.8	2	–		1600	9.8	48/28	20	8	0	6	200			.5	6	72	22	
5-8	10,563	12.9	43	5.2	2	–		1900	9.5	53/30	23	7	0	2	240			.45	6	70	24	
5-9	10,687	13.3	42	5.2	2	–		2000	10.0	50/28	22	6	0	1	240			.6	6	70	24	
5-10	10,850	13.4	46	6.0	2	–		2100	9.8	60/34	26	8	0	2	240			.45	7	67	26	
5-11	11,097	14.1	42	5.8	2	–		2000	10.0	55/30	25	5	0	1	280			.65	8	64	28	
5-13	11,260	14.4	50	6.2	2	–		2400	9.0	82/47	35	12	0	4	320			.4	6	66	28	
5-15	11,651	14.5	51	5.6	2	–		2600	9.5	80/46	34	12	0	2	200			.5	7	65	28	
5-16	11,928	14.5	99	7.8	2	–		4800	8.5	110/65	45	20	0	15	400			.15	8	64	28	9:45 AM.
	11,928	14.5	42	6.6	2	–		4500	9.0	49/28	21	7	0	1	440			.3	–	–	–	12:30 PM.

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BAROIL DIVISION
NATIONAL LEAD COMPANY

Page # 2 of 2

DRILLING MUD RECORD

COMPANY Humble Oil & Ref. Co. STATE ______ CASING PROGRAM: ______ inch at ______
WELL Armstrong #22 COUNTY ______ ______ inch at ______
DATE ______ CONTRACTOR ______ LOCATION ______ ______ inch at ______
STOCKPOINT ______ BAROID ENGINEER ______ SEC. ______ TWP. ______ RNG. ______ TOTAL DEPTH ______

DATE	DEPTH feet	WEIGHT lb/gal	VISCOSITY Sec	FILTRATION cc	Cake 32nd	SAND %	SALT NaCl ppm	SALT Cl ppm	pH	VISCOSITY cp	Pv	Yp	GELS In	GELS 10 min	FILTRATE ANALYSIS Cl ppm	Ca ppm	SO_4 ppm	Alk Pf	RETORT ANALYSIS Oil %	Water %	Solids %	REMARKS AND TREATMENT
5-17	11,929	14.5	37	4.8	2	–		6200	9.8	45/25	20	5	0	0	440			.5	7	65	28	Spotted pill at
		14.5	42	5.6	2	–		7400	9.8	[illegible]/30	20	6	0	1	560			.5	–	–	–	bottom, treated with
	Pill	14.5	38	1.6	1	–		8100	12.5		6	0	0	0	520			2.5	–	–	–	Caustic & Q Broxin to
																			–			overcome contamination
																						while running logs.
5-18	11,928	14.4	45	13.0	2	–		11,500	10.6	[illegible]/34	26	8	0	0	640			1.4	6	66	28	10:00 P.M.
	"	14.4	47	5.8	2	–		9500	10.0	[illegible]/36	28	8	0	0	640			.7	–	–	–	11:00 P.M.
	Pill	14.5	40	1.4	1	–		9200		[illegible]/28	22	6	0	0	–			1.3	–	–	–	12:40 A.M.
																						First mud check was
																						from mud on bottom
																						when well was
																						kicking.
																						pumped in & spotted
																						in open hole, mud
																						treated with 15 sks
																						Q Broxin, 4 Caustic Soda
																						10 Carbonox.
[illegible]	[illegible]																					
5-21	11,637	16.0	50	5.0	2	–		9000	11.7	43	36	14	0	0	480			2.2	5	64	31	
5-22	12,157	16.0	49	4.8	2	–		8500	11.5	40	32	16	1	0	480			1.7	7	62	31	
5-23	12,376	16.0	49	4.8	2	–		8400	11.3	35	30	10	0	0	440			1.5	7	62	31	
5-24	12,632	16.1	50	4.1	2	–		8200	10.7	36	31	10	0	0	380			1.2	6	63	31	
5-25	12,812	16.1	49	4.6	2	–		8100	10.7	35	30	10	0	0	480			1.2	5	64	31	
5-26	12,922	16.3	48	6.2	2	–		8600	9.8	[illegible]/43	35	8	0	2	560			.8	8	58	34	
5-27	13,122	16.3	50	5.8	2	–		8500	10.0	[illegible]/45	37	8	0	1	480			.8	8	57	33	API. Solids – 3.95
5-28	13,260	16.3	46	4.0	2	–		8500	10.2	[illegible]/38	31	7	0	1	280			1.0	9	57	34	
5-29	13,469	16.3	46	3.6	1/32	–		8600	10.2	[illegible]/42	36	6	0	1	240			1.1	9	57	34	Ht. Filter 250°-300# 12.8 cc
5-30	13,470	16.3	48	2.8	1/2	–		8600	10.8	[illegible]/42	36	6	0	1	160			1.7	9	57	34	
6-1	13,680	16.4	46	2.4	2	–		8600	11.0	[illegible]/39	31	7	0	1	120			1.7	8	58	34	APG Solids – 3.9
6-3	13,995	16.3	46	2.6	2	–		8700	10.8	[illegible]/43	35	8	0	0	120			1.6	8	58	34	APG Solids – 3.85

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I-21

BAROID DIVISION
NATIONAL EAD COMPANY

\ / [illegible]

COMPANY Humble Oil & Ref. Co. STATE Texas

WELL Armstrong #22 COUNTY Kenedy

CONTRACTOR Monte Christo Drlg. Co. LOCATION ______ SEC ______ TWP ______ RNG ______

STOCKPOINT Falfurrias DATE [illegible] BAROID ENGINEER John Cubine

CASING PROGRAM: 13 3/8 Inch at 2050 ft
9 5/8 Inch at 10,200 ft
7 Inch at 11,916 ft
TOTAL DEPTH 13,995 ft

DATE	DEPTH	WEIGHT	VISCOSITY	FILTRATION		SAND	SALT		pH	VISCOSITY			GELS		FILTRATE ANALYSIS				RETORT ANALYSIS			REMARKS AND TREATMENT
	feet	lb/gal	Sec	cc	Cake 32nd	%	NaCl ppm	Cl ppm		cp	Pv	Yp	In	10 min	Cl ppm	Ca ppm	SO_4 ppm	Alk Pf	Oil %	Water %	Solids %	

Lost Returns 11,200± Let Hole soak (12 HRS) and Cut Mud weight from 14.8 to 14.4

Lost Partial Returns in intermediate Hole

High Gel strengths reduced loss

No treatment with LCM Made –

NOTE: Cost included Q-Broxin + Caustic Soda furnished by Humble O & R. from Humble Company Stock.

MATERIAL	AMOUNT	COST $	MATERIAL	AMOUNT	COST $	MATERIAL	AMOUNT	COST $
A. Stearate	3	41.73	Carbonox	450	2106.00			
Aquagel	380	881.60	Hydrotan	14	122.50			
Baracor	33	585.75	Micatex C.	8	30.08	Caustic Soda	300 #	6,941.61
Baroid 100# Bags	304	659.68	SF 100	0	0	Q-Broxin	680 #	1,288.26
			Soda ash	12	56.00			
Baroid Bulk-TONS	636.47	28,259.27	Rig Tanks	3	75.00	Drayage		119.36
						Sales Tax		656.79
Bicarb. of Soda	13	97.50	[illegible]			TOTAL COST		41,922.13

BAROID

MUD MATERIALS USED (Total)

DRILLING MUD RECORD

PBS 6C 9-64

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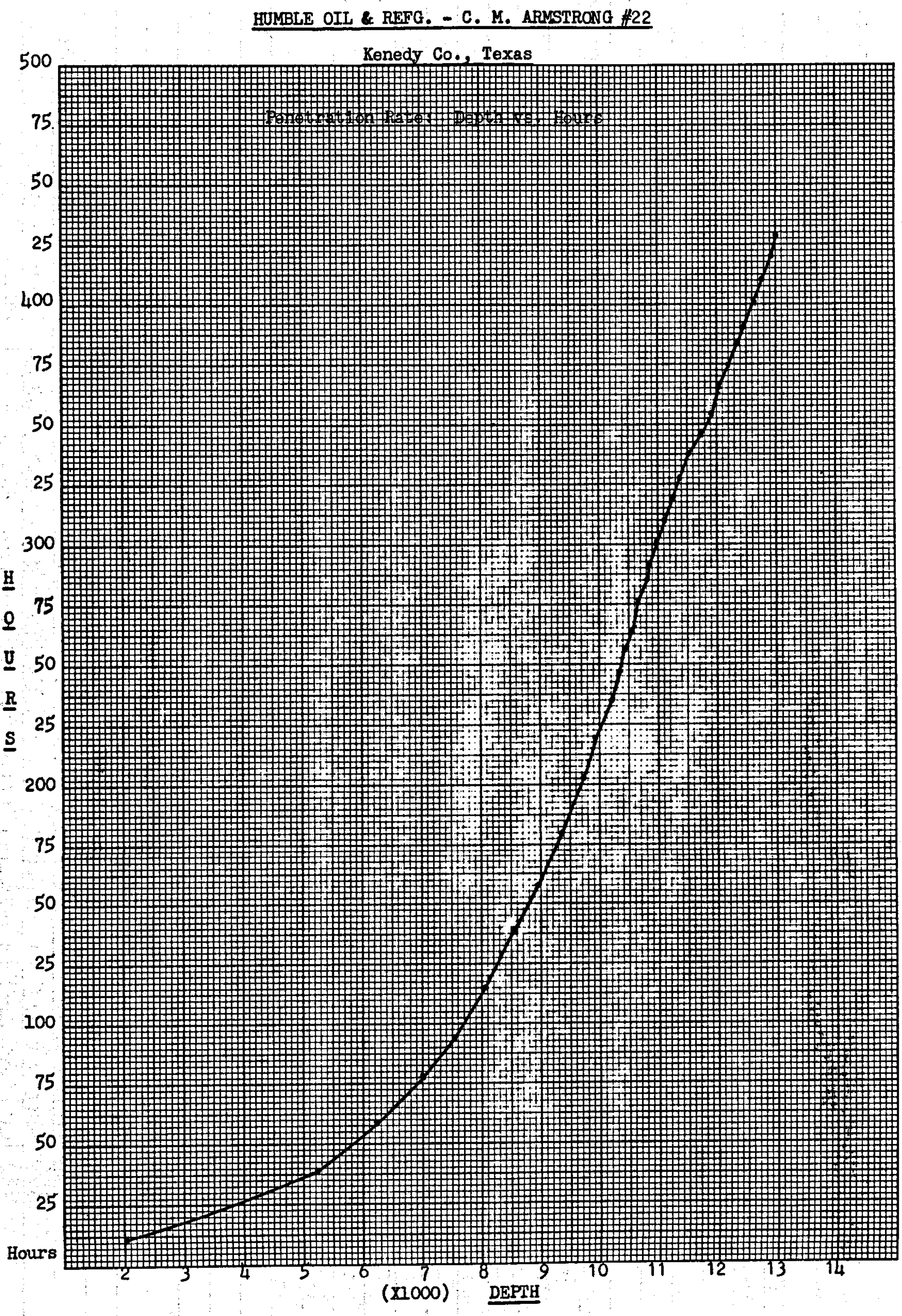
HUMBLE OIL & REFG. - C. M. ARMSTRONG #22
Kenedy Co., Texas
Penetration Rate: Depth vs. Hours
HOURS
500
75
50
25
400
75
50
25
300
75
50
25
200
75
50
25
100
75
50
25
Hours
2
3
4
5
6
7
8
9
10
11
12
13
14
(X1000) DEPTH

I-24

5 Mi S' V Armstrong Texas **HUGHES BIT RECORD** of 2 FILE NUMBER 186

COUNTY: Kenedy | FIELD: Armstrong | STATE: Texas | SECTION | TOWNSHIP: -- | RANGE | OPERATOR: Humble Oil & Refg. Co. X (1)

CONTRACTOR: 2 Monte Christo Drlg. Co. X (2) | LOCATION: C.M. Armstrong #22 | SPUD: 4-15-65 | US: 4-17 | INTER: 5-21-65 | TOTAL DEPTH DATE: 6-5-65 | TOOL PUSHER: Leroy Cook

GIVE SIZE & TYPE: 1. 4½ IF O.D. 2. O.D. | DRILL COLLARS NO. O.D. I.D. | PUMPS 1. Natl. H-850M 2. Natl. C-350 | DRAWWORKS & POWER: NATL 80-B | FUEL: Diesel | WATER: Well | NO. OF DULLS

SALESMAN: Wehdell | DIVISION: Corpus Christi | STOCKPOINT NO.: 14135 | DO NOT USE | STATE | ZONE | FIELD | CONTRACTOR | OPERATOR | DATE | PURCHASER

CONFIDENTIAL

NOT USE TYPE	WC	NO.	SIZE	MAKE	TYPE	√ REG	JET 32nd IN.	SERIAL	DEPTH OUT	FEET	HOURS	WT. 1000 LBS.	RPM	VERT. DEV.	PUMP PRESS.	NO. 1 SPM	NO. 1 LINER	NO. 2 SPM	NO. 2 LINER	MUD WT.	MUD VIS.	MUD W.L.	DULL COND. T	DULL COND. B	DULL COND. OTHER	√ DULLS	FORMATION CALL DATES REMARKS
				RELEASE ONLY BY CONTRACTORS PERMISSION NOTED																							
		A	18½	HTC	OSC3AJ		2-16 1-19	ReRun	2050	1990	12	20 30	200		2000	62	7	51	5½								
		1	12¼	HTC	X3A		2-18 1-16	8829	5226	3176	26	25 60	100 190		2000	60	7	56	5½	9.2	36		4	8	SF		SFSF
		2	12¼	HTC	X3A		2-16 1-18	8840	6252	1026	20½	46 70	100 160		1500 1800	60	7	56	5½	9.3	35		5	7	SE		SFE
		3	12¼	HTC	X3A		3-13	8837	7002	750	19	20 65	70 160		2000	61	7			9.4	32		5	8	SF		SF SF
		4	12¼	HTC	X3		3-13	4090	7551	549	15¼	50 60	70 120		2000	61	7			9.8	32		2	?	SE		SE SE
		5	12¼	HTC	X3A		3-13	8828	8096	545	22	50 60	90 120		2200	60	7			10.2	40		5	5	SE		
		6	12¼	HTC	X3A		3-10	8839	8638	542	23½	50 60	90 120		2300	59	6			10.4	36		5	7			
		7	12¼	HTC	X3		3-10	13379	8982	349	19	50 75	90 120		2400	60	6			10.3	36		5	7	Drpd		
		8	12¼	HTC	X3		3-10	4092	9391	409	22½	50 75	90 120		2400	60	6			10.3	38		5	6			
		9	12¼	HTC	X1G		3-10	7778	9754	363	22½	50 70	90 120		2400	61	6			11.2	49		6	8			
		10	12¼	HTC	X1G		2-10 1-11	13378	9961	207	17	45 60	90 120		2400	61	6			12.0	52		5	6	SE		
		11	12¼	HTC	X3		2-10 1-11	7794	10205	244	16	45 60	90 120		2400	61	6			12.0	42		4	8			
									TD 10205	5-2-65																	
				HUMBLE O&R BUYING BITS TO TOTAL DEPTH																							
										Set 9⅝ Csg					5-5-65	Drill out				5-6-65							
		1	8⅝	HTC	OWVJ		2-10 1-11	15001	10331	126	11	45	100		2600		62	6		12.4	50		5	6	BT		
		2	8⅝	HTC	OSC1GJ		3-13	35757	10448	117	10	30 45	140		2200		64	6		"	"		5	7			
		3	8⅝	HTC	OSC1GJ		3-11	35749	10578	130	9½	45	120 140		2600		62	6		12.8	42		5	7			
		4	8⅝	HTC	OWVJ		2-11 1-12	7463	10697	119	9½	30 45	140		2600		62	6		13.1	45		5	6	BT		
		5	8⅝	HTC	OWVJ		"	15000	10831	134	9½	45	140		2600		62	6		"	"		5	6	BT		
		6	8⅝	HTC	OWVJ		"	26928	10904	73	7½	40	150		2600		62	6		13.3	46		5	5			PULL WO DC
		7	8⅝	HTC	OWVJ		"	24482	11009	105	8½	"	155		2600		62	6		"	"		5	5			
		8	8⅝	HTC	OSC1GJ		"	25461	11101	92	8½	"	150		2600		58	6		14.3	42		5	6			

7050

HUGHES BIT RECORD

SHEET 2 OF 2 — FILE NUMBER 386

COUNTY	FIELD	STATE	SECTION	TOWNSHIP	RANGE	OPERATOR
KENEDY	ARMSTRONG	TEXAS				HUMBLE O&R

CONTRACTOR	LOCATION	SPUD	US	INTER	TOTAL DEPTH DATE	TOOL PUSHER
MONTE CHRISTO	ARMSTRONG #22				6/5/65	LEROY COOK

GIVE SIZE & TYPE	DRILL COLLARS	PUMPS	DRAWWORKS & POWER	FUEL	WATER	NO. OF DULLS
1. 3 1/2 XH 2.	16.5"	1. NATL 850 2. " C350	NATL 80-B	DIESEL	WELL	

SALESMAN	DIVISION	STOCKPOINT NO.	DO NOT USE	STATE	ZONE	FIELD	CONTRACTOR	OPERATOR	DATE	PURCHASER
DICK WEBDEL	Corpus Christi	1435								

NO.	SIZE	MAKE	TYPE	JET 32nd IN.	SERIAL	DEPTH OUT	FEET	HOURS	WT. 1000 LBS.	RPM	VERT. DEV.	PUMP PRESS.	NO. 1 SPM	NO. 1 LINER	NO. 2 SPM	NO. 2 LINER	MUD WT.	VIS.	W.L.	DULL T	DULL B	OTHER	FORMATION CALL DATES REMARKS
9	8 5/8	HTC	OSC1GJ	2-11 1-12	25463	11256	155	10 1/2	45	140		2600	58	6 1/2			14	48		2	8	CD BT	LOCATION: 5 mi SW Armstrong, 49,396-ac lse, La Barreta Grt, A-3; 9943' NE of #3, dry hole & 11,031' SE of #6, dry hole; also being 1320' NE-FN'ly SWL of Grt & 17,472' S of #8, dry hole; sc FNW/cor of San Juan de Carricitos Grt, A-8, go SE alg NEL 3300', th NE@RA 1320' to loc, 9 mi NE of Julian Fld. [Corrected to show correct accreage 49,396' other than 49,396]. (WHICO Coord: H-4).
10	"	"	OSC1GS	"	35738	11373	117	8	"	"		2500	"	6			"	"		5	7		
11	"	"	OSC1GJ	"	25474	11528	155	9 1/2	45	140		2600	"	"			"	49		3	8	BT	
12	"	"	OSC1GJ	"	28471	11749	221	9	45	145		2600	"	"			"	47		3	8	CD	
13	"	"	OSC-1GJ	"	25472	11928	179	8	40	140		2600	"	"			"	"		3	7	BT	
					Ran 7" Csg.																		
1	6 1/4	HTC	OWV-J	3-10	31762	12055	127	12	20	70		3000	62	5			16	50					
2	6 1/4	HTC	OSC-1GJ	2-10 1-9	79561	12206	151	8	25	120	1 3/4	3500	62	5			16	49					
3	6 1/4	HTC	OSC-1GJ	2-10 1-9	52057	12369	163	9	20	120		3500	62	5			16	48		4	6		
4	6 1/4	HTC	OSC-1GJ	2-10 1-9	79604	12484	115	9	20 25	120		3500	62	5			15.9	45		5	7		
5	6 1/4	HTC	OSC-1GJ	2-10 1-9	2485	12632	148	9	25	122		3500	62	5			16	48		4	8		
6	6 1/4	HTC	OSC-1GJ	2-10 1-9	21262	12786	154	9	20	120		3500	62	5			16	45		5	7		
7	6 1/4	HTC	OSC-1GJ	2-10 1-9	9309	12912	126	9 1/2	20	120		3500	62	5			16	49		4	8		
8	6 1/4	HTC	OSC-1GJ	2-10 1-9	66961	13022	110	9	20 25	122		3500	62	5			16	48		5	7		
9	6 1/4	HTC	OSC-1GJ	2-10 1-9	10527	13144	122	9	25	122		3500	62	5			16.2	52		3	8	CD	
10	6 1/4	HTC	OSC-1GJ	2-10 1-9	46896	13255	111	9 1/2	25	120		3500	61	5			16.2	49		3	7		
11	6 1/4	HTC	OSC-1GJ	2-10 1-9	64341	13385	130	9 1/2	20 25	"		"	"	"			"	"		3	0	DC OFF	5-25-65
12	6 1/4	HTC	OSCIEJ	"	2979	13470	85	3	"	"		"	"	"			"	"		4	6		
13	6 1/4	HTC	OSCIEJ	"	38555	13610	140	10	"	"		"	"	"			16.3	46		3	4		
14	6 1/4	HTC	OSCIEJ	"	66963	13712	102	9	"	"		"	"	"			"	"		5	8		
15	6 1/4	HTC	OSCIEJ	"	2486	13831	119	10	"	"		"	"	"			"	"		5	8		
16	6 1/4	HTC	OSCIEJ	"	10712	14000	169	10	"	"		"	"	"			"	"				TD	

TOTAL DEPTH 14000 6-5-65

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NIXON BLUE PRINT Co.
Wilson Tower TU 2-2551
P.O. BOX 407
CORPUS CHRISTI TEXAS

SCHLUMBERGER INDUCTION ELECTRICAL LOG
SCHLUMBERGER WELL SURVEYING CORPORATION
Houston, Texas

COUNTY KENEDY
FIELD or LOCATION WILDCAT (TULLIDOS AREA)
WELL CHARLES M. ARMSTRONG #22
COMPANY HUMBLE OIL & REFINING COMPANY

COMPANY HUMBLE OIL & REFINING COMPANY
26S-18E-2
WELL CHARLES M. ARMSTRONG #22
FIELD WILDCAT (TULLIDOS AREA)
COUNTY KENEDY STATE TEXAS
EI-16

LOCATION LA BARRETA GRANT, 9943' NE OF #3 & 11031' SE OF #6, ALSO 1320' N'LY SWL OF GRANT (A SWL OF LSE.) & 17472' S OF #8.

Other Services: BHC, HDT, FT

Permanent Datum: GROUND LEVEL, Elev.: *
Log Measured From KB 19 Ft. Above Perm. Datum
Drilling Measured From KB
Elev.: K.B. * D.F. G.L.

SCHLUMBERGER INDUCTION ELECTRICAL LOG
SCHLUMBERGER WELL SURVEYING CORPORATION
Houston, Texas

COUNTY
FIELD or LOCATION
WELL
COMPANY

COMPANY
WELL
FIELD
COUNTY STATE
LOCATION
Sec. Twp. Rge.
Other Services:

Permanent Datum: GROUND LEVEL, Elev.: *
Log Measured From KB 19 Ft. Above Perm. Datum
Drilling Measured From KB
Elev.: K.B. * D.F. G.L.

Date	5-2-65	5-16-65	5-20-65	6-1-65	6-6-65
Run No.	ONE	TWO	THREE	FOUR	FIVE
Depth—Driller	10202	11928	13610	14000**	14226
Depth—Logger	10201	11924	13612	13927	14226
Btm. Log Interval	10200	11923	13611	13926	14225
Top Log Interval	2005	10200	11923	13611	13982
Casing—Driller	13-3/8" @ 2005	9-5/8" @ 10199	7-5/8" @ 11916	7" @ 11916	7" @ 11916
Casing—Logger	2005	10200	11915	11915	11915
Bit Size	12-1/4"	8-5/8"	6-1/4"	6-1/4"	6-1/4"
Type Fluid in Hole	Q-BROXIN-OIL EMUL.	Q-BROXIN-OIL EMUL.	CAUSTIC-Q-BROX -O F	CAUSTIC-Q-BROXIN	CARBONOX-Q-BROXIN
Dens. / Visc.	12.0 / 40	14.5 / 51	16.3 / 48	16.3 / 46	16.4 / 47
pH / Fluid Loss	9.0 / 8.0 ml	9.5 / 5.6 ml	10.8 / 2.8 ml	10.8 / 2.6 ml	11.0 / 1.8 ml
Source of Sample	FLOWLINE	FLOWLINE	FLOWLINE	FLOWLINE	FLOWLINE
R_m @ Meas. Temp.	1.99 @ 75°F	1.0 @ 75°F	.53 @ 98°F	.62 @ 80°F	.65 @ 78°F
R_{mf} @ Meas. Temp.	1.08 @ 75°F	.56 @ 75°F	.36 @ 75°F	.31 @ 75°F	.28 @ 75°F
R_{mc} @ Meas. Temp.	2.2 @ 75°F	.63 @ 246°F	.35 @ 290°F	.30 @ 294°F	1.48 @ 75°F
Source: R_{mf} / R_{mc}	M / C	FP / C	FP / C	FP / C	FP / FP
R_m @ BHT	.75 @ 195°F	.305 @ 246°F	.18 @ 290°F	.18 @ 294°F	.18 @ 292°F
Time Since Circ.	4 HOURS	4 HOURS	4 HOURS	4 HOURS	11 HOURS
Max. Rec. Temp.	195 °F	246 °F	290 °F	294 °F	292 °F
Equip. / Location	4515 / KINGS	3533 / KINGS	3533 / KINGS	3533 / KINGS	3533 / KINGS
Recorded By	PORTER	SHAW	SHAW	SHAW	HUFFSTUTLER
Witnessed By	MR SLATE	SLATE	SLATE	SLATE	SLATE

FOLD HERE

REMARKS *UNAVAILABLE **TWO ATTEMPTS TO GET TO DRILLERS T.D.

Changes in Mud Type or Additional Samples

Date / Sample No.			
Depth—Driller			
Type Fluid in Hole			
Dens. / Visc.			
pH / Fluid Loss	ml		
Source of Sample			
R_m @ Meas. Temp.	@ °F	@ °F	
R_{mf} @ Meas. Temp.	@ °F	@ °F	
R_{mc} @ Meas. Temp.	@ °F	@ °F	
Source: R_{mf} / R_{mc}			
R_m @ BHT	@ °F	@ °F	
R_{mf} @ BHT	@ °F	@ °F	
R_{mc} @ BHT	@ °F	@ °F	

Scale Changes

Type Log	Depth	Scale Up Hole	Scale Down Hole

Equipment Data

Run No.	Tool Type	Tool Position	Other

Run No.	ONE	TWO	THREE	FOUR	FIVE
C.O.	USED	USED	---	NOT USED	NOT USED
S.O.	1.5"	1.5"	---	---	---
Equip. Used: CART. No.	F-55	F-88	F-23	F-23	F-23
PANEL No.	G-207	G-15	G-15	G-15	G-15
SONDE No.	M-144	M-29	M-29	M-29	M-29
S.S.R.	1	1	1	1	1

RUN #4 RERUN WITH RUN 5

SPONTANEOUS POTENTIAL millivolts	DEPTHS	RESISTIVITY ohms-m²/m	CONDUCTIVITY millimhos/m = 1000/ohms-m²/m
- |10| +	2"=100 CSG. 2005'	0 A-16"-M SHORT NORMAL 4; 0 20; 0 200	1000 6FF40 INDUCTION 0; 2000 1000
		0 INDUCTION 20; 0 200	

I-26

APPENDIX IB

PRELIMINARY DRILLING AND DRILLING FLUIDS PROGRAM

This tentative program was prepared by the Baroid division of N. L. Industries, with the objective of illustrating a typical drilling program for geothermal geopressured well and obtaining approximate cost estimates.

THE UNIVERSITY OF TEXAS AT AUSTIN
GEOTHERMAL TEST WELL
"LA BARRETA" GRANT
KENEDY COUNTY, TEXAS

PROGNOSIS

OBJECTIVE

The objective of this research project are those water sands below the overpressure transition zone (13,000'±), and in particular the sands between 11,400' and 11,800'. With specific reference to Humble Oil & Refining Company - C. M. Armstrong Well #20, it is assumed the afore lower sands to be Vicksburg and upper sands to be Frio Formation. Our recommendations are for the preliminary planning of the mud system and its estimated total cost. The proposed drilling location to be that area of East Candelaria - Tullidos, being south of Armstrong, Kenedy County, Texas.

GEOLOGICAL CONTROL

The recommended mud program is based upon an examination of mud recapitulations and electric logs of the following wells:

Humble Oil & Refining Company - C. M. Armstrong #20
Humble Oil & Refining Company - C. M. Armstrong #22

HAZARDS

This well will encounter abnormal pressure and temperatures.

In this discussion, abnormal pressure is defined as any pressure which exceeds the hydrostatic pressure of a column of water, extending from the stratum tapped by the well to the land surface, containing 80,000 milligram per liter total solids. A pressure of approximately 0.465 psi (equivalent to 8.9 ppg) is exerted by each foot of such a water column. The pressures in this area will increase from normal to a maximum which will require a 16.0-17.0 ppg mud. We recommend that a Baroid Computerized Drilling Control Unit be used from 6000' to Total Depth to assist in determining actual mud weight requirements. Our mud engineers on location can also assist with this task. If casing seats are picked properly, casing shoes properly cemented and tested, and Calculated Fracture Gradients adhered to, problems associated with abnormal pressures can be eliminated.

Stuck Pipe is a hazard anywhere after the abnormally pressured section is penetrated due to differential pressures. Excessive mud weights should be avoided as an aid in preventing differential sticking. Should stuck pipe occur, we recommend that an EZ-SPOT/Diesel Oil mixture be spotted around the stuck zone. Further discussion of

EZ-SPOT and its applications will be found in the Mud Program. To prevent formation sticking, we recommend that TORQ-TRIM and/or AKTA-FLO-S be added to the mud system if torque or drag develop.

Abnormal Temperatures will be encountered on this well. The Calculated Geothermal Gradient for this area is 1.7°F per 100'. Using this gradient, the following Bottom Hole Temperatures are anticipated:

157°F @ 5,000'
242°F @ 10,000'
259°F @ 11,000'
276°F @ 12,000'
293°F @ 13,000'

The thermal degradation of drilling mud additives is as follows:*

Lignosulfonate (Q-BROXIN)	-	325 - 350°F
Lignite (CARBONOX)	-	400 - 425°F
CMC (CELLEX)	-	300°F
DEXTRID	-	300°F

*These are generally accepted figures; however, certain conditions may vary these limits.

The above temperatures do not preclude the Lignite/Surfactant Mud System recommended in our program as this same system has been successful with temperatures exceeding 450 Degrees F.

Lost Circulation is likely to occur in any drilling operation. However, induced fracturing as a cause for loss of returns will be a hazard to be aware of from Intermediate Pipe depth to Total Depth.

In the event of loss while drilling above Intermediate Pipe depth, we recommend:

(1) Reduce circulating rates, or
(2) Add 2-3 ppb fine to medium lost material, and/or
(3) Increase the Bentonite content, or
(4) All of the above

Should loss occur below Intermediate Pipe, we recommend:

(1) Reduce mud weight, if possible.
(2) Lower equivalent circulating density by lowering yield point or circulating rate.
(3) Pull into casing and wait 5-6 hours to see if hole will heal itself.
(4) Set a DIASEAL M or similar squeeze in the suspected loss zone.

A good preventative measure is to maintain mud weights and equivalent circulating densities as low as possible. This can best be accomplished by utilizing the Computerized Drilling Control parameters.

HOLE AND CASING CONFIGURATION

The recommended Hole and Casing Program of:

Depth	Hole Size	Casing Size	Fracture Gradient (ppg)
0 - 2,000'	17-1/2"	--	--
2,000'	--	13-3/8"	14.0
2,000-10,000'	12-1/4"	--	--
10,000'	--	9-5/8"	17.4
10,000-13,000'	8-1/2"	--	--

is based upon an examination of I.E.S. Logs, Fracture Gradient (Mathews & Kelly) and review of wells in the area of the proposed.

MUD MAINTENANCE EQUIPMENT

Depth	Mud Wgt.	
0- 2,000'	9.0 ppg	Baroid Desander/Desilter; High Speed Shaker.
2,000- 6,000'	9.5 ppg	Baroid Desander/Desilter, Baroid Double Deck Shaker, Degasser, Cameron Choke.
6,000-10,000'	12.0 ppg	Baroid Double Deck Shaker, Degasser , Desilter, Cameron Choke, Baroid C.D.C. Unit.
10,000-13,000'	16.5+ ppg	Baroid Double Deck Shaker, Baroid Centrifuge, Degasser, Cameron Choke, Baroid C.D.C. Unit.

BAROID DIVISION
N L Industries, Inc.
RECOMMENDED MUD PROGRAM

REVISED

Company: The University of Texas at Austin — Date: December 22, 1975

Well Name and Number: Geothermal Test — Proposed Depth: 13,000'±

Location: South Armstrong Area — County: Kenedy — State: Texas

Casing: Surf. 13-3/8" @ 2000' — Inter. 9-5/8" @ ±10,000' — Prod. 7" Liner or Casing as required

RECOMMENDED MUD PROPERTIES

DEPTH FEET	WEIGHT LB/GAL	VISCOSITY SEC.	FILTRATE ml	TREATMENT
0- 2,000'	8.8-9.0	35-40	N/C	Native spud mud: AQUAGEL/QUIK-GEL and Lime.
2,000- 6,000'	9.0-9.5	32-34	10-15	Native mud: AQUAGEL/QUIK-GEL for viscosity, CON DET for lubricity and BARAFOS for flow properties.
6,000- 7,300'	9.5-9.7	34-36	8-10	Begin light chemical additions of Q-BROXIN and CARBONOX/CC-16 for filtrate and rheology control, Caustic Soda for alkalinity, and AQUAGEL for viscosity. Diesel Oil (4-6% by volume) may be added if desired for lubricity. Should Diesel not be used and torque or drag develop, we recommend the addition of 3 ppb TORQ-TRIM.
7,300- 9,000'	9.7-10.3	36-38	6-8	
9,000- 9,500'	10.3-10.6	38-42	4-6	
9,500- 9,800'	10.6-11.2	42-45	3-4	
9,800-10,000'	11.2-12.0	45-48	3-4	

Remarks:

Set 9-5/8" Intermediate Casing @ ±10,000' in an 11.5-12.0 ppg Pore Pressure, as determined by Baroid's Computerized Drilling Control Unit. Fracture Gradient @ 10,000' in a 12.0 ppg Pore Pressure will equivalent a 17.4 ppg mud weight. After drilling out, pressure test casing seat to an equivalent of 16.5 ppg mud.

CONTINUED ON NEXT PAGE

Estimated cost for mud materials: See Cost Estimate

Recommended Program Based Upon

Refer to Prognosis

CUSTOMER'S COPY

BAROID DIVISION
N L Industries, Inc.
RECOMMENDED MUD PROGRAM
REVISED

PAGE NO. 2

Company: The University of Texas at Austin — Date: December 22, 1975

Well Name and Number: Geothermal Test — Proposed Depth: 13,000'±

Location: South Armstrong Area — County: Kenedy — State: Texas

Casing: Surf. 13-3/8" @ 2000' — Inter. 9-5/8" @ 10,000'± — Prod. TD - 7"

RECOMMENDED MUD PROPERTIES				
DEPTH FEET	WEIGHT LB/GAL	VISCOSITY SEC.	FILTRATE ml	TREATMENT
10,000-10,500'	12.5-13.0	42-46	3-4	Continue chemical treatments of Q-BROXIN, CARBONOX and Caustic Soda. Begin additions of AKTAFLO-S (2-3 ppb) for stabilization of rheology and filtration properties as determined from pilot tests.
10,500-11,000'	13.0-14.5	46-50	3-4	
11,000-11,500'	14.5-14.7	48-52	2-3	
11,500-11,800'	14.7-15.5	48-52	2 or less	Continue with above chemical additions, increase CARBONOX ppb for filtrate and rheology control. TORQ-TRIM is recommended should excessive torque or drag develop.
11,800-12,500'	15.5-16.0	48-55	2 or less	
12,500-13,000'	16.0-16.5	55-60	2 or less	

Remarks:

It is recommended that Baroid's Computerized Drilling Control Unit be used to ascertain pore pressures and advise of exact mud weights required through this interval, or possible addition of liner pipe to safely reach total depth objective.

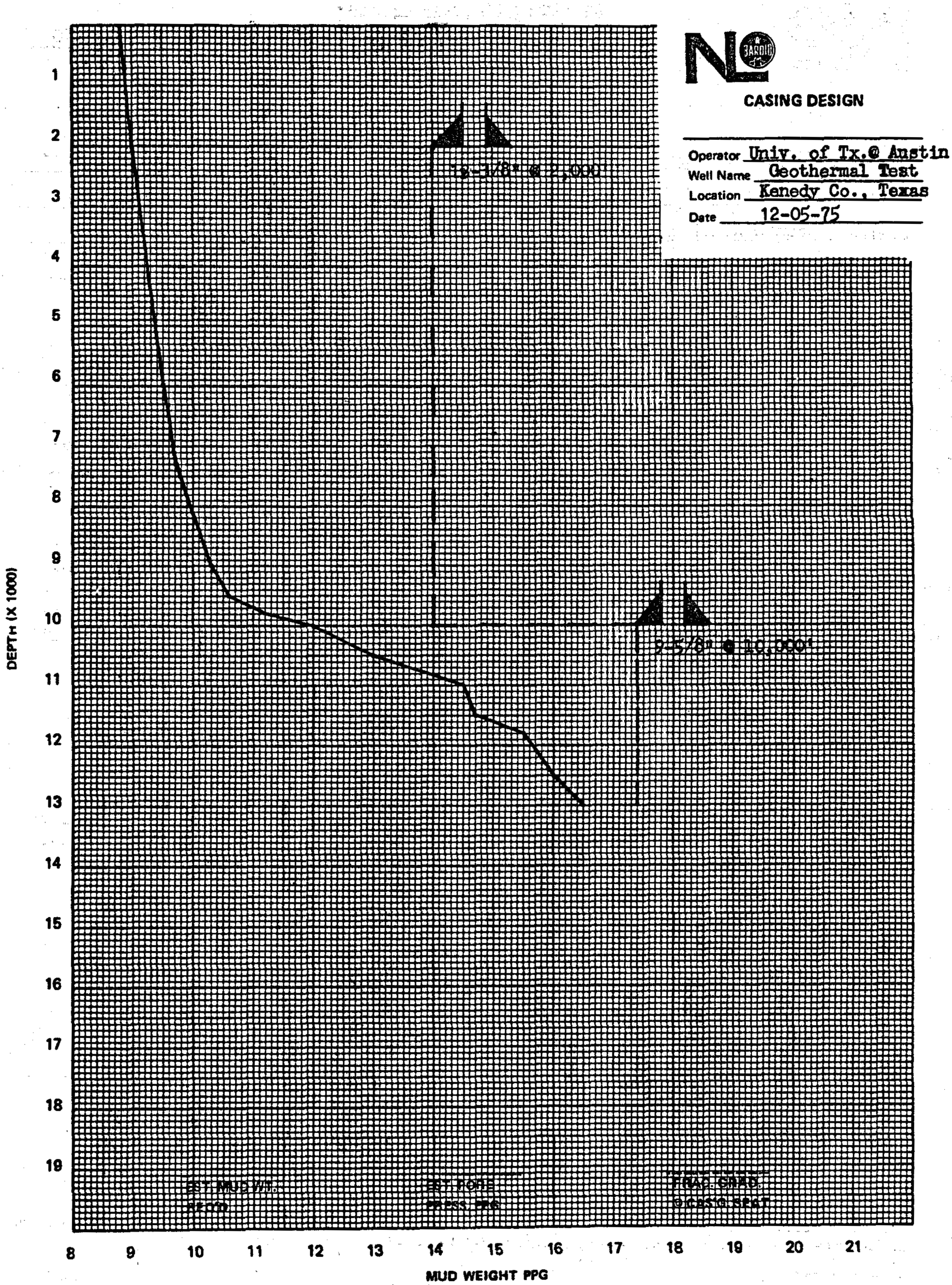
Estimated cost for mud materials: (See Cost Estimate) $180,000 - $198,000

Recommended Program Based Upon

Refer to Prognosis

BR-1807-2A S&C

CUSTOMER'S COPY


CASING DESIGN
Operator Univ. of Tx.@ Austin
Well Name Geothermal Test
Location Kenedy Co., Texas
Date 12-05-75
9-5/8" @ 10,000'
EST. MUD WT.
PRESS. PPG
FRAC. GRAD.
DEPTH (X 1000)
1
2
3
4
5
6
7
8
9
10
11
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13
14
15
16
17
18
19
8 9 10 11 12 13 14 15 16 17 18 19 20 21
MUD WEIGHT PPG

THE UNIVERSITY OF TEXAS AT AUSTIN
GEOTHERMAL TEST WELL
KENEDY COUNTY, TEXAS

DEPTH INTERVAL DISCUSSION
LIGNITE/SURFACTANT MUD

0-2000'

An AQUAGEL/QUIK-GEL native spud mud is recommended. Treat with AQUAGEL/QUIK-GEL for viscosity and carrying capacity, and water to control the mud weight at 8.8-9.0 ppg in suction pit. Run rig desander and Baroid Desilter to control solids and mud weights at a minimum. Use QUIK-GEL and Lime, as needed, to maintain a viscosity sufficiently high to clean hole.

2000-6000'

We recommend that a non-dispersed AQUAGEL/QUIK-GEL mud be used through this interval. Primary additives are: (1) AQUAGEL/QUIK-GEL for viscosity and carrying capacity, (2) Water for weight control, and (3) BARAFOS for rheology control.

It is recommended that AQUAGEL be added at the rate of 3-5 sacks per 100' of new hole drilled, or in sufficient quantity to provide a yield point value of 4#/100 sq. ft. or greater.

To promote maximum penetration rates, solids and mud weights should be maintained at a minimum as dictated by existing hole conditions. For this reason proper solids control is essential. We recommend that a Baroid Desilter and Double Deck Shaker with a 30/50-mesh screen combination be utilized along with rig desanders to remove low gravity drill solids.

Install a Baroid Computerized Drilling Control (C.D.C.) Unit at 6000' for the purpose of gathering data for use in determining Intermediate Casing depth and Pore Pressures below Intermediate Casing.

6000-10,000'

Continue to exercise stringent control of solids. Run daily Methylene Blue tests in conjunction with Baroid Retort Analysis to monitor optimum solids control program. Maintain good Bentonite content.

Begin light treatment of the mud with Q-BROXIN, CARBONOX/CC-16 and Caustic Soda. Q-BROXIN (a lignosulfonate) is the most effective and versatile organic thinner available. This versatility stems from Q-BROXIN's ability to function effectively in the low to medium pH range in the presence of electrolytes. CARBONOX (a lignite) is widely used in fresh water muds for both rheological and filtration control. The Caustic Soda is necessary to adjust the alkalinity of the fluid. The use of Q-BROXIN and CARBONOX, in tandem, offers the advantage of combining the overall thinning efficiency of Q-BROXIN with the economy of CARBONOX for filtration control. Historically, Diesel Oil has been added to drilling fluids to achieve certain benefits such as (1) increased penetration rates, (2) reduced torque and drag, and (3) prolonged bit life. However, field and laboratory data indicate that the Baroid product TORQ-TRIM (a non-polluting, biodegradeable lubricant) provides the same benefits and, at the same time, eliminates the concerns dictated by ecological and/or geological considerations. Normal concentration of TORQ-TRIM used is 3-5 ppb. In the event the Operator options to use Diesel Oil, we recommend that the oil be added directly through the pump suction on a continuous basis at the rate of 1-2 barrels per drilling hour. Using this method, the maximum concentration which may be expected in the mud would be in the range of 4-6% by volume.

