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FINAL TECHNICAL REPORT
PARCERDUE
GEOPRESSURE—GEOTHERMAL PROJECT

U. S. DEPARTMENT OF ENERGY/THE DOW CHEMICAL COMPANY
CONTRACT NO. DE-AC08-79 ET 27255

**"Study a Geopressured Reservoir by Drilling and Producing
a Well in a Limited Geopressured Water Sand"**

September 28, 1979 thru December 31, 1983.

Prepared for:

U. S. Department of Energy, Nevada Operations Office

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ABSTRACT

In 1979, The Dow Chemical Company proposed to investigate the behavior of geopressured reservoirs by drilling and producing a well in small, well defined, geopressured reservoir; and performing detailed pressure transient analysis together with geological, geophysical, chemical, and physical studies.

The Dow-DOE L. R. Sweezy No. 1 well was drilled to a depth of 13,600 feet in Parcperdue field, just south of Lafayette, Louisiana, and began production in April, 1982. The production zone was a poorly consolidated sandstone which constantly produced sand into the well stream, causing damage to equipment and causing other problems. The amount of sand production was kept manageable by limiting the flow rate to below 10,000 barrels per day.

Reservoir properties of size, thickness, depth, temperature, pressure, salinity, porosity, and permeability were close to predicted values. The reservoir brine was undersaturated with respect to gas, containing approximately 20 standard cubic feet of gas per barrel of brine. Shale dewatering either did not occur or was insignificant as a drive mechanism.

Three significant, unanticipated phenomena were observed:

1. Pressure transient analysis of drawdown and buildup data yielded inconsistent results. Additional rock mechanics studies and reservoir analyses indicated that formation compressibility was much higher than expected, and was higher in drawdown than in buildup. The high compressibility of the reservoir increases the expected ultimate recovery several times.

2. Aromatic hydrocarbons: benzene, toluene, ethylbenzene, and xylenes were detected in and condensed from the gas stream, possibly indicating past or present contact with a liquid petroleum, or petroleum-rich gas phase.
3. Heavy paraffinic oil was produced in small quantities late in the history of the well. The source of the oil production is uncertain.

Production terminated when the gravel-pack completion failed and the production well totally sanded in, February, 1983. Total production up to the sanding incident was 1.94 million barrels brine and 31.5 million standard cubic feet gas.

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- B Final Reservoir Analysis: Otis Engineering
- C Reservoir Analysis and Simulation: S-Cubed
- D Contracts and Agreements
- E Rock Mechanics: Terra Tek
- F Core Examination & Mineral Identification: Dow Chemical Co.
- G Casing Failure Reports: Great Lakes Engineering
- H Paleontological Report: George May & Assoc.
- I Acid Solubilities and Sieve Analyses: Dowell
- J Geochemical Analysis: Geochem Laboratories Inc.
- K PVT Analysis: Weatherly Labs
- L Gravel-Pack Failure Report: Completion Technology Inc.
- M Analysis of Fluids: Drs. Keeley & Meriwether - USL

Complete sets of Appendices for Dow Report No. DOE/ET/27255-1 are on file at the following locations:

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Executive Summary

The United States Department of Energy and earth scientists in general became aware in the early 1970's that the deep geopressured aquifers of the Gulf Coast contained tremendous amounts of energy in the form of heat, pressure, and methane gas. The energy shortages of that decade spurred interest in geopressure as a potentially exploitable economic resource.

The basic exploitation scheme involves drilling one or more deep, large diameter, high pressure water wells. Excess reservoir pressure (geopressure) would supply the driving force to produce reservoir fluid at high rates - often estimated to be on the order of 40,000 barrels per day brine and over 1 million cubic feet of gas per day. Mechanical energy would be extracted from the well stream through the use of turbines; heat, through the use of binary cycle heat exchangers or flash systems; gas, utilizing relatively standard oilfield technology for the separation of gas from liquids.

The feasibility of such a system was highly uncertain from both the economic and technological aspects. One fact was certain: the capital costs to drill wells and install the various equipment necessary for production and the extraction of energy

would be very high; the net recoverable energy per well would be low compared, for example, to a high pressure gas well costing approximately the same amount of money to drill. The payout, then, on a geopressure-geothermal operation would have to be over an extremely long period of time - twenty years is a time period frequently used in economic calculations.

At this time in the mid-seventies, very little was known about the behavior of strongly geopressured aquifers undergoing long-term, high rate pressure depletion. In fact, there existed widespread disagreement among reservoir engineers as to exactly how these reservoirs would behave; and yet, the long-term reservoir behavior was critical to the viability of the resource.

The United States Department of Energy funded several projects designed to tap very large geopressured reservoirs and produce test wells for indefinite, but very long periods of time. The Dow Chemical Company felt that much could be learned about the long-term behavior of geopressured reservoirs if a small, well defined reservoir could be depleted and intensively studied over a short period of time - a year or two.

Such a reservoir was located in Parcperdue field, in Vermilion Parish, Louisiana, approximately twelve miles south of Lafayette. Dow obtained a geothermal lease in the field and submitted a proposal to the Department of Energy. In September, 1979, Dow was awarded a contract to drill and test the Dow/DOE L.R. Sweezy No. 1 in Parcperdue field.

Drilling operations commenced in January, 1981, with a rig contract from the Welsh Drilling Company. The proposed total depth was 13,600 feet and the objective was the Upper Oligocene "Cib jeff" sand. Drilling proceeded with only minor problems to the top of the Cib jeff sand. At this point, two, conventional diamond bit, sixty foot cores were successfully cut. Total depth was reached and the hole was logged in April, 1981.

While tripping the drill string out of the hole, the tongs engaged and broke the drill string and 2463 feet of drill pipe and bottom assembly fell to the bottom of the hole. Fishing operations failed to recover the entire string and the hole was sidetracked to TD and logged. A second major incident occurred when threads failed while attempting to run casing, and 262 joints of 7-5/8" - 8-5/8" casing dropped into the hole. Again, an incomplete fishing job required a second sidetrack hole.

The well was successfully completed in the second sidetrack hole. The unconsolidated nature of the sandstone, as observed in the core, required that the well be gravel-packed to minimize sand production. The well was completed in August, 1981. For budgetary reasons, the completion of the companion disposal well was delayed until April of 1982.

The local geology was determined from surrounding well control, from pre-existing seismic control and from a 3-D seismic project carried out by the University of Southwestern Louisiana under separate contract to DOE, from drill cuttings and the 120 feet of whole core which was recovered, and from a complete suite of well logs.

The Cib jeff sand is in the Anahuac formation of Upper Oligocene age and is located at a depth of 13,500 feet. The sand is 50 feet thick and is overlain by approximately 1300 feet of marine shale and underlain by approximately 3000 feet of shale. The bounding faults are believed to seal the reservoir, which is between 1 square mile and 1.5 square miles in area, depending on whether geological, geophysical, or pressure transient methods are used to estimate size.

Well logs indicate an average porosity of approximately 28% and a shaliness ranging from 0% to 5% in the upper part of the sand to 24% in the lower part of the sand. Permeabilities at

bench conditions were in the range of several darcies, but are much lower at in-situ conditions. Water salinity was calculated using several different methods; however, a simple Rwa calculation produced the most accurate estimate of salinity - 100,000 parts per million. The mechanical properties log produced extremely erroneous results, the reasons for which are not clear.

The core material was labeled and described in the field, and later studied and tested in detail: including thin section study, X-ray micrography, scanning electron micrography, X-ray diffraction, X-ray emission, and rock mechanics at in-situ conditions.

The sand itself can be characterized into two zones - the upper is coarser grained, clean, and structureless; the lower is finer grained, more consolidated, shaley, and contains numerous sedimentary structures.

Mechanical testing done at in-situ conditions included porosity, permeability, and ultrasonic wave velocity measurements; rock deformation tests included uniaxial compaction, triaxial tests to failure, and creep tests. Late in production testing it was determined that additional information regarding rock compressibility and creep would be required to properly

evaluate the reservoir behavior. A suite of additional rock - mechanical tests were performed to obtain this information. Average values for the mechanical testing were as follows: porosity was 30%; permeability coefficient was 6 md to 914 md; Young's modulus was 1.06×10^6 psi; the shear modulus was 0.51×10^6 psi; bulk compressibility was 3 to 5 $\times 10^{-6}$ 1/psi. Rock creep appears to be a significant factor during the early stages of geopressure depletion.

The source rock geochemistry of the shale core material was studied and the shale was found to be low in total organic carbon and thermally immature. The low maturity indicates the most likely hydrocarbon generated to be a small amount of biogenic gas. This fact is consistent with the gas-undersaturated reservoir fluid, but does not explain the source of oil and gas production from the Cib jeff sand in wells located in nearby fault blocks.

Production testing of the well began in April, 1982. The production system consisted of the production wellhead with emergency shut down valves, a data header, including sand detector and dead-weight tester, total flow turbine meter, expansion loop, choke manifold with dual chokes, three-phase high volume separator, gas and water metering devices, a filter unit, disposal well, and gas flare stack.

Problems were encountered from the start - the most significant of which was the production of fine grained sand, sometimes in large slugs at high production rates. This sand problem continued throughout the life of the well, requiring constant monitoring of sand production and effectively limiting production rates to less than 10,000 barrels per day - approximately half the desired rate. The sand problem culminated in the catastrophic massive sanding which occurred on February 5, 1983. It was impossible to determine the exact cause of the sanding; however, subsequent review indicated that failure to pre-pack and stage pack the gravel may have left a zone of weakness in the gravel pack through which sand was able to flow and cut out the screen. Alternative procedures in perforating, packing, and setting the pack might have lessened the severity of the problem.

The stem-and-seat type adjustable chokes used to control flow were designed for gas wells and would not operate properly with high velocity brine. The carbide facings were repeatedly cut and fractured, and the face of the high pressure, high velocity water in back of the stem flange caused the stem to close against the seat, shutting off flow. The adjustable chokes were exchanged for a system of dual positive chokes, which performed adequately in this application.

Measurement of liquid volume was made with a total flow turbine meter, upstream of the choke manifold, and with a turbine meter downstream of the separator. Both meters operated well as determined by frequent calibration.

Corrosion was monitored with an electronic corrosion meter, and was minimal except in spots subjected to high turbulence. Scale was not a problem due to the fairly low salinity of the brine; however, a scale inhibitor was used.

Disposal well management was a major concern. The separator operating pressure of 600 psi to 650 psi limited the maximum disposal well backpressure to approximately 400 psi. A number of techniques were used to keep the backpressure in the acceptable range, including: conventional acidization of the well, adding dry citric acid to the filter cannisters, short (30 second to 1 minute) backflushing of the well to clean the formation face, long (24 hour) backflow of the injection well to the brine pit to remove gas which had broken out in the formation, and injection of a surfactant into the flow stream.

Gas measurement was quite difficult due to the low volume of gas produced and the inability to maintain a constant backpressure on the gas line. An orifice meter was used initially to meter gas; it was replaced with a positive displacement meter; finally the two were used in conjunction.

A full suite of PVT (pressure, volume, temperature) measurements was made on the reservoir fluid. This data, together with the gas measurements made at the surface, indicated a gas to water ratio of approximately 17.2 SCFG/BBL water, with an additional 3 SCFG being re-injected into the disposal formation. The methane saturation value for this fluid would be approximately 30 SCFG/BBL; hence, the brine is undersaturated and no free gas is likely in the reservoir. The reservoir bubble point is 8550 psia.

Samples of water and gas were taken at frequent intervals for chemical analysis. Most of the brine constituents remained fairly constant throughout production; calcium, zinc, and bromine, however, showed a sharply decreasing concentration with production. The elution curves of these ions indicate the clean-up of contamination from Hevi-water® (a $\text{CaBr}_2\text{-ZnBr}_2$ mixture) used as a completion fluid in the well. Trace elements were analyzed using the PIXE technique. None of the trace element data indicated a source of brine from outside the formation - from shale de-watering, for example. Total dissolved solids in the formation brine was 99,700 Mg/L.

Gas was analyzed using chromatographic techniques. The gas was composed of approximately 94% methane, 2.5% ethane, 2.5% carbon dioxide, and 1% other gases.

Early in the production of the well, a yellow color was noted in the gas flare along with some smokiness of the flame. A dry-ice/acetone cold trap was placed in the gas stream to attempt to condense out the hydrocarbons that were responsible for the unusual flame. The material condensed was highly aromatic in nature; approximately 33% benzene, 36% toluene, with the remainder made up of ethylbenzene and xylenes. The amount of aromatic material in the gas stream apparently increased during production; in September, 1982, aromatic condensate was noted in the drainage from the water drip pot in the gas line. This continued to increase until most of the material from the drip pot was condensate. In November, 1982, approximately one barrel of heavy, dark, highly paraffinnic oil was discovered while cleaning the separator. The well continued to produce small quantities of oil for the remainder of the production test. The source of the condensate and oil is unclear; possible explanations involve the solubility of hydrocarbons in brine, coning of thin layers of oil, and movement of dead, or "irreducible" oil.

Downhole pressure transient testing was the heart of the research project, yielding the fundamental information about the reservoir. Pressure monitoring was done using a Hewlett-Packard quartz pressure gauge and multiplexed temperature gauge latched in downhole at the bottom of the gravel-pack assembly, a depth of

13,395 feet. Surface temperature and pressure was monitored at the wellhead, on the flow line, and at the disposal well, and flow rates were continuously monitored from the total-flow turbine meter. All data was recorded by computer on magnetic tape, then transmitted via telephone to a mainframe computer in Dallas, Texas, where processing was done.

The original plan was to run a series of short term isochronal tests upon production startup, followed by long-term buildup tests at selected intervals. Startup problems of sand production and choke failures prevented this plan from being carried out; the first tests, instead, were run as reservoir limit tests. A time interval of 60 days, assuming a flow rate of approximately 10,000 barrels per day, was selected as the ideal period between long-term buildup tests. A total of eleven drawdown and buildup tests were run.

The initial reservoir analyses by conventional methods yielded confusing and contradictory results. Good results were finally obtained using a "water potential function" - a technique which uses non-linear regression analysis to determine reservoir parameters as a function of pressure.

