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United States Gulf Coast Geopressured Geothermal Program
Special Projects Research and Coordination Assistance

Final Report for the Period
1 December 1978 - 30 October 1980

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D R A F T

I. INTRODUCTION

In 1975, the United States Energy Research and Development Administration awarded contracts for preliminary studies of the development of geopressured-geothermal energy underlying the United States Gulf Coast. Among these was a contract for a Management and Scope-of-Work Study with the Center for Energy Studies (CES) at The University of Texas at Austin.

The results and recommendations of these studies were presented at the Second Geopressured-Geothermal Energy Conference sponsored by DOE in Austin February 23-28, 1976, and were published as Volume 1, Summary and Future Projections, of the proceedings of that conference.

In addition to recommendations concerning future research and development, the document suggested the formation of a coordination assistance unit to assist DOE in the orderly development of the region's potential resource. It was suggested that this unit could interact with state and local agencies, maintain liaison with various industrial components that participate in the overall program, and disseminate results of research in each of the component areas; this unit would thereby serve to coordinate developing field research in the bi-state area so that a colloquy could be established which would incorporate all elements concerned with resource assessment, advanced reservoir research and technology, resource utilization, and legal, social, and environmental research into a meaningful, pragmatic, and cost-effective program. This

approach would facilitate the DOE strategy of involvement of state and local agencies and industry in the total program so that as success was demonstrated, those entities could assume a greater portion of costs and risks inherent in the development of a new technology.

In the course of planning for establishment of this coordination assistance unit, it became obvious that the need for special projects research could be expected to arise from time to time as the overall research program progressed.

To fill its needs for coordination assistance and periodic special projects research, DOE in July, 1976, contracted with the Center for Energy Studies and the Bureau of Economic Geology (BEG) to perform these tasks. The CES and BEG have performed these tasks under various contracts and extensions since that time. This final report documents work for the period: December 1, 1978, through October 31, 1980. The relevant contract numbers for this period are: EY-76-S-05-5243, DE-AS05-76ET28466, and DE-AS05-76-ET27020.

To the extent possible, the following sections of this report document the work performed in the sequence in which project tasks were specified in contract EY-76-S-05-5243. A few deviations from this sequence arise because (1) two contract extensions somewhat modified the December, 1978, description of project tasks and (2) unanticipated difficulties with the Brazoria County design wells deprived researchers of some of the data required for analyses contemplated in the December, 1978, task descriptions.

II. PROJECT TECHNICAL COORDINATION ASSISTANCE AND LIAISON

A. ATTENDED MEETINGS, LECTURES, AND PUBLIC ADDRESSES

During the previous contract period, members of the geothermal project staff have provided technical coordination and liaison between DOE, other federal agencies, state and local governmental agencies, industrial groups, and research participants. This has been accomplished by the attendance of qualified staff members at various meetings, and through talks to state, county, civic, and professional organizations which express interest in the geothermal project. The following is a record of such meetings, listed in chronological order.

1/4/79 Houston, Texas

Dr. Robert C. MacDonald and Dr. Myron Dorfman met with DOE personnel to review program.

1/16/79 Houston, Texas

Dr. J. Parker Lamb presented an overview of resource utilization to the Industrial Advisory Committee of Commissioner Mack Wallace, Texas Railroad Commission.

1/23/79 Houston, Texas

Dr. Myron Dorfman presented a seminar on geopressured geothermal research to the management of Tenneco Oil Company.

1/25/79 Houston, Texas

Dr. Don Bebout reviewed results of Armstrong Geothermal Fairway Exxon office study with Exxon Exploration Department geologists.

1/25-27/79 Houston, Texas

Mr. Lewis Jones attended a conference regarding the Natural Gas Policy Act of 1978.

2/12-13/79 San Francisco, California

Mr. Lewis Jones attended public hearings on proposed revisions to the Geothermal loan guaranty regulations.

2/14-15/79 Tulsa, Oklahoma and Houston, Texas

Dr. Myron Dorfman made presentations to the SPE chapters in these cities regarding the geopressed geothermal program.

2/18-21/79 New Orleans, Louisiana

Dr. Zwy Eliezer attended a meeting of AIME in which two sessions were devoted to corrosion in geothermal environments.

2/23/79 Houston, Texas

Drs. Dorfman and Podio and Mr. Will Boyd met with representatives of General Crude Oil to discuss drilling and completion technology for the Pleasant Bayou Well #2.

3/6/79 Baton Rouge, Louisiana

Dr. C. Dale Zinn attended a geopressed fluids disposal workshop held at Louisiana State University.

3/21/79 Houston, Texas

Dr. Parker Lamb met with General Crude Oil representatives for a discussion and review of the design of surface equipment to be installed in geothermal test well.

3/22/79 Houston, Texas

Sixty individuals representing government and industry met to review the geothermal program. Presentations on the UT program were made by Drs. Dorfman and Gray and by Mr. Tom Hill.

4/4/79 Los Angeles, California

Dr. Myron Dorfman made presentations on the geothermal program at the University of Southern California.

4/4/79 Roanoke, Virginia

Mr. Lewis Jones attended a Symposium on Geothermal Energy and Its Direct Uses in the Eastern U.S. (Institutional Aspects).

4/16/79 Houston, Texas

Dr. J. Parker Lamb met with General Crude Oil Company and the Department of Energy personnel to review preliminary designs for the surface facilities at the test well site.

4/17/79 Baton Rouge, Louisiana

Mr. Ray Gregory attended a workshop on the geopressured-geothermal resources of the Gulf Coast. This meeting was primarily concerned with geothermal projects in Louisiana which will be coordinated with Texas through DOE.

4/23-24/79 Houston, Texas

Dr. C. Dale Zinn gave a presentation at Industrial Commission of Texas Conference on Industrial Energy, Conservation and Technology. His presentation related to geothermal energy for industrial uses.

4/27/79 Houston, Texas

Dr. Don Bebout presented reviews of geopressured geothermal energy research at the DOE Well of Opportunity RFP meeting.

5/1/79 Houston, Texas

Dr. J. Parker Lamb met with officials of General Crude Oil for a discussion of surface equipment design related to test well program, Brazoria County.

5/3/79 Baton Rouge, Louisiana

Dr. Don Bebout reviewed the Louisiana geopressed geothermal program at Louisiana State University.

5/8/79 Las Vegas, Nevada

Drs. Don Bebout and Myron Dorfman attended a briefing on geothermal energy at the Las Vegas operations office. They presented a resume of the program at The University of Texas to Dr. John Salisbury, Deputy Director of the Division of Geothermal Energy.

5/8/79 San Francisco, California

Mr. Lewis Jones attended a short course sponsored by the Geothermal Resources Council entitled, "An Introduction to the Exploration and Development of Geothermal Resources."

5/14-16/79 Marina del Rey, California

Dr. Myron Dorfman attended the National Advisory Committee meeting of the Department of Energy Geothermal Reservoir Engineering Management Program. This meeting was for the purpose of prioritizing research for fiscal year 1980.

5/20-23/79 Tulsa, Oklahoma

Dr. Robert Loucks attended meeting on deep burial diagenesis given by American Association of Petroleum Geologists, including sessions related to study of burial diagenesis in sandstones.

5/21/79 Houston, Texas

Dr. Myron Dorfman met with General Crude Oil and DOE representatives relative to ongoing research.

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6/16-25/79 Austria

Drs. Dorfman, Zinn, Bebout and Loucks served as a U.S. delegation to meet at International Institute for Applied Systems Analysis with a Soviet delegation to discuss geopressed basins in both regions. The Soviet delegation included the Deputy Minister for Gas, the Energy Economist from the Praesidium in Moscow, the Chief Soviet Drilling Engineer, and the Chief Geologist of the Caucasus.

6/24/79 Monterey, California

Mr. Lewis Jones presented a report on the UT project at the Electrical Power Research Institute (EPRI) meeting. Dr. Zwy Eliezer also attended.

7/22/79 San Francisco, California

Mr. Lewis Jones attended the National Conference of State Legislatures to gather information about major issues such as energy conservation, alternative source development, the National Energy Plan, and federal mandates.

8/1/79 Houston, Texas

Drs. Dorfman, Bebout, Gray, Loucks and Mr. Will Boyd participated in a geopressed industrial advisory committee meeting. Some 75 representatives of the industrial community were present to hear the latest results of well testing from Brazoria County and one short term test in Louisiana.

8/5-9/79 San Diego, California

Dr. J. Parker Lamb presented a technical paper entitled, "Wellhead Flow Predictions for Texas-Louisiana Geopressed Reservoirs" at the 18th National Heat Transfer Conference sponsored by the American Society of Mechanical Engineers.

8/27/79 Washington, D.C.

Dr. Robert Morton and Dr. Don Bebout discussed the Bureau of Economic Geology's geothermal program and future proposals.

9/4-6/79 Los Alamos, New Mexico

Dr. Don Bebout attended the Gas Recovery Workshop and chaired the geopressured gas section.

9/23/79 Reno, Nevada

Mr. Lewis Jones attended the annual meeting of the Geothermal Resources Council.

10/23/79 Victoria, Texas

Dr. Myron Dorfman gave an invited lecture to the Victoria Chapter of the American Petroleum Institute regarding geopressure geothermal research in progress.

10/24/79 Washington, DC

Dr. J. Parker Lamb met with technical personnel in Division of Geothermal Energy, DOE, to discuss progress of UT research program.

11/7/79 New Orleans, Louisiana

Dr. Myron Dorfman presented a paper entitled, "Geopressured Formation Parameters of the Armstrong and Corpus Christi Fairway, Frio Formation (Oligocene), Central and South Texas," at the 40th Annual International Meeting of the Society of Exploration Geophysicists.

11/27/79 San Diego, California

Mr. Lewis Jones attended conference regarding federal and western state laws, regulation, orders, and procedures.

12/2-5/79 Los Angeles, California

Dr. Myron Dorfman attended the December meeting of the Interstate Oil Compact Commission and served as Chairman of the Geothermal Resources Committee. He reported on results available on Pleasant Bayou Well #2 at that time.

1/16-18/80 Sea Island, Georgia

Dr. J. Parker Lamb participated at the National Conference on Geotechnical and Environmental Aspects of Geopressed Energy. Dr. Henry Dunlap served as session chairman at the conference.

1/23-24/80 New Orleans, Louisiana

Drs. Morton and Dorfman made presentations to the U.S. Geothermal Coordinating Committee on the status of The University of Texas project and on the #2 Pleasant Bayou Well.

2/5/80 New Orleans, Louisiana

Dr. J. Parker Lamb presented a paper on geopressed energy conversion at the ASME Petroleum Engineering Conference.

2/13/80 Baton Rouge, Louisiana

Dr. Robert Morton and members of the Bureau of Economic Geology research group presented results of ongoing research to the Gas Research Institute project advisors.

2/14-15/80 San Francisco, California

Mr. Lewis Jones attended a legal and institutional seminar, "Geothermal Environmental Problems." The major topic concerned the subsidence and seismicity and the resultant socio-economic considerations.

2/20-23/80 Houston, Texas

Mr. Lewis Jones attended the Environmental Law Institute and the State Bar of Texas annual meeting to update environmental lawyers on state and federal regulations.

2/21/80 Houston, Texas

Dr. Myron Dorfman gave a presentation to the Electric Women's Roundtable State Workshop entitled "Geothermal Energy."

3/5/80 Chicago, Illinois

Dr. Zwy Eliezer participated in the Geothermal corrosion sessions of the Corrosion 80 meetings.

3/5/80 Austin, Texas

Dr. Myron Dorfman gave a talk to the Gas Research Institute Industrial Advisory Committee at the request of its head Mr. Jeff Simmons of United Gas Corporation.

3/11-12/80 New Orleans, Louisiana

Dr. Robert Morton gave a talk to DOE representatives regarding the status of Geopressure-Geothermal prospects in Texas and a talk at the CK GeoEnergy meeting regarding critical factors in the Exploration of Geothermal Resources.

3/12/80 Austin, Texas

Dr. Myron Dorfman spoke to the American Association of University Women on the subject of Geopressure-Geothermal Energy.

3/27/80 Freeport, Texas

Dr. Myron Dorfman gave a presentation, "Geothermal-Geopressured Wells in Brazoria County" of research in progress to the Texas Gulf Coast Section of the American Institute of Chemical Engineers.

4/14-16/80 Houston, Texas

Dr. J. Parker Lamb attended 1980 Conference on Industrial Energy Conservation Technology sponsored by the Texas Industrial Commission.

4/22/80 Corpus Christi, Texas

Dr. Robert Morton met with Mr. Dick Foote of the U.S. Geological Survey to discuss geothermal research being conducted by the Bureau of Economic Geology and the possibility of a cooperative project for offshore Texas.

5/12-15/80 Dallas, Texas

Mr. Lewis Jones attended a short course entitled "Oil and Gas Law and Taxation."

5/27-28/80 Houston, Texas

Dr. Robert Morton discussed Bureau geothermal projects and need for salinity analyses with Mr. Jesse Johnson and Mr. Don Keppta, Arco Oil and Gas Company.

5/27-29/80 Nashville, Tennessee

Dr. Zwy Eliezer presented results and initiated joint research activities with corrosion and wear group of Vanderbilt University and the geothermal group of the Oak Ridge National Laboratories.

5/27-29/80 Washington, D.C. and Houston, Texas

Dr. Thomas Gustavson met with Robert Holliday, Interagency Geothermal Guidance Committee to discuss progress in environmental monitoring at the Brazoria test-well site. Presented material on environmental aspects of geopressured-geothermal development to an Industrial Forum on geothermal energy development.

5/28/80 Houston, Texas

Dr. Myron Dorfman attended Department of Energy Geothermal Industrial Advisory Committee meeting to discuss and review research in progress.

5/28/80 Houston, Texas

Mr. Lewis Jones spoke at GeoTech meeting on leasing state lands for geothermal development.

6/5-15/80 Denver, Colorado

Mr. Richard Schatzinger hauled cores for Sandstone and Stuart City display to Denver AAPG/SEPM meetings for SEPM core workshop given on 6/8/80 and 6/12/80. Assisted in Bureau paper presentation at Carbonate Core Workshop. Dr. Robert Loucks attended AAPG/SEPM annual meeting, presenting latest work on Sandstone Consolidation II project and Ellenburger project.

6/10/80 Chicago, Illinois

Dr. Myron Dorfman presented results of the Geopressure Geothermal research team at the First International Gas Conference sponsored by Gas Research Institute.

6/20-21/80 Vail, Colorado

Dr. Myron Dorfman made a presentation of the results of the Geopressure Geothermal research team to the Interstate Oil Compact Commission.

6/30-7/6/80 Schloss Laxenburg, Austria

Drs. Dorfman, MacDonald and Caudle represented The University of Texas Geothermal Research Team at the International Conference on Gas held at the International Institute for Applied Systems Analysis. Papers were presented on the overall program, reservoir engineering and reinjection of water, by these representatives. A paper prepared by Dr. Robert Morton of the Bureau of Economic Geology, "Entrained Methane Contained in Geopressured Aquifers," was presented.

7/8-9/80 Houston, Texas

Dr. Robert Morton discussed reservoir continuity in Cuero and Austin Bayou prospects with DOE and industry representatives at meeting sponsored by C.K. GeoEnergy.

7/10/80 Dallas, Texas

Dr. Myron Dorfman presented a paper on geopressured geothermal energy to the Texas Energy Symposium held at The University of Texas at Dallas.

7/21/80 Austin, Texas

A standardization committee meeting on well logging was chaired by Dr. Robert Morton and attended by Drs. Dorfman, Dunlap, and Mr. Biggs of The University of Texas with representatives of logging companies and other entities present.

7/31/80 Washington, D.C.

Dr. Myron Dorfman testified in favor of Senate Bill 2774 before the Senate Committee on Energy Research and Development.

8/11-15/80 Princeton, N.J. and Philadelphia, Pennnsylvania

Dr. Zwy Eliezer attended a demonstration of the new model 355 Curve Storage Module to be used in conjunction with our corrosion instrumentation, Princeton N.J. Discussed problems related to geothermal sampling and standardization at ASTM Headquarters and the National Bureau of Standards in Washington, D.C.

8/17-19/80 Seattle, Washington

Dr. Parker Lamb attended 15th Intersociety Energy Conversion Engineering Conference and presented paper entitled, "Generalized Performance Predictions on Energy Conversion Plants using Geopressured Geothermal Fluids."

8/20-21/80 Houston, Texas

Dr. Robert Morton attended meeting of SEPM Research Conference Committee to discuss Bureau's research on Woodbine and Tuscaloosa trends in East Texas and Louisiana with other meeting participants.

8/27/80 Las Vegas, Nevada

Drs. Morton and Dorfman presented comprehensive reviews of the geopressured-geothermal research at The University of Texas to Mr. Bennie DiBona, Former Director of Geothermal Energy, the Department of Energy.

9/4-5/80 Alvin, Texas

Mr. Fred Fox and Dr. Robert Morton reviewed surface installations at the #2 Pleasant Bayou Well and met with representatives of Fenix and Scisson and Gruy Federal to discuss collection and distribution of test data prior to flowing well.

9/7-11/80 Salt Lake City, Utah

Mr. Lewis Jones attended the annual Geothermal Resources Council meeting and visited with the international representatives of the industry regarding the progress of our project. Drs. Morton, Gustavson presented a paper entitled "Critical Factors Defining Geopressured Geothermal Prospects."

9/9-11/80 Dallas, Texas

Dr. Robert Morton presented a talk on geopressured gas at an industrial marketing seminar sponsored by the AGA.

10/2/80 Houston, Texas

Dr. Robert Morton met with representatives for the U.S. Department of Energy, U.S. Geological Survey and Louisiana Geological Survey to discuss and rank geopressure geothermal design well test sites in Texas and Louisiana.

10/4/80 Metals Park, Ohio

Dr. Zwy Eliezer attended the American Society for Metals Conference.

10/7-8/80 Pittsburgh, Pennsylvania

Ms. Katherine Pearsall presented a paper entitled, "The Nature of the Surface Film on Highly Alloyed Austeritic Stainless Steel in High Salinity Brines," at the fall 1980 AIME convention.

10/15-17/80 Lafayette, Louisiana

Dr. Robert Morton attended meeting of Gulf Coast Association of Geological Societies to preside at technical session, including discussions of geopressure geothermal research.

10/21-23/80 Houston, Texas

Drs. Morton, Dorfman, Gray and MacDonald participated in CK GeoEnergy meeting with representatives from industry and the Department of Energy.

10/25/80 Las Vegas, Nevada

Dr. Myron Dorfman presented paper at Gas Resource Technology Symposium entitled, "Evaluation of the Geopressed Resources of the United States Gulf Coast."

B. FOURTH UNITED STATES GULF COAST GEOPRESSURED-GEOTHERMAL ENERGY
CONFERENCE, GEOTHERMAL BOARD OF ADVISORS MEETING

In addition to the preceding series of ad hoc coordination and liaison activities, the Center for Energy Studies, Bureau of Economic Geology, and DOE hosted the Fourth United States Gulf Coast Geopressed-Geothermal Energy Conference in Austin, Texas, on October 29-31, 1979. Forty-six papers, reporting the research of 102 authors, were presented. These papers were printed and distributed in a three-volume set of Proceedings.

Following the conference, a meeting of the Geothermal Board of Advisors was convened in Austin, Texas. The UT geothermal program was reviewed with this (primarily, industrial) board, whose members are set out in Appendix A, and the board's advice on future appropriate research was received.

III. TECHNICAL ASSISTANCE FOR REVIEW AND EVALUATION OF PROPOSALS AND CONTRACT RESULTS;

TECHNICAL ASSISTANCE FOR GEOPRESSURED-GEOTHERMAL TEST WELLS

During the report period, the CES/BEG research group provided technical assistance to the DOE program in the following areas:

A. WELL TEST STRATEGIES

Recommended testing strategies (flow and buildup tests) on the #2 Pleasant Bayou well. This resulted in flow testing and beginning of buildup tests in December, 1980. Drs. MacDonald and Dorfman presented a paper on these test results at the Stanford University Geothermal Reservoir Symposium on December 18, 1980, and also presented data at the C. K. GeoEnergy meeting in Houston, December 1980.

B. DGE WELL TEST ADVISORY COMMITTEE

Drs. MacDonald and Dorfman serve as members of the Well Test Advisory Committee of DGE Houston; this committee was recommended by Dr. Dorfman to quickly cover problems that might arise on both design wells and wells of opportunity.

C. LOUISIANA DESIGN WELL REVIEW

Dr. Dorfman reviewed casing and testing procedures on the Magma Gulf/Technidrill and Dow design wells, and made recommendations during drilling of the former with respect to setting depth of intermediate casing. Drs. Gray and Dunlap also made recommendations, in accordance with standardization procedures, on cores and well logs.

D. WELLS OF OPPORTUNITY REVIEW

Drs. Morton and Dorfman have reviewed the geology and well logs for salinity determinations on some 37 Wells of Opportunity candidates,

and made recommendations either for inclusion and exclusion of various wells in both Texas and Louisiana on the basis of reservoir continuity, porosity, permeability, and salinity.

E. CORE COLLECTION, STORAGE, AND TESTING

Cores on the Magma Gulf/Technidrill well were recovered and samples obtained by Dr. Gray for studies of rock mechanics in accordance with standardized procedures. Storage of samples, as well as petrographic studies, will be undertaken by BEG.

F. STANDARDIZATION OF PROCEDURES

Dr. Gray headed the Committee on formulating standardized procedures for cores, core handling, storage, and rock mechanics. This report is now in final form. Dr. Dunlap headed the Committee for formulating standardized procedures for well logging, which report was presented and adopted by DGE/DOE.

G. WATER SALINITY STUDIES

Dr. Dunlap continues studies of water salinity by well log determinations, and has made several significant discoveries of error in past procedures. Lab testing of drilling fluids, and back calculations of R_w from produced water samples are the basis for continuing IMPORTANT work in this area.

IV. TECHNICAL ASSISTANCE, COORDINATION AND PLANNING OF SURFACE UTILIZATION PROGRAM

A. MATERIALS AND ENERGY CONVERSION STATE-OF-THE-ART SURVEY

A.1 Energy Conversion

An extensive literature review was completed and visits were made by Dr. Lamb to Bechtel Power Corporation and Rogers Engineering Company in San Francisco in December, 1978. While in San Francisco, Dr. Lamb also attended the ASME meeting at which there were two technical sessions on energy conversion related to geopressured geothermal systems. Dr. Lamb and two Research Assistants visited with Professor K. E. Starling and his research group at Norman, Oklahoma, in March, 1979, to discuss binary plant designs.

A.2 Corrosion and Metallurgy

An extensive literature survey on the material problems encountered in several geothermal plants and testing facilities was performed. The geothermal sites surveyed included locations in the United States (Geysers, Salton Sea, East Mesa, Heber, Raft River, Baca) and abroad (Wairakei, Cerro Prieto). The materials used in different components of the surface facilities were identified and critically analyzed.

B. POWER SYSTEMS ADVISORY GROUP COORDINATION

B.1 Energy Conversion

In January, 1979, Dr. Lamb was invited to deliver an oral report on geopressured geothermal energy conversion to a Special Task Force of the Texas Railroad Commission. This meeting was held at the Houston Natural Gas Headquarters with Mr. John Foy presiding. Two formal presentations of technical papers were made by Dr. Lamb during 1978-79; in October,

1978, an SPE paper was presented in Houston and in August, 1979, an ASME paper was presented at San Diego. During the latter meeting, discussions of related work were held with investigators from Oak Ridge National Lab, Lawrence Livermore Lab, and the University of Utah.

At the invitation of Houston Lighting and Power Company, Dr. Lamb prepared a written summary of the entire UT Austin geopressured geothermal program which was included in the proceedings of the Third Annual Geothermal Conference of the Electric Power Research Institute held at Monterrey in June, 1979.

Detailed thermodynamic analyses of conversion plants have been initiated and preliminary results have been obtained. These results, along with related corrosion/metallurgy studies, were reviewed at a meeting in Austin on August 27, 1979 which was attended by representatives of sponsoring electric utilities (Gulf States, Central Power and Light, Houston Lighting and Power) as well as DOE (Houston) and Mobil-General Crude. A written summary of these studies will be included in the proceedings of the Fourth Geopressured Conference at Austin in October, 1979. An ASME paper on the thermodynamic analysis was submitted.

Assisting Dr. Lamb in this portion of the project have been three M.S. degree candidates.