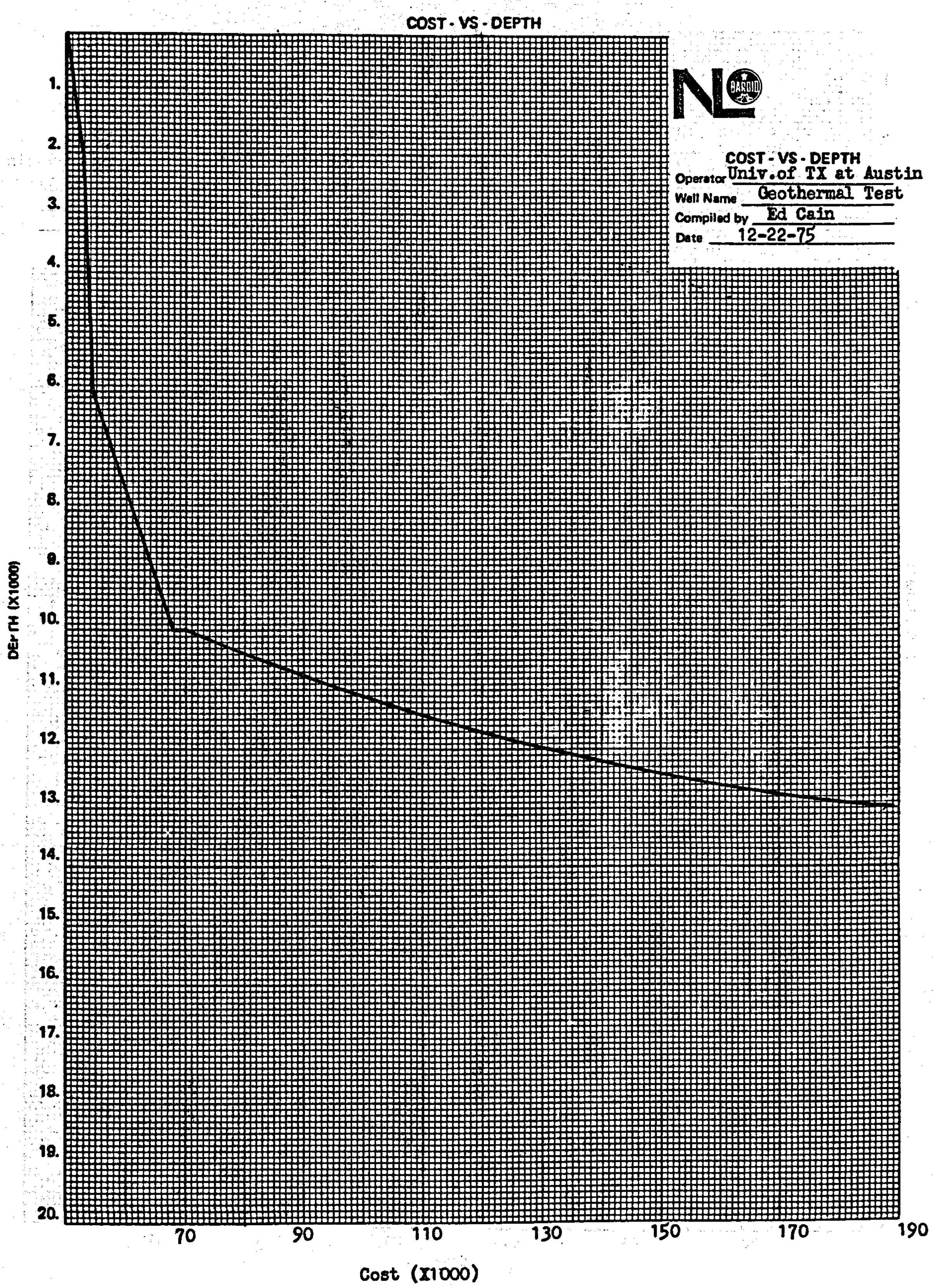
To help in reducing the chance of lost circulation below Intermediate Casing, pipe needs to be set in an 11.5-12.0 ppg pore pressure, which should be encountered at approximately 10,000'. Use C.D.C. to determine this pressure.

While drilling the interval in which intermediate pipe will be set, it is important to avoid 'dog legs'. The intermediate hole will be exposed to drill pipe wear for a substantial period of time at tensile loads, producing severe friction force at all deflection points. Directional surveys at 250' intervals are generally adequate to detect and control significant deviations.

10,000-13,000'

A gradual change from Q-BROXIN to CARBONOX as the primary thinner should occur during this interval as the bottom hole temperature approaches 300 Degrees F expected by 13,000'. We suggest adding 2-3 ppb of AKTAFLO-S (non-ionic surfactant) to the system by 10,500' to aid in controlling the flow properties and high temperature filtration. This product has proven to be a very good rheology and filtration stabilizer to the Q-BROXIN/CARBONOX Mud System.

Through this interval hole conditions should be monitored at all times due to possible abnormal pressures exceeding hydrostatic head and if overbalanced the possibility of losing returns as experienced on referenced area wells. Care also should be taken to keep the hole filled while trips are being made. The exact mud weight requirements through this interval can be determined by C.D.C.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COST - VS - DEPTH
Operator Univ. of TX at Austin
Well Name Geothermal Test
Compiled by Ed Cain
Date 12-22-75
DEPTH (X1000)
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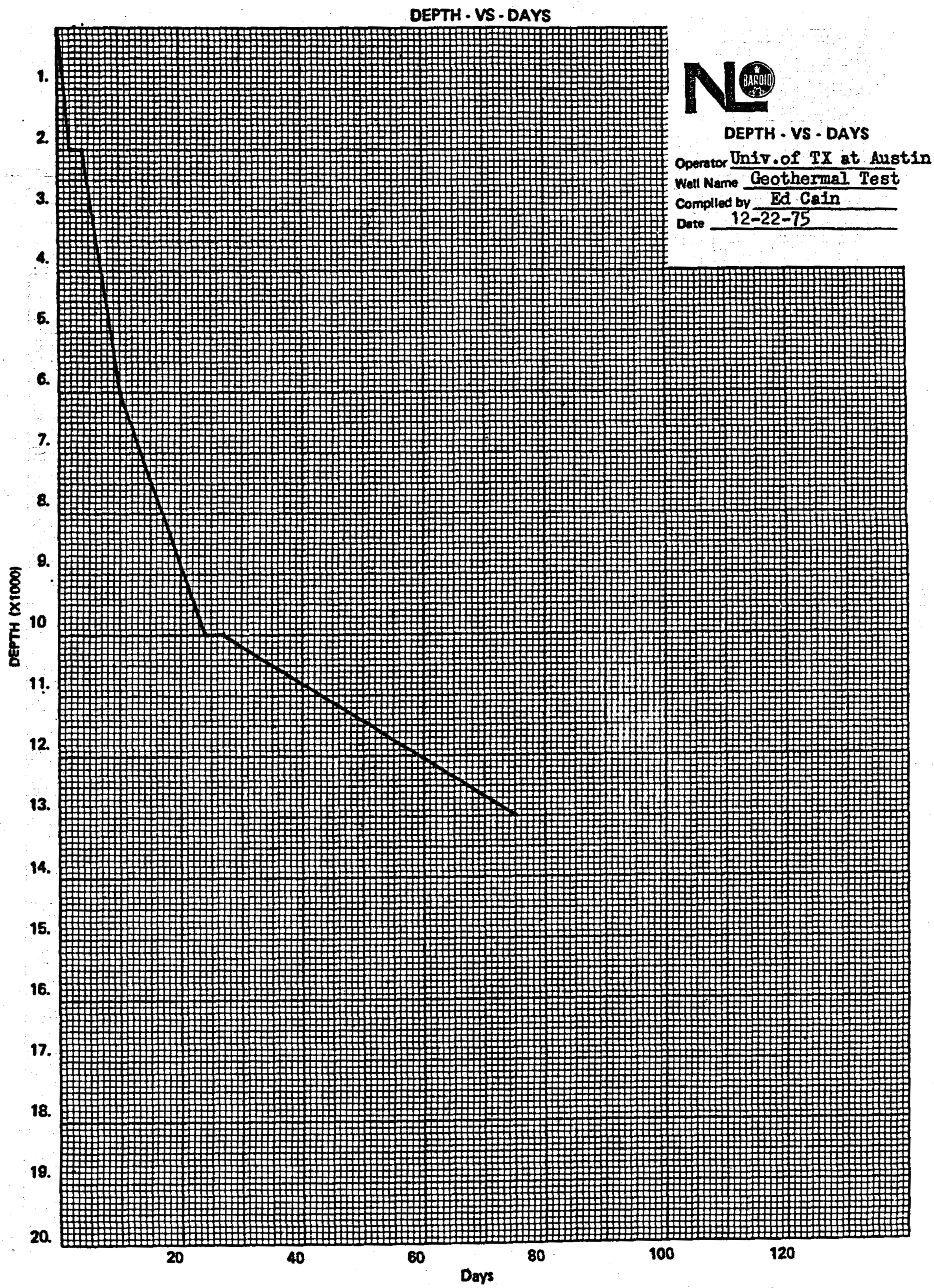
Cost (X1000)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NL BAROID
DEPTH - VS - DAYS
Operator Univ.of TX at Austin
Well Name Geothermal Test
Compiled by Ed Cain
Date 12-22-75
DEPTH (X1000)
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20
40
60
80
100
120
Days

THE UNIVERSITY OF TEXAS AT AUSTIN
GEOTHERMAL TEST WELL
KENEDY COUNTY, TEXAS

COST ESTIMATE

(Estimated 90-Days with Potential Hazard & Sundry Costs)

			CUMULATIVE COST
0-2000'			
Hole Size: 17-1/2"			
Estimated Days to Drill:	2		
Estimated Volume:	950 bbls.		
Estimated Maintenance Cost: ($0.85/bbl/day)		$ 1,615.00	
Estimated Trouble Cost: (See #1)		$ 7,106.00	
Estimated Interval Cost:		$ 8,721.00	$ 8,721.00
2000-6000'			
Casing: 13-3/8" @ 2000'			
Hole Size: 12-1/4"			
Estimated Days to Drill:	8		
Estimated Volume:	1350 bbls.		
Estimated Maintenance Cost: ($0.55/bbl/day)		$ 5,940.00	$ 14,661.00
6000-10,000'			
Casing: 13-3/8" @ 2000'			
Hole Size: 12-1/4"			
Estimated Days to Drill & Test:	16		
Estimated Volume:	1900 bbls.		
Estimated Maintenance Cost: ($0.65/bbl/day)		$ 19,760.00	
Estimated Trouble Cost: (See #2)		$ 13,753.00	
Barite Cost: 9.8-12.0 ppg:		$ 12,916.00	
Barite (Slugs):		$ 2,163.00	
Estimated Interval Cost:		$ 48,592.00	$ 63,253.00

The University of Texas at Austin
Geothermal Test Well
Kenedy County, Texas
Cost Estimate (cont'd.)

10,000-13,000'

Casing: 9-5/8" @ 10,000'
Hole Size: 8-1/2"

Estimated Days to Drill & Test:	64		
Estimated Volume:	1425 bbls.		
Estimated Maintenance Cost: ($0.75/bbl/day)		$ 68,400.00	
Estimated Trouble Cost: (See #3)		$ 13,716.00	
Barite Cost: 12.0-16.5 ppg:		$ 27,345.00	
Barite (Slugs):		$ 5,407.00	
Estimated Interval Cost:		$114,868.00	$178,121.00
Estimated Diesel Oil Cost, to 4-6% by volume including daily maintenance: (See #4)		$ 7,489.00	$185,610.00
Estimated Rental Equipment Cost:		$ 24,520.00	$210,130.00
Estimated Drayage:		$ 2,400.00	$212,530.00

TOTAL ESTIMATED DAYS TO DRILL & TEST: 90

TOTAL ESTIMATED MUD & EQUIPMENT COST: $212,530.00*

*(Excluding CDC Rental Equipment)

REFERENCES

#1. Lost Circulation:

a. 950 bbls. volume X 16 ppb AQUAGEL = 152 sacks @ $5.34/sack:	$ 812.00
b. 950 bbls. X 14 ppb lost circulation material = 333 sacks @ $18.90/sack:	$ 6,294.00
TOTAL:	$ 7,106.00

The University of Texas at Austin
Geothermal Test Well
Kenedy County, Texas
Cost Estimate (cont'd.)

#2.	**Lost Circulation:**	
	a. 1900 bbls. volume X 20 ppb lost circulation materials = 950 sacks @ $11.35/sack:	$ 10,783.00
	Stuck Pipe:	
	b. 4 Drums E Z SPOT @ $560.15/drum + 50 bbls. Diesel Oil @ $14.57/bbl.:	$ 2,970.00
	TOTAL:	$ 13,753.00
#3.	**Lost Circulation:**	
	a. 1425 bbls. volume X 22 ppb lost circulation material = 784 sacks @ $11.35/sack:	$ 8,898.00
	Stuck Pipe:	
	b. 6 Drums E Z SPOT @ $560.15/drum + 100 bbls. Diesel Oil @ $14.57/bbl.:	$ 4,818.00
	TOTAL:	$ 13,716.00
#4.	Diesel Oil - (Estimated @ $0.347/gal. at bulk tank wagon price. To be adjusted if by competitive bid.) 86 bbls. initial injection to 6% by volume plus (+) 428 bbl. maintenance @ $14.57/bbl.:	$ 7,489.00

THE UNIVERSITY OF TEXAS AT AUSTIN
GEOTHERMAL TEST WELL
KENEDY COUNTY, TEXAS

COST ESTIMATE (REVISED)

RECAPITULATION: Drilling Fluid and Rental Equipment

60 Days Total Estimated to Drill & Test:	$165,577.00
90 Days Total Estimated to Drill & Test:	$212,530.00
TOTAL ESTIMATED COST: (60 + 90 DAYS)	$378,107.00
AVERAGE COST - 60 TO 90 DAYS:	$189,054.00

SUMMARY OF AVERAGE COST
FOR 60 TO 90 DAYS DRILLING & TESTING

Drilling Fluids:	$138,239.00
Rental Equipment:	$ 19,347.00
Trouble Cost:	$ 24,575.00
Diesel Oil:	$ 5,093.00
Drayage:	$ 1,800.00
AVERAGE COST:	$189,054.00
AVERAGE DAYS TO DRILL:	75

THE UNIVERSITY OF TEXAS AT AUSTIN
GEOTHERMAL TEST WELL
KENEDY COUNTY, TEXAS

RENTAL EQUIPMENT COST ESTIMATE

		COST
DESILTER		
Interval:	0-9000'	
Days:	30	
Cost:	$80.00/Day	$ 2,400.00
DOUBLE DECK SHAKER		
Interval:	0-13,000'	
Days:	90	
Cost:	$50.00/Day	$ 4,500.00
CENTRIFUGE		
Interval:	10,000-13,000'	
Days:	64	
Cost:	$100.00/Day	$ 6,400.00
WELLCO DEGASSER		
Interval:	2000-13,000'	
Days:	88	
Cost:	$75.00/Day	$ 6,600.00
CAMERON CHOKE (Remote Manual)		
Interval:	2000-13,000'	
Days:	88	
Cost:	$52.50/Day	$ 4,620.00
TOTAL RENTAL EQUIPMENT COST: (90 Days)		$24,520.00

RECOMMENDED EQUIPMENT AND SERVICES

SOLIDS CONTROL

The advantages of using a drilling fluid with the lowest possible drilled solids content are well known. Most important of all the advantages is that faster penetration rates can be achieved. Not only are increased penetration rates possible, but pumps are more efficient and fewer replacement parts are required. The pump can discharge the fluid at a given rate with less pressure buildup, thus reducing annular pressure to help minimize loss of circulation. More of the hydraulic horsepower otherwise expended inside the drill pipe and drill collars is delivered to the bit nozzles in the form of hydraulic horsepower.

If an effective drilled solids removal program can be followed, the Operator and Contractor will realize savings on bits, rotating hours, chemical treatment cost and pump maintenance cost.

To implement an effective solids control program, it is recommended the following mechanical devices be installed and fully utilized in the drilling of the proposed well.

BAROID DOUBLE DECK SHAKER

Regular shale shakers use 12 or 20 mesh screens. The Baroid Double Deck Shaker is normally equipped with 30, 50 or 80 mesh screens. The advantage of the two finer screens is twofold: (1) larger amounts of solids are removed and (2) smaller particles are removed. Therefore, more reactive surface is eliminated resulting in reduced chemical treatment and dilution.

It is recommended that a Baroid Double Deck Shaker be installed and used from the base of the surface casing to total depth.

DESANDER

Desanders are conical classifiers commonly used for corrective solids removal of particles down to about 74 microns. The conventional desander is economical for low weight, inexpensive muds that can tolerate discarded solids. The desander becomes uneconomical when the liquid phase of the mud is of significant value. Also, desanders are not practical for use on weighted muds because sand, whole mud and Barite are discharged simultaneously. This piece of equipment is found on most of the drilling rigs operating on the Texas Gulf Coast.

BAROID DESILTER

A desilter is a bank of small diameter classifying cones operating at higher pressure and greater centrifugal force enabling the desilter to remove effectively up to 95% of the solids above 20 to 40 micron size. Desilters, like desanders, are not economical for weighted mud systems because they discard too much Barite along with the drilled solids. Only a few drilling rigs are equipped with effective desilters. Baroid can furnish a self-contained unit composed of 12 (four-inch diameter) cones and a power unit. Use from spud to depths where economics dictate discontinued use.

BAROID DECANTING CENTRIFUGE

This unit will be useful for solids control from intermediate casing point to total depth. The centrifuge will reclaim 90% of the Barite while discarding 60-65% of the drill solids, thus reducing the water dilution necessary to control mud properties. The water dilution reduction will result in lower mud maintenance costs and, therefore, lower total mud costs.

WELL CONTROL EQUIPMENT

DEGASSER

We recommend that a 5200 Series Degasser, manufactured by Well Control, Inc., be installed and available for use from below Surface Casing to Total Depth.

ADJUSTABLE CHOKE

An Adjustable Choke, available from Cameron Iron Works, should be installed after setting the Surface Casing. These units can be supplied with either manual or automated controls.

COMPUTERIZED APPLIED DRILLING TECHNOLOGY SERVICE

The objective of the Computerized Applied Drilling Technology Service is to utilize modern digital electronics and digital computer technology to augment the Mud Logging and ADT Services.

I. Equipment and Services Provided with the Computerized Applied Drilling Technology Service

Applied Drilling Technology Service is a combined geological and drilling engineering tool. The Mud Logging Unit is the base upon which the Applied Drilling Technology Service is built. With the aid of this service, an operator can drill deep troublesome wells with optimum efficiency and safety.

A. Applied Drilling Technology System

1. Baroid's Applied Drilling Engineer works with an operator's drilling department to plan:

   - drilling and casing programs
   - mud programs for each drilling interval
   - mud hydraulics
   - minimum equivalent circulating density (ECD) for each interval
   - detection and control of formation pressure
   - avoidance of drilling hazards
   - solids control and economy of mud maintenance
   - hole stability and formation protection
   - corrosion control
   - complete geological information

2. Control wells are carefully examined by Baroid's engineers to prepare a proposed drilling program based upon pressure abnormalities found in these wells. The control well formation pressure profile construction and usage is as follows:

   a. Short-Normal resistivity values from shale sections are plotted versus depth. (Sonic or conductivity values can also be used when available.) During normal compaction, the resistivity increases with depth. A departure from the normal trend is an indication of abnormal pressure.

   b. Formation pressure can be estimated by relating the amount of departure from the normal trend to empirical values of pressure common to the local area. In cases where there are no control wells, data from a similar geological environment are used.

   c. Fracture gradient is determined by relating the formation pore pressure and depth to fracture pressure gradients common to the area throughout each drilling interval. The gradient is then drawn on the pressure profile for casing seat and mud weight evaluations.

d. Casing depths are important tothe drilling program, because they determine the maximum mud weight that can be used prior to the next casing seat.

e. The weight of the drilling fluid is important, not only to contain formation fluids, but to improve penetration rate. APPLIED DRILLING TECHNOLOGY uses the information from a pressure profile to determine the minimum ECD for safe and economical operations.

B. Equipment and Services to be Provided with Applied Drilling Technology Service

1. All equipment and services provided for Mud Logging Service.

2. Shale Density Equipment

3. Shale Factor Kit

4. Weight on Bit, Rotary RPM and Hook Load Panel and Recorder

5. "d_c" Exponent Plot

6. Individual Mud Pit Lever and Totalizer Panel and Recorder

7. Mud Flow (in and out) Panel and Recorder

8. Mud Pressure (in and out) Panel and Recorder

9. Mud Temperature (in and out) Panel and Recorder

10. Mud Conductivity (in and out) Panel and Recorder

11. Mud Density (in and out) Panel and Recorder

12. Data Acquisition Panel--print-out of pertinent drilling data for selected drilling intervals.

13. Programmable Calculator with program cards as listed below:

a. Hydraulics

(1) Equivalent circulating density--given the geometry of the various sections of the hole and the mud properties, the circulating pressure drop for each section is calculated and the equivalent mud weight determined.

(2) Surge pressure while running pipe--given the geometry of the various sections of the hole, mud properties, and pipe velocity, the circulating pressure drop for each section and the total pressure and equivalent mud weight at the casing point are calculated.

(3) Pump output at which critical velocity occurs--given the hole geometry and mud properties, the pump output at which critical velocity occurs is computed.

(4) Cutting slip velocity--given the hole geometry, mud properties and cutting size, the critical annular velocity, actual annular velocity, cutting slip velocity, and cutting net rise velocity are calculated.

(5) Velocity and pressure drop through bit jets--given the bit jet diameters, I.D. of drill pipe, mud weight and pump output, the velocity of the fluid and pressure drop through the jets are calculated.

(6) Pressure drop in the drill string--given the various pipe I.D.'s for the drill string and the mud properties, the circulating pressure drop for the drill string is calculated.

(7) Mud weight in the annulus--given the pump output, bit diameter, drill rate, mud weight, and an average specific gravity for cuttings, an average weight for the cuttings laden fluid in the annulus is calculated.

(8) Bit nozzle selection for maximum jet velocity - the pressure available for the bit is determined and a total nozzle area calculated.

b. Blowout Control

(1) Drill-pipe pressure method--based on the method of Goins and O'Brien, this program calculates the mud weight required to kill the well, final drill pipe pressure, and the weight of the invading fluid.

(2) Casing pressure method--based on the method of H. G. McDonald, this program calculates the weight of the invading fluid, mud weight required to kill the well, initial and final circulating pressures, reservoir pressure, the maximum surface casing pressure expected, volume of gas expected at surface, and the volume of new mud pumped at which the maximum pressure and volume occur.

c. ADT General

(1) Fracture Gradient Calculation--given the pore pressure gradient and depth of interest, this program calculates the matrix stress coefficient, fracture gradient, and equivalent mud weight by the method presented by Matthews and Kelly.

(2) Propagation or Injection Gradient--based on the method described by H. E. Whalen, this program calculates a minimum and maximum estimate of propagation gradient. This assumes that the horizontal stress approximates one-third to one-half the vertical stress.

(3) Best constant weight and rotary speed--based on the method of Galle and Woods, this program requires the graph and table look-up from their article.

(4) Percent gas porosity by Pirson formula--given the formation pressure, formation temperature, pump rate, ppm analysis of the drilling fluid, bit diameter and drill rate, an estimate of formation porosity as the gas percent of volume drilled is calculated. The equation for the calculation was developed by S. J. Pirson, University of Texas.

(5) Open hole flow potential--this method of measuring the capacity of gas wells was adapted to the drilling situation by D. E. Boone. Given the formation pressure and temperature, bit diameter, drill rate, ppm analysis of the drilling fluid, pump rate, mud weight and depth, an estimate of the open hole flow potential of the well being drilled is calculated.

(6) Geothermal Gradient from Mud Temperature.

(7) Circulating mud temperature--based on the procedure presented by C. S. Holmes and S. C. Swift, the temperature of a circulating fluid in both the drill pipe and annulus at a specified depth is calculated.

(8) Free point--the length of free pipe in a frozen column is estimated based on the measurement of the change in stretch that is obtained for a predetermined amount of tension release.

II. Computer and Associated Peripheral Equipment

The computer and associated peripheral equipment necessary to monitor, record, process and display instantaneously, pertinent vital information relative to the total drilling operation.

A. The computer system is interfaced with an electronic keyboard printer and dual head magnetic cassette tape. Additional programs can be implemented when required. The recorded drilling data may be translated to compatible IBM magnetic tape for analysis on a large scale computer system.

B. Data are collected from analog rig sensors and converted into engineering units at predetermined intervals. The data are analyzed by lagging certain measured mud properties, applying proven equations to the collected information and presenting the results in a form suitable for immediate on-site use.

C. Data Collection, Presentation and Retrieval

1. A general purpose digital mini-computer is used, together with the necessary data acquisition equipment to monitor, analyze and record all pertinent drilling data. The drilling intervals and depth may be monitored in either the English or metric system. The computer is connected to an A/D multiplexter capable of inputting 24 channels of analog data. The configuration also consists of four digital/analog channels which are used to drive strip recorders.

a. Parameters input to computer:

	Data	Method of Collection
(1)	Bit Weight	Transducer
(2)	RPM	Tachometer
(3)	Torque	Electrical shunt
(4)	Standpipe pressure	Transducer
(5)	Flow in	Transducer
(6)	Flow out	Transducer
(7)	Mud Weight in	Transducer
(8)	Mud weight out	Transducer
(9)	Mud Temperature in	Thermistor
(10)	Mud Temperature out	Thermistor
(11)	Resistivity in	Electrode
(12)	Resistivity out	Electrode
(13)	Pit volume total	Floats
(14)	Pit volume change	Floats
(15)	Mud gas	Gas panel
(16)	Formation density	Manual*
(17)	Formation factor	Manual*

(18)	Plastic viscosity	Manual*
(19)	Yield Point	Manual*
(20)	Pump No. 1 strokes	Micro-switch
(21)	Pump No. 2 strokes	Micro-switch
(22)	Depth interval	Follow line
(23)	On bottom indicator	Depth panel relay
(24)	Optional	

*These data are collected manually and entered via the keyboard to the computer.

b. Computer output:

	Data	Method of Collection
(1)	Drilling rate, min/ft	Each 5' interval
(2)	Drilling rate, min/ft	Each 25' interval
(3)	Drilling rate, ft/hr	Each 5' interval
(4)	Drilling rate, ft/hr	Each 25' interval
(5)	Drilling rate, ft/hr	Bit run avg., each 5'
(6)	"d" exponent	Each 5' interval
(7)	"d" exponent	Each 25' interval
(8)	Drillability	Each 5' interval
(9)	Drillability	Each 25' interval
(10)	Lagged differential conductivity	Each 5' interval
(11)	Lagged differential temperature	Each 5' interval
(12)	Strokes to drill	Each 5' interval
(13)	Feet on bit	Each 5' interval
(14)	Time on bit	Continuous
(15)	Time of day	Continuous
(16)	Average bit weight	Each 5' interval
(17)	Average bit weight	Each 25' interval
(18)	Average bit weight	Bit run avg.each 5'
(19)	Average RMP weight	Each 5' interval
(20)	Average RPM weight	Each 25' interval
(21)	Average RPM weight	Bit run avg.each 5'
(22)	Average torque	Each 5' interval
(23)	Average torque	Each 25' interval
(24)	Average torque	Bit run avg.each 5'
(25)	Bearing wear	Continuous
(26)	Tooth wear	Continuous
(27)	Cost per foot	Each 5' interval

c. Output data recorded on step drive recorders:

(1) Drill rate, min/ft
(2) Cost per foot, $
(3) "d" exponent
(4) Drillability (Optional)
(5) Four additional channels are available for analog data

d. Output data recorded on cassette tape for future use and in addition printed in report form for immediate use (depth interval 5')

(1) Bit weight (averaged over interval)
(2) Rotary speed (averaged over interval)
(3) Rotary torque (averaged over interval)
(4) Drilling rate (min/ft over interval)
(5) Drilling rate (ft/hr over interval)
(6) Depth
(7) Time of day
(8) Lagged differential temperature
(9) Mud temperature in
(10) Mud temperature out
(11) Lagged differential temperature
(12) Mud resistivity in
(13) Mud resistivity out
(14) Lagged differential conductivity
(15) Strokes to drill (over interval)
(16) Flow in
(17) Flow out
(18) Mud density in
(19) Mud density out
(20) Standpipe pressure
(21) Formation density
(22) Formation factor
(23) Pit volume
(24) Mud gas
(25) Plastic viscosity
(26) Yield Point
(27) Current feet on bit
(28) Current time on bit
(29) Current cost per foot
(30) "d" exponent (using average data over 5')
(31) Drillability (using average data over 5')
(32) Computed bit bearing wear
(33) Computed bit tooth wear

(a) The printed version of the above data is designed for use both as a current operating status report and as an aid for data tape editing.

e. Output data printed each 25' interval:

(1) Depth
(2) Time on bit
(3) Feet on bit
(4) 25' drill rate, min/ft
(5) 25' drill rate, ft/hr
(6) 25' average bit weight

(7) 25' average RPM
(8) 25' average torque
(9) 25' "d" exponent
(10) 25' Drillability
(11) Average bit weight of entire bit run
(12) Average RPM of entire bit run
(13) Average torque of entire bit run

(a) The above data is computed and output primarily for use by Baroid personnel to aid in developing 25' interval logs and other ADT functions.

f. Alarm messages automatically generated by computer include:

(1) "Drilling Break" - A running average of the last eight interval drillabilities is maintained. The next drillability may not deviate from the average more than the limit without generating a printed alarm.

(2) "Rotary Torque" - Three different torque limits are entered by the operator for low, high and maximum torque; alarm messages will be printed if any limit violation occurs.

(3) "Mud Gas" - The current mud gas reading must be less than the operator entered maximum gas limit, otherwise, a printed alarm message is generated.

(4) "Flow Rate" - The difference between flow in and flow out must be less than the flow deviation limit; otherwise, an alarm message is printed.

(5) "Mud Density" - The difference between density in and density out must be less than the density deviation limit; otherwise, an alarm message is printed.

(6) "Pit Volume" - A special pit monitoring and alarming program has been developed. The pit volume change is monitored and six different alarm messages output, depending on conditions. Bot pit gains and losses are noted as well as detecting sudden small volume changes.

D. Additional Computer Capabilities

1. Once a digital computer is on-location, a number of additional benefits are provided. These include the use of special engineering programs that may be implemented during trips. The following offline programs are currently available:

a. Pressure control--computes bottom hole pressure, mud weight and casing pressure following a well kick, predicts density of the contaminate.

b. Fracture gradient--computes pressure which will break down the formation.

c. Freepoint--computes depth to stuck point in pipe string.

d. Lost circulation--computes the mud properties and flow rate changes necessary to get full returns.

e. Temperature analysis--computes temperature gradient and maximum mud temperature in the annulus.

f. Optimum bit weight/rotary speed.

g. Bit constant computation (required for bearing and tooth wear calculations).

h. Data retrieval--reads the real-time generated data tapes and generates headed, paged, and columnarized data reports. Four different report formats allow all recorded data to be printed in columnar form.

E. The Computerized ADT System provides complete well programming from the planning stage to formation evaluation; the service monitors, assists and optimizes the exploratory drilling program.

III. Special Equipment and Services

Baroid Mud Logging Service provides valuable exploratory and drilling engineering information to meet your specific needs. The use of auxiliary equipment supplements Baroid's Mud Logging Service in order to render a more complete drilling engineering service, provide monitor and alarm capabilities and assist in safe balanced pressure drilling.

A. Optional Instruments Include:

1. Weight on Bit and Rotary RPM with Recorder

2. Mud Temperature, in and out, with Recorder

3. Mud Pit Volume Totalizer with Recorder

4. Mud Resistivity, in and out, with Recorder

5. Mud Density, in and out, with Recorder

6. Mud Flow, in and out, with Recorder

7. Baroid Programmable Calculator with Programs.

8. Rotary Torque and Total RPM

IV. Miscellaneous Portable Mud Logging Equipment

A. Automatic Recording Gas Detector

The Automatic Recording Gas Detector Unit is available in two styles. The console type unit is suitable for use in a trailer or dog-house. The skid-mounted unit may be placed on the rig floor or any semi-protected area. It is reasonably weatherproof. Both units are designed for operation by customer personnel. The same reliable up-to-date gas detection equipment that is used in the Well Logging Units make possible--at an economical price--an automatic record of methane and total gas in any type drilling mud. Automatic drill time recording equipment may be attached and record made on the Gas Detector chart.

The Automatic Gas Detector is also available in a weatherproofed model suitable for installation at the driller's console with or without remote recorder.

B. Gas Chromatograph and Steam Still

The Baroid Gas Chromatograph and Steam Still-Reflux Unit provides additional formation evaluation information.

C. Hydrogen Sulfide Detector

The Baroid H_2S Gas Detector is designed to detect H_2S gas in a gas stream from a remote point or points, or from the Baroid gas trap. The versatility of the equipment makes it possible to detect concentrations of H_2S gas in air from .01 to 5000 ppm by adjustment of the flow control of the sampled gas. A visual and audio alarm responds when the concentration of H_2S exceeds any predetermined value.

INDUSTRIES

BAROID DIVISION

December 24, 1975

Dr. A. Podio
The University of Texas at Austin
Petroleum Engineering Building, Suite 211
Austin, Texas 78712

Sir:

Enclosed is a revision of our previously submitted Mud Program for Kenedy County, Texas. Baroid will supply a C.D.C. Unit and a Drilling Engineer for $975/day. Stand-by charges (24 consecutive hours that crews are permitted to leave location) will be $685/day.

A communication feature can be installed in the unit for an additional $50/day.

At periodic intervals during the day, recorded information can be transmitted over a phone line to storage in either one of the time sharing systems, or to the computer you mentioned on the campus. Baroid will only be responsible for the assimilation of the monitored parameters and their transmission from the location.

Based upon eighty (80) drilling days and ten (10) stand-by days, the total cost of the C.D.C. Unit without the communicating feature would be $84,850 and $89,350 with the feature. Therefore, the entire package of drilling mud and rental equipment is estimated not to exceed $297,380.00.

If at all possible, one month lead time prior to spudding would be desirable in order to secure the C.D.C. Unit and completely bring the equipment up to our standards.

Thank you,

Very truly yours,

BAROID DIVISION

Larry H. Leggett

L. H. Leggett
Regional Technical Service Manager

LHL/cat

encls-

300 Southwest Tower • Houston, Texas 77002 • (713) 524-6381 • Cable Address: Baroid - Houston
Division of N L Industries, Inc.

APPENDIX Ic

TEST WELL CONFIGURATION AND COST ESTIMATES

TEST WELL CONFIGURATION

The following is a brief outline of the possible well configuration, drilling and completion procedures for a test well in the Kenedy County geothermal fairway. The objective of this section is to illustrate one possible method of completion compatible with the recommendations of this report. It should be considered as a preliminary plan to be used as a starting point for definition of detailed plans for specific sites. The producing intervals consist of sands A, B, and C between 11,400 and 13,000 feet as described in Volume II of this report. Fig. 1 is a sketch of the well configuration and fig. 2 represents a detail of the packer and expansion receptacle.

GEOTHERMAL TEST WELL

Kenedy County

Proposed Depth 14,000 ft.

Preliminary Drilling Program:

1. Drive 20" conductor casing to 100'
2. Install casinghead and 20" 3M# Hydril blowout preventers
3. Drill 17-1/2" hole to 2500'
4. Run 13-3/8" casing and cement to surface
5. Remove 20" Hydril and install 13-3/8" slip-on and weld X 12" 3M# bradenhead
6. Nipple up 12" 3M# type "U" and Hydril blowout preventers
7. Drill 12-1/4" hole to 10,000' and log
8. Run and cement 9-5/8" casing
9. Install 12" 3M# x 10" 5M# casinghead spool and nipple up 10" 5M# blowout preventers
10. Drill 8-1/2" hole to 14,000' and log
11. Run repeat formation tester over producing intervals
12. Run and cement 7-5/8" casing
13. Run cased hole reference logs
14. Run 5-1/2"tubing with packer, sliding bore assembly, Permagauge chamber and tubing
15. Remove blowout preventer and install tree
16. Perforate as recommended (trigger completion)

Casing Design:

Surface Casing:

2000' - 13-3/8", 54.5#/ft., K-55, ST&C

500' - 13-3/8", 61.0#/ft., K-55, ST&C

Intermediate Casing:

500' - 9-5/8", 40.0#/ft., N-80 Buttress
1300' - 9-5/8", 40.0#/ft., N-80, LT&C
2600' - 9-5/8", 40.0#/ft., S-95, LT&C
1700' - 9-5/8", 43.5#/ft., S-95, LT&C
1600' - 9-5/8", 47.0#/ft., S-95, LT&C
2300' - 9-5/8", 53.5#/ft., S-95, LT&C

Production/Protection Casing:

5600' - 7-5/8", 38.1#/ft., P-110, TS
5300' - 7-5/8", 38.1#/ft., S-95, SFJP
3100' - 7-3/4", 45.4#/ft., S-105, FJP

	Hole Size (in)	Pipe Size (in)	Volume of Slurry Required Cu.Ft.	Sacks	Volume of Spacer Required
Surface Pipe	17½	13-3/8	2600	1700	10 bbls. water
1st Intermediate	12¼	9-5/8	1870	760 Lead Slurry 305 Tail-in Slurry	1000 gals.CW7
Production String	8½	7-5/8	550	360	8 bbls.spacer

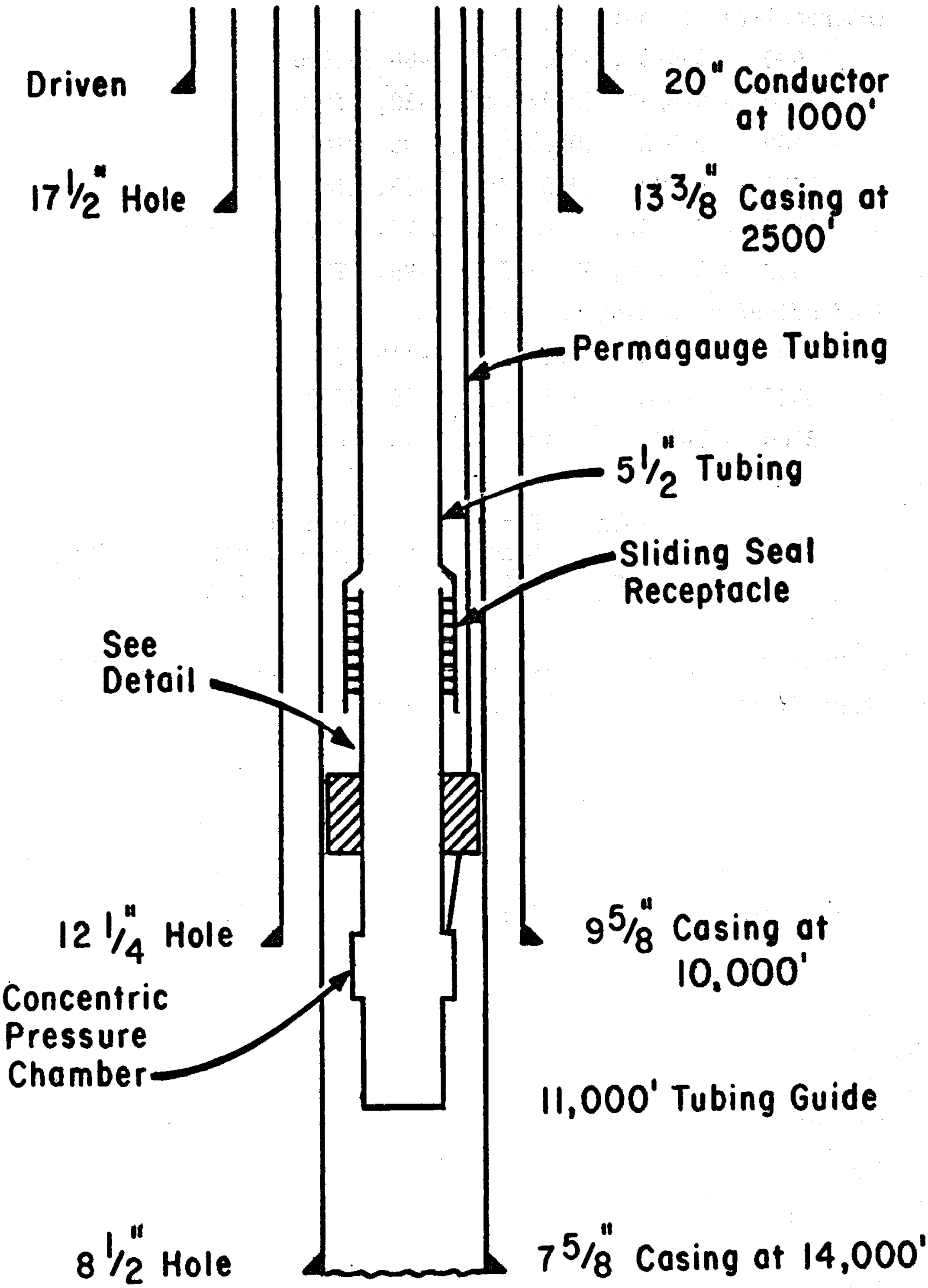


Figure 1. Geothermal test well configuration.

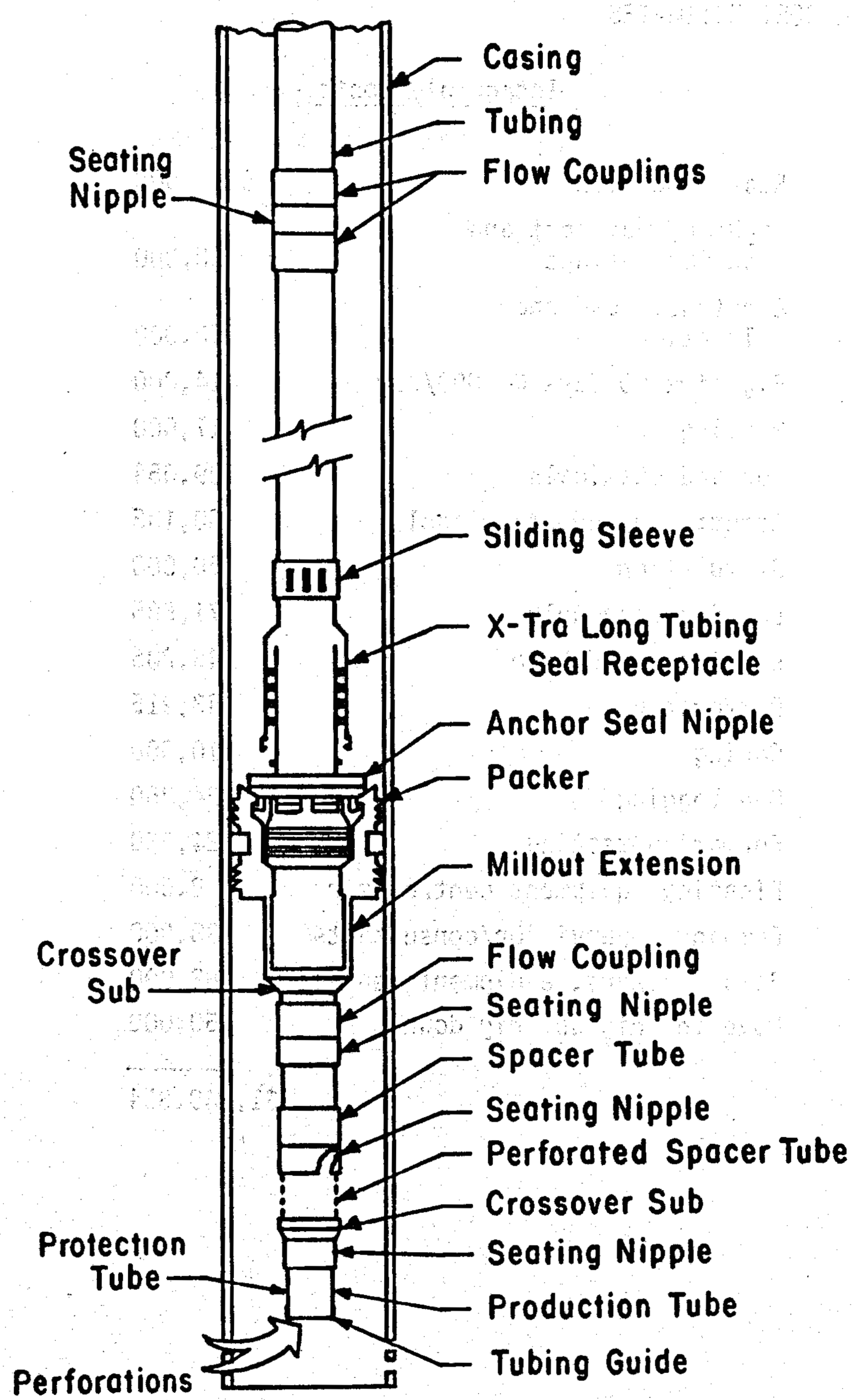


Figure 2. Detail of bottom hole completion assembly.