The most significant result of the reservoir study is the discovery that the rock compressibility of this reservoir is far greater than anticipated, and varies as a function of pressure. Rock compaction is the primary drive mechanism of the reservoir, contributing approximately 94% of the total subsurface energy to expulse water. The change in compressibility with pressure is so significant that the resulting compaction and pore relaxation propagate outward from the wellbore in transient fashion, leading to radically different values being calculated for drawdown versus buildup tests, and complicating reservoir interpretation.

Reservoir boundaries define a rectangle 12,700 feet by 3,000 feet, or approximately 880 acres. This compares favorably with the reservoir size and configuration determined by geology. Permeability calculated at initial reservoir pressure is approximately one darcy. Skin effect and turbulent flow effect were significant, but decreased as the reservoir was produced and permeability reduction stabilized.

Initial water in place is calculated to be 97 million separator barrels, equivalent to 2209 barrels per acre-foot. The stabilized absolute open flow of the well is calculated to be approximately 40,000 barrels per day. The productivity index was

6.3 barrels per day per psi drawdown at termination of testing. The depletion constant was 3853 cumulative barrels of brine per psi depletion after steady state flow conditions were achieved. The contribution of water influx from vertical (shale de-watering) or edge is minimal; the two influx constants being, respectively, 22 barrels per psi and 184 barrels per psi, compared to the total depletion performance of over 3800 barrels per psi.

On February 5, 1983, when the massive sanding incident shut down the production well permanently, the cumulative brine production was 1,936,323 barrels and the cumulative gas production was 31,498 Mscf. The ultimate predicted recovery based on abandonment at the bubble point of 8550 psia and a production rate of 8500 separator barrels per day is 11,078,051 barrels brine and 183,563 Mscf gas over a period of 3.7 total years. This represents a recovery of 11.4% of the water in place, two to three times greater recovery than predicted from water compressibility. The difference is due to the very high rock compressibility; ultimately, however, damage to flow efficiency due to the high formation compressibility may preclude the ability to flow the well at acceptable rates to full depletion.

Environmental monitoring of this project was extensive; including air, groundwater, surface water, and microseismic observations. The one sensitive incident was some leakage of

brine from the salt water pit through a tear in the liner. The contaminated soil was removed and replaced during site restoration. Some environmental monitoring continues; however, the site has been completely restored and returned to the landowner.

The information and knowledge to be gained from studying the Parcperdue data is far from exhausted. Particularly in the areas of rock mechanics, reservoir mechanics, and reservoir simulation, valuable future work can and should be done utilizing the tremendous amount of data generated by this project.

1. Introduction

The U.S. Department of Energy has been active since the early 1970's in supporting research to determine the potential of geopressured gas and geothermal energy as alternative sources of energy for the future. The economic viability of the geopressured resource is dependent on being able to produce large quantities of water from high-volume reservoirs over long periods of time, perhaps twenty years or more. The long term behavior of these reservoirs under strong depletion drive is highly uncertain. It was determined that one way to learn about possible reservoir behavior would be to locate a small geopressured reservoir which could be studied in detail as pressure is depleted over a relatively short production life.

The Dow Chemical Company located such a reservoir in the Parcperdue field in Vermilion Parish, Louisiana. The reservoir is in the Cib jeff sand of upper Oligocene age and has an areal extent of slightly over one square mile, average thickness of 50 feet, and an average depth of 13,500 feet. Thick shale sections overlie and underlie the Cib jeff sand; hence the bounding growth faults should isolate the reservoir from the outside water influx.

In 1977 Dow submitted a proposal to the Department of Energy to test this reservoir by re-entering a plugged dry hole, the

Section 1

Phillips Petroleum No. 1-A Lee Roy Sweezy, T.D. 17,736 feet. After much discussion it was decided that a better alternative would be to drill a new well specifically to test the reservoir. The proposal was revised and in September, 1979, Dow was awarded Department of Energy Contract No. DE-AC08-79ET27255 for the purpose of drilling and completing production and disposal wells and testing and evaluating the Cib jeff reservoir. The Dow-DOE L. R. Sweezy No. 1 was spud in January, 1981, and was completed to a plug back total depth of 13,534 feet in August, 1981. Testing operations began in April, 1982, and ended in February, 1983, when the gravel pack gave way and the well sanded in.

Information generated by this project included: the drilling and completion of the well, coring and core testing, mechanical properties, well logs, geology, geochemistry, geophysics, chemistry, PVT data, production testing and management, pressure transient testing, reservoir analysis and simulation, and environmental monitoring.

This report summarizes and presents the results of these investigations. It represents the efforts of many individuals and companies, and many parts of this report are excerpted from

reports submitted to The Dow Chemical Company. These reports are included in their entirety in the extensive appendices. In most cases, lists of references have been deleted from the Final Report, but are included in the appendices.

Because of the number of investigators and diverse disciplines involved in this project, various results may not be in total agreement, or may appear to be contradictory. For example, estimated reservoir size varies from 661 acres to over 900 acres, depending on whether geological, geophysical, or pressure transient methods were used. None of the answers are wrong; they just represent the results obtained using different approaches and different assumptions.

In another case, source rock and PVT analysis show the brine to be undersaturated; some of the chemical analytical results seem to imply free gas and liquid hydrocarbon phases present in the reservoir. Resolution of inconsistencies such as this is beyond the scope of this project; however, such finding will stimulate scientific debate and provide focus for future research.

2. Project Administration

The program described in this Final Report was conducted by The Dow Chemical Company under contract number DE-AC08-79ET27255, Las Vegas Operations Office, U.S. Department of Energy. The purpose was to drill a 13,600 feet depth well into a small geopressured water sand and conduct a complete reservoir study. The well site was approximately 12 miles south of Lafayette, Louisiana.

2.1 Management Organization

Program administration was furnished by Hydrocarbons & Energy Department, Dow Chemical USA, Texas Division. Mr. G. E. White, Hydrocarbons & Energy manager, delegated on-site administration to a Project Manager.

During the drilling of the production and disposal wells, December 1980 through March 1982, the on-site Project Manager was Dr. John S. Wilson. Upon Dr. Wilson's retirement in April, 1982, Mr. Randall Q. Storm was appointed Project Manager for the well testing, plug and abandonment, and evaluation and reporting phases, April 1982 through May 1983 on-site.

Technical Manager of the program was Mr. J. R. Hamilton, Senior Geologist, on loan from the Minerals Department,

Dow Chemical USA, Houston. Mr. Hamilton conducted the testing and data evaluation phases of the work, and was in overall charge of the project report. Assisting Mr. Hamilton in on-site testing coordination was Mr. J. L. Henley, on loan from Brine Operations, Dow Chemical USA, Texas Division. Hamilton and Henley were on-site approximately half-time each during the testing operations and plug and abandonment from April 1982 through May 1983.

Assisting the Project Manager on-site during the entire program was the Project Business Manager, Mr. J. G. Stanley, on temporary assignment from Engineering & Construction Services Division, Dow Chemical USA, Houston. Mr. Stanley administered purchasing and subcontracting activities, records keeping and cost reporting, property management, and general office operations.

Contract Administration and government liaison was conducted by the Contract Research, Development, and Engineering Group, Dow Chemical USA, Midland, Michigan. Mr. I. G. Morrison, deceased, and Mr. G. C. Higgins from that group were responsible for the project during the entire contract period.

2.2 Subcontracts

All other program activities were performed by subcontractors, generally selected by formal competitive bidding. During the drilling of the two wells Dow contracted with

Mr. C. A. Bell, Inland Enterprises, Inc., to reside on site and execute the drilling plan as Drilling Consultant. Mr. Bell was responsible to the Project Manager and to Dow's Regional Drilling Manager, Mr. J. C. Hammer, Oil & Gas Division, Houston.

Drilling contractor for the production well was Welsh Drilling & Services, Inc., Houston. For the disposal well, the contractor was WellTech, Inc., Lafayette, Louisiana. Both wells were drilled on a day-rate basis under International Association of Drilling Contractors standard agreements.

Downhole instrumentation and testing was furnished by Otis Engineering Corporation, Houma, Louisiana. Surface testing equipment and data accumulation was supplied by Johnston-Macco Schlumberger, whose personnel were housed in a trailer on-site to provide two-man, 24-hour, 7-day coverage. During drawdown and build-up tests, Otis also provided on-site, around-the-clock attendance.

Overall data evaluation and reservoir analysis was furnished by Otis Engineering Corporation, Dallas, Texas.

An on-site laboratory for chemical and physical data accumulation and evaluation was maintained and staffed by the

University of Southwestern Louisiana, Lafayette. Drs. J. R. Meriwether and D. F. Keeley from the university staff supervised and conducted this effort.

Relationships and project responsibilities among Dow and its major subcontractors are shown in the organizational chart, Figure 2-1. These and other major subcontractors, with services provided and cost figures are listed in the following section.

Important contributors to the successful completion of the project were divisions of The Dow Chemical Company. The Oil & Gas Division whose primary business is the exploration, drilling, and producing of oil and natural gas for company use, provided consultation and personnel support throughout the project. The Lafayette office of this division assisted with initial administrative services and later with technical consultation on well drilling and operations.

The Dowell Division provided a number of major services from offices in the Lafayette area. These included drilling mud and chemicals, well clean-up and acidizing, completion fluids and hardware, nitrogen service, general pumping, saltwater reinjection, gravel packing and consultation.

A major contributor to the overall project was Central Industries, Inc., Scott, Louisiana. Through competitive bidding,

FIGURE 2-1

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this subcontractor performed site preparation, utilities tie-in, board road and pad installation, pond construction, site maintenance, polluted soil removal and replacement, and site restoration.

2.3 Major Subcontractors

Welsh Drilling & Services, Inc.,	Houston, TX
Rig & crews-production well	\$2,209,979
WellTech, Inc.	Lafayette, LA
Rig & crews-disposal well	\$236,692
Johnston-Macco Schlumberger	Lafayette, LA
Well testing-surface	\$660,813
Otis Engr. Corp.	Houma, LA
Well testing-downhole	\$370,323
Otis Engr. Corp.	New Iberia, LA
Well completion & plugging	\$117,233
Otis Engr. Corp.	Dallas, TX
Reservoir Analysis	\$78,875
NL Baroid	Houston, TX
Drilling mud & chemicals	\$603,609
Central Industries, Inc.	Scott, LA
Site prep., maint., & restoration	\$533,248
B&M Oilfield Supply	Broussard, LA
Bits & supplies	\$53,255
Circle M Supply	Lafayette, LA
Bits & supplies	\$52,218

Dunigan Tool & Supply	Abilene, TX
Casing - 10-3/4"	\$496,105
Eastman Whipstock, Inc.	Lafayette, LA
Well Surveying	\$56,543
Elder Leasing Co.	Houston, TX
Trailer Rental	\$40,121
FMC Corporation	Broussard, LA
Production wellhead & maint.	\$205,636
E. L. Farmer & Company	Odessa, TX
Hauling-tubulars	\$50,751
Gearhart Industries, Inc.	Lafayette, LA
Logging, perforating, tools	\$139,587
Grant Oil Country Tubular Corp.	Houston, TX
8-5/8" & 7-5/8" Casing, tubing 5-1/2"	\$675,169
Greene's Pressure Testing	Lafayette, LA
Blow-out preventor testing	\$28,695
Gulf Coast Vacuum Services, Inc.,	Abbeville, LA
Hauling-saltwater & sludge	\$26,683
Howard Trucking Co., Inc.,	New Iberia, LA
Hauling - parts, supplies, etc.	\$28,786
Inland Enterprises, Inc.	Ball, LA
Drilling consultant	\$185,824
Fred S. James & Co.	Houston, TX
Well blowout insurance	\$105,203
McEvoy Oilfield Equipment	Lafayette, LA
Disposal wellhead & maint.	\$23,533

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NL McCullough	Houston, TX
Logging, casing cutting	\$31,342
National Security Service	Lafayette, LA
Security guards	\$47,323
Oil Field Rental Service Co.	Lafayette, LA
Drill pipe & tools rental	\$288,093
PALCO Linings, Inc.	Stanton, CA
Salt water pit lining	\$31,677
Production Rentals, Inc.	Lafayette, LA
Pump rental, filters	\$26,812
Redman Pipe & Supply	Tulsa, OK
16" casing	\$261,554
REAMCO, Inc.	Lafayette, LA
Stabilizers, rental tools	\$67,882
Rig Housing Services, Inc.	Lafayette, LA
Personnel trailer rentals	\$72,130
Roy Young, Inc.	Abbeville, LA
Hauling-equipment, vacuum trucks	\$40,215
Schlumberger Well Services	Lafayette, LA
Logging, perforating	\$245,650
Sperry-Sun, Inc.	Houston, TX
Logging, casing cutting	\$30,307
SWACO-Dresser Industries	Lafayette, LA
Choke & degasser rental	\$37,308
SWECO, Inc.	Lafayette, LA
Mud cleaner rental	\$59,051

TerraTek, Inc.	Salt Lake City, UT
Core testing, reservoir studies	\$103,558
Texas Iron Works	Houston, TX
Liner tools	\$63,176
TIMCO, Inc.	Lafayette, LA
Casing driving & handling	\$239,855
Tri-State Oil Tool Industries, Inc.	Bossier City, LA
Fishing, tool rental	\$68,960
Univ. of Southwestern Louisiana	Lafayette, LA
Chemical & physical analysis	\$341,745
Varian Associates, Inc.	Sunnyvale, CA
Laboratory equipment	\$32,066
Kelly Services, Inc.	Lafayette, LA
Secretarial Services	\$41,108

The above list represents subcontract expenditures exceeding \$9 million with some 40 vendors. More than 100 other vendors supplied lesser services, equipment, and supplies. Total subcontracting activity was \$9.5 million, excluding the Dowell Division of The Dow Chemical Company. Of that total, ten percent was contracted to Small Business firms and four percent to disadvantaged firms.

The prime contract between Dow and the D.O.E., with modifications, and the major subcontracts are included in Appendix D: Contracts and Agreements.