B.2 Corrosion and Metallurgy

A state-of-the-art computerized corrosion instrument (Princeton Applied Research 350-1) was purchased (from private donations) and is in current use for laboratory experiments. The instrument is capable of determining corrosion rates (using the Linear Polarization and Tafel Slope Techniques) and passivation, pitting, and crevice tendencies (using the

potentiokinetic technique). Potentiokinetic and galvanic corrosion experiments can also be performed.

The following structural materials were tested in various synthetic and natural brines: low carbon steel (AISI 018), austenitic stainless steels (304, 316), ferritic stainless steels (430), martensitic stainless steel (410), non-ferrous materials (copper aluminum), two specialty Sandvik alloys (San 28 and SAF 2205) etc. The sensitization of stainless steel pipes welded by the homopolar pulse process was also examined.

The test brines included (1) NaCl aqueous solutions with NaCl contents from zero to 100,000 ppm, (2) NaCl aqueous solutions with different additions of NaHCO₃, and (3) brine from Pleasant Bayou #2 well. Experiments were done in both aerated and deaerated solutions. The deaeration was achieved by passing an inert gas e.g., He₂, through the solution during the measurements.

Assisting Dr. Eliezer in this work have been one M.S. and one Ph.D. degree candidates.

C. SURFACE FACILITY DESIGN

C.1 Energy Conversion

In April, 1979, Dr. Lamb met with Mr. John Stevens of General Crude Oil Company at Dayton, Texas, to discuss design of the surface facilities (first phase) for the Pleasant Bayou #2 well. These discussions were continued in two meetings at the General Crude Oil Headquarters in Houston in late April and early May. The latter meetings included DOE, GCO, and Eaton personnel with Dr. Lamb as the UT representative.

C.2 Corrosion and Metallurgy

Dr. Eliezer contacted a number of organizations and individuals in order to determine the best design for conducting corrosion experiments

at the wellsite. It appears that field electrochemical corrosion tests have been performed only very recently and only by two organizations: Lawrence Livermore Laboratories (Dr. L. B. Owen) and U.S. Bureau of Mines (Dr. Stephen Cramer). Their work is being evaluated and a decision will be made in the near future on the design for a well-site lab. The latter facility has also been discussed with Petrolite Corporation of Houston.

D. CONTRACT EXTENSION WORK

During this period a study of the basic thermodynamic principles related to energy conversion plants was completed. A comprehensive computer code was developed which simulates the performance of both binary and dual-flash plants when coupled with a hydraulic turbine.

Binary plant working fluids included both isobutane and propane. Results of this study are presented in Refs. 1 and 2, which describe primary operating characteristics and demonstrate the importance of hydraulic energy recovery.

A second plant performance study was initiated during this period. The emphasis in this investigation was on possible improvements in resource utilization which would occur from (a) operation of a binary plant in a "floating cooling" mode and (b) integration of a geopressured energy source with conventional fossil fueled plants. The first portion of this work deals with the possibility of allowing the binary Rankine cycle to operate at condensing conditions which vary with seasonal climatological parameters; in this way the cold weather operation produces additional output beyond that which is possible if the plant operation is fixed at the summer time temperature and humidity levels.

The second phase of this new study will attempt to determine if, by using the low grade thermal energy of geopressured fluids to augment the performance of a conventional steam or gas turbine plant, one can obtain improved utilization (or Second-Law efficiency) of the brine.

References

1. Polansky, G. F. and Lamb, J. P., "Thermodynamic Analysis of Energy Conversion Plants Using Geopressured Fluids," Report ME EFS 8001, June 1980.
2. Lamb, J. P. and Polansky, G. F., "System Thermodynamics of Energy Conversion Plants Using Geopressured Geothermal Fluids," ASME Paper 80-PET-13, February 1980.

D R A F T

 

V. LEGAL RESEARCH

A. DOCUMENTATION OF LEGAL LIAISON ACTIVITIES

This section documents legal advisory activities which were of an ongoing nature during the period of this contract. These activities were called for under the legal research and geopressured-geothermal resource development section of our contract, specifically, in Subtask 1 to Task 1, Subtask 1 to Task 2, Task 3, Subtask 2 to Task 4, and Bullet 2 of the "Legal Studies" area of work described in attachment "A" to our original contract extension.

A.1 1978

DECEMBER. Members of the legal research team prepared a written summary and analysis of the Smith-Southwest Industries vs. Friendswood Development Co. case, in which the Texas Supreme Court held that it would henceforth hold liable for subsidence damage developers whose negligent withdrawal of groundwater directly causes subsidence. Similarities and distinctions between this new rule applying to groundwater and the interests of geopressured-geothermal resource developers were discussed.

A.2 1979

JANUARY. A member of the legal research team, Mr. Lewis Jones, attended a Natural Gas Policy Act of 1978 Conference sponsored by the State Bar of Texas in Houston. A written description of the most relevant points of the NGPA was prepared, in part from information garnered from this conference.

FEBRUARY. Arthur Oberbeck prepared for circulation to interested geopressured-geothermal research personnel a written analysis of the

EPA's proposed rule for implementation of its hazardous waste management system. He pointed out that (1) coordination between this, the National Pollution Discharge Elimination System, and the Safe Water Drinking Act permit requirements and (2) the possibility of trace elements (such as boron) in geopressured brines might substantially complicate geopressured-geothermal resource development.

MARCH. Mr. Oberbeck and the legal staff from the Texas Railroad Commission completed their efforts to draft a bill to the Texas Legislature which would define the product of the geopressured-geothermal resource development to be a mineral resource. Legislative adoption of such a definition would serve to reduce uncertainty as to whether the geopressured-geothermal resource is to be treated as a mineral or water resource for private contract purposes.

APRIL. Mr. Oberbeck appeared before the Texas Legislature representing the Center for Energy Studies and the Texas Railroad Commission to defend their resource definition bill. This bill ultimately passed both houses of legislature and was signed by the governor.

Mr. Oberbeck also prepared a preliminary analysis of the EPA's proposed rules on underground injection controls required under the Safe Drinking Water Act.

MAY. Mr. Lewis Jones traveled to San Francisco, California, to establish contacts and discuss potential legal problems with individuals involved in development of non-geopressured geothermal resources in the western states.

JUNE. Mr. Oberbeck prepared and circulated a written analysis of proposed EPA regulations governing the National Pollutant Discharge

Elimination System and its interaction with the EPA's programs for hazardous waste management and underground injection under the Safe Drinking Water Act. Mr. Jones presented a paper at EPRI's Annual Meeting in Monterey, California.

JULY. Mr. Jones attended the National Conference of State Legislators in San Francisco, California, and met there with various legislators from around the country interested in matters bearing on geothermal development.

SEPTEMBER. A. W. Oberbeck undertook an investigation of the status of insurance on the Brazoria County well. The results of this investigation were written up and distributed to interested parties. The gist of Mr. Oberbeck's work was that the well operator, General Crude Oil Company, had secured 20 million dollars "control of well" coverage and 18 million dollars "excess liability" coverage. The total premium for this coverage was approximately \$125,000. The possibility of future subsidence had initially been an impediment to securing this insurance, but Lloyd's of London hired an engineer to survey the risk and, on the basis of this engineer's survey, concluded that the risk of subsidence was very small.

OCTOBER. During October, the Fourth Geopressure-Geothermal Energy Conference was held at the University of Texas. During this conference, members of the UT legal research team had numerous meetings and discussions with attendees concerning the legal aspects of geopressured-geothermal development.

A.3 1980

JANUARY. Contacts were made with the firm of Coroon and Black of Philadelphia, which has formally announced an intention to enter the field

of geothermal energy reservoir insurance. A written summary of the Bureau of Land Management's Phased Environmental Review for Development of Geothermal Leases on Federal Land was prepared and circulated to potential geopressured-geothermal resource developers to whom it might be of interest.

FEBRUARY. Lewis Jones attended attended a Legal and Institutional Seminar sponsored by the Geothermal Resources Council in San Francisco, California. Also this month, members from the legal research team attended the annual meeting of the State Bar of Texas' Environmental Law Institute.

A. W. Oberbeck prepared and circulated to interested parties an extensive review of the National Pollution Discharge Elimination System, as that system applies to geopressured-geothermal development in Texas. This was, at the time, an area of particularly intricate law because Texas had not yet received delegation of the NPDES Permitting Program from the EPA and therefore, permitting under the system occurred under an intricate system of shared federal and state responsibilities.

MAY. Members of the legal research team consulted closely with attorneys from the General Land Office concerning the request presented to the General Land Office that public lands be opened to geothermal lease bids. Before this can be done, it will be necessary to develop a lease form and determine an appropriate royalty figure. To this end, members of the legal research team met with the Southwest Legal Foundation and attorneys from the Texas Railroad Commission to begin development of such a lease. Also this month, Lewis Jones made a presentation at the C. K. GeoEnergy meeting in Houston on the leasing of State lands for geothermal development.

JUNE. DOE, Division of Geothermal Energy, requested that a member of the legal research team prepare a response to the Economic Regulatory Administration's notice of inquiry concerning incentives for development of high-cost gas, such as geopressured methane. This was done, and the response forwarded to the Economic Regulatory Administration and members of the geopressure-geothermal community.

AUGUST. Members of the legal research team reviewed the General Land Office's proposed lease for land for experimental drilling and testing of geopressure reservoirs. This review was conducted simultaneously by attorneys in Office of the Attorney General of Texas and by attorneys of various oil and gas firms in the state. Research on legal ramifications of subsidence continued. Finally, Lewis Jones attended the annual Geothermal Resources Council meeting in Salt Lake City, Utah, and visited with international representatives of the industry regarding the progress of geopressured-geothermal development along the Texas and Louisiana Gulf Coasts.

B. CURRENT GOVERNMENT POLICIES BEARING ON GEOPRESSURED-GEOTHERMAL DEVELOPMENT

This section presents the results of work described in Tasks 3, 5, and 6 of the "Legal Studies" area of our contract. This work is ongoing and has been incorporated in our current contract; it is expected that more particular legal analyses will be required as O.R. projects give more definition to development plans and as more complete test results become available from design wells.

A number of federal and, to a lesser extent, state policies bearing on geopressured-geothermal development have been enunciated. The following paragraphs explain these policies as they now (December, 1980)

exist. They are grouped for the purposes of this explanation under (1) the Geothermal Loan Guaranty Program, (2) the Geothermal Reservoir Confirmation Program, (3) DOE support of R, D, and E projects, (4) federal tax policies, (5) methane price and market incentives and disincentives, and (6) electric power and process heat policies; they are discussed in this order.

B.1 Geothermal Loan Guaranty Program

The Geothermal Loan Guaranty Program may be relevant to geopressured-geothermal development. It operates under regulations promulgated by the Department of Energy (10 C.F.R. Part 790). The statutory authority for this program is found in the Geothermal Energy Research, Development, and Demonstration Act of 1974. 30 U.S.C. 1141, et seq. (1974, amended 1978, 1980). The purpose of the program is to reduce the exposure of lenders to commercial projects which would develop practical means of producing energy from geothermal resources with environmentally acceptable processes. The following paragraphs explain the provisions of the geothermal loan guaranty program as it has been structured under the DOE's regulations.

The loan guaranty program is operative through fiscal 1990. Guaranty agreements made prior to that date will remain in effect until the guaranty obligation terminates as provided in the terms of the agreement. Through the termination date of the program, the proposed rules empower DOE to obligate the full faith and credit of the United States to the payment of a total of \$300,000,000 in loan guaranties.

DOE's authority to enter into loan guaranties for any particular geothermal project is subject to two limitations: (1) the guaranty may

not exceed 75% of the estimated aggregate cost of the project, and (2) the amount of the guaranty may not exceed \$100,000,000. The total dollar amount of guaranties which DOE may extend for any combination of loans by a single borrower may not exceed \$200,000,000, unless neither house of congress, after being given an opportunity, objects to a greater amount.

"Geopressured fluids" and "byproducts derived from them" (10 CFR Part 790.5) are specifically defined to be geothermal resources. Presumably, "geopressured fluids" encompasses liquid and gaseous water, and natural gas. If the natural gas is not considered a fluid, there is some question as to whether it would be considered a byproduct because the byproduct definition is limited to "minerals or gases" which have a value of less than 75% of the value of the geothermal resource and which are not of sufficient value to warrant their extraction and production without producing the geothermal resource. If geopressured methane is neither a "geopressured fluid" nor a "byproduct," the loan guaranty would apparently not be available to a developer who did not plan to market the heat or pressure components of the resource.

A geothermal "project" is any project which develops geothermal resources for which a market potentially exists in an environmentally acceptable manner. The definition is broad enough to fund exploration expenses, power plants, process heat facilities, etc.

The program has not been used to date for development for geopressured-geothermal projects. It has not been particularly successful (six guaranties) in the financing of more conventional geothermal projects in the western states, either; this is in part because of delays

in approval of loan guaranty applications and the relatively low initial guaranty ceiling, (\$25,000,000 per project). Both of these shortcomings have been largely corrected. A continuing problem of the program is that it does little to reduce the financial risk to the principal obligor on the loan, who may avoid this obligation as a practical matter only if the loan is declared to be in default; because of indentures in other outstanding loans and because they anticipate future reliance on debt markets, very few firms can tolerate the damage which would flow from having once been declared in default on a large loan obligation.

Louise H. Nasr's 1978 study for DOE, Geothermal Loan Guaranty Program and its Impact on Exploration and Development, is a thorough and critical evaluation of the program; Nasr did not recommend extending the program beyond its then-expiration date, 1984.

B.2 Geothermal Reservoir Confirmation Program

The Energy Security Act of 1980 (the "Synfuels Act") made an appropriation to the Geothermal Resources Development Fund of monies to be loaned by the Secretary of Energy to developers who would explore for and confirm the economic viability of geothermal reservoirs. Loans may be made from this appropriation until September 30, 1986. The loans are generally limited to 50% of exploration and confirmation costs, or \$3,000,000, whichever is less. Where loans are secured for exploration and confirmation of reservoirs which prove not to be commercially viable, the Secretary of the DOE may forgive the principal and interest nominally due. The total amount of loans authorized is rather small, \$85,000,000 maximum during the lifetime of the program.

B.3 DOE Support of Geopressured-Geothermal R, D, and D Projects

DOE and its predecessors have funded approximately \$8,000,000 for research at The University of Texas alone. The Geothermal Division of the Department of Energy had a fiscal year 1979 budget of slightly more than \$27,500,000; its budget for fiscal year 1980 was \$36,000,000.

Geopressured-geothermal research now accounts for the bulk of that budget. In addition to academic research, DOE has two significant ongoing programs which are targeted to reduce resource uncertainty for potential developers by the drilling of test wells (design wells) and the re-entry of other wells (wells of opportunity) to gather practical data on the drilling, completion, and production of geopressured-geothermal wells.

It is under the test well program which General Crude Oil Company contracted with DOE for the drilling of what was the first geopressured-geothermal production well in the world in Brazoria County, Texas. This well and subsequent wells are each expected to cost, for drilling alone, in the neighborhood of \$6,000,000. The other well drilling program, the wells of opportunity program, is the one under which Gruy Federal and Eaton Operating Company have acquired existing wells for re-entry in Louisiana. This program currently calls for re-entry costs of approximately \$5,000,000 per well.

The purpose of both the design well and the well of opportunity programs is to gather hard data on such reservoir parameters as methane content, porosity, permeability, volume, and fluid temperatures and makeup. Testing of surface equipment such as turbines and gas strippers will provide similar first hand data on utilization parameters. Would-

be participants in geopressured-geothermal development are almost unanimous in their agreement that programs such as these will be necessary to stimulate commercialization of the resource because current unknowns are so numerous that expected rates of return cannot be calculated with any confidence.

B.4 Federal Tax Policies

The Energy Tax Act of 1978 provided a number of federal tax incentives to producers and users of geothermal energy and to producers of geopressured methane. Conventional wisdom is, and the following discussion assumes, that the tax incentives extended to geothermal energy users and producers are also available to those who produce or use the geothermal component of geopressured-geothermal resources; this may not in fact be the case, depending on how the Internal Revenue Service interprets the language of the Act.

Whether producers and users of the geothermal component of geopressured-geothermal resources may claim the tax deductions and credits allowed by the Energy Tax Act depends on whether Congress intended that its "geothermal deposit" definition encompass reservoirs which also contain natural gas; there are several indications that Congress did not intend that "geothermal" deposits and "gas" deposits could occupy the same geologic space. All references to geothermal energy in the IRS Code cite the definition set out in Section 613(e)(3), the pertinent part of which reads as follows:

"...the term 'geothermal deposit' means a geothermal reservoir consisting of natural heat which is stored in rocks or in an aqueous liquid or vapor (whether or not under pressure). Such deposit shall in no case be treated as a gas well for purposes of this section or Section 613A, and ..."

Sections 613 and 613A contain the rules for percentage depletion deductions on oil, gas, and geothermal properties.

The first sentence of the definition certainly seems to include the geothermal component of a geopressed reservoir, and the second sentence (if in fact part of the definition) says only that the geothermal component should not be considered a gas "well" for purposes of the depletion deduction. Nonetheless, in three separate comments, the House-Senate Conferees on the Energy Tax Act indicated that they intended wells which produce natural gas from geopressed brine to be "gas" wells. Concerning intangible drilling cost deductions, their Report said: "The conference agreement does not change present law with respect to wells producing natural gas from geopressed brine, so that these will continue to be treated as natural gas wells for purposes of the IDC election." Concerning minimum tax treatment, the Conferees said: "Thus, income and deductions from wells producing natural gas from geopressed brine will continue to be aggregated with income and deductions from all oil and gas property for purposes of the related income offset under the minimum tax." Finally, concerning the recapture of IDC deductions, they said: "However, geopressed natural gas wells are to be treated as gas wells as under present law." It is also troublesome that the Conferees at no time referred to the obvious problem of keeping separate accounts for expenses related to geopressed-geothermal heat or pressure development and use, on the one hand, and geopressed natural gas development and use, on the other.

It is very difficult to determine what the Conferees actually intended (if anything) regarding the geothermal component of geopressed deposits because the Conferees expressly addressed only the gas

component of that resource and apparently focused on the Western-state resources when they dealt with geothermal energy in general. A definitive Internal Revenue interpretation of the geothermal deposit definition may be a long time coming in light of the embryotic nature of geopressured-geothermal development; the following explanation assumes the definition includes the geothermal component of the geopressured resource.

a. TAX POLICIES APPLICABLE TO GEOTHERMAL ENERGY IN GENERAL. Section 44C of the IRC provides a tax credit for investment, including labor expenses, in renewable energy source property. This is referred to as the Residential Energy Credit. The term "renewable energy source property" specifically includes property installed in connection with a dwelling and which transmits or uses energy derived from geothermal deposits (as defined in Section 613(e)(3)). The amount of the credit is figured by taking 40% of the first \$10,000 expended for renewable energy source property each year; this means that the maximum credit available in any one year is \$4,000. The credit applies to expenditures made on or after April 20, 1977, and before January 1, 1986. The credit is available in addition to the 10% credit which is available for the purchase of depreciable (usually, non-residential) property in general and portions of the credit which are not used the year the expenditure is made (because the taxpayer does not have enough tax liability against which to apply all of the credit) may be carried forward for use in future tax years through 1987. The impact of this residential energy credit on geopressured-geothermal development will apparently be negligible because residential use of this resource is probably more remote than 1985.

IRC Section 48 provides a business investment tax credit on expenditures for the purchase and installation of "energy property". Energy property is defined to be any of six categories of property, two of which are related to utilization of geothermal energy. The credit allowed on these expenditures is in addition to the standard 10% investment tax credit and may be claimed for expenditures on property for which erection is completed after September 30, 1978, or with respect to new energy property only, which is acquired by the taxpayer after that date.

Section 48(1)(3) defines one of the categories of energy property on which the credit is available, "alternative energy property", to mean equipment used to produce, distribute, or use energy derived from a geothermal deposit (within the meaning of Section 613(e)(3)). The credit is equal to 15% of the expenditure, except in the case of expenditures financed by industrial development bonds, in which case the credit is only 7 1/2%. In the case of property used to generate electricity from a geothermal deposit, the alternative energy property definition covers property up through the electricity generation turbines, but not the electricity transmission facilities. Alternative energy property does not include public utility property; public utility property is used predominately in the trade or business of the furnishing or sale of:

1. electric energy, water, or sewage disposal services,
2. gas through a local distribution system,
3. telephone and telegraph service,
4. steam through a local distribution system, or
5. the transportation of gas or steam by pipeline

if the rates for the furnishing or sale are approved by a political subdivision of any state or the United States. This "public utility property" exclusion obviously means that alternative energy property tax credits will not be available to electric utilities or gas transmission or distribution companies. Geothermal Alternative Energy Property tax credits apply to expenditures made prior to December 31, 1985.

Section 48(1)(5) defines the other category of energy property, "specially defined energy property", on which a 10% additional business investment credit is available. This category is specifically defined to include, among other things, a heat exchanger or a preheater. This category of property may also be enlarged by regulation promulgated by the Secretary of Treasury. Specially defined energy property must be used to reduce the amount of energy consumed in an existing industrial or commercial process in an existing industrial or commercial facility; the date on which the facility and the process must have been existing is October 1, 1978. Unlike the alternative energy property category, the specially defined energy property category includes public utility property. This credit is potentially attractive to industrial concerns which might utilize geopressured-geothermal energy directly, but its termination date, December 31, 1982, is probably too close at hand to allow impact on parties of this type.

These credits may be used to offset up to 100% of tax liability.

The Energy Tax Act also amended IRC Section 263(c) to provide that the producer of a geothermal deposit (as defined in Section 613(e)(3)) may elect to (1) deduct as a current business expense his intangible drilling and development costs (IDC's) or (2) capitalize those costs and

add them to the basis of the property for recovery through depletion or depreciation. The situation rarely arises in which the producer will elect to capitalize IDC's. The word "property" is a word of art (Section 614), but generally refers to the aggregate of an operator's working interests in a geothermal deposit, as long as they are located on a single parcel or tract of land, or are produced as a unit.

Subsection (e) to IRC Section 613 provides for an elective percentage depletion deduction for geothermal producers and defines what a geothermal deposit is. The definition is the one previously quoted. The deduction allowed is a percentage of the gross brine-sale income from the geothermal property, exclusive of any rents or royalties paid by the taxpayer in respect to that property. The percentage is 22% through taxable years beginning in 1980 and is gradually decreased to 15% for taxable years beginning in 1984 and thereafter. Cumulative depletion deductions may exceed the cost of the property.

There are a number of limitations on the IDC and percentage depletion provisions which affect the extents to which they operate as incentives. Portions of both the IDC deduction and the percentage depletion deduction may be treated as items of tax preference (ITP's) subject to levy of the minimum tax. The minimum tax is 15% of the lesser of (1) the sum of all ITP's minus \$10,000 or (2) the sum of all ITP's minus 50% or (for corporations) 100% of the taxpayer's tax liability computed without regard for tax deductions but with allowance for tax credits. Geothermal IDC's become ITP's to the extent that the IDC's which were claimed on all geothermal properties in excess of the amounts which could have been claimed under the capitalization and ten-year depreciation methods exceed the net income which the taxpayer realizes from

all geothermal properties during the tax year. This is an extremely complicated area of tax law, but it obviously could work to lessen the IDC incentive for a geothermal developer who, at least in early years, may have IDC's which are well in excess of his net income from geothermal properties. As for percentage depletion deductions, these become ITP's as soon as their cumulative total on a property exceeds the taxpayer's basis (costs) in the property.

There are two limitations imposed on the geothermal IDC deduction which are not imposed on the geothermal percentage depletion deduction. The first of these is found in IRC Section 1254, which provides that when a geothermal property on which IDC's have been claimed is sold, the federal government will recapture (by attributing to the ordinary income of the taxpayer) the difference between the aggregate money amount actually claimed as IDC's and the amount which could have been claimed had the IDC's been capitalized and depreciated as part of the basis of the property. This section highlights the apparent need of a geopressed-geothermal producer to keep separate accounts which reflect the expenses which should be attributed to the geothermal resource, on one hand, and the geopressed methane source, on the other. He needs to do this so that the appropriate amount of recapture may be calculated should the producer sell only one part of the energy-producing property.