TEST WELL COST ESTIMATES

Intangible Costs

Stake location	$ 500
Right of way cost and surface damage	20,000
Construct road and location	50,000
Rig time 90 days @ 4000/day	414,000
Hauling	17,000
Mud and chemicals	189,054
Cement and cementing tools	50,135
Stimulation	50,000
Logging open hole	71,585
Logging cased hole	45,285
Perforating	43,915
Coring	10,000
Mud logging	84,850
Formation testing	24,530
Floating equipment centralizers	9,000
Company supervision/consultants	38,000
Bits, packers, equipment rentals	182,000
Move in, rig up, rig down	50,000
	$1,349,854

Tangible Costs

Conductor Casing 100 ft. of 20" OD	$ 3,000
Surface Casing 2500 ft. of 13-3/8"OD	48,000
Protection Casing 10,000 ft. of 9-5/8" OD	216,000
Production Casing 14,000 ft. of 7-5/8" OD	312,000
Tubing 11,000 ft. of 5-1/2" OD	215,000
Wellhead	140,000
Packers, special equipment	166,400
	$1,100,400

Special Data Acquisition Equipment

Downhole pressure recorder, chamber, surface readout and interface	21,760
Data acquisition system	73,000
Interfacing and surface system	20,000
Fluid sampling bombs and assemblies	25,000
	$ 139,760
TOTAL COSTS	$2,590,014

APPENDIX ID

Estimated Costs for:

1. Well logging program for geothermal test well
2. Perforating costs
3. Fluid sampling and formation pressure measurements

These estimates were prepared by Schlumberger Well Service with the objective of illustrating possible costs and procedures for evaluation and completion of a test well at the Kenedy County test site.

Schlumberger

SCHLUMBERGER WELL SERVICES
5000 GULF FREEWAY, P.O. BOX 2175
HOUSTON, TEXAS 77001, (713) 928-2511

January 14, 1976

Dr. A. Podio
The University of Texas at Austin
Department of Petroleum Engineering
Petroleum Engineering Building 211
Austin, Texas 78712

Dear Sir:

Attached are recommended services and estimated prices for formation evaluation, completing and monitoring the proposed ERDA Test Well to be drilled in South Texas in 1976. The services listed should meet all the requirements discussed on your visits of September 25 and December 17, 1975.

The Geothermal SARABAND provides detailed information on formation characteristics through a continuous computation of volume of shale, permeability index, porosity analysis, apparent water salinity, and a bulk volume analysis of the percent clay, matrix and porosity. It is presented on a tabular listing and also on an analog, so it's easy for those not used to working with logs to read, correlate and understand. This program requires the Induction, Neutron, Density and Gamma Ray logs.

The estimated perforating prices are based on a 300' interval with four shots/foot. Lab test with the actual cores from the zone of interest will probably alter these recommendations.

Since the price estimates are based on a tentative well design, I have also attached a Price Schedule for Gulf Coast Land. Services will be performed in accordance with the General Terms and Conditions of this Schedule.

Please let me know if you need additional information.

Sincerely,

J. M. Jones

J. M. Jones

JMJ:akb
Attachments
cc: Texas Coast Division
SWS-Operations-Tech
SWS-Engineering

PRE-COMPLETION (OPEN HOLE)

Run One 17-1/2" Bit Size 2,500'

ISF - Induction	1,325	
CNL - Compensated Neutron	950	
FDC-GR - Formation Density w/Gamma Ray	1,050	
LSS - Long Spaced Sonic	1,050	
BGT - 4-Arm Caliper with Continuous Directional Survey	1,175	
RA - Bullet Placement 24 shots	1,700	
Tool Protection Charges @ $35/Service	210	
Total Run One		$ 7,460

Run Two 12-1/4" Bit Size 10,000

ISF - Induction	3,725	
CNL - Compensated Neutron	3,350	
FDC-GR - Formation Density w/Gamma Ray	4,200	
LSS - Long Spaced Sonic	3,725	
BGT - 4-Arm Caliper with Continuous Directional Survey	3,725	
RA - Bullet Placement 75 shots	5,750	
Tool Protection Charges @ $35/Service	245	
Total Run Two		$24,720

Run Three 8-1/2" Bit Size 14,000'

ISF - Induction	3,945	
CNL - Compensated Neutron	3,520	
FDC-GR - Formation Density w/Gamma Ray	3,880	
LSS - Long Spaced Sonic with Variable Density Recording	4,580	
HDT - High Resolution Dipmeter with Continuous Directional Survey and Borehole Geometry	6,870	
MLL - Micro Laterolog	2,840	
NML - Nuclear Magnetic Log	5,820	
RFT - Repeat Formation Tester - 8 Fluid Test and 25 Pressure Test	24,530	
HRT - High Resolution Thermometer	2,580	
RA - Bullet Placement 20 shots	3,800	
Tool Protection @ $35/Service	350	
Computed Logs		
Mechanical Properties Log	750	
Geothermal SARABAND	470	
Total Run Three		$63,935

PRE-COMPLETION (CASED HOLE)

7-5/8" Csg @ 14,000'

CBL/VDL/GR/CCL - Cement Bond Log, Variable Density, Gamma Ray, Casing Collar Locator	3,925	
TDT - Thermal Decay Time Log	5,575	
MULTI-CCL (Casing Subsidence Reference)	5,600	
MULTI-GR (Formation Subsidence Reference)	5,600	
CNL - Compensated Neutron	3,520	
PAL - Pipe Analysis Log (Casing Corrosion Reference)	4,200	
Tool Protection @ $20/Service	120	
Total		$28,540

COMPLETION

Based on 300' zone, 13-14,000' Depth @ 4 Shots/ft
1200 shots with 2-7/8" HyperDome with 4000 psi
surface pressure — $43,915
For additonal shots, add $33/shot
For reduced shots, deduct $33/shot

POST COMPLETION

Run One

HRT - Thermometer	2,525	
TDT - Thermal Decay Time	5,095	
CNL - Compensated Neutron	3,520	
FBS - Flowmeter	2,860	
PFS - Fluid Sampler	1,485	
Pressure Charges	1,160	
Tool Protection @ $20/Service	100	
Total Run One		$16,745
Run Two - Same Services as Run 1		16,745
Run Three " " " "		16,745
Run Four " " " "	16,745	
Plus the Following:		
MULTI-CCL (Csg Subsidence)	5,600	
MULTI-GR (Formation Subsidence)	5,600	
PAL-Pipe Analysis (Csg Corrosion)	4,200	
Tool Protection @ $20/Service	60	
Total Run Four		$32,205

ESTIMATED CHARGES FOR TOTAL PROJECT

Pre-Completion (Open Hole)	$96,115
Pre-Completion (Cased Hole)	28,540
Completion	43,915
Post Completion	82,440
TOTAL	$251,010

APPENDIX IE

Data Acquisition

1. Cost estimate for continuous monitoring of bottom hole pressure
2. Cost estimate for data acquisition system for monitoring of well performance in testing phase

sperry-sun
P. O. Box 36363
Houston, Texas 77036
Telephone (713) 494-3021
Telex—76-2795

QUOTATION PRO-FORMA INVOICE

QUOTATION NO.: N/A

TO: The University of Texas at Austin
Department of Petroleum Engineering
Petroleum Engineering Building 211
Austin, Texas 78712 Attn: Dr. A. Podio

INQUIRY NO.: DATED: SIGNED:

TERMS & CONDITIONS:	DELIVERY PROMISED	QUOTATION DATE	EXPIRES
For Cost Analysis			

ITEM	QNTY. OR UNIT	PART NO.	DESCRIPTION OUTRIGHT SALE PERMAGAUGE SYSTEM	UNIT PRICE	TOTAL
1	1	2A5209	Concentric Chamber 4" x 20'	$1980.00	$1,980.00
2	15100	2A3071	Tubing Stainless .094" OD x .026" ID/ft.	0.38	5,738.00
3	484	2A2750	Tube Collar Protectors	0.75	363.00
4	968	2A3206	Stainless Steel Straps	0.50	484.00
5	1	Package	Well Head Assembly	200.00	200.00
6	1	2A3326-M2	10K Permagauge Surface Recorder	6045.00	6,045.00
			OPTIONAL		
7	1	2A3865	Gas Intensifier for 3 Days	Min.	300.00
8	1 est	3 Days	Sperry-Sun Installation Consultant, Engineer	350.00	1,050.00
9			Mileage, Sperry-Sun Engineer Car, transportation (est. 100.00)	0.40	As Incurred
10			Living Expenses (est 150.00)		As Incurred
			Estimate		$16,760.00

SPERRY-SUN WELL SURVEYING COMPANY

B Carl Kisinger, Jr. TITLE: DATE:

Carl Kisinger, Jr.

FORM SP-446

SOCIETY OF PETROLEUM ENGINEERS OF AIME
6200 North Central Expressway
Dallas, Texas 75206

PAPER NUMBER SPE 5607

THIS PRESENTATION IS SUBJECT TO CORRECTION

Permaguage - A Permanent Surface Recording Downhole Pressure Monitor - Through A Tube

By

Steve G. Weeks, Member SPE-AIME, Shell Oil Co. and Gerald F. Farris, Sperry-Sun

ABSTRACT

A permanent means of continuously monitoring downhole pressures without interruption of producing or injection operations, was first tested in Germany more than 25 years ago. This initial development plus subsequent modifications each require an electric cable to transmit a signal reflecting downhole pressures. A new tool has been introduced which does not utilize any downhole electronics or electrical conduit. This pressure transmission system, or Permagauge, consists of a 3/32-inch O.D. tube, attached to the outside of the production tubing, connecting a surface recorder to a downhole chamber in communication with the well fluids. Downhole pressures are determined by adding the recorded surface pressures to the calculated pressure exerted by the weight of an inert gas column in the small tube. A portable surface unit provides a permanent printed record of pressure versus time as well as a digital display for continuous pressure monitoring.

Since initial installation, more than 75 Permagauges have been run, including installations in a CO_2 pilot project in Southeastern Mississippi. Discussed are a general description of previously available remote reading bottom-hole pressure gauges, a resume of all Permagauge installations, plus detailed experience with the Mississippi runs verifying the accuracy of the Permagauge to be equal to wireline pressure surveys.

References and illustrations at end of paper.

INTRODUCTION

Bottom-hole pressure data are routine requirements for evaluation of production and reservoir performance. Monitoring of reservoir pressure response may be especially helpful in evaluation and control of supplemental recovery projects. This might include producing, build-up and static surveys as determined by pressure recorders run on wireline. However, frequency and number of wells surveyed may be limited due to interruption of normal production routine, as well as expense. Presence of some artificial lift equipment will prevent running conventional pressure surveys. Furthermore, production of highly corrosive fluids, together with potential damage from wireline cutting where plastic-coated tubing is installed, can also be a deterrent to obtaining useful pressure data.

Permanent installation of a downhole pressure detector provides a means of continuously recording pressures and may aid in adjustment of fluid movement within a reservoir. Several such detectors have been developed which utilize an electrical cable to transmit a pressure-induced signal to the surface. These gauges include installation of a downhole electronic assembly with exposure of a pressure diaphragm to well fluids. Selection of cables and electronic assemblies sufficient to withstand well conditions becomes more difficult with increased depths and temperatures. With a Permagauge pressure monitor, downhole pressures are transmitted to the surface by means of a small diameter tube without use of any downhole electronic equipment or moving parts. At the surface, the pressure impulse is then converted to bottom-hole pressure.

Since initial installation, during 1973 in a 4,300-foot hole, approximately 75 Permagauges have been run. These have included operations in: (1) routine oil and gas producers or water injectors, (2) water source wells, to enable adjustment of pumping rates in relation to well bore fluid entry, (3) gas storage input wells, (4) a shale-oil development project, and (5) a CO_2 miscible flood project at below 10,500 feet in the Little Creek, Mississippi Field. A summary of pertinent data for all installations is listed in Table 1, with detailed discussion limited to the Little Creek installations.

ELECTRICAL METHODS

Stressing a wire or other electrical conductor will result in an increase in electrical resistance. Strain gauges utilizing this principle to measure pressure have been available in several forms for many years. In 1948, a taut wire gauge was developed and first received widespread use in Europe. The ends of the taut wire are attached to a sealed steel housing and a steel diaphragm. The wire is energized by a current pulse transmitted downhole. As pressure is applied to the diaphragm, tension in the wire is changed with accompanying changes in natural frequency of the wire. An electrical signal is transmitted to a surface receiver for comparison with a signal from a standard calibrated wire for determination of the applied pressure. Detailed description of this equipment plus practical applications in the Rocky Mountain Area have been well documented by Engel.[1] More recently,[2] a pressure gauge utilizing a quartz transducer rather than a taut wire has become available for field application.

During 1959, a downhole bourdon tube-type gauge was developed in the United States. As pressure is applied to the spiral-formed tube coupled to a code wheel made of an electrical conductor and an electrical insulator, a pattern change in current requirements is effected. By decoding the current pattern, the bottom-hole pressure can be determined.[1]

In each of the above methods, downhole signals are transmitted to the surface by means of an electrical cable which is normally attached to the exterior of the production or injection tubing.

PERMAGAUGE SYSTEM

The basic Permagauge system consists of a downhole chamber connected to a surface monitor by a small diameter tube filled with a single-phase gas, usually nitrogen. The tube is normally secured to the outside of the production tubing, extended through a packing gland in the casinghead, hence to a surface pressure recorder and optional digital readout unit.

Downhole Installation

The downhole chamber permits expansion and compression of the pressure transmitting gas without entry of well fluids into the tube. The size of the chamber is dependent on the anticipated pressure range to be encountered as well as diameter of tubulars. See Figure 1-A and refer to Appendix A for chamber length and volumetric calculations. Care must be taken that the ratio of chamber volume and transmission tube is sufficiently large so that, with prevailing pressure fluctuations, well fluids will rise in the chamber only without entering the tube. The chamber can be run immediately above a production packer with screened ports to permit pressure communication between the production stream and the chamber.

The pressure transmission tube is 3/32-inch O.D. with 0.026- or 0.054-inch I.D. In most cases, either a 304 or 316 stainless steel tube has been used. Special consideration should be given to the tube metallurgy. For some unsupported or free-hanging installations, the anticipated tensile strength requirements may necessitate a high yield strength tube. However, such a tube may be susceptible to failure in a chloride environment.[3]

The tube is covered at each collar by a protector or guard banded to the production tubing. (See Figure 1-B.) For shallower, less demanding conditions, nylon banding straps have been adequate; however, at elevated temperatures and in the deeper wells, metal bands are used. Anticipated annulus fluids should be of primary consideration when selecting the type of metal band to be used.

After installation of the production equipment, the 3/32-inch tube and expansion chamber are displaced with nitrogen. A progressive increase in shut-in monitor readings after purging should indicate continued removal of liquid. Displacement is continued until static surface pressure readings remained constant. Insufficient displacement to remove all liquids, or the effect of any cumulative loss of gas, such as through surface leaks, will result in lower indicated downhole pressures.

Surface Recording

Several options are available with regard to surface pressure recording. These may vary from a simple calibrated pressure gauge, deadweight tester, single pen recorder, digital pressure monitor or a combination digital unit and pressure recorder. The principle of operation and a schematic of the digital pressure monitor are shown on Figure 2. Since pressures measured at the surface do not account for the weight of gas in the transmission tube, a correction must be made. (See Appendix B.) A computer program is available to provide for direct conversions, incorporating the conditions for a specific installation.

Installation Experience - Little Creek Field

During the first attempted installation, nylon straps were used to band the tube guards. After an unsuccessful attempt to effect a seal with the production packer, it was necessary to pull the production tubing and pressure assembly. Although the production tubing had not been rotated during installation or initial pulling operations, most of the straps had failed and the guards were left in the well. Extensive fishing was required to recover the pressure chamber and packer. Recovery was especially difficult as a result of the guards falling and becoming wedged with loops of the small tube between the 3 1/2-inch chamber and the less than 5-inch I.D. casing. Figure 3 indicates some of the tubing and protectors accumulated at the top of the pressure chamber, attributing to the difficulty in recovery.

Subsequently, various metal bands were tested. Based on this evaluation, exposure to salt water in the annulus plus possible exposure to a CO_2 environment in the event of later production tubing leakage, monel straps with "cut-and-crimped" connections have been used without further failure of the bands. In addition, to minimize chances of having to pull the assembly as a result of casing, production tubing, or packer leaks, wireline packers were set with pushout plugs in place to permit pressure testing the packer and casing before running the production tubing and pressure assembly.

The first two Permagauges installed in the Little Creek Field, at about 10,500 feet utilizing 316 stainless steel, were each in service about one year before it became necessary to pull the production equipment — the first after sand-bridging in the production tubing and the other as a result of ultimate failure of the production packer assembly. The transmission tube was retrieved from the first well without difficulty and appeared to be in good condition. However, later testing revealed leaks in the tube. Inspection showed corrosion pitting which, in conjunction with the full hard temper and accompanying low ductility, resulted in mechanical failure. Micrographs did not show evidence of stress corrosion even though this might be suggested by the presence of chlorides. The tube recovered from the second well had parted in numerous places; although, for the most, the pieces were retained by the bands and protectors at each tubing coupling. After recovery, the yield strengths of samples from the two tubes tested between 112,000 and 159,000 psi. A length of tube immediately above the downhole chamber in the second well had a yield strength of 43,000 psi. This piece of tube was not damaged.

Immediately prior to pulling, both of the Permagauges reflected realistic downhole pressures. Apparently, ultimate failure occurred as the tubes were stressed during pulling and/or as the tubes were rolled on a reel after having been subjected to a chloride environment. Since replacement with annealed 304 stainless steel tubes, with average yield strengths of about 40,000 psi, no further failures have occurred.

Comparison of Wireline BHP Data With Permagauge Results

Initially, wireline pressure surveys were run in the two wells to determine the reliability of results from a Permagauge installation. These surveys utilized pressure bombs normally used for routine field bottom-hole pressure work. By comparison, the Permagauge reflected 25 psi higher pressure in Well No. 1-7 and 109 psi lower pressure in Well No. 1-11, with recorded pressures ranging from about 5,500 to 6,500 psi.

Subsequently, the tube in LCU No. 1-11 was purged with additional nitrogen and a calibrated Sperry-Sun precision pressure gauge run on wireline. Special care was taken to tie in the depth of the wireline gauge with the sensing ports of the Permagauge downhole pressure chamber. Depth measurements were verified by means of a restricting nipple in the production tubing 36 feet below the Permagauge. This wireline survey reflected a downhole pressure of 6,562 psi. Concurrently, the surface monitor reading was 5,118 psi. With this surface reading plus the calculated pressure exerted by the weight of the gas column, based on an average tube temperature of 175°F, the Permagauge system indicated a downhole pressure of 6,561 psi.

Calculation of the weight of the gas column in the transmission tube and ultimate determination of downhole pressures are sensitive to the prevailing temperature. The 175° average temperature used for this specific comparison was based on geothermal and flowing temperature gradients for the subject area (API Paper No. 926-4-S) at the sustained flow rate prior to the wireline survey. With an estimated average 150°F static temperature, the same monitor reading would have indicated an approximate 70 psi greater pressure.

For most shallower installations, variation in average temperature will not have an appreciable effect on reported downhole pressures. However, where a detail pressure analysis is being made, consideration should be given to this factor - especially for deeper wells and thermal operations.

COST COMPARISON

Installation expense for permanent downhole pressure recorders will vary with depth. This is due primarily to required transmission tube, or wire conductor, protectors and bands. Comparative costs (January 1974) for a 10,500-foot permanent installation, such as at Little Creek, are as follows:

	Permagauge	Type "A"(1)	"B"(2)
Additional Rig Expense	$ 600	$ 600	$ 600
Tube or Wire	3,550(T)	5,170(W)	5,170(W)
Protectors and Bands	825	825	2,100
Pressure Unit			
Bottom-Hole	885	9,980	2,825
Surface	1,340*	2,755**	1,270
Total Costs	$7,200*	$19,330**	$11,965

* Add $4,800 for digital unit plus printer.
** Add $4,500 for printing digital recorder.
(1) Quartz transducer detector.
(2) Bourdon tube detector.

Cost for a single routine (Amerada) flowing BHP with a 72-hour buildup run on a wireline under the same conditions is about $750.

DISCUSSION

Observation of wellhead pressures is a routine daily function in normal well surveillance. Determinations of bottom-hole pressures, even though of greater significance, are done far less frequently due to comparative expense or practicality of obtaining such information. Where the expense can be justified, installation of permanent bottom-hole pressure monitors offer a continuous means of securing such data. Since a large part of this expense is due to the transmission tube or wire and associated protectors and bands, installation in deeper wells may be more difficult to justify. However, one should expect longer-lasting, trouble-free performance with the Permagauge, which contains no moving parts, as compared to an electronic or downhole bourdon tube-type gauge, which may require periodic recalibration and rely on an insulated electric conductor cable.

The surface monitors can either be transported to different wells or tubes from various wells connected to a manifold at a central location. As a side benefit, the combination monitor and printer can also be used for continuous recording of surface buildups or other pressure monitoring on wells which have no downhole detector.

CONCLUSIONS

The initial expense of permanent downhole pressure monitors is greater than routine wireline pressure surveys. This may tend to limit installations to special studies or specific problem wells. It is believed, however, that the Permagauge offers a definite potential for narrowing this difference in cost. This detector can be used effectively to monitor downhole pressure through a small diameter tube. However, care must be exercised in selection and securing adequate banding straps and proper metallurgy for transmission tubes to assure against failure. The transmission tube should be thoroughly purged with a single-phase gas and precautions taken to assure against any leakage. When temperatures adjacent to the transmission tube may vary appreciably as a result of changing production rates or the well being shut in, this change should be considered in determining the weight of the gas-filled tube column.

ACKNOWLEDGMENTS

We are particularly grateful to Mr. R. E. Douglas for his valuable contribution in installation and evaluation of the Permagauges in the Little Creek Field Unit.

REFERENCES

1. Engel, R. F., "Remote Reading Bottom-Hole Pressure Gauges - An Evaluation of Installation Techniques and Practical Applications," J. Pet. Tech. (December 1963).

2. Miller, G. B., Seeds, R. W. S., and Shira, H. W., "A New, Surface Recording, Down-Hole Pressure Gauge," SPE No. 4125 (October 1972).

3. Paul, G. T., and Zeis, L. A., "Here's How To Minimize Stress-Corrosion Cracking," Oil and Gas Journal (October 1974).

APPENDIX A

CHAMBER VOLUMETRIC AND LENGTH CALCULATIONS

Tube Volume, (3/32" O.D. & 0.054" I.D.)
$(0.7854)\ (0.054)^2\ (12) = 0.0275$ cu.in./ft.
or 10,500 feet = 288.57 cu.in.

Concentric Chamber Volume,
(3 1/2" O.D., 2.992" I.D., w/2 3/8" bore)
$= (0.7854)\ \left[(2.992)^2 - (2.375)^2\right]\ (12)$
= 31.21 cu.in./ft.

For Maximum 6500 psi & Minimum 3000 psi BHP

Chamber Volume =

$$\frac{(\text{Max. Pressure})\ (\text{Tube Volume})}{\text{Min. Pressure}} - \text{Tube Volume}$$

Chamber Volume =

$$\frac{(6500)\ (288.57)}{3000} - 288.57 = 336.67 \text{ cu.in.}$$

$$\text{Required Chamber Length} = \frac{336.67}{31.21} = 10.78 \text{ ft.}$$

APPENDIX B

CORRECTION FACTOR (For Nitrogen-Filled System)

BHP = Surface Pressure + (Gradient) (Depth)

$$\text{Average Pressure} = \frac{\text{BHP + Surface Pressure}}{2}$$

Gradient = (D_x) (.433333 psi/ft)

With:

$$\frac{P_1V_1}{Z_1T_1D_1} = \frac{P_2V_2}{Z_2T_2D_2}\ ;\ D_2 = \frac{P_2V_2Z_1T_1D_1}{Z_2T_2P_1V_1}$$

Where:

P_1 = 1 Atmosphere (14.6735 psia)

$V_1 = V_2$ = Volume of System

$T_1 = 0^oC = 32^oF = 492^oR$

D_1 = Density of N_2 at 0^oC = 0.001251

Z_1 = Compressibility of N_2 @ 0^oC & 1 atm. = 1

P_2 = Average pressure, atmospheres

T_2 = Average temperature, ^oR

D_2 = Average Density of N_2

Z_2 = Super Compressibility

$$D_2 = \frac{(P_2)\ (1)\ (492)\ (0.001251)}{(Z_2)\ (460 + t)\ (14.6735)}$$

Average Gradient =

$$(.43333)\left[\frac{(P_2)\ (492)\ (0.001251)}{(Z_2)\ (460 + t)\ (14.6735)}\right]$$

or

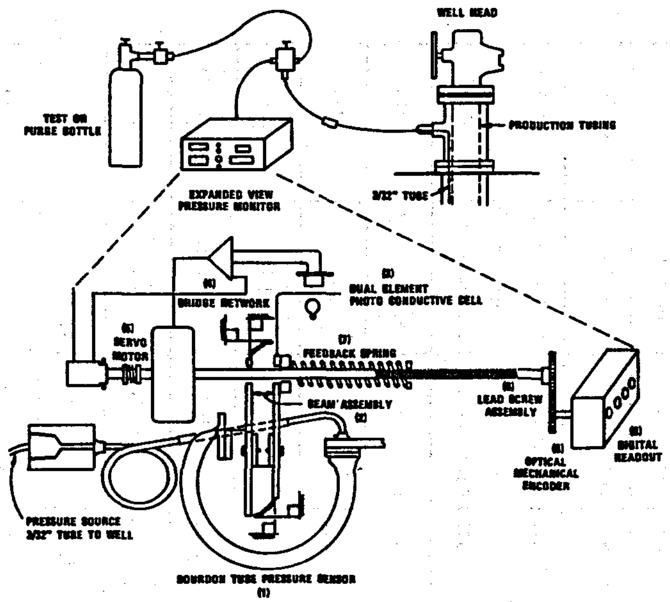
$$\frac{(0.0181765)\ (P_2)}{(Z_2)\ (460 + t)}$$

As compressibility will vary with pressure and temperature, which also vary with depth, corrections must be provided for changes in these conditions throughout the anticipated pressure range to be recorded.

TABLE 1 - SUMMARY - PERMAGAUGE INSTALLATIONS

LOCATION	NUMBER INSTALLED	TYPE WELL	WELL FLUID	AVERAGE DEPTH (FT.)	AVERAGE TEMP. (°F)	PRESSURE RANGE MIN. (PSI)	PRESSURE RANGE MAX. (PSI)	DESCRIPTION CHAMBER	AVERAGE LENGTH SERVICE	INITIAL INSTALLATION
California	3	Observation & Producer	Water & Steam	3,600	350-600	1,400	1,600	Suspended	3 Months	1/74
Colorado	1	Producer	Water	5,618	(a)	200	2,400	Suspended	3 Months	1/74
Colorado	23	Water Level Observation	Water	800-3,000	50	200	860	Suspended	7 Months(b)	10/74
Colorado	1	Storage & Observation	Gas	4,837	80	700	1,200	Suspended	13 Months	5/74
Louisiana	1	Producer	Water & Steam	1,185	90-600	100	600	Concentric	2 Months(c)	9/74
Mississippi	2	Producer	Oil, Water & CO_2	10,500	175	3,000	6,800	Concentric	12 Months(d)	2/74
Oklahoma	1	Supply	Water	1,487-2,000	70	10	250	Suspended	20 Months	7/73
Oklahoma	1	Producer	Oil	6,400	74	300	1,250	Concentric	8 Months	3/74
Oklahoma	20	Supply	Water	600-2,000	70	20	7,000	Suspended	12-19 Months	'73 & '75
Texas	1	Producer	Oil, Gas & Water	4,346	110	1,200	1,500	Concentric	21 Months	2/73
Texas	12	Injection	Water	4,950	125	300	2,800	Concentric	8± Months(a)	8/73
Texas	4	Producer	Oil & Water	4,950	85	0	500	Saddle Mount	(a)	11/73
Utah	1	Producer	Oil & Water	10,700	160	3,500	9,000	Concentric	3 Months	4/75

(a) Data not available or incomplete.
(b) Pulled and reused in other locations.
(c) Test completed.
(d) Wells pulled for remedial work. New tubes installed (refer to Installation Experience - L. C. Field).



PRINCIPLE OF OPERATION

The Permagauge features a force balance system combining a pressure sensor with an electro-mechanical feedback. THE FORCE APPLIED TO THE PRESSURE SENSOR IS MATCHED EQUALLY BY A FORCE DEVELOPED BY A FEEDBACK SPRING WHICH RETURNS THE SYSTEM TO A POSITION OF NO AFFECT. The electro-mechanical system is connected to an optical-mechanical encoder that in turn relays a signal for numerical display of applied pressure.

Referring to the schematic drawing, the pressure transmitted by the gas column filling the small diameter tube is applied to the bourdon tube sensing element (1). This element is in turn attached to a beam assembly (2). Any variation in pressure will deflect the sensor and hence the beam assembly. The free end of the beam is attached to a slotted vane, which interrupts a ray of light impinging on a dual element photo conductive cell (3). The photo conductive cell is coupled into a bridge network (4). Any motion of the slotted vane will cause an unbalanced condition or differential signal in the bridge. This signal, amplified, drives a servomotor (5) and a lead screw (6). A feedback spring assembly (7), riding on the lead screw, is also connected to the beam assembly. Movement of the lead screw moves the feedback spring to balance the force initially applied through the gas column to the pressure sensor. Thus, the system is returned to a null position. Turning of the lead screw positions the optical-mechanical encoder (8) to reflect the applied pressure with lighting of display bulbs for digital readout (9).

Fig. 2 - Permagauge digital pressure monitor and surface installation.

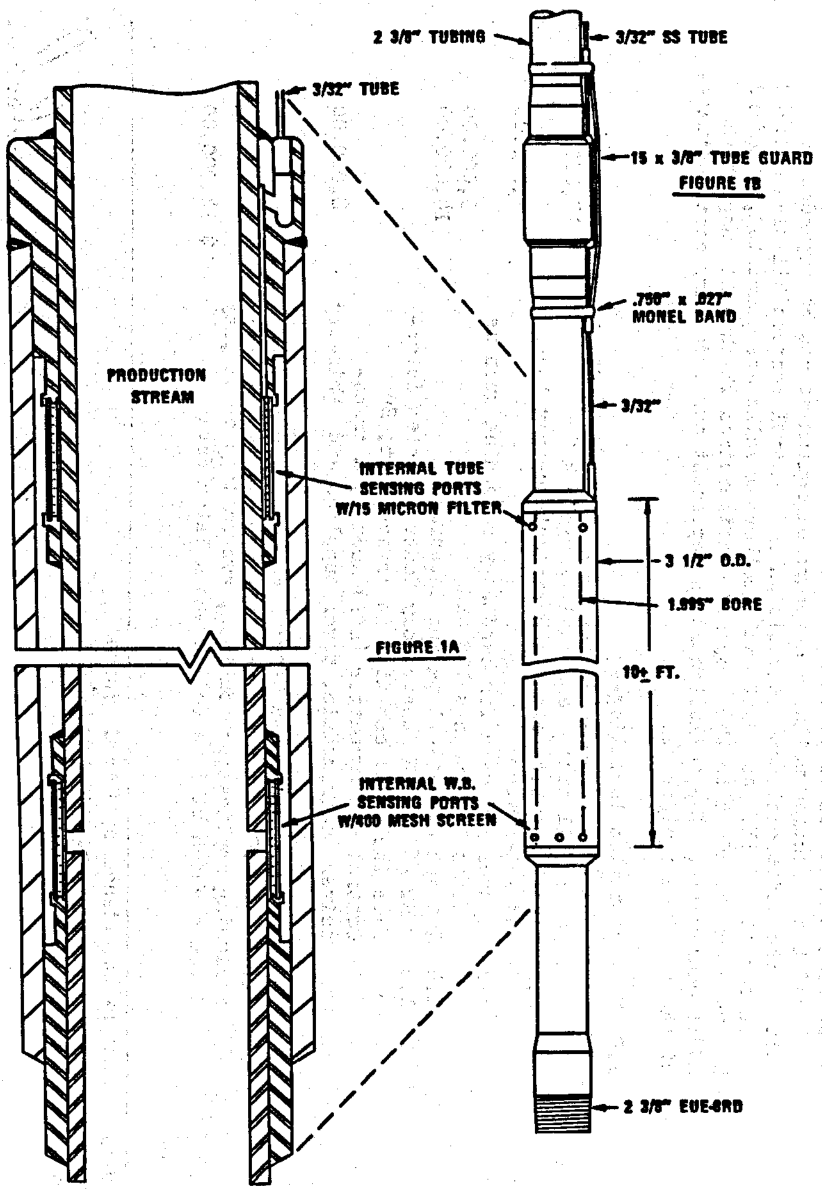


Fig. 1 - Permaguage downhole pressure sensor assembly.

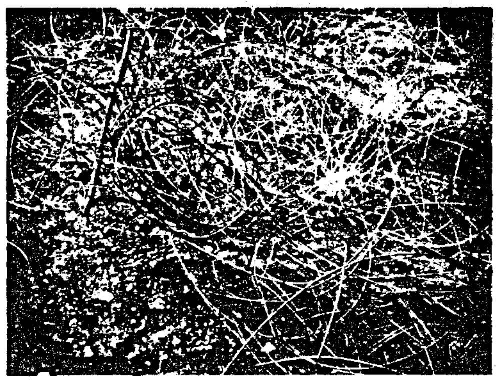


Fig. 3A - Recovered 3/32-inch tube.

Fig. 3B - Junk accumulation at top pressure chamber.

QUOTATION

BASIC
A BAKER OIL TOOLS COMPANY

BAKER AUTOMATION SYSTEMS a division of KOBE, INC.
7130 HARWIN DR., HOUSTON, TEXAS 77036 • TEL. (713) 781-5600 • TELEX 762-734

BASIC REFERENCE	EXPIRATION DATE	CUSTOMER REFERENCE	PAGE
B-1275-08	BUDGETARY	Verbal Request	1 of 2

December 22, 1975

Mr. Tony Podio
The University of Texas at Austin
Department of Petroleum Engineering
Petroleum Engineering Building 211
Austin, TX 78712

Gentlemen:

As a result of our meeting Tuesday, December 15, 1975, during which you described the data acquisition and control requirements associated with the evaluation of geothermal energy resources, we are pleased to provide the following budgetary quotation. The equipment listed below is intended to provide a solution to your Phase I requirements for the Production Test well and the injection wells. The proposed equipment can be expanded to satisfy the additional data acquisition and control responsibilities defined in Phases IA and II. As additional geothermal wells are completed, standard hardware can be added to the proposed configuration which will support the additional wells. The following costs represent our budgetary cost estimates of the required equipment.

1.0	Master Station including—	
1.1	Data General computer with 32,000 words of memory, power fail option and real time clock	$ 17,000.00
1.2	Black and white alpha numeric cathode ray tube and interface	4,000.00
1.3	Printer/Keyboard for hard copy recording such as a Texas Instruments 733 ASR	5,000.00
1.4	7 track magnetic tape and interface	14,000.00
1.5	PERT 26/31 BCH Supervisory Control System interface including computer interface unit, Bus Control and Formatter (BCF) module, a transceiver modem module, power supplies and cabinetry	8,000.00
2.0	Software including Data General executive telemetry driver and PRIMUS data base management system but not including application routines, system logs or display formats which will be defined at a later data	$ 14,000.00

Orders subject to acceptance by BASIC. Entire agreement will consist of order, acceptance and Terms and Conditions of Sale on reverse hereof.

FORM NO. BB-1-203 (1/75)

MANAGER—APPLICATION ENGINEERING

BASIC
A BAKER OIL TOOLS COMPANY

Mr. Tony Podio
Department of Petroleum Engineering
Austin, TX 78712

December 22, 1975
Page 2 of 2
B-1275-08

3.0 PERT 26/31 BCH Remote Terminal Unit with cabinet, power supplies, data modem, timing and control, address decode, relays and filed terminals for the following Input/Output:

- -30 analog inputs requiring Analog-to-Digital converter and 8 four-point analog input cards
- -3 analog outputs requiring 2 two-point analog output cards
- -4 Digital control outputs requiring one 24-point control output card
- -9 status/alarm inputs requiring one 24-point input card

In this configuration there are 3 spare input/output card slots for future expansion. $ 6,000.00

4.0 Project Management $ 5,000.00

Total Estimated System Cost $ 73,000.00

We estimate that six months will be required to implement the system over which time progress payments will be required.

We appreciate the interest you have shown in Baker Automation Systems and our products. If we can be of any further assistance, please do not hesitate to contact us.

- End of Quotation -

bh

BASIC
division of KOBE, Inc.
A BAKER OIL TOOLS COMPANY

BAKER AUTOMATION SYSTEMS
7130 HARWIN DR., HOUSTON, TEXAS 77036 • TEL. (713) 781-5600 • TELEX 762-73

A DESCRIPTION OF BASIC'S PERT 26/31 BCH SUPERVISORY CONTROL AND DATA ACQUISITION SYSTEM

1.0 INTRODUCTION

There was a time, and not too long ago, when a desk top calculator capable of adding, subtracting, multiplying, and dividing was reasonably priced at six hundred dollars. Moreover, the unit weighed in excess of twenty pounds and occupied one square foot of desk space. Times have changed! Today calculators are priced as low as twenty dollars, weigh no more than eight ounces, and fit in the palm of the hand. As an added benefit, calculators of today are many times faster in operation than their electro-mechanical predecessors. These improvements are the results of advances in solid state technology. The same technological advancements have been applied to supervisory control and data acquisition systems with equally impressive results.

A new generation of solid state integrated circuit (IC) has evolved; it is called Complementary Metal-Oxide Semiconductor (CMOS). Just as silicon devices provided advances over germanium, CMOS provides advantages over its silicon predecessor. For example:

> Chip reliability is increased because there are fewer components inside the chip. For instance, a simple CMOS inverting amplifier is composed of only two field effect transistors.
>
> Wide temperature range allows greater flexibility in design. Typical range for CMOS is -40°C to +85°C.
>
> Wide power supply range places fewer restrictions on choice of power supply. CMOS ICs operate at voltages from 3 to 15 volts.
>
> Current consumption in CMOS devices is extremely low. Maximum quiescent current is 0.5 microamperes with a 5V power supply.
>
> CMOS devices exhibit high DC noise immunity and provide good AC noise immunity for high to low level transitions of short duration pulses.

BASIC began using CMOS circuitry early in 1973 with the introduction of the PERT (Power Efficient Remote Terminal) 11/15 BCH System to the supervisory control industry. Spurred by the success of the PERT 11/15 System, BASIC increased the input/output capacity of the system with the PERT 26/31 BCH System.

2.0 SYSTEM OVERVIEW

PERT 26/31 is a digital, continuous scanning, remote control and data acquisition system. Typically, the system consists of a Central Control Station (CCS) and one or more field-located Remote Terminal Units (RTU). Data transmission between the central and remote locations is accomplished on a single communication channel. Accessing many remote stations from the CCS over a single communication channel is termed a "party line system." This party line scheme naturally saves cable costs and is possible because the CCS initiates and has full control of all communication on the channel. The RTUs respond only when addressed by the CCS.

Regardless of the communication scheme employed--leased telephone lines, direct wire line, a radio channel, a microwave system, or some combination of these methods--system operation follows a set philosophy. The CCS initiates periodic interrogations of each RTU and the selected RTU responds with the state of its associated end element points. As the CCS transmits an interrogation onto the channel, each RTU on the party line receives the message and attempts to decode the address portion of the message. Since the message is destined for a particular RTU, only that RTU can decode the address. All other RTUs revert to a standby mode, awaiting a further incoming message. The addressed RTU performs the BCH security check on the message, determines the nature of the message, and initiates the appropriate functions to input data or perform a control output. The rate of these interrogations is dependent upon the criticality of the data being retrieved and type of communication media used.

The RTU assumes the following functions in addition to that of address decoding and recognition.

> Signal digitization - all data is filtered, converted to digital form and then converted to representative frequencies for transmission, as opposed to transmitting actual voltage levels and tolerating the attendant signal degradation.
>
> Data multiplexing - all end points are interfaced to the communications channel via appropriate input/output cards in the RTU. Many inputs and outputs are available to the CCS over a single communication channel.
>
> Time multiplexing - each RTU "time shares" the party line with other RTUs under the direction of the CCS.

The electronics within a remote unit allow field data to be transmitted from environments which are not conducive to measurement or communication. Since all data is transferred in digital form, message validity checks are necessary. Each binary digit (bit) of data transferred is either 100% right or 100% wrong because only two logical states are used (logical "1" and logical "0"). Therefore, to detect message errors, PERT 26/31 employs the Bose-Chaudhuri/Hocquenghem (BCH) error detection code. Five check bits are associated with each 26 data bits. The BCH code bits are attached at the end of each data block whether transmitted by the CCS or the RTU. In addition to the BCH security scheme, a CHECK-BEFORE-OPERATE scheme is used for control outputs. The CCS requests a control output of an RTU and the RTU responds with an echo of this request. This echo verifies selection, and the CCS then transmits an executive command to complete the sequence.

Security, reliability, and flexibility characterize the PERT 26/31 BCH System. The CMOS circuitry of the system not only results in a more reliable method of remote control and data acquisition, but also provides a cost effective system solution.

3.0 COMMUNICATIONS

The system communication interface may be chosen from a number of available options such as modem, RS-232C, and D.C. keying, to mention a few. With this degree of flexibility any communication method may be selected by the system engineer with the assurance that the PERT hardware is able to support the method selected. For example, the communication system may be a direct wired channel, a radio and/or microwave system, or narrow band frequency multiplexed channels. Some of these communication systems and their application to the PERT 26/31 BCH Systems are briefly covered below.

3.1 Direct Hardwired Line - When the PERT system is to be installed in open country with a sparsity of population, direct wired systems consisting of aerial or direct buried 19-22 AWG cable provide a possible communication solution. After years of experience with hardwired communication circuits operating at speeds up to 18,000 bits per second, BASIC engineers are available to assist with the design of hardwired circuits. Typical considerations include the need for amplifiers, impedance matching techniques and the physical layout of the cable system in order to minimize reflections. In many subsea installations it is desirable to install communication cables in the same cable as power. There exist inexpensive practices which, if employed, make this a perfectly sound communication system.

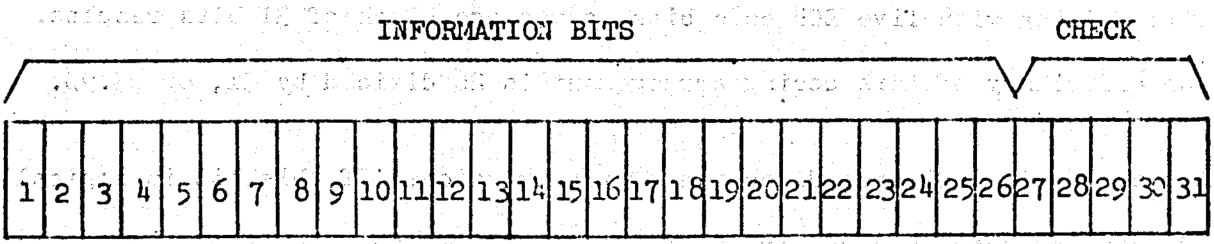
3.2 Leased Telephone Lines - Frequently, the system is installed in areas where telephone companies have existing facilities. In this case, leased lines can be considered. In almost all cases, modems are employed for interfacing to the communication channel. A typical voice grade leased line permits communication speeds of 1200 bits per second and by frequency multiplexing procedures other communication speeds of 600, 300, 150 or 75 bps can be implemented with standard asynchronous modems. By use of synchronous modems and conditioned lines, speeds up to 2400 bits per second can be achieved over the leased facilities. If leased lines are considered, the telephone companies provide all of the amplification, equalization, and impedance matching required to maintain satisfactory channel operations.

3.3 Radio and Microwave Communication System - Radio and microwave communications systems lend themselves readily to use in supervisory control applications involving locations where access by cable is difficult. Modems are again employed to provide an interface for the PERT 26/31 BCH equipment to the communication channel. These two solutions each require investigation of feasibility in terms of cost effectiveness, terrain, licensing procedures and required maintenance. The best selection of a UHF or VHF radio system involves F.C.C. regualtions, channel availability and the topography of the installation site. Before implementing any of these methods, thorough consideration must be given as to the best scheme for each installation.

On the best communication system, data errors will result from the effects of electrostatic and/or electromagnetic noise. To combat this undesired effect of spurious noise, PERT 26/31 BCH employs input filters, signal frequency discrimination circuits and a highly secure message format.

4.0 MESSAGE STRUCTURE AND CODING

The PERT 26/31 BCH System employs the Bose-Chaudhuri/Hocquenghem (BCH) error detection code as the primary message security scheme. BCH codes have found wide use in supervisory control and data acquisition systems. This scheme involves dividing the data prior to transmission by a selected divisor. The remainder from this division process is then transmitted as BCH check bits with each data block. At the receiving end, electronic circuitry performs the same division on the incoming data bits. If there have been no transmission errors, the two remainders will be identical. So, after the division is complete the transmitted remainder is simply compared against that generated within the receiver. The PERT 26/31 BCH System utilizes five check bits within each message block. This five bit code will allow detection of <u>all</u> single and double bit errors, <u>all</u> error bursts of length five or less, 94% of all error bursts in excess of six bits. The PERT 26/31 BCH message word is shown in Figure 1 a.