2.4 Reporting

In compliance with contract requirements, Dow has submitted management and technical reports to the Department of Energy.

During the initial 15 days after contract award in September 1979, Dow submitted:

- a Management Plan,
- a Milestone Schedule & Status Report,
- a Cost Plan,
- a Manpower Plan.

Before site operations began, the Drilling Plans for both wells were submitted in October 1980. A Test Plan followed in February, 1982, after completion of the production well.

Amended Cost Plans were submitted on 1/20/82 and 1/15/83 to accommodate changes in contract scope, total estimated costs, and contract completion dates.

Monthly reports consisted of the Contract Management Summary Report, The Cost Management Report, Government-Owned Property Inventory, and the Project Status Report.

A report of Subcontracting Activity including Small Business and Disadvantaged Utilization was submitted on a quarterly basis.

Since early in drilling operations, Dow has prepared a Cost Management Weekly Report which delineated contract estimated cost, current cost, estimated cost to complete, and over-run or under-run cost of some fifty categories of project work.

This summary of technical and administrative reporting is a part of the Final Technical Report, required by the contract.

3. Well Site Location

North Parcperdue field is located in Vermilion and Lafayette Parishes, approximately twelve miles south of the city of Lafayette, just off Highway 339. This area of South Louisiana is on a Pleistocene terrace of the Gulf coastal plain. Surface elevation is approximately 20 feet and drainage is into Bayou Parcperdue and the Vermilion River. The Lee Roy Sweezy lease is 37.5 acres and is comprised of pasture land. The well location is 1,800 feet from the south line and 1,350 feet from the east line of Section 26, Township 11 south, Range 4 east. Good paved roads (Racca Road, Romero Road) access the lease area. Figure 3-1 State of Louisiana map, shows the general location plus the location of El Tigre Lagoon, the site of the No. 1 Edna Delcambre well, the first geopressured geothermal test; the Gladys McCall design well test site; and the Sweet Lake design well test site. Figure 3-2 shows the location of the North Parcperdue field on the parish highway map, and Figure 3-3 shows the location of the well site. Figure 3-4 shows the surveyors' location of the test well and disposal well.

The test well is located in a well-defined fault block. Fault cuts in wells, plus seismic data afford high definition of reservoir geometry. The location of the test well within Parcperdue field is shown in Figure 4-4 of this report, the Geologic Structure Map.

Figure 3-1. State of Louisiana: Location Map

Scale: 1" = Approximately 40 Miles

FIGURE 3-2. N. PARCPERDUE FIELD

Location Map
Louisiana Gulf Coast Area
Showing Well Location.

FIGURE 3-3. LOCATION MAP LOUISIANA GULF COAST AREA SHOWING WELL LOCATION

I, Ellis L. Jones, hereby certify that the loc'n of
The Dow Chem. Co. - D.O.E. Lee Roy Sweezy No.1
is as follows: 1800' NORTH and 1350' EAST from
the Southwest corner of Sec 26, T11S-R4E,
Vermilion Parish, Louisiana

Ellis L. Jones
REGISTERED LAND SURVEYOR NO. 354
STATE OF LOUISIANA
JOHN E. CHANCE & ASSOCIATES, INC.

LOUISIANA DEPT. OF CONSERVATION

THE DOW CHEMICAL CO. - D.O.E.

PERMIT PLAT

VERMILION PARISH, LOUISIANA

SCALE: 1" = 1000'

JAN 23, 1980

FIGURE 3-4

4. Geology

The regional geology of the Gulf Coast and the Southwestern Louisiana area in particular was known through a thorough review of the literature and Dow's own oil and gas experience in the area.

The local geology was determined from surrounding well control, from pre-existing seismic control and from a 3-D seismic project carried out by the University of Southwestern Louisiana under separate contract to DOE, from drill cuttings and the 120 feet of whole core which was recovered, and from a complete suite of well logs.

4.1 Regional Geologic Setting

The Gulf Coast geosyncline extends from Alabama to northern Mexico and covers an area greater than 250,000 square miles. Cenozoic clastic sediments fill the basin and attain a maximum thickness of greater than 50,000 feet in southern and offshore Louisiana, east of the Sabine arch.

Sedimentation patterns are influenced by differential rates of sediment influx, changing sea levels, deeply buried salt structures and salt tectonics, and down-to-the-coast

contemporaneous faulting. Dip is generally southeastward and is modified by a series of basinward flexures which exhibit great thickening of sedimentary units on the downdip sides, generally reflecting the effect of contemporaneous faulting. These faults are the typical Gulf Coast "growth faults", and can have throws ranging from a few feet to thousands of feet at depth.

Figure 4-1, taken from U.S.G.S. circular No. 726, shows the 21 subareas of the Gulf Coast containing geopressed zones. Parcperdue is located in Louisiana subarea DL5.

A major marine transgression occurred during the upper Oligocene epoch. The massive Anahuac shale was deposited at this time on the continental shelf. The proto-Mississippi embayment was located in the area of south-central Louisiana during Frio-Vicksburg time (upper Oligocene), which further influenced the marine character of the sediments. Minor regressive episodes caused the formation on the continental shelf of shoals, barrier bars, and possibly barrier islands. Many of these barrier bars are now targets of oil and gas exploration. They are typically isolated sand bodies in an interval of massive shale and exhibit a coarsening-upward log character. In south Louisiana, such sands are usually identified by a characteristic foraminifera (fossil). The objective sand, equivalent in age to the Anahuac formation, is

FIGURE 4-1 LOCATION MAP SHOWING THE EXTENT OF THE ASSESSED GEOPRESSURED ZONES AND THEIR DIVISION INTO SUBAREAS (AT, BT, AND SO ON).
(FROM USGS CIRC. 726)

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identified by the foraminifera *Cibicides jeffersonensis*, henceforth referred to as *Cib jeff*.

Figure 4-2, Oil and Gas Fields of Southwestern Louisiana, shows the trend of oil and gas fields which produce from Miocene and Frio formations. In general, the more northern fields produce from the older formations while the more southern fields produce from younger (Miocene) formations. A few fields produce from formations as old as Eocene (Wilcox formation). The generalized foraminiferal sequence of the Louisiana Gulf Coast is shown in Figure 4-3.

4.2 Geology of Parcperdue Area

The geopressured zone at Parcperdue occurs in sediments of Upper and Middle Oligocene age, in the Anahuac and Frio formations. The top of the Oligocene is picked at the first occurrence of the foram *Discorbis gravelli*, which occurs in the abandoned well, the Phillips No. 1-A Sweezy, at a depth of approximately 12,700'. Figure 4-3 illustrates the paleogeologic zones of the Louisiana Gulf Coast based on foraminiferal first picks.

FIGURE 4-2 OIL & GAS FIELDS OF SOUTHWESTERN LOUISIANA

SERIES	FORMATION	FORAMINIFERAL ZONES		AGE (MILLION YEARS)
MIOCENE	FLEMING	<i>Discorbis</i> (12)		26
		<i>Textularia</i> (L)		
		<i>Bigennerina</i> (2)		
		<i>Textularia</i> (W)		
		<i>Bigennerina humblei</i>		
		<i>Cristellaria</i> "1"		
		<i>Amphistegina</i> "B"		
		<i>Robulus</i> "43"		
		<i>Operculinoides</i> sp.		
		<i>Robulus chambersi</i>		
		<i>Marginulina ascensionensis</i>		
		<i>Siphonina davis</i>		
		<i>Planulina palmerae</i>		
		<i>Discorbis gravelli</i>		
		<i>Heterostegina</i> sp.		
OLIGOCENE	ANAHUAC	<i>Bolivina perca</i>		37
		<i>Marginulina vaginata</i>		
		<i>Marginulina howel</i>		
		<i>Camerina</i> "A"		
		<i>Cibicides hazzardi</i>		
	FRIO	<i>Marginulina texana</i>		
		"Hackberry" fauna		
		<i>Nonion struma</i>		
		<i>Nodosaria blanpiedi</i>		
		<i>Discorbis</i> "D"		
EOCENE		<i>Vicksburg</i> (Herpin Sd.)		54
		COCKFIELD		
		SPARTA		
		WILCOX		

FIGURE 4-3 PALEONTOLOGICAL MARKERS
- S. LOUISIANA

Abbeville field to the southwest produces from the Camerina "A" zone (Frio) and several Miocene zones. Due south, Tigre Lagoon field, site of the first geopressured test in 1975, produces from Miocene formations. Maurice field to the west produces from Oligocene (Anahuac and Frio) sands.

Parcperdue field produces most prolifically from the Camerina sands, principally gas. The Cib jeff sand in Parcperdue field produces gas in the Dome No. 1 Hulin, Phillips No. 1 Blanchard, and Stone No. 1 Duhon. The Cib jeff produces oil in the Stone No. 1 Broussard, North of the Dow/DOE No. 1 Sweezy. As of March, 1983, cumulative oil production was 364,411 bbls. Another zone, the Hebert sand, a Cib jeff equivalent, has produced oil in Parcperdue field.

The Parcperdue area is traversed by a number of faults which intersect to form discrete blocks, as shown in Figure 4-4, Cib jeff structure map. The overall structure is that of a faulted anticline. Production gas is from closures within fault blocks or against faults. The objective Cib jeff reservoir is a fault block bounded by faults "A", "B", and "C", as shown in Figure 4-4.

FIGURE 4-4 CIB JEFF STRUCTURE MAP

4.3 Reservoir Geology

Reservoir geology is determined from well logs, well control, seismic data, and cores.

4.3.1 Reservoir Description

The sand occurs at a depth of 13,350 feet and is approximately 50 feet thick. The Cib jeff sand represents an offshore barrier bar environment of deposition. Such deposits are elongated and lenticular in form and may vary in size from a few square miles to several hundred square miles. The upper Anahuac marine facies of south Louisiana contains numerous minor regressive episodes which have produced overlapping and offlapping sand bodies of limited areal extent, such as the Cib jeff and Hebert sands. The Cib jeff sand in the Parcperdue area is conservatively estimated to have an areal extent of about ten square miles. The areal extent of the Cib jeff reservoir within the fault block is approximately 1.0 square mile (See Figure 4-5).

Geologic control on the fault block is excellent. Fault cuts can be picked or inferred in eight wells located near Faults A, B and C, as shown on the Seismic Control map, Figure 4-6. The area is traversed by seven CDP seismic lines which intersect the test fault block at eleven points. The total of nineteen control

FIGURE 4-5 CIB JEFF ISOPACH MAP

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points affords very accurate mapping of the fault block dimensions, essential in making reservoir calculations. The total area of the fault block has been determined to be 661 acres.

Sand thickness varies from greater than 100 feet in the southwest corner of the fault block to as thin as 10 feet in the northeast corner. Assuming an average thickness of 50 feet, reservoir pore volume is 74.3×10^6 bbl (661 ac X 43,560 ft²/ac X 50 ft X 29% ϕ X 0.178 bbl/ft³.)

Total water produced over the duration of the test represents 2.8% of the water in place, where:

$$\% \text{ Produced} = \frac{\text{Water Produced} \times B_o}{\text{Water in Place}}$$

$$B_o = \text{Formation volume factor} = 1.04$$

$$\% \text{ Produced} = \frac{1.99 \times 10^6 \text{ bbl}}{74.3 \times 10^6 \text{ bbl}} \times 1.04 = 2.8\%$$

The Cib jeff sand is overlain by approximately 1,300 feet of marine shale and underlain by approximately 3,000 feet of shale. The bounding faults, which range in throw from 150 feet to over 500 feet provide an excellent seal against the shale and isolate the Cib jeff reservoir.

The Cib jeff sand is continuous and relatively consistent in thickness over the test fault block as illustrated on the isopach map, Figure 4-5.

4.3.2 Test Well Geology

The original hole was drilled to a T.D. of 13,600' and logged on April 12, 1981. Shallower formations (principally Miocene) are continental-fluvial in nature. Transition to a more marine facies occurs at depth of approximately 11,800'. Below that depth, the entire section is shale with the exception of three sands, each 100' or less in thickness, occurring at depths of 11,290', 12,305', and the objective Cib jeff sand at 13,341'.

Paleontology was done by George N. May and Associates of Lafayette. A summary of their report is given in Table 4-1. The complete report is attached as Appendix H.

TABLE 4-1
SUMMARY OF PALEONTOLOGY

SAMPLE RANGE 11500'	-----13600'
IN SIPHONINA DAVISI	-----11500'
CRISTELLARIA 47	-----11900'
NOSDOSARIA VERTEBRALIS	-----12170'
DISCORBIS GRAVELLI	-----12780'
HET SP. (VERY RARE)	-----12880'
CIBICIDES JEFFERSONENSIS	-----13140'
BOLIVINA PERCA	-----13490'
NO FURTHER DIAGNOSTIC FOSSILS WERE ENCOUNTERED.	

Figure 4-7 is a NE-SW structural cross-section across the test fault block. The line of section crosses into the test fault block at Fault 'A', between the Dow No. 1 Bacque and the Dow-DOE No. 1 Sweezy and out of the fault block at Fault 'C', between the Texaco No. 1 Bares and the Chevron No. 1 LeBlanc. The Phillips No. 1 Denais, not shown on the line of section, would be in a similar structural position as, but slightly higher than, the Texaco No. 1 Bacque. The Denais well log shows the Cib jeff sand to be completely wet. Top of the sand is at 13,120' which makes

PARCERDUE GEOPRESSURED GEOTHERMAL PROSPECT
VERMILLION PARISH AND LAFAYETTE PARISH, LOUISIANA
S-N Structural Cross-Section A-A'

FIGURE 4-7

it the highest on structure in the fault block, indicating no gas cap or a very small gas cap in the reservoir.