The second limitation concerns the "at risk" ceiling on losses which may be deducted if incurred in exploring for, or exploiting, geothermal deposits. The at risk limitation applies to individuals and closely held corporations and provides that they may not claim as deductions related to exploring for, or exploiting, geothermal deposits

amounts in any year which are in excess of income from those activities, unless they (the taxpayers) are actually at risk for the excess amounts at the end of the year. Subsection (b)(4) of Section 465 provides that "a taxpayer shall not be considered at risk with respect to amounts protected against loss through nonrecourse financing, guaranties..., or similar arrangements"; this indicates that money borrowed under the Geothermal Loan Guaranty Program likely will not be considered an amount at risk against which a taxpayer may claim geothermal deductions in excess of income.

Concerning the percentage depletion available for geothermal producers, it is not limited to 65% of overall taxable income or to taxpayers who are not integrated oil companies, as is percentage depletion on oil and gas property, but it is subject to the limitation that it not exceed 50% of the taxable income (computed without regard for the depletion deduction) from the geothermal property on which it is claimed. This latter restriction, which is also imposed on such percentage depletion allowances as are available for oil and gas properties, may eliminate the percentage depletion deduction in the first year of production when IDC's lower taxable income. However, the mere availability of percentage depletion on geothermal properties probably makes those properties attractive to integrated oil companies, which no longer enjoy a similar deduction on most oil and gas properties. The recapture and at risk rules do not apply to the geothermal percentage depletion allowance.

b. TAX POLICIES APPLICABLE TO GEOPRESSURED METHANE. The energy Tax Act also included a couple of tax incentives for producers of the geopressured

natural gas portion of the geopressured-geothermal resource. The first of these is an additional investment credit of 10% on expenditures for "equipment for producing natural gas from geopressured brine" (IRC Section 48 (1)(2)(A)(vi)). The equipment must be used exclusively for this purpose. The credit is available only through December 31, 1982.

For geopressured wells spudded after October 1, 1978, but before January 1, 1984, IRC Section 613A provides for a yearly deduction equal to 10% of the gross income (less royalties) a taxpayer derives from the sale of natural gas produced from geopressured brine. As long as the well is spudded during that time period, the 10% yearly depletion allowance may be taken for the life of the well.

The 10% depletion allowance is not subject to the 65% of total taxable income limitation or, significantly, to the integrated oil and gas company limitation. However, it is subject to the limitation that it not exceed 50% of the taxable income from the geopressured natural gas property. Percentage depletion claimed in excess of the taxpayer's basis (costs) in the geopressured natural gas property is an item of tax preference, in the same way that the geothermal percentage depletion deduction previously explained is an item of tax preference.

Note that an "independent" geopressured methane producer may apparently claim the 15% depletion allowance available (to him) on natural gas generally.

IDC's on wells producing natural gas from geopressured brine may be deducted. Excess geopressured natural gas IDC's may also be ITP's; as noted in the discussion of the geothermal deposit definition, however, these IDC's are aggregated with IDC's from other oil and gas properties,

thereby lessening their potential for treatment under the minimum tax provisions.

c. MISCELLANEOUS TAX PROVISIONS. The Energy Tax Act also amended IRC Section 48(a) to provide that no investment credits be allowed against federal income tax for expenditures on oil or gas boilers used in conjunction with manufacturing, processing, or mining facilities unless environmental regulations preclude the use of coal-fired boilers.

"Mining" does not include oil or gas operations. IRC Section 167(p) was amended to provide that oil and gas boilers which are ineligible for investment tax credits are also ineligible for any form of rapid depreciation. IRC Section 167(q) was likewise amended to encourage early abandonment of oil or gas boilers or other combustors by providing that they may be straight-line depreciated as though their useful lives terminated on the date scheduled for abandonment. These provisions obviously do nothing to help the market for geopressed natural gas, but they could stimulate interest in the use of the geothermal component as an oil and gas substitute.

B.5 Geopressed Methane Price Incentives and Use Disincentives

From the 1954 Supreme Court decision in the case of Phillips Petroleum Company vs. Wisconsin, 347 U.S. 672, until 1978, the well head price of all natural gas sold in the interstate market has been subject to federal price regulation by the Federal Power Commission and, more recently, by the Federal Energy Regulatory Commission under the Natural Gas Act of 1938 (NGA). Historically, price regulation under the NGA was cost-based and sought to limit producer profits to a reasonable return on prudent investments. On November 9, 1978, the Natural Gas Policy Act

of 1978 (NGPA) became effective. The NGPA modified federal well head pricing standards in several ways, an important one of which is that it mandated a switch to incentive pricing theory in the setting of well head price ceilings for all natural gas; incentive pricing is intended to stimulate natural gas production and is not formally cost-based. The NGPA operates to remove disincentives to the production of all forms of natural gas by allowing producers to negotiate more nearly free market prices for their gas.

Section 121 of the NGPA provides that the first sale price of various categories of "high-cost" gas will cease to be controlled by the federal government. Subsection 107(c) defines high-cost natural gas to include gas which is produced from geopressured brine; whether a particular quantity of gas has in fact been produced from geopressured brine is determined at the state agency level, by the Railroad Commission in the case of natural gas produced from geopressured brine in Texas. The absence of federal price regulation on natural gas produced from geopressured brine will presumably encourage producers to develop this resource.

Subsection 107(d) of the NGPA requires that a producer of high-cost natural gas who wishes to enjoy unregulated prices for his product may not simultaneously claim "any credit, exemption, deduction, or comparable adjustment applicable to the computation of any federal tax... allowable...under any provision of law enacted after the date of enactment of this act..." This means that a producer would be forced to an election between unregulated prices and any post-1978 tax incentives which might emerge to stimulate the production of natural gas from geopressured brine.

Natural gas from geopressured brine is also subject to the incremental pricing provisions of the NGPA.

Under these provisions, interstate transmission companies are required to pass on to certain customers so much of the first sale purchase price of natural gas from geopressured brines as is in excess of the "incremental pricing threshold". The category of customers who must bear the incremental pricing differential is determined by the FERC; large industrial users of natural gas for boiler fuel are automatically included and other industrial users of natural gas may be included. The incremental pricing differential may not be passed through to institutions or electric utilities and the FERC may provide an exemption for industrial cogenerators who use natural gas to produce both electricity and other forms of useful energy. The incremental pricing differential paid by the end user may not rise so high that the burner tip cost of natural gas exceeds the burner tip cost of the cheapest appropriate alternate fuel.

The incremental pricing threshold for natural gas from geopressured methane is 130% of the Btu equivalent price of a barrel of #2 fuel oil landed in New York City during the preceding month; thus, if the landed price of #2 fuel oil in New York City is \$34.00 per barrel, first sale gas acquisition costs in excess of \$8.72 per mcf would be borne by the specified industrial users.

Incremental pricing rules apply to all categories of high-cost natural gas. They do not apply to synthetic gas. The incremental pricing provisions obviously have the potential to act as a disincentive to the production of natural gas from geopressured brine, but this is

not thought likely to occur because the burner tip cost of appropriate alternate fuels is expected to be about at the incremental pricing threshold, anyway.

Under Title II of the Power Plant and Industrial Fuel Use Act (1978), the use of natural gas or oil as the primary fuel in new (post-April, 1977) electric power plants and major fuel burning installations is prohibited. Both temporary and permanent exemptions from this prohibition may be secured from the Department of Energy, generally because of environmental considerations, site limitations (no storage space), or inadequacy and unreliability of the supply of alternate fuels.

Title III of the Fuel Use Act prohibits existing power plants from using natural gas as a primary fuel after 1989. It grants the Secretary of Energy the authority to prohibit the use of either natural gas or petroleum as primary fuels in either electric power plants or major fuel burning installations after 1989. As in the case for new power plants and major fuel burning installations, a number of exemptions are available.

Both Titles II and III provide that the Secretary of Energy may grant permanent exemptions from the prohibitions of the Fuel Use Act to cogeneration facilities.

Of great potential importance to geopressured methane development, the Economic Regulatory Administration has excluded geopressured methane from its "natural gas" definition and, thus, from the restrictions of the Fuel Use Act. Geopressured methane may be burned in gas boilers.

B.6 Electric Power and Process Heat Policies

The Public Utility Regulatory Policies Act of 1978 contained two amendments to the Federal Power Act which might have an impact on development of geopressured-geothermal resources along the Texas Gulf Coast. These had to do with inter-connection and wheeling orders for the transmission of electricity. The PURPA also made possible potentially significant exemptions for non-utilities from the Public Utility Holding Company Act and other utility regulation.

The pertinent amendments to the Federal Power Act affected qualifying small power production facilities and qualifying cogeneration facilities. Under Section 17, Federal Power Act, a qualifying small power production facility is a facility owned by a person not primarily engaged in the generation or sale of electric power (other than electric power solely from cogeneration or small power production facilities) which produces electric energy primarily from biomass, waste, or renewable resources and which has a capacity of not greater than 80 megawatts. 1980 amendments to this section (contained in the "Synfuels Bill") make it clear that the FERC may define "geothermal" resources as primary resources appropriate to the small power production facility definition.

Section 18, Federal Power Act, defines a qualifying cogeneration facility as one owned by a person not primarily engaged in the generation or sale of electric power (other than electric power solely from cogeneration facilities or small power production facilities and which produces electric energy and steam or other forms of useful energy (such as heat) which are used for industrial, commercial, heating, or cooling purposes.

Obviously, if the geothermal component of the geopressured-geothermal resource is treated as "geothermal" for purposes of Section 17, a non-utility which produced electric power from this resource might qualify as a small power producer; similarly, if one who uses the geothermal component to produce electric energy can also be said to "produce" steam or other forms of useful energy (such as heat) which are used for industrial or other purposes, then that person may qualify as a cogenerator.

The definitions could be important because the PURPA added a new Section 210 to the Federal Power Act which provides that a qualifying cogenerator or small power producer may petition the FERC for an order requiring the interconnection of the applicant's facility with transmission facilities of any electric utility. The FERC is also empowered to order the sale or exchange of electricity between a qualifying cogenerator or small power producer and any electric utility. These provisions could be important to a non-utility which contemplated generation of electricity near geopressured reservoirs for use elsewhere or for use "in-house" (regardless of whether that use is physically elsewhere).

Section 210 of the PURPA (not the Federal Power Act) directed the FERC to promulgate rules under which small power producers and cogenerators may purchase electric energy from, and sell electric energy to, electric utilities. The same section, as amended by the Synfuels Bill, also provided that certain small power producers and qualifying cogenerators could be exempt, under rules promulgated by the FERC, from all or part of the Public Utility Holding Company Act and other state or federal laws respecting the rates of electric utilities. This provision

could be important to any non-utility, such as a petrochemical plant, which might want to generate electricity for predominately in-house use but would not want to fall subject to utility regulation. The provision might also be attractive to a company which, but for the provision, might be classified as a public utility and therefore be denied the additional 10% investment tax credit on alternative energy property.

Finally, PURPA and the Synfuels Bill added a new Section 211 to the Federal Power Act which provides that any electric utility or geothermal power producer may petition the FERC to order any electric utility to wheel power for the applicant from one site to another. This might be important to electric utilities and geothermal power producers which would develop geopressured-geothermal resources which lie outside their service areas or remote from their plants.

C. CORRELATIVE RIGHTS ISSUE

C.1 Introduction

Correlative rights issues arise because the rights of the "owner" of a mineral in the ground are generally meaningful only if that owner is allowed to extract the mineral; in the course of extraction, the "rights" of owners of minerals located nearby may be jeopardized, as may be collective interests (e.g., resource conservation) of society as a whole.

Correlative rights issues arising from geopressured-geothermal development will be resolved on the basis of well established property law and the state's right to regulate resource production in the common interest. Presumably, analogies to oil and gas law will direct evolution of geopressured-geothermal correlative rights law.

The extents to which these analogies are drawn and are appropriate depend largely on the physical characteristics of the geopressured-geothermal reservoirs. Data from the various DOE design wells will answer most of the important questions concerning geopressured-geothermal reservoir characteristics. Unfortunately, the pertinent data from those wells are not yet (October 1980) available; the following paragraphs, therefore outline the framework in which the correlative rights law will evolve, but necessarily do not present the more informed opinion which future data will make possible.

C.2 Ownership

The Texas Supreme Court has ruled that Texas is an "ownership" jurisdiction as concerns oil and gas (and, presumably, geopressured-geothermal) resources. Eliff v. Texon Drilling (1948). In an ownership jurisdiction, the mineral owner holds title to the mineral whether or not it has been severed (produced). This is distinguished from the rule in "qualified ownership" jurisdictions, such as Louisiana, where title to oil and gas is not secured until the resource is severed.

The acknowledgement of title to property is important legally because it means that the taking of that property (by the state or another individual) amounts to confiscation. The U.S. Constitution prohibits confiscation ("taking") of property without "just compensation." Case law or regulations which prohibited absolutely the production of property to which one held title would confiscate that property and, therefore, be unconstitutional in the absence of just compensation.

One who owns oil, gas, or other minerals in place in Texas may not be absolutely prohibited from producing that resource. The point at

which state regulation of resource production becomes so onerous or unreasonable as to amount to a production prohibition is a legal question, the answer to which depends on facts peculiar to the resource and its would-be producer.

C.3 The Rule of Capture

The rule of capture could not be invoked by a geopressured-geothermal developer to produce a reservoir in the face of statutory or regulatory restrictions. It might, however, shield the non-negligent developer from liability for production of a resource to which another person held title.

The rule was announced in an old Pennsylvania case, Bernard v. Monoghela Natural Gas, in 1906. An oil company had drilled a well on its own property and drained through it oil which underlay its own and another's (Bernard's) property. When Bernard sued, the court said the oil company was not liable for the value of Bernard's oil it had produced. This case was decided at a time when knowledge of oil and gas reservoirs was very rudimentary; the court analogized the capture of oil to the capture of wild animals--if the "animals" had fled from the reservoir beneath Bernard's land to the oil company's well, that was not something for which the oil company could be blamed. Bernard's remedy was to drill a well of his own.

The application of this rule has been somewhat restricted by statutes and regulations directed to insuring that resources are produced in a manner consistent with resource conservation. Although there is confusion on this point, it has never been a rule which authorizes production; it in some cases shields a producer from liability for aspects of production which is otherwise justified.

C.4 State Regulation: Spacing and Pooling

The U.S. Supreme Court held early on (1900) that a state may, to protect correlative rights, restrict the ability of a titled owner of oil or gas resources to produce those resources. Ohio Oil Co. v. State of Indiana. Texas, through the Texas Railroad Commission, has done this in numerous respects. For example, in 1947 it ruled that oil and gas producers could not "flare" natural gas at the well head, because to do so squandered one of the state's natural resources. (Texas Railroad Commission treatment of the anti-flaring rule may be important as an indicator of its treatment of the Texas Natural Resources Code, Section 141, proscription against waste of the heat component of the geopressured-geothermal resource; the anti-flaring rule is applied statewide, but exemptions are occasionally granted because of special circumstances.)

The Texas Railroad Commission's Spacing Rules (Rule 37) are founded on resource conservation theory. These hold, at the most basic level, that an oil producer may not locate wells any more densely than every 40 acres and that a gas producer may not locate wells any more densely than every 160 acres. A similar rule could be developed for geopressured-geothermal resource production.

To protect the rights of an owner of oil or gas in place whose property is too small to qualify for a permit under the spacing standards of Rule 37, that owner is allowed to petition the Commission for formation of a "pool" (production unit), of which that owner's property would be a component. Other resource owners included in the pooling agreement are required to participate in the cost of drilling if they are to

receive shares of production from a successful well. Pooling law is still controversial and has become quite complicated, turning on such points as whether property subdivisions were made voluntarily or involuntarily, and were made with, or without, knowledge of the subsurface mineral resource. The administrative and legal overhead involved in establishing a pool for production from reservoirs of the size contemplated for profitable geopressured-geothermal development will be substantial.

VI. SPECIAL PROJECTS

A. STANDARDIZATION OF SAMPLE COLLECTION AND ANALYSIS

To resolve the problem of lack of uniformity in sampling and analytical procedures during drilling and testing phases of geopressured geothermal wells, standardized procedures for fluid sampling and analysis, well logging, coring and core handling, and rock mechanics analyses have been considered.

A.1 Fluid Sampling and Analysis of Geopressured Fluids

The geopressured geothermal resource being investigated consists of gases and liquids. It is apparent that every effort should be made to obtain accurate chemical analyses of these fluids for proper assessment of the resource. Toward that end an agenda was prepared by Karkalits and Hankins of McNeese State University in Lake Charles, Louisiana, and a meeting was held December 5, 1979, in Austin, Texas with the following participants: Keith Westhusing, D.O.E; B. E. Hankins and O. C. Karkalits, McNeese University; Jack Matson, University of Houston; Yousif Kharaka and Tom Kraemer, U.S.G.S.; L. S. Land, The University of Texas at Austin; and Bob Morton, Bureau of Economic Geology, Austin.

Discussion of the different elements of fluid sampling and analysis led to certain conclusions and agreements as to standard field and laboratory procedures, however additional details needed to be resolved.

A second meeting was held in Houston on January 18, 1980, to resolve procedural differences and discuss other items, such as downhole sampling, pH, and scaling. Attendees were: Keith Westhusing, Fred Goldsberry, D.O.E.; John Sharer, G.R.I.; Mason Thompson, Rice University;

O. C. Karkalits, Bob Hankins, McNeese University; Tom Kraemer, Yousif Kharaka, U.S.G.S.; and Bob Morton, B.E.G.

At this meeting fluid analyses standards were agreed upon. McNeese State agreed to be responsible for preparing a document setting forth standardized procedures and to act as a clearing house for monitoring test wells to check analytical results of work done by commercial labs.

A draft document was circulated to participants in February, with a final draft prepared in March by Hankins and Karkalits of McNeese State.

A.2 Coring and Core Handling and Rock Mechanics Analyses for Geopressured Geothermal Wells

A rock mechanics testing program is essential for developing an understanding of the mechanics of geopressured reservoirs. For maximum usefulness in assessment of the resource, these analyses need to be standardized to provide compatible data from different design wells.

With an agenda prepared by Morton, B.E.G., a workshop meeting was held in Austin, May 2, 1980 to discuss coring and rock testing. In attendance were: Keith Westhusing, D.O.E.; John Sharer, G.R.I.; Phil Randolph, Walter Rose, I.G.T.; John Schatz, Terra Tek; Tom Kraemer, U.S.G.S.; Ken Gray, Thomas Thompson, Bob MacDonald, U.T. Austin Petroleum Engineering Dept.; and Bob Morton and Chet Garrett, B.E.G.

Significant discussions developed along four separate lines (1) coring procedures, (2) core distribution and storage, (3) basic physical properties analyses, and (4) rock mechanics procedures and analyses including specific tests, equipment design and present capabilities of rock mechanics laboratories. Ken Gray agreed to be responsible for receiving written comments from participants, circulating these to the

others, calling another workshop to agree upon and formalize a series of recommendations for standardizing the different elements of rock mechanics.

With this general format an additional meeting was held in Austin on June 18, 1980. In attendance were: Keith Westhusing, D.O.E.; Don Bebout, Louisiana State Geological Survey; Dale Carver, Louisiana State University; Tom Kraemer, U.S.G.S.; John Schatz, Tera Tek; Walter Rose, I.G.T.; Ken Gray, U.T. Austin, Petroleum Eng. Dept.; and Bill Kaiser, Bob Morton, and Chet Garrett, B.E.G.

Reports on coring procedures, core handling procedures, and rock mechanics were presented and, after further discussion, generally agreed upon. Ken Gray was charged with the responsibility of preparing a draft copy of the standardization and recommendations for further comments and discussions. This was done and, after incorporating additional suggestions, a final draft copy of this report was being prepared in December, 1980.

A.3 Well Logging of Geopressured Geothermal Wells

A standard well logging program is also essential to achieve assessment objectives for the geopressured geothermal resource. For this reason an agenda was prepared by Garrett, B.E.G., and a well logging workshop was held in Austin on July 21, 1980. Participants were: Keith Westhusing, D.O.E.; Joseph Brivetti, Schlumberger; Myron Dorfman, Pat Biggs, and Henry Dunlap, U.T. Austin Petroleum Eng. Dept.; Barry Satterwhite, Wellex; Helmut Cmelik, Gearhart Industries; Walter Fertl, Dresser Atlas Co.; and Bob Morton, Ray Gregory, and Chet Garrett, B.E.G.

Henry Dunlap agreed to be responsible for preparing and distributing to participants draft copies of the proposals for standardization, which were discussed at the meeting.

It was generally agreed that there should be a specified list of essential logs for both hydro pressured and geopressured regimes, with additional logs listed as desirable but not essential. A first draft of recommendations for standardization, which included a section devoted to special research needs in logging geopressured geothermal reservoirs was distributed July 29, 1980.

An "official" report with attached cost estimates from the logging companies represented was distributed on September 2, 1980.

B. INTEGRATION OF SANDSTONE CONSOLIDATION AND ROCK MECHANICS STUDIES

Samples of Frio sandstone subjected to laboratory creep tests were examined petrographically to determine if the test procedures and conditions caused permanent deformation or other alterations to the rock samples.

Three core samples from 14,056 ft, 14,093 ft, and 14,097.6 ft in GCO/DOE #1 Pleasant Bayou were examined. Six thin sections (3 parallel and 3 perpendicular to bedding) were taken at equal spacings from each core. Thin sections were examined petrographically and compared to existing sections from unstressed core over the same depths. In no case was any definitive evidence of experimentally induced strain observed. Point counts (200 points per slide) of porosity on stressed and unstressed samples gave comparable results. However, two of the three cores contain abundant matrix and therefore had extremely low porosities (<1%) even prior to testing. The remaining sample (from 14,056 ft) is

matrix-poor and contains approximately 14.5% porosity after testing. Unstressed samples from just above and below contain 9.5% and 16.0% porosity, respectively. Absence of porosity reduction in this sample is substantiated by petrographic observations of oversized secondary pores (fig. 1), leached remnants of grains remaining in optical continuity (fig. 2), and undeformed clay rims with no internal support (fig. 3). Also, mechanically unstable constituents are abundant in this sample. If significant compaction had occurred, they should have been deformed, resulting in substantial porosity occlusion.

Some features were observed in thin section which are traditionally attributed to pressure deformation: strain-banding in quartz, bent twin lamellae in plagioclase, and deformed cleavage traces in biotite. However, these features are fairly uncommon and seem to be randomly distributed and oriented. They probably formed in the source area or during deposition rather than from subsequent testing. The elastic behavior of the rock, determined from laboratory measurements, explains the lack of porosity reduction, microfractures, or any other evidence of test induced deformation.

This special project is being continued under the consolidated contract so that additional samples can be analyzed as they are made available.

C. STUDY OF LOG-DERIVED WATER RESISTIVITY DATA IN GEO² FORMATIONS

Summary. This project, initiated in March, 1980, was set up to determine the cause of the error in SP derived water resistivity in geothermal geopressed formations, and, hopefully, to improve the accuracy of the calculation. Tests in several wells had shown the calculated water

Figure 1. Oversized secondary pore (p) in plane light.

Figure 2. Remnants of leached feldspar (f) in optical continuity around secondary pore (p) under crossed polars.

Figure 3. Unsupported clay rim (cr) surrounding leached pore (p) in plane light.

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resistivity to be in error by factors of 1.5 to 2, generally in the direction of predicting too fresh a formation water.

Work through October, 1980 has been of two types: (1) searching the literature for previous work relating to this problem, and (2) searching for deep hot wells drilled with high density muds, where we have reliable formation water data (resistivity and/or salinity) together with good logs, so that we can compare SP derived with actual water resistivity. Such examples are not easy to get, but we have accumulated 24 of them.* Using this data, we calculated the formation water resistivity from the SP in various ways (using the measured R_{MF} value given on the log header; using the R_{MF} value given by the empirical R_{MF} vs R_M and mud density relation - Schlumberger's chart Gen-7; and using an average R_M vs R_{MF} correlation obtained from a back calculation of the "true" R_{MF} from the known formation water resistivity and SP data). This work has led to several tentative conclusions and working hypotheses. These are listed below, along with references to the progress reports where these points are discussed more completely.