FUNDAMENTAL 26/31 MESSAGE

Figure 1 a

The message format of the PERT 26/31 System represents optimization of both message efficiency and security. The fundamental 31-bit message block is divided into bit groupings as shown in Figure 1 b.

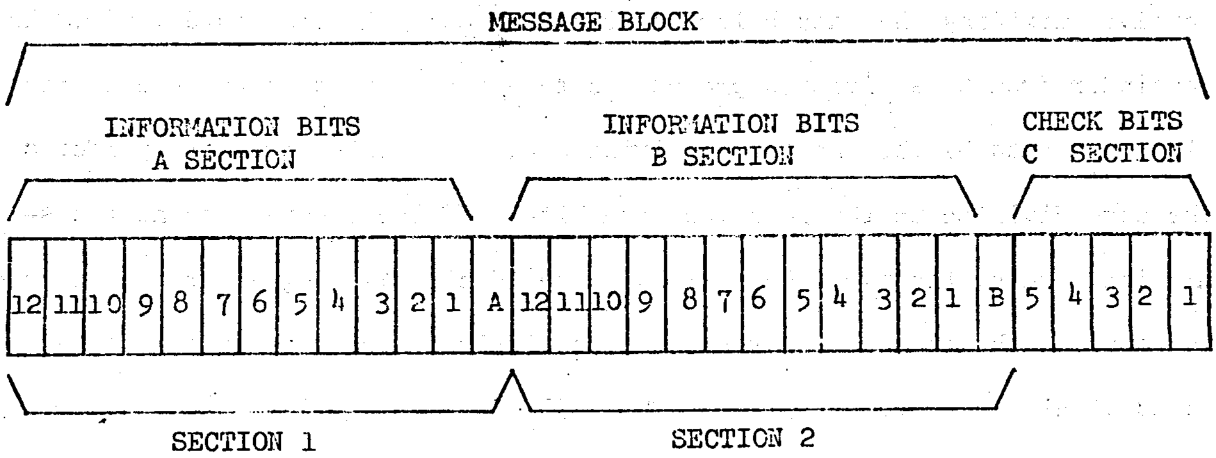


Figure 1 b

Two 13-bit information sections are arranged as 12 information bits and one bit for internal control purposes. These two sections total 26 information bits. Along with five BCH code bits, a message block of 31 bits results. The efficiency of this coding arrangement is 26 divided by 31, or 83.9%.

A control bit indicates direction of transmission. If this bit is logical "0", the message is a central to remote transmission. For transmission in the opposite direction, (i.e., remote to central) the A bit is set to a logical "1". After the message format of the system is defined, the operating mode of the system (scan or control) is established by the manner in which the data bits are organized.

4.1 Scan Messages - The scan message contains an address (in section one). One remote can be required to decode a number of scan requests. Note that three bits in the first section and twelve bits in the second section are not used for scan requests. A data streaming feature of the PERT 26/31 BCH System allows the remote station to respond to each scan request with as few as one, or an many as eight message blocks. Each message block in the reply consists of two 13-bit groups called sections. A data section may contain information from twelve individual status/alarm points, six points of status with memory, one analog point (telemetered value) or one point of accumulation. The first section of the first data block returned contains a remote station "echo" which defines the remote unit responding. The remaining sections of each block contain system data. Since there are nine binary digits in the address field, 512 individual scan addresses may be assigned to one or more remotes on each communication channel. Figure 2 shows a typical scan message.

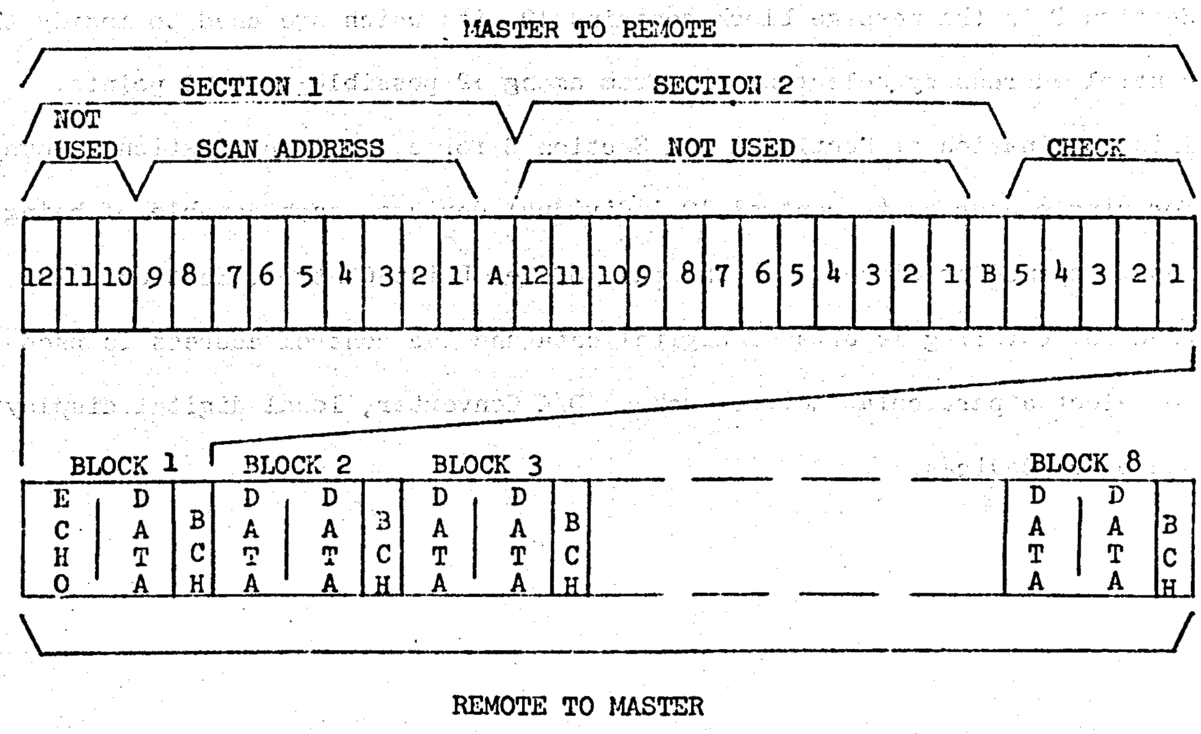


Figure 2

4.2 Control Messages - Like the scan message, the first section of each control message contains the address. Each of the 512 possible addresses defines twelve points of discrete control or one point of analog output control. A control message is shown in Figure 3.

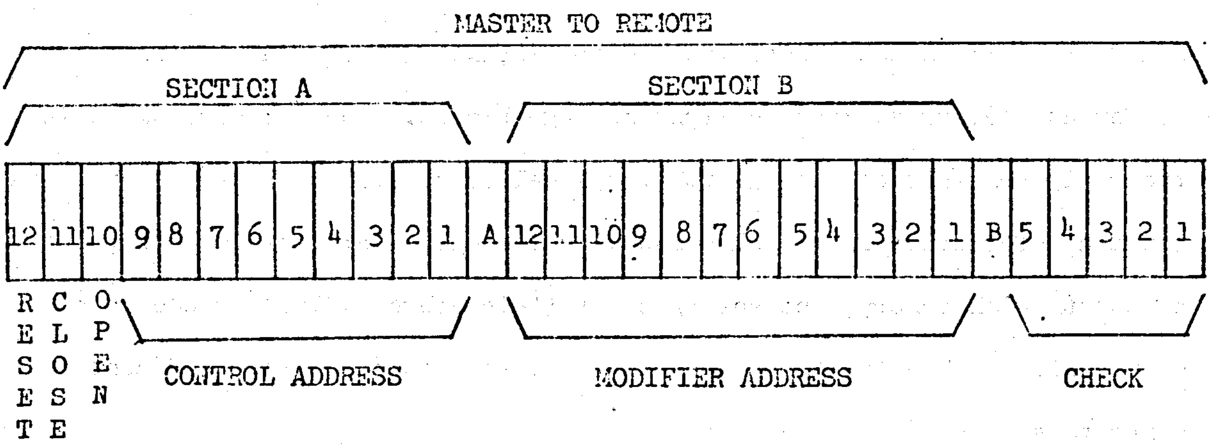
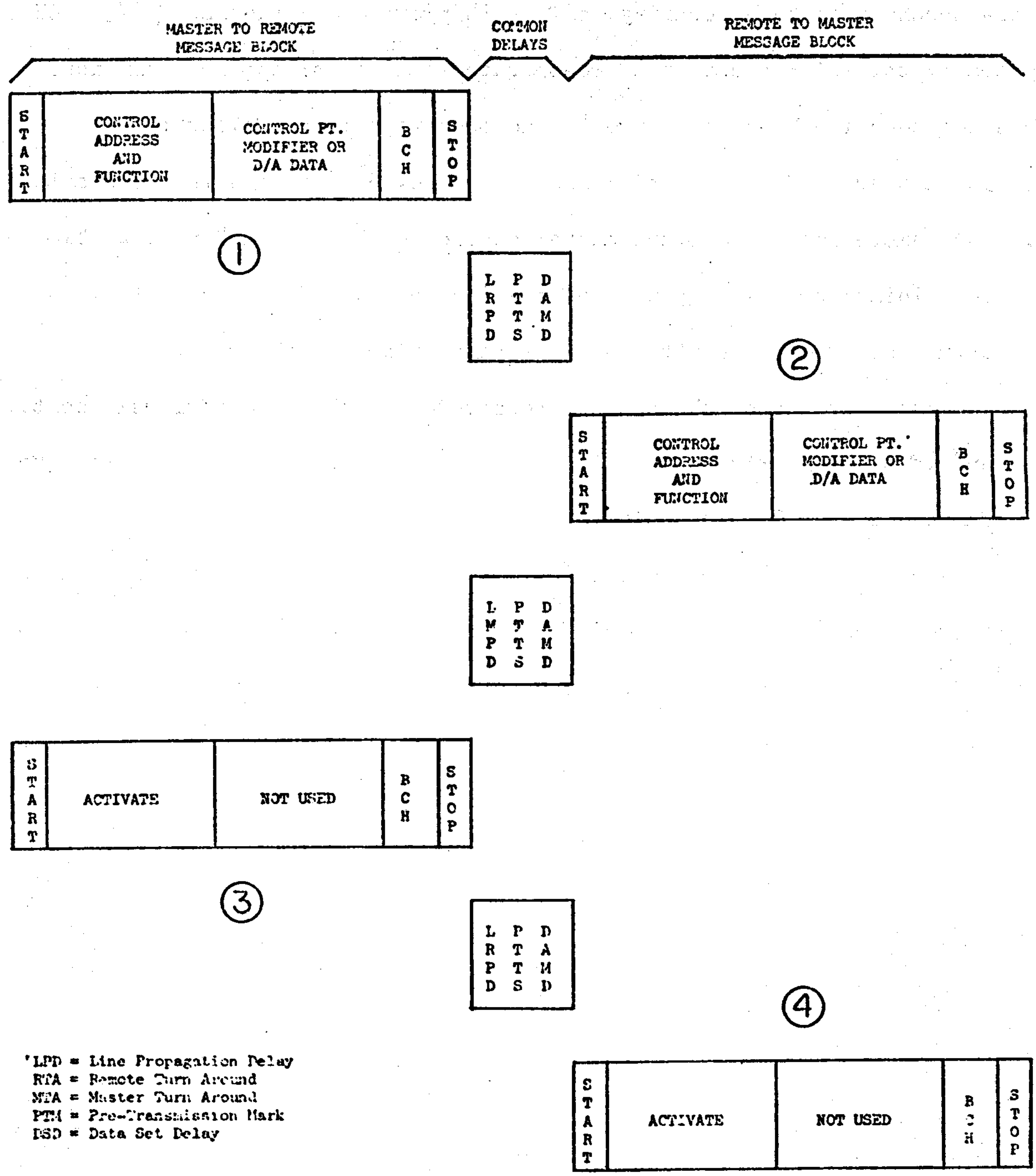


Figure 3

Both the A and B sections of the message are used to format a control request message. The leading bits in Section A are assigned to identify RESET-CLOSE-OPEN functions. The remaining 9 bits in Section A are address bits. Section B in the message block contains 12 bits which are used to modify the control address by selecting one from among 12 possible control points. This combination of Section A and Section B for control application allows for single address to control 12 individual devices, each capable of being reset, opened or closed. In the case of Set Point Control, Section B is used for covering 12 bits of digital data and the control address is used to select a particular device such as D/A Converter, local digital display and other devices.

4.3 Control Sequence Check-Before-Operate - In addition to Bose-Chaudhuri message security, safety is provided in the PERT 26/31 BCH system by utilizing a check-before-operate feature for control commands. This sequence is shown in Figure 4; the operation is as follows:

1. The master sends a control message to a device within a remote station.
2. The remote responds to the master station with an "echo" message block containing indentically the information received from the master. No actual end element control has yet taken place in the remote.
3. The master compares the message received with the one previously sent, and if the comparison is valid, the master generates a message (to the remote) containing an activate code.
4. The remote able to decode the activate message will execute the previously selected control point and will respond to the master with another echo indicating that the control sequence has been successfully completed.



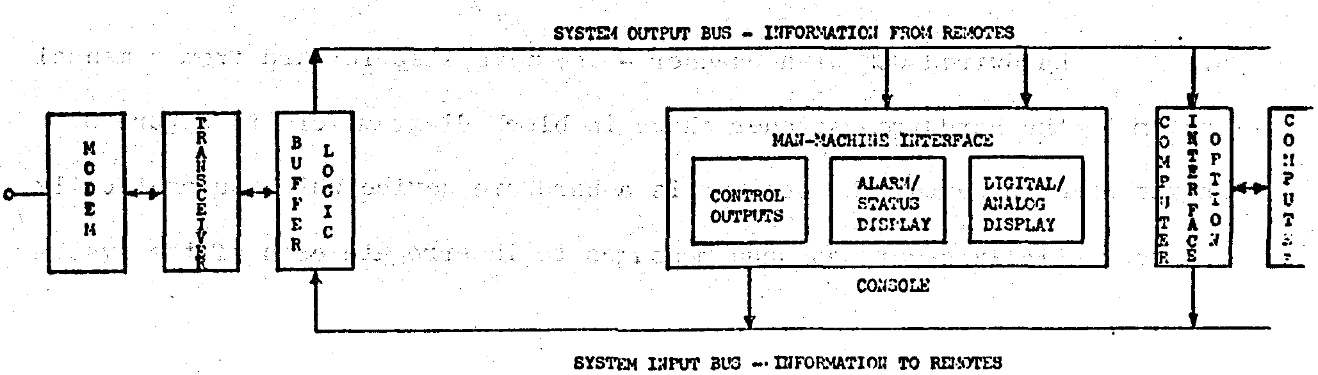
CONTROL MESSAGE SEQUENCE - CHECK BEFORE OPERATE
PERT 26/31 BCH SYSTEM

Figure 4

5.0 CENTRAL CONTROL STATION

Consistent with the philosophy of continuous scanning systems, total system control originates from the Central Control Station (CCS). The CCS may be under the direction of a digital computer, a hardwired scanner, or a manual operator's panel. Any of these configurations is available with the PERT 26/31 BCH Master Terminal Unit (MTU) hardware. The components of the MTU are modular. (The block diagrams illustrate component interaction and the configuration of various CCS types.) Designed around concepts used in modern digital computers, the PERT Master Terminal employs a parallel data bus to which functional modules are connected as required to satisfy the input/output requirements of any CCS.

5.1 Manual CCS - The most elementary Central Station configuration is a manual station and is completely contained within a 5" high x 19" wide x 12" deep chassis with a front panel. The operator's display/control panel provides the system operator with the means for total system control. Through this panel, the operator communicates with the system on a demand basis. The operator decides when and which RTU to interrogate. As shown in Figure 5, the required hardware includes a manual operator's panel, modem/transceiver logic, and the buffer logic.



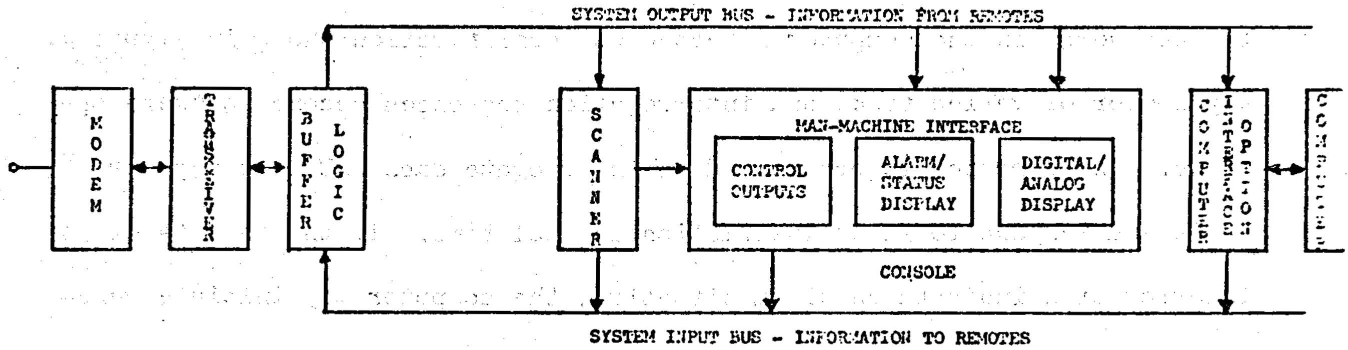
MANUAL SCAN - INTERROGATE AND CONTROL

Figure 5

The panel contains the necessary thumbwheel and pushbutton switches and display lights to allow the operator to manually enter a request for interrogation or control. The operator must enter the message in the proper format in order to communicate with the RTUs. After configuring the message, the operator releases it for transmission. The panel gates the message through the line buffer electronics to where the BCH code bits are generated and attached. The message is serialized and transferred to the communication facility through the modem. If the addressed RTU does not respond within a specified time period, a NO RU RESPONSE diagnostic is presented to the operator. Response messages from an RTU are clocked into the modem transceiver logic, demodulated, checked for validity, and gated to the buffer logic electronics for distribution to the display portions of the operator's panel.

Because the manual system requires continual operator action, the manual system is cumbersome and not recommended as satisfactory when large numbers of remotes are involved. The manual equipment does have a benefit to large system configurations to provide backup and/or diagnostic capability. In non-computer based systems the scanner can be added to the manual station to relieve the operator of the burden of system scanning.

5.2 Hardwired CCS With Scanner - The next step forward from a manual system is the hardwired scanner shown in block diagram form in Figure 6. As its name suggests, the scanner is a hardware device which automatically and sequentially generates scan messages to interrogate each of the system RTUs.

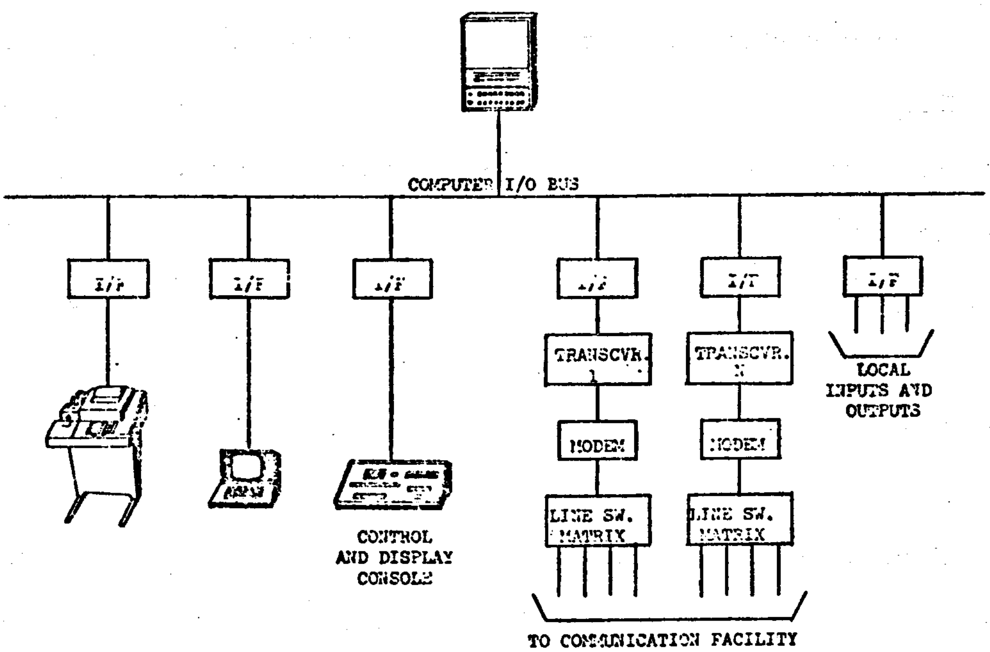


AUTOMATIC SCAN - INTERROGATE

Figure 6

This device interrogates the system in a continuous sequence. Data received from the RTUs may be displayed in a number of different methods. The two extremes are: one single multiplexed display unit which can be time-shared among all points in the field; and the opposite extreme, to have an individual display device for each field point. While the latter is obviously the most costly, a number of cost effective data display opportunities exist between these extremes. Any request for control or out-of-sequence interrogation is initiated by the system operator. The sequence of events involved in getting a message from the CCS to an RTU is identical to that described in the manual operation of the CCS with the exception that the scanner generates interrogations automatically and sequentially. The operator's console is usually a custom-designed device which services the particualr needs of each installation. Standard display and control modules are, however, available to provide the man/machine interface.

5.3 Computer Directed CCS - Flexibility and low cost expansion are the key words in the Computer Directed CCS configuration shown in Figure 7. Any number of varied tasks and interrogation sequences become software options. The computer is programmed to interrogate each RTU on a regular basis and respond to input information in real time. If the results of an interrogation indicate an alarm situation, the computer may initiate remedial action, notify the operator by an audible signal, or initiate other combinations of actions.



COMPUTER DIRECTED MASTER

Figure 7

The computer communicates with the line buffer via the data bus through the computer interface card. This card performs necessary handshakes between the computer input/output ports and the data bus. Operation of the CCS is identical to the two previous cases once the message from the computer is placed on the system data bus. A properly configured hardware and software system invites expansion since only minor change is required.

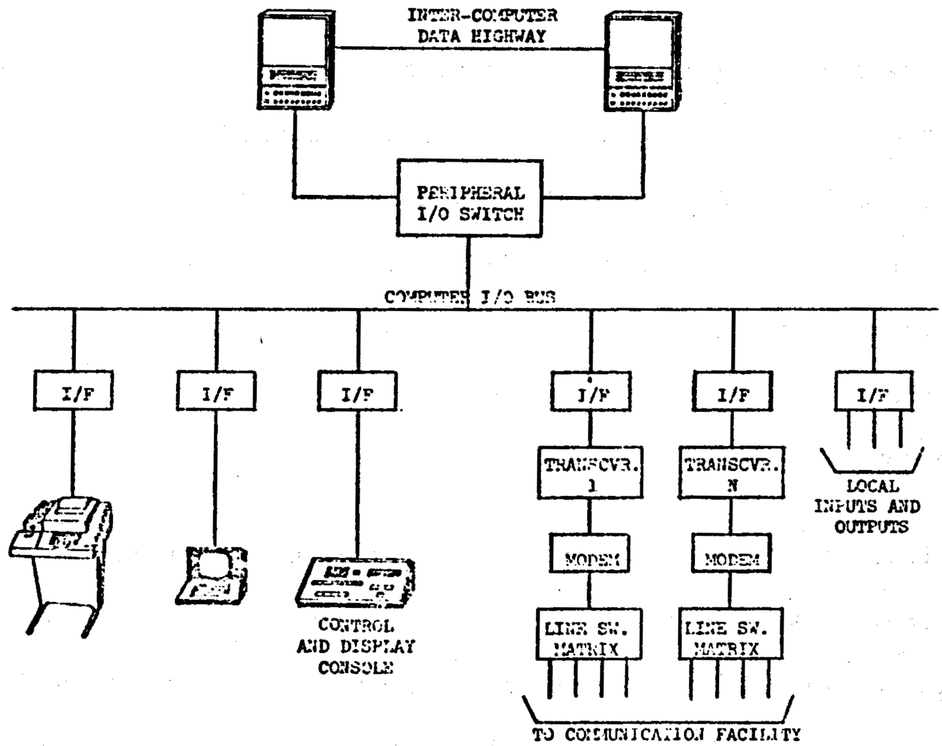
The transceiver and modem modules (termed as line buffer) are used for communication between CCS and the remote stations. Multiple line buffers may be utilized with a single computer interface card. The line buffers are addressable by the computer and each may operate at different communication speeds. Multiple buffers are used to reduce the total system scan time and to provide hardware backup of CCS equipment. A line switching matrix is available and is used to selectively connect a line buffer with one of four communication channels.

The line switching capability also provides beneficial backup capabilities. For instance, if through a line buffer/line switching complex, a computer was communicating with twelve RTUs and a break in the channel developed, communication with some number of RTUs would be lost. However, if the communication line were looped back to a second terminal on the line switching device, then the RTUs beyond the break from one direction could be reached from the opposite end of the loop.

In addition, if two line buffers each employed a line switching device, backup provisions between the two lines could be accomplished by interconnection of the lines. If one line buffer/line switching complex failed, the other complex could service both lines. Selection from among these alternatives is strictly a function of customer requirements, but it is important to note that the standard PERT hardware provides these options.

A wide range of man/machine interface possibilities exist when the CCS includes a computer. Cathode Ray Tube displays, line printers, and magnetic tape cassette drives are a few examples. Bulk data storage units such as discs can be used to provide trending information. In addition, many complex calculations and sophisticated data reduction techniques may be accomplished with the computer.

5.4 Computer Directed CCS - Redundant (backup) Configuration - For applications requiring maximum safety and operational availability, PERT 26/31 BCH CCS is configured for standby mode, as shown in Figure 8.



COMPUTER DIRECTED MASTER WITH REDUNDANT CAPABILITY

Figure 8

The concept utilized is that of redundant equipment allocations for the control areas of the system modules. The equipment which is used for convenience (such as control points, extra loggers, support and off-line equipment) is generally not duplicated due to economic reasons. However, any device which upon failure will affect a major portion of the overall system operation is backed up.

Dual computers together with interfaces to the CCS hardware are provided. Any failure in one of the computers would result in the other computer taking over the system operation. At least two communication modules consisting of Transceiver, Modem and line switching are used. Failure in either unit would result in the other unit taking over system data reception and transmission.

Failure in the control and display console is termed non-critical since the overall system operation can be performed by use of the available logger and/or CRT and keyboard. If no degradation of system operation or operational convenience can be tolerated, then all of the modules at the CCS are backed up. Main and backup power units are configured to offer overall safety to the system.

Further backup capability can be implemented by the use of manual panels and by the use of portable test equipment. Both units can provide manual interrogation of the remote station data and have the capability of sending control commands to the remote stations.

6.0 SOFTWARE

The PERT 26/31 BCH System software belongs to one of two software groups, the executive routines and application software. The amount of custom programming necessary is dependent on the uniqueness of a particular installation. Since BASIC has written software for a number of systems, an extensive list of generalized application routines are in the software library and may be able to be adapted to various requirements. The functions to be performed by the system define the application routines required. The executive routine devotes central processor resources to the execution of each application routine. So, while the application routines will vary from one system to another, the same executive routine will satisfy a number of different systems. RECOM, the executive routine written by BASIC specifically for core based supervisory control application, has been supplied in more than forty separate systems without modification. RECOM is a multi-tasking executive routine which is responsible for task scheduling, interrupt processing, and control of application routines. Tasks or application routines are scheduled based on their priority established at the time of system generation. Up to 63 application routines may be scheduled under RECOM. Each routine may be non-interruptable, interruptable and non-reentrant or interruptable and fully reentrant. RECOM, including math packages and input/output controllers, occupies only three thousand memory locations.

The application routines perform specific intended functions according to the needs of the particular installation. Application routines include such programs as the PERT Telemetry Driver, Operator Input/Edit Program, and specialized and general scan routines. The applications routines are responsible for building the data tables associated with particular types of data. These routines must be kept abreast of changes to the system via the generalized calling routines. A calling routine such as an analog scan will request the telemetry driver to scan RTUs. Scan addresses for all of the RTUs are contained in data tables. As each remote is scanned, another data table is constructed. The analog scan routine then investigates the entries of the data table constructed by the scanning activity. The addition of remotes to the system or the addition of points to a remote requires that the data tables be extended to accommodate the addition. No program rewrite is required.

7.0 PERT 26/31 BCH REMOTE (RTU)

Modular in design, the RTU, like the CCS, is functionally integrated until the input/output requirements of the remote location are satisfied. Modules such as pre-fabricated field terminal sets and cable harness assemblies are combined with input/output card types as defined by the end devices at each location. The I/O card types, the communication modem and the timing and control portion of the RTU are interconnected with each other by means of a printed circuit mother board. Selection of one from a number of standard power supplies and equipment enclosures completes the configuration of the remote unit.

Unique, space saving, and cost effective electronics packaging is possible through the use of CMOS circuitry. The RTU consists of a lightweight anodized aluminum chassis and printed circuit mother board. Data modems, power supplies and timing and control cards make up the overhead requirements at each RTU location. Various input/output cards exist for connection to all end element types. Therefore, the point configuration of each system can be custom tailored by using only those card types needed. Maintenance and expansion are enhanced by this modularity. A technician may isolate malfunctions to a particular card; the faulty card is simply replaced, system operation is recovered, and the card is repaired at the technician's convenience. Hardware expansion is simplified; as additional functions are required, the appropriate input/output cards are added to the card file and interconnecting wiring is added as necessary. The key features of the PERT 26/31 BCH RTU are, therefore, ease of maintenance, simplified expansion, efficient packaging, low power drain (typically 500 milliamps @ 12VDC), and low cost configuration. The remote unit operates over the temperature range of from -25°C to +80°C (-13°F to +176°F). Figure 9 presents an exploded view of the RTU chassis. This particular chassis is the rack-mount version.

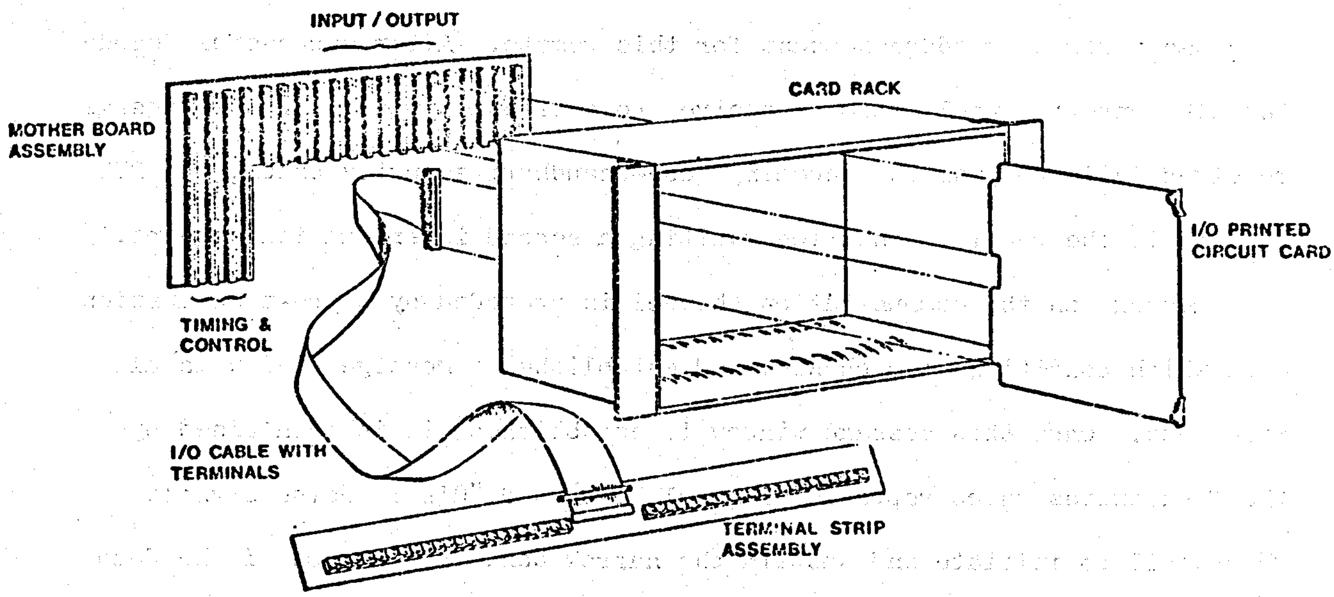


Figure 9

The PERT 26/31 BCH RTU is used for the multiplexing of process parameters and telemetering these inputs to a central location. Moreover, control commands from the central location may be sent to the RTU for distribution to appropriate control output modules. This input/output operation is accomplished over a single communication channel. Reliable operation in electrical environments not conducive to accurate data transmission is a necessity. To that end, PERT 26/31 BCH employs in each input circuit filters to clamp noise to a minimum and over-voltage protection circuitry to protect the electronics from the application of AC to the input.

The PERT 26/31 BCH RTUs operate in a polling mode and individually respond to interrogations initiated from the CCS. While awaiting interrogations, all of the RTUs in the system are in the receive mode of operation. Because they are partylined onto the communication facility, each RTU "hears" all of the communication activity on the channel. However, only one RTU will decode the particular address meant for this remote. After successful decode the RTU converts itself from a receive to a transmit mode. If the message received fails to pass the incoming Bose-Chaudhuri security check, the RTU remains in the receive condition awaiting a second interrogation attempt. Each message on the communication channel is preceded by a pre-transmission mark which conditions the channel and establishes a message window in all receivers. Once this message window is established, it is maintained by the frequencies which represent logical "1's" and "0's". Noise signals which fail to initiate and sustain the narrow band pass region of the data modems do not affect the RTU receivers.

In the case of a control command, the control will be performed and a message will be transmitted to the CCS identifying the control point activated. In the case of a data scan, the RTU will multiplex the various data words onto the communication channel, and transmit the information to the CCS. In any case, an RTU will become active only after a comprehensive and pre-defined set of security checks have been successfully performed on the command word received from the central station.

The input/output duties within the RTU are handled by individual input or output printed circuit card modules. Functional modularity is afforded by designing an individual card to perform an individual input/output function. The following paragraphs provide a brief description of the typical modules and their application.

7.1 Status/Digital Data Input Card - The status/digital data input card is used to input dry contact closures or logical signal voltages indicating the state of end element devices. Each input employs a noise suppression filter to combat contact bounce and induced noise. The continuous application of 120VAC is rendered harmless by the over-voltage protection circuitry. Each card provides 24 input points corresponding to two 12-bit sections of the message format. Typically, this card is used to provide information as to the ON/OFF status of an electric motor, a valve position, or the condition of an alarm contact.

7.2 Analog Input Card - This card accepts analog inputs from field end points and multiplexes them to the analog-to-digital converter to be digitized. Each input employs a voltage limiter to protect the circuitry. A filter network provides filtering of high frequency transients. A multiplicity of standard input ranges are available such as: 4-20 ma, 1-5 ma, and 10-50 ma, 0-1 ma, 0-3 ma, 0-10 ma, 1-5V, including low level current and voltage inputs. The current inputs are dropped across an input resistor to provide voltage inputs for the analog-to-digital converter. The analog input card features individually adjustable gain of 0-1000 and an offset span from -10V to +10V. Typical analog inputs are associated with temperature and pressure transducers, flow meters, volts, amps, watts, vars transducers and a multiplicity of other devices.

7.3 Accumulator Input Card - This card provides a 12-bit binary counter designed to accept and accumulate pulsed dry contact closure inputs. The capacity of the counter is 4096 pulses. Over-voltage protection circuitry is standard on each input as well as input filtering to prevent contact bounce and random signals on the input from falsely incrementing the accumulator. An available option with this card is the strapping of the two 12-bit registers to form one point of 24-bit accumulation. Turbine flow meters, positive displacement meters, KWH and other pulsed output devices provide typical applications for the accumulator input card.

7.4 Control Output Card - The control output card provides the interface between RTU logic and the field located control output device such as a valve actuator, an electric motor starter, a circuit breaker and other devices. The card employs output signals in the form of momentary dry contact closures which are adjustable over a 500 millisecond to 5 second range. Continuous control outputs can be provided when required. A transistor-diode pair across each relay coil supplies the relay drive. Fail-safe design employed assures no single component failure can cause the issuance of an unintended control. If security in the performance of control outputs is critical, a check-before-operate mode of operation is available. In this mode, the initial request for control readies the RTU for the output. However, actual execution comes only after the RTU echos the address portion of the message back to the CCS for verification. Upon verification of selection of the proper point, the CCS issues the execute command.

7.5 Analog Output Card (Set Point) - The analog output card provides analog set point outputs to operate set point controllers associated with various processes. The card utilizes a digital-to-analog converter followed by a voltage-to-current converter in its standard configuration. The digital input is in the form of a 12-bit digital portion of the control output message format. Output ranges available are 4-20 ma, 1-5 ma, and 10-50 ma. A 0-5VDC output range is also available. The output of this card is typically used to adjust set point limits on process control devices.

Any combination of these input/output cards may be utilized in an RTU. Through the use of these cards, each RTU can be tailored to satisfy the exact requirements and spare or anticipated points may be included during initial installation. Activation of spare points then involves only performing necessary interconnecting and end device wiring.

8.0 SYSTEM SUPPORT

Of equal importance to system design and operation is the support offered by BASIC for the PERT 26/31 System.

As a Baker Oil Tools Comapny, BASIC can provide system support from more than fifty Baker offices in the United States. Internationally, support is available in more than 23 countries. These Baker facilities are available for use as spare parts depots, repair facilities, and can be staffed with electronic service personnel.

BASIC offers, in Houston, Texas, training schools which provide instruction on both system hardware and software. The schools are taught by qualified instructors and will provide the student with the degree of instruction necessary to enable complete self-dependence where hardware or software maintenance are concerned. Pre-class study material distributed to the students provides each class with a common starting point. Course content is a combination of practical description and hands-on experience. Student development is metered by tests which are administered at key points during the training. In addition to practical experience the instructional program is augmented with audio-visual aids and personal sets of system documentation to ensure that the student not only derives maximum knowledge from attendance, but also graduates from the class with material useful for future reference and for refresher purposes.

To further support field service of the PERT 26/31 hardware, BASIC provides a portable remote station test set. The primary function of the test set is to enable someone not electronically oriented to isolate remote station malfunctions to a faulty printed circuit board. Since printed circuit card replacement can be accomplished quickly, system downtime is minimized. The test set is packaged in an aluminum suitcase and powered from A.C. or the remote station power source. Because the test set contains its own data modem, it may be interfaced on either the frequency or logic side of the remote station data modem. Three distinct modes of operation are provided by the test set which are:

Control: The test set encodes and transmits to the remote a control request message and verifies proper reception of the check back message from the remote. The control sequence is then completed by issuing the executive command from the test set.

Interrogate: The test set contains the necessary switches and displays to interrogate any data point within any remote and to display the results of the interrogation. An electronic memory in the test set provides a sample and hold capability for data which may be moving at many thousand bits per second.

Eavesdrop: The eavesdrop mode of operation allows the test set operator to "capture" and display a system data word when that data word is on the communication facility. With this feature the test set allows the operator to analyze the message from the master station to any remote station.

Although the test set is portable by design, it is sufficiently self-contained to be used at the master station as a manual panel. As a manual panel it can be used to diagnose remote station anomalies before field maintenance crews are dispatched.

TITLE

GEOTHERMAL WELL DATA

APPENDIX II

Drilling and completion cost estimates for well depths of 14,000, 16,000, and 18,000 feet, and production tubing sizes of 4½", 5½", and 7".

Estimates prepared by Oil and Gas Division of Dow Chemical.

GEOTHERMAL WELL NO. 1
CAMERON COUNTY, TEXAS
PROPOSED TOTAL DEPTH - 18,000'

Preliminary Drilling Program:

1. Drive 20" conductor casing to 100'.
2. Install casinghead and 20" 3M# Hydril blowout preventer.
3. Drill 18-1/2" hole to 2500'.
4. Run 16" casing and cement to surface.
5. Remove 20" Hydril and install 16" slip-on and weld x 16" 3M# bradenhead.
6. Nipple up 16" 3M# type LWS and Hydril blowout preventers.
7. Drill 14-3/4" hole to 11,000' and log.
8. Run and cement 11-3/4" casing.
9. Install 16" 3M# x 13-5/8" 5M# casinghead spool and nipple up 13-3/8" 5M# blowout preventers.
10. Drill 10-5/8" hole to 16,000' and log.
11. Run and cement 9-5/8" casing.
12. Install 13-5/8" 5M# x 11" 10M# casinghead spool and nipple up 11" 10M# blowout preventers.
13. Drill 8-1/2" hole to 18,000' and log.
14. Run and cement 7" liner with a PBR.
15. Run 7" tie-back and seal into PBR.
16. Remove blowout preventers and install tree.

GEOTHERMAL WELL NO. 1 - Page 2

Mud Program:

Depth	Weight	VIS	WL
0 -8,000'	9.0-9.9	32-36	NC
8,000'-9,500'	9.9-11.0	36-42	10-6
9,500'-11,000'	11.0-12.0	38-44	6-4
11,000'-14,500'	12.0-15.3	40-48	4
14,500'-16,000'	15.3	40-48	4
16,000'-18,000'	Raise weight as dictated by hole conditions		

Casing Design:

Surface Casing:
2500' - 16", 84#/ft., K-55, ST&C

Intermediate Casing:
500' - 11-3/4", 60#/ft., N-80, Buttress
4150' - 11-3/4", 60#/ft., S-95, ST&C
1600' - 11-3/4", 65#/ft., S-95, ST&C
4750' - 11-7/8", 71#/ft., S-95, ST&C

Production/Protection Casing:

5,800' - 9-5/8", 53.5#/ft., P-110, TS
10,200' - 9-3/4", 59.2#/ft., S-105, FJP

Production Tubing:
15,500' - 7", 38#/ft., P-110, TC4S
2,500' - 7", 38#/ft., P-110, FJP

Cementing Program:

Surface Pipe - 2500 Feet of 16" Casing in an 18-1/2" hole:

	Recommended Slurry	Slurry Properties
Log Temperature - 120°F	Class H Cement	Weight - 15.7 lbs./gal.
Mud Weight - 9.0 ppg	35% D66	Yield - 1.53 cu.ft./sk.
Desired Fillup - 2500 feet	2% S-1	
Estimated Excess Required - 50%	6.33 gals. Water/sk.	
Cement Slurry Needed - 1764 ft.	Sacks Needed, 1153	

Procedure:

1. Run 16" casing with an orifice fill stab-in cementing shoe. Install centralizers on bottom three joints.

GEOTHERMAL WELL NO. 1 Page 3

2. A stab-in stinger and centralizer are made up on the drill pipe and run into the well.

3. When the stinger is seated, establish circulation, pump 20 bbls. water.

4. Mix and pump the 1153 sacks of cement, or mix cement until returns are seen.

5. Unseat stinger and circulate excess cement from the pipe.

6. Wait on cement for 12 hours.

1st Intermediate String - 11,000 Feet of 11-3/4" Casing in a 14-3/4" hole:

Log Temperature - 224° F
Mud Weight - 12 ppg
Desired Fillup - 4000 feet
Estimated Excess Required - 35%
Cu. Ft. of Slurry Needed - 2342 Cu.Ft.

Recommended Slurries

Lead Slurry	Tail-End Slurry
Class H Cement	Class H Cement
4% D20	35% D66
35% D30	.2% D8
.3% D8	6.33 gals. water/sk
Slurry Weight - 14.6 lbs/gal	Slurry Weight - 15.7 lbs/gal.
Slurry Yield - 1.85 Cu.Ft./sk	Slurry Yield - 1.53 Cu.Ft./sk
Sacks Needed - 950	Sacks Needed - 383

Procedure:

1. Run 11-3/4" casing with a differential fill collar and differential fill shoe with centralizers on each of the bottom three joints.

2. Pump 1000 gallons of Dowell Chemical Wash 7. Drop the bottom cement plug, followed by 950 sacks of lead slurry and 383 sacks of the tail-end slurry.