Both core examination and well logs (see Section 5.1, Production Well Logs) indicate two distinct zones, upper and lower, both reflecting the depositional history and diagenesis of the sand and surrounding shale facies. These are shown in Figure 4-8, Vertical Profile of Cored Interval. Both the zones have similar mineralogies, but the ratio of their sand to clay contents differ significantly. The lower sand interval (13,391 - 13,424) exhibits an abundance of sedimentary structures, i.e., cross-bedding, sand flow casts, and burrowing. Grains are commonly subangular, fair to poorly sorted, and average 0.15 mm in size. Detrital grains are predominantly quartz (average 60%), feldspar (5-10%), volcanic lithic fragments (5-10%), and minor mafics. Bonding agents are predominantly clay with scattered glauconite and carbonate cement. Although the porosity values obtained at bench conditions generally are high (average $\phi=28\%$), fluid permeabilities are low (average 20 md) for this porosity. This anomaly is due to the high clay content within pore throats as shown in SEM photomicrographs, (See Appendix F: Dow Core Analysis). Much of the clay found in the lower zone is detrital and was probably produced as a by-product of bioturbation, although authigenic kaolinite is also found commonly replacing

FIGURE 4-8 VERTICAL PROFILE FOR CORED INTERVAL.

early carbonate cement which has been dissolved. These clays appear to be loosely bound and extremely susceptible to mobilization with flow of brine through the rock matrix. Therefore, clay bridging at pore throats is a distinct probability during flow. This behavior was observed when saturating core samples for test purposes. It is clear that the clay in the lower zone will have a definite impact on efficient fluid production from this portion of the reservoir.

The upper sand interval (13,343-13,391) exhibits larger grain size (average 0.3 mm), improved sorting, rounded detrital grains and a greatly reduced clay matrix fraction. The sand is generally friable and in some sections a total of approximately 5 feet is practically unconsolidated. Mineralogically, detrital grains are predominantly quartz (approximately 70%) with feldspar and volcanic lithic fragments composing 5-10% each. Matrix components are authigenic clays (average 3%), trace mafics and early carbonate cement remnants. Bench condition porosities are unusually high (approximately 30%) and fluid permeabilities are in the range of one hundred millidarcies to one darcy. These porosity values reflect the restoration and enhancement of primary porosity accompanying secondary porosity development and absence of subsequent late precipitation of carbonate cement. Permeability values are approximately an order of magnitude higher

than those measured from core samples in the lower sand zone. The upper sand interval exhibits fewer sedimentary structures and minimal bioturbation compared to the lower sand interval. Clays found in the upper zone are authigenic and are believed to have occurred late in the diagenesis of the sand.

The Cib jeff sand reservoir is ideally suited for a test of the geopressured geothermal concept. The reservoir is exceptionally well defined, is consistent within the fault block, is sealed on all sides, and possesses good porosity and permeability. The smallness of the reservoir allowed a significant pressure depletion over a relatively short period of production, thus providing detailed information on the production characteristics of a geopressured reservoir.

4.3.3 Porosity Development

TerraTek, Inc., of Salt Lake City performed detailed description of the core material and petrographic analysis of thin sections, as well as rock mechanical testing. The full TerraTek report(s) is presented in Appendix E; the interpretation of porosity development is taken from that report.

Secondary porosity development constitutes the predominant form of effective porosity found in the Cib jeff sand. Approximately half of the total sand interval has excellent reservoir potential based on petrographic analysis. Careful analysis of these depth intervals was considered when placing perforations in the well. Pore geometries have been altered with secondary porosity development, developing different reservoir characteristics in the Cib jeff sand where total sand diagenesis had not been uniform.

Porosity development within the upper and lower sand zones reflects the depositional history and diagenesis of the total sand and surrounding shale facies. Clay content is the primary factor controlling secondary porosity development. The lower sand zone contains an abundance of detrital clay which is a product of extensive bioturbation of the zone during deposition. These clays filled much of the available pore space prior to burial. In contrast, the upper sand zone shows little evidence of bioturbation. Massive bedding of the upper zone coupled with absence of clays are features which allow good vertical permeability within the sand. Initially, during burial and compaction of surrounding shales, selective replacement of feldspars and volcanic lithic fragments with carbonate occurred in both zones. Early precipitation of poikilotopic calcite cement

exclusively filled all uncompacted pore space. Remaining pore space in the lower zone not occupied by detrital clays was also filled with carbonate cement.

Normal compaction and cementation proceeded with burial of the Cib jeff sand, and consequently primary porosity was reduced to less than 10% at depths of a few thousand feet (Figure 4-9). Upper zone core sample porosities measured at bench conditions average approximately 30 percent. Such porosity values are not possible when considering compaction and loss of fluids within pore space at depths below a few thousand feet.

Figure 4-9 Depth Distribution and Evolutionary Sequence of Primary and Secondary Porosity

With burial of Gulf Coast sediments, mud with up to 80% pore water is dewatered by compaction until porosity is about 15% at depths of several thousand feet. Figure 4-10 shows the decrease of shale porosity with depth, and also shows that water squeezed from the mud enters the more permeable sands and flows laterally through the sands toward the surface. Various chemical reactions accompany shale dewatering and water chemistry changes compositionally updip as dissolved ions are exchanged and removed. For example, kerogen diagenesis in shales was accompanied by decarboxylation - a reaction which created acidic fluids that entered the sand zone. These pore fluids preferentially leached soluble detrital grains and carbonate cements formed during initial cementation of the total sand interval. Once dissolution began, removal of soluble grains and cements created flow channels causing increased flow rate, which in turn increased dissolution rates and the process became self-accelerating. Subsequently, these carbonate rich fluids may be flushed updip to be precipitated as early diagenetic cement.

Fluids from shale dewatering flowed preferentially into the massive upper zone within the Cib jeff sand where near complete secondary leaching of carbonate cement, feldspars, and lithic fragments occurred. Migration of abundant clay into pore throats and presence of detrital clays within the lower zone prevented secondary porosity development to the degree of that seen in the upper zone.

Figure 4-10 Shale Porosity Versus Depth, and Flow Paths of Shale Water During Compaction and Diagenesis.

Evidence supporting the existence of secondary porosity can be documented in thin section analysis. Schmidt, et al (1977) presented criteria for identifying secondary porosity development in thin section, all of which may be observed in portions of the Cib jeff sand. The criteria for identifying secondary porosity are listed below and are referenced with photomicrographs in Appendix E.

1. Partial dissolution of the soluble constituents
2. Inhomogeneity of Packing
3. Recognizable Molds
4. Oversized Pores
5. Elongate Pores
6. Corroded Grains
7. Honeycombed Grains
8. Fractured Grains

Textural development of secondary porosity is illustrated in Figure 4-11. Primary porosity was destroyed with carbonate cementation and initial compaction. Feldspars and lithic fragments were also subjected to partial solution and replacement by carbonate. With diagenesis and flow of pore fluids through the rock matrix, preferential solution of the carbonate occurred, creating secondary porosity.

Figure 4-11 Textural Development of Secondary Porosity.

4.3.4 X-Ray Micrography Study

A suite of ten samples of core material was studied by The Dow Chemical Co. Analytical Laboratory in Freeport, Texas, using the techniques of scanning electron micrography (SEM), X-ray diffraction (XRD), and energy dispersive X-ray fluorescence (EDX).

EDX data was collected with 20 key accelerations voltage. This technique is only sensitive to elements of atomic number 11 (sodium) or greater, so lighter elements are undetected. All XRD data was collected using copper radiation. High-resolution Huber-Guinier films were obtained using monochromatized (Cu K-alpha-1) radiation and were used for most of the identification work. To identify the clay minerals, diffractometer scans were made using Cu K-alpha radiation, and scanning a limited region (4 to 20 deg.) in 0.02 to 0.03 degree steps with extended counting times to obtain the best possible signal-to-noise ratios. Montmorillonite and related clays were further tested in some of the samples by grinding the sample in ethylene glycol and scanning slowly from 2 to 20 deg. to ascertain if there had been a shift in any of the X-ray peaks, which would indicate an expansion of the layer spacing.

As expected for these sandstone samples, they all have far more quartz than any other component. At first glance it would appear that there is some ambiguity in the identification of the clay minerals, as every time illite or glauconite occur, they are listed as a pair, as are montmorillonite and montmorillonite-illite. The reason for this ambiguity is that each of these pairs have very similiar x-ray diffraction patterns, and are difficult to tell apart without a nearly pure phase sample, and impossible when the compound is a minor component in a mixture like this. In the case of illite and glauconite, the similarity extends further, with the two minerals being nearly isostructural.

The presence of halite (NaCl) in several of the samples may be surprising, but in two of the samples the diffraction evidence is virtually overwhelming (D-7 and D-47), and in one of these (D-7), halite furnishes the best explanation for the chloride observed by EDX.

A typical sample, D-10, taken from a depth of 13,346', is described below. The complete data for all ten samples is presented in Appendix F-Mineral Identification of core samples.

Figure 4-12 shows the SEM photos of the sand at magnifications from 100 X to 10 KX. Note the well rounded and well sorted character of the sand grains in the 100X photo, and the presence of clay on the grain surfaces and in the pore throats.

Silicon is the most intense element in the EDX spectrum (Figure 4-13) for this sample, but there is a significant amount of chlorine and smaller amounts of calcium and titanium, and a trace of potassium. The XRD (Figure 4-14) shows mainly quartz, with a small amount of halite (NaCl) and possibly some anorthite ($\text{CaAl}_2\text{Si}_2\text{O}_8$).

4-12A: 100 X MAG

4-12B: 500 X MAG

FIGURE 4-12 SCANNING ELECTRON MICROGRAPHS-SAMPLE D-10 13,346'

4-12C: 2KX MAG

4-12D: 10KX MAG

FIGURE 4-12 (CONT.) SCANNING ELECTRON MICROGRAPHS-SAMPLE D-10 13,346

0X10^0S 20.46 KEV 52 SEC
 VS= 1K 1A+B M HS= 20EV 1AB

FIGURE 4-13 ENERGY DISPERSIVE X-RAY (EDX) TYPICAL SAMPLE

FIGURE 4-14 X-RAY DIFFRACTION (XRD) TYPICAL SAMPLE

4.4 Reflection Seismic Studies - U.S.L.

The reflection seismic work was carried out at the University of Southwestern Louisiana (USL) under the direction of Dr. Gary L. Kinsland, under separate contract to the D.O.E.

One of the major unknowns in the geopressured-geothermal reservoir exploitation is reservoir extent. Commonly, maps available prior to fluid production are found through depletion data to not completely describe the reservoir being drained by the well. Various discrepancies are possible:

1. unrecognized faults exist which limit the reservoir
2. unrecognized permeability barriers (other than faults) exist (shale outs)
3. permeability barriers, which were thought to be sealing, are leaky.

If a seismic "picture" could be taken of the reservoir before production and if a second "picture" could resolve changes in the reservoir due to depressurization, then such a multi-picture procedure would be a powerful aid in reservoir development. A series of "pictures" during the utilization of the reservoir would monitor the depressurization front and allow more judicious reservoir engineering decisions to be made; e.g., placement of subsequent wells, or capital investment in existing wells.

The Parcperdue project was deemed particularly suited to be a test of the ability of two pictures to resolve the depressurization of the Cib jeff sand. A high degree of existing control, both geological and geophysical, indicated the reservoir to be bounded by sealing faults. The experimental depletion to be carried out was to take place in a short time period so that a project of reasonable duration could acquire "before" and "after" seismic data. Calculations of the predicted effect of depressurization on acoustic parameters indicated, though not conclusively, that changes sufficient to be detected were likely to occur.

4.4.1 Description of 2-d and 3-d Seismic Surveys

In 2-d acquisition data are recorded, processed, and displayed as if a picture of a cross-section of the geology were obtained. In fact the image which is obtained is nearly like that of a cross-section; however, geometrical considerations, (cross-dip, side-swipe, out-of-plan diffractions, etc.) for which there is no correction with 2-d data leave error and ambiguity in the interpretation.

In 3-d data acquisition, reflection returns from a volume of the geology are gathered. (As opposed to the supposed plane of data gathered in 2-d work). Having three dimensional subsurface reflection control allows corrections (3-d migration) to be made to the data to properly place all subsurface reflection points in

their correct geological/geometrical positions. Having corrected the volume of data, correct 2-d surfaces of data may be extracted from the volume. These 2-d surfaces may be extracted at any desired position and orientation, including horizontal. These may be extracted to paper and interpreted like normal 2-d seismic data or the images may be extracted to a computer display screen, interpreted there and the interpretations stored in the computer for later composite displays.

To gather 2-d data in the field, sources and receivers are normally arranged in a line, yielding (ideally) data on the plane under the line. To gather 3-d data, sources and receivers are arranged over an area of the ground surface and the volume under that surface yields reflection data.

4.4.2 Geometry of the Parcperdue 3-d Survey

Figure 4-15 illustrates the geometry utilized in the 3-d survey conducted at Parcperdue. Source points in line with the receivers yield 2-d data; source points on a line perpendicular to a line of receivers produce 3-d data.

In the first part of this survey the receivers were laid out at 100' spacing along N-S lines. These lines are labeled with R's in the figure. Source points were laid out at 50' intervals along approximately E-W lines. These lines are marked with S's. 1024 receivers were laid out and active at any one time and three

FIGURE 4-15 GEOMETRY OF PARCERDUE 3-D SURVEY

vibrator trucks supplied the energy at each source point. All of the receiver locations could not be occupied at one time so a system of leap-frogging active receiver points and reoccupying source points was employed.

Three source lines and seven receiver lines were occupied in this phase (the unprimed phase). Following this the receivers were laid out at 50' intervals on three E-W lines, R's; and two N-S source lines were occupied at 50' intervals, S's. Once again this geometry produced 3-d data; however, these data are concentrated in a different area and help fill out the desired coverage.

Following the primed phase the double primed phase was undertaken to acquire three sets of 2-d data. In this phase, receiver lines R" were left in place (labeled R" to indicate this) and source line S" was occupied at 50' intervals. This produced three sets of relatively conventional 2-d data: one set under the line which is both a source and receiver line, and one each one-half way between the other two receiver lines and the source line.

This survey was performed by Geophysical Systems Corporation (GSC) under a subcontract to USL. GSC was chosen because of its particular ability to simultaneously record 1024 channels and to utilize vibrators as the energy source. Such a high number of active channels was necessary to efficiently perform a survey of this magnitude. The use of vibrators was necessary because of the high number of source points required and the proximity to the many structures and water wells in the survey area. GSC was also under contract to perform much of the processing of the data.