C.1 Work to Date

a. Temperature corrections for muds and mud filtrates are usually carried out assuming that NaCl solutions are involved. Actual muds and filtrates behave differently, leading to errors of 10 to 20% at temperatures of 300°F depending on the mud type involved. The proper

*See Table I of Second Progress Report, Third Progress Report, Fourth Progress Report, Sixth Progress Report, and Eighth Progress Report for well names, locations, etc. Progress Reports 1-8 are included in Appendix B.

temperature vs mud type relation should be used for best accuracy. (See Fig. 3, Fourth Progress Report.)

b. Mud properties at the time the formation is drilled (as well as when it is logged) are needed. Most of the filtrate is lost to the formation when the formation is drilled. It is the filtrate in the invaded zone that primarily controls the SP development, rather than the mud in the hole at the time of logging, days to weeks later. Literature and field data indicate that the ratio of R_M/R_{MF} could vary as much as a factor of 2 between logging runs. (See Fig. 2, Fourth Progress Report, and Fig. 2 plus accompanying discussion, Seventh Progress Report.)

c. Use of log header values for measured R_{MF} in hot wells using high density muds leads to large errors in calculating formation water resistivity from the S.P. Usually, but not always, the error is in the direction of calculating too fresh a water (too high calculated R_w). The errors are different for different basic mud types, and are worst for lignosulfonate muds which is the most often used in today's deep drilling. Use of the Schlumberger Gen-7 correlation to obtain R_{MF} from R_M and mud density is better than use of the header data for R_{MF} but still leads to large errors. Best values of R_{MF} are obtained using an average curve we have fitted to the back calculated "true" R_{MF} values obtained from known SP and formation water resistivity data. We conjecture the difficulty in using the header (measured) values of R_{MF} is due to the presence of substances in the mud filtrate which increase its viscosity, thereby increasing its resistivity proportionally. If this resistivity is interpreted in terms of a NaCl solution in water, too low a salinity will be inferred, leading to calculation of too low a

salinity for the formation water. (See Third Progress Report, and Sixth Progress Report.)

C.2 Future Plans

a. We plan to continue to gather statistical data as it becomes available, although this will not have first priority.

b. We plan experimental work in the lab and field to obtain data which would confirm or refute our various hypotheses. These include: temperature vs resistivity data for various muds and filtrates; study of filtrate resistivity and viscosity for various muds; field data on short term variation in mud and filtrate properties in deep, hot wells drilled with high density muds; field data on mud filtrate properties using filtrate recovered from the invaded zone with the repeat formation tester. This data may be difficult to get in unconsolidated formations, as the tool may stick, but in competent formations similar to the zone being tested in the Pleasant Bayou #2 well, the danger of sticking should not be great. Use of a tracer in the mud (NO_3^- ion for example) should permit measurement of contamination of the filtrate by formation water.

D. REGIONAL STUDY OF SALINITY DATA

Consultation with industry representatives resulted in their recommendations that requests for chemical analyses of formation water be as specific as possible in order to facilitate data retrieval. Consequently, much time was needed to compile lists of operators with county and field designations that may contain producing geopressed reservoirs. More than 750 oil and gas operators were screened for the number of wells in each field area. Initial work focused on the prime prospect

areas in Texas; later work included all the deep producing fields in the Wilcox and Frio trends. In all, more than 240 fields were listed for requests of site specific field data.

Water analyses previously published were compiled from the literature. In conjunction with this effort, more than 75 references pertaining to salinity of formation water were compiled and reviewed. An annotated bibliography describing the important concentrating mechanisms was prepared for those references.

A preliminary investigation of spatial variations in salinity was conducted using detailed structural and stratigraphic cross-sections. The salinity values used in these plots (figs. 1 - 3) were calculated from electric logs as part of the entrained methane project (DE-AC08-78ET11397). The calculated data showed a general decrease in salinity with depth and a general increase of salinity with increased sand thickness. These trends agree with published reports using electric logs, however they are highly suspect because of the documented discrepancies between log-derived salinities and actual field measurements for geopressured sandstones.

This special project has been expanded and continued under the consolidated contract and coordinated with the sandstone consolidation study.

E. CORROSION AND METALLURGY STUDY

An extensive literature survey on the material problems encountered in several geothermal plants and testing facilities was performed. The geothermal sites surveyed included locations in the United States (Geysers, Salton Sea, East Mesa, Heber, Raft River, and Baca) and abroad

Figure 4. Locations of wells and structural cross sections, Blessing Prospect, Matagorda County, Texas.

Figure 6. Structural section D-D' showing salinities calculated from the Rmf (header) method.

(Wairakei and Cerro Prieto). The materials used in different components of the surface facilities were identified; later they would be critically analyzed.

In addition to this, direct contact was made with George Crabtree of "Geothermal Pumps" and P. D. Huey of "Solar Turbines." Their input was helpful in directing the course of our investigation. P. D. Huey supplied us with additional literature on materials in geothermal applications.

During the course of this contract the following meetings have been attended:

- a) Third Annual Geothermal Conference
(June 25-29, 1979; Monterey, California)
- b) Organizational Meeting of Committee E45 on Geothermal
Resources and Energy
(October 17-18, 1979; Philadelphia)
- c) Fourth United States Gulf Coast Geopressure Geothermal Energy
Conference: Research and Development
(October 29-31, 1979; Austin, Texas)

At this conference a paper entitled, "Electrochemical Corrosion Measurements in Geothermal Brines" was presented. The text of this presentation was published in the Proceedings of the conference.

- d) A paper entitled "The Nature of Surface Films in High-Salinity Brines" was presented at the Fall, 1980, Convention of the American Institute of Petroleum, Mining and Metallurgical Engineers; Pittsburgh, Pa, October, 1980.

A state-of-the-art computerized corrosion instrument (Princeton Applied Research 350-1) was purchased and is currently being used for laboratory electrochemical measurements. The instrument is capable of determining corrosion rates, passivating, pitting and crevicing tendencies. A friction and corrosive wear unit was designed, built and interfaced with the 350-1. It serves as an electrolytic cell in the static condition; and, as both an electrolytic cell and friction and wear apparatus in the dynamic condition. Using this equipment and the knowledge gained from the information survey, a corrosion investigation of materials used in geothermal facilities was carried out.

The corrosion investigation of materials used in geothermal facilities consisted of three sections. First, a general screening of materials through electrochemical measurements was initiated, followed by Auger analysis of the surface film formed on set specimens from this process. Second, using the results from Section I, specimens were machined for friction and corrosive wear testing in an electrochemical cell specifically designed and built for this application. Third, sensitization studies of the heat affected zone of welded 304 stainless steel rods was begun.

An abstract of each stage is presented below. For details on these studies, refer to Sections I, II, and III immediately following the abstracts.

Electrochemical Corrosion Measurements in Geothermal Brines:

The Nature of the Surface Film on Highly Alloyed Austenitic Stainless Steels in High Salinity Brines

Electrochemical corrosion measurements on several types of structural materials were performed in both synthetic and natural brines. It

has been found that the uniform corrosion rate is relatively low for all the materials tested (except the low carbon steel). The localized corrosion is very severe for the regular austenitic, martensitic, and ferritic stainless steels as well as for Inconel 600. No localized corrosion was seen on the low carbon 1018 steel. The two alloys identified in the text as 28 and 2205 showed excellent resistance to localized corrosion. The nature of the passivating film formed in brine on alloy 28 was identified by the Auger electron spectroscopy (AES) technique. It has been found that the protective film is depleted of molybdenum and enriched in manganese. The possible effects of these findings on the development of new corrosion-resistant alloys for the geothermal industry are currently under study.

The corrosion layer formed on a highly alloyed austenitic stainless steel in high salinity synthetic and natural brines has been studied by electrochemical and Auger spectroscopy techniques. At relatively low polarization voltages (below +600mv vs SCE) the passive layer consisted of the matrix elements and oxygen; molybdenum seemed to be in a very low concentration at the very surface. At high polarization voltages, a definite step appeared in the polarization curve in natural brine, the passive current increasing by almost one order of magnitude. The film formed at these high polarization voltages was positively identified as manganese, the formation of which cannot be explained in terms of the chemical composition of the brine. Comparisons of shape of polarization curve and film composition were made with more conventional types of austenitic stainless steel, like AISI 304 and 316, and other highly alloyed steels such as C-276 and Stellite 6B.

Friction and Wear of Stainless Steels in High-Salinity Brines

The friction and wear characteristics of stainless steels in high-salinity brines are being studied on a friction apparatus coupled with a computerized corrosion system model PAR-350. Electrochemical polarization curves, wear rates, and friction coefficients are being determined for different types of stainless steels in different experimental conditions, i.e.: (1) sliding in air, (2) stationary in brine, and (3) sliding in brine. The nature of the passive films will be studied by SEM and Auger Electron Spectroscopy techniques. The interrelation between the wear rates in the corrosive environment and the dynamic characteristics of the protective film will be studied.

Sensitization Measurements of the Heat Affected Zone (HAZ) of Welded 304 Stainless Steel Rods by the Electrochemical Potentiokinetic Reactivation Technique (EPR)

Many welded parts or material sections are found in geothermal applications. Welded stainless steels are very susceptible to corrosion because of sensitization. Welds affected by the homopolar technique induce a much smaller HAZ than is normally encountered with welded parts. Because of this the standard oxalic etch test is unable to detect it; whereas, the EPR technique can detect and quantify the degree of sensitization. The progress of this work is summarized in this section.

E.1 Section I. Electrochemical Corrosion Measurements in Geothermal Brines.

It is well known that due to their high temperature and high concentration of chloride ions, geothermal brines are corrosive to many metals and alloys. The type of corrosion and methods of preventing it

are important considerations in the utilization of geothermal waters for power generation. Reliable results on the behavior of materials in different geothermal environments can be achieved only in long-term experiments in the brine of interest. Never-the-less, valuable information can be gained from short-term electrochemical measurements at the well site, and in the laboratory. This paper describes the results obtained on several structural materials tested in our labs in both synthetic and natural brines, and also contains AES analysis of the passive films formed on selected specimens.

a. EXPERIMENTAL PROCEDURE. Materials. Eight different structural materials were tested. They are listed in Table 1. All the materials (except Inconel 600) were machined in the form of a disc with a diameter of 1.6 cm and height of 0.32 cm. The area exposed to the brine was 1 cm². The Inconel 600 was machined in the form of a cylinder with a 0.95 cm diameter and 1.27 cm height. The exposed area was 5 cm². All the specimens were polished and cleaned according to ASTM G5 specifications before being immersed in the brine.

Apparatus. The electrochemical measurements were performed with a PAR 350-1 corrosion system. All the potentials were measured against a saturated calomel electrode. Two examples of polarization curves obtained with this instrument are presented in Figures 7 and 8. It can be seen that the Tafel constants, the corrosion current, and the uniform corrosion rate in mpy are automatically calculated and displayed. The scan rate employed in all experiments was 1 mv/sec.

Table 1

CHEMICAL COMPOSITION OF ALLOYS USED IN THIS INVESTIGATION

ALLOY	Fe	C	Si	Mn	P	S	Cr	Ni	Mo	N	Cu	Al
1018	98.7	0.18	0.20	0.80	0.04	0.05	--	--	--	-	--	--
304	70.8	0.08	1.0	2.0	0.04	0.03	18	8	--	-	--	--
316	64.3	0.08	1.0	2.0	0.04	0.03	18	12	2.5	-	--	--
410	85.5	0.15	1.0	1.0	0.04	0.03	12	--	--	-	--	--
430	79.5	0.12	1.0	1.0	0.04	0.03	18	--	--	-	--	--
600	7.5	0.07	0.24	0.2	----	0.007	15.54	76.31	--	-	0.11	--
28	36.1	0.01	0.12	1.74	0.01	0.003	26.3	31.00	3.58	0.036	1.07	0.014
2205	67.4	0.03	0.8	2.0	0.03	0.02	22	5.5	3.0	0.14	--	--

Figure 7: Polarization Curve of 430ss in 1N H₂SO₄

Figure 8: Typical Polarization Curve of a High-Cr, High-Ni SS in NaCl Aqueous Solutions

The scanning electron micrographs and the Auger electron spectra were taken on a JEOL JSM-2 Scanning Electron Microscope and a PHI-590 Auger electron spectrometer respectively.

Results. The anodic polarization curves for the 304, 316, 410, and 430 stainless steels are presented in Figure 9. It can be seen that all these alloys display a passive region at a current density on the order of 10^3 Na/cm^2 . The same results are replotted in Figure 10 with the potential axis shifted so that the corrosion potential for all the alloys coincide. In this way the relative position of the breakdown potentials (E_b) can be better resolved. The largest passivation range is displayed by 316 and the lowest one by 410. The SEM micrographs in Figures 11 and 12 show that the amount of localized corrosion for the 410 alloy (lowest E_b) is higher than for the 316 alloy (highest E_b).

Figure 13 shows the anodic polarization curves for the low carbon steel (1018), Inconel 600, alloy 28 (austenitic), alloy 2205 (ferritic-austenitic) and Stellite 6B. It can be seen that both Inconel 600 and Stellite 6B have a relatively low range of passivation compared to either 28 or 2205. These two latter alloys have their breakdown potentials at very high positive values, close to 1 V. The micrographs presented in Figures 14 and 15 show that the low carbon alloy steel (1018) exhibits significant uniform corrosion but no visible localized corrosion; Inconel 600 exhibits severe pitting, while alloys 28 and 2205 are practically unattacked.

More information about the susceptibility to localized corrosion can be gathered from Figure 16. It can be seen that alloy 28 has a protection potential (E_p) very close to the breakdown potential (E_b). Pits

Figure 9: Anodic Polarization Curves for 304, 316, 410 and 430 Stainless Steels in 3% NaCl Brine

Figure 10: Same Curves as in Figure 3, with the Vertical Axis Shifted to a Common Corrosion Potential

(a)

(b)

Figure 11
SEM MICROGRAPHS FOR
(a) 410 AND (b) 430 SS

(a)

(b)

Figure 12
SEM MICROGRAPHS FOR
(a) 304 AND (b) 316 SS

D
R
A
F
T

Figure 13: Anodic Polarization Curves for 1018, Inconel 600, Alloy 28, Alloy 2205, and Stellite 6B

Figure 14
SEM MICROGRAPHS FOR
(a) 1018 AND (b) INCONEL 600

Figure 15
SEM MICROGRAPHS FOR
(a) ALLOY 28 AND (b) ALLOY 2205

Figure 16: Forward and Reverse Polarization Curves for 1018, 304ss, Inconel 600, and Alloy 28

cannot initiate or propagate at any potential between E_{corr} and E_p . Existing pits can eventually propagate at potentials between E_p and E_b . The very high value of E_p for this alloy confers it a high degree of immunity against localized corrosion. The lower difference between E_p and E_{corr} for Inconel 600 makes this alloy much more susceptible to localized corrosion. Alloy 304 has a protection potential below the corrosion potential meaning that pits can propagate at the corrosion potential. The sensitivity of this stainless steel to localized corrosion is thus very high. The very low degree of hysteresis exhibited by 1018 is an indication that this steel does not undergo localized corrosion in the conditions of our experiment. Figure 17 shows that, as far as the uniform corrosion is concerned, all the alloys studied (with the exception of 1018) perform satisfactorily; their corrosion rate is on the order of 0.5 mpy or less.

b. ELECTROCHEMICAL MEASUREMENTS IN THE BRINE FROM PLEASANT BAYOU #2 WELL.

A comparison has been made between the corrosion properties of selected materials in the well brine and in a synthetic brine having the same chloride ion concentration. The principal components of the brine are shown in Table 2. Figure 18 shows that the behavior of alloy 2205 in the well brine is similar to that in the synthetic brine having the same amount of chloride ions, except that a step is observed in the polarization curve in the well brine at a potential of about +500 mv. The interpretation is that a protective film forms on the surface of the specimen which is then penetrated and replaced by a less protective film. This same phenomenon was exhibited by alloy 28, Stellite 6B, and C276. Therefore a thorough auger electron study of the films both above and below the step was indicated.

Figure 17: The Uniform Corrosion Rates of the Materials Studied

Table 2

BRINE ANALYSIS, PLEASANT BAYOU #2, JULY 10, 1979

Dissolved Solids			
Cations	mg/L	Anions	mg/L
Na	32,697	Cl	113,156
Ca	9,640	SO ₄	5
Mg	18,760	CO ₃	1
Ba	875	HCO ₃	226

Fe(total) 76

Total Dissolved Solids 175,435

Specific gravity	1.090
Resistivity (ohm-meters)	0.24
pH	6.15

Figure 18: A Comparison Between the Polarization Curves of Alloy 2205 in the Well Brine and in a Synthetic Brine

Auger Electron Study. In order to gain some information about the nature of this corrosion layer, an Auger electron spectroscopy study has been performed on the following alloys: 304, 316, 28, 2205, C-276 and Stellite 6B. (Refer back to Table I for specimen compositions.) Each specimen was metallographically polished, cleaned and left in air for a period of one hour. AES analysis was then carried out on the naturally grown oxide before and after sputtering. In this manner the relative peak ratios could be characterized for the bulk material. For brevity's sake, only the results for 28 are presented in Figures 13 and 14. It can be seen that the film contains all the bulk elements (Fe, CR, Ni, Mo) and a strong oxygen peak. The oxygen is probably combined with chromium as a chromium oxide. After sputtering (Figure 14) the film is removed, the oxygen peak drastically decreases, and the composition underneath the film is that of the bulk material.

At this point it was necessary to determine the length of time needed for film growth at a set potential. This was determined by the following procedure on alloy 28: a 28 specimen was prepared in the manner noted above, but this time it was immersed in the brine, anodically polarized to about +600 mv, and immediately removed. In this way, a very thin corrosion film was formed. Figure 15 shows that a manganese peak is present together with the peaks corresponding to the other bulk elements. After sputtering (Figure 16) the manganese peak disappears. A third specimen was then prepared and placed in brine, and a polarization curve was performed up to the same potential as before. This time, however, the specimen was held at that potential for a period of 30 minutes. In this way a relatively thick corrosion film was formed.

Figure 19: Auger Spectrum of Alloy 28 Oxidized in Air

Figure 20: Same Specimen as in Figure 13, After Argon Ion Sputtering

Figure 21: Auger Spectrum of Alloy 28 After Polarization in Brine at 600mV

Figure 22: Same Specimen as in Figure 15 After Argon Ion Sputtering

Figure 23 shows that at the surface of this thick film, molybdenum, iron, and nickel are not present. Instead, the manganese peaks are very intense and so are the chromium and oxygen peaks. After sputtering (Figure 24), the oxygen peak drastically decreases. The manganese peak disappears and the elements present are characteristic of the bulk material.

Films were then grown for a period of 30 minutes at potentials corresponding roughly to the middle of the passive range for alloys 304 and 316, and at potentials below and above the step for the other four specimens, +.200V and +.600V versus SCE respectively. It can be seen that the films grown at high polarization voltages contain a heavy manganese scale, while those grown at low polarization voltages contain no manganese. Moreover, no molybdenum can be seen at the very surface of any film, independent of the polarization voltage at which the film was grown. After sputtering (removal of the surface layer by Argon ion bombardment) the chemical composition of the outer layer is identical to that of the bulk material (Figure 25).

It should be emphasized that molybdenum, which is added to stainless steels for better corrosion protection in chloride media, is not present. Two explanations are suggested in the literature:

1. Molybdenum can change the nature of the bonding at the film-bulk interface making it more difficult to penetrate.
2. Molybdenum has a lower affinity to chloride ions than chromium, thus reducing the chloride absorption which in turn decreases corrosion, (Figure 26).

A typical Auger spectrum is shown in Figure 27. It shows the composition of the passivation layer formed on AISI-316 at a polarization

Figure 23: Auger Spectrum of Alloy 28 After Polarization in Brine at 600mV and Kept at That Potential for 30 Minutes

Figure 24: Same Specimen as in Figure 17 After Argon Ion Sputtering

Figure 25: Summary of Auger Results

Mo CHANGES NATURE OF BONDING AT THE
FILM-SUBSTRATE INTERFACE?

304 (No Mo)

316, 2205, 28
(contain Mo)

EFFECT OF CHROMIUM: HIGHER AFFINITY FOR OXYGEN
THAN IRON.

EFFECT OF MOLYBDENUM: LOWER AFFINITY FOR CHLORIDE
THAN CHROMIUM.

Figure 26: Effect of Molybdenum

voltage of +.221V. On the right hand side of the figure, a blow-up of the low energy iron peak from the Auger spectrum (encircled) is displayed. It is very interesting to note that the peak characteristics of the iron in the oxide state (in the film) are totally different from those of the iron in the metallic state (after sputtering). There also exist refined methods of distinguishing between different types of iron oxides from the shape of the double peak (relative position and intensities).

Conclusions: Electrochemical Measurements

1. As far as the uniform corrosion is concerned, all the alloys tested (except 1018) perform satisfactorily. Their corrosion rate is on the order of 0.5 mpy or lower.
2. Alloys 304, 316, 410, 430, and Inconel 600 are very susceptible to pitting corrosion.

AES Results of Passive Films on 28, 2205, and C-276

1. Addition of Molybdenum to the Cr-Ni stainless steels may improve their corrosion resistance by affecting the nature of the film-bulk bonds and/or by decreasing the chloride ion affinity.
2. At high polarization voltages, the surface layer is covered by a manganese scale, the formation of which cannot be explained in terms of the chemical composition of the brine.
3. The transition from iron oxide to metallic iron in the surface film can be described in terms of the shape (relative position and intensities) of the low energy iron peaks in the Auger spectrum.
4. Since the surface layer is the key element in conferring protection against corrosion, a thorough understanding of its nature is of paramount importance in any alloy development for practical applications.

DRAFT

E.2 Section II. Friction and Wear Characteristics of Stainless Steels in High-Salinity Brines.

For the vast majority of stainless steel applications throughout industry, such as tanks, vessels, piping, structural components, utensils, and general hardware items, material selection is based on four criteria:

- (a) corrosion resistance,
- (b) mechanical properties,
- (c) fabricability, and
- (d) cost.

For mechanical equipment, however, such as pumps, valves, bearings, seals, in which mating metal surfaces rub together -- consideration should also be given to wear.

Finding the most effective alloy to simultaneously withstand corrosion and wear constitutes a worrisome problem for equipment engineers and manufacturers. This paper is aimed at a basic understanding of the interaction between a corrosive environment and a sliding contact system. Special attention will be given to the study of such a system in hypersaline brines, characteristic of the Texas Gulf Coast Geothermal Geopressured Fields.

a. EXPERIMENTAL PROCEDURES. Apparatus. The electrolytic cell used for the tests is schematically drawn in Fig. 28. The cylindrical specimen is rotated at constant velocity by a speed-controlled electric motor pulleyed to yield rpm ranges of 40 to 2000 rpm. The counterspecimen is made of a sintered Al_2O_3 plate which is virtually inert in the test brine. The counterspecimen is held by an arm which also serves as a means of applying the load. Small horizontal displacements of the loading arm are used to measure friction forces by strain gauges. The electrolyte is contained in a perspex trough.

The rotating specimen constitutes the working electrode. The counter-electrode consists of two graphite rods symmetrically placed about the rotating specimen. A saturated calomel electrode enables the measurement of the potential close to the surface of the worn part of the cylindrical specimen. During the tests, the applied potential, the resulting current, the friction coefficient and the amount of wear are being continuously recorded.

Material Preparation and Experiment. The Al_2O_3 counterspecimen is polished to 600 grit silicon carbide paper, then ultrasonically degreased in freon for 5 minutes, followed by a methanol ultrasonic cleaning for an additional 5 minutes. It is then inserted into its holder. The working electrode is then polished in a lathe using 240, then 600 grit paper. The specimen is washed in hot soapy water, dried, weighed to the nearest ten-thousandth of a gram and ultra-sonically cleaned in freon for five minutes, followed by ultrasonically cleaning in methanol for five minutes. Prior to the insertion of the specimen into the electrolytic friction cell, the strain gauges and loading arm must be balanced and zeroed.

Figure 28: Schematic of Friction and Wear Electrolytic Cell With Front Face Removed

A dummy specimen is placed into the cell so that the loading arm can be zeroed on the specimen. A counterbalance is adjusted on the end of the loading so that no weight is applied to the specimen by the arm itself. Then the "dummy" specimen is removed, and the loading arm is held level such that the line of axis of the counterspecimen/working electrode interface is that of the kardanic bearing. At this point a counterweight hanging down from the arm is used to stabilize the arm such that it will balance (stay at rest) in every position as the arm is turned to the left or right.