3. Drop the top plug and complete displacement.

4. Wait on cement for 12 hours.

2nd Intermediate String - 16,000 Feet of 9-5/8" Casing in a 10-5/8" hole:

GEOTHERMAL WELL NO. 1 - Page 4

	Recommended Slurry	Spacer Composition For 1 Barrel
Log Temperature - 428°F	Class H	30.6 gals. Water
Mud Weight - 15.3 lbs./gal.	35% D66	370 lbs. D21
Desired Fillup - 6000 Feet	1.0% D65	18 lbs. D20
Estimated Excess Required - 20%	.6% D28R	1.5 lbs. D13
Cement Slurry Needed - 794 Cu.Ft.	6.33 gals. water/sk	5 lbs. D65
	Slurry Weight - 15.7 lbs./gal.	
	Slurry Yield - 1.53 Cu.Ft./Sk.	
	Sacks Needed - 519	

Procedure:

1. Run 9-5/8" casing with differential fill collar and differential fill shoe. Put centralizers on each of the bottom three joints: Two centralizers two joints apart within the 11-3/4" casing at 10,800 feet to assure a good cement sheath in the lapover of the previous cement job.

2. Circulate the hole (bottoms up minimum). Pump 15 barrels spacer; drop the bottom plug; and start mixing cement.

3. This slurry is designed to be displaced in turbulent flow for maximum efficiency in removing the mud from the wellbore and replacing it with cement. Pipe movement, either rotation or reciprocation, will improve mud removal and cement bonding.

4. Complete the mixing of cement; drop the top plug; and displace in turbulent flow until the plug bumps. Wait on cement time will be determined by laboratory tests.

Production String - 18,000 Feet of 7" Casing in an 8-1/2" hole:

	Recommended Slurry	Spacer Composition For 1 Barrel
Log Temperature - 400°F	Class H	27.9 gals. Water
Mud Weight - 17.0 lbs./gal.	35% D66	465 lbs. D31
Desired Fillup - 2500 Feet	15.6 lbs. D76	18 lbs. D20
% of Excess Required - 20%	.75% D65	1.5 lbs. D13
Cement Slurry Needed - 793 Cu.Ft.	1.6% D92	5 lbs. D65
	5.68 gals. Water/sk	
	Slurry Weight 17.0 lbs./gal.	
	Slurry Yield - 1.48 Cu.Ft./sk	
	Sacks Needed - 536	

GEOTHERMAL WELL NO. 1 - Page 5

Procedure:

1. Run 7" casing with a differential fill collar and differential fill shoe. Attach centralizers to each of the bottom three joints. Put two additional centralizers, 2 joints apart, within the 9-5/8" casing at 15,800 feet to assure a uniform cement sheath within the lap area.

2. Circulate the hole (bottoms up minimum); pump 13 barrels of spacer; drop the bottom plug and start mixing cement.

3. This slurry is also designed to be displaced in turbulent flow for maximum mud removal efficiency. Moving the pipe (either reciprocating or rotating) while the cement is being displaced will facilitate mud removal and improve the bond.

4. When the cement mixing is complete, drop the plug and displace at the required rate for the cement slurry to be in turbulent flow.

5. Bump plug and wait on cement (WOC time will be determined by laboratory tests).

Evaluation Program (To be run in open hole):

1. A complete suite of Coraband or Saraband logs should be run at the following depths: 11,000'; 16,000'; and 18,000'.

2. Continuous mud log from 9000' to T.D.

3. Conventional core prospective zones at discretion of wellsite geologist.

4. Sidewall core prospective zones at discretion of wellsite geologist.

Completion Procedure:

1. Run a Gamma Ray - Cement Bond Log through the prospective zones.

2. Squeeze cement, if necessary, according to results of bond log.

3. Drill out cement.

4. Perforate prospective zones.

5. Production test well.

AFE NO.______

THE DOW CHEMICAL COMPANY
OIL AND GAS DIVISION
AUTHORITY FOR EXPENDITURE

Well Name Geothermal #1 Area or Field Wildcat

Location

Cameron County, Texas

Work To Be Performed Drill, Test and Complete

Proposed Depth ______ Objective Formation ______

INTANGIBLE COSTS:	Estimated Cost Dry Hole	Estimated Cost Completion
Stake Location	$ 500	$ -
Right of Way Cost and Surface Damage, Clean-up	20,000	-
Clear Right of Way, Construct Road and Location	50,000	-
Contract Drilling Cost - Ft. @ $ - Ft.	-	-
Rig Time - Daywork with Drill Pipe 132/20 days @ $ 4600 day	607,200	92,000
Rig Time - Daywork without Drill Pipe - days @ $ - day	-	-
Hauling or Boat Rental	15,000	5,000
Mud and Chemicals	270,000	15,000
Cement, Cementing and Tools	45,000	10,000
~~XXXXXXXXXXXXXXXXXXXXXX~~ Stimulation	-	50,000
Logging - Open Hole	70,000	-
Logging - Cased Hole	-	10,000
Perforating	-	10,000
Coring and Core Analysis	10,000	-
Mud Logging	35,000	-
Formation Testing - Open Hole and Casing	10,000	10,000
Floating Equipment, Centralizers, Scratchers	3,000	1,500
Bits, Permanent Packer and Rentals	225,000	36,000
Company Supervision, and/or consultant	53,000	8,000
Miscellaneous Services and Supplies, Bridge Plugs, Retainers, Fishing Tools, etc., Contingencies	200,000	37,000
Move-in, Rig-up, Rig down	50,000	-
Total Intangible Costs	$1,663,700	$284,500

DC-USABD-2

AFE NO.______

THE DOW CHEMICAL COMPANY
OIL AND GAS DIVISION
AUTHORITY FOR EXPENDITURE

Well Name Geothermal #1

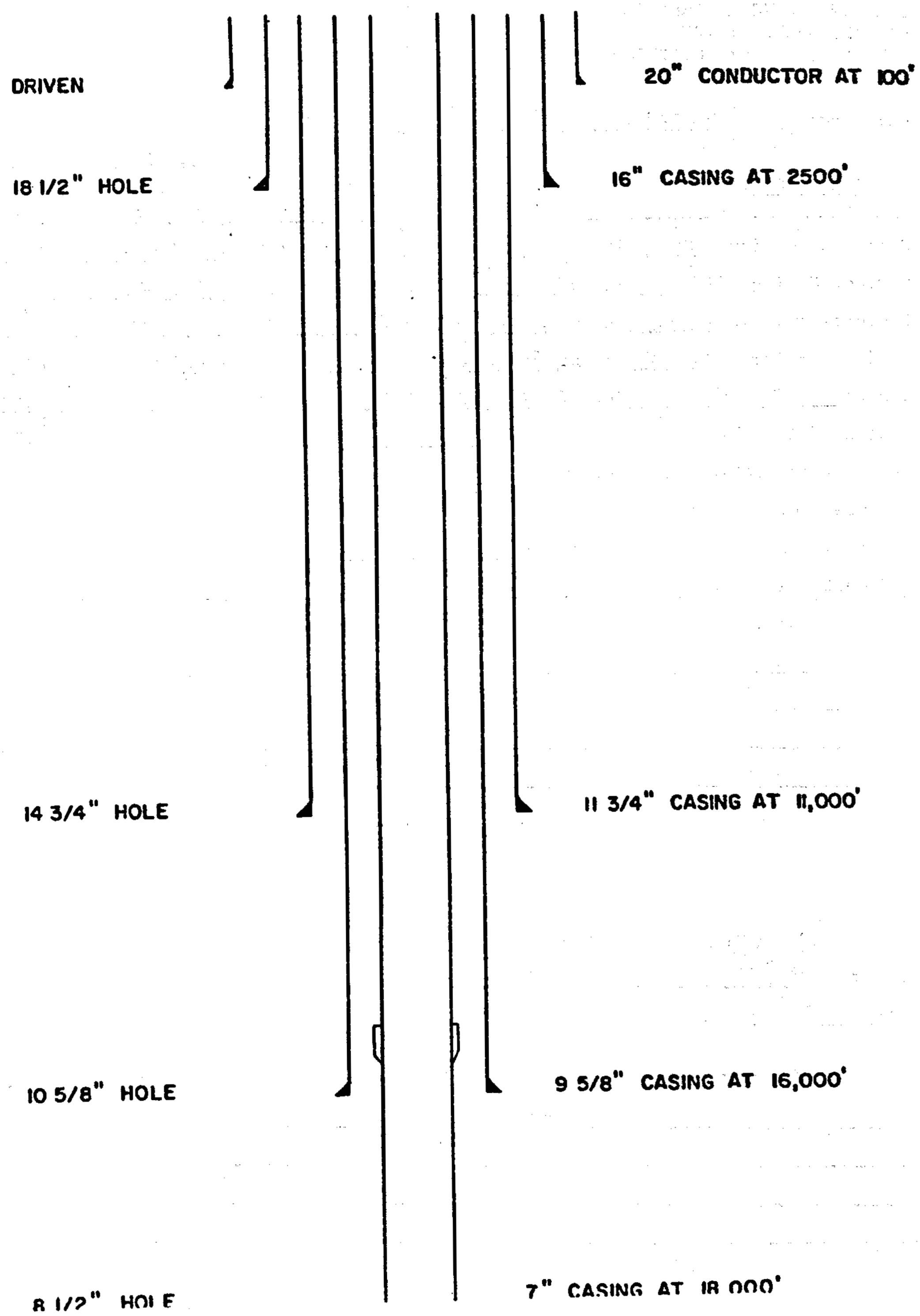
TANGIBLE COSTS:	Estimated Cost Dry Hole	Estimated Cost Completion
Conductor Casing 100 Ft. of 20" O.D. @ $____/Ft.	$ 3,000	$ -
Surface Casing 2500 Ft. of 16" O.D. @ $____/Ft.	67,000	-
Protection Casing 11,000 Ft. of 11-3/4" O.D. @ $____/Ft.	327,000	-
Production String 16,000 Ft. of 9-5/8" O.D. @ $____/Ft.	454,000	-
Tubing 18,000 Ft. of 7" O.D. @ $____/Ft.	-	500,000
Well Head Assembly	25,000	125,000
Retrievable Packers, Liners, Special Hole Equipment	-	10,000
Surface Production Facilities:		
Tanks, Treater, Heater, Separator		
Flow Lines, Connections		
Related Contract Labor, etc.		
Total Tangible Costs	$ 885,000	$635,000
Total Tangible & Intangible	$2,548,700	$919,500
TOTAL WELL COST	$3,468,200	

Prepared By L. E. Thomas Approved By______

Date 9/15/75 Date______

Joint Owners	Approved	Date Approved
	By	
	By	
	By	
	By	

GEOTHERMAL WELL NO. 1
CAMERON COUNTY, TEXAS



GEOTHERMAL WELL NO. 1, ALTERNATE I
CAMERON COUNTY, TEXAS
PROPOSED TOTAL DEPTH - 18,000'

Preliminary Drilling Program:

1. Drive 20" conductor casing to 100'.
2. Install casinghead and 20" 3M# Hydril blowout preventer.
3. Drill 17-1/2" hole to 2500'.
4. Run 13-3/8" casing and cement to surface.
5. Remove 20" Hydril and install 13-3/8" slip-on and weld X 12" 3M# bradenhead.
6. Nipple up 12" 3M# type "U" and Hydril blowout preventers.
7. Drill 12-1/4" hole to 11,000' and log.
8. Run and cement 9-5/8" casing.
9. Install 12" 3M# x 10" 5M# casinghead spool and nipple up 10" 5M# blowout preventers.
10. Drill 8-1/2" hole to 16,000' and log.
11. Run and cement 7-5/8" casing.
12. Install 10" 5M# x 11" 10M# casinghead spool and nipple up 11" 10M# blow-out preventers.
13. Drill 6-1/2" hole to 18,000' and log.
14. Run and cement 5-1/2" liner with a PBR.
15. Run 5-1/2" tie-back and seal into PBR.
16. Remove blowout preventers and install tree.

GEOTHERMAL WELL NO. 1 - ALTERNATE I - Page 2

Mud Program:

Depth	Weight	VIS	WL
0 -8,000'	9.0-9.9	32-36	NC
8,000'-9,500'	9.9-11.0	36-42	10-6
9,500'-11,000'	11.0-12.0	38-44	6-4
11,000'-14,500'	12.0-15.3	40-48	4
14,500'-16,000'	15.3	40-48	4
16,000'-18,000'	Raise weight as dictated by hole conditions.		

Casing Design:

Surface Casing:
2000' - 13-3/8", 54.5#/ft., K-55, ST&C
500' - 13-3/8", 61.0#/ft., K-55, ST&C

Intermediate Casing:
500' - 9-5/8", 40.0#/ft., N-80, Buttress
1300' - 9-5/8", 40.0#/ft., N-80, LT&C
2600' - 9-5/8", 40.0#/ft., S-95, LT&C
1700' - 9-5/8", 43.5#/ft., S-95, LT&C
1600' - 9-5/8", 47.0#/ft., S-95, LT&C
3300' - 9-5/8", 53.5#/ft., S-95, LT&C

Production/Protection Casing:
5600' - 7-5/8", 38.1#/ft., P-110, TS
5300' - 7-5/8", 38.1#/ft., S-95, SFJP
5100' - 7-3/4", 45.5#/ft., S-105, FJP

Production Tubing:

15,500' - 5-1/2", 23#/ft., P-110 TC4S
2,500' - 5-1/2", 23#/ft., P-110, FJP
Alternate Design - may be utilized depending upon pressures encountered:
15,500' - 5", 23.2#/ft., S-95, TC4S
2,500' - 5", 23.2#/ft., S-95, FJP

Cementing Program:

For Alternate I, the depth, temperature, amount of fillup desired and the mud weight will remain the same. Only the hole size, the pipe size and volumes of cement, and spacer will change:

GEOTHERMAL WELL NO. 1 - ALTERNATE I - Page 3

	Hole Size (in)	Pipe Size (in)	Volume of Slurry Required Cu. Ft.	Sacks	Volume of Spacer Required
Surface Pipe	17-1/2	13-3/8	2600	1700	10 bbls. water
1st Intermediate	12-1/4	9-5/8	1870	760 Sx. Lead Slurry; 305 Sx. Tail-in Slurry	1000 gals. CW7
2nd Intermediate	8-1/2	7-5/8	550	360	8 bbls. spacer
Production String	6-1/2	5-1/2	197	133	8 bbls. spacer

Evaluation Program (To be run in open hole):

1. A complete suite of Coraband or Sarband logs should be run at the following depths: 11,000'; 16,000'; and 18,000'.
2. Continuous mud log from 9000' to T.D.
3. Conventional core prospective zones at discretion of wellsite geologist.
4. Sidewall core prospective zones at discretion of wellsite geologist.

Completion Procedure:

1. Run a Gamma Ray - Cement Bond Log through prospective zones.
2. Squeeze cement, if necessary, according to results of bond log.
3. Drill out cement.
4. Perforate prospective zones.
5. Production test well.

DC-USABD-2

AFE NO.______

THE DOW CHEMICAL COMPANY
OIL AND GAS DIVISION
AUTHORITY FOR EXPENDITURE

Well Name Geothermal #1 - Alternate I Area or Field Wildcat

Location

Cameron County, Texas

Work To Be Performed Drill, Test and Complete

Proposed Depth 18,000' Objective Formation

INTANGIBLE COSTS:	Estimated Cost Dry Hole	Estimated Cost Completion
Stake Location	$ 500	$ -
Right of Way Cost and Surface Damage, Clean-up	20,000	-
Clear Right of Way, Construct Road and Location	50,000	-
Contract Drilling Cost - Ft. @ $ - Ft.	-	-
Rig Time - Daywork with Drill Pipe 92/20 days @ $4600 day	423,200	92,000
Rig Time - Daywork without Drill Pipe - days @ $ - day	-	-
Hauling or Boat Rental	15,000	5,000
Mud and Chemicals	150,000	12,000
Cement, Cementing and Tools	40,000	10,000
~~XXXXXXXXXXXXXXXXXXXXXX~~ Stimulation	-	50,000
Logging - Open Hole	70,000	-
Logging - Cased Hole	-	10,000
Perforating	-	10,000
Coring and Core Analysis	10,000	-
Mud Logging	35,000	-
Formation Testing - Open Hole and Casing	10,000	10,000
Floating Equipment, Centralizers, Scratchers	2,000	1,000
Bits, Permanent Packer and Rentals	156,000	36,000
Company Supervision, and/or Consultant	37,000	8,000
Miscellaneous Services and Supplies, Bridge Plugs, Retainers, Fishing Tools, etc., Contingencies	150,000	37,000
Move-in, Rig-up, Rig-down	50,000	-
Total Intangible Costs	$1,218,700	$281,000

DC-USABD-2

AFE NO.______

THE DOW CHEMICAL COMPANY
OIL AND GAS DIVISION
AUTHORITY FOR EXPENDITURE

Well Name Geothermal #1 - Alternate #I

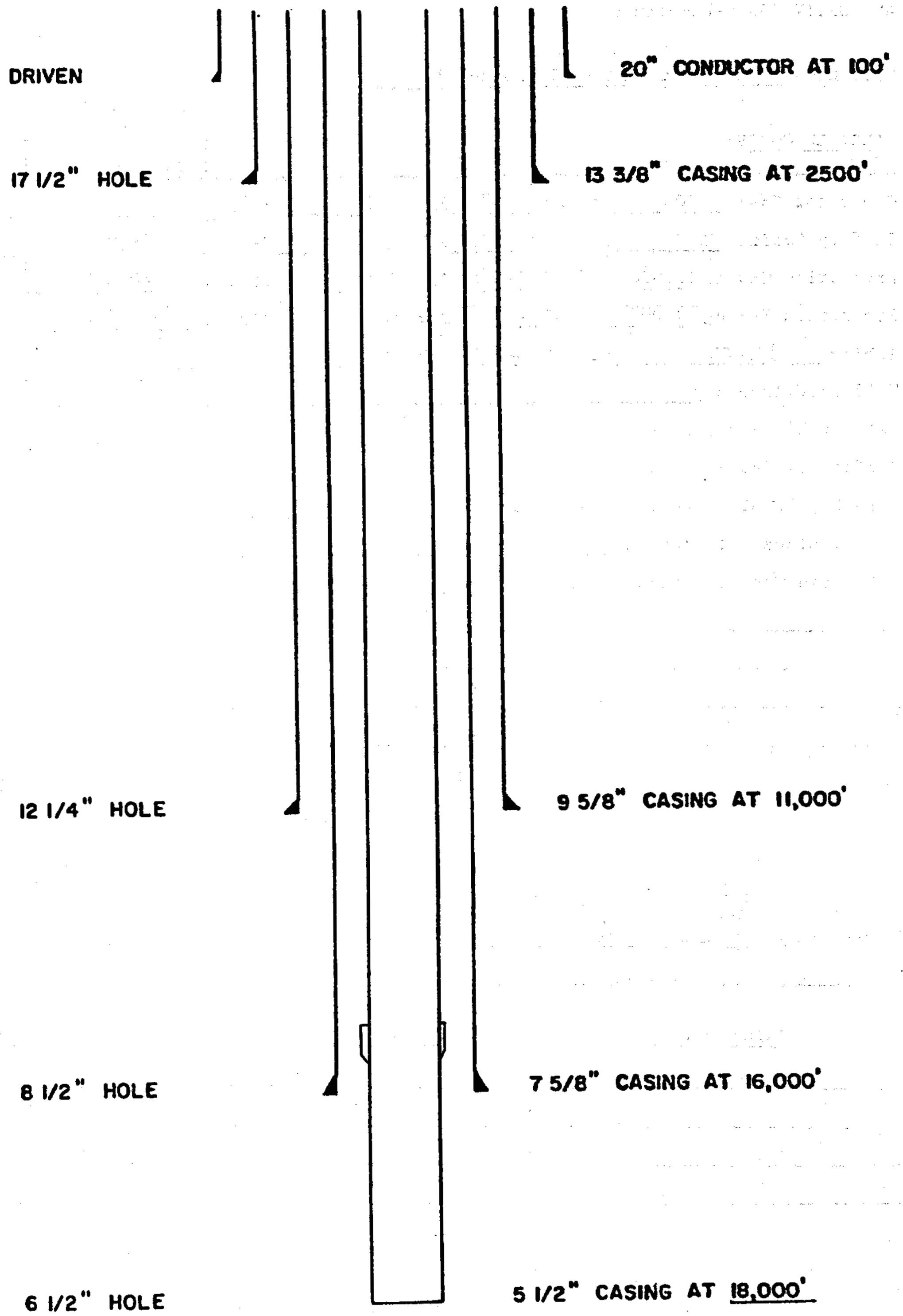
TANGIBLE COSTS:	Estimated Cost Dry Hole	Estimated Cost Completion
Conductor Casing 100 Ft. of 20" O.D. @ $______/Ft.	$ 3,000	$ -
Surface Casing 2500 Ft. of 13-3/8" O.D. @ $______/Ft.	48,000	-
Protection Casing 11,000 Ft. of 9-5/8" O.D. @ $______/Ft.	240,000	-
Production String 16,000 Ft. of 7-5/8" O.D. @ $______/Ft.	365,500	-
Tubing 18,000 Ft. of 5-1/2" O.D. @ $______/Ft.	-	356,500
Well Head Assembly	20,000	120,000
Retrievable Packers, Liners, Special Hole Equipment	-	10,000
Surface Production Facilities:		
Tanks, Treater, Heater, Separator		
Flow Lines, Connections		
Related Contract Labor, etc.		
Total Tangible Costs	$ 676,500	$486,500
Total Tangible & Intangible	$1,895,200	$767,500
TOTAL WELL COST	$2,662,700	

Prepared By P. E. Thomas Approved By______

Date 9/17/75 Date______

Joint Owners	Approved	Date Approved
	By	
	By	
	By	
	By	

GEOTHERMAL WELL NO. 1 - ALTERNATE I
CAMERON COUNTY, TEXAS



GEOTHERMAL WELL NO. 1, ALTERNATE II
CAMERON COUNTY, TEXAS
PROPOSED TOTAL DEPTH - 18,000'

Preliminary Drilling Program:

1. Drive 20" conductor casing to 100'.
2. Install casinghead and 20" 3M# Hydril blowout preventer.
3. Drill 17-1/2" hole to 2500'.
4. Run 13-3/8" casing and cement to surface.
5. Remove 20" Hydril and install 13-3/8" slip-on and weld X 12" 3M# bradenhead.
6. Nipple up 12" 3M# type "U" and Hydril blowout preventers.
7. Drill 12-1/4" hole to 11,000' and log.
8. Run and cement 9-5/8" casing.
9. Install 12" 3M# x 10" 5M# casinghead spool and nipple up 10" 5M# blowout preventers.
10. Drill 8-1/2" hole to 16,000' and log.
11. Run and cement 7-5/8" casing.
12. Install 10" 5M# x 11" 10M# casinghead spool and nipple up 11" 10M# blowout preventers.
13. Drill 6-1/2" hole to 18,000' and log.
14. Run and cement 4-1/2" liner with a PBR.
15. Run 4-1/2" tie-back and seal into PBR.
16. Remove blowout preventers and install tree.

GEOTHERMAL WELL NO. 1 - ALTERNATE II - Page 2

Mud Program:

Depth	Weight	Vis	WL
0 - 8,000'	9.0-9.9	32-36	NC
8,000'- 9,500'	9.0-11.0	36-42	10-6
9,500'-11,000'	11.0-12.0	38-44	6-4
11,000'-14,500'	12.0-15.3	40-48	4
14,500'-16,000'	15.3	40-48	4
16,000'-18,000'	Raise weight as dictated by hole conditions.		

Casing Design:

Surface Casing:
2000' - 13-3/8", 54.5#/ft., K-55, ST&C
500' - 13-3/8", 61.0#/ft., K-55, ST&C

Intermediate Casing:
500' - 9-5/8", 40.0#/ft., N-80, Buttress
1300' - 9-5/8", 40.0#/ft., N-80, LT&C
2600' - 9-5/8", 40.0#/ft., S-95, LT&C
1700' - 9-5/8", 43.5#/ft., S-95, LT&C
1600' - 9-5/8", 47.0#/ft., S-95, LT&C
3300' - 9-5/8", 53.5#/ft., S-95, LT&C

Production/Protection Casing:
5600' - 7-5/8", 38.1#/ft., P-110, TS
5300' - 7-5/8", 38.1#/ft., S-95, SFJP
5100' - 7-3/4", 45.4#/ft., S-105, FJP

Production Tubing:

15,500' - 4-1/2", 15.1#/ft., P-110, TC4S
2,500' - 4-1/2", 15.1#/ft., P-110, FJP
Alternate Design - may be utilized depending upon pressures encountered:
substitute 18.1#/ft., P-110

Cementing Program:

For Alternate II, the depth, temperature, amount of fillup desired and the mud weight will remain the same. Only the hole size, the pipe size and volumes of cement, and spacer will change:

GEOTHERMAL WELL NO. 1 - ALTERNATE II - Page 3

	Hole Size (in)	Pipe Size (in)	Volume of Slurry Required Cu.Ft.	Volume of Slurry Required Sacks	Volume of Spacer Required
Surface Pipe	17-1/2	13-3/8	2600	1700	10 bbls water
1st Intermediate	12-1/4	9-5/8	1870	760 Sacks Lead Slurry; 305 Sacks Tail-in Slurry	1000 gals CW7
2nd Intermediate	8-1/2	7-5/8	550	360	8 bbls. spacer
Production String	6-1/2	4-1/2	323	218	10 Bbls. spacer

Evaluation Program (To be run in open hole):

1. A complete suite of Coraband or Sarband logs should be run at the following depths: 11,000'; 16,000'; and 18,000'.
2. Continuous mud log from 9,000' to T.D.
3. Conventional core prospective zones at discretion of wellsite geologist.
4. Sidewall core prospective zones at discretion of wellsite geologist.

Completion Procedure:

1. Run a Gamma Ray - Cement Bond Log through prospective zones.
2. Squeeze cement, if necessary, according to results of bond log.
3. Drill out cement.
4. Perforate prospective zones.
5. Production test well.

DC-USABD-2

AFE NO.______

THE DOW CHEMICAL COMPANY
OIL AND GAS DIVISION
AUTHORITY FOR EXPENDITURE

Well Name Geothermal #1 - Alternate II Area or Field Wildcat

Location

Cameron County, Texas

Work To Be Performed Drill, Test and Complete

Proposed Depth 18,000' Objective Formation

INTANGIBLE COSTS:	Estimated Cost Dry Hole	Estimated Cost Completion
Stake Location	$ 500	$ -
Right of Way Cost and Surface Damage, Clean-up	20,000	-
Clear Right of Way, Construct Road and Location	50,000	-
Contract Drilling Cost - Ft. @ $ - Ft.	-	-
Rig Time - Daywork with Drill Pipe 92/20 days @ $ 4600 day	423,200	92,000
Rig Time - Daywork without Drill Pipe - days @ $ - day	-	-
Hauling or Boat Rental	15,000	5,000
Mud and Chemicals	150,000	12,000
Cement, Cementing and Tools	25,000	10,000
~~XXXXXXXXXXXXXXXXXX~~ Stimulation	-	50,000
Logging - Open Hole	70,000	-
Logging - Cased Hole	-	10,000
Perforating	-	10,000
Coring and Core Analysis	10,000	-
Mud Logging	35,000	-
Formation Testing - Open Hole and Casing	10,000	10,000
Floating Equipment, Centralizers, Scratchers	2,000	1,000
Bits, Permanent Packer and Rentals	156,000	36,000
Company Supervision, and/or Consultant	37,000	8,000
Miscellaneous Services and Supplies, Bridge Plugs, Retainers, Fishing Tools, etc., Contingencies	150,000	37,000
Move-in, Rig-up, Rig-down	50,000	-
Total Intangible Costs	$1,218,700	$281,000

UC-USABD-2

AFE NO.______

THE DOW CHEMICAL COMPANY
OIL AND GAS DIVISION
AUTHORITY FOR EXPENDITURE

Well Name Geothermal #1 - Alternate II

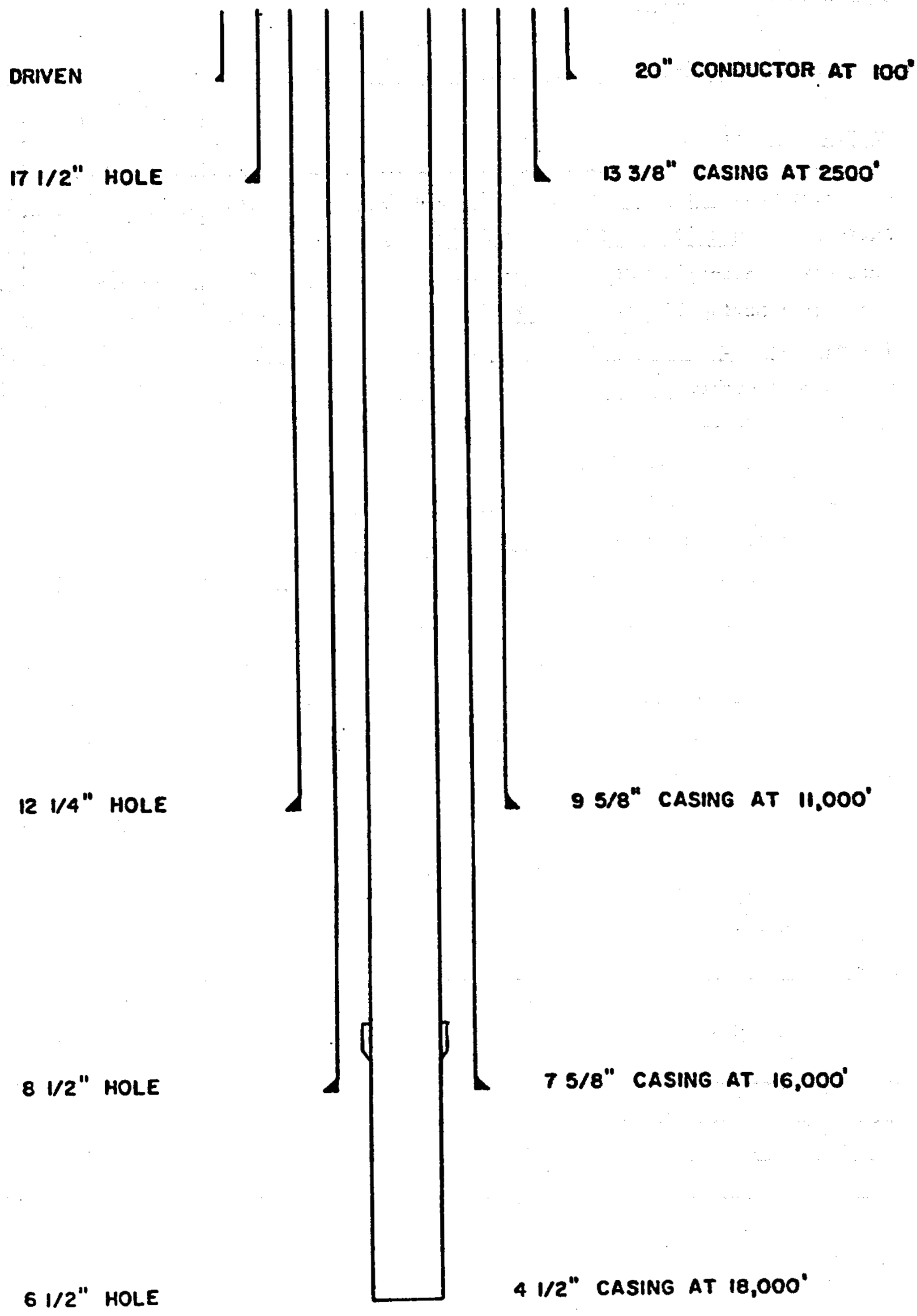
TANGIBLE COSTS:	Estimated Cost Dry Hole	Estimated Cost Completion
Conductor Casing 100 Ft. of 20" O.D. @ $____/Ft.	$ 3,000	$ -
Surface Casing 2500 Ft. of 13-3/8" O.D. @ $____/Ft.	48,000	-
Protection Casing 11,000 Ft. of 9-5/8" O.D. @ $____/Ft.	240,000	-
Production String 16,000 Ft. of 7-5/8" O.D. @ $____/Ft.	365,500	-
Tubing 18,000 Ft. of 4-1/2" O.D. @ $____/Ft.	-	289,000
Well Head Assembly	20,000	120,000
Retrievable Packers, Liners, Special Hole Equipment	-	10,000
Surface Production Facilities:		
Tanks, Treater, Heater, Separator		
Flow Lines, Connections		
Related Contract Labor, etc.		
Total Tangible Costs	$ 676,500	$419,000
Total Tangible & Intangible	$1,895,200	$700,000
TOTAL WELL COST	$2,595,200	

Prepared By L. E. Thomas Approved By______

Date 9/17/75 Date______

Joint Owners	Approved	Date Approved
	By	
	By	
	By	
	By	

GEOTHERMAL WELL NO. 1-ALTERNATE II
CAMERON COUNTY, TEXAS



GEOTHERMAL WELL NO. 1
MATERIAL LIST FOR LONG DELIVERY ITEMS

The following is a listing of material required for drilling this well that may have a long delivery time. Since this is only a preliminary drilling program, this list is being supplied for information purposes only and is not to be used for requisitioning materials.

Wellhead Equipment: Estimated delivery 12-18 months

1 - 16" slip-on and weld x 16" 3M# bradenhead
1 - 16" 3M# x 13-5/8" 5M# casinghead spool
1 - 13-5/8" 5M# x 11" 10M# casinghead spool
1 - 11" 10M# x 7-1/16" 15M# adaptor
1 - 7" 15M# Xmas tree

Casing: Estimated delivery 12-18 months

500' - 11-3/4", 60#/ft., N-80, Buttress
4,150' - 11-3/4", 60#/ft., S-95, ST&C
1,600' - 11-3/4", 65#/ft., S-95, ST&C
4,750' - 11-7/8", 71#/ft., S-95, ST&C
5,800' - 9-5/8", 53.5#/ft. P-110, TS
10,200' - 9-3/4", 59.2#/ft., S-105, FJP
15,500' - 7", 38#/ft., P-110, TC4S
2,500' - 7", 38#/ft., P-110, FJP

Drill Bits: Estimated delivery 6 months

14-3/4" Bits of various types and number dependent upon formations to be drilled
10-5/8" Bits of various types and number, dependent upon formations to be drilled.

GEOTHERMAL WELL NO. 1, ALTERNATE I
MATERIAL LIST FOR LONG DELIVERY ITEMS

The following is a listing of material required for drilling this well that may have a long delivery time. Since this is only a preliminary drilling program, this list is being supplied for information purposes only and is not to be used for requisitioning material.

Wellhead Equipment: Estimated delivery 12-18 months

1 - 13-3/8" slip-on and weld x 12" 3M# bradenhead
1 - 12" 3M# x 10" 5M# casinghead spool
1 - 10" 5M# x 11" 10M# casinghead spool
1 - 11" 10M# x 7-1/16" 15M# adaptor
1 - 5-1/2" 15M# Xmas tree

Casing: Estimated delivery 12-18 months

5,600' - 7-5/8", 38.1#/ft., P-110, TS
5,300' - 7-5/8", 38.1#/ft., S-95, SFJP
5,100' - 7-3/4", 45.5#/ft., S-105, FJP
15,500' - 5-1/2", 23#/ft., P-110, TC4S
2,500' - 5-1/2", 23#/ft., P-110, FJP
or, alternately in the place of 5-1/2" casing
15,500' - 5", 23.2#/ft., S-95, TC4S
2,500' - 5", 23.2#/ft., S-95, FJP

GEOTHERMAL WELL NO. 1, ALTERNATE II
MATERIAL LIST FOR LONG DELIVERY ITEMS

The following is a listing of material required for drilling this well that may have a long delivery time. Since this is only a preliminary drilling program, this list is being supplied for information purposes only and is not to be used for requisitioning materials.

All long delivery tiems for this well will be the same as for Alternate I with the exception of the utilization of 4-1/2" casing in place of 5-1/2" casing. The 4-1/2" casing will be as follows:

15,500' - 4-1/2", 15.1#/ft., P-110, TC4S
2,500' - 4-1/2", 15.1#/ft., P-110, FJP

or

15,500' - 4-1/2", 18.1#/ft., P-110, TC4S
2,500' - 4-1/2", 18.1#/ft., P-110, FJP

GEOTHERMAL WELL NO. 2
NUECES COUNTY, TEXAS
PROPOSED TOTAL DEPTH - 16,000'

Preliminary Drilling Program:

1. Drive 20" conductor casing to 100'.
2. Install casinghead and 20" 3M# Hydril blowout preventer.
3. Drill 18-1/2" hole to 2500'.
4. Run 16" casing and cement to surface.
5. Remove 20" Hydril and install 16" slip-on and weld X 16" 3M# bradenhead.
6. Nipple up 16" 3M# type LWS and Hydril blowout preventers.
7. Drill 14-3/4" hole to 10,000' and log.
8. Run and cement 11-3/4" casing.
9. Install 16" 3M# X 13-5/8" 5M# casinghead spool and nipple up 13-5/8" 5M# blowout preventers.
10. Drill 10-5/8" hole to 14,000' and log.
11. Run and cement 9-5/8" casing.
12. Install 13-3/8" 5M# X 11" 10M# casinghead spool and nipple up 11" 10M# blowout preventers.
13. Drill 8-1/2" hole to 16,000' and log.
14. Run and cement 7" liner with a PBR.
15. Run 7" tie-back and seal into PBR.
16. Remove blowout preventers and install tree.

GEOTHERMAL WELL NO. 2 - Page 2

Mud Program:

Depth	Weight	VIS	WL
0 - 2,500'	9.0	32-36	NC
2,500'-10,000'	9.0-12.0	36-44	10-6
10,000'-14,000'	12.0-16.3	44-48	6-4
14,000'-16,000'	16.3-17.0	44-50	4

Casing Design:

Surface Casing:
2500' - 16", 84#/ft., K-55, ST&C

Intermediate Casing:
500' - 11-3/4", 60#/ft., N-80, Buttress
4150' - 11-3/4", 60#/ft., S-95, ST&C
1600' - 11-3/4", 65#/ft., S-95, ST&C
3750' - 11-7/8", 71#/ft., S-95, ST&C

Production/Protection Casing:
5800' - 9-5/8", 53.5#/ft., P-110, TS
8200' - 9-3/4", 59.2#/ft., S-105 FJP

Production Tubing:
13,500' - 7", 38#/ft., P-110, TC4S
2,500' - 7", 38#/ft., P-110, FJP

Cementing Program:

Surface Pipe - 2500 Feet of 16" Casing in an 18-1/2" hole:

	Recommended Slurry	Slurry Properties
Log Temperature - 120°F	Class H Cement	Weight - 15.7 lbs./gal.
Mud Weight - 9.0 ppg	35% D66	Yield - 1.53 cu.ft./sk.
Desired Fillup - 2500 feet	2% S-1	
Estimated Excess Required - 50%	6.33 gals. Water/sk.	
Cement Slurry Needed - 1764 ft.	Sacks Needed, 1153	

Procedure:

1. Run 16 inch casing with an orifice fill stab-in cementing shoe. Install centralizers on bottom three joints.

2. A stab-in stinger and centralizer are made up on the drill pipe and run into the well.

GEOTHERMAL WELL NO. 2 Page 3

3. When the stinger is seated, establish circulation, pump 20 barrels water.

4. Mix and pump the 1153 sacks of cement, or mix cement until returns are seen.

5. Unseat stinger and circulate excess cement from the pipe.

6. Wait on cement for 12 hours.

1st Intermediate String - 10,000 Feet of 11-3/4" Casing in a 14-3/4" hole:

	Recommended Slurries	
	Lead Slurry	Tail-End Slurry
Log Temperature - 224° F	Class H Cement	Class H Cement
Mud Weight - 12 ppg	4% D20	35% D66
Desired Fillup - 4000 feet	35% D30	.2% D8
Estimated Excess Required - 35%	.3% D8	6.33 gals. Water/sk.
Cu. Ft. of Slurry Needed - 2342 Cu. Ft.	Slurry Weight - 14.6 lbs./gal.	Slurry Weight - 15.7 lbs./gal.
	Slurry Yield - 1.85 Cu.Ft./sk.	Slurry Yield - 1.53 Cu.Ft./sk.
	Sacks Needed - 950	Sacks Needed - 383

Procedure:

1. Run 11-3/4" casing with a differential fill collar and differential fill shoe with centralizers on each of the bottom three joints.

2. Pump 1000 gallons of Dowell Chemical Wash 7. Drop the bottom cement plug, followed by 950 sacks of lead slurry and 383 sacks of the tail-end slurry.

3. Drop the top plug and complete displacement.

4. Wait on cement for 12 hours.

2nd Intermediate String - 14,000 Feet of 9-5/8" Casing in a 10-5/8" hole:

	Recommended Slurry	Spacer Composition For 1 Barrel
Log Temperature - 300°F	Class H	30.6 gals. Water
Mud Weight - 16.3 lbs./gal.	35% D66	370 lbs. D31
Desired Fillup - 6000 Feet	1.0% D65	18 lbs. D20
Estimated Excess Required - 20%	.6% D28R	1.5 lbs. D13
Cement Slurry Needed - 794 Cu.Ft.	6.33 gals. Water/Sk.	5 lbs. D65
	Slurry Weight - 16.7 lbs./gal.	
	Slurry Yield - 1.53 Cu.Ft./Sk.	
	Sacks Needed - 519	

GEOTHERMAL WELL NO. 2 - Page 4

Procedure:

1. Run 9-5/8" casing with differential fill collar and differential fill shoe. Put centralizers on each of the bottom three joints: Two centralizers two joints apart within the 11-3/4 inch casing at 9800' feet to assure a good cement sheath in the lapover of the previous cement job.

2. Circulate the hole (bottoms up minimum). Pump 15 barrels spacer; drop the bottom plug; and start mixing cement.

3. This slurry is designed to be displaced in turbulent flow for maximum efficiency in removing the mud from the wellbore and replacing it with cement. Pipe movement, either rotation or reciprocation, will improve mud removal and cement bonding.

4. Complete the mixing of cement; drop the top plug; and displace in turbulent flow until the plug bumps. Wait on cement time will be determined by laboratory tests.

Production String - 16,000 Feet of 7" Casing in an 8-1/2" hole:

	Recommended Slurry	Spacer Composition For 1 Barrel
Log Temperature - 350°F	Class H	27.9 gals. Water
Mud Weight - 17.0 lbs./gal.	35% D66	465 lbs. D31
Desired Fillup - 2500 Feet	15.6 lbs. D76	18 lbs. D20
% Excess Required - 20%	.75% D65	1.5 lbs. D13
Cement Slurry Needed - 793 Cu. Ft.	1.6% D92	5 lbs. D65
	5.68 gals. Water/Sk.	
	Slurry Weight - 17.0 lbs./gal.	
	Slurry Yield - 1.48 Cu.Ft./Sk.	
	Sacks Needed - 536	

Procedure:

1. Run 7" casing with a differential fill collar and differential fill shoe. Attach centralizers to each of the bottom three joints. Put two additional centralizers, 2 joints apart, within the 9-5/8" casing at 13,800 feet to assure a uniform cement sheath within the lap area.

2. Circulate the hole (bottoms up minimum); pump 13 barrels of spacer; drop the bottom plug and start mixing cement.

GEOTHERMAL WELL NO. 2 - Page 5

3. This slurry is also designed to be displaced in turbulent flow for maximum mud removal efficiency. Moving the pipe (either reciprocating or rotating) while the cement is being displaced will facilitate mud removal and improve the bond.

4. When the cement mixing is complete, drop the plug and displace at the required rate for the cement slurry to be in turbulent flow.