4.4.3 Coverage of the Surveys

In Figure 4-16 the density of subsurface reflection points is indicated by grey tones. The darkest lines running E-W in the plot indicated the subsurface coverage of the double primed phase...the 2-d data phase. These 2-d data were separated from and processed independently of the rest of the data which are the 3-d data.

Comparison of Figure 4-16 with Figure 4-4, which is the fault block geometry, illustrates the densest 3-d coverage to be over the reservoir block as desired.

4.4.4 Reconstructed Output Lines

In Figure 4-17, N-S lines numbered from 1-8 and NW-SE lines numbered from 9-19 have been drawn over the coverage map. Along each of these lines 2-d data sets have been extracted prior to migration of the data volume, for reasons of expediency. As Figure 4-18 shows, interpretable data have been achieved by this technique. To achieve these 2-d sections a swath of data 1000' wide has been horizontally summed to the plane of the section and traces output at 100' intervals. It is recognized that this procedure slightly "smears" the data. The effects of this smearing are apparent in the reconstructed 2-d sections and must be considered when interpreting. Tests with different width swaths were performed. The 1000' width (500 feet either side of the line) was necessary to gather enough data into each output trace to achieve a sufficient signal-to-noise ratio.

4.4.5 Preliminary Seismic Constant Time Fault Map

A seismic constant time fault map from a preliminary interpretation of these reconstructed 2-d lines is presented in Figure 4-19. This map illustrates the intersections of the faults which play a role in bounding the reservoir with the seismic time 3.2 seconds. Such a map differs somewhat from the more commonly seen map of a stratigraphic horizon or a seismic reflection

FIGURE 4-16 DENSITY OF SUBSURFACE REFLECTION POINTS

FIGURE 4-17 SUMMATION OF 2-D DATA

Reconstructed Line #5.
 Reflector near Cib Jeff Sand
 is shown as cross-hatched pattern.
 Well bore of Dow/DOE Sweezy #1
 is shown as vertical line.

FIGURE 4-18

FIGURE 4-19

horizon. The horizon map contours the depths (times) to a horizon and faults appear as areas in which the horizon does not exist; i.e., has been faulted out. In the map of Figure 4-19 the faults appear as lines of intersection with the time 3.2 seconds. In the present map the surface being mapped is flat, and in general a mapped horizon is not flat. The faults on a horizon map occur at different elevations (times) at different places along the fault. Consequently, the part of the fault being mapped has a complex path up and down along the fault plane. This often obscures the true smooth curvature of the fault plane. On the seismic constant time map the curvature of the fault plane is better illustrated, facilitating initial interpretation of relationships between faults. For this reason, this map has been prepared first and is presented here as the only map available from the data at the time this report goes to press.

The differences between this map and the final horizon map are expected to be minor because the stratigraphic (seismic) dips are relatively small. Since the horizon of interest is at about 3.2 seconds throughout the fault block, the bounding faults will appear very little different in the final maps. Faults outside the reservoir block will appear a bit different.

The faults in Figure 4-19 are labeled A-D to illustrate a genetic order which has been deduced from the seismic sections and the mapped geometrics of the faults.

4.4.6 Conclusions

The fault block is surrounded by faults with large enough throws to seal the Cib jeff sand in the reservoir fault block.

The reservoir is smaller and of a somewhat different geometry than originally estimated. Interestingly, it appears that the Dow/DOE Sweezy No. 1 well is more nearly in the center of the reservoir than predicted.

Evidence of a relief fault (a small down to the north fault relieving stress of a major down to the south fault) has been found which apparently cuts the Cib jeff sand inside the fault block. Conclusions concerning the existence of the fault and whether its throw is sufficient to pose a threat to fluid communication in the Cib jeff sand await further work on the presently available data and on data to come from further processing, especially offset-dependent processing and migration of the volume.

4.4.7 Future Work

Processing planned to be performed on these data include:

- 1) studies to determine the utility of using an offset dependent velocity function in the stacking procedure;

- 2) migration of the portion of the volume from 2.7 to 3.7 seconds;
- 3) creation of horizontal time slices (these and other vertical slices will be interpreted interactively on a computer);
- 4) color studies of seismic attributes...phase, velocity, polarity, and amplitude.

These and all other subsequent (and some already completed) processing procedures will be completed under a subcontract between the University of Houston Allied Geophysical Laboratories (UHAGL) and USL. UHAGL has been involved in this project since its inception in various capacities.

A physical model study is being carried out at UHAGL to better understand the reservoir and its response to depressurization.

Due to lack of sufficient reservoir pressure depletion, the post-production survey originally planned will probably not be performed.

5. Petrophysics

5.1 Production Well Logs

A complete suite of logs was run on both the production well and the disposal well. Production well logs include:

- Dual induction - Short focus log - Sonic - Figure 5-1,
- Compensated Neutron - Formation Density - Figure 5-2,
- Saraband Computer Log - Figure 5-3,
- Mechanical Properties Computer Log - Figure 5-4,
- Continuous Dipmeter (4-arm) - Figure 5-5,
- Differential Temperature,
- Borehole geometry,
- Continuous directional survey.

All production well logs were run by Schlumberger, except the differential temperature log, which was run by Gearhart. The logs shown in Figures 5-1 to 5-3 are from the second sidetrack hole, in which the well was actually completed. Note that the core was taken from the original hole; thus any correlations of core data to log data should be made with logs of the original hole. Figures 5-4 and 5-5, the mechanical properties log and dipmeter log, are from the original hole.

5.1.1 Formation Porosity and Shaliness

The Cib jeff sand interval has been divided into four porosity zones for computational purposes, : A,B,C,and D, as shown in Figure 5-1. Each zone probably reflects a distinct sedimentary event. Zone B, the lower portion of the massive sand, appears to have the best porosity, slightly over 30% (from density log and SARABAND). The SARABAND log, Figure 5-3, shows each porosity zone as a distinct sedimentary unit. Table 5-1 summarizes calculated porosities from the density, neutron (and neutron corrected to sandstone porosity), and acoustic logs.

TABLE 5-1
COMPARISON OF DENSITY, NEUTRON , AND ACOUSTIC POROSITIES

Zone	ρ_B	ϕ_D	ϕ_N	$\phi_{N(s)}$	Δt	ϕ_A
A	2.20	27	33	29	95	25
B	2.155	30	31	27	98	27
C	2.21	27	36	33	95	25
D	2.18	28	38	36	98	27

The compaction correction for the acoustics log porosity was derived from the following:

$$C_p = \frac{\Delta t_{\text{shale}}}{100} ,$$

and

$$C_p = \frac{120}{100} = 1.2 ,$$

$$\phi_A = \frac{\Delta t - \Delta t_{\text{ma}}}{\Delta t_f - \Delta t_{\text{ma}}} \times \frac{1}{C_p} ;$$

where:

- ϕ_A = Porosity, acoustic,
- C_p = Compaction coefficient,
- Δt = Transit time,
- Δt_{ma} = Matrix transit time,
- Δt_f = Fluid transit time,
- Δt_{shale} = Shale transit time.

The acoustic porosities were determined from Schlumberger chart POR-3 (1972) shown in Figure 5-6, using $C_p = 1.2$.

Neutron and density porosities were read directly off the log, Figure 5-2. Neutron versus density values are shown cross-plotted on Figure 5-7. Note that the values fall below and to the right of the sandstone porosity line. This is due to: 1) shale effect, and 2) geopressure effect. The percent shale, V_{sh} is low, as seen on the SARABAND, Figure 5-3, and as calculated from the gamma-ray:

I_{gr} = gamma-ray index,

V_{sh} = Fractional volume shale, %,

GR_{cl} = gamma-ray clean sand = 12.5,

GR_{sh} = gamma-ray shale = 62;

$$I_{gr} = \frac{GR - GR_{cl}}{GR_{sh} - GR_{cl}},$$

$$V_{sh} = 0.083 (2^{3.7 \times I_{gr}} - 1).$$

A summary of the shaliness characteristics of the formation is given in Table 5-2.

TABLE 5-2

Shaliness of Cib jeff Porosity Zones

Porosity Zone	GRmax	GRmin	I_{GR}^{max}	I_{GR}^{min}	V_{sh}^{max}	V_{sh}^{min}
A	20	12.5	0.16	.01	5%	0%
B	17	12	0.10	0	2%	0%
C	35	35	0.46	.46	20%	20%
D	37	37	0.50	0.50	24%	24%

The separation between the density porosity and the neutron porosity seen on Figure 5-2 is due to shale content in the sandstone. Note that on Figure 5-2, at a depth of 13,377 feet, the density and neutron logs touch, indicating a zero shale content at this point, the top of porosity zone B. The continuous

**DOW-DOE NO.1 L.R. SWEETZ
SCHLUMBERGER**

DUAL INDUCTION-SFL-SONIC

	ILD (OHMM) 0.0 10.00 SFLA (OHMM) 0.0 2.000 SFLA (OHMM) 0.0 10.00	CILD (MM/M) 4000. 0.0
SP (MV) -160.0 40.00		

COMPANY THE DOW CHEMICAL COMPANY (SIDETRACK HOLE) WELL LEE ROY SWEETZ NO. 1 FIELD PARC PARDUE COUNTY VERMILION STATE LOUISIANA	SCHL FR13528 SCHL TD13531 DRLR TD13533 Elev: KB - DF - GL -
--	--

**FIGURE 5-1 PRODUCTION WELL
DUAL INDUCTION-SFL-SONIC LOG -
SHOWING POROSITY ZONES**

DOW-DOE NO. 1 L.R. SWEZY
SCHLUMBERGER
COMPENSATED NEUTRON-FORMATION DENSITY

FIGURE 5-2 PRODUCTION WELL CNL-FDC LOG

SARABAND-SYNERGETIC LOG

**FIGURE 5-3 PRODUCTION WELL SARABAND-COMPUTER
PROCESSED SYNERGETIC LOG**

**DOW-DOE NO 1 L.R. SWEZY
SCHLUMBERGER**

MECHANICAL PROPERTIES-COMPUTER PROCESSED LOG

COMPUTATION PARAMETERS													
Depth Interval		R _w @	PHI	PHI	PHI	PHI	ρ _{ma}	SSP	ρ _{HY}	GR Sand		GR Shale	
From	To	FT	max	N-clay	D-clay	N-sho		(CWSP)	(ROP)	MIN(DAGA)	MAX(DALUM)	MIN(DAX)	MAX(DASH)
13590	13000	.02	.31	.53	.18	.28	2.65	-80	.7	12	16	56	116
13000	12715							-90					

10 G/CB (DASHED) 2!!
 10 BACKUP 10!! 10... USHALE... 100!
 10... CB... 3!! 100... SW... 010... UCLAY... 100!
 10... FPG... 110... G... 5!! 100... PHIT... 0! 100... PHIE... 0!

**FIGURE 5-4 PRODUCTION WELL-ORIGINAL HOLE
MECHANICAL PROPERTIES LOG**

DOW-DOE NO 1 L.R. SWEETZ
SCHLUMBERGER
CONTINUOUS DIPMETER

FIGURE 5-5 PRODUCTION WELL ORIGINAL HOLE
CONTINUOUS DIPMETER
BLACK ARROWS POOLED RESULTS

843
C-44

POROSITY FROM SONIC LOG

Schlumberger

	V_{sh} (ft/sec)	Δt_{sh} ($\mu\text{sec/ft}$)
Sandstones	18,000-19,500	55.5 - 51.2
Limestones	21,000-23,000	47.6 - 43.3
Dolomites	23,000-26,000	43.5 - 38.5

FIGURE 5-6 ACOUSTIC POROSITY

Schlumberger

POROSITY AND LITHOLOGY DETERMINATION FROM FORMATION DENSITY LOG AND COMPENSATED NEUTRON LOG (CNL) FRESH WATER, LIQUID-FILLED HOLES

CP-1c
32

FIGURE 5-7 POROSITY-NEUTRON/DENSITY CROSSPLOT

dipmeter, Figure 5-5, indicates an unconformity at 13,369 feet; which correlates exactly with the top of zone B (Figure 5-2 is the sidetrack hole, Figure 5-5 is the original hole). This point also is the point of maximum porosity in the sand, and probably is a zone of weakness and poor consolidation. This zone of weakness may have been a contributing factor in the sanding problems experienced during production.

5.1.2 Formation Water Salinity

Formation water salinity was calculated using the conventional SP method and the R_{wa} method. The values used for calculation were taken from the Dual Induction-SFL-Sonic log, Figure 5-1. Input parameters and results are summarized in Table 5.3. The SP method of calculation results in a salinity value of 110,000 ppm. The actual measured salinity of the formation water is 100,000 ppm, which is in good agreement with calculated values.

The " K_f " method of Dunlap and the "Shale resistivity" method of Bassiouni, which have recently been used to calculate salinity in geopressured formations, yielded identical results of 125,000 ppm salinity. The values used for computation were:

$$K_f = \frac{R_{mf}}{R_m} = 0.16,$$

and
 $R_{sh} = \text{Shale resistivity } (R_{ild}) = 0.3 \text{ ohms.}$

TABLE 5-3

Log Values Used for Salinity Calculations

Zone	Depth + 13,000	SSP	RFL	RILM	RILD	t
A	350-380	58	0.3	0.2	0.2	94
B	380-392	58	0.3	0.2	0.1	98
C	398-405	58	0.45	0.25	0.2	90
D	406-410	56	0.45	0.28	0.25	100

TABLE 5-3 (CONT'D)

Zone	$\frac{R_{mf}}{R_{we}}$	$\frac{R_{mf} = .16 @ T_f}{R_{we}}$	R_w (SP)	Salinity (SP) NaCl ppm	R_{wa}	Salinity (R_{wa}) NaCl ppm
A	5.3	.03	.035	80,000	.025	110,000
B	5.3	.03	.035	80,000	.025	110,000
C	5.3	.03	.035	80,000	.025	110,000
D	4.8	.03	.035	80,000	.04	N/A

5.1.3 Mechanical Properties

A Schlumberger mechanical properties log (MECPRO) was run on the production well to evaluate the necessity of gravel packing

the well and to help evaluate elastic properties for future reservoir analyses. A presentation of the log data is shown in Figure 5-5 and a summary of each foot through the productive zone is given in Table 5-4.