This completed, the strain gauges are balanced and zeroed using an HP321 dual chart recorder. Calibration of the gauges is then done using a 1/2# weight on the number 2 attenuator setting. At this point a specimen (working electrode) is installed in the unit along with the counterspecimen and its holder. To insure intimate line contact between the working electrode and the counterspecimen a 600 grit paper is affixed to the counter specimen, and a slight load is applied to the arm while the specimen is turning. It is removed and both the working electrode and counterspecimen are cleaned with dry methanol.

A 3% NaCl solution electrolyte is poured into the cell, electrical connections are made, the reference electrode is set into place, and the desired rpm is obtained from the meter. The PAR 350-1 unit is then programmed for the corrosion test.

Expected Results. The relationships that are expected to exist between different parameters when the applied external potential is varied are presented in Fig. 29. Fig. 29 is a regular potentiokinetic curve describing the variation of the corrosion current as a function of

Figure 29: Predicted Coefficient of Friction Versus Active and Passive Regions on Polarization Curve

applied polarization potential. It shows the existence of an active, a passive, and a transpassive region when the polarization is anodic (in the "noble" direction). If the protective film formed in the passive region has lubricating properties (which is generally the case) the coefficient of friction (Fig. 29) will show a minimum value in the same region where the corrosion current is minimum. When, during the sliding, the protective film is altered, both the polarization curve and the friction curve will vary in a manner consistent with the subsurface properties and the lubricating characteristics of the altered film. As long as the passive film is intact, the wear versus potential curve is expected to follow the polarization curve, showing a maximum at the maximum corrosion current. When the film breaks, however, the variation of wear both in time and as a function of potential is virtually unpredictable.

Preliminary Results. All the friction and corrosive work to date has been done only in the passive region. The bulk of the data has been collected for 304 SS; but, some experiments have been done on 316, 347, 321 and 416 SS. A load of 400 grams and 48 rpm was selected for these tests. The results can be summarized as follows:

- 1) effect of stirring versus non stirring
- 2) effect of the passive film on the friction coefficient

Effect of Stirring: For all stainlesses tested, the E_{corr} was shifted in the active direction and the current density of the passive region was also shifted to the right (increased in some cases by one order of magnitude). It appears that the critical pitting potential remains approximately the same.

Effect of the Passive Film on the Friction Coefficient: In all cases the μ coefficient for sliding in air was ~ 0.8 . Sliding in brine, while a passive potential was impressed on the specimen, yielded a lower coefficient of friction, $\sim .65$.

E.3 Section III. EPR: Sensitization of Welded 304 Stainless Steels.

A sensitization study of the heat affected zone (HAZ) of 304ss affected by the Homopolar welding technique was initiated. The impetus for this is that the standard oxalic etch test for testing degree of sensitization is not sensitive enough to detect minute degrees of sensitization by the homopolar welding technique. Since welded joints are found in geothermal construction facilities and are susceptible to stress corrosion cracking, it was felt that the study on the PAR 350 corrosion unit would be beneficial. The EPR (Electrochemical Potentiokinetic Reactivation) Method would be used for this study.

There are definite benefits to this technique: the major one being that it yields a means for quantifying degree of sensitization; and, it requires minimum time. A 1 cm^2 area of the specimen is exposed to a specified electrolyte. (Refer to Table 3). Potentiodynamic curves are obtained by controlled sweeping of the potential in the cathodic direction from the passive. By doing so, the surface is reactivated when crossing from the passive to the active region.

The electrolyte is a $0.5 \text{ M H}_2\text{SO}_4$ and 0.01 M (KCNS) potassium thiocyanate solution maintained at 30°C . Approximately 600 ml of this solution is put into the cell. The specimen is then polished to 1 diamond paste (ASTM E3) and degreased, rinsed in distilled H_2O , then ethanol, followed by air drying. The specimen is placed in the cell and the cell

Table 3
EPR TEST CONDITIONS

Electrolyte	0.5 M H_2SO_4 + 0.01 M KCNS
Temperature	23°C
Specimen Surface Finish	0.05 μm (Alumina Slurry)
Reactivation Scan Rate	1 mV/sec
Passivation Potential	+ 200 mV for 2 minutes
Dearation	N_2
Auxiliary Electrodes	Graphite
Reference Electrodes	Standard Calomel
Polarization System	Princeton Applied Research Model 350 Corrosion Measurement System

is purged with N_2 for 2 minutes prior to the beginning of the test, and continuously throughout at .3 sc/min. The specimen is polarized at +.200 v for 2 minutes, then the cathodic scan is carried out at +.166 v/sec (6v/hr). The reactivation scan is continued until E_{corr} is reached. Data is recorded, the specimen is removed, rinsed in distilled H_2O , then in alcohol, then air dried. Then the specimen is photographed at 100X, so that grain size measurements can be obtained.

The EPR unit measures the charge associated with the active dissolution of the Cr-depleted grain boundary area as the reactivation scan is performed. (Figure 30).

Figure 30

EPR Curve Noting Activated Region Q

Q is the integrated area under the curve of the reactivated peak only. Since sensitized steels are easily reactivated, the greater the Q the greater the degree of sensitization. The obtained Q is then normalized per grain boundary area. (Refer to Table 4.)

Table 4

NORMALIZED CHARGE PER GRAIN BOUNDARY AREA (Pa) CALCULATION

$$Pa(C/cm^2) = \frac{Q(C)}{GBA(cm^2)}$$

Where Q = Charge Measured on Current
Integrating Instrument
(Coulombs)

GBA = Grain Boundary Area

GBA = $As [5.09544 \times 10^{-3} \exp$
 $(0.34696X)]$

As = Sample Area (cm^2)

X = ASTM Grain Size at x100

Following the outlined procedure, five 304 specimens were sensitized in the furnace at 482°C, 537°C, 597°C, 649°C and 709°C. One specimen was used in the received condition and one was furnace annealed. The results are given in Table 5.

Table 5

Specimen	Condition	Q (coulombs)
1	as received	0.0187
2	solution annealed	0.0116
3	482°C	0.0964
4	537°C	0.2429
5	597°C	0.2554
6	649°C	0.7177
7	709°C	1.1532

As stated Q does increase with increasing sensitization. 304 rods are presently being welded by the Homopolar technique. Specimens will be sectioned at the weld line and at .050 inch increments from the weld zone. The degree of sensitization will then be plotted versus distance from the weld zone to determine how far away from the weld zone the material has been sensitized. This will then be repeated for different welding parameters.

This special project has been expanded and continued under the consolidated contract and coordinated with the sandstone consolidation study.

F. A DRILLING OPTIMIZATION STUDY OF BRAZORIA COUNTY GEOTHERMAL
GEOPRESSURED WELLS

A drilling optimization study of Brazoria County Geothermal Geopressured Wells is being conducted to develop optimized drilling programs for future Brazoria County Geothermal Geopressured Wells. This objective is achieved through thorough analysis of available drilling records of the two Brazoria County test wells and offset wells.

Phase I of this study consisted of collecting all available records on the two test wells and offset wells. Two volumes of data have been compiled for the test wells, Pleasant Bayou No. 1 and No. 2. These volumes contain records collected to perform this drilling optimization study. These records include the proposed drilling programs, the IADC reports, the Daily Drilling Reports, I. P. Farms cost data, mud, bit, and coring recaps, cement records and completion equipment records.

Phase II of this study attempts to reconstruct the events which occurred in the drilling and completion of Pleasant Bayou No. 1 and No. 2. With the data collected in Phase I, the following areas were reviewed for both test wells:

1. Actual Time Distribution
2. Well Costs
3. Mud Program
4. Hydraulics Program
5. Bit Performance
6. Formation Evaluation Program
7. Casing Program

8. Cement Program
9. Completion Equipment Program

Phase III consists of analyzing specific areas with the aid of the results of Phase I and II and with the use of Amoco's Drilling Optimization Programs available through the GE timeshare service. These areas include:

1. Examination of drilling function cost breakdowns to identify areas of major cost overrun.
2. Examination of the casing program for possible modifications.
3. Analysis of bit performance to reduce cost per foot.
4. Drilling problem analysis to reduce trouble and nontrouble costs.

The final phase, Phase IV, presents an optimized drilling program for future Brazoria County Geothermal Geopressured Wells. This program is based on all data and analysis results compiled in the previous phases.

A major difficulty experienced in this study was in the collection of drilling data from the two test wells. This problem was foreseen due to the number of people and companies involved in the drilling of these wells. Currently, this study is in the final stages of Phase III. All report figures have been drafted and tables have been typed. Estimated completion date of this project is September 1, 1981, and a complete report will be submitted after completion.

APPENDIX A

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APPENDIX B

MONTHLY PROGRESS REPORTS

FIRST PROGRESS REPORT - MARCH 1980

"Study of Log Derived Water Resistivity Data in Geo² Formations"

Summary: Work was begun on a study of methods of deriving water resistivity data in geo² formations using well log data. Several previous tests have shown that water resistivity calculated from the SP log is too high by a factor of 1.5 or more. We will attempt to improve this accuracy by modifying the conventional SP calculation, or by using an alternate method based on logging data exclusive of the SP.

As a working hypothesis we assume that at high temperature the conventional SP calculation breaks down due to changes in the shale properties, the mud properties, or both. A related and alternate hypothesis could attribute the difficulty to the high dissolved CO₂ content of the formation water observed in many geo² zones. This would change the pH of the water, and presumably its electrochemistry. In either case, a method which avoids the use of the SP should avoid the difficulty. One such method calculates formation water resistivity from true formation resistivity and porosity derived formation factor (The R_{wa} method). Results from several wells tested in the geo² program appear to support this approach. Considerable additional field data, and probably some lab tests, will be required to identify the difficulty and provide an optimum solution to the problem.

A literature search has been carried out using the computer retrieval system of the University of Texas Center for Energy Studies. A total of 198

references were obtained, of which 17 look particularly relevant and will be studied in detail. We have also collected a few references of recent work relating to shale diagenesis, water resistivity data in the Gulf Coast Region, etc. We have asked Exxon and Atlantic Richfield for available data on water resistivity from geo² reservoirs, and may request additional data from other companies.

Plans have been made to begin use of the University of Texas Center for Energy Studies "Digitized Log Data Base" (abbreviated "Logdex") for testing the validity of the above working hypothesis. Other data bases at the University of Oklahoma and Louisiana State University may also be used.

Discussion: Tests carried out in the Edna Delcambre well, Vermilion Parish, La.; F. F. Sutter well, St. Mary Parish, La.; and Pleasant Bayou #2 well, Brazoria County, Texas, have shown that the water resistivity predicted from the SP equation normally used - i.e. $SSP = K \log_{10} \left(\frac{R_{MFE}}{R_{WE}} \right)$, is substantially higher than the measured water resistivity. This is important, since the amount of methane which can be dissolved in water of a given temperature and pressure decreases as the salinity increases. Since water resistivity and water salinity are inversely related, the SP derived water resistivity has been widely used in the past to estimate water salinity, and hence, methane solubility of a given formation water. If this method tends to overestimate formation water resistivity, the methane solubility is also overestimated, which affects the economics of production of a geo² formation very significantly.

Table I shows data for these wells, as well as for the Beulah Simon #2 well, Vermilion Parish, La. This well has been tested, but measured water resistivity has not yet been received from Gruy Federal, Inc., who carried out the tests. Note that the SP derived water resistivity, R_{wsp} , is typically higher than the measured water resistivity, R_w , with R_{wsp}/R_w ranging from 1.5 to 3.2, and averaging 2.1 for the four wells where we have good data.

We have advanced a working hypothesis that the difficulty is associated with the high temperature of the formations. We know that a major diagenetic change occurs in the shale at temperatures of 200°F to 220°F when montmorillonite is converted to illite. Indeed this diagenetic change and the associated release of bound water from the shale is believed to be largely responsible for the phenomenon of geopressed zones. The diagenesis increases the porosity of the shales and changes the shale chemistry (the electrochemistry of montmorillonite and illite are not identical), both of which effects might be expected to change the value of K in the SP equation $SSP = k \log_{10} \left(\frac{R_{MFE}}{R_w E} \right)$.

Also, the high temperature might affect the mud chemistry so that the mud filtrate resistivity R_{MF} at high temperature is incorrectly predicted from mud data at lower temperatures (which is the value usually measured).

Finally, the value of K might be affected by a significant amount of dissolved CO_2 , which is found in most geo² formations. Carbon dioxide forms a weak acid when dissolved in water which might affect the electrochemical properties of the system and thus affect the value of K.

All of these disturbing effects could be avoided by estimating R_w using log data not including the SP curve. A number of methods not requiring SP information exist, but most call for logs not normally available. One method, however, estimates R_w from knowledge of the formation resistivity R_T (usually obtainable from the induction log) and from knowledge of the formation porosity ϕ (from the sonic, density, or neutron log). From the porosity log (usually the sonic in the Gulf Coast area) we can calculate the formation factor $F = .81/\phi^2$. Since the geo² zones of interest to us are 100% water saturated, we can neglect saturation effects, and Archie's equation becomes $R_T = FR_w/\phi^2$. Knowing ϕ and R_T we can calculate an estimate for formation water resistivity, R_{wa} , independent of SP data $R_{wa} = \phi R_T / .81$.

We have used this approach on the four cases where good measured formation water data is available, as shown in Table I. The results are encouraging, but should be viewed with caution, as in most cases we don't have logs with sufficient depth detail to be certain of the depth correlation between ϕ and R_T . The estimated range of R_{wa}/R_w is 1.7 to .9, and the average value is 1.3, which is considerably better than the R_{wSP}/R_w ratios of 3.2 to 1.5, with average value of 2.1. We will continue to refine the R_{wa} estimates as we get better logging data. For the Beulah Simon well, where measured water resistivity is not yet available, note that $R_{wSP} > R_{wa}$, so that in this case also we will probably come closer to the measured formation water resistivity if we use R_{wa} rather than R_{wSP} .

A literature search has been carried out using the University of Texas Center for Energy Studies search system. Files used were Engineering Index, 1970 to present; National Technological Information System (Gov't Reports), 1964 to present; and "Geo Archive", 1974 to present. We used such search words and phrases as "water resistivity", "SP logging", "shale", "diagenesis", "clay", "montmorilinite", "illite", "self potential", "connate water", "interstitial water", "formation water", "salinity", "Gulf Coast", etc., singly and in combination. A total of 198 titles and abstracts were recovered. Seventeen of these looked especially pertinent and will be studied further. In addition, we have surveyed the very recent literature to pick up references which might not be included in the data base used in the computer searches. We have also requested formation water resistivity data from geo² reservoirs from Exxon and Atlantic Richfield Companies, but have not received any data to date.

The Center for Energy Studies has compiled 1200 digitized log traces of wells penetrating the geo² interval in Texas. We have made plans for studies in Brazoria County (near the Pleasant Bayou #2 well) using this data base (Logdex). There are 39 wells in Brazoria County which are in the data base which penetrate to at least 13,000 feet. Of these, sonic logs are available on 24 wells. We plan to calculate R_{wSP} and R_{wa} on these 24 wells to see if there is a significant difference in the R_{wSP} and R_{wa} data above and below the 200°F level, where the montmorilinite to illite diagenesis

begins to occur. Presumably R_{WSP} is more likely to be affected by this diagenesis than R_{wa} .

Significant data bases exist also at the University of Oklahoma, (Petroleum Data System), and at Louisiana State University, ("Geopressure Energy Resource of Southern Louisiana"). It is possible that work will be done using these sources.

Henry H. Dunlap, Ph.D.
March 1980

1dm

TABLE 1 - MEASURED AND LOG DERIVED WATER DATA FROM GEO² RESERVOIRS

TEST #	WELL NAME	LOCATION	SAND DEPTH	TEMP. °F	PRESSURE PSI	Measured R_w @ Form. Temp. °M	Calculated R_w		Dissolved Gas Composition		REMARKS
							R_{wsp} °M	$R_{wa} = R_T/F$ °M	C ₁ H ₄ %	CO ₂ %	
1	F. F. Sutter #2	St. Mary's Parish LA. E. Franklin Field	15781-15,878	303	12,220	.015	.0231 $\frac{R_{wsp}}{R_w} = 1.5$	.023 → .013 $\frac{R_{wa}}{R_w} = 1.5 \rightarrow .9$	89.6	7.9	Detailed log calculations need to be made to properly match R_T and F values to get a more accurate value for $R_{wa} = R_T/F$
2	Beulah Simon #2	Vermilion Parish, LA Cossinade Field	14,674-14,770	285	13,000	?	.035	.017	?	?	Measured R_w value not yet available; The fact that $R_{wa} < R_{wsp}$ checks data in other test wells reported here.
3	Edna Delcambre #1 sand #1	Vermilion Parish, LA Tigre Lagoon Field	12,573-12,605	234	10,858	.021	.038 $\frac{R_{wsp}}{R_w} = 1.8$	.021 $\frac{R_{wa}}{R_w} = 1.0$	95.4	2.0	R_{wa} calculation checks measured R_w value better than R_{wsp} does.
4	Edna Delcambre #1 sand #3	Vermilion Parish, LA Tigre Lagoon Field	12,869-12,911	238	11,012	.025	.045 $\frac{R_{wsp}}{R_w} = 1.8$	.044 → .032 $\frac{R_{wa}}{R_w} = 1.7 \rightarrow 1.3$	92.3	1.1	R_{wa} calculation checks measured R_w value better than R_{wsp} does.
5	Pleasant Bayou #2	Brazoria County, Tx. Chocolate Bayou Field	14,644-14,704	300	11,275	.017	.055 $\frac{R_{wsp}}{R_w} = 3.2$	.025 → .017 $\frac{R_{wa}}{R_w} = 1.5 \rightarrow 1.0$	84.5	10.5	R_{wa} calculation checks measured R_w value better than R_{wsp} does. "Dunlap - March 1980"

"Study of Log Derived Water Resistivity Data in Geo² Formations"

SUMMARY:

We have explored use of data bases at Louisiana State University and the University of Oklahoma to obtain measured formation water resistivity (or chemical analysis) data in geo² zones. The L.S.U. file has no such data; the Oklahoma file (Petroleum Data System) has considerable water data which may be useful to us. We are just beginning to get some data from them using the G. E. Time Share System.

Plans to use the University of Texas digitized log file (Logdex) have been delayed due to lack of manpower. This work is now getting underway. It will be directed at comparison of calculation of R_w from the S.P. (i.e., $R_{w_{sp}}$) with R_w calculated from resistivity and sonic logs (R_{wa}) in geopressured and hydropressured zones. If our hypothesis linking failure of the S.P. method of calculating water resistivity in geo² zones to shale diagenesis is correct, the R_{wa} values and $R_{w_{sp}}$ values should match better in the cooler, hydropressured zones than in the hot, geo² zones.

Data for Beulah Simon #2 water resistivity has been received, along with logs and water resistivity data for the Exxon Fee #80, Pecan Island Field, Vermilion Parish, La. The $R_{w_{sp}}$ values for both these wells are substantially higher than the measured formation water resistivities, continuing the trend of the data reported last month.

Additional work with the R_{wa} method indicates that sonic derived formation factors (corrected for compaction effects) are apparently quite acceptable in calculating R_{wa} . This is fortunate, since sonic logs are run much more often than density, neutron or shallow, "flushed zone" resistivity logs, all of which can be used to obtain values for F . Even so, if sonic logs are required to obtain reliable R_w values it will be a great handicap to the geothermal program, since these logs are available in only a small fraction of the wells which have S.P. logs. We will try to modify the S.P. calculation to make it more reliable, since we nearly always have S.P. logs.

Literature data indicate that temperature affects the formation factor, F , for a given porosity and permeability sand. As the temperature increases, the rock expands and increases the tortuosity, which increases F . Application of

the temperature correction to F values previously reported should bring the R_{wa} value closer to the measured R_w value. It is too early to say whether this temperature correction will be useful.

If we can obtain enough formation water data, with matching logs, we hope to develop a new correlation of S.P., mud filtrate resistivity, and formation water resistivity, that will permit more accurate $R_{w_{sp}}$ values to be calculated in geo^2 zones. A start on such a correlation is shown in Figure 1. We obviously have a long way to go.

DISCUSSION

A. Acquisition of Formation Water Data from Geo^2 Zones

Progress has been slow. The data file at L.S.U. does not contain water data. Enquiries to Arco and to Exxon have not been fruitful, although Mr. Keith Westhusing was able to obtain data on the Exxon Fee #80 well, included in this report. The Petroleum Data System file at Oklahoma University does contain considerable water data, some of which is probably from geo^2 zones. We have been trying to work with this file through the G. E. Time Share System and have obtained a couple of water analyses from a geo^2 zone in Hidalgo County, Texas. We have not yet obtained the corresponding well logs, so we cannot include these cases in our comparisons as yet. We believe we will be able to get considerably more water data from the Oklahoma file, but it is slow going so far. Mr. John Wilkins is handling the computer aspects of this approach.

B. Use of The University of Texas digitized log file (Logdex)

Plans have been made to study $R_{w_{sp}}$ and R_{wa} in a number of wells in Brazoria County in the hydropressure and geopressure regime, as outlined in last month's report. Dr. Tom Hill, who will be carrying out this phase of the work, has been tied up on other jobs and has only recently been available for this effort. Some modification in the programs appear to be needed, but these are not thought to be major. Hopefully we will have some results next month.

C. Calculation of R_w from S.P. Data

Table I shows results to date. This is similar to the Table accompanying last month's report but has been reworked to make comparisons of measured and calculated R_w at well temperature, rather than formation temperature (generally

well temperature is about 30°F cooler than equilibrium formation temperature.) We believe this is the proper comparison to make when calculating R_w from log data, since the material producing the log measurements is much closer to well temperature than equilibrium formation temperature. Table I also shows measured water data from B. Simon #2 well (not available last month) and tests 6 and 7 for Exxon Fee #80 and Pleasant Bayou #2 wells. Note that the average $R_{w_{sp}}/R_w = 2.0$, with values ranging from 1.28 to 2.98. In no case was the $R_{w_{sp}}$ less than measured R_w .

We have calculated the K value needed to make the conventional S.P. equation yield the correct value of R_w for each of these 7 cases. We have:

$$SSP = K \log_{10} R_{MFE}/R_{WE}$$

Since we can estimate SSP and R_{MFE} from log data, and R_w is known for each of these cases, we can calculate R_{WE} , and hence, K from the above equation. This K value is listed as "Actual K" in Table I, and is also plotted vs. temperature in Figure 1. We also show the theoretical value of K versus temperature in Figure 1. Note that the actual K values are well below the theoretical values in all seven zones. It is also fairly evident that an additional variable (or perhaps more than one) will be needed to get a better grouping of the actual K values. An attempt to correlate against effective pressure (overburden pressure minus fluid pressure) was unsuccessful. There is a suggestion that % CO_2 dissolved in the water correlates with K value, but much more data will be needed to establish this.

One interesting point is that the true formation water resistivities observed in these seven geo² zones does not vary greatly. As shown in the last column of Table I, the measured R_w averages .064 ΩM @ 75°F, with a standard deviation of $\pm .008$, about $\pm 12.5\%$. This is about as good as could be expected to be calculated from logs, even assuming no systematic errors. It is probably an accident due to our small sample base of only 7 formations, but I thought it worthy of comment.

There is some concern about S.P. derived R_w values due to the effect of shale in the sand bodies, which lowers the S.P. and raises the calculated $R_{w_{sp}}$ value. In the case of test #5, we have density and neutron logs, which let us estimate shale content of the sands. Figure 2 shows a crossplot of density derived porosity ϕ_D , versus neutron derived porosity, ϕ_n , for the sand at 14,644'-704'

(the main producing sand), and a nearby shale at 14750-60 feet. The sand appears to be reasonably clean, with not more than 10-15% of shale present. The large error in $R_{w_{sp}}$ for this zone cannot be caused principally by "shaley sand" effects.

D. Calculation of R_{wa} from Porosity and Resistivity Data

Table II shows the current status of this approach (outlined in last month's report). We see that the R_{wa} values calculated from log or core data generally agree much more closely with measured water data than the $R_{w_{sp}}$ values do. The trouble is that we often don't have porosity logs or cores which will permit this calculation, so if we are forced to rely on R_{wa} for water salinity estimates, application of the method will be severely limited. In contrast we almost always have S.P. logs, hence the desire to make the S.P. method work in geo^2 zones.