5. Bump plug and wait on cement (WOC time will be determined by laboratory tests).

Evaluation Program (To be run in open hole):

1. A complete suite of Coraband or Saraband logs should be run at the following depths: 10,000'; 14,000'; and 16,000'.

2. Continuous mud log from 8000' to T.D.

3. Conventional core prospective zones at discretion of wellsite geologist.

4. Sidewall core prospective zones at discretion of wellsite geologist.

Completion Procedure:

1. Run a Gamma Ray - Cement Bond Log through prospective zones.

2. Squeeze cement, if necessary, according to results of bond log.

3. Drill out cement.

4. Perforate prospective zones.

5. Production test well.

DC-USÅBD-2

AFE NO.______

THE DOW CHEMICAL COMPANY
OIL AND GAS DIVISION
AUTHORITY FOR EXPENDITURE

Well Name Geothermal No. 2 Area or Field Wildcat

Location

Nueces County, Texas

Work To Be Performed Drill, Test and Complete

Proposed Depth 16,000' Objective Formation

INTANGIBLE COSTS:	Estimated Cost Dry Hole	Estimated Cost Completion
Stake Location	$ 500	$ -
Right of Way Cost and Surface Damage, Clean-up	20,000	-
Clear Right of Way, Construct Road and Location	50,000	-
Contract Drilling Cost - Ft. @ $ - Ft.	-	-
Rig Time - Daywork with Drill Pipe 100/20 days @ $ 4600 day	460,000	92,000
Rig Time - Daywork without Drill Pipe - days @ $ - day	-	-
Hauling or Boat Rental	13,000	4,000
Mud and Chemicals	240,000	13,000
Cement, Cementing and Tools	45,000	10,000
~~XXXXXXXXXXXXXXXXXX~~ Stimulation	-	50,000
Logging - Open Hole	70,000	-
Logging - Cased Hole	-	10,000
Perforating	-	10,000
Coring and Core Analysis	10,000	-
Mud Logging	30,000	-
Formation Testing - Open Hole and Casing	10,000	10,000
Floating Equipment, Centralizers, Scratchers	3,000	1,500
Bits, Permanent Packer and Rentals	198,000	36,000
Company Supervision and/or Consultant	47,000	8,000
Miscellaneous Services and Supplies, Bridge Plugs, Retainers, Fishing Tools, etc., Contingencies	180,000	37,000
Move-in-Rig-up, Rig-down	50,000	-
Total Intangible Costs	$1,426,500	$281,500

DC-USABD-2

AFE NO.______

THE DOW CHEMICAL COMPANY
OIL AND GAS DIVISION
AUTHORITY FOR EXPENDITURE

Well Name Geothermal No. 2

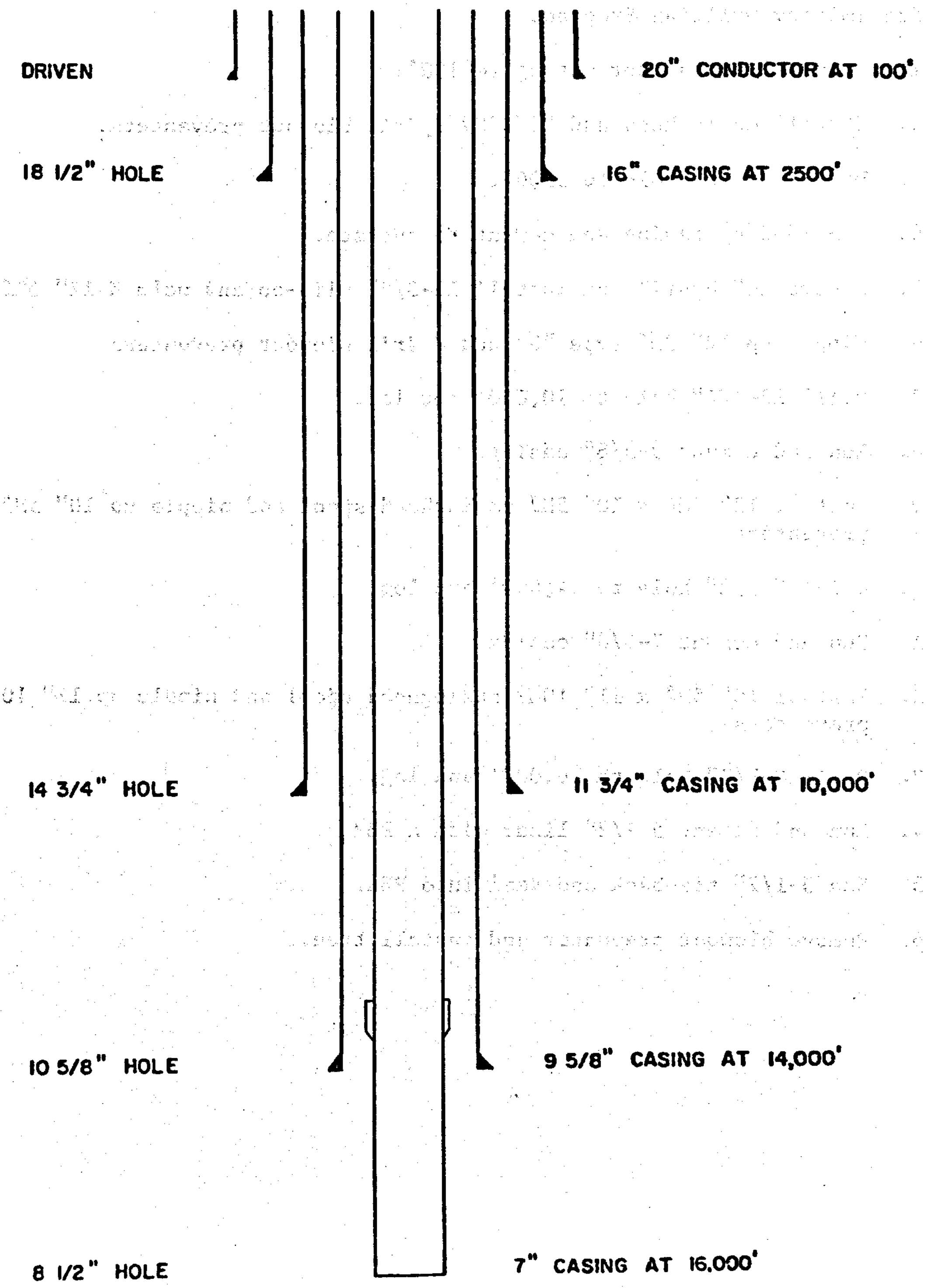
TANGIBLE COSTS:	Estimated Cost Dry Hole	Estimated Cost Completion
Conductor Casing 100 Ft. of 20" O.D. @ $____/Ft.	$ 3,000	$ -
Surface Casing 2500 Ft. of 16" O.D. @ $____/Ft.	76,000	-
Protection Casing 10,000 Ft. of 11-3/4" O.D. @ $____/Ft.	295,000	-
Production String 14,000 Ft. of 9-5/8" O.D. @ $____/Ft.	395,000	-
Tubing 16,000 Ft. of 7" O.D. @ $____/Ft.	-	440,000
Well Head Assembly	25,000	125,000
Retrievable Packers, Liners, Special Hole Equipment	-	10,000
Surface Production Facilities:		
Tanks, Treater, Heater, Separator		
Flow Lines, Connections		
Related Contract Labor, etc.		
Total Tangible Costs	$ 794,000	$575,000
Total Tangible & Intangible	$2,220,500	$856,500
TOTAL WELL COST	$3,077,000	

Prepared By L E Thomas Approved By______

Date 11/18/75 Date______

Joint Owners	Approved	Date Approved
	By	
	By	
	By	
	By	

GEOTHERMAL WELL NO. 2
NUECES COUNTY, TEXAS



GEOTHERMAL WELL NO. 2, ALTERNATE I
NUECES COUNTY, TEXAS
PROPOSED TOTAL DEPTH - 16,000'

Preliminary Drilling Program:

1. Drive 20" conductor casing to 100'.
2. Install casinghead and 20" 3M# Hydril blowout preventers.
3. Drill 17-1/2" hole to 2500'.
4. Run 13-3/8" casing and cement to surface.
5. Remove 20" Hydril and install 13-3/8" slip-on and weld X 12" 3M# bradenhead.
6. Nipple up 12" 3M# type "U" and Hydril blowout preventers.
7. Drill 12-1/4" hole to 10,000' and log.
8. Run and cement 9-5/8" casing.
9. Install 12" 3M# x 10" 5M# casinghead spool and nipple up 10" 5M# blowout preventers.
10. Drill 8-1/2" hole to 14,000' and log.
11. Run and cement 7-5/8" casing.
12. Install 10" 5M# x 11" 10M# casinghead spool and nipple up 11" 10M# blowout preventers.
13. Drill 6-1/2" hole to 16,000' and log.
14. Run and cement 5-1/2" liner with a PBR.
15. Run 5-1/2" tie-back and seal into PBR.
16. Remove blowout preventer and install tree.

GEOTHERMAL WELL NO. 2 - ALTERNATE I - Page 2

Mud Program:

Depth	Weight	VIS	WL
0 - 2,500'	9.0	32-36	NC
2,500'-10,000'	9.0-12.0	36-44	10-6
10,000-14,000	12.0-16.3	44-48	6-4
14,000-16,000	16.3-17.0	44-50	4

Casing Design:

Surface Casing:
2000' - 13-3/8", 54.5#/ft., K-55, ST&C
500' - 13-3/8", 61.0#/ft., K-55, ST&C

Intermediate Casing:
500' - 9-5/8", 40.0#/ft., N-80, Buttress
1300' - 9-5/8", 40.0#/ft., N-80, LT&C
2600' - 9-5/8", 40.0#/ft., S-95, LT&C
1700' - 9-5/8", 43.5#/ft., S-95, LT&C
1600' - 9-5/8", 47.0#/ft., S-95, LT&C
2300' - 9-5/8", 53.5#/ft., S-95, LT&C

Production/Protection Casing:
5600' - 7-5/8", 38.1#/ft., P-110, TS
5300' - 7-5/8", 38.1#/ft., S-95, SFJP
3100' - 7-3/4", 45.4#/ft., S-105, FJP

Production Tubing:
13,500' - 5-1/2", 23#/ft., P-110, TC4S
2,500' - 5-1/2", 23#/ft., P-110, FJP
Alternate Design - may be utilized depending upon pressures encountered:
13,500' - 5", 23.2#/ft., S-95, TC4S
2,500' - 5", 23.2#/ft., S-95, FJP

Cementing Program:

For Alternate I, the depth, temperature, amount of fillup desired and the mud weight will remain the same. Only the hole size, the pipe size and volumes of cement, and spacer will change:

GEOTHERMAL WELL NO. 2 - ALTERNATE I - Page 3

	Hole Size (in)	Pipe Size (in)	Volume of Slurry Required Cu.Ft.	Sacks	Volume of Spacer Required
Surface Pipe	17-1/2	13-3/8	2600	1700	10 bbls. water
1st Intermediate	12-1/4	9-5/8	1870	760 Sacks Lead Slurry; 305 Sacks Tail-in Slurry	1000 gals. CW7
2nd Intermediate	8-1/2	7-5/8	550	360	8 bbls spacer
Production String	6-1/2	5-1/2	197	133	8 bbls spacer

Evaluation Program (To be run in open hole):

1. A complete suite of Coraband or Saraband logs should be run at the following depths: 10,000'; 14,000'; and 16,000'.

2. Continuous mud log from 8,000' to T.D.

3. Conventional core prospective zones at discretion of wellsite geologist.

4. Sidewall core prospective zones at discretion of wellsite geologist.

Completion Procedure:

1. Run a Gamma Ray - Cement Bond Log through prospective zones.

2. Squeeze cement, if necessary, according to results of bond log.

3. Drill out cement.

4. Perforate prospective zones.

5. Production test well.

DC-USABD-2

AFE NO.______

THE DOW CHEMICAL COMPANY
Brazos Division
AUTHORITY FOR EXPENDITURE

Well Name Geothermal No. 2 - Alternate I   Area or Field Wildcat

Location

Nueces County, Texas

Work To Be Performed Drill, Test, and Complete

Proposed Depth 16,000'   Objective Formation

INTANGIBLE COSTS:	Estimated Cost Dry Hole	Estimated Cost Completion
Stake Location	500	—
Right of Way Cost and Surface Damage, clean-up	20,000	—
Clear Right of Way, Construct Road and Location	50,000	—
Contract Drilling Cost — Ft. @ $ — Ft.	—	—
Rig Time - Daywork with Drill Pipe 72/20 days @ $4600 day	331,200	92,000
Rig Time - Daywork without Drill Pipe — days @ $ — day	—	—
Hauling or Boat Rental	13,000	4,000
Mud and Chemicals	120,000	12,000
Cement, Cementing and Tools	40,000	10,000
~~Acid, Service and Tools~~ Stimulation	—	50,000
Logging - Open Hole	70,000	—
Logging - Cased Hole	—	10,000
Perforating	—	10,000
Coring and Core Analysis	10,000	—
Mud Logging	28,000	—
Formation Testing - Open Hole and Casing	10,000	10,000
Floating Equipment, Centralizers, Scratchers	2,000	1,000
Bits, Permanent Packer and Rentals	122,000	36,000
Company Supervision and/or consultant	30,000	8,000
Miscellaneous Services and Supplies, Bridge Plugs, Retainers, Fishing Tools, etc., contingencies	127,000	37,000
Move-in, rig-up, rig down	50,000	—
Total Intangible Costs	1,023,700	280,000

DC-USABD-2

AFE NO.______

THE DOW CHEMICAL COMPANY
Brazos Division
AUTHORITY FOR EXPENDITURE

Well Name Geothermal No. 2 - Alternate I

TANGIBLE COSTS:	Estimated Cost Dry Hole	Estimated Cost Completion
Conductor Casing 100 Ft. of 20 O.D. @ $____/Ft.	3,000	—
Surface Casing 2,500 Ft. of 13-3/8 O.D. @ $____/Ft.	48,000	—
Protection Casing 10,000 Ft. of 9-5/8 O.D. @ $____/Ft.	216,000	—
Production String 14,000 Ft. of 7-5/8 O.D. @ $____/Ft.	312,000	—
Tubing 16,000 Ft. of 5-1/2 O.D. @ $____/Ft.	—	313,700
Well Head Assembly	20,000	120,000
Retrievable Packers, Liners, Special Hole Equipment		10,000
Surface Production Facilities:		
Tanks, Treater, Heater, Separator		
Flow Lines, Connections		
Related Contract Labor, etc.		
Total Tangible Costs	599,000	443,700
Total Tangible & Intangible	1,622,700	723,700
TOTAL WELL COST	2,346,400	

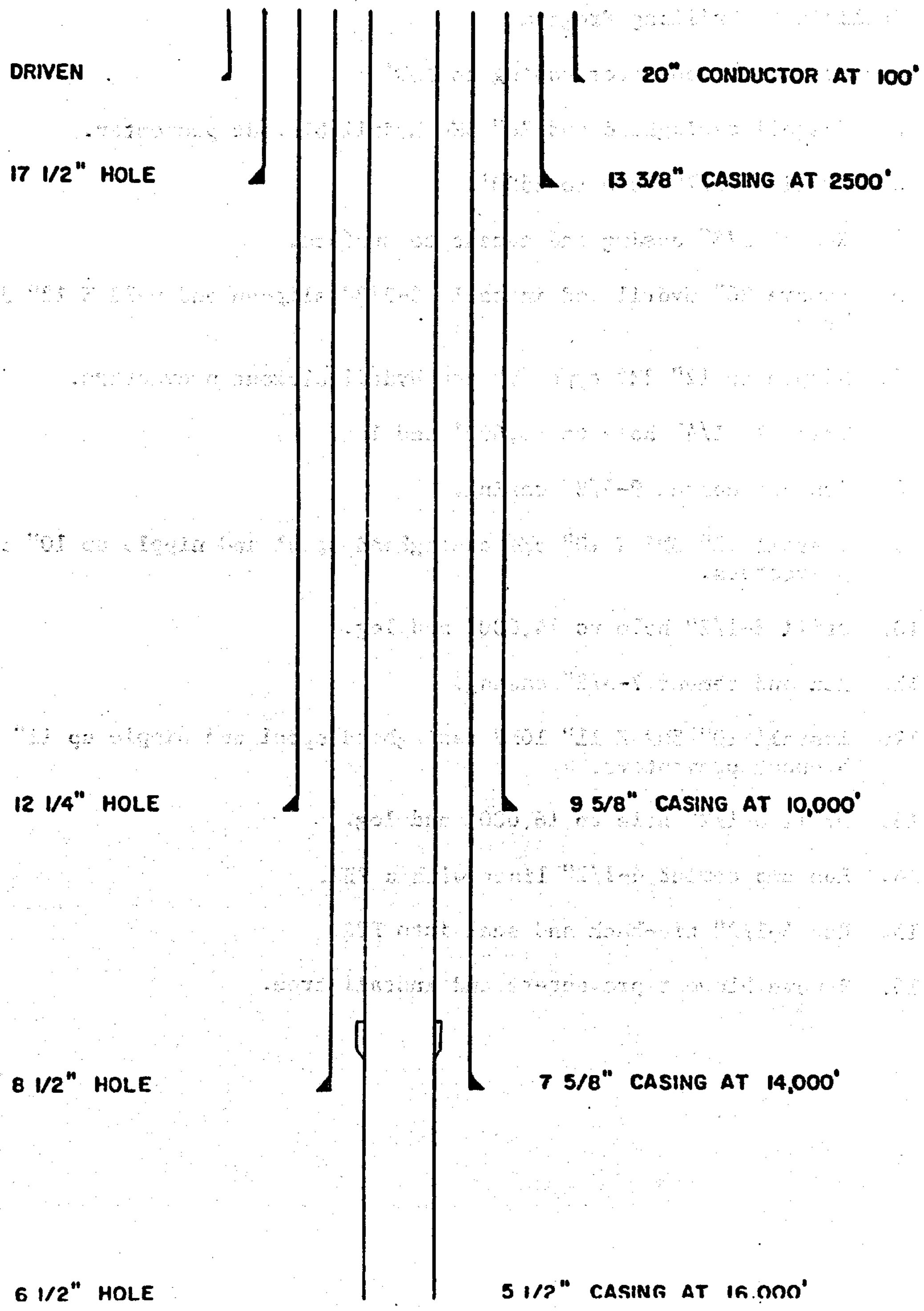
Prepared By L. E. Thomas Approved By______

Date______ Date______

Joint Owners	Approved	Date Approved
	By	
	By	
	By	
	By	

GEOTHERMAL WELL NO. 2 - ALTERNATE I

NUECES COUNTY, TEXAS



GEOTHERMAL WELL NO. 2, ALTERNATE II
NUECES COUNTY, TEXAS
PROPOSED TOTAL DEPTH - 16,000'

Preliminary Drilling Program:

1. Drive 20" conductor casing to 100'.
2. Install casinghead and 20" 3M# Hydril blowout preventer.
3. Drill 17-1/2" hole to 2500'.
4. Run 13-3/8" casing and cement to surface.
5. Remove 20" Hydril and install 13-3/8" slip-on and weld X 12" 3M# braden-head.
6. Nipple up 12" 3M# type "U" and Hydril blowout preventers.
7. Drill 12-1/4" hole to 10,000' and log.
8. Run and cement 9-5/8" casing.
9. Install 12" 3M# X 10" 5M# casinghead spool and nipple up 10" 5M# blowout preventers.
10. Drill 8-1/2" hole to 14,000' and log.
11. Run and cement 7-5/8" casing.
12. Install 10" 5M# X 11" 10M# casinghead spool and nipple up 11" 10M# blowout preventers.
13. Drill 6-1/2" hole to 16,000' and log.
14. Run and cement 4-1/2" liner with a PBR.
15. Run 4-1/2" tie-back and seal into PBR.
16. Remove blowout preventers and install tree.

GEOTHERMAL WELL NO. 2 - ALTERNATE II - Page 2

Mud Program:

Depth	Weight	VIS	WL
0 -2,500'	9.0	32-36	NC
2,500'-10,000'	9.0-12.0	36-44	10-6
10,000'-14,000'	12.0-16.3	44-48	6-4
14,000'-16,000'	16.3-17.0	44-50	4

Casing Design:

Surface Casing:
2000' - 13-3/8", 54.5#/ft., K-55, ST&C
500' - 13-3/8", 61.0#/ft., K-55, ST&C

Intermediate Casing:
500' - 9-5/8", 40.0#/ft., N-80, Buttress
1300' - 9-5/8", 40.0#/ft., N-80, LT&C
2600' - 9-5/8", 40.0#/ft., S-95, LT&C
1700' - 9-5/8", 43.5#/ft., S-95, LT&C
1600' - 9-5/8", 47.0#/ft., S-95, LT&C
2300' - 9-5/8", 53.5#/ft., S-95, LT&C

Production/Protection Casing:
5,600' - 7-5/8", 38.1#/ft., P-110, TS
5,300' - 7-5/8", 38.1#/ft., S-95, SFJP
3,100' - 7-3/4", 45.4#/ft., S-105 FJP

Production Tubing:

13,500' - 4-1/2", 15.1#/ft., P-110, TC4S
2,500' - 4-1/2", 15.1#/ft., P-110, FJP

Alternate Design - may be utilized depending upon pressures encountered:
Substitute 18.1#/ft., P-110

Cementing Program:

For Alternate II, the depth, temperature, amount of fillup desired and the mud weight will remain the same. Only the hole size, the pipe size and volumes of cement and spacer will change.

	Hole Size (in)	Pipe Size (in)	Volume of Slurry Required Cu.Ft.	Sacks	Volume of Spacer Required
Surface Pipe	17-1/2	13-3/8	2600	1700	10 bbls. Water
1st Intermediate	12-1/4	9-5/8	1870	760 Sx. Lead Slurry; 305 Sacks Tail-in Slurry	1000 gals. CW7

GEOTHERMAL WELL NO. 2 - ALTERNATE II - Page 3

	Hole Size (in)	Pipe Size (in)	Volume of Slurry Required Cu. Ft.	Volume of Slurry Required Sacks	Volume of Spacer Required
2nd Intermediate	8-1/2	7-5/8	550	360	8 bbls. Spacer
Production String	6-1/2	4-1/2	323	218	10 bbls. Spacer

Evaluation Program (To be run in open hole):

1. A complete suite of Coraband or Saraband logs should be run at the following depths: 10,000'; 14,000'; and 16,000'.
2. Continuous mud log from 8000' to T.D.
3. Conventional core prospective zones at discretion of wellsite geologist.
4. Sidewall core prospective zones at discretion of wellsite geologist.

Completion Procedure:

1. Run a Gamma Ray - Cement Bond Log through prospective zones.
2. Squeeze cement, if necessary, according to results of bond log.
3. Drill out cement.
4. Perforate prospective zones.
5. Production test well.

DC-USABD-2

AFE NO.______

THE DOW CHEMICAL COMPANY
Brazos Division
AUTHORITY FOR EXPENDITURE

Well Name Geothermal No. 2 - Alternate II Area or Field Wildcat

Location ______

Nueces County, Texas

Work To Be Performed Drill, Test, and Complete

Proposed Depth 16,000' Objective Formation ______

INTANGIBLE COSTS:	Estimated Cost Dry Hole	Estimated Cost Completion
Stake Location	500	---
Right of Way Cost and Surface Damage, clean-up	20,000	---
Clear Right of Way, Construct Road and Location	50,000	---
Contract Drilling Cost -- Ft. @ $ -- Ft.	---	---
Rig Time - Daywork with Drill Pipe 72/20 days @ $4600 day	331,200	92,000
Rig Time - Daywork without Drill Pipe -- days @ $ -- day	---	---
Hauling or Boat Rental	13,000	4,000
Mud and Chemicals	120,000	12,000
Cement, Cementing and Tools	40,000	10,000
~~Acid, Service and Tools~~ Stimulation	---	50,000
Logging - Open Hole	70,000	---
Logging - Cased Hole	---	10,000
Perforating	---	10,000
Coring and Core Analysis	10,000	---
Mud Logging	28,000	---
Formation Testing - Open Hole and Casing	10,000	10,000
Floating Equipment, Centralizers, Scratchers	2,000	1,000
Bits, Permanent Packer and Rentals	122,000	36,000
Company Supervision and/or consultant	30,000	8,000
Miscellaneous Services and Supplies, Bridge Plugs, Retainers, Fishing Tools, etc. contingencies	127,000	37,000
Move-in, rig-up, rig down	50,000	---
Total Intangible Costs	1,023,700	280,000

DC-USABD-2

AFE NO.______

THE DOW CHEMICAL COMPANY
Brazos Division
AUTHORITY FOR EXPENDITURE

Well Name Geothermal No. 2 - Alternate II

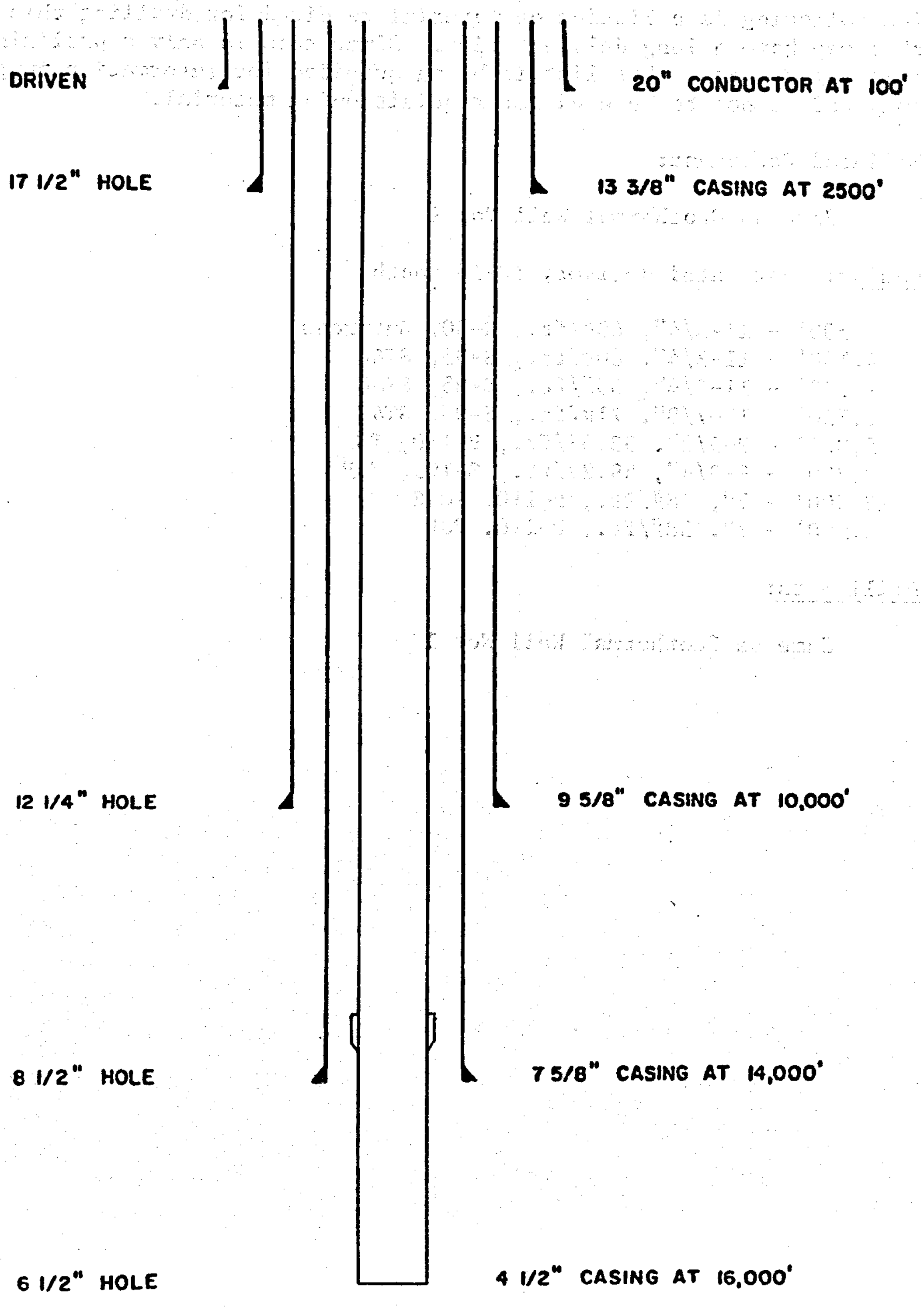
TANGIBLE COSTS:	Estimated Cost Dry Hole	Estimated Cost Completion
Conductor Casing 100 Ft. of 20 O.D. @ $____/Ft.	3,000	—
Surface Casing 2500 Ft. of 13-3/8 O.D. @ $____/Ft.	48,000	—
Protection Casing 10,000 Ft. of 9-5/8 O.D. @ $____/Ft.	216,000	—
Production String 14,000 Ft. of 7-5/8 O.D. @ $____/Ft.	312,000	—
Tubing 16,000 Ft. of 4-1/2 O.D. @ $____/Ft.	—	255,000
Well Head Assembly	20,000	120,000
Retrievable Packers, Liners, Special Hole Equipment		10,000
Surface Production Facilities:		
Tanks, Treater, Heater, Separator		
Flow Lines, Connections		
Related Contract Labor, etc.		
Total Tangible Costs	599,000	385,000
Total Tangible & Intangible	1,622,700	665,000
TOTAL WELL COST	2,287,700	

Prepared By L. E. Romes Approved By______

Date______ Date______

Joint Owners	Approved	Date Approved
	By	
	By	
	By	
	By	

GEOTHERMAL WELL NO. 2 - ALTERNATE II
NUECES COUNTY, TEXAS



GEOTHERMAL WELL NO. 2
MATERIAL LIST FOR LONG DELIVERY ITEMS

The following is a listing of material required for drilling this well that may have a long delivery time. Since this is only a preliminary drilling program, this list is being supplied for information purposes only and is not to be used for requisitioning material.

Wellhead Equipment:

Same as Geothermal Well No. 1

Casing: Estimated delivery 12-18 months

500' - 11-3/4", 60#/ft., N-80, Buttress
4,150' - 11-3/4", 60#/ft., S-95, ST&C
1,600' - 11-3/4", 65#/ft., S-95, ST&C
3,750' - 11-7/8", 71#/ft., S-95, ST&C
5,800' - 9-5/8", 53.5#/ft., P-110, TS
8,200' - 9-3/4", 59.2#/ft., S-105, FJP
13,500' - 7", 38#/ft., P-110, TC4S
2,500' - 7", 38#/ft., P-110, FJP

Drill Bits:

Same as Geothermal Well No. 1

GEOTHERMAL WELL NO. 2, ALTERNATE I
MATERIAL LIST FOR LONG DELIVERY ITEMS

The following is a listing of material required for drilling this well that may have a long delivery time. Since this is only a preliminary drilling program, this list is being supplied for information purposes only and is not to be used for requisitioning material.

Wellhead Equipment:

Same as Geothermal Well No. 1, Alternate I

Casing: Estimated delivery 12-18 months

5,600' - 7-5/8", 38.1#/ft., P-110, TS
5,300' - 7-5/8", 38.1#/ft., S-95, SFJP
3,100' - 7-3/4", 45.5#/ft., S-105, FJP
13,500' - 5-1/2", 23#/ft., P-110, TC4S
2,500' - 5-1/2", 23#/ft., P-110, FJP
or, alternately in the place of 5-1/2" casing
13,500' - 5", 23.2#/ft., S-95, TC4S
2,500' - 5", 23.2#/ft., S-95, FJP

GEOTHERMAL WELL NO. 2, ALTERNATE II
MATERIAL LIST FOR LONG DELIVERY ITEMS

The following is a listing of material required for drilling this well that may have a long delivery time. Since this is only a preliminary drilling program, this list is being supplied for information purposes only and is not to be used for requisitioning material.

All long delivery items for this well will be the same as for Alternate I with the exception of the utilization of 4-1/2" casing in place of 5-1/2" casing. The 4-1/2" casing will be as follows:

13,500' - 4-1/2", 15.1#/ft., P-110, TC4S
2,500' - 4-1/2", 15.1#/ft., P-110, FJP

or

13,500' - 4-1/2", 18.1#/ft., P-110, TC4S
2,500' - 4-1/2", 18.1#/ft., P-110, FJP

GEOTHERMAL WELL NO. 3
NUECES COUNTY, TEXAS
PROPOSED TOTAL DEPTH - 14,000'

Preliminary Drilling Program:

1. Drive 20" conductor casing to 100'.
2. Install casinghead and 20" 3M# Hydril blowout preventer.
3. Drill 17-1/2" hole to 2500'.
4. Run 13-3/8" casing and cement to surface.
5. Remove 20" Hydril and install 13-3/8" slip-on and weld X 13-5/8" 5M# bradenhead.
6. Nipple up 13-5/8" 5M# type "U" and Hydril blowout preventers.
7. Drill 12-1/4" hole to 10,000' and log.
8. Run and cement 9-5/8" casing.
9. Install 13-5/8" 5M# X 11" 10M# casinghead spool and nipple up 11" 10M# blowout preventers.
10. Drill 8-1/2" hole to 14,000' and log.
11. Run and cement 7" liner with a PBR.
12. Run 7" tie-back and seal into PBR.
13. Remove blowout preventer and install tree.

GEOTHERMAL WELL NO. 3 - Page 2

Mud Program:

Depth	Weight	VIS	WL
0 - 2,500'	9.0	32-36	NC
2,500'-10,000'	9.0-12.0	36-44	10-6
10,000'-14,000'	12.0-16.3	44-48	6-4

Casing Design:

Surface Casing:
2,000' - 13-3/8", 54.5#/ft., K-55, ST&C
500' - 13-3/8", 61.0#/ft., K-55, ST&C

Production/Protection Casing:
4,850' - 9-5/8", 53.5#/ft., V-150, LT&C
2,500' - 9-5/8", 53.5#/ft., P-110, LT&C
2,650' - 9-5/8", 53.5#/ft., S-105, LT&C

Production Tubing:
10,000' - 7", 38#/ft., P-110, TC4S
4,000' - 7", 38#/ft., P-110, FJP

Cementing Program:

Surface Pipe - 2500 Feet of 13-3/8" Casing in a 17-1/2" hole:

	Recommended Slurry	Slurry Properties
Log Temperature - 120°F	Class H Cement	Weight - 15.7 lbs./gal.
Mud Weight - 9.0 ppg	35% D66	Yield - 1.53 cu.ft./sk.
Desired Fillup - 2500 feet	2% S-1	
Estimated Excess Required - 50%	6.33 gals. Water/sk.	
Cement Slurry Needed - 2604 ft.	Sacks Needed, 1702	

Procedure:

1. Run 13-3/8" casing with a float collar and float shoe with centralizers on each of the bottom three joints.

2. Pump 1000 gallons of Dowell Chemical Wash 7. Drop the bottom cement plug, followed by the cement slurry.

3. Drop the top plug and complete displacement.

4. Wait on cement for 12 hours.

GEOTHERMAL WELL NO. 3 - Page 3

Production/Protection String - 10,000 Feet of 9-5/8" Casing in a 12-1/4" hole:

Log Temperature - 224° F
Mud Weight - 12 ppg
Desired Fillup - 4000 feet
Estimated Excess Required - 35%
Cu. Ft. of Slurry Needed - 1690 Cu. Ft.

Recommended Slurries: Lead Slurry	Tail-End Slurry
Class H Cement	Class H Cement
4% D20	35% D66
35% D30	.2% D8
.3% D8	6.33 gals. Water/sk.
Slurry Weight - 14.6 lbs./gal.	Slurry Weight - 15.7 lbs./gal.
Slurry Yield - 1.85 Cu.Ft./sk.	Slurry Yield - 1.53 Cu.Ft./sk.
Sacks Needed - 685	Sacks Needed - 276

Procedure:

1. Run 9-5/8" casing with a differential fill collar and differential fill shoe with centralizers on each of the bottom three joints.

2. Pump 1000 gallons of Dowell Chemical Wash 7. Drop the bottom cement plug, followed by 685 sacks of lead slurry and 276 sacks of the tail-end slurry.

3. Drop the top plug and complete displacement.

4. Wait on cement for 12 hours.

Production String - 14,000 Feet of 7" Casing in an 8-1/2" hole:

Log Temperature - 300° F
Mud Weight - 16.3 lbs./gal.
Desired Fillup - 4000 Feet
Estimated Excess Required - 20%
Cement Slurry Needed - 608 Cu.Ft.

Recommended Slurry	Spacer Composition For 1 Barrel
Class H	30.6 gals. Water
35% D66	370 lbs. D31
1.0% D65	18 lbs. D20
.6% D28R	1.5 lbs. D13
6.33 gals. Water/Sk.	5 lbs. D65
Slurry Weight - 16.7 lbs./gal.	
Slurry Yield - 1.53 Cu.Ft./sk.	
Sacks Needed - 398	

Procedure:

1. Run 7" casing with differential fill collar and differential fill shoe.

GEOTHERMAL WELL NO. 3 - Page 4

2. Circulate the hole (bottoms up minimum). Pump 15 barrels spacer, drop the bottom plug; and start mixing cement.

3. This slurry is designed to be displaced in turbulent flow for maximum efficiency in removing the mud from the wellbore and replacing it with cement. Pipe movement, either rotation or reciprocation, will improve mud removal and cement bonding.

4. Complete the mixing of cement; drop the top plug; and displace in turbulent flow until the plug bumps. Wait on cement time will be determined by laboratory tests.

Evaluation Program (To be run in open hole):

1. A Complete suite of Coraband or Saraband logs should be run at the following depths: 10,000' and 14,000'.

2. Continuous mud log from 8,000' to T.D.

3. Conventional core prospective zones at discretion of wellsite geologist.

4. Sidewall core prospective zones at discretion of wellsite geologist.

Completion Procedure:

1. Run a Gamma Ray - Cement Bond Log through prospective zones.

2. Squeeze cement, if necessary, according to results of bond log.

3. Drill out cement.

4. Perforate prospective zones.

5. Production test well.

DC-USABD-2

AFE NO.______

THE DOW CHEMICAL COMPANY
OIL AND GAS DIVISION
AUTHORITY FOR EXPENDITURE

Well Name GEOTHERMAL WELL NO. 3 Area or Field Wildcat

Location

Nueces County, Texas

Work To Be Performed Drill, Test and Complete

Proposed Depth 14,000' Objective Formation

INTANGIBLE COSTS:	Estimated Cost Dry Hole	Estimated Cost Completion
Stake Location	$ 500	$ --
Right of Way Cost and Surface Damage, Clean-up	20,000	--
Clear Right of Way, Construct Road and Location	50,000	--
Contract Drilling Cost -- Ft. @ $ -- Ft.	--	--
Rig Time - Daywork with Drill Pipe 50/18 days @ $ 4600 day	230,000	82,800
Rig Time - Daywork without Drill Pipe -- days @ $ -- day	--	--
Hauling or Boat Rental	11,500	3,500
Mud and Chemicals	105,000	10,000
Cement, Cementing and Tools	35,000	10,000
~~Acid, Service and Tools~~ Stimulation	--	50,000
Logging - Open Hole	65,000	--
Logging - Cased Hole	--	10,000
Perforating	--	10,000
Coring and Core Analysis	10,000	--
Mud Logging	22,000	--
Formation Testing - Open Hole and Casing	10,000	10,000
Floating Equipment, Centralizers, Scratchers	2,000	1,000
Bits, Permanent Packer and Rentals	100,000	34,000
Company Supervision and/or Consultant	22,000	7,000
Miscellaneous Services and Supplies, Bridge Plugs, Retainers, Fishing Tools, etc., Contingencies	105,000	33,000
Move-in, rig-up, rig down	50,000	--
Total Intangible Costs	$ 838,000	$ 261,300

DC-USABD-2

AFE NO.______

THE DOW CHEMICAL COMPANY
OIL AND GAS DIVISION
AUTHORITY FOR EXPENDITURE

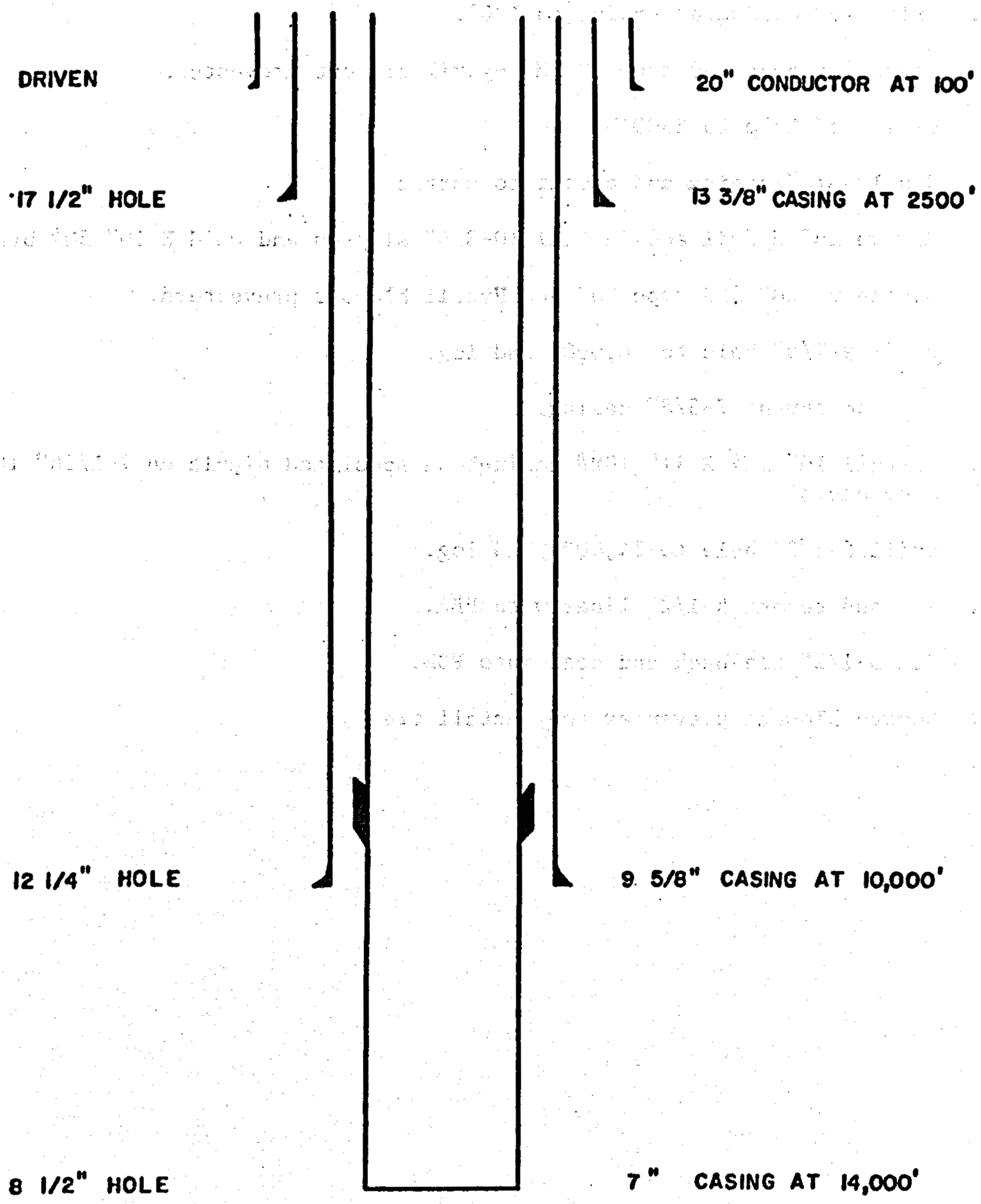
Well Name GEOTHERMAL WELL NO. 3

TANGIBLE COSTS:	Estimated Cost Dry Hole	Estimated Cost Completion
Conductor Casing 100 Ft. of 20 O.D. @ $____/Ft.	$ 3,000	$ --
Surface Casing 2500 Ft. of 13-3/8 O.D. @ $____/Ft.	48,000	--
Protection Casing 10,000 Ft. of 9-5/8 O.D. @ $____/Ft.	240,000	--
Production String 14,000 Ft. of 7 O.D. @ $____/Ft.	--	385,000
Tubing 14,000 Ft. of 5½ O.D. @ $____/Ft.	--	275,000
Well Head Assembly	20,000	120,000
Retrievable Packers, Liners, Special Hole Equipment	--	10,000
Surface Production Facilities:		
Tanks, Treater, Heater, Separator		
Flow Lines, Connections		
Related Contract Labor, etc.		
Total Tangible Costs	$ 311,000	$ 515,000
Total Tangible & Intangible	$ 1,149,000	$ 776,300
TOTAL WELL COST	$ 1,925,300	

Prepared By L.E. Thomas Approved By______
Date 12/22/75 Date______

Joint Owners	Approved	Date Approved
	By	
	By	
	By	
	By	

GEOTHERMAL WELL NO. 3
NUECES COUNTY, TEXAS



GEOTHERMAL WELL NO. 3, ALTERNATE I
NUECES COUNTY, TEXAS
PROPOSED TOTAL DEPTH - 14,000'

Preliminary Drilling Program:

1. Drive 16" conductor casing to 100'.
2. Install casinghead and 16" 3M# Hydril blowout preventer.
3. Drill 15" hole to 2500'.
4. Run 10-3/4" casing and cement to surface.
5. Remove 16" Hydril and install 10-3/4" slip-on and weld X 10" 5M# bradenhead.
6. Nipple up 10" 5M# type "U" and Hydril blowout preventers.
7. Drill 9-7/8" hole to 10,000' and log.
8. Run and cement 7-5/8" casing.
9. Install 10" 5M# X 11" 10M# casinghead spool and nipple up 7-1/16" 10M# blowout preventers.
10. Drill 6-1/2" hole to 14,000' and log.
11. Run and cement 5-1/2" liner with PBR.
12. Run 5-1/2" tie-back and seal into PBR.
13. Remove blowout preventer and install tree.