Average values for the formation were:

$$\text{Bulk compressibility } C_b = 0.53 \times 10^{-6} \frac{1}{\text{psi}};$$

$$\text{Shear Modulus, } G = 1.00 \times 10^6 \text{ psi};$$

$$\text{Ratio, } G/C_b = 1.89 \times 10^{12}.$$

The accepted industry criterion for sandstone formations capable of production without sanding is a ratio of $G/C_b > 0.8 \times 10^{12}$. Every value obtained for the Cib jeff sand was much greater than 0.8, indicating that the formation should have been safe for sand-free production. The core of the sand interval; however, had several zones which were obviously friable or unconsolidated. Moreover, rock mechanical testing (static) was performed by TerraTek, Inc, of Salt Lake City, on the core material. The average values obtained were:

$$\text{Bulk compressibility, } C_b = 2.82 \times 10^{-6} \frac{1}{\text{psi}};$$

$$\text{Shear modulus, } G = 0.51 \times 10^6 \text{ psi};$$

$$\text{Ratio, } G/C_b = 0.2 \times 10^{12}.$$

Clearly, the results obtained from the mechanical properties log (dynamic) were misleading or erroneous, while the results of

TABLE 5-4
DOW-DOE NO.1 L.R. SWEETZ
FORMATION MECHANICAL PROPERTIES-SCHLUMBERGER MECHPRO

DEPTH	RATIO	RHEAR	BULK	VOL	POIS.	EFF.	PORE	FRAC
G/CH	MOD.	COMP.	CLAY	RATIO	POR.	PRES	PRES	
FT	PS12	GPS1	RPS1	PU	PH	PHIE	GRAD	GRAD
38.0	1.50	.93	.62	79	.26	0	.815	
39.0	1.46	.91	.62	71	.26	0	.823	
13340.0	1.53	.94	.61	73	.26	0	.819	
41.0	1.98	1.07	.54	74	.26	.5	.804	
42.0	2.22	1.11	.50	54	.27	1.1	.829	
43.0	2.51	1.12	.45	21	.29	14.0	.864	
44.0	2.49	1.15	.46	27	.28	10.6	.850	
45.0	1.84	.98	.54	40	.27	7.8	.837	
46.0	1.56	.93	.60	66	.26	.5	.825	
47.0	1.70	.94	.56	31	.28	11.7	.845	
48.0	1.92	.97	.51	11	.29	23.3	.889	
49.0	2.03	1.03	.51	16	.28	19.5	.851	
13350.0	2.26	1.05	.47	10	.29	21.5	.891	
51.0	2.29	1.07	.47	4	.29	24.4	.880	
52.0	2.17	1.06	.49	1	.28	25.9	.857	
53.0	2.13	1.04	.49	2	.28	26.4	.852	
54.0	2.08	1.04	.50	3	.28	26.6	.839	
55.0	2.02	1.07	.50	2	.28	27.3	.854	
56.0	2.10	1.04	.49	2	.28	27.1	.858	
57.0	2.09	1.04	.50	1	.28	27.3	.847	
58.0	2.08	1.03	.50	1	.28	27.4	.858	
59.0	2.04	1.01	.50	1	.28	27.7	.871	
13360.0	1.91	.94	.51	1	.29	28.6	.871	
61.0	1.86	.96	.52	2	.29	28.4	.872	
62.0	1.82	.96	.53	4	.28	27.0	.862	
63.0	1.97	.98	.50	3	.29	27.4	.874	
64.0	2.02	1.00	.49	2	.29	27.3	.881	
65.0	1.92	.99	.51	4	.28	27.1	.864	
66.0	1.78	.95	.53	5	.28	27.6	.860	
67.0	1.82	.96	.53	2	.28	28.7	.865	
68.0	2.06	1.02	.49	0	.28	28.1	.869	
69.0	2.18	1.04	.48	0	.29	27.4	.880	
13370.0	2.13	1.03	.48	0	.29	27.7	.879	
71.0	2.06	1.02	.49	0	.29	28.1	.874	
72.0	2.00	1.00	.50	0	.29	28.5	.871	
73.0	1.98	.99	.50	2	.29	27.9	.876	
74.0	1.88	.97	.52	8	.28	25.1	.870	
75.0	1.84	.97	.53	10	.28	24.2	.853	
76.0	1.69	.93	.55	9	.28	25.7	.859	
77.0	1.57	.89	.56	8	.29	27.4	.875	
78.0	1.73	.94	.54	3	.28	28.9	.855	
79.0	1.64	.91	.56	3	.28	29.4	.858	
13380.0	1.60	.89	.56	5	.29	29.0	.872	
81.0	1.70	.93	.55	5	.28	28.3	.862	
82.0	1.88	.98	.52	2	.28	28.5	.848	
83.0	1.87	.98	.52	1	.28	28.8	.891	
84.0	1.98	1.01	.51	2	.28	27.4	.845	
85.0	2.85	1.26	.44	0	.26	27.9	.902	

DEPTH	RATIO	RHEAR	BULK	VOL	POIS.	EFF.	PORE	FRAC
G/CH	MOD.	COMP.	CLAY	RATIO	POR.	PRES	PRES	
FT	PS12	GPS1	RPS1	PU	PH	PHIE	GRAD	GRAD
86.0	5.05	1.80	.36	0	.23	28.6	.709	
87.0	3.43	1.41	.41	0	.26	27.5	.777	
88.0	2.22	1.08	.49	5	.28	25.5	.834	
89.0	1.70	.94	.55	22	.28	18.9	.849	
13390.0	1.54	.93	.60	67	.26	0	.824	
91.0	1.46	.92	.63	77	.26	0	.818	
92.0	1.69	.98	.58	70	.26	0	.816	
93.0	1.89	1.01	.53	42	.27	6.1	.832	
94.0	1.58	.94	.59	65	.26	0	.824	
95.0	1.59	.94	.59	65	.26	0	.829	
96.0	1.69	.97	.57	60	.27	.8	.825	
97.0	1.60	.92	.68	41	.27	10.9	.847	
98.0	1.46	.86	.58	17	.29	24.0	.884	
99.0	1.66	.91	.53	12	.29	24.6	.878	
13400.0	1.56	.89	.57	13	.29	25.0	.875	
1.0	1.39	.84	.60	18	.28	23.8	.863	
2.0	1.71	.94	.55	13	.28	23.8	.855	
3.0	1.67	.93	.56	20	.28	19.9	.853	
4.0	1.88	1.01	.54	42	.27	7.9	.831	
5.0	1.96	.89	.57	23	.24	20.0	.875	
6.0	1.69	.94	.55	20	.28	21.3	.849	
7.0	1.87	.99	.53	17	.28	20.1	.845	
8.0	1.78	.97	.55	14	.27	12.7	.839	
9.0	1.83	.99	.54	39	.27	8.1	.835	
13410.0	1.71	.98	.57	65	.26	0	.821	
11.0	2.00	1.06	.53	60	.26	.9	.815	
12.0	2.55	1.19	.47	36	.27	10.7	.809	
13.0	2.27	1.11	.49	27	.27	12.7	.825	
14.0	2.34	1.12	.48	21	.27	14.6	.828	
15.0	1.74	.96	.55	37	.27	10.4	.840	
16.0	1.61	.95	.59	66	.26	0	.823	
17.0	1.54	.93	.61	68	.26	0	.824	
18.0	1.70	.98	.57	61	.26	0	.822	
19.0	1.89	1.01	.53	42	.27	6.0	.832	
13420.0	1.84	.99	.54	40	.27	7.9	.835	
21.0	1.79	.98	.55	38	.27	9.0	.837	
22.0	1.83	.99	.54	40	.27	7.9	.835	
23.0	1.60	.95	.59	65	.26	0	.825	
24.0	1.62	.96	.59	71	.26	0	.818	
25.0	2.39	1.17	.49	66	.26	0	.799	
26.0	2.53	1.19	.47	40	.27	8.0	.809	
27.0	1.93	1.02	.53	39	.27	8.3	.831	
28.0	1.82	.99	.54	39	.27	8.3	.836	
29.0	1.61	.92	.57	34	.28	13.0	.847	
13430.0	1.54	.93	.60	67	.26	0	.824	
31.0	1.24	.85	.69	42	.26	0	.820	
32.0	1.30	.87	.67	85	.25	0	.815	
33.0	1.32	.87	.66	78	.26	0	.822	

mechanical core testing (static) much more accurately reflected the true condition of the formation.

The exact reason for the inaccuracy of the mechanical properties log is unclear. There are several possible, partial explanations.

It is a well demonstrated fact that dynamically determined elastic properties always yield higher values than statically determined properties. The magnitude of geopressure on this effect is uncertain; however, the tendency will be to increase the difference between Δt_s and Δt_c . Because t_s in the MECHPRO algorithms is calculated from the Δt_c which is actually measured from the acoustic log, the net result will be a value for G which is too high.

The elastic constants are determined from the following basic relationships:

$$G = \frac{\rho_b}{\Delta t_s^2}, \quad (1)$$

$$\lambda + 2G = \frac{\rho_b}{\Delta t_c^2}, \quad (2)$$

$$K = \frac{1}{C_b} = \frac{3\lambda + 2G}{3} = \rho_b \left[\frac{1}{\Delta t_c^2} - \frac{4}{3\Delta t_c^2} \right], \quad (3)$$

$$C_b = \frac{3}{3\lambda + 2G}, \quad (4)$$

$$G = \frac{A\rho_b}{\Delta t_c^2}, \quad (5)$$

$$K = \frac{1}{C_b} = \frac{B\rho_b}{\Delta t_c^2}; \quad (6)$$

where

- G = shear modulus,
- ρ_b = bulk density - from density log,
- Δt_s = shear transit time,
- λ = Lamé' constant,
- Δt_c = compressional transit time - from sonic log,
- K = bulk modulus,
- C_b = bulk compressibility,
- A & B = constants determined from Poisson's Ratio.

It can be seen that by substituting equation (4) for C_b in the ratio G/C_b , the expression becomes:

$$G/C_b = G \lambda + \frac{2}{3} G^2. \quad (7)$$

Hence, a small change in the value of G results in an extremely large change in the value of G/C_b . Inaccuracies in the value of G as determined from the inferred value of t_s probably were magnified greatly in passage through the various algorithms to obtain G/C_b , resulting in the misleading interpretation of the mechanical properties.

The coring of the Cib jeff sand was extremely important because it allowed the direct observation and measurement of formation mechanical properties. Sole reliance on the mechanical properties log would have led to a decision not to gravel-pack the production well, perhaps resulting in the total inability to produce the well at all.

5.2 Disposal Well Logs

The disposal well, the Dow-DOE L. R. Sweezy No. 2 (ref. State of Louisiana: Dow-DOE No. 1. L. R. Sweezy SWD) was drilled to a total depth of 5000 feet in Miocene sands and logged with an Induction-Electrical/B.H.C. Sonic log and a Compensated Density/Compensated Neutron log. The CD/CN log failed due to large diameter washout through the disposal formation. It was decided to use the data from the I.E.S./Sonic log and not to re-run the CD/CN log. The logs were run by GO International, Inc.. The I.E.S./Sonic log is shown in Figure 5-8.

DOW-DOE L.R. SWEETZ NO. 2
(NO.1 SWD) GEARHART
INDUCTION ELECTRICAL/BHC SONIC LOG

FIGURE 5-8 DISPOSAL WELL - IES/SONIC LOG
SHOWING DISPOSAL ZONE

No whole core, sidewall core, or formation tests were run.

A summary of formation characteristics is given below:

Depth: 4520' to 4660',

Net sand: 134',

Bottom Hole Temperature: 101° F,

Formation Salinity (R_{wa}): 25,000 ppm,

Sonic Porosity: 35%.

6. Core Analysis

Two sequential 60 foot conventional 4" cores were cut through the production sand under the supervision of Christiansen Diamond Products, Inc., in the interval from 13,340 feet to 13,460 feet. Recovery was 100%. The upper core cut just above the top of the sand and the second core cut approximately 45' of shale below the sand.

Core handling in the field was done by TerraTek, Inc., of Salt Lake City. As core was removed from the core barrel, it was wiped clean, marked to indicate depth and orientation, logged and placed in metal trays. The core material was then heel-slabbed, wrapped in foil, sealed in beeswax, and labeled.

TerraTek performed lithologic and petrographic descriptions of the core, determined physical properties, and did detailed rock mechanics testing of the core material. This work is referred to in this report as "Phase One" testing. Late in the production testing phase of the project, it was determined that additional rock mechanics testing was required to help sort out the reservoir drive mechanisms which were affecting production. The work, consisting of determining shale permeability, uniaxial testing, and short and long (creep) term hydrostatic testing was initiated in March, 1983, and completed in July, 1983. This work is

referred to as "Phase Two" mechanical testing. Both TerraTek reports are attached in their entirety as Appendix E, Part I and Part II.

Samples of the core were sent to Core Laboratories for conventional porosity and permeability determination; to Dowell for sieve analysis and acid solubilities; to the Dow Laboratory, Freeport, Texas, for scanning electron micrography, x-ray diffraction, and x-ray emission studies; and to Geochem Laboratories, Houston, Texas, for source rock (shale) geochemistry. In addition, shale samples were taken by the U.S.G.S., Bay St. Louis, Miss., for work outside the scope of this report.

6.1 Lithology

Detailed core description, lithology, and petrographic description are presented in Section 5 of this report and in Appendix E. Section 4.3.3 presents the results of a Dow x-ray micrographic study including scanning electron micrography, x-ray diffraction, and x-ray emission. In physical appearance, the reservoir rock is a dark gray, fine to medium grained, generally friable sandstone, intercalated with several silty or shaley layers. The sand itself can be divided into two zones -- the upper zone from 13,340 feet to 13,370 feet, characterized as relatively structureless, coarse-grained, clean, and

unconsolidated; and the lower zone from 13,370 feet to 13,425 feet, characterized as finer grained, more consolidated and containing fine clay and numerous sedimentary structures.