We have come across one literature reference that affects this R_{wa} calculation. Sanyal et. al. point out a significant temperature effect on formation factor, due to expansion of the silica matrix as temperature increases, which causes the area of small "necks" between larger pore spaces to decrease. This raises the formation factor for a given porosity, while not significantly affecting the porosity value itself. Figure 3 shows a plot of data taken from Sanyal's paper. Note that a 10 to 20% increase in formation factor is possible for a 20% porosity formation in the 250° to 300°F temperature range. This should be taken into account to the extent possible when calculating R_{wa} . Unfortunately, the effect depends on permeability as well as porosity. (Note the difference between the 250 md and 750 md formations, both with 20% porosity, in Figure 3.) I have attempted to apply this correction in the last column of Table II. In the two cases shown, the correction was apparently too great, as the R_{wa} calculated from the compaction corrected sonic log was closer to R_w measured than the R_{wa} calculated using the temperature correction also. More work is needed here.

One encouraging aspect of the data is that the sonic derived porosities, corrected for compaction, seem adequate to calculate R_{wa} . This is good, since more elaborate methods involving cross plots and/or density or neutron or "flushed zone" resistivity logs call for logs which are not usually available.

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5-8-80

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TABLE I
MEASURED AND SP DERIVED WATER DATA
FROM GEO² RESERVOIRS

Test#	Well Name	Location	Sand Depth (Ft.)	Form. Temp °F	Well Temp °F	Pressure	Measured Rw @ Well temp. ΩM	Calculated RwSP ΩM	R _{WSP} / Rw	Theor. K, M.V.	Actual K, M.V.	Measure @ 75°F, ΩM
1	Sutter #2	St. Mary's Parish, La.	15781-15878	303	270	12,220	.017	.023	1.35	95.9	73.8	.054
2	B. Simon #2	Vermilion Parish, La.	14674-14770	285	256	13,000	.026	.033	1.28	94.0	74.6	.075
3	Delcambre #1 Sand 1	Vermilion Parish, La.	12573-12685	234	196	10,858	.025	.053	2.12	87.1	48.2	.060
4	Delcambre #1 Sand 3	" "	12869-12911	238	204	11,012	.028	.053	1.89	87.7	57.4	.070
5	Pleasant Bayou #2	Brazoria County, Tx.	14644-14704	300	270	11,275	.019	.057	2.98	95.9	48.1	.062
6	"	" "	15,581-15590	318	288	?	.020	.054	2.70	98.3	50.2	.070
7	Exxon Fee #80	Vermilion Parish, La.	14,126-14,164	278(?)	248	12,544	.020	.032	1.60	93.0	60.4	.060
									2.0 AVERAGE R _{WSP} / R _w			.064 Ave. Rw ± .008 Std. Dev.

TABLE II

MEASURED AND R_{wa} WATER DATA FROM GEO² RESERVOIRS

Test #	Well Name	Sand Depth (ft.)	Form. Temp. (°F)	Well Temp. (°F)	Measured R_w @Well Temp. ΩM	R_{wa} Cross Plot or Core	R_{wa} Sonic ΩM	R'_{wa} ΩM Sonic, Temp. Cor
1	Sutter #2	15,781- 15,878	303	270	.017	.023 $\rightarrow$.013	---	---
2	B. Simon #2	14,674- 14770	285	256	.026	.017	.025 $C_p = 1.2$	.023 $C_T = 1.10$
3	Delcambre #1 Sand 1	12,573- 12,685	234	196	.025	.021	---	---
4	Delcambre #1 Sand 3	12,869- 12,911	238	204	.028	---	---	---
5	Pleasant Bayou #2	14,644- 14,704	300	270	.019	.025	.020 $C_p = 1.0$	.018 $C_T = 1.13$
6	" "	15,581- 15,590	318	288	.020	---	---	---
7	Exxon Fee #80	14,126- 14,164	278	248	.020	.068 (swc) .026 (core)	---	--- B-13

FIGURE 1

K VS TEMPERATURE

↑
K (K₂)

$$K = 60 + 1.33T_{AF}$$

FIGURE 2

 ϕ_N Vs ϕ_D CROSSPLOT, PLEASANT BAYOU 2

• SAND @ 14.644 - 704

x Shale @ 14.750 - 60

FIGURE 3

FORMATION FACTOR VS TEMPERATURE

AFTER SANYAL, 1974

THIRD PROGRESS REPORT - MAY 1980

"Study of Log Derived Water Resistivity Data in Geo² Formations"

Summary: We believe we understand the difficulty we have had in calculating formation water resistivity from the S.P. log. For the high density muds used in drilling geo² formations, the log header data for R_{mF} often appears to be incorrect (R_{mF} is too large). Also, the method for determining R_{mF} from R_m given in the Schlumberger chart book (Gen. 7) as a function of mud density appears to be incorrect in the high density region (R_{mF} is too large). Since the basic equation to get R_w from the S.P. is: $SSP = K \log_{10} R_{mFE}/R_{WE}$, and R_{mFE} and R_{WE} increase smoothly with R_{mF} and R_w , if R_{mF} is too large then R_w as calculated from this equation will be too large. For the eleven cases where we have logs and measured formation water data, the calculated water resistivity using header data for R_{mF} is typically too high, with a standard deviation of 82%. If R_{mF} is calculated from R_m header data, using the Schlumberger chart Gen 7, the calculated water resistivity is better, but still too high, with a standard deviation of 45%. If R_{mF} is calculated using an average fit to "observed" R_{mF} (back calculated from known water data) in these eleven wells, the calculated water resistivities fall on both sides of the observed water resistivities, and the standard deviation drops to 33%. Further improvement should be possible by getting specific correlations of R_m and R_{mF} for various mud types, but this will require much more data. Hopefully, this additional data can be obtained from the Petroleum Data System file.

The reason for the incorrect R_{mF} header data is unknown but may include: (1) use of calculated rather than measured R_{mF} values, (2) experimental error, or (3) variation in R_{mF} values at down hole conditions.

Some progress has been made in obtaining water data from Petroleum Data Systems. Data from two geo^2 zones in the Sun Bentsen C-1 well, Hidalgo County, Texas, has been obtained and is included in the data reported this month. We have decided it would be quicker and cheaper to get the Gulf Coast water data file (about 9000 samples) on tape here at U.T. rather than continuing to try to work through Time Share. We hope we will be able to get perhaps 100 good water samples in geo^2 zones from this data. This may be enough to give useable correlations of R_M/R_{MF} versus mud types.

No results are available as yet from our work with the University of Texas Logdex data file. Some programming errors have been corrected.

Discussion:

A. Obtaining correct R_{MF} values.

We believe we now understand why the S.P. derived R_w values have been consistently high, and so poor. It is because the R_{MF} values have been correspondingly high. We have up until recently been using the log header values of R_{MF} as best representing the available data. In some old wells we were reviewing recently, no header data on R_{MF} was given, and we had to calculate R_{MF} using the method given in the Schlumberger chart book (Gen. 7) and reproduced as Figure 1 of this report. The method shows R_{MF} decreasing considerably as mud density increases for a given R_M , and leads to R_{MF} values consistently lower than the log header values for the 10 wells for which we now have good data for R_w and header values for R_{MF} . Figure 2 shows a plot of $R_{MF}(\text{header})/R_{MF}(\text{Gen. 7})$ versus mud density. All values of this ratio are greater than one, with a mean ratio of 1.8.

The method of calculating R_{MF} from R_m given in Figure 1 is based on data from a paper of Overton et. al, which presents an empirical correlation between R_{MF} and R_m given below

$$(1) \quad R_{MF} = K_m (R_m)^{1.07}$$

where K_m decreases as mud density increases as shown in the table given in Figure 1, and Figure 3 of Overton's paper (attached). Note that for mud densities greater than about 14 pds/gallon, the value of K_m decreases very little. This is surprising, since K_m should continue to decrease as the "water saturation" of the mud slurry decreases. For example, I have shown the value of $K_m \approx .12$ calculated from the usual soft rock formation factor equation, $F = .81/\phi^2$, for porosity $\phi = 30\%$. This value is far below the K_m value of .38 shown as the asymptotic value of K_m in Overton's Figure 3, and is in fact about in line with a smooth extrapolation of Overton's data for mud densities less than 14 pds/gal. Overton speculates about possible reasons for the asymptotic behavior of his K_m curve, but concludes that "more work is needed." I suspect that the data is in error and that the curve does not flatten out at 14 pds/gallon. The data supporting this view is given below.

From the measured formation water resistivity, we can calculate R_{MF} values needed to match the known S.S.P. and well temperature using the basic equation:

$$(2) \quad \text{S.S.P.} = K \log_{10} R_{MFE}/R_{WE},$$

plus data given in the Schlumberger chart book, (S.P. 2), for converting R_{MF} AND R_W TO R_{MFE} and R_{WE} . If we do this we can calculate a "true" value of K_M , if we assume that the header value of R_M is correct. We have done this, and the results are shown in Fig. 3. This figure also shows a plot of K_M vs mud density as taken from the table in Fig. 1 (essentially this is Overton's data), as well as K_m values derived from "Header" values of R_m and R_{mf} . We see that "true" values of K_M generally fall considerably under the Overton curve, and that the value of K_m using "header" values of R_{mf} and R_m fall considerably above the Overton curve.

The only severe exception to this generalization is sample 10, which is from Chocolate Bayou Field. We have severe reservations about the quality of both the header R_{MF} value, and the measured R_W value for this sample. The mud density for this well was 15.7 pds/gallon, yet the header ratio of $\frac{R_{MF}}{R_W}$ was $\frac{.72}{1.05} = .69$. This is very close to the old rule of thumb relation used for much lighter muds; $\frac{R_{MF}}{R_m} \approx .75$. In spite of the questionably high R_{MF} header value, use of this value in equation (2) gives $R_{wsp} = .040 \Omega M$ @ well temperature, a value which checks measured $R_W = .037 \Omega M$ rather well. I suspect that both the header R_{MF} and the measured R_W values are incorrect in this case. The produced water salinity is known to vary with pressure drops associated with production for many sands in the Chocolate Bayou Field, and since this water sample was taken about 4 years after the well was drilled, it is quite possible that the sample water does not represent the water in the formation when it was logged.

Other data which support the idea that there are not sharp discontinuities in the R_{MF}/R_M vs mud weight relation are discussed below. Fig. 4 taken from Patnode's paper shows a plot of the resistivity of water to the resistivity of the quartz sand slurry made using the water, as a function of percent water in the slurry, over the range 45 to 100% water content. This includes the region of the anomalous data reported by Overton. Note that Patnode's data is quite smooth through this region. When extrapolated, it points nicely to the F value calculated from the "Humble" formation factor formula $F = .81 / \phi^2$, at 30% porosity.

Finally, Mr. Will Roper of Mobil Field Research Lab informed us of some unpublished 20 year old lab data on lime base muds covering the range from 9 to 19 pds/gallon. Values of R_{MF}/R_M for this data also do not support the severe flattening of the K_m curve shown by Overton at high mud weights.

We conclude, therefore, that there are two main reasons for the large errors in the SP derived water resistivities for geo² zones: (1) The header R_{MF} data is likely to be incorrect, for unknown reasons (2) The calculated R_{MF} value is incorrect (too large) for dense muds, greater than 14 pds/gal.

On Fig. 3 we have dotted in a possible "true" K_m curve for the 14 to 22 pd/gal. mud density region. This is not a least squares fit, or any other sort of scientific fit, as we suspect there are several branches to this curve, one for each of several mud types. (lignosulfonate, lime base, etc.). It does more or less go through the point at 30% water derived from the Humble relation, and through the main body of the "true" K_m points.

K_m values read from this dotted curve were used to calculate R_{mf} and thence values for R_w . We will call these the "curve" R_{mf} values. It represents the best we can do to calculate R_w from the S.P. at the present.

Figure 5 shows a plot of calculated water resistivity vs measured water resistivity using (1) header R_{MF} values, (2) Gen 7 R_{MF} values, and (3) "curve" R_{MF} values. Points that fall on the straight line would be a perfect match with measured formation water. Note that the "header" points are all above the line, the "Gen 7" points are mostly above the line, and "curve" points fall above and below the line. The standard deviations are: for the "header" data, $\sigma = 82\%$; for the "Gen 7" data, $\sigma = 45\%$; and for the "curve" data, $\sigma = 33\%$.

With additional data we believe that separate K_m curves for different mud types could be developed, which would further reduce the error. For example, in Fig. 3, points 1, 2, 3, 4 and 7 all represent lignosulfonate muds. We doubt that SP methods will ever be capable of much better than 15 to 20% accuracy, due to inherent uncertainties (variation in shale content of sands, uncertainties in converting "equivalent" to actual resistivity, etc.).

B. Other work

Most of this report has been devoted to the R_{MF} question, as this represented a break through in our understanding of the problem. A little progress has been made in obtaining R_w data from Petroleum Data Systems, and in calculating R_{wsp} and R_{wa} values from Brazoria County wells in the U. Texas Logdex file. This will be covered in more detail next month.

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TABLE 1
 Measured and SP_2 Derived Water Data
 From Geo Reservoirs

TEST #	WELL NAME	LOCATION	SAND DEPTH ft.	WELL TEMP °f	MUD DENSITY pds/gal	PRESSI PSI	MEAS R_w AT WELL TEMP ΩM	CALC. R_{wsp} (Header) ΩM	CALC. R_{wsp} Gen 7 ΩM	CALC. R_{wsp} curve ΩM
8	Sun Bentsen C-1	Hidalgo County Texas	11941 -88	266	17.8	9043	.014	.040	.035	.024
9	"	"	12069 -91	266	17.8	?	.017	.040	.034	.023
10	Gardiner #1	Brazoria Co, Texas	11772 -86	219	15.7	?	.037	.040	.030	.026
11	Laterre D-7	Terrebonne Parish La	15225 -380	238	17.1	?	.036	No Header R_{MF}	.029	.022

ESTIMATION OF R_{mf} and R_{mc} ¹

(Not applicable to Lignosulfonate Muds)

B-25

Figure 1 (From Schl. Chart Book)

Direct measurement of filtrate and mud-cake samples are preferred. When not available, they may be calculated from the following formulas.

For drilling muds with R_m at 75°F (24°C) in the range from 0.1 to 10 $\Omega \cdot m$, where K_m is given by:

Mud Weight		K_m
lb/gal	kg/m ³	
10	1200	0.847
11	1320	0.708
12	1440	0.584
13	1560	0.488
14	1680	0.412
16	1920	0.380
18	2160	0.350

$$R_{mf} = K_m (R_m)^{1.07}$$

$$R_{mc} = 0.69 (R_m) \left(\frac{R_m}{R_{mf}} \right)^{2.65}$$

EXAMPLE:

Given: $R_m = 3.5$ at 75°F (24°C)
mud weight = 12 lb/gal (1440 kg/m³)

SOLUTION:

$$R_{mf} = (0.584) (3.5)^{1.07}$$

$$R_{mf} = 2.23 \text{ at } 75^\circ\text{F}$$

$$R_{mc} = 0.69 (2.23) \left(\frac{3.5}{2.23} \right)^{2.65}$$

$$R_{mc} = 5.07 \text{ at } 75^\circ\text{F}$$

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The calculated value of R_{mf} is more reliable than that of R_{mc} .

Another statistical approximation, for predominantly NaCl muds, is $R_{mc} = 1.5 R_m$ and $R_{mf} = 0.75 R_m$.

Figure 2

RATIO OF RME (HEADER) TO RME (GEN 7)

Numbers show Test Numbers

3.0

2.0

$$\frac{RME(H2O2)}{RME(GEN7)}$$

1.0

0

 8 10 12 14 16 18 20 22
 11.00 DENSITY, PDS/GALLON →

HID Jan 30

 6, 10
 5

1

 2
 3

 2
 3

 3
 4

Figure 3 K_m VS MUD DENSITY

Figure 4

Resistivity of Water-Silica
Slurry (From Patnode)

(●) Header R_w
 (□) Gen 7 R_w
 (△) Curve R_w

FIGURE 5
Calculated Vs True
 R_w Values

FIG. 2—MUD RESISTIVITY VARIATION AS MUD WEIGHT IS CHANGED FOR 61 FIELD AND LABORATORY MUDS.

$$R_m = C (R_f)^m \quad (4)$$

Fig. 2 shows the relationship between R_m and R_f for three weight ranges. The individual weights represent averages of the weight range. For example, 9.5 lb/gal represents weights from 9.0 to 10.0 lb/gal mud weight. Note that a fairly consistent slope on this graph is maintained for the three weight ranges. For the normal range of usage ($R_m < 5$ ohm-m) these graphs are represented by

$$R_m = C (R_f)^{1.07} \quad (1)$$

This relation is not strictly correct at high resistivities since the clay in suspension conducts current somewhat and the value of C is not constant.

For the influence of weight material alone it is interesting to note the change of the constant, C , for the different mud weights. Fig. 3 shows this relationship. This graph presents a qualitative check on the previous work because of the nature of the resistivity factor. At 8.3 lb/gal the C factor should be approximately unity, as R_m is equal to R_f for muds of approximately 1-ohm-m resistivity. For practical purposes the C factor varies inversely with weight up to weights of about 14 lb/gal. This condition holds notwithstanding the fact that muds with weights below 10 lb/gal consist mostly of clay and water. Muds not in this weight category contain increasing barium sulfate. Note in Fig. 3 that the C factor is asymptotic with the fraction, 0.35. The reason for this is not clear but it is possible that the minimum effective porosity is reached at weights of about 15 lb/gal. The minimum effective porosity indicates the minimum fluid (as viewed electrically) which a unit amount of the mud contains regardless of the solids present. Since the conductivity of the filtrate from a unit amount of mud mainly determines the mud conductivity, the weight material present in a drilling mud does not further affect the mud conductivity after the minimum porosity is reached. Further investigation is being made on this phenomenon.

EFFECT OF CLAY ON MUD RESISTIVITY

Fig. 2 indicates that the slope, m , of the graph of R_m vs R_f is constant. This suggests that R_m is a function only of R_f for a given mud weight. This is true for practical consideration but not in theory. Actually the clay component contributes its own conductive properties. The resistivity factor, F , of any porous system

allows inspection of the contribution to conductivity by clay. It is known that F is not constant in porous rock for several reasons: the liquid in the porous system is not the only conductor and the electrolyte itself affects the conductivity of the solids portion of the system.

Fig. 4 shows that the mud resistivity factor, F_m , is also not a constant for a given amount of solids. Note that the resistivity factor becomes smaller when the mud resistivity exceeds 1 ohm-m. For practical electric logging work and for conditions where the mud resistivity does not exceed 10 ohm-m the mud resistivity factor remains approximately constant. However, some native muds which have mud resistivities less than filtrate resistivities are exceptions to this generality. In these cases the clay material definitely conducts electrical current. A well-dispersed clay and water suspension maintains its own conductivity which is not entirely dependent upon added electrolytes.

FIG. 3—VARIATION OF C IN THE EQUATION, $R_m = C(R_f)^{1.07}$, AS MUD WEIGHT IS VARIED.

FIG. 4—VARIATION OF THE MUD RESISTIVITY FACTOR WITH MUD RESISTIVITY FOR 55 FIELD MUDS OF VARYING WEIGHTS.

Fourth Progress Report, June 1980

"Study of Log¹ Derived Water Resistivity Data
in Geo² Formations"

Summary: Six additional tests have been calculated. Review of all the data to date (17 tests) indicates strongly that the difficulty in obtaining reliable R_{MF} data is limited to the lignosulfonate mud systems, and that the lime base and gyp base systems give fairly good data using the Schlumberger "Gen 7" correlations. See Tables I, II, and III.

A new relation which may be simpler to use for relating R_{MF} to R_m is proposed, namely

$$R_{MF} = K_F R_M, \text{ where } K_F = \frac{\phi^2}{e^{.5(\phi-1)}},$$

where ϕ = water content (or "porosity") of the mud. Note that this is equivalent to the Archie equation, if "F" in the Archie equation,

$R_o = FR_w$, is taken to be $1/K_F$. See Fig. 1.

Literature data suggest that the resistivity of muds and mud filtrates may vary substantially from day to day in drilling wells, even with no major changes in the mud system. If this occurs often, it will be necessary to keep closer checks on mud and filtrate resistivity variations than has been the usual practice. See Fig. 2.

Effect of temperature on mud and filtrate resistivity is usually assumed to be that for NaCl solutions (Schlumberger Gen 9 data). Significant differences from the NaCl correction curve are observed for various mud types, and the proper correction should be used for each mud when R_{wsp} is calculated. See Fig. 3.

Five of the six new tests obtained during the past month resulted from work with the Petroleum Data System file. We believe we will be able to get additional data from this source.

Discussion: Six additional tests have been calculated, five of which were obtained using the Petroleum Data Systems file which we now have on tape at U.T. See Table I. Two of these wells used lignosulfonate muds, the others used lime base or gyp base muds, and were drilled in the 1949-62 period. All but one of the tests previously reported used lignosulfonate muds. (Test #11 used a gyp base mud, and was drilled in 1960). See Table II. We were able to convert the rather sketchy well log header information as to mud type into the basic mud type involved using data given in J. Leonard's recent "Guide to Drilling, Workover and Completion Fluids".¹ Review of all the data strongly indicates that the difficulty in calculating (and measuring) R_{MF} is limited to the lignosulfonate mud systems. Since most of the hot, high pressure wells from the mid sixties on have been drilled with lignosulfonate muds, the problem is a significant one.

Table III shows the average errors defined as ratio: $(\text{Calc. } R_{wsp})/(\text{Meas. } R_w)$ for R_{mf} "Header" data, R_{MF} "Gen 7" data, and R_{MF} "curve" data.* We see that for the 12 lignosulfonate cases the header data and Gen 7 data are badly off (Calc. R_{wsp} is too high) while "curve" data is much better. For the 2 cases using gyp base muds and 3 cases using lime base muds, we have no header data (R_{MF} was not reported on log headings when these wells were drilled), but the "Gen 7" data for these wells is about as good as the "curve" data for the lignosulfonate wells.

* See Third Progress Report for definition of "curve" data, "header" data etc.

The use of the 1.07 power in Overton's relation $R_{MF} = K_m(R_m)^{1.07}$ is probably not justified in view of the spread of the data, and the rather arbitrary variation in K_m . We believe that a relation of the form $R_{MF} = K_F R_m$ is more reasonable, where K_F is a function of the water-content ϕ (i.e. "porosity") of the mud, corresponding to one over the formation factor, F , in the Archie equation. A function $K_F = \frac{\phi^2}{e^{.5(\phi-1)}}$ appears to fit Patnode's data for water-silica slurries very well for high water contents typical of muds, and also to agree with the Humble equation $F = \frac{.81}{\phi^2}$ for low water contents typical of rocks. See Fig. 1.

Variations in mud and mud filtrate resistivity over short time intervals may occur in some wells, even though the basic mud type is not being changed during these intervals.³ We believe that the mud filtrate is controlled mainly by the mud in the well when the formation is being drilled, rather than when it is logged, days or weeks later. If the mud properties do vary as much as indicated by the data in Fig. 2, it may be necessary to monitor mud resistivity continuously (or at least measure it daily) as the well is drilled in order to make accurate R_{wsp} calculations. We have contacted Baroid to try to get more data on short term variations in R_m .

The effect of temperature on NaCl solution resistivities, and on various mud and mud filtrate resistivities, is significantly different.⁴ See Fig. 4. Optimum accuracy in calculation of R_{wsp} will require use of temperature correction data proper for the mud system used. Up to now we have been using NaCl temperature correction data

for all types of muds and mud filtrates (Schlumberger Gen 9). We plan to recalculate all of our R_{wsp} values using the proper temperature corrections for the mud system used.

The Petroleum Data System (U. of Okl.) formation water data base for the Texas and Louisiana Gulf Coast region has been obtained for use at U.T. The file contains chemical analyses and/or resistivity data on about 9000 water samples. A test retrieval of Texas data deeper than 9000 ft. yielded 387 samples. Eight of these were selected as most likely to be good geo^2 samples, and well logs on these eight were ordered. Five of the eight were good tests (#13 thru 17 of Table I). More good geo^2 tests can undoubtedly be obtained using this data base.

H. F. Dunlap
July 3, 1980

References

1. J. Leonard, "Guide to Drilling, Workover and Completion Fluids," World Oil, June 1980, pp 57-114.
2. H. W. Patnode, "Relation of Drilling Mud Resistivity to Mud Filtrate Resistivity," SPE Tech. Paper #2512, October 1948.
3. R. D. Lynn, "Effect of Temperature on Drilling Mud Resistivities," SPE Paper #1302-G, October 1959.
4. G. C. Wang et al, "Laboratory Resistivity Evaluation of Lime, Gyp, and Calcium Lignite-Calcium Lignosulfonate Muds," 3rd Annual SPWLA Symposium, May 1962.