GEOTHERMAL WELL NO. 3 - ALTERNATE I - Page 2

Mud Program:

Depth	Weight	VIS	WL
0 - 2,500'	9.0	32-36	NC
2,500'-10,000'	9.0-12.0	36-44	10-6
10,000'-14,000'	12.0-16.3	44-48	6-4

Casing Design:

Surface Casing:
2,500' - 10-3/4", 40.5#/ft., K-55, ST&C

Production/Protection Casing:
2,000' - 7-5/8", 33.7#/ft., V-150, LT&C
2,900' - 7-5/8", 39.0#/ft., P-110, LT&C
2,500' - 7-5/8", 33.7#/ft., P-110, LT&C
2,300' - 7-5/8", 33.7#/ft., S-105, LT&C
300' - 7-5/8", 39.0#/ft., P-110, LT&C

Production Tubing:
10,000' - 5-1/2", 23#/ft., P-110, TC4S
4,000' - 5-1/2", 23#/ft., P-110, FJP

Cementing Program:

For Alternate I, the depth, temperature, amount of fillup desired and the mud weight will remain the same. Only the hole size, the pipe size and volumes of cement, and spacer will change:

	Hole Size (in)	Pipe Size (in)	Volume of Slurry Required Cu.Ft.	Sacks	Volume of Spacer Required
Surface Pipe	15	10-3/4	2238	1462	10 bbls. water
Production/Protection	9-7/8	7-5/8	1158	470 Sacks Lead Slurry; 189 Sacks Tail-in Slurry	1000 gals. CW7
Production String	6-1/2	5-1/2	313	205	8 bbls. spacer

Evaluation Program (To be run in open hole):

1. A complete suite of Coraband or Saraband logs should be run at the following depths: 10,000' and 14,000'.

2. Continuous mud log from 8,000' to T.D.

3. Conventional core prospective zones at discretion of wellsite geologist.

4. Sidewall core prospective zones at discretion of wellsite geologist.

GEOTHERMAL WELL NO. 3 - ALTERNATE I - Page 3

Completion Procedure:

1. Run a Gamma Ray - Cement Bond Log through prospective zones.
2. Squeeze cement, if necessary, according to results of bond log.
3. Drill out cement.
4. Perforate prospective zones.
5. Production test well.

DC-USABD-2

AFE NO.______

THE DOW CHEMICAL COMPANY
OIL AND GAS DIVISION
AUTHORITY FOR EXPENDITURE

Well Name GEOTHERMAL NO. 3 - ALTERNATE I Area or Field Wildcat

Location

Nueces County, Texas

Work To Be Performed Drill, Test and Complete

Proposed Depth 14,000' Objective Formation

INTANGIBLE COSTS:	Estimated Cost Dry Hole	Estimated Cost Completion
Stake Location	$ 500	$ --
Right of Way Cost and Surface Damage, Clean-up	20,000	--
Clear Right of Way, Construct Road and Location	50,000	--
Contract Drilling Cost -- Ft. @ $ -- Ft.	--	--
Rig Time - Daywork with Drill Pipe 45/18 days @ $ 4600 day	207,000	82,800
Rig Time - Daywork without Drill Pipe -- days @ $ -- day	--	--
Hauling or Boat Rental	11,500	3,500
Mud and Chemicals	100,000	10,000
Cement, Cementing and Tools	30,000	10,000
~~Acid, Service and Tools~~ Stimulation	--	50,000
Logging - Open Hole	65,000	--
Logging - Cased Hole	--	10,000
Perforating	--	10,000
Coring and Core Analysis	10,000	--
Mud Logging	21,000	--
Formation Testing - Open Hole and Casing	10,000	10,000
Floating Equipment, Centralizers, Scratchers	2,000	1,000
Bits, Permanent Packer and Rentals	95,000	34,000
Company Supervision and/or Consultant	21,000	7,000
Miscellaneous Services and Supplies, Bridge Plugs, Retainers, Fishing Tools, etc. Contingencies	96,500	33,000
Move-in, rig-up, rig down	50,000	--
Total Intangible Costs	$ 789,500	$ 261,300

DC-USABD-2

AFE NO.______

THE DOW CHEMICAL COMPANY
OIL AND GAS DIVISION
AUTHORITY FOR EXPENDITURE

Well Name GEOTHERMAL NO. 3 - ALTERNATE I

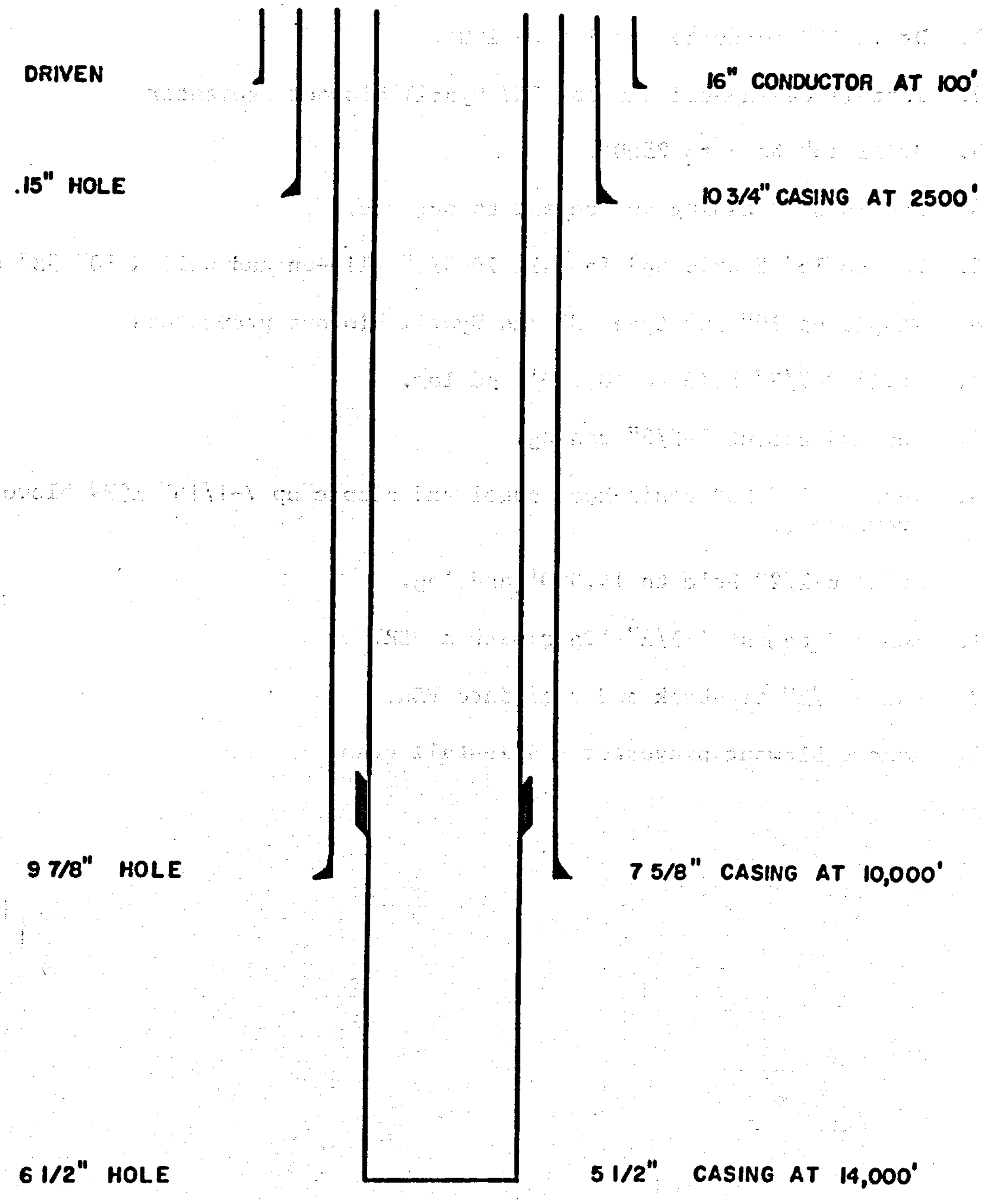
TANGIBLE COSTS:	Estimated Cost Dry Hole	Estimated Cost Completion
Conductor Casing 100 Ft. of 16 O.D. @ $______/Ft.	$ 2,500	$ --
Surface Casing 2,500 Ft. of 10-3/4 O.D. @ $______/Ft.	32,000	--
Protection Casing 10,000 Ft. of 7-5/8 O.D. @ $______/Ft.	223,000	--
Production String 14,000 Ft. of 5-1/2 O.D. @ $______/Ft.	--	275,000
Tubing ______ Ft. of ______ O.D. @ $______/Ft.	--	--
Well Head Assembly	20,000	120,000
Retrievable Packers, Liners, Special Hole Equipment	--	10,000
Surface Production Facilities:		
Tanks, Treater, Heater, Separator		
Flow Lines, Connections		
Related Contract Labor, etc.		
Total Tangible Costs	$ 277,500	$ 405,000
Total Tangible & Intangible	$ 1,067,000	$ 666,300
TOTAL WELL COST	$ 1,733,300	

Prepared By L. E. Thomas   Approved By ______

Date 12/22/75   Date ______

Joint Owners	Approved	Date Approved
______	By ______	______
______	By ______	______
______	By ______	______
______	By ______	______

GEOTHERMAL WELL NO. 3 - ALTERNATE I
NUECES COUNTY, TEXAS



GEOTHERMAL WELL NO. 3, ALTERNATE II
NUECES COUNTY, TEXAS
PROPOSED TOTAL DEPTH 14,000'

Preliminary Drilling Program:

1. Drive 16" conductor casing to 100'.
2. Install casinghead and 16" 3M# Hydril blowout preventer.
3. Drill 15" hole to 2500'.
4. Run 10-3/4" casing and cement to surface.
5. Remove 16" Hydril and install 10-3/4" slip-on and weld X 10" 5M# bradenhead.
6. Nipple up 10" 5M# type "U" and Hydril blowout preventers.
7. Drill 9-7/8" hole to 10,000' and log.
8. Run and cement 7-5/8" casing.
9. Install 10" 5M# casinghead spool and nipple up 7-1/16" 10M# blowout preventers.
10. Drill 6-1/2" hole to 14,000' and log.
11. Run and cement 4-1/2" liner with a PBR.
12. Run 4-1/2" tie-back and seal into PBR.
13. Remove blowout preventer and install tree.

GEOTHERMAL WELL NO. 3 - ALTERNATE II - Page 2

Mud Program:

Depth	Weight	VIS	WL
0 - 2,500'	9.0	32-36	NC
2,500'-10,000'	9.0-12.0	36-44	10-6
10,000'-14,000'	12.0-16.3	44-48	6-4

Casing Design:

Surface Casing:
2500' - 10-3/4", 40.5#/ft., K-55, ST&C

Production/Protection Casing:
2000' - 7-5/8", 33.7#/ft., V-150, LT&C
2900' - 7-5/8", 39.0#/ft., P-110, LT&C
2500' - 7-5/8", 33.7#/ft., P-110, LT&C
2300' - 7-5/8", 33.7#/ft., S-105, LT&C
300' - 7-5/8", 39.0#/ft., P-110, LT&C

Production Tubing:
10,000' - 4-1/2", 15.1#/ft., P-110, TC4S
4,000' - 4-1/2", 15.1#/ft., P-110, FJP

Cementing Program:

For Alternate II, the depth, temperature, amount of fillup desired and the mud weight will remain the same. Only the hole size, the pipe size and volumes of cement, and spacer will change.

	Hole Size (in)	Pipe Size (in)	Volume of Slurry Required Cu.Ft.	Sacks	Volume of Spacer Required
Surface Pipe	15"	10-3/4"	2238	1462	10 bbls. water
Production/Protection	9-7/8"	7-5/8"	1158	479 Sacks Lead Slurry; 189 Sacks Tail-in Slurry	1000 gals. CW7
Production String	6-1/2"	4-1/2"	576	376	8 bbls. spacer

Evaluation Program (To be run in open hole):

1. A complete suite of Coraband or Saraband logs should be run at the following depths: 10,000' and 14,000'.

2. Continuous mud log from 8,000' to T.D.

GEOTHERMAL WELL NO. 3 - ALTERNATE II - Page 3

3. Conventional core prospective zones at discretion of wellsite geologist.

4. Sidewall core prospective zones at discretion of wellsite geologist.

Completion Procedure:

1. Run a Gamma Ray - Cement Bond Log through prospective zones.

2. Squeeze cement, if necessary, according to results of bond log.

3. Drill out cement.

4. Perforate prospective zones.

5. Production test well.

DC-USABD-2

AFE NO.______

THE DOW CHEMICAL COMPANY
OIL AND GAS DIVISION
AUTHORITY FOR EXPENDITURE

Well Name Geothermal No. 3-Alternate II Area or Field Wildcat

Location

Nueces County, Texas

Work To Be Performed Drill, Test and Complete

Proposed Depth 14,000' Objective Formation

INTANGIBLE COSTS:	Estimated Cost Dry Hole	Estimated Cost Completion
Stake Location	$ 500	$ -
Right of Way Cost and Surface Damage, Clean-up	20,000	-
Clear Right of Way, Construct Road and Location	50,000	-
Contract Drilling Cost - Ft. @ $ - Ft.	-	-
Rig Time - Daywork with Drill Pipe 45/18 days @ $4600 day	207,000	82,800
Rig Time - Daywork without Drill Pipe - days @ $ - day	-	-
Hauling or Boat Rental	11,500	3,500
Mud and Chemicals	100,000	10,000
Cement, Cementing and Tools	30,000	10,000
~~Acid Service and Tools~~ Stimulation	-	50,000
Logging - Open Hole	65,000	-
Logging - Cased Hole	-	10,000
Perforating	-	10,000
Coring and Core Analysis	10,000	-
Mud Logging	21,000	-
Formation Testing - Open Hole and Casing	10,000	10,000
Floating Equipment, Centralizers, Scratchers	2,000	1,000
Bits, Permanent Packer and Rentals	95,000	34,000
Company Supervision and/or Consultant	21,000	7,000
Miscellaneous Services and Supplies, Bridge Plugs, Retainers, Fishing Tools, etc., Contingencies	96,500	33,000
Move-in, rig-up, rig-down	50,000	
Total Intangible Costs	$789,500	$261,300

DC-USABD-2

AFE NO.______

THE DOW CHEMICAL COMPANY
OIL AND GAS DIVISION
AUTHORITY FOR EXPENDITURE

Well Name Geothermal No. 3-Alternate II

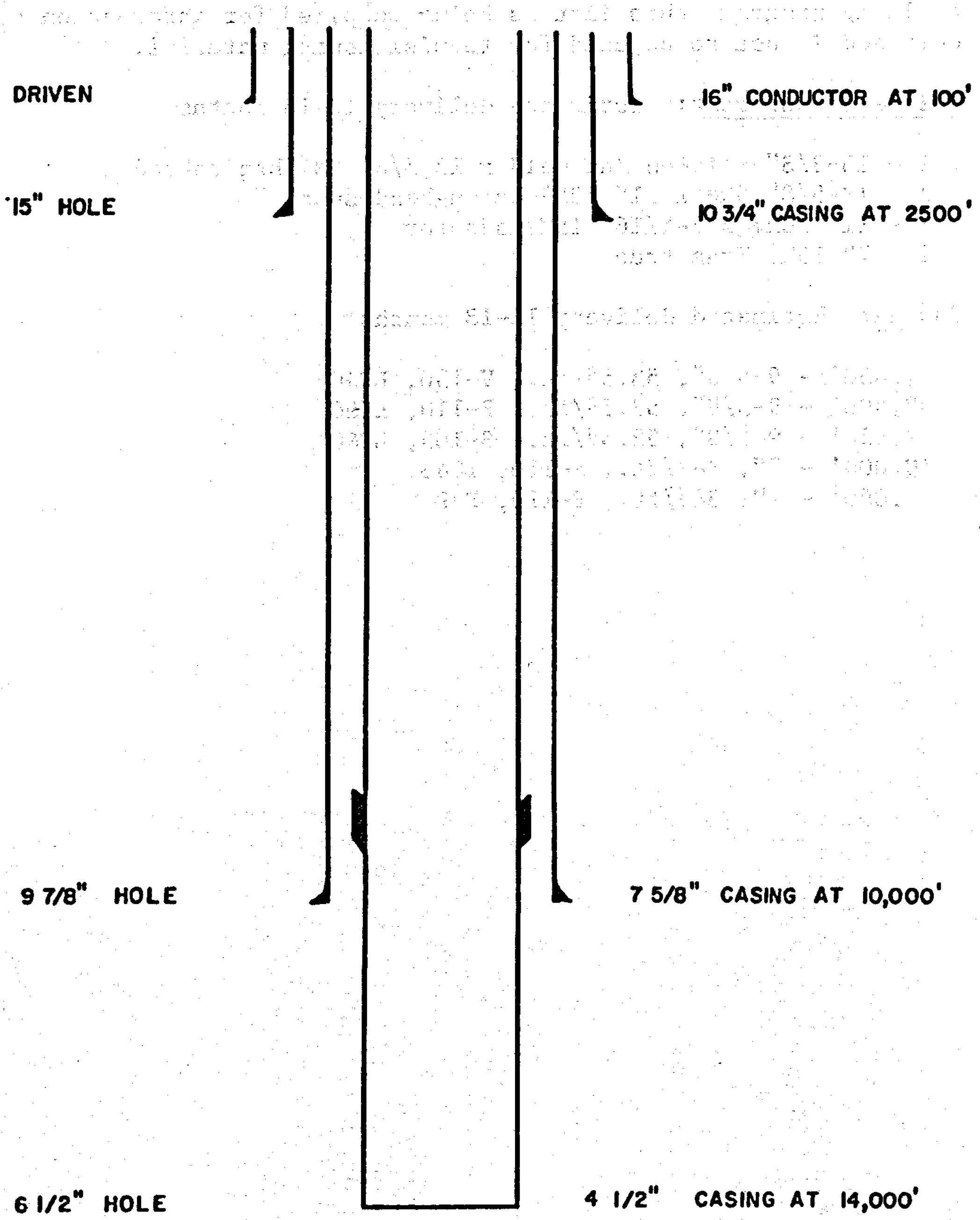
TANGIBLE COSTS:	Estimated Cost Dry Hole	Estimated Cost Completion
Conductor Casing 100 Ft. of 16" O.D. @ $____/Ft.	$ 2,500	$ -
Surface Casing 2500 Ft. of 10-3/4" O.D. @ $____/Ft.	32,000	-
Protection Casing 10,000 Ft. of 7-5/8" O.D. @ $____/Ft.	223,000	-
Production String 14,000 Ft. of 4-1/2" O.D. @ $____/Ft.	-	223,000
Tubing ____ Ft. of ____ O.D. @ $____/Ft.	-	-
Well Head Assembly	20,000	120,000
Retrievable Packers, Liners, Special Hole Equipment	-	10,000
Surface Production Facilities:		
Tanks, Treater, Heater, Separator		
Flow Lines, Connections		
Related Contract Labor, etc.		
Total Tangible Costs	$277,500	$353,000
Total Tangible & Intangible	$1,067,000	$614,300
TOTAL WELL COST	$1,681,300	

Prepared By J. E. Thomas Approved By______

Date 12/22/75 Date______

Joint Owners	Approved	Date Approved
	By	
	By	
	By	
	By	

GEOTHERMAL WELL NO. 3 - ALTERNATE II
NUECES COUNTY, TEXAS



GEOTHERMAL WELL NO. 3
MATERIAL LIST FOR LONG DELIVERY ITEMS

The following is a listing of material required for drilling this well that may have a long delivery time. Since this is only a preliminary drilling program, this list is being supplied for information purposes only and is not to be used for requisitioning material.

Wellhead Equipment: Estimated delivery 12-18 months

1 - 13-3/8" slip-on and weld x 13-5/8" 5M# bradenhead
1 - 13-5/8" 5M# x 11" 10M# casinghead spool
1 - 11" 10M# x 7-1/16" 15M# adaptor
1 - 7" 15M# Xmas tree

Casing: Estimated delivery 12-18 months

4,850' - 9-5/8", 53.5#/ft., V-150, LT&C
2,500' - 9-5/8", 53.5#/ft., P-110, LT&C
2,650' - 9-5/8", 53.5#/ft., S-105, LT&C
10,000' - 7", 38#/ft., P-110, TC4S
4,000' - 7", 38#/ft., P-110, FJP

GEOTHERMAL WELL NO. 3, ALTERNATE I
MATERIAL LIST FOR LONG DELIVERY ITEMS

The following is a listing of material required for drilling this well that may have a long delivery time. Since this is only a preliminary drilling program, this list is being supplied for information purposes only and is not to be used for requisitioning material.

Wellhead Equipment: Estimated delivery 12-18 months

1 - 10-3/4" slip-on and weld x 10" 5M# bradenhead
1 - 10" 5M# x 11" 10M# casinghead spool
1 - 11" 10M# x 7-1/16" 15M# adaptor
1 - 5-1/2" 15M# Xmas tree

Casing: Estimated delivery 12-18 months

2,000' - 7-5/8", 33.7#/ft., V-150, LT&C
2,900' - 7-5/8", 39.0#/ft., P-110, LT&C
2,500' - 7-5/8", 33.7#/ft., P-110, LT&C
2,300' - 7-5/8", 33.7#/ft., S-105, LT&C
300' - 7-5/8", 39.0#/ft., P-110, LT&C
10,000' - 5-1/2", 23#/ft., P-110, TC4S
4,000' - 5-1/2", 23#/ft., P-110, FJP

GEOTHERMAL WELL NO. 3, ALTERNATE II
MATERIAL LIST FOR LONG DELIVERY ITEMS

The following is a listing of material required for drilling this well that may have a long delivery time. Since this is only a preliminary drilling program, this list is being supplied for information purposes only and is not to be used for requisitioning material.

All long delivery items for this well will be the same as for Alternate I with the exception of the utilization of 4-1/2" casing in place of 5-1/2" casing. The 4-1/2" casng will be as follows:

10,000' - 4-1/2", 15.1#/ft., P-110, TC4S
4,000' - 4-1/2", 15.1#/ft., P-110, FJP

APPENDIX III

Temperature Distribution and Pressure Losses in a Geothermal Well

TEMPERATURE DISTRIBUTION AND PRESSURE LOSSES IN A GEOTHERMAL WELL

ABSTRACT

This study covers two basic problems; (1) temperature distribution; and (2) pressure drops in a geothermal well. Pressure drop calculations depend on the computed temperatures. The temperature computations were made by using Ramey's[1] technique. Pressure computations were made by following formulas given in Streeter[2]. At the end of these two steps the amount of natural gas released by hot water is computed. The theory is developed in the theory section. An example follows the theory. Finally, computer program is placed into the appendix.

INTRODUCTION

Several methods have been proposed to compute the temperature distribution in hot water injection well. Among them, for a single phase flow Ramey's analytical solution has found wide applications in the industry. His formula to compute the temperature distribution is easy to use. The other methods involve numerical solutions which are also applicable but which require more computer time and storage.

Although Ramey's solution has been developed for hot water injection wells, it can easily be modified for geothermal wells with some specified geothermal gradients.

The following assumptions were made:

1. Physical and thermal properties of earth and geothermal water do not vary with temperature
2. Heat will transfer radially in the earth and heat transfer in the wellbore is rapid compared to the heat flow in the formation, thus can be represented by steady state solutions
3. Flow is single phase

DEVELOPMENT OF EQUATIONS FOR TEMPERATURE

Let us consider the flow element taken from the well (fig. 1).

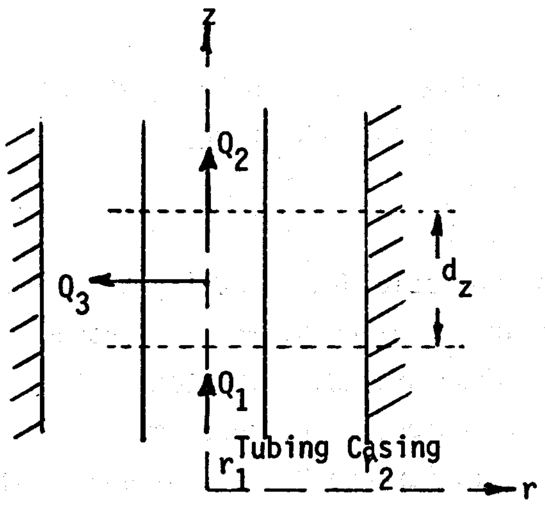


Figure. 1. Flow element.

Assuming no phase change an approximate energy balance over the differential element dz

$$Q_1 = Q_2 + Q_3 \tag{1}$$

let

$$dQ = Q_1 - Q_2$$

then

$$dQ = WC_w dT_i$$

and

$$Q_3 = 2\ r_1\ U(T_1 - T_2)dz \tag{2}$$

The rate of heat conduction from the casing to the surround formation is obtained by solving the diffusion equation assuming line source at the well. (Reader is referred to Carslaw and Jeager[2] for more details.)

According to Ramey, dQ is given by

$$dQ = \frac{2\pi k(T_2 - T_e)dz}{f(t)} \tag{3}$$

where f(t) is called "time function" and defined by the same author. T_e is the earth temperature. For times greater than seven days this function is closely approximated by the following formula.

$$f(t) = \ln \frac{2\ \alpha t}{r_2'} - 0.290 \tag{4}$$

where α is the thermal diffusivity of earth, t is the time and r_2' is the outside radius of the casing. For times less than seven days, there is a plot for f(t) function in the same reference and the reader is again referred to Carslaw and Jeager[2] for analytical forms. For geothermal reservoir, one may be interested in longer times, say, months or years. Therefore equation (4) is certainly applicable.

Removing T_2 from equations (3) and (1)

$$(T_1 - T_2)\ 2\pi r_1\ Ud_z = -wcdT_1\ (\frac{1}{u})\ \frac{1}{r_1}$$

$$(T_2 - T_e)\ 2\pi k\ \ d_z = -wcdT_1\ f(t)$$

$$T_1 - T_e = -wc\ \frac{k+r_1uf(t)}{r_1uK2\pi k}\ \ \frac{dT_1}{dz}$$

$$A(t)$$

$$\frac{\partial T_1}{\partial z} + \frac{T_1}{A(t)} - \frac{T_e}{A(t)} = 0 \qquad (5)$$

In equation (5) $T_1 = T_1\ (z,t)$ and it is an ordinary differential equation for any time t. The earth temperature is known by geological data, and it is computed from the geothermal gradient.

Equation (5) only requires one boundary condition, that is the temperature at the geothermal reservoir

$$T_1(0) = T_{bh} \qquad (6)$$

Usually the geothermal temperature gradients are as shown on fig. 12, Part I. On the same figure, the well completion is also drawn. As seen on this figure geothermal gradient is not a simple line; it is a broken line yielding two different gradients. This is typical for geothermal reservoirs.

Let G_1 be the geothermal gradient for the vertical distances z such that $0 < z < z_1$ and G_2 be the gradient for z such that $z_1 < z < L$, where L is the total depth of the well. Also notice that the origin of the coordinate system (r,z) is placed at the bottom of the well, i.e., the coordinate of the surface z = L, not z = 0.

Geothermal temperatures are defined as follows (t_e is the earth temperature):

$$T_e \begin{cases} = T_{bh} - G_{,}z,\ 0 < z < z_1 \\ = T_b - G_1 z_1 - G_2 z_2,\ z_1 < z < L \end{cases} \tag{7}$$

Integration of differential equation (5) between 0 and z_1 yields[1]:

$$T_1 e^{\frac{z}{A}} \quad \frac{(T_{bh} - G_1 z)}{A(t)} \quad e^{z/A}\, dz + B(t) \tag{8}$$

where B(t) is some time dependent constant.

Then:

$$T_1(z,t) = T_b - G_{,}z + G_1 A(t) - G_1 A(t) - G_1\ A(t) e^{-z/a(t)} \tag{9}$$

Equation (8) and (9) are used to compute the temperature distribution in the well.

PRESSURE DROP CALCULATIONS

Assuming flow is incompressible, first law of thermodynamics results in the following mechanical energy balance, between the two points in the pipe. Let us denote these two points by i and i+1, then

$$-\nu dp = \frac{g}{gc}\ dz + \frac{VdV}{\alpha gc} + \frac{4fV^2 dL}{2gcD} \tag{10}$$

Writing (10) for a pipe element as mentioned above and noting that $V_i = V_{i+1}$

$$P_i - P_{i+1} = \frac{g}{gc}\ (z_{i+1} - z_i)\ \rho + h_L \tag{11}$$

where $v = 1/\rho$ and $h_L = \frac{4fV^2dL}{2gcD}$ were used, h_L is called "head loss", f is the Moody's friction factor. Thus the first term in (11) denotes the static pressure drop and the second term is due to friction inside the pipe. Equation (11) gives the pressure drop at two selected levels of pipe, namely z_i and z_{i+1}.

It is also noticeable in equation (11) that this equation has some temperature dependent variables such as ρ and viscosity μ. Viscosity does not appear explicitly; however, it is necessary to compute f.

Also f, friction factor is obtained from Moody's diagram for a specified roughness. All these data are supplied to the computer program as will be explained in the application section.

A third stage is the computation of dissolved gas; it is also explained in the application.

APPLICATION

The data for a 15,000 ft geothermal well is given in fig. 2. Well design is shown on the same figure.

Temperature distribution was computed by equations (8) and (9) for one week intervals and later one month intervals. Temperatures were computed for the first five years of production. Temperature and pressure distribution in the well is shown on fig. 4 and 5 after a month of production.

It was assumed that

1. Temperature of the reservoir remained constant (300°F) over a five year period
2. Pressure of the reservoir was constant over the five year period (11,713 psi)
3. Production rate was constant.

The following emperical formulas were used for the viscosity and density of the water:

$$\rho = 61 - \frac{7}{200}\ (T-200)$$

$$\mu = 0.68 - \frac{0.36}{200}\ (T-200)$$

The friction factor was approximated by the Colebrook formula developed by Wood (see Streeter).

This formula is good for Reynolds numbers greater than 10,000 and 1×10^{-5} E/D 0.04- where E is the roughness of the inside pipe surface.

$$f = a + b\, R_e^{-C}$$

where

$$a = 0.094\, k^{0.225} + 0.53\, k$$
$$b = 88\, k^{0.44}$$
$$c = 1.61\, k^{0.134}$$

where

$$k = E/D$$

RESULTS

It was determined that most of the transient flow took place within a couple of days. A week after temperature changes were negligible (less than 0.01° F). The total temperature drop was about 5° F thus surface temperature was 295° F for the first week of production. At the end of five year period there was no significant changes found in the well head temperatures.

Well head pressures were computed as about 6475 psi. (See fig. 4 and 5.)

Assuming that water was saturated with methane, one can go to the chart (fig. 3) and find the methane to be released at well head pressure, which in this case about 38 sdf/bbl.

CONCLUSIONS

1. Ramey's method can be applied to obtain the temperature distribution in a geothermal well
2. In the green example, temperature drop was very small (about 5°F)
3. It appears that 38 scf/bbl methane can be produced if the water is saturated with methane

APPENDIX IV

Wireline Formation Testing

The following is a reprint of a paper describing the proposed Wireline-Formation-Tester techniques.

SOCIETY OF PETROLEUM ENGINEERS OF AIME
6200 North Central Expressway
Dallas, Texas 75206

PAPER NUMBER **SPE 5035**

THIS IS A PREPRINT — SUBJECT TO CORRECTION

ADVANCEMENTS IN UNCASED-HOLE WIRELINE-FORMATION-TESTER TECHNIQUES

By

A. L. Schultz, W. T. Bell, and H. J. Urbanosky
Members SPE-AIME, Schlumberger Well Services, Houston, Texas

This paper was prepared for the 49th Annual Fall Meeting of the Society of Petroleum Engineers of AIME, to be held in Houston, Texas, Oct. 6-9, 1974. Permission to copy is restricted to an abstract of not more than 300 words. Illustrations may not be copied. The abstract should contain conspicuous acknowledgment of where and by whom the paper is presented. Publication elsewhere after publication in the JOURNAL OF PETROLEUM TECHNOLOGY or the SOCIETY OF PETROLEUM ENGINEERS JOURNAL is usually granted upon request to the Editor of the appropriate journal provided agreement to give proper credit is made.

Discussion of this paper is invited. Three copies of any discussion should be sent to the Society of Petroleum Engineers office. Such discussions may be presented at the above meeting and, with the paper, may be considered for publication in one of the two SPE magazines.

ABSTRACT

The wireline formation tester, introduced some years ago, serves to provide confirmation of formation-fluid type and indications of producibility and formation pressure.

The technique, as originally introduced, has not entirely satisfied all industry-performance requirements for the following reasons:

- *the success ratio was lower than desired, about 70 percent overall. This figure resulted from tests that were unsuccessful because they were made opposite tight streaks in the formation or because seal was lost due to bore-hole rugosity, and from the difficulty of testing unconsolidated sands.*
- *additional rig time was required for multiple-zone sampling or pressure measurements because only a single test or test attempt could be made per trip in the well.*
- *sampling time in formations of low porosity and permeability was often long because of the inability to re-position the tool to place it opposite the more permeable zones in the formation.*
- *the accuracy of the pressure measurements was not as good as desired.*

Recently, substantial improvements in technique have been effected through the development of a tester with a multiple-set capability. The new Repeat Formation Tester can be set any number of times in the well; this permits the operating engineer to "pre-test" or "probe" the formation for the more permeable zones and to check for adequate seal before attempting a fluid sample.

Other improvements include the ability, while in the well, to record any number of pressure measurements rapidly, and with greater accuracy than with previously existing equipment. Two fluid samples can be recovered on one trip in the well. Sampling can now be done in both consolidated and unconsolidated formations. Provisions are included to help eliminate tool sticking.

Field results on 600 zones with the new tester indicate a success ratio of better than 90 percent in the Gulf Coast. Rig time is substantially reduced.

SPE 5035

ADVANCEMENTS IN UNCASED-HOLE WIRELINE-FORMATION-TESTER TECHNIQUES

By

A. L. Schultz, W. T. Bell, and H. J. Urbanosky

INTRODUCTION

The wireline-formation-tester (FT*) technique was introduced to provide confirmation of formation-fluid type, indications of productivity, and formation pressures.[1] Various improvements have been made over the years, and interpretation methods have been developed for best utilization of the information from the recovered fluid samples and the pressure recordings.[2]

While the technique has been locally successful, it has not realized its full potential, basically due to the long rig time required with prior existing testers for multiple-zone testing. Once the tester was set in the well, it could not be repositioned at another level in the zone of interest. Consequently, any test failure, due to a tool setting in an impervious streak, or due to a packer-seal failure, resulted in an extra trip in the well.

Performance in many unconsolidated sands was not acceptable with these older tools. Techniques to combat the flow of sand into the tester were never completely successful; this caused undermining of the packer seal, with subsequent mud-sample recovery. These factors combined to produce an overall success ratio of about 70 percent for all formations, and roughly half that for unconsolidated sands.

Also, tool redressing required between runs was extensive. This added to the overall operating time unless additional tools were available at the well.

Another limitation of existing FT tools was the insufficient accuracy of the recorded pressures (in the range of ± 2 to 3 percent). This, combined with the single-test-per-trip capability, often discouraged the use of these tools for recording several pressure measurements in a well.

In summary, major limitations of these older tools were their inability to be repositioned after having once been set, their single-test capacity, and the lack of a reliable means for testing the integrity of the seal before attempting a sample.

To overcome the above shortcomings, a new formation tester has been developed.

*Trademark of Schlumberger.

PRINCIPAL FEATURES OF THE NEW TESTER

The new tester has several distinguishing features as compared with the prior tools. Several successful tool settings are possible without bringing the equipment out of the hole. Combined with this is a "pretest" capability which permits the operating engineer to ascertain, in advance of attempting to take a sample, whether the packer is sealing properly and, if so, whether fluid flow is adequate to obtain a sample in a reasonable period of time.

Thus, if the tool is set and the packer seal fails, or if the indications are that the tool is set in an impervious streak, the tool is simply retracted and moved to another position in the formation of interest. On the other hand, if both seal and flow indications on "pretest" are satisfactory, a sample is taken.

Two separate sample chambers make it possible to obtain two separate samples on a single trip into the well. This further reduces testing time. The samples may be from different depths, or they may be from a single test at a given depth, in which the fluid produced last is put in a separate chamber, and thus is segregated from that produced first.

The new tester also provides for sampling in both consolidated and unconsolidated formations.

Pressure-recording accuracy has been improved to ± 1 percent or better. With special calibration of the equipment, an accuracy of about ± 0.18 percent can be obtained. The multiple-set and pretest features permit any number of pressure tests to be made on a single trip in the well.

Finally, upon return to the surface, very little redressing of the tool is required. Once the chambers are emptied of their recovered fluids, the tool may be lowered again for additional tests.

TOOL DESCRIPTION

The general configuration of the new Repeat Formation Tester (RFT*) tool is similar to that of prior equipment. It consists of control panels in the truck, a down-

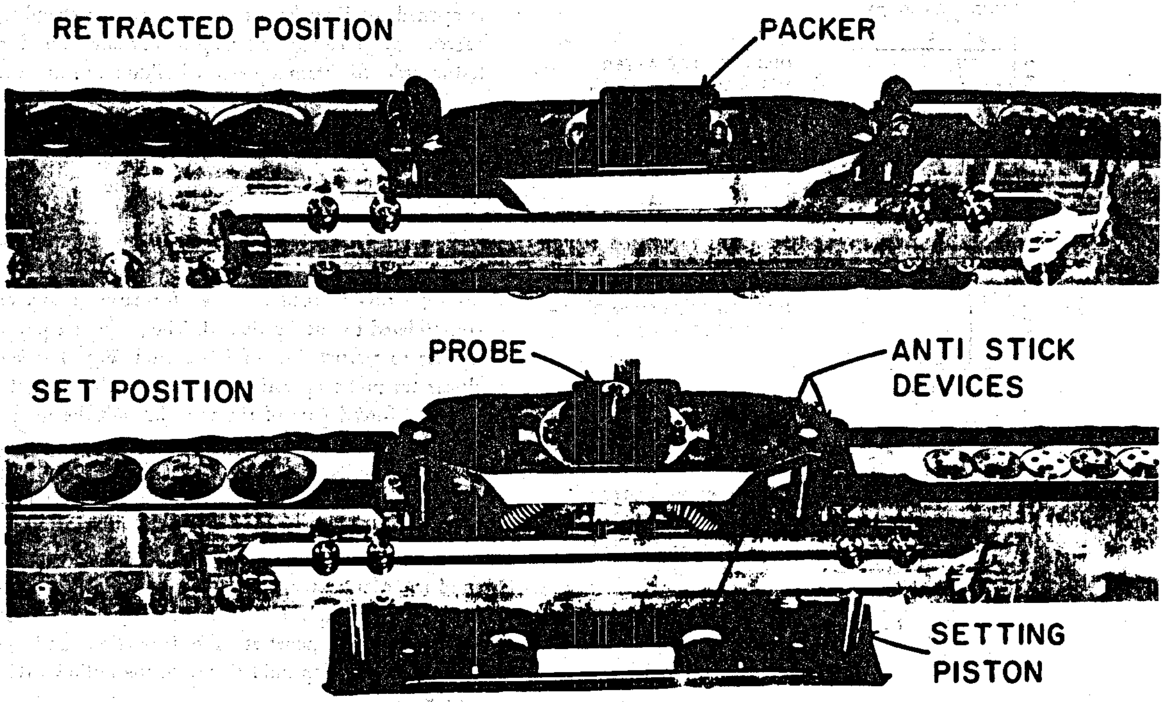


Fig. 1 — (Above) Setting section of the Repeat Formation Tester mechanical unit.

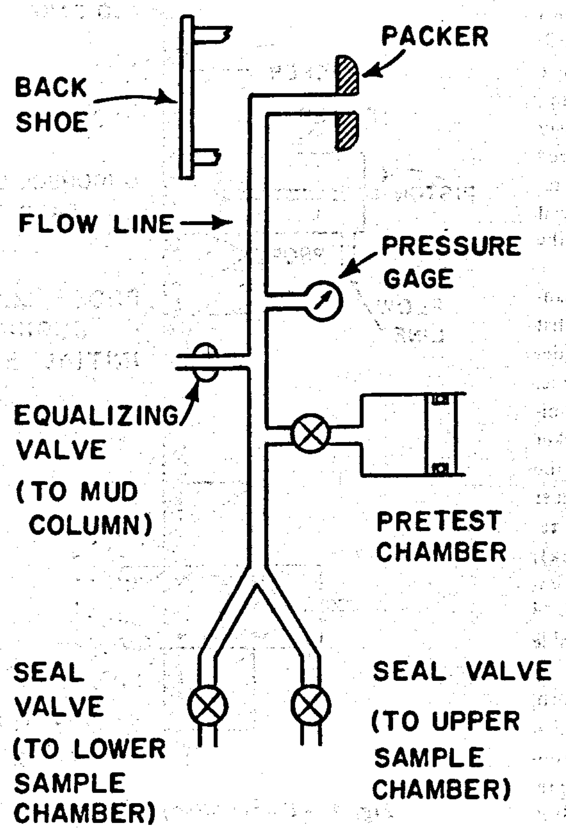


Fig. 2 — Functional schematic of Repeat Formation Tester sampling system.

Table I
RFT SPECIFICATIONS

Pressure Rating	20,000 psi		
Temperature Rating	350°F		
Minimum Hole Size	6 in.		
Maximum Hole Size	14¾ in.		
Basic Make-up Length (excluding options)	33 ft		
Average Tool-Setting and -Retracting Times	0.6 min each		
Formation Type	Hard or Soft		
Average Sampling Rate — No water cushion, High-permeability formation	1 gal/min		
Formation-Pressure Readings per trip in hole	Any Number		
Sample-Chamber Sizes	1, 2¾, 6, and 12 gal		
Strain Gage Transducer Pressure-Measuring Specifications:	*Accuracy	Resolution	Repeatability
Room-Temperature Calibration	0.73%	1.0 psi	0.05%
Well-Temperature Calibration	0.18%	1.0 psi	0.05%

*Based on full-scale reading, 10,000 psi gage.

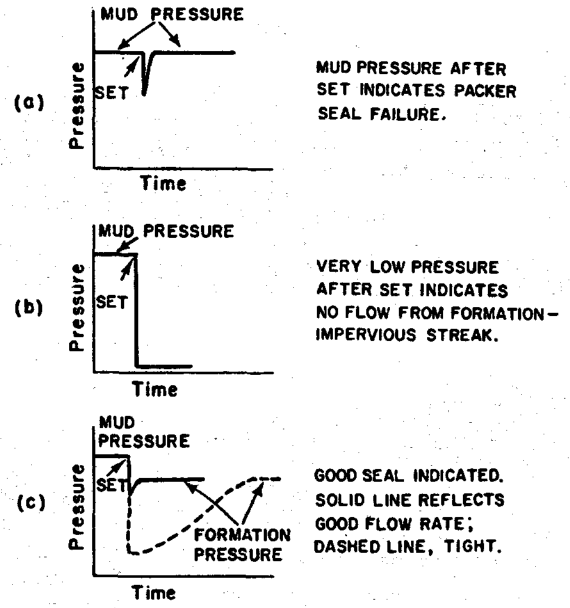


Fig. 3 — Pretest indications.

hole electronic cartridge, a mechanical unit, and sample chambers. General specifications are outlined in Table I.

The setting section of the mechanical unit is shown in Fig. 1. The packer assembly and backup shoes are shown in the extended (or set) and retracted (or running) positions. The small-area wall-contact points serve to minimize differential-pressure sticking which has troubled existing techniques. Actuation is by means of a hydraulic power system in the mechanical unit, which may be energized on command from the surface to control setting and retracting of the packer assembly and backup shoe, as well as all valving functions. This feature helps to provide the multiple-set provision.

The "pretest" function, incorporated in the mechanical unit, permits the operating engineer to ascertain that the packer is sealing properly and that the fluid flow is adequate to obtain a sample in a reasonable period of time. As shown schematically in Fig. 2, a small pretest chamber, with a 15-cc volume, is located between the packer and the valves leading to the sample chambers. When the packer is set, the equalizing valve closes and the chamber is opened, resulting in one of three possible pressure responses: indication of mud pressure if seal is lost (Fig. 3a), a very low pressure if the packer is seated on an impervious streak (Fig. 3b), or a pressure decrease followed by a buildup to formation pressure if in a permeable zone (Fig. 3c).

Since the volume of the pretest chamber is known, the rate of fill-up provides an indication of the time that would be required to fill one of the larger sample chambers located below the seal valves on Fig. 2. If all "pretest" indications are satisfactory, one of the seal valves is opened to allow fluid to enter a sample chamber. These valves may be closed and reopened at any time during the test in order to obtain a pressure-buildup measurement.