The underlying shale was dark gray to black, slightly carbonaceous and silty, with no obvious sedimentary structure.

Refer to Figure 4-8 for a schematic vertical profile of the cored interval.

6.2 Conventional Porosity and Permeability Measurements

The work was performed by Corelab, Lafayette. Average porosity was 28% and average permeability was 3700 md. Results are presented in Table 6-1.

TABLE 6-1PERMEABILITY AND POROSITY ANALYSIS

<u>Samp.</u>	<u>Depth</u>	<u>Perm. MD.</u>	<u>Por. %</u>	<u>Description</u>
2	13342.5	260	25.9	SD VF-FG SHY
3	13343.2	810	22.2	SD FG SSLTY
4	13344.5	4550	26.4	SD FG CLN
5	13346.5	4370	29.7	SD FG CLN
6	13348.5	4780	29.2	SD FG CLN
7	13350.0	4740	30.1	SD FG CLN
8	13352.7	5160	27.8	SD FG CLN
9	13355.5	7780	29.6	SD FG CLN
10	13357.6	6580	29.3	SD FG CLN
11	13360.5	3650	28.1	SD FG CLN
12	13362.2	2590	27.8	SD FG CLN
13	13364.0	1420	27.8	SD FG CLN SSLTY
14	13365.5	2300	27.4	SD FG CLN
15	13367.5	5350	28.6	SD FG CLN
16	13368.5	27	22.7	SD VGD SSHY SLIG (L) SSLTY
17	13369.5	825	29.4	SD FG SSLTY
18	13370.5	7620	30.5	SD FG CLN
19	13372.5	4920	30.4	SD FG CLN
20	13375.5	2930	29.1	SD FG SSLTY

23	13390.0	205	28.4	SD VFG SLTY
24	13394.5	410	31.5	SD VFG SLTY
27	13397.5	1260	29.2	SD VF-FG SSLTY
28	13400.0	.06	14.8	SD VFG SSHY SLTY
29	13401.0	36	23.3	SD VFG SLTY
30	13402.0	46	21.1	SD VFG SLTY
32	13404.0	15	21.2	SD VFG VSLTY
33	13406.0	265	25.2	SD VG-FG SSLTY- SLTY
36	13409.0	.26	18.6	SD VFG VSLTY
46	13419.0	0	10.2	SD VFG VSLTY VCALC
61	13438.0	.63	13.1	SD VFG SHY (L) VSLTY
71	13450.0	.35	12.2	SD VFG SS-SHY (L) VSLTY
78	13454.0	1.1	20.9	SD VFG VSLTY

6.3 Acid Solubility and Sieve Analysis

Solubility of formation samples in 15 x HCl and mud acid, and sieve analyses were performed by Dowell on the residual samples from the Corelab tests. Test procedures and complete results, with graphic representation of sieve analyses are presented in Appendix I.

Acid solubilities were run gravimetrically. One gram samples were placed in 100 ml of acid and heated for 1 hour at 150°F. The residue was filtered, dried and weighed. Solubility is reported as per cent by weight. Table 6-2 gives the average solubilities for 29 samples.

TABLE 6-2
AVERAGE ACID SOLUBILITY

	<u>Percent Solubility</u>	
	<u>15 x HCL</u>	<u>Mud Acid</u>
Ave-29 samp., $\bar{X}$	8.5	45.4
Std. dev., S	4.8	21.9

Sieve analyses were performed using 50-75 gram samples placed on the top of a U.S. Standard Sieve Series and shaking for 15 minutes on a Tyler Shaker. The weight of sample retained on each screen was then recorded. Table 6-3 and Figure 6-1 represents a "typical" sample sieve analysis (Sample 13394.5'). All the analyses are reported in Appendix I.

TABLE 6-3CORE SIEVE ANALYSIS - "TYPICAL SAMPLE"

Depth - 13,394.5

<u>Screen #</u>	<u>Mass</u>	<u>% Retained</u>	<u>% Cumulative</u>
50	4.7	7.6	7.6
70	3.1	5.0	12.6
100	13.9	22.3	34.9
140	13.5	21.7	56.6
200	18.5	30.2	86.8
270	6.6	10.6	97.4
Pass	1.6	2.6	100.0

FIGURE 6-1

6.4 Mechanical Properties - Phase One

Mechanical testing at in-situ conditions was performed by TerraTek, Inc., of Salt Lake City, to provide data to determine reservoir parameters for modeling and reservoir evaluation (Phase One). Late in 1982, production data from the L.R. Sweezy No. 1 indicated that an unusual drive mechanism or pressure support phenomenon was occurring. In order to determine the nature of this, a suite of uniaxial drawdown, and short and long term (creep) hydrostatic compression tests were designed and performed by TerraTek. In addition, permeabilities for five shale samples were determined in "Phase Two" testing. This work was completed in July, 1983. Both reports are attached as Appendix E.

6.4.1 Test Matrix - Phase One

The position of the samples for mechanical testing taken from the core is shown in Figure 6-2. Sample numbers 1 through 5 represent the samples used for the Phase Two tests in 1983. It should be noted that the beeswax seal on the core had been broken some time prior to the selection of samples for the Phase Two tests.

In order to maximize the data obtained, a test matrix was

FIGURE 6-2 CORE TEST AND PETROGRAPHIC ANALYSIS INTERVALS

designed such that a number of various tests could be run on a sample, as long as the results of a given test would not be affected by previous tests on that sample.

The test matrix is shown in Table 6-4.

6.4.2 Sample Preparation

Cylindrical test specimens, each 2 inches in diameter and 4 inches in length were obtained from the whole core samples according to standard procedures specified in Appendix E. A one inch diameter satellite core was obtained from each of the whole core samples for density, porosity and a limited number of ultrasonic velocity measurements.

6.4.3 Test Equipment

All tests were performed using a system designed and built at TerraTek for high-temperature creep measurements. The system uses gas-backed, thermally stabilized hydraulic accumulators for applying the axial, confining and pore pressures. Figure 6-3 shows a schematic of the axial load, confining pressure and pore pressure units. The pore pressure unit is also used for flow (permeability) and ejected fluid volume (pore volume changes) measurements. The axial and transverse strain measurements are

TABLE 6-4. TEST MATRIX

Type	Number	Porosity	Compressibility	Young's Modulus	Poisson's Ratio	Compaction Coefficient	Pore Volume Change	Permeability	Resistivity	Ultrasonic Velocities	Strength	Creep Strain
Quick-Response	2	2	2	2	2	2	2	4	--	--	--	--
Compaction	5	5	5	5	5	5	5	10	--	6	--	--
Triaxial	3	3	3	3	3	--	3	6	--	--	3	--
Creep	3	3	3	3	3	3	3	3	--	--	--	3
Resistivity	1	1	--	--	--	--	--	--	1	--	--	--
Total	14	14	13	13	13	10	13	23	1		3	3

DISPLACEMENT OF ACCUMULATOR PISTON
IS MEASURED ELECTRONICALLY

a) Loading Units

FIGURE 6-3. DETAILS OF THE TESTING SYSTEM COMPONENTS

made using, respectively, linear variable differential transformers (LVDTs) and strain-gaged cantilever fixtures. The strain gages have some drift over prolonged measurement durations, especially at elevated temperature. The LVDTs, on the other hand, are extremely stable and have high sensitivity for prolonged measurements on most rocks. The specimen is heated internally within the cell by convection of the hot cell fluid within a ceramic shroud. Temperatures are measured by thermocouples attached to the test specimen and placed in the cell fluid at several positions.

The system is electronically linked with a PDP-11 computer system, with the pressure, temperature, stress and strain transducer outputs being acquired in real time.

6.4.4 Test Procedures

Tests consisting of several hydrostatic, triaxial and uniaxial loading and unloading cycles and pore pressure reductions were designed to provide measurements for calculating several mechanical and transport properties. A schematic description of these tests is given in Figure 6-4.

6.4.4.1 Tests for Obtaining Deformational Characteristics

The test specimen, inside the pressure vessel, is heated and

FIGURE 6-4. SCHEMATIC DESCRIPTION OF TESTS TO OBTAIN MECHANICAL AND TRANSPORT PROPERTIES

loaded to simulate the estimated reservoir conditions at the depth from which the specimen originated. The approximate reservoir conditions simulated in each case are: temperature 107°C, confining pressure 13,000 psi; total overburden stress 13,500 psi and pore pressure 12,000 psi. The confining pressure and the pore pressure are increased simultaneously (maintaining a constant differential of approximately 50 psi to prevent a jacket failure). After the pore pressure reaches its maximum value, the confining pressure is increased to the reservoir level, followed by deviatoric stress application. Once reservoir conditions have been attained, the test procedure varies for different test types.

In the compaction tests, the pore pressure is lowered to approximately 60% of its maximum value while constantly adjusting the confining pressure and the deviatoric stress values to obtain a uniaxial compaction (no lateral strain change) and maintain a constant total axial stress (representing the overburden).

In the triaxial tests to failure, conducted on three sand samples from generally the same level, the pore pressure is reduced to approximately 20%, 40% and 60%, respectively, of their maximum values (representing the reservoir condition). The deviatoric stress is then increased until the specimen fails while

maintaining the pore pressure and the confining pressure constant.

In the creep tests, the pore pressure is lowered to approximately 7000 psi while maintaining a constant axial stress and uniaxial compaction. The specimen is allowed to creep for several days under constant stress conditions.

6.4.4.2 Permeability Measurements

In all these tests, except the test on the shale specimen, permeability measurements are made after attaining the reservoir conditions. A second permeability measurement is made after the 1-D compaction phase in the type 1 tests to assess the influence of fluid production on the porosity and permeability of the reservoir rock.

The transient pulse technique which is especially suited for the low porosity, low permeability range was used to measure permeability for a single shale specimen. In the transient technique, the two ends of a test specimen are kept open to fixed volumes of permeating fluid and a differential pressure pulse of the magnitude approximately 1% of confining pressure is applied across the specimen. The pressure pulse results in fluid flow across the specimen and the equilibrium is reestablished. The

pressure differential decay with time is monitored and the results in conjunction with the properties of permeating fluid, specimen geometry and the system volumes enable the permeability calculation. Figure 6-5 shows a schematic of the test setup.

After the fluid pressure stabilized (approximately two hours duration) an electrical resistivity measurement was made using a four pole AC resistivity device to verify proper functioning of measurement devices. The temperature was then raised to 106°C and after a thermal stabilization was attained (approximately 45 minutes duration) the final resistivity measurement was made.

6.4.4.3 Porosity Measurements

Porosity measurements were done on samples from each of the whole core pieces used for test specimen preparation. The dual chamber helium-gas Boyle's Law method was used to determine volume of solids, V_s , for each specimen. The chamber volumes are optimized for the sample size to give near maximum resolution for porosity determination. The apparatus was calibrated with known volumes. Porosity (ϕ), was then determined by:

$$\phi = 1 - \frac{V_s}{V_t}$$

where V_t is the total sample volume as determined by immersion

FIGURE 6-5 SCHEMATIC OF THE TEST SET-UP FOR TRANSIENT TECHNIQUE OF PERMEABILITY MEASUREMENT.

and displaced fluid volume measurement. Resolution is estimated to be approximately $\pm 0.5\%$ porosity.

6.4.4.4 Ultrasonic Wave Velocity Measurements

The ultrasonic velocities in three sand samples were measured using a "Through Transmission Technique". The travel time of an ultrasonic signal through a core sample is derived from the frequency of a very stable and accurate (stability ± 1 part in 10^7 /month; accuracy $\pm 0.001\%$) variable frequency synthesizer (VFS). The VFS triggers a pulse generator transmitting pulses through the core sample. The pulse shapes are adjusted so that the initial pulse, the signal received through the specimen and the VFS output itself (comparison wave) match exactly in shape. The VFS frequency is varied so that an exact number of comparison wave cycles are included between the time that initial pulse is transmitted and the specimen signal is received. The travel time is determined by VFS frequency.

6.4.5 Deformation Characteristics - Phase One

Average values of mechanical and transport properties are given in Table 6-5. A summary of all the test results and ranges of values obtained for different parameters are given in Table 6-6.

The deformational behavior of a test specimen under a complex

**TABLE 6-5. AVERAGE VALUES FOR MECHANICAL AND
TRANSPORT PROPERTIES**

Parameters	Values	Number of Values Used In Averaging
Porosity	$(29.9 \pm 3.81)\%$	16
Young's Modulus	$(1.06 \pm 0.43) 10^6 \text{ psi}$	11
Shear Modulus	$(0.51 \pm 0.25) 10^6 \text{ psi}$	16
Bulk Compressibility	$(4.93 \pm 1.9 \sim 2.82 \pm 0.80) 10^{-6} \text{ 1/psi}$	14 and 10
Compaction Coefficient	$(0.56 \pm 0.16) 10^{-6} \text{ 1/psi}$	7
Permeability Coefficient (at reservoir condition)	6 ~ 914 md	Varies greatly and averaging these may not be meaningful.
Electrical Resistivity at 106°C	217 $\Omega \text{ m}$	1

**TABLE 6-6 SUMMARY OF RESULTS DESCRIBING
DEFORMATION CHARACTERISTICS**

Rock Type	Sample Number	Depth (ft)	Porosity (%)	Young's Modulus (psi) x10 ⁶	Shear Modulus (psi) x10 ⁶ *	Compressibility ($\frac{1}{\text{psi}}$) x10 ⁻⁶ **	Compaction Coefficient ($\frac{1}{\text{psi}}$) x10 ⁻⁶
Compaction							
Sandstone	6	13,344	28.6	1.26 3.24†	0.58 1.31†	3.30~1.38	0.35 0.30††
	33	13,364	25.8	0.84 1.27†	0.36 0.49†	10.30~1.95	0.35
	35	13,366	28.0	1.69	0.61	6.66~2.26	0.46
	67A	13,389	30.1	0.60	0.25	5.12~3.54	0.72
	68	13,390	26.7	1.55 2.16†	0.35~1.0 0.85†	5.08~3.19	0.65
Shale	129	13,446	20.2	0.54	--	3.15	--†††
Triaxial (to failure)							
Sandstone	41	13,371	36.2	1.18	0.75~0.45	3.52~2.58	--
	42	13,372	33.7	0.97	0.45~0.44	4.87~2.95	--
	75	13,395	27.9	0.96	0.51~0.37	5.59~3.85	--
Creep							
Sandstone	71A	13,393	29.6	1.58	1.06~0.52	4.06~2.83	0.70
	67B	13,389	30.1	0.68	0.30	4.42~3.69	0.66
Compaction or Creep§							
Sandstone	78	13,398	30.2	0.40	0.19	6.06	--
	7	13,344	23.0	--	--	3.24	--
	10	13,346	30.4	--	--	3.45	--
	40	13,369	37.5	--	--	--	--
	48	13,373	33.2	--	--	--	--
	80	13,400	26.7	--	--	3.33§§	--
						2.66§§	--
						2.55§§	--

*The range of values correspond to initial and final stages of triaxial loading phase.