TABLE I

Measured and SP Derived Water Data from Geo² Reservoirs

Test #	Well Name	Location	Sand Depth (ft)	Well Temp. °F	Mud Dens. pds/gal	Pressure PSI	Meas. R _w @ Well Temp. ΩM	Calc. R _{wSP} (Header) ΩM	Calc. R _{wSP} (Gen 7) ΩM	Calc. R _{wSP} (Curve) ΩM	Mud Type	
											Header Data	Basic Mud Type
12	Exxon Armstrong 46	Candelaria Fld, Kennedy Co., Texas	15,728-828	304	18.0	11,765	.021	.037	.030	.017	Spersene XP-20	Chrome-lignite Chrome-lignosulfonate
13	Sun Jefferies #2	Flores Fld. Hidalgo Co., Texas	9,913-20	244	15.9	?	.042	No R _{MF} data	.041	.036	Gyp-Oil Emulsion	Gyp-Oil Emulsion
14	Sun Laguna Madre #1	Murdock Pass Fld, Kennedy Co., Texas	10,348-53	244	13.0	?	.029	No R _{MF} data	.027	.027	Gel-Lime-Starch-Chem	Lime Base
15	Texas Co. Weiting #1	Choc. Bayou Fld., Brazoria Co., Texas	12,101-29	227	17.1	?	.029	No R _{MF} data	.026	.022	Lime Base 11 % Oil Emulsion	Lime base oil emulsion
16	Humble Armstrong 20	E. Candelaria Fld., Kennedy Co., Texas	17,535-80	332	17.3	?	.021	.042	.038	.025	Spersene XP-20	Chrome-lignite Chrome-lignosulfonate
17	Sun State 76 #8	Fulton Beach Fld., Aransas Co., Texas	9,644-64	193	16.1	?	.037	No R _{MF} data	.056	.040	Lime-Caustic	Lime Base

Mud Types Used in Test Wells

Test #	Well Name	Date Drilled	Mudwt. Pds/gal.	Visc. sec.	Fluid Loss CC/30 min.	Header Mud Type	Basic Mud Type
1	F.F. Sutter #2	1979	16.1	48	3.2	Ligno	Lignosulfonate
2	B. Simon #2	1979	17.7	49	2.0	Ligno	Lignosulfonate
3	E. Delcambre #1	1967	18.2	51	4.0	CLCLS	Chrome Lignite; Chrome Lignosulfonate
4	"	"	"	"	"	"	" "
5	Pl. Bayou #2	1979	15.7	48	8.4	Spersene XP-20	" "
6	"	"	"	"	"	"	" "
7	Exxon Fee #80	"	17.9	54	2.3	Lignosulf.	Lignosulfonate
8	Bentsen Bros. C #1	1967	17.8	49	1.5	CC-16	Sodium Salt of Lignite Material
9	"	"	"	"	"	"	" "
10	Gardiner #1	1964	15.6	54	2.2	Q-Broxin	Ferrochrome Lignosulfonate
11	Laterre D 7	1960	17.1	55	5.2	Gyp-Base	Gyp-Base
12	Armstrong #46	1978	18.0	44	6.4	Spersene XP-20	Chrome Lignite Chrome Lignosulfonate
13	Jefferies #2	1960	15.9	54	3.0	Gyp Oil Emulsion	Gyp-Base-Oil Emulsion
14	State Laguna Madre #1	1949	13.0	49	9(?)	Gel-Lime Starch-Chem	Lime Base
15	Weiting #15	1954	17.1	55	4.5	Lime Base 11% oil Emul	Lime Base-Oil Emulsion
16	Armstrong #20	1962	17.3	60	1.6	Spersene XP-20	Chrome Lignite Chrome Lignosulfonate
17	State 76 #8	1951	16.1	61	?	Lime-Caus.	Lime Base

TABLE III

R_{WSP} Calculations for Various Mud Types

Basic Mudtype	No. of tests in sample	Average Mud Dens. Pds/gal	Average Errors; (Calc.R _{WSP})/(Meas.R		
			Header Data	Gen 7 Data	"Curve" Data
Lignosulfonate	12	17.2	2.0	1.46	1.11
Gyp Base	2	16.5	No Header R _{MF}	.87	.74
Lime Base	3	15.4	No Header R _{MF}	1.11	.87

FIGURE 1

$K_F = \frac{R_{MF}}{R_M}$ VS WATER CONTENT OF SYSTEM

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○ PATNODE-SAND WATER SLURRY
 $\square K_F = \frac{\phi^2}{e K_0 (1 - \phi)}$, $K_0 = 5$

$\otimes K_F = \frac{1}{F} = \frac{\phi^2}{.81}$

$K_F = \frac{R_{MF}}{R_M}$

Ratio R_M/R_{MF} IN DRILLING
WELL, SAMPLED OVER
3 TO 10 DAY INTERVALS -
OVER 6 WEEK PERIOD.
OIL EMULSION GEL MUD
CONTAINING CARBONOX,
CAUSTIC SODA, & SODA ASH.
 $R_M \approx 1.3 - 2 M @ 125^\circ F$
MUD WEIGHT NOT GIVEN.
(FROM R.D. LYNN
S.P.E. PAPER #1302G,
1959)

FIGURE 3:
RESISTIVITY VS TEMPERATURE
FOR MUDS AND FILTRATES
(WANG ET AL DATA)

Temp. °F →

NFD June 26-80

Fifth Progress Report, July 1980
 "Study of Log Derived Water Resistivity Data
 in Geopressured Geothermal Formations"

Summary: Four additional tests have been calculated, three with driscose base muds and one with a quebracho (tannin extract) mud system. In the driscose systems, the "header" data and "Gen 7" data both appear to overestimate the formation water salinity, in contrast to the results for the lignosulfonate systems. The single test of the quebracho system gave a perfect check with measured water data using the "Gen 7" data. There was no "header" R_{MF} data for this test. The "curve" data for all these tests substantially overestimates water salinity. This is not surprising, since the "curve" correlation was based on lignosulfonate data.

We have contacted Mr. Bill Goins of Baroid Mud Logging Co. in an attempt to get more data on short term variations of mud resistivity in wells drilling geopressured geothermal formations. He has agreed to look for such data but so far has not found any. It may be possible to get data from a well which has a continuous mud resistivity instrument in the mud flow line. He will be on the lookout for such a well.

We have done a little more work on the new formation factor relation proposed last month i.e., $F = \frac{e^{.5(\phi-1)}}{\phi^2}$. Application of this relation to data reported by Winsauer et al.¹ indicated that it fits the measured F data about as well (actually a little better) than Winsauer's relation $F = .62 / \phi^{2.15}$ or the commonly used Schlumberger modification of this equation, $F = .81 / \phi^2$. (See Table III.)

The latter part of the report period was taken up with preparation of a draft of "Standard Well Logging Program for Geopressured - Geothermal Wells", with attached addendum, "Research Needs for Geothermal - Geopressured Well Logging". The final version of this program will be sent to the Department of Energy around September 1st. During this time we also prepared a proposal for research on log derived formation water resistivity calculations for the period of November 1980 - November 1981. As a result we did not have time to make the planned recalculation of formation water resistivity using best estimates for resistivity vs. temperature of mud filtrate, etc. We hope to do this in August.

Discussion: Four additional tests have been obtained using data from East Chocolate Bayou Field, Brazoria County, Texas. Three of these wells were drilled using driscose based oil emulsion muds, which we had not previously worked with in this study. It appears that for the driscose mud systems, the calculated formation water resistivity is too low (salinity too high) regardless of whether "header" data, "Gen 7" data or "curve" data is used. This is just the reverse of the situation for lignosulfonate muds where "header" and "Gen 7" values for R_{MF} lead to calculated water resistivities which are too high (salinities too low). The quebracho mud system (perhaps by chance) checked the measured water resistivity perfectly when the "Gen 7" data was used for R_{MF} .

Mr. Bill Goins of Baroid has kindly volunteered to look for mud resistivity data which has been obtained over short time intervals. So far he has not been successful, but will continue to look. He says there is a chance that we will be able to get data from a well with a resistivity meter continuously recording from the mud flow line. We will keep in touch with this possible source of data.

Table III shows a comparison of measured and various calculated estimates of formation factor based on data from Winsauer's classic 1952 paper.¹ The table is taken from Winsauer's Table II, and the missing core #'s were missing in his paper also. It is interesting that this data indicates that all three calculation methods give about 20% std. dev. between calculated and measured values of F . For whatever it is worth, $F_1 = .81/\phi^2$, shows a 23% std deviation; $F_2 = .62/\phi^{2.15}$, which is Winsauer's original equation, shows a std. deviation of 22%, while the new relation proposed in last month's progress report, $F_3 = e^{.5(\phi-1)}/\phi^2$ shows the lowest standard deviation of 19 percent. We will continue to check the accuracy of the F equations as data becomes available. Incidentally, these results imply an accuracy of no better than $\pm 20\%$ in the R_{WA} calculations for formation water resistivity.

We did not have time to recalculate our previous results using optimum resistivity vs. temperature corrections for each mud type, etc. We plan to do this in August.

H. F. Dunlap
August 5, 1980

References:

1. W. O. Winsauer et. al., "Resistivity of Brine Saturated Sands in Relation to Pore Geometry," Bull. AAPG, Feb., 1952, pp. 253-277.

Table 1
Measured and SP Derived Water Data
from Geopressed Geothermal Reservoirs

Test #	Well Name	Location	Sand Dept (ft)	Well Temp °F	Mud Dens. Pds. gal.	Pressure Psi	Meas. R_w @Well Temp. ΩM	Calc. R_{wsp} (Header) ΩM	Calc. R_{wsp} (Gen 7) ΩM	Calc. R_{wsp} (curve) ΩM	Mud Type	
											Header Data	Basic Mud Type
18	Phillips Houston M#2	E. Choc. Bayou Fld, Brazoria Co., Tx.	11470-80	191°	13.5	?	.058	NO R_{mf} Data	.038	.038	Phos. Driscose Oil Emulsion	Driscose Oil Emulsion
19	Phillips Houston Z#1	"	12620-28	235°	17.2	7000	.036	.030	.026	.020	Drisc -O.E.	Driscose Oil Emulsion
20	Phillips Houston Z#1 *	"	12829-13	240°	17.1	?	.041	.030	.025	.020	Driscose -O.E.	Driscose Oil Emulsion
21	Phillips Kentzelmar #1	"	10960-11,032	193°	14.9	?	.050	No R_{mf} Data	.050	.045	Water Base Quebracho	Quebracho (Tannin extra)

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for sand at 12829-38 looks reduced relative to nearby sands - analysis based on SP values for sands at 12,930-40 12,620-70, where $SP \approx 100$ MV.

TABLE II

 R_{wsp} Calculations for Various Mud Types

Basic Mud Type	No. of Tests in Sample	Average Mud Density Pds/gal	Average Errors: (R_{wsp} Calc.)/(Meas. R_w)		
			Header Data	Gen 7 Data	"Curve" Data
Lignosulfonate	12	17.2	2.0	1.46	1.11
Gyp Base	2	16.5	No Header R_{mf}	0.87	0.74
Lime Base	3	15.4	No Header R_{mf}	1.11	0.87
Driscose Base	3	15.9	0.78 (2 tests)	0.66	0.57
Quebracho (Tannin Extract)	1	14.9	No Header R_{mf}	1.00	0.90

Comparison of Measured with Various Formulas for Formation Factor, Based on Winsauer et. al. Data

Winsauer Core #	Porosity ϕ	Measured $F = R_o/R_w$	$F_1 = .81/\phi^2$	$F_2 = .62/\phi^{2.15}$	$F_3 = e^{.5(\phi-1)}/\phi^2$
1	.170	23.3	28.0	28.0	22.8
2	.147	51	37.5	38.3	30.2
3*	.067	67	175	207	140
4	.176	16.6	26.1	26.0	21.4
5	.263	8.6	11.7	11.0	10.0
6	.256	9.4	12.4	11.6	10.5
10	.139	33	41.9	43.1	33.6
11	.186	22.9	23.4	23.1	19.2
12	.188	18.6	22.9	22.5	18.8
13	.161	42	31.2	31.5	25.4
14	.150	41	36.0	36.6	29.0
15	.221	13.1	16.6	15.9	13.9
16	.206	16.6	19.1	18.5	15.8
17	.307	8.4	8.59	7.85	7.5
20	.164	21.1	30.1	30.2	24.5
22	.188	19.3	22.9	22.5	18.8
23	.248	10.8	13.2	12.4	11.2
25	.191	17.2	22.2	21.8	18.3
28	.298	8.4	9.12	8.37	7.93
31	.271	11.7	11.0	10.3	9.45
32	.282	10.9	10.2	9.43	8.78
33	.194	24.0	21.5	21.1	17.8
34	.197	20.8	20.9	20.4	17.3
35	.315	6.9	8.16	7.43	7.15
36	.193	24.4	21.7	21.3	17.9
37	.273	12.4	10.9	10.1	9.33
38	.251	11.6	12.9	12.1	10.9
39	.150	37.3	36.0	36.6	29.0
40	.184	19.0	23.9	23.6	20.6
41	.395	4.65	5.19	4.57	4.74

Standard Deviation of % Error in $F_1 = 23\%$

Standard Deviation of % Error in $F_2 = 22\%$

Standard Deviation of % Error in $F_3 = 19\%$

*Core #3 not included in standard deviation calculation, since large errors in all cases.

Sixth Progress Report, August 1980
 "Study of Log Derived Water Resistivity Data
 in Geo² Formations"

Summary: We have developed a working hypothesis which appears to explain most of the data to date. We believe that the mud filtrate obtained using the standard filter press cell may often contain small concentrations of viscofying material from the mud which passes through the filter paper and mud cake which forms in the cell. Only small amounts of these high molecular weight viscofying materials would be required to raise the bulk viscosity of the filtrate from 1 cp (water) to 1.5 or 2 cp. This would not be a noticeable increase in viscosity when the filtrate is drawn into a resistivity cell, but it should increase the resistivity by a factor roughly proportional to the viscosity ratio. The measured resistivity of the filtrate would be correct, but because of the high viscosity, the salinity of the filtrate inferred from this resistivity measurement would be too low. This is just what we observe in most of the lignosulfonate, high density muds we work with in geo² log interpretation.

The solution may be to measure the viscosity of the mud filtrate, as well as the resistivity and temperature. If the measured viscosity is greater than the viscosity of a simple brine at the observed temperature and resistivity, a viscofying material has passed into the filtrate from the mud. The measured filtrate resistivity should be corrected by dividing by a factor equal to the ratio of measured filtrate viscosity to the viscosity of brine at the observed temperature.

The above hypothesis of filtrate viscosity variation leading to filtrate resistivity variation, plus the evidence for short term variation in mud and filtrate resistivity cited in Fig. 2 of the fourth progress report are together capable of explaining most of the cases we have studied to date.

Although we believe there is a very good chance that we have hit on a solution to our problem, we will not know for sure until we carry out experimental work in the lab (for the viscosity hypothesis) and in the field (for the short term mud variation hypothesis).

We have recalculated all the data using depth interpolated values of mud density, mud and filtrate resistivity, etc., and using appropriate temperature vs. resistivity correction curves for the various mud types taken from Fig. 3 of the Fourth Progress Report. There is a suggestion that the driscore muds, the gyp muds, and the lignosulfonate, lime and tannin muds form three separate curves when plotting $K_F = \frac{R_{MF}}{R_M}$ vs. mud density (See Fig. 1).

We have obtained one additional test, #22, the Vaineco Girouard #1. This is unusual in that although it was drilled with a lignosulfonate mud, the SP derived formation water resistivity is much too low (salinity much too high) relative to the produced water. We speculate that this may result from short term variations in properties of mud and mud filtrate.

Discussions: To a first approximation, brine conductivity is proportional to the viscosity of the brine. ¹ ² The attached Fig. 11, taken from Fricks Petroleum Production Handbook, Vol. 11, shows in Fig. 22-22 the variation of water viscosity with temperature. I have added to this plot (using x's) the value of solution resistivity variation ⁸² with temperature, using the arps correction factor $R_T = R_{75} \frac{82}{T+7}$, where T is solution temperature in F. ³ Note how closely the resistivity data coincide with the viscosity data.

The viscosity of a brine is also a function of salinity, but for dilute solutions characteristic of most mud filtrates (less than 10,000 ppm equivalent salinity) the effect is small. See Fig. 22-23 from Frick's handbook, also shown on Fig. 11.

In view of the above, the resistivity of the mud filtrate should be a function not only of the salinity and the temperature, but of any material present which might change the viscosity of the filtrate. The mud contains significant amounts of viscosity modifiers, and it appears reasonable that some of this material might be able to get into the mud filtrate. Early in the filtrate extraction, before a good filter cake forms, there would be less resistance to loss of the viscofying additives. Also, when high density muds are used, the weighing materials make up a considerable part of the mud solids, and these do not make a good filter cake. In lighter muds, most of the solids are clays, which do form good filter cakes. Loss of viscofying material to the filtrate might be expected to be greater for high density muds than for low density muds.

If enough of the viscofying material came through in the filtrate to raise its viscosity at room temperature from the normal value of about 1 cp. to 1.5 or 2 cp., this would explain the abnormally low water salinities we have been calculating from the SP. Although we cannot prove this is happening, it appears very reasonable, and we will adopt this as a working hypothesis pending experimental confirmation. We hope to carry out lab work later this fall which will prove or disprove this hypothesis.

The solution to the problem, granted that the above speculation is correct, is quite simple. We need to measure the filtrate viscosity, and correct the filtrate resistivity accordingly before calculating R_w from the SP log. The filtrate viscosity could be readily measured in the field by timing the discharge from a calibrated pipette, (Cannon-Finske viscometer) or perhaps by use of a small vibrating reed viscometer.

We have recalculated the data previously reported (plus data from Test 22, the Wainoco Girouard Number, well reported here for the first time), using appropriate resistivity vs. temperature corrections from Fig. 3 of the Fourth Progress Report, and assuming that the mud properties of density and resistivity vary linearly from one logging run to the next; interpolating to get mud density and resistivity values corresponding to the zone tested. There is some doubt this linear interpolation is valid, since a major mud change is often made after a logging run when casing is set. Without detailed information on mud composition and properties from day to day it is impossible to know the best method for estimating mud properties when a given zone is drilled.

At any event, when the "correct" mud filtrate is back calculated using known values of SP and known produced formation water resistivity as outlined above, a value of $K_F = \frac{R_M}{R_{MF}}$ can be computed.

This is plotted in Fig. 1 vs. mud density. There appear to be 3 different curves for K_F ; one for driscord muds, one for gyp muds, and one for lignosulfonate, lime, and tannin (quebracho) muds, except for the lignosulfonate muds, we have only a few examples of each type, so the data should be viewed with caution. Note that we have dropped the 1.07 exponent used in the Gen 7 correlation as not justified by the accuracy of our data.

We have also plotted in Fig. 1 the function $K_F = \frac{\phi^2}{e^{.5(\phi-1)}}$ discussed in the Fourth and Fifth progress reports. As was shown in these two progress reports, this function should represent the resistivity behavior of slurries and slurry filtrates provided conductive solids and viscosity modifiers are not present, as we can see, this curve, shown dotted in Fig. 1, goes generally through the experimental mud data, but also implies there are large conductive solids and/or viscosity effects for the various mud types. When calculating this K_F curve, a constant mud solids spec. grav. of 3.31 was assumed in order to convert mud density to porosity, ϕ . An accurate calculation would require knowledge of the amount of bentonite, barite, etc. actually used in a given mud.

The Wainoco Girouard Number well, reported this month in Table 1 as test 22, is unusual in that the SP derived formation water resistivity is much lower than the produced water resistivity (calculated salinity much higher than produced water salinity). The only way we can account for this at present is by assuming that it is due to short term variation in mud properties.

H. F. Dunlap

Footnote:

*Prof. Robert Schechter points out that a low concentration of high molecular weight viscofying material may not increase the "micro" viscosity which determines ionic mobility (and hence conductivity) as much as it would increase the bulk viscosity of the liquid. To the extent this is true, the viscosity correction which we are postulating would be reduced.

Bibliography:

- 1 "Electrical Methods in Geophysical Prospecting", Keller and Frischknecht, pp 27-30, Pergamon Press, 1961
- 2 Schlumberger Chart Book, 1972 edition, p. 9.
- 3 "Electrolyte Solutions", Robinson and Stokes, pp. 123-126; 147-155, Butterworth, 1955.

D R A F T

Seventh Progress Report

September 1980

"Study of Log Derived Water Resistivity Data
in Geopressure Geothermal Formations"

Summary: We have obtained detailed mud records from the Pleasant Bayou #2 well which give some support to the concept that there are significant short term variations in mud properties. Daily measurements of mud filtrate chloride ion content, plastic viscosity of mud, pH of mud, and percent oil in mud show variations of ± 10 to 20%, even though the mud weight is fluctuating only a few percent and the mud type is constant. Unfortunately no resistivity measurement of mud or filtrate were reported.

We believe we will be able to start our experimental work around November 1. It has proven difficult to locate a suitable research assistant for this phase of the work, but we believe we have now found an excellent candidate. Mr. Koso Idigbe, a graduate student in the Petroleum Engineering Dept., will be able to work half time on the project starting in November. The work will be carried out at the Balcones Research Center Petrophysics laboratories operated by Professor Ken Gray. He has much of the equipment needed for the planned tests, and we plan to order the balance in the near future.

We have discussed our research with Mr. Kinder Chambers of Sweco Inc., a mud equipment manufacturer located in Austin. He has long experience in the mud industry, and while not able to offer direct help or data, thought our concepts were reasonable. He suggested we contact several other old timers in the Houston area for comments and or data. We plan to do this in early October.

Discussion: By courtesy of Professor Tony Podio and graduate student, Ms. Cindy Betz of the University of Texas Petroleum Engineering Dept., we have obtained detailed mud records for the Pleasant Bayou #2 well. Table 1 shows the Magcobar record of mud properties from 13820 to 14942 ft., which includes the test #5 interval (see second progress report for other data on this test) at 14644-704 ft. This is the main producing interval now undergoing long term testing in this well. Table 2 shows Magcobar mud additives used in Table 1, with weight units for the various additives in lbs/sack, lbs/drum, or whatever. Figures 1-5 show variation in mud weight, total chlorides in mud filtrate, plastic viscosity of mud, pH of mud, and percent oil in mud from surface to T.D. of the Pleasant Bayou #2. Considering only the sections from 14,333 to 16,500 ft. T.D., which

includes tests 5 and 6, it is interesting that variations in such properties as filtrate salinity and mud viscosity, is much greater (about $\pm 20\%$) than variations in mud weight (about $\pm 2\%$). Variations in mud pH and percent oil in mud were intermediate (about $\pm 10\%$) but still large compared to variations in mud weight. This data supports our hypotheses that mud properties obtained at the time of drilling a given zone can be considerably different from mud properties at the time of logging, and that more detailed records of mud resistivity and mud filtrate resistivity should be obtained.

It is also interesting that the chloride content in the mud filtrate varied from 5200 to 5600 ppm (obtained from titration tests, not resistivity data) while the 14644-704 interval (test #5) was being drilled as compared to 4000 ppm chloride content in the filtrate at 16,500 T.D., when the section was logged. This is a variation of $\frac{1400}{4000} = 35\%$, which is indeed substantial. Although the error is in the right direction to account for the error in calculated water resistivity in this well, the actual error is about 100%. This means that other factors, probably related to the down hole filtration process, are also entering.

One other interesting result should be noted. The log header value of RMF at 16,500' T.D. was listed as $.9 \Omega m @ 85^\circ F$. This corresponds to 5500 ppm NaCl, or 3318 ppm Cl ion content. The titration test of the filtrate showed 4000 ppm Cl content at T.D., a difference of $\frac{682}{4000} = 17\%$. This is in the right direction (measured RMF too high) to be caused by the viscosity of the mud filtrate being greater than the viscosity of water. The two effects together (viscosity increase and short time mud property variation) would account for about a 50% error ($17\% + 35\%$) in the water resistivity calculated from the S.P. log in this well. The remaining 50% of the error may be caused by differences between down hole and up hole filtration processes.