On the other hand, if the pretest indications are negative, the tool is simply retracted. In this event, the pretest chamber is automatically emptied, and the equalizing valve is automatically opened as the tester is retracted for the next attempt.

A special probe, which can be seen protruding from the center of the packer in Fig. 1, provides more efficient testing across a broad range of formation characteristics—consolidated to unconsolidated. The probe is equipped with a filter to restrict flow of loose sand. Fig. 4 schematically illustrates probe operation. On setting the tool, the closed probe is forced part of the way through the mud cake. A piston is then retracted exposing the tubular filter to the formation fluids. If the formation is unconsolidated, sand flows into the probe where its further movement is restrained by the filter. Concurrently, the probe moves into the formation to occupy the void produced by the flowing sand in order to avoid undermining of the packer seal and subsequent failure. If the formation is consolidated, the probe does not penetrate the formation, and only mud cake and formation fluid flow into the hollow cavity of the probe.

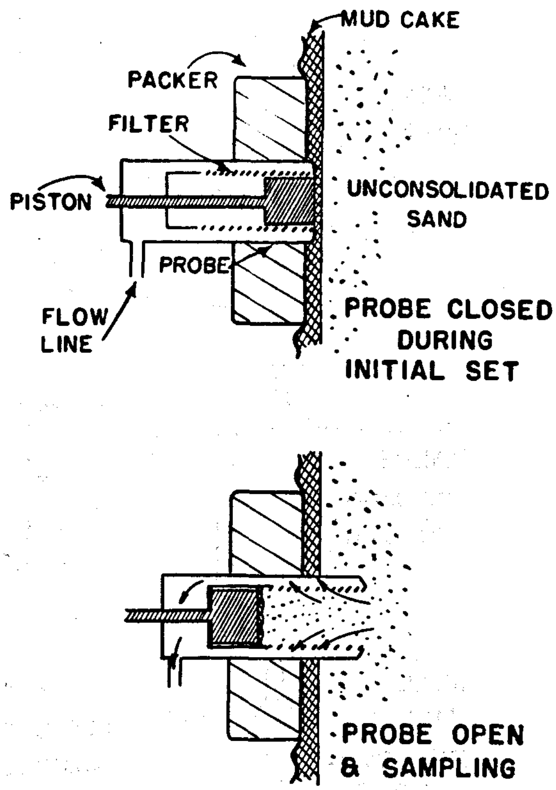


Fig. 4 — Packer filter-probe assembly.

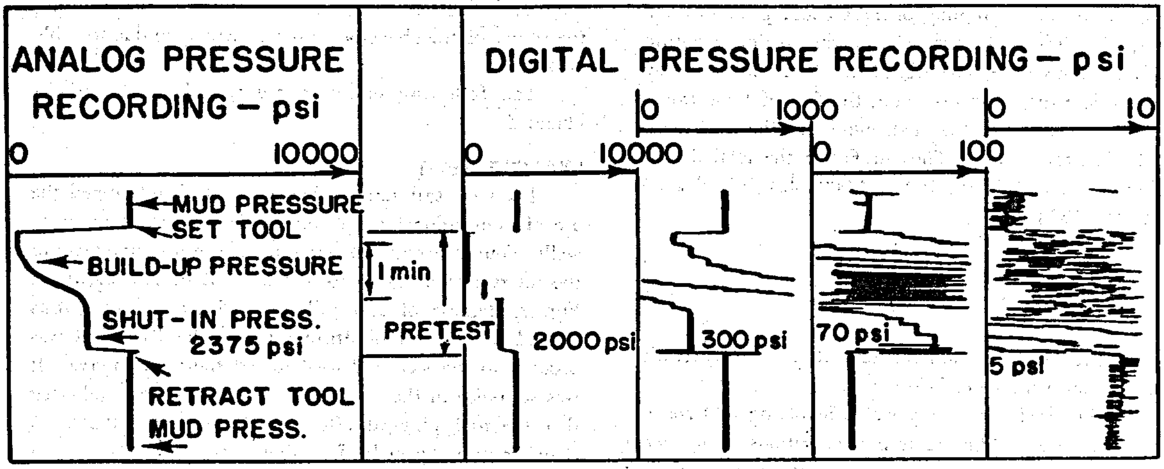


Fig. 5 — Recording of a pressure test only. Sample chamber is not opened.

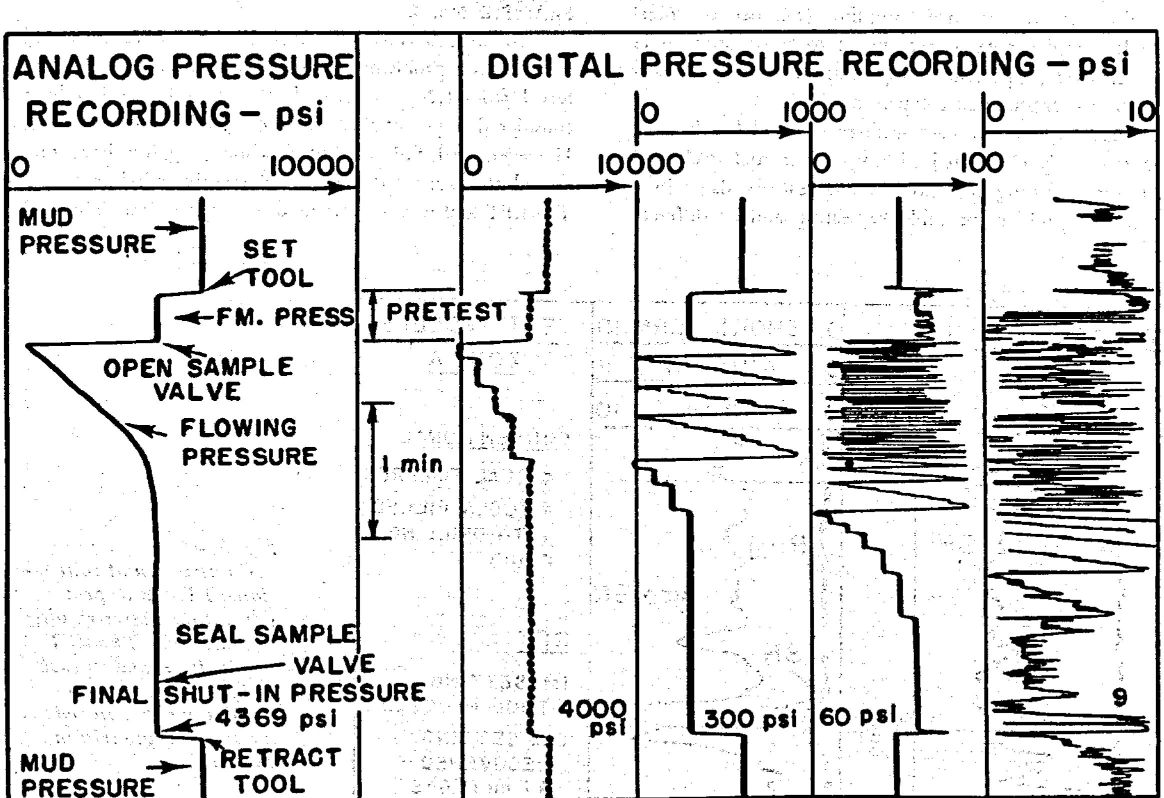


Fig. 6 — Recording of a sample test.

When the tool is retracted, the piston within the probe moves back into closed position in preparation for another test, wiping the filter clean in the process. Cleaning the filter is an important part of the multiple-set operation.

A strain-gage transducer is used to achieve pressure measurements of excellent accuracy, high resolution, and good repeatability, (See Table I.) Direct digital pressure read-out is provided on the control panel in the truck, with simultaneous analog and digital curve recordings on film.

A typical recording of a pressure test only is shown in Fig. 5, and of a sampling operation in Fig. 6. In these figures, the left-hand track shows the analog pressure recording versus time. The right-hand four tracks display the equivalent digital information; the first of these tracks gives thousands of psi, the next, hundreds, the next, tens, and the last track, units. Thus in Fig. 6 the total digital reading at the end of the test is 4,000 plus 300 plus 60 plus 9, or 4,369 psi.

FIELD RESULTS

The Repeat Formation Tester technique is currently being evaluated in the Gulf Coast area.

One hundred and eighty wells, involving 600 zones, have been tested. Fluid-sampling operations were performed on half the zones and pressure tests only on the remainder. An average of over ten set/retract operations were performed on each well.

The success ratio for sampling (number of interpretable samples obtained compared to those attempted) has been over 90 percent. For pressure tests only, the success ratio has approached 100 percent.

The small wall-contact surfaces featured by the tool have essentially eliminated sticking of the tool itself and the resultant fishing operations. These features also relieve the general problem of cable keyseating and/or differential-pressure sticking by minimizing the pull necessary on the tool during retraction. Ten fishing jobs occurred during the course of the above operations; these were due to cable keyseating.

The following examples are typical of the results obtained.

EXAMPLE No. 1

Excessive seal failures have severely handicapped the use of conventional formation-testing equipment in many wells. Four conventional wireline tests were attempted in the interval from 4,496 to 4,502 ft (Zone A) shown in Fig. 7. Because of seal failures, each of the four tests yielded a tool full of drilling mud. The RFT tool was brought to the well and used to test the same interval. It was set twice in the same zone. The first setting indicated that the tool plugged after the 2¾-gallon (10,250-cc) chamber was opened. The tool was retracted and set again. This time, 8.1 cu ft of gas, 2,000 cc of oil and 5,000 cc of oil-cut mud were recovered.

EXAMPLE No. 2

Shallow, unconsolidated shaly sands have presented many testing problems in Gulf Coast formations. The interval from 1,248 to 1,267 ft shown in Fig. 8 has been considered a potential shallow gas pay for several years. However, seal failures and flowline plugging have prevented this zone from being successfully wireline tested. The RFT tool was recently used to test this zone. Three at-

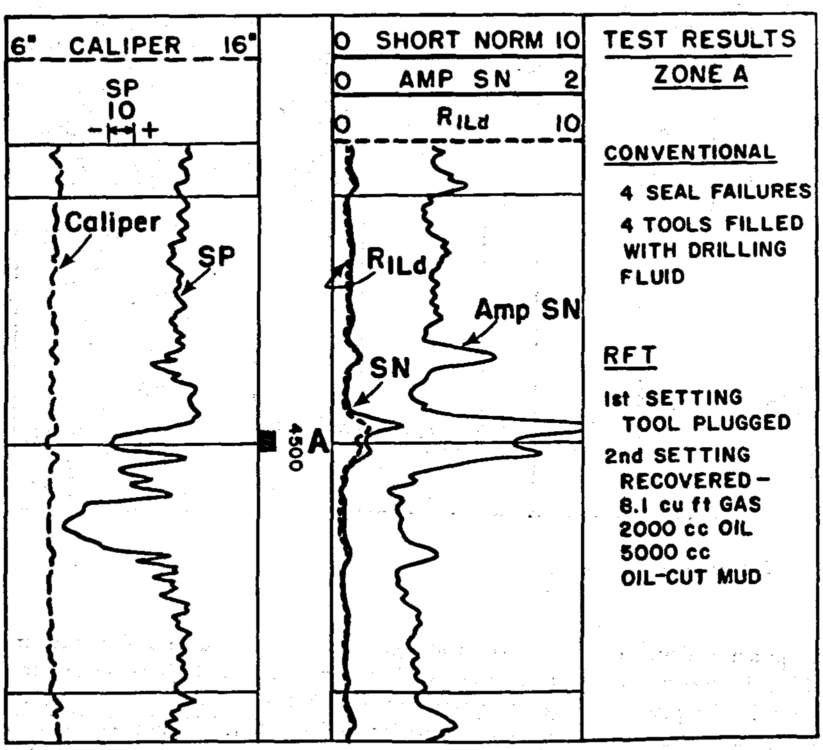


Fig. 7 — Comparison of conventional FT and Repeat Formation Tester results in same zone. The RFT results here, and in each of the subsequent examples, were achieved during a single trip in the hole.

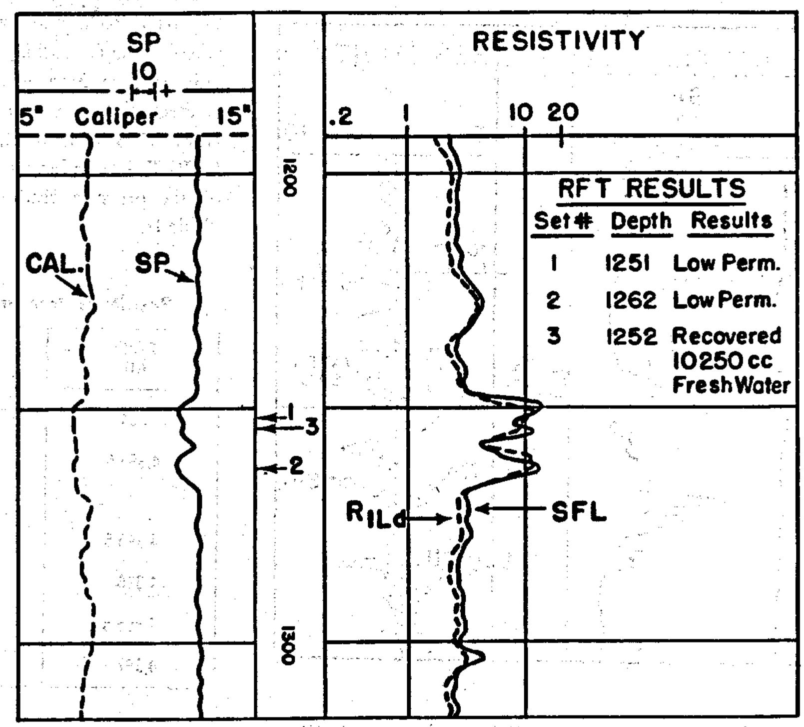


Fig. 8 — RFT results in shallow, unconsolidated sand.

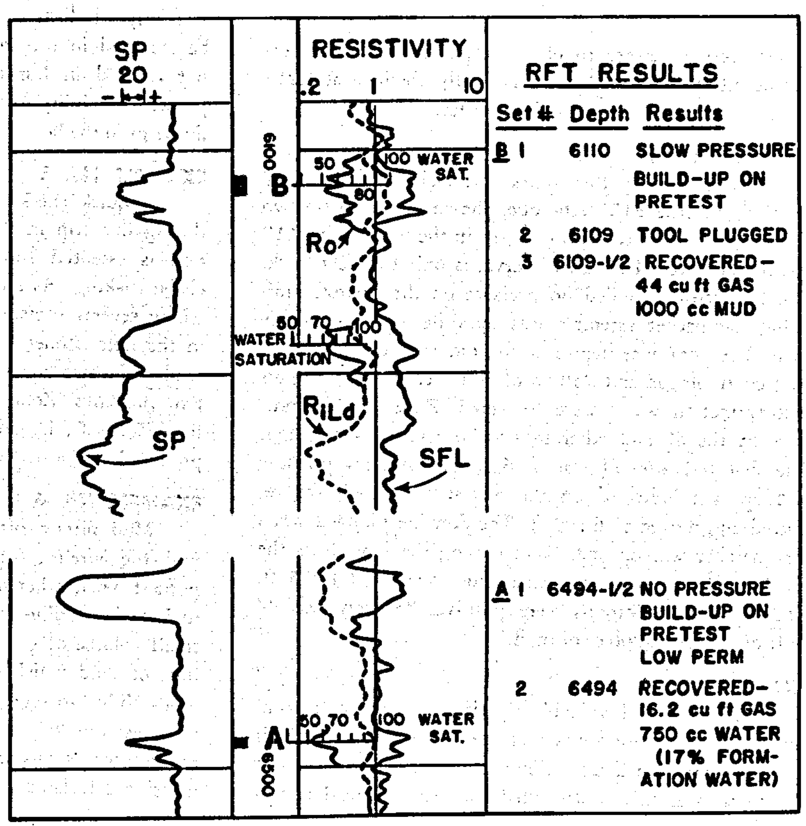


Fig. 9 — Example of RFT use for multiple tests in thin, shaly sands.

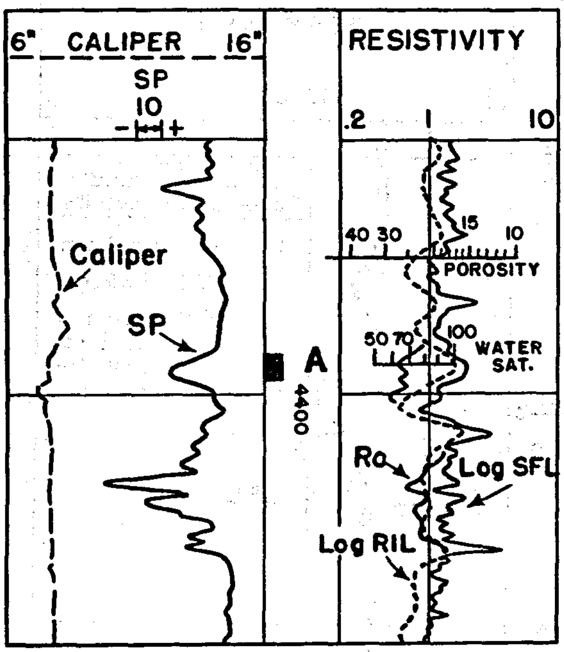


Fig. 10 — Example of multiple settings in an interval of low natural permeability.

tempts were necessary to obtain a packer seal in a permeable interval. A good test was finally obtained at 1,252 ft. Recovery was 10,250 cc of fresh water.

EXAMPLE No. 3

Testing in very thin zones and shaly sands is easily handled with the RFT technique. Shown in Fig. 9 are two zones that were tested with one trip in the well. Zone "A" was tested at 6,494 ft. This interval is only two feet thick. The first setting yielded no pressure on the pretest, indicating the packer assembly was opposite an impermeable zone. The tool was repositioned. On the second setting 16.2 cu ft of gas and 750 cc of water containing 17-percent formation water were recovered. Zone "B" is indicated by the SP and other logs to be a rather shaly sand. The first test attempt was at 6,110 ft. A slow pressure buildup was indicated on the pretest. The tool was retracted and moved to 6,109 ft. The flowline plugged when the chamber was opened. Since closing the tool clears the flowline, the tool was retracted and moved to 6,109.5 ft, where pretest indications were positive. Recovery was 44 cu ft of gas and 1,000 cc of mud.

EXAMPLE No. 4

Many hours of valuable rig time are frequently consumed trying to test zones that are impermeable and will not yield fluid on a test. When a sustained effort to test a zone such as this is attempted with conventional equipment, many trips in and out of a well are necessary. With the RFT technique, sufficient pressure readings can be taken in the formation, during one trip in the well, to provide an indication as to whether its natural permeability is adequate for commercial production. In Fig. 10, Zone A, from 4,393 to 4,398 ft, is an interval which was indicated by RFT tests to have low natural permeability. The results of six pressure readings in the interval are shown in Table II.

Table II

Results of Pressure Readings in Well of Fig. 10

Depth (ft)	Pressure (psi)	Buildup Time (minutes)
4,394	252	3
4,394.5	2,440 (hydrostatic pressure)	immediate (seal loss)
4,395.5	2,050	5
4,396	83	3
4,396.5	374	3
4,397	1,350	4

The very slow rate of pressure buildup in the flowline volume is an indication that this formation is not commercially productive. Commercial production should not be expected in this zone because formation pressure was not reached in less than 30 seconds during the pretest phase. The ability to take multiple-pressure readings saved five trips in the hole.

EXAMPLE No. 5

A quick check of formation pressures can be made during one trip in the hole in areas where this information is essential for good reservoir evaluation and decision making. As an example, Fig. 11 shows an interval where several pressure tests were taken on the same trip in the hole. Zones F and G are known pressure-depleted sands. The two zones were tested in order to measure current pressures. Zone B shows a somewhat lower pressure than Zones C, D, and E; this was because it was being produced in a nearby well.

EXAMPLE No. 6

Mud filtrate often masks the results of tests taken with the wireline formation tester. This can be quite important when other means of evaluation indicate the zone to be a borderline case and the wireline tester recovers a small volume of gas and/or a trace of oil and a large volume of fluid which appears to be mud filtrate. The RFT tool's ability to segregate the fluids recovered near the end of a test can help solve this problem in areas where test results such as this are common, or where the diameter of invasion calculated from logs indicates that deep invasion

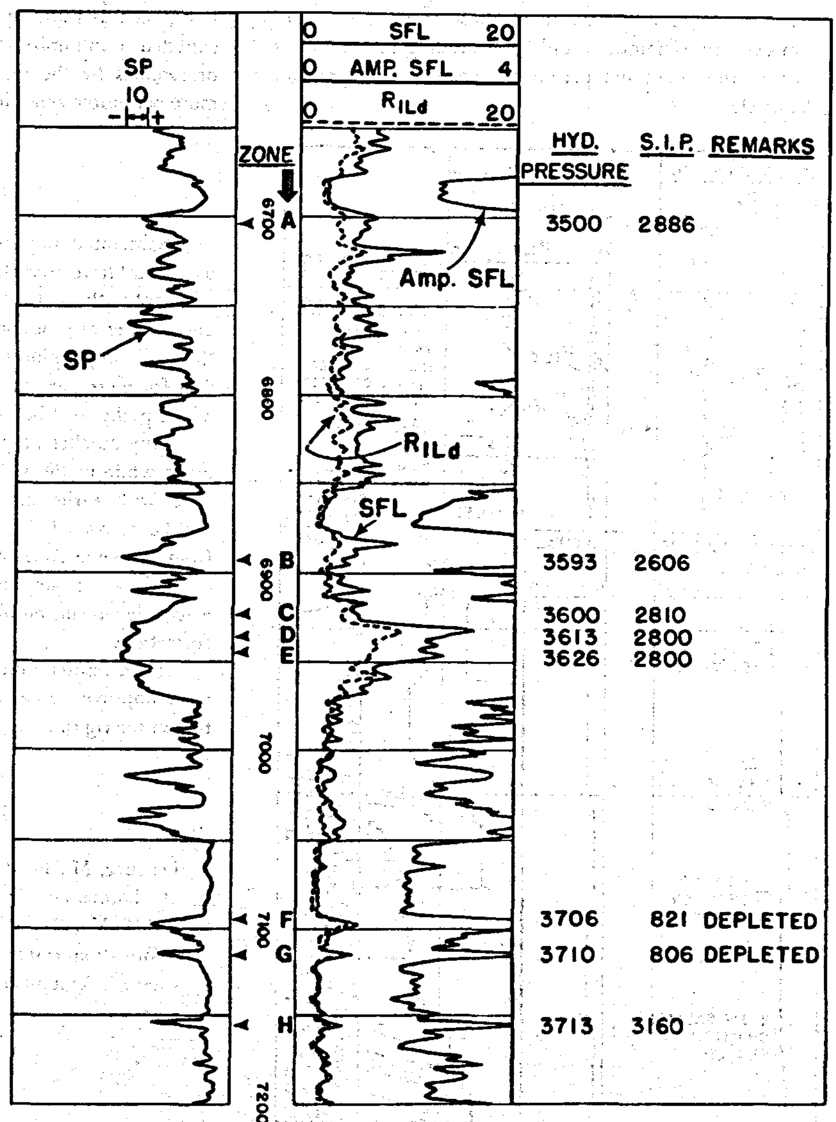


Fig. 11 — Example of a series of pressure tests.

may be a problem. Zone A in Fig. 12 was tested at 5,441 ft and the last gallon of the fluids recovered by the tool was segregated. The decision to segregate was based upon previous testing experience in this area. After setting the tool, the 2¾-gallon chamber was allowed to fill, and after 7 minutes it was sealed. The one-gallon chamber was then opened for three minutes after which it was sealed and the tool was retracted and brought to the surface. Recovered in the 2¾-gallon chamber were 1.8 cu ft of gas, a trace of oil, and 10,000 cc of water the resistivity of which measured 2.06 ohm-m at 75°F. The filtrate, at the time of logging, measured 1.59 ohm-m at 75°F. From this sample, one might conclude that this zone will probably make gas and some oil, since there is no evidence that formation water was produced in the test. This conclusion would be reinforced by the fact that this well is running high compared to another one that had a good show in the equivalent geologic interval. However, the recovery from the one-gallon chamber changes this picture drastically. Recovery for this chamber was 0.8 cu ft of gas, a trace of oil, and 2,300 cc of water the resistivity of which measured 0.147 at 75° (as compared with 2.06 ohm-m at 75°F for the water sample in the 2¾-gallon chamber). This resistivity corresponds to over 90-percent formation water. Therefore, the final result of the test indicates that water production can be expected from this zone.

The above results illustrate the importance of the multiple-set and pretest features for achieving high success ratios with minimum rig time. Indeed, experience with the RFT tester suggests that without those features test data from existing techniques could be misleading in some cases —where time does not permit the zone to be "probed" adequately.

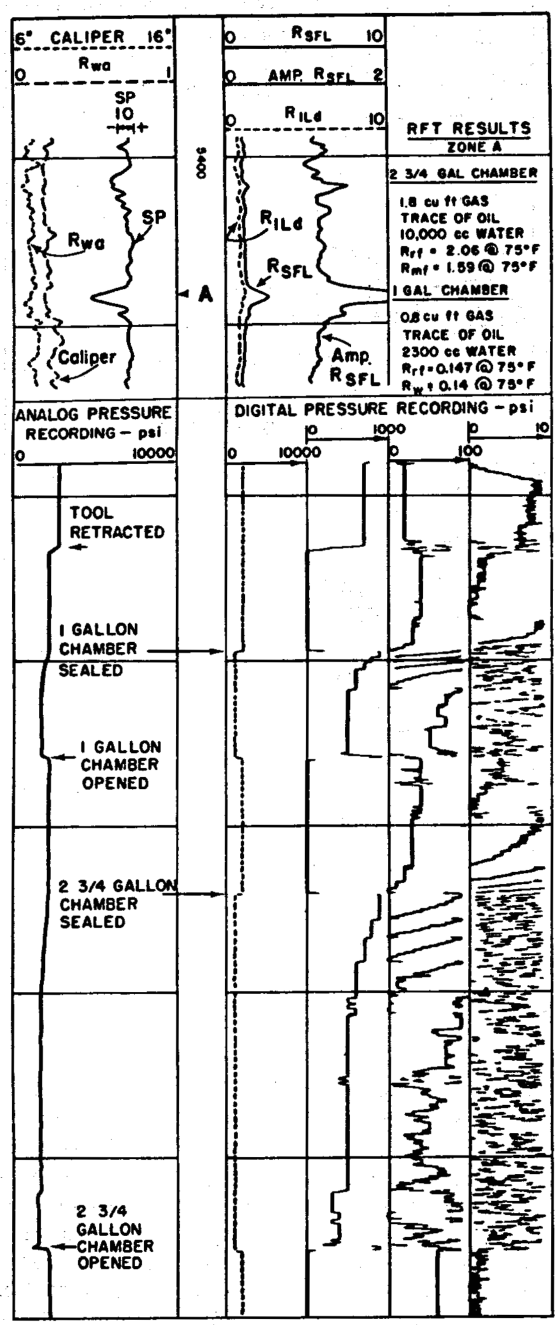


Fig. 12 — Example where, by use of the Repeat Formation Tester, segregation of the fluid produced last from that produced first clarified the interpretation of the zone.

While no results are yet available from tighter formations, such as those in the Mid-Continent, the new tool is expected to minimize test time and improve interpretability of samples by the capability it provides to seek out the more permeable zones in the formation.

SUMMARY

Substantial improvements in wireline-formation-tester techniques have recently been effected through development of a tool with multiple-set capability. The device can be set any number of times on a single trip in the well, permitting the operating engineer to "pretest" or "probe" the formation for more permeable regions and to check the integrity of the packer seal before taking a fluid sample.

Any number of pressure measurements can be rapidly made while in the well with greater accuracy than is possible with earlier-model equipment. Two fluid samples can be recovered. Two segregated samples can be taken from the same zone. Numerous pressure-buildup tests can be made while sampling. Sampling can now be done more efficiently in unconsolidated as well as in consolidated formations.

Field results indicate success ratios of over 90 percent, with improved zone interpretation and significant reduction in the rig time required for the testing.

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APPENDIX V

PROGRAM OUTLINE AND COST ESTIMATE OF ROCK MECHANICS AND FLOW PROPERTY STUDIES

An outline of the recommended direction for the rock mechanics research effort has been given in the main body of the report. In this Appendix more detailed recommendations for the research content are given and used as a guide for estimations of organization, scheduling and budgeting.

1. Research Objectives

The overall objective of the research program is to develop the ability to predict the behavior of a geopressured reservoir during fluid withdrawal and reintroduction, as a means of determining stability of the overburden and surface during operation. While a research program in this area will be particularly related to the behavior of the reservoirs of the Texas Gulf Coast, many of the techniques and abilities developed will be applicable to other regions, given the necessary rock properties.

A comprehensive research program would consider three major areas:

1. The development of computer programs simulating the mechanical effects of fluid withdrawal and introduction.

2. The investigation in the laboratory of the mechanical and thermal properties of a typical reservoir rock and overburden, to allow formulation of a suitable constitutive relationship for the various materials, and to give numerical data for the relevant mechanical and thermal parameters. In addition data on heat diffusivities and conductivities necessary for other areas of investigation may be obtained as part of the rock mechanics program for little extra effort or expense.

3. The verification in the laboratory and in the field of the mechanical behavior simulator.

These three areas of reasearch are interelated and a continuous interfacing between them will be necessary. Thus the simulator development will depend upon the constitutive relationships developed from laboratory testing, while the simulator verification may well lead to modification of the simulator and will depend upon laboratory data both for running the simulator and for applying the verification.

2. The Development of the Mechanical Simulator

Any change in pore pressure within the reservoir will cause an equivalent change in the effective stress field operating on this rock. It has been seen that although the change in stress at any point will be hydrostatic, it will be non-uniform over the reservoir. This lack of uniform stress change will lead to non-uniform deformation and to conditions of shear. Two quantities require prediction, firstly the reservoir deformation and secondly the change in porosity, both being required as functions of space and time. Futhermore, compaction of the reservoir rock will induce, in general, a change in permeability. This may be calculated either by the use of existing theories, or from empirical laboratory data. Allowance must be made also for the effects of non-uniform temperature fields within the reservoir and surrounding rocks.

The deformation field determined for the reservoir rock and the surrounding sediment, should these be subjected to dewatering and compaction may be used as a boundary condition for the deformation and stress fields in the overburden. The effects on the overburden may be calculated using finite element techniques, the form of the code used being dependent upon the nature of the predominant deformation mechanisms exhibited by the overburden rocks.

The amount of work necessary for the development of the mechanical behavior simulator will depend upon the nature of the rocks within the zone of interest.

The development of the mechanical behavior simulator outlined above and in the main body of the report may be summarized as a series of tasks:

Task 1. Determine the simplest realistic mathematical model for the deformation behavior of the reservoir rock, including the degree of inhomogenity and anisotropy.

Task 2. Develop theory and code for the calculation of reservoir compaction and porosity change for any given pressure and temperature fields, based on the model from Task 1.

Task 3. Determine the dependence of permeability on compaction and porosity with the help of existing theory and laboratory data.

Task 4. Develop code for the calculation of permeability fields from reservoir compaction and porosity data.

Task 5. Maintain close contact with fluid flow simulator group in carrying out Tasks 2 and 4.

Task 6. Determine the simplest realistic mathematical models for the overburden rocks, including the degree of inhomogeneity and anisotropy.

Task 7a Develop general theory and code for the calculation of the stress and deformation fields within the overburden, based on existing finite element codes and the model(s) of Task 6.

Task 7b Develop a geometrical model for the overburden at possible test site(s).

Task 8. Develop the necessary code for automatic scanning of data from the results of Task 7 in relation to rock strength data, and for the output of subsidence data in a meaningful form.

Task 9. Verification of the simulator on the basis of:

a. laboratory data,

b. field data from previous cases of removal of pore fluid from reservoir rocks,

c. field data from a pilot test.

Task 10. Maintain close contact throughout with other workers in these areas.

The tasks listed above are, as near as possible, placed in their expected order of execution, but a considerable degree of overlap and juxtaposition may be expected. It will be appreciated that the development of any simulation facility of this type is a dynamic process and close interelation between tasks and with the mechanical testing program is essential.

3. The Laboratory Test Program

The laboratory test program should have three major objectives:

1) The determination of the simplest realistic mathematical model for the various rock materials, and of their anisotropy and inhomogeneity.

2) The measurement of the relevant mechanical and thermal properties of the rocks together with the dependence of these properties on stress and temperature.

3) The verification of parts of the mechanical simulator.

3.1 The Pilot Study

The form of the bulk of the test program will depend upon the predominant deformation mechanisms displayed by the various rocks, and on their degrees of anisotropy and inhomogeneity. It is recommended that the first phase of this test program be considered as a pilot study which is aimed at defining these mechanisms. This pilot study is envisaged as a preliminary unsophisticated, and mainly qualitative, examination of the major deformation properties of the different rocks. The duration of this study will be short, no more than one month, and could be concurrent with the development of equipment for the main test program.

3.2 The Main Test Program

The main test program will be directed towards the determination of the relevant material properties, and, if necessary, the refinement of the general mathematical model defined in the pilot study. The relevant material properties are:

1) <u>Deformation moduli</u> - these will be in general functions of temperature and stress; where the stress dependence is high the material will be non-linear, where it is absent or low over the range of stress of interest a linear approximation will be possible. For a perfectly elastic isotropic material the relevant moduli

will be Young's Modulus, Poisson's ratio, Bulk modulus and shear modulus, any two of these being sufficient to define the ramainder. For an anisotropic elastic material the moduli are the same, but will now be dependent upon direction. For a linear viscoelastic material the relevant moduli will be the time-dependent analogues of the elastic moduli.

2) Material strengths - the compressive and shear strengths of the various materials under different stress and temperature conditions must be known. Depending upon the degree of non-elastic behavior it may be necessary to determine time-safe strength criteria (1). For elastic-plastic materials the yield strength is an important parameter.

3) Fluid flow properties - the permeability of the reservoir rock and its dependence on stress and temperature must be determined.

4) Thermal properties - calculation of the thermal stress effects of non-uniform temperature fields will depend upon a knowledge of the thermal expansion coefficients (isotropic or anisotropic). Moreover determination of the temperature fields will require the knowledge of conductivity and diffusivity for the rocks, and the rate of heat transfer between rock and fluid.

The properties to be determined are summarized in Table 1.

In designing the experimental program, and the equipment to be used, consideration should be taken of the need to measure as many parameters as possible in one test, to allow maximum use to be made of the necessarily limited supply of specimens, and of the reduction in cost possible in making the necessary equipment as versatile as possible, to reduce unnecessary replication.

In determining the deformation behavior it is suggested that two series of tests be used, one under hydrostatic loading and loads slightly disturbed from hydrostatic, and one under torsional loading. The advantages in this approach are many.

Thus

1) The effect of lowering pore pressure is essentially volumetric;

2) The direct determination of bulk moduli for the reservoir matrix, that is without the pores, will be more easily made by measurement of volumetric strain under hydrostatic loading, than by measurement of linear or shear strain;

3) Where non-elastic behavior is evident it is normal to assume the non-elastic components to be confined to non-hydrostatic loading conditions (2,3);

4) The measurement of volumetric strain under hydrostatic loading automatically takes account of any minor, and insignificant, anisotropy which may be present.

5) In considering instability of the roof rock shear is of major importance.

6) Equipment for measuring deformation in torsion within the pressure and temperature range is already available.

For an isotropic elastic material the deformation moduli may be fully defined by measurement of volumetric strain under hydrostatic loading, and of torsional strain under torsional loading. If anisotropy is not negligible the measurement of volumetric strain will have to be supplemented by linear strain determination under non-hydrostatic triaxial normal stress. The thermal expansion may be measured by determining volumetric strain on change of temperature, giving the linear expansion for an isotropic material. For an anisotropic rock linear expansion may be determined directly by measurement of linear strain.

If time dependent deformation is significant it will be necessary to carry out longer term creep tests which, by their nature, require several test rigs to ensure a reasonable turn round of results. In this case the relative expense and complexity of either the hydrostatic or torsional equipment will preclude their replication, and long term creep behavior of the material may be quantified most economically by the use of a series of triaxial normal loading rigs.

Having achieved a desired stress and temperature condition in any specimen the fluid flow behavior may be determined by establishing a pressure gradient across the specimen and determining the resulting flow rates. Similarly by varying the temperature of the incoming and outgoing fluid the rate of heat transfer between rock and fluid may be measured.

As has been noted above the thermal conductivity and diffusivity of the various rocks are necessary for the calculation of the temperature field around the reservoir rock. Since these parameters may vary with temperature and/or stress their values over the likely range of ambient temperature and pressure must be known.

The measurement of these parameters is notoriously difficult to achieve to any high degree of accuracy (4), and this will be particularly true when the additional complexities of confining pressure and high ambient temperature are included. However while a reasonable degree of precision is required for these parameters it will not be necessary to achieve excessive accuracy, since the analysis in which they are to be used can only be approximate in itself.

3.3 Laboratory Test Program Organization

A test program of the type recommended may be divided into a series of tasks:

Task 1. Preliminary investigation of the principle deformation mechanisms, anisotropy and inhomogeneity.

Task 2. Definition of a simple but realistic mathematical model for the material.

Task 3. Development of equipment.

Task 4. Determination of deformation moduli under hydrostatic and near hydrostatic loading, permeability, fluid/rock heat transfer properties, and thermal expansion in as many directions as required by the material anisotropy.

Task 5. Determination of compressive strength and yield strength for elasto-plastic material.

Task 6. Determination of shear deformation behavior under torsional load and yield strength for elasto-plastic material.

Task 7. Determination of long term creep constants for viscoelastic material.

Task 8. Determination of thermal conductivity and diffusivity.

It should be noted that many of these tasks can be carried out concurrently - and that Task 7 may not be necessary. Certain additional tasks should be carried out over a time frame encompassing the whole project, these being:

Task 9. Analysis of data, incorporation into, and verification and modification of, the mechanical behavior simulator.

Task 10. Contact with other workers in the relevant areas of research.

3.4 Specimen Availability

The success of the laboratory test program outlined in this Appendix will depend upon the availability of cores for testing. The exact quantity of material necessary will depend upon the homogeneity of the various strata - the greater the heterogeneity the greater will be the number of specimens required to ensure statistically valid results. It is strongly recommended that the necessary steps be taken to ensure this availability. However, it must be appreciated that even under ideal conditions specimen availability will be limited. It is recommended, therefore, that the test program be made as efficient as possible by the use of multi-purpose tests and by the limitation of specimen size to the minimum compatible with test validity. It is also suggested that much of the preliminary work could be carried out using similar material from other locations.

4. Simulator Verification

One of the most important aspects of simulator development should be the verification, and where necessary modification, of the various techniques and codes used by comparison with measured data. In the laboratory this verification process may be applied to individual sections of code, in particular those sections relating pressure and/or temperature change to permeability.

The second, and vital, phase of the verification process will depend upon field results from a pilot reservoir where subsurface deformation data could be obtained and used to compare with predictions from the simulator. Subsidence data could be obtained by conventional surveying techniques. Subsurface data aquisition will be limited by the number of available boreholes and by the need to fit any measuring devices into the overall well bore monitoring system.

Additional verification could be obtained by the use of subsidence data from operational oil and gas reservoirs, or producing aquifers, where these are known to occur in a similar lithological setting.

The details of any field investigation and the resulting simulator verification will depend upon the performance of the reservoir and moreover depends upon overlap with other areas considered in this report. As a result it is not possible at this time to give recommendations as specific as those given for the other areas.

However, some general recommendations may be made. Surface,and if possible subsurface, subsidence should be monitored and the resulting data be used for verification and, if necessary, modification of the mechanical simulator. Monitoring should be carried out fairly intensively over the short term, say for 1 or 2 years depending upon the period of operation of a pilot facility. Further, less intensive monitoring should subsequently be carried out over a longer period. The span of this longer period will depend upon the measured behavior, but may be expected to be of the order of 5 years.

Finally, it should be appreciated that some modification of standard surveying and deformation monitoring techniques may be required. Sufficient lead time should be allowed for this area to allow any development which may prove necessary.

5. Personnel, Scheduling and Cost

Table 2 gives estimates of the personnel requirements for the operation of the recommended research program, based on a University research system. Table 3 indicates the estimated time required for the completion of various tasks.

Table 4 summarizes the estimated costs for the recommended work, and is again based on a University research system. Costs may be expected to vary in minor respects between different locations, but significant variations from those given should not occur within the University system.

No details have been given for the retrieval of cores since this falls into another area of this report. No details of field subsidence monitoring are included since this will be strongly dependent upon the locality and mode of operation of a pilot reservoir and also overlaps other work considered in different parts of this report.

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TABLE 1

Laboratory Test Programs

Required Material Properties

Material Type	Deformation Moduli	Strengths	Fluid Flow Properties	Thermal Properties
Linear Elastic	Young's modulus Bulk modulus Shear modulus Poisson's ratio	Compressive Shear	Permeability	Conductivity Diffusivity Expansion Rock/Fluid Heat Transfer
Non-Linear Elastic	As for linear elastic, all or some will be functions of stress			
Elasto-plastic	As elastic	Compressive Shear Yield	As elastic	As elastic
Linear Visco-elastic	Depend upon de tails of model, analogues of linear elastic	Compressive Shear as functions of time at load	As elastic, but functions of time	
Non-linear Visco-elastic	Depend upon details of model, analogues of non-linear elastic	As linear visco-elastic		

Note: a) All properties are in general functions of direction for anisotropic materials.

b) Visco-elastic deformation parameters are normally relatable to elastic by the use of Laplace transformation.

References

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b) Visco-elastic deformation parameters are normally relatable to elastic by the use of Laplace transformation.

TABLE 2

Personnel Requirements

Simulator Development and Laboratory Testing

Description	Duration	Proportion of Time	Responsibility
Principal Investigator	2 yrs.	1/8	Project direction
Research Engineer	2 yrs.	1/2	Research supervision
Graduate Assistant	2 yrs.	1/2	Lab. testing and analysis
Graduate Assistant	2 yrs.	1/2	Lab. testing and analysis and simulator development
Graduate Assistant	2 yrs.	1/2	Simulator development
Technician	2 yrs.	1	Lab. equipment development, specimen preparation, lab. assistance
Technician (computer)	2 yrs.	1/5	Programming and data aquisition assistance
Secretary	2	1/10	Report and paper preparation, general secretarial duties

TABLE 3

Estimated Time Schedules

TASK	Year 1												Year 2											
	1	2	3	4	5	6	7	8	9	10	11	12	1	2	3	4	5	6	7	8	9	10	11	12
A. Simulator development																								
1. Res. rock model development	x	x	x	x																				
2. Res. compaction code			x	x	x	x	x	x																
3. Perm/compaction relation										x	x	x	x	x	x									
4. Perm. code												x	x	x	x									
5. Contact with fluid flow group	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
6. Overburden model development	x	x	x	x																				
7. a) Overburden behavior code			x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x						
b) Overburden geometry			x	x	x																			
8. Data scan & assesment																		x	x	x	x	x	x	x
9. Lab. verification																		x	x	x	x	x	x	x
10. Contact maintenance	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
B. Laboratory investigation																								
1. Pilot study	x	x																						
2. Primary model development	x	x	x	x																				
3. Equipment development	x	x	x	x	x	x	x	x	x															
4. Deformation moduli (hydro-static) & fluid flow										x	x	x	x	x	x									
5. Comp. strength & yield strength										x	x	x	x	x	x									
6. Shear moduli & strength										x	x	x	x	x	x									
7. Creep constants*										x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
8. Thermal conductivity & diffusivity																x	x	x	x	x	x			
9. Data analysis	x	x	x	x						x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
10. Contact maintenance	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x

* May not be necessary

TABLE 4

Estimated Cost Analysis

Simulator Development and Field Investigation

Item	Description	Year 1 Cost	Year 2 Cost
1.	Salaries, staff benefits[1] and indirect costs[2]	73,700	80,200
2.	Equipment		
	a) Pressure cell, ancillary equipment, conductivity rig	17,000	13,000
	b) Creep rigs[3] (10 of)	25,000	
3.	Computor facilities Major installation and data aquisition	10,000	13,000
4.	Publishing costs	800	800
5.	Travel	500	1,000
	TOTAL	127,000	95,000
		GRAND TOTAL	222,000

Footnotes

1. Staff benefits estimated to include Federal Social Security, Unemployment Compensation Insurance, Workmen's Compensation Insurance, Insurance Premium Sharing

2. Indirect costs estimated at 54% of salaries

3. Creep rigs may not be required