We hope to start our experimental work around November 1 at the Balcones Research Center laboratories of Professor Ken Gray, who has much of the equipment needed. We have been fortunate in locating an excellent research assistant who can work half time on this project starting in November. He is Mr. Koso Idigbe, a graduate student in Petroleum Engineering at the University.

During the next month we plan to consult with several people knowledgeable in mud engineering, and will probably visit Houston in early October for this purpose. We also plan to do additional reading on mud testing and simulated down hole mud filtration tests that have been carried out in the past, order needed

equipment, etc. A new edition (1980) of the Gray, Darley & Rogers text, "Composition and Properties of Oil Well Drilling Fluids" is proving helpful in this regard. A discussion was held last month with a local mud engineer from Sweco, Inc., Mr. Kinder Chambers. He had no specific data or suggestions, but thought our working hypothesis of major short term mud resistivity variations and possible viscosity effects on mud filtrate resistivity were reasonable.

H. F. Dunlap
October 6, 1980

Magcobar

WELL HISTORY										MAGCOBAR										MAGCOBAR										MAGCOBAR									
General Crude Oil Company										Spernese/XP-20 Lignosulfonate										MAGCOBAR										MAGCOBAR									
Pleasant Bayou No. 2										Wildcat										MAGCOBAR										MAGCOBAR									
Welch Drilling Company #15										Brazoria										MAGCOBAR										MAGCOBAR									
M. Balch/K. Wischkaemper										Texas										MAGCOBAR										MAGCOBAR									
DATE	WELL	DEPTH	TIME	WELL	DEPTH	TIME	WELL	DEPTH	TIME	WELL	DEPTH	TIME	WELL	DEPTH	TIME	WELL	DEPTH	TIME	WELL	DEPTH	TIME	WELL	DEPTH	TIME	WELL	DEPTH	TIME	WELL	DEPTH	TIME	WELL	DEPTH	TIME	WELL	DEPTH	TIME	WELL	DEPTH	TIME
1979	4-13	13820	13820	15.8	42		375	140	25	13	1/2	11.3	3.4	9.2	1.8	5.5	2.0	9000	40	31	5	35		35	35	30	5	Lime	D-C	Bulk	SAPP	Resinex					285439.00		
Short trip @ 13796' BU gas- 145 units. TCI 9200 ppm.																																							
4-14	13953	13953	16.1	41		375	141	25	8	1	9	11.7	3.0	8.0	1.1	3.0	2.3	9000	160	32	4			45	46	11	10										293606.00		
Drilling with no trouble																																							
4-15	14116	14116	16.2	41		375	140	25	11	1	8	11.0	3.0	9.4	1.0	3.5	1.6	7150	120	32	4			31	44	31	7	21	10								298962.00		
Raised wt. to 16.2 as per Co. orders. Drilling ahead with no trouble																																							
4-16	14147	14147	16.2	43		375	140	28	10		9	10.8	3.0	10.8	1.0	3.8	1.6	7100	160	32	4	35		11	4	4	6	2	34	29							302324.71		
Made short trip @ 14147 w/no trouble																																							
4-17	14147	14147	16.2	43		375	130	32	12		9	10.8	3.0	9.0	9	3.4	1.4	7100	100	33	4																302824.71		
Circulating.																																							
4-18	14194	14194	16.2	44		366	130	34	12		9	10.2	3.2	10.8	7	4.3	1.3	8000		33	4			10	45	45	26	35	7								307036.55		
Drilling. Background gas 8-10 units.																																							
4-19	14433	14433	16.1	42		84	130	25	10		7	11.2	2.4	9.8	1.5	3.8	2.2	5600	100	32	4			30	35	22	25	5	25	19							313155.09		
PU to CFX @ 14434 and not stuck- Circ. & worked pipe 7 hrs. Ran freepoint- stuck at 10751'. Displaced w/16.2 ppg Black Magic.																																							
4-20	14333	14333	16.1	42		25	10		7	11.2	2.4	9.8	1.5	3.8	2.2	5600	100	32	4																		313155.09		
Working stuck pipe. Displacing whole system w/Black Magic. Receiving heavy rains.																																							
4-25	14333	14333	15.6	43		27	11		7	10.7	2.7	9.8	1.4	3.6	2.1	5400	80	29	4																		313155.09		
Running 9-5/8" casing.																																							
4-27	14333	14333	15.1	39		84	21		2	1	11.8	1.6	8.6	1.8	4.6	2.5	7800	120	26	7	1		33	20	20	17											322435.44		
Lost circulating while displacing w/cement. Cond. mud from duck's nest (raised MW to 15.3)																																							
4-28	14338	14338	14.2	41		125	5		1	11.6	2.6	9.4	1.5	5.2	2.5	5500	120	25	6			35															322726.44		
W.O.C. - Squeezed w/cement at 8700'. (Cement weighed 16.6 mud 15.3) Filling hole w/water. Well flowing a little																																							
4-29	14338	14338	14.9	42		27	5.1		1	11.6	3.6	9.8	1.5	4.1	1.9	5000	80	22	5			60															323172.96		
Tested em. & barite plug for 880 psi. No test. Built 750 bbls. mud to 15.0 ppg. Squeezed w/cement at 8700' W.O.C. for 24 hrs.																																							
5-1	14338	14338	15.2	39		25	5		1	11.7	3.8	9.8	1.9	5.0	2.1	4200	80	25	5			55															333182.74		
Built volume in pits. (900 bbls. @ 15.2/gal.) W.O.C.																																							
5-2	14338	14338	15.2	38		25	4		1	11.7	3.9	10.0	1.2	4.6	2.0	4200	80	25	5																		338218.65		
Nipple up.																																							
5-3	14338	14338	14.6	38		19	2		1	11.7	3.9	10.1	1.2	4.6	2.2	4200	80	23	5																		338218.65		
Finished nipping up.																																							
5-4	14338	14338	14.4	37		18	2		1	11.5	4.2	10.1	1.5	4.3	1.8	4100	80	22	5																		340155.71		
Finished nipping up. PU DC & HW DP. GIM to drill cement.																																							
5-5	14338	14338	16.2	46		353	38		10	2	11.2	3.0	9.3	1.4	4.3	1.9	5800	160	30	5			60	20	20	8											347181.10		
Drilled cement to float shoe. Circ. & cond. hole to log & raised MW to 16.2 ppg. Logging.																																							
5-6	14324	14324	16.2	50		310	40		12	1	11.0	3.2	9.1	1.2	4.8	1.8	5600	200	30	5			5	5													352752.51		
Ran CBL & casing caliper logs. T.H. Drilling cement.																																							
5-7	14441	14441	16.2	46		110	44		1	11.2	3.0	9.5	1.3	4.9	2.1	5700	80	29	5			25	35	18													353759.31		
Drilled float shoe & tested csg. seal to 1340'. OK. Drilling ahead. No problems. Trip for Bit #23																																							
5-8	14610	14610	16.2	43		102	126		33	2	11.7	2.8	9.4	2.1	5.6	2.3	5600	40	29	5			8	40	55	25											356758.24		
Drilling ahead. No trouble.																																							
5-9	14675	14675	16.2	44			6		1	11.6	3.0	10.2	2.3	5.2	2.6	5200	40	31	5			5	20	8													357386.77		
Trip to PU core barrel at 14675'. GIM w/Diamond coring bit.																																							
5-10	14716	14716	16.0	45		233	114		34	5	2	11.7	3.3	10.2	2.1	6.3	2.7	5200	40	30	5			5	25	50	16										359197.41		
Coring with no problems.																																							
5-11	14766	14766	15.9	45		306	118		37	8	2	11.3	3.0	9.0	2.0	6.1	2.8	5100	40	30	5			15	10	20	4										259970.77		
Tripped w/core barrel. Remove core. T.H. w/new bit.																																							
5-12	14762	14762	15.9	45		306	124		34	6	2	11.2	2.6	8.4	1.2	3.8	2.1	5200	40	30	5			26	50	10											361677.77		
Testing the drill bit to 15.0/gal																																							

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FORMATION PRESSURE GREGORY ET AL.

FIGURE 1

MUD WEIGHT RECORD
PLEASANT BAYOU #2

25120

Depth (1000 ft)

collapse line

Test 5

Test 6

Mudobar
Record

MUD WT

Stabilizer ranging up to 2.5% - Added 1% Diesel

Hole packed at 2826'

DFA check @ 10809' well found circulation

Flowed 5.1100 Gallons

Well found, tested 1.11
in 1.11.5 by logging

on 2.11.11.6 more under casing shot

with 5.11.11.6 SKT 1.11.11.6
2.11.11.6 SKT 1.11.11.6
2.11.11.6 SKT 1.11.11.6
2.11.11.6 SKT 1.11.11.6

S.D. P.B.L.

MW (PPg)

Figure 2
 B-55
 Total Chlorides in
 Filtrate (Titration)
 Pleasant Bayou #2

Figure 3
 Plastic Viscosity
 Pleasant Bayou #2

P.B. #2
 T.D. P.B. #2
 P.B. #1
 P.B. #2
 P.B. #2

25120

Depth (100 ft)

ST collage line

Test 5

Test 6

2

1

0

10

11

12

14

16

18

7 8 9 10 11 12
PH

Figure 4
PH Record
Pleasant Bayou #2

P.B. #2

P.T.D. P.B. #1

3.5 P.T.

P.B. #1

P.B. #1 READING

P.B. #2

Figure 5
Percent Oil in Mud
Pleasant Bayou #2

25120

Depth (1000 ft)

College Ave.
St. L.

Test 5

Test 6

16

18

0

1

2

3

4

5

6

20 SQUARES PER INCH

Oil (%)

Crust on top of up in Algal

P.B. #2

P.B. #2

P.B. #1

P.B. #2

Table 2
Weight Units for Mud Additives

PRODUCT	CODE	PRICING UNIT
BENEX	3511	BAG 25 LBS
BIT LUBE II	3555	DRUM 55 GAL
CALCIUM BROMIDE	4046	BAG 25 KGM
CALCIUM CHLORIDE	4017	BAG 80 LBS
CALCIUM CHLORIDE (FLAKE)	4020	BAG 100 LBS
CALCIUM CHLORIDE (PWD.)	4018	BAG 100 LBS
CAUSTIC SODA	4024	BAG 50 LBS
CEASCAL	3527	BAG 50 LBS
CEASTOP	3529	BAG 50 LBS
CELL-O-SEAL	3023	BAG 25 LBS
CELLOSIZ HEC	3024	BAG 50 LBS
CHIPSEAL	3026	BAG 40 LBS
COTTONSEED HULLS	3028	BAG 100 LBS
COTTONSEED HULLS	3052	BAG 50 LBS
CYRAN	2030	BAG 50 LBS
D-D	3528	DRUM 55 GALS
D-D	3533	CAN 5 GALS
D-D (COLD WEATHER TYPE)	3537	CAN 5 GALS
D-D (COLD WEATHER TYPE)	3543	DRUM 55 GALS
DESCO	1021	BAG 25 LBS
DICK'S MUD SEAL	3030	BAG 40 LBS
DOS 3	3512	DRUM 55 GALS
DRISPAC	2040	BAG 50 LBS
DRISPAC SUPER LO	2041	BAG 50 LBS
DUOVIS	3986	BAG 50 LBS
DV 22	2035	BAG 50 LBS
DV 33	2525	DRUM 55 GALS
DV 33	2526	CAN 5 GALS
FLAKE GRAPHITE	3550	BAG 50 LBS
FLOSAL	4042	BAG 50 LBS
FLOXIT	3551	BAG 50 LBS
GEO-GEL	0316	BAG 50 LBS
GYPSUM	4062	BAG 100 LBS
HME	2560	CAN 50 LBS
IRONITE SPONGE	3992	BAG 50 LBS
KLEEN UP	3557	CAN 5 GALS
KLEEN UP	3558	DRUM 55 GALS
KWIK SEAL	3155	BAG 40 LBS
KWIK THIK	10309	BAG 50 LBS
LIME	4111	BAG 50 LBS
LO LOSS	3600	BAG 50 LBS
LUBE-KOTE	3601	BAG 50 LBS
M.C. QUEBRACHO	1083	BAG 50 LBS
MAGCO ALUMINUM STEARATE	3502	BAG 25 LBS
MAGCO CMC-HI-VIS	2096	BAG 50 LBS
MAGCO CMC-REG	2095	BAG 50 LBS
MAGCO MICA FINE & COARSE	3113	BAG 50 LBS
MAGCO POLY DEFOAMER	4034	CAN 5 GAL
MAGCO-INHIBITOR A-101	3598	DRUM 55 GALS
MAGCO-INHIBITOR A-202	3602	CAN 5 GAL
MAGCO-INHIBITOR A-202	3603	DRUM 55 GALS
MAGCO-INHIBITOR A-303	3620	DRUM 55 GALS
MAGCO-LUBE	3634	DRUM 55 GALS
MAGCO-LUBE	3635	CAN 5 GALS
MAGCO-POLY-SAL	2203	BAG 50 LBS
MAGCOBAR-BAGGED	0001	BAG 100 LBS
MAGCOBAR-BULK	0003	TON 2000 LBS
MAGCOBAR-EXPORT	0002	BAG 100 LBS
MAGCOGEL	0300	BAG 100 LBS
MAGCOGEL-EXPORT	0301	BAG 100 LBS
MAGCONATE	2611	CAN 5 GALS
MAGCONOL	3616	DRUM 55 GALS
MAGCONOL	3617	CAN 5 GALS
MAGCOPHOS	1060	BAG 100 LBS
MF-1	3561	BAG 50 LBS
MIXICAL	3581	BAG 50 LBS
MUD FIBER	3118	BAG 40 LBS
MY-LO-JEL	2140	BAG 50 LBS
MY-LO-JEL PRESERVATIVE	3618	BAG 50 LBS

PRODUCT	CODE	PRICE	UNIT
MY-LO-JEL PRESERVATIVE	3618	BAG	50 LBS
NUT PLUG-COARSE	3123	BAG	50 LBS
NUT PLUG-FINE	3121	BAG	50 LBS
NUT PLUG-MEDIUM	3122	BAG	50 LBS
OILFAZE	2612	BAG	50 LBS
OS-1	4191	BAG	50 LBS
OS-1-L	4197	DRUM	55 GALS
PHENOSEAL	3137	BAG	40 LBS
PIPE LAX	3630	DRUM	55 GALS
PIPE LAX	3631	CAN	5 GALS
POLY MIX	4033	BAG	50 LBS
POLYBRINE	3584	BAG	50 LBS
POTASSIUM CHLORIDE	3640	BAG	100 LBS
RAPIDRILL	3587	BAG	2 LBS
RESINEX	2497	BAG	50 LBS
S.A.P.P.	1100	BAG	100 LBS
SALINEX (DRY)	2617	BAG	35 LBS
SALT	4180	BAG	100 LBS
SALT GEL	0314	BAG	50 LBS
SE-11	2635	DRUM	55 GALS
SE-11	2638	CAN	5 GALS
SI-1000	4192	DRUM	55 GALS
SODA ASH	4181	BAG	100 LBS
SODIUM BICARBONATE	4183	BAG	100 LBS
SODIUM CHROMATE	4187	BAG	100 LBS
SOLTEX	3560	BAG	50 LBS
SOS-200	3996	DRUM	55 GALS
SPERSENE	1105	BAG	50 LBS
STABILHOLE	2636	BAG	50 LBS
SUPERDRILL	3188	BAG	50 LBS
SURFAK E	2528	DRUM	55 GALS
SURFAK M	3520	DRUM	55 GALS
TANNATHIN	1111	BAG	50 LBS
VERTOIL	2697	BAG	50 LBS
VG 69	2675	BAG	50 LBS
WL-100	2498	BAG	50 LBS
WL-100 LIQUID	2496	CAN	5 GALS
WONDERSEAL	3800	DRUM	55 GAL
XP-200	1140	BAG	50 LBS
XPK-2000	3624	DRUM	55 GALS
ZC-100-L	4153	CAN	5 GAL

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FIGURE 1
Mud Weight Record
Pleasant Bayou #2

FORMATION PRESSURE GREGORY FIG 7

Depth (1000 ft)

25120

St. College Inc.

Test 5

Test 6

0
2
4
6
8
10
12
14
16
18

5' of fill on bit after trip

MUD WEIGHT

Stabilizer logging up in Anahuac - Added Mucilose
GUMM

Hole packed off @ 9826'

Delg knex @ 10809 - well flowed line & raise

Flowed @ 11100' Raise MW

Well flowed before TTH
MC to 11.5, bit logging, RAS

ON TRIP, THE HOLE UNDER CASING SHOUL

while BULK @ 10954
GOT STUCK - Displaced
casing system w/ Black
Problems cementing 5 7/8

T.O.
P.B. #2

PB #2

MW (ppg)

FIGURE 2
TOTAL CHLORIDES IN
FILTRATE (TITRATION)
PLEASANT BAYOU #2

B-68

FIGURE 3

PLASTIC VISCOSITY

PLEASANT BAYOU II

25120

Depth (1000 ft)

Test 5

Test 6

13

0 10 20 30 40 50

20 SQUARES PER INCH

PV (CP)

PL, B, 112

T.D.

PL-5

PL-22

PB #2

PLASTIC VISCOSITY

B-64

FIGURE 4
PH RECORD
PLEASANT BAYOU

25120

Depth (1000 ft)

St. J. college line

Test 50

Test 60

16

18

7 8 9 10 11 12 13

20 SQUARES PER INCH

- 4

> 10 pps
mod

PB 42

T.D.

PB 41

PB 42

B-65

FIGURE 5
PERCENT OIL IN MUD
PLEASANT RANCH #2

25120

Depth (1000 ft)

Test 5
Test 6

OIL % →

PB #2

TD PB #2

PB #1

PB #2

Stabil bit logging up in Anahuac

PROGRESS REPORT # 8, Oct., 1980

"Study of Log Derived Water Resistivity Data
in Geo² Formations"

SUMMARY: We have made relatively little progress during the past month, in part because of red tape involved in ordering equipment and supplies for the planned experimental work. We have borrowed enough equipment and supplies from other labs to let us start some work in early November, but the material ordered under contract will apparently not be delivered for several weeks (at the earliest) to several months (most likely). Initial experiments will measure mud resistivity, and mud filtrate resistivity, viscosity, and chloride content for several temperatures and mud weights.

Data from the Lear Koelemay #1, Jefferson County, Texas; and from the Riddle, Saldana #2, Zapata County, Texas, have been analyzed. Both tests are different from the majority of wells with lignosulfonate muds studied to date, in that the calculated water resistivity is lower than the measured formation water resistivity (calculated water salinity too high).

Visits to the Houston offices of Eaton Operating Co; Baroid, Inc; and Dr. George Gray, consulting mud engineer were made during the month. The Lear Koelemay and Riddle Saldana tests were discussed at Ben Eaton. Availability of continuous mud resistivity data was discussed at Baroid (not much encouragement from them). The general concepts we have developed of mud filtrate viscosity variations were discussed with Dr. Gray. (He believed these to be reasonable.)

Another variable which may affect the log derived water resistivity values is the amount of methane dissolved in the water. The water resistivity is expected to increase with methane content, but the amount of this increase is not known at present. The effect would be to make the calculated water resistivity too high (calculated water too fresh). We may carry out some experiments to determine the effect of dissolved methane on water resistivity if no good

literature data can be located.

DISCUSSION:

We have borrowed enough material and equipment to let us begin experimental work in early November. We had hoped to order these items in October so we could have them by now, but red tape requirements for multiple bids plus the October 31 termination date for the old D.O.E. contract prevented us from placing any orders until November 3. We expect to receive the items ordered in a few weeks to a few months.

Meanwhile, we plan to make measurements on several mud types to test the concept advanced in the 6th and 7th progress reports that variations in mud filtrate viscosity may be affecting our calculations of water resistivity. By next month we hope to have data that should support or refute this hypothesis.

The test data from two additional wells, the Lear, Koelemay #1, and the Riddle, Saldana #2 have been studied (see Table 1). In both cases the results differ from the majority of wells studied previously with lignosulfonate muds, in that the calculated water resistivity is too low (water too salty) compared to the measured resistivity of the produced water. The errors are large, from 50% to 200%, regardless of whether the water resistivity is calculated using the header data, the Gen 7 data or the "curve" data for mud filtrate resistivity. In the case of the Saldana well, if the produced water data and measured mud filtrate data are accepted as correct, the SP curve should not have responded as it did, with approximately 25 mv deflection to the left (negative). It should have, instead, deflected to the right (positive), since the formation water has a higher resistivity than the mud filtrate! Something is very wrong here, but we don't know just what.

On October 10 we visited several Houston companies to obtain additional data and information. At Eaton Operating Co. we discussed the Koelemay and Saldana tests, and learned that it may not be possible to use the RFT wire

line tool to obtain in situ samples of mud filtrate because of the danger of tool sticking. We also learned from Eaton of a possible source of additional water data, at U.S.G.S. Gulf Coast Hydro Science Center, NASA Lab, Mississippi (Mr. Richard Taylor). We have written them for additional information.

The discussion with Baroid was held to review some of our results with them, and to request their assistance in getting data on variations in mud and mud filtrate resistivity in drilling wells on a continuous basis, or at least on a daily basis if continuous data was not available. They agreed to keep our interest in mind, but knew of no such data at present.

Dr. George Gray has had many years experience with Baroid and is now retired, operating as a mud consultant. We reviewed our problem informally with him, including our hypotheses of short term mud resistivity variation and variable viscosity of mud filtrate. He thought both of these were reasonable. In the discussion, he was able to suggest several references which are pertinent to our problem.¹⁻³

Reference 2 in particular was interesting since this gives the only data we have seen on the viscosity of a mud filtrate. Table 5 of this paper reports the viscosity of the filtrate vs temperature in the 78°F to 139°F range. The results are shown in Figure 1, along with Bureau of Standards data on the viscosity of pure water. As can be seen, there is practically no difference in the two viscosities in this temperature range, and hence no evidence for viscofying materials passing from the mud to the filtrate. The recipe for this mud was given as follows: 330 gm/liter of Limburgia clay, 50 gm/liter of bentonite, 2.3 gm/liter of NaOH, 5.2 gm/liter of Na₂CO₃, 4.2 gm/liter of Quebracho, and 5 gm/liter of sodium-carboxymethylcellulose. Mud density was 1.24 gm/cc, equivalent to 10.3 pd/gal. This is a relatively light mud, and contains no lignosulfonate, so this result may not be too pertinent to our problem. We plan to work with Dr. Gray further as we begin our experimental program.

If the resistivity of brines containing methane in solution is changed by the presence of the methane, this must be taken into account. We would expect that the resistivity would be increased as dissolved methane increases, but the amount of resistivity increase is not known. It may not be a very large effect, according to the following argument. A pound molecular wt of any gas occupies 358 std. cu. ft. The brines we are concerned with contain about 35 std. cu. ft/bbl of C_1H_4 in solution, or about 1/10 of a pound molecular weight of C_1H_4 , which would be 1.6 pds of C_1H_4 per barrel. The salt content of a typical brine would be 100,000 ppm, or about 35 pds/bbl of NaCl. On a mol basis, we would have .1 mol C_1H_4 and $35/58 = .6$ mol NaCl, or a ratio of 6 NaCl to 1 C_1H_4 molecules. It is hard to see how the C_1H_4 could double the brine resistivity, but the effect may be large enough to be significant. This would be particularly true for the fresher brines, where the ratio of C_1H_4 to NaCl molecules may reach 1 to 1 or even higher.

We plan to look for published work in this area. If we can't find any, we may carry out a few experiments to define the effect of dissolved methane on water resistivity.

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TABLE 1

Measured and SP Derived Water Data from Geopressured Geothermal Reservoirs

Test #	Well Name	Location	Sand Depth	Well Temp °F	Mud Dens #/gal	Pressure	Meas Rw ΩM @ well Temp	Calc Rwsp (Header) ΩM	Calc Rwsp Gen 7 ΩM	Calc Rwsp (Curve) ΩM	Mud Type	
											Header Data	Basic Mud Type
23	Lear Koelemay #1	Jefferson Co, Tex.	11641-780'	209°	16	?	.152 (calc. from T.D.S.)	.108	.066	.041	SPER-XP-20	Chrome L.S. Chrome Lignite
24	Riddle oil Saldana #2	Zapata Co, Tex.	9745-9835	251°	16.1	?	.181 (calc from cl content)	.051	.071	.037	RD-111	IMCO L.S.