**The range of values correspond to stress range between zero effective stress and reservoir conditions.

†These values were obtained from sonic velocity measurements.

††This value was obtained by repeating the uniaxial compaction phase.

†††Experimental results indicated a compaction coefficient of 0.85×10^{-6} 1/psi in this case. However, further investigation of the failed specimen indicated that during the testing a horizontal failure (along the bedding) was created in the specimen just above the lateral strain transducer stand-offs and the failure was confined in the upper half of the specimen. This resulted in recording of all the axial compression, but no lateral extension and hence a fictitiously high compaction coefficient.

§Partially completed tests (not completed due to specimen or equipment failure).

§§These values were obtained during subsequent loading cycles.

triaxial loading sequence can be represented by a mean effective pressure (σ_m) versus volumetric strain (ϵ_v) relationship. Figure 6-6 shows a plot of this for a sandstone and a shale specimen. Initial nonlinearity in the stress-strain relationships is significant and can be attributed to the closure of pre-existing cracks and pore collapse. Inelasticity is clearly exhibited resulting in hysteresis. In one sandstone sample (DOW #6, depth 13,344 ft.) only about 33% of the strain at the maximum effective stress of 6000 psi was recovered during unloading to 200 psi.

Figure 6-7 shows the compressibility variation with the mean effective stress for the same sandstone and shale specimens. Compressibility is obtained for all phases of loading by the slope of the tangent to the ($\sigma_m \sim \epsilon_v$) curve. These curves are typical of all the samples tested.

The Young's and shear moduli are calculated from the deviatoric stress-strain ($\sigma_1 - \sigma_3 \sim \epsilon_1 - \epsilon_3$) and shear stress-strain ($\frac{\sigma_1 - \sigma_3}{2} \sim \epsilon_1 - \epsilon_3$) curves. The Young's modulus remained very much constant throughout the deviatoric stress loading phase although the shear modulus decreased considerably near the maximum shear stress.

The elastic constants obtained from the sonic velocity

FIGURE 6-6. MEAN EFFECTIVE PRESSURE-VOLUMETRIC STRAIN RELATIONSHIP FOR SANDSTONE (#68) AND SHALE (#129) SPECIMENS

FIGURE 6-7. COMPRESSIBILITY VARIATION WITH MEAN EFFECTIVE STRESS FOR SANDSTONE (#68) AND SHALE (#129) SPECIMENS

measurements on three sandstone samples are much higher than the corresponding values obtained from static measurements. This is expected due to the low stress and short duration pulses used in sonic velocity measurements, and helps explain the discrepancy between the mechanical properties log and the measured properties.

Compaction coefficient (C_m) is obtained from the pore pressure axial strain relationship during uniaxial compaction phase simply as the slope $\partial \epsilon_1 / \partial P_p$. Compaction coefficients are fairly constant throughout the uniaxial compaction phase for most of the samples tested.

Mohr's circles and the failure envelopes were obtained from the triaxial tests on three sandstone samples. The failure envelope at lower normal stress is very linear and if extrapolated downwards, gives a cohesion of approximately 3000 psi and a friction angle of 28° . This is shown in Figure 6-8.

Figure 6-9 shows the creep curves obtained for a sandstone specimen allowed to creep under constant stress conditions for approximately five days. It appears that a steady-state creep mode had been attained in this case. Other creep tests yield similar results. Although it is difficult to say from these results how long the steady-state creep would have taken place,

FIGURE 6-8 MOHR'S CIRCLES AND FAILURE ENVELOPE FOR SANDSTONE SPECIMENS

FIGURE 6-9. CREEP CURVES FOR A SANDSTONE SPECIMEN (# 67B)

over extended production periods creep compaction probably would be significant.

6.4.6 Transport Characteristics - Phase One

Table 6-7 gives permeability values for different sand samples. These permeability values have been obtained by flowing NaCl brine through the specimen at reservoir conditions of stresses and temperature. The second permeability value reported from some cases corresponds to the test stage after the fluid production simulation phase.

The permeability values reported in Table 6-7 are approximately $1/4$ to $1/10$ of those reported by Core Laboratories, Inc. for samples from the same depth. This significant difference is due to the fact that the Core Laboratory results are gas permeabilities obtained at bench condition.

There is significant reduction, ranging from 26% to 88%, in permeability, caused by one-dimensional compaction simulating the fluid production phase.

Figure 6-8 shows the result from the permeability measurement on a single shale specimen using the transient pulse technique. The final value corresponds to reservoir conditions as closely as the experimental setup permitted.

TABLE 6-7 STEADY STATE PERMEABILITY VALUES FOR SAND SAMPLES

Sample Number	Depth (ft)	Porosity (%)	Permeability (millidarcy)	
			Reservoir Cond.	After Fluid Prod. Simulation Phase
#6	13,344	28.6	43.8	23.8
#33	13,364	25.8	188.8	*
#35	13,366	28.0	193.2	142.7
#41	13,371	36.2	914.4	*
#42	13,372	33.7	92.3	*
#67A	13,389	30.1	6.0	3.7
#67B	13,389	30.1	6.0	*
#68	13,390	26.7	26.3	3.1
#71A	13,393	29.6	13.6	4.5
#75	13,395	27.9	26.1	*

*Indicates that the permeability measurements were not reliable in these cases or the measurement was not made.

6.4.7 Electrical Resistivity

Electrical resistivity of a sandstone specimen (#41) from 13,371 ft depth, obtained at an effective pressure of 980 psi and at temperature of 23°C and 106°C, are 266 ohm-meters and 217 ohm-meters, respectively. These values are approximately an order of magnitude higher than those expected or determined from the well logs.

6.5 Mechanical Properties - Phase Two

The early production history and results of the first six drawdown and buildup tests of the Dow/DOE No. 1. L. R. Sweezy Geopressured Test Well indicated that an increasing pressure support mechanism, not anticipated, was effecting the reservoir.

Ambiguity of interpretation of the data allowed several possible explanations of this phenomenon, including shale dewatering, edge water influx, and change in rock compressibility. Also, apparent changes in permeability, some distance from the wellbore, were occurring.

A set of tests was designed to determine the change in reservoir rock properties as a function of pressure drawdown and time. These tests include: uniaxial strain with pore pressure drawdown to determine change in porosity, permeability, and formation compressibility during reservoir drawdown at simulated in-situ conditions; short vs. long term hydrostatic compaction at the same net effective stress to determine the role of time-dependent (creep) behavior in affecting formation compressibility; and high resolution shale permeability to determine the contribution of shale water influx.

6.5.1 Sample Characterization

A total of five core samples, numbered 1 through 5 and shown in Figure 6-2, were selected for mechanical testing. Five shale core samples, numbered D113, D123, D125, D132, and D134, also shown on Figure 6-2, were submitted by the U.S.G.S. for permeability measurements.

A total of seven mechanical tests and five high resolution permeability tests were run on the core material. In addition to this, the core was characterized by determining six physical properties, as shown in Table 6-8.

TABLE 6-8 PHYSICAL PROPERTIES OF CORE FROM SWEETZ NO. 1 WELL

Sample I.D.	Depth (ft)	Natural Density (gm/cc)	Dry Density (gm/cc)	Effective Porosity (%)	Total Porosity (%)	Permeability (md)	Grain Density (gm/cc)
D113	13,431	2.16	2.06	24.4	25.0		2.72
D123	13,439	2.31	2.09	23.5	23.8		2.73
D125	13,444	2.33	2.09	23.5	25.7		2.73
D132	13,449	2.28	2.03	25.4	25.5		2.72
D134	13,451	2.25	2.02	25.4	26.0		2.70
1	13,345	2.14	1.97	26.1	26.1	1972	2.66
2	13,354	2.16	1.89	28.9	30.1	5524	2.66
3	13,378	2.02	1.84	30.8	30.9	1106	2.66
4	13,368	2.04	1.79	32.8	32.7	1768	2.66
5	13,396	2.04	1.86	30.2	30.3	415	2.67

6.5.2 Test Procedures

Details of the specific testing procedures are contained and presented by test type in Appendix E. Deviations from these standard procedures and details specific to these tests are discussed in this section.

6.5.2.1 Uniaxial Strain Test with Pore Pressure Drawdown

Three uniaxial strain tests with pore pressure drawdown and subsequent pore pressure increase were specified for samples #1, 5 and 3. These samples, as were all of the mechanical test samples, were 1 inch in diameter and 2 inches in length, cored parallel to the whole core axis. After machining, all samples were saturated using a simulated formation brine. The chemical composition of this brine is presented in Appendix E.

After initial preparation and installation of the instrumented sample in the test cell, nominal 100 psi confining stress and 50 psi pore pressure were applied. The samples were then heated to the 226°F in-situ temperature. When temperature equilibration had been attained, the confining and pore fluid pressures were increased to 11,525 psi and 11,475 psi respectively. During this portion of the load path the differential between the confining and pore pressures was

approximately 100 psi. The pore fluid pressure was then maintained at this level and the confining stress increased to 13,500 psi (1 psi/ft). The first permeability measurement was made at this point. The pore pressure drawdown sequence was then initiated to the abandonment pressure of 6050 psi. After reaching the abandonment pressure the pore fluid pressure was subsequently increased slowly to the original level. Permeability measurements were made at four equally spaced intervals during the pressure drawdown and subsequent increase. The target pore pressures at which permeability was measured were 11,475 psi, 9666 psi, 7858 psi and 6050 psi. The testing sequence was terminated after the initial pore fluid pressure had been re-established.

6.5.2.2 Short-Term Hydrostatic Compression

Two short-term hydrostatic compression tests were performed on samples #2 and #3 to determine the bulk sample response to an increasing hydrostatic pressure. The samples were instrumented and installed in the test cell and nominal confining and pore fluid pressures of 200 psi and 100 psi, respectively, were applied. Hydrostatic loading commenced when the sample had reached temperature equilibrium. The confining pressure was increased in approximately five minutes time to 1870 psi. At this point the loading rate was decreased such that the maximum confining stress of 3600 psi was reached in approximately one

hour. Unloading proceeded in the same manner with 1870 psi being reached in one hour and subsequent unloading to 200 psi in five minutes.

6.5.2.3 Long-Term Hydrostatic Compression

Two long-term hydrostatic compression/creep tests were performed to determine time dependence of the formation compressibility. Samples from cores #2 and #3 were used for these tests. These tests were performed in a small, heated hydrostatic test cell. The prepared and instrumented samples were placed in this test cell and brought to temperature equilibrium with nominal pore and confining stress. The confining stress was increased to approximately 1900 psi in 5-10 minutes time. This stress was then maintained constant for approximately 24 hours. During this time, the sample deformation was recorded by computer at 45 minute intervals. At the end of the 24 hour creep phase, the confining stress was increased approximately 430 psi. The confining stress was increased five times over five days to the maximum stress of 3600 psi, the same confining stress as that reached in the short term tests. After the creep period at the maximum level the sample was unloaded in approximately 10 minutes time.

6.5.2.4 High Resolution Permeability Tests

Five barrier shale samples were received from the U.S.G.S.

for permeability determinations. These samples were saturated in the synthetic formation brine prior to testing. Permeabilities were measured using a transient pulse technique at room temperature with a confining stress of 13,775 psi and a pore fluid pressure of 12,325 psi. These measurements were made on samples that were taken parallel to the whole core axis. They are plotted in Figure 6-10.

6.5.3 Results

Samples D113-134 were shale core that underwent permeability testing only. Samples 1-5 underwent uniaxial drawdown tests and short-term and long-term hydrostatic compression tests as described.

6.5.3.1 Uniaxial Strain with Pore Pressure Drawdown

Uniaxial strain tests were run on samples 1,3, and 5. Sample #3 underwent an inadvertent and sudden loss of pore pressure to approximately 5000 psi. The mean effective stress increased past the point where yielding would have been expected. The proper pore pressure was reestablished and the test continued to completion.

The results of the uniaxial strain tests with pore pressure drawdown on Sample No. 1 are shown in Figures 6-11A through

FIGURE 6-10 PERMEABILITY REDUCTION WITH EFFECTIVE STRESS APPLICATION FOR A SHALE SPECIMEN (TRANSIENT PULSE TECHNIQUE).

6-11F. These plots show:

- A) Pore and mean effective stress versus volume strain,
- B) Confining, pore and total axial stress versus time,
- C) Pore volume strain versus pore pressure,
- D) Formation compressibility versus pore pressure,
- E) Porosity versus pore pressure,
- F) Permeability versus pore pressure.

Computer printouts of these and other data acquired during the test are presented in the Appendix E.

Three general regions are distinguishable in the stress-strain plots. The first region shows the path followed to the in-situ stress conditions when the first permeability measurement was made. The second region in these plots shows the reduction in pore pressure to 6050 psi. Four permeability measurements taken during this drawdown phase are marked K1-K4 on the plots. Region 3 is characterized by the increase in pore pressure back to the original reservoir pressure. Three permeability measurements were made in this region, points K5-K7.

There is little volume strain during loading to the in-situ conditions when the effective stress is relatively low. The volume strain then increases as the pore pressure is lowered and the effective stress increases. In samples #3 and #5 a definite yield point was reached at approximately 4000 psi mean effective

Figure 6-11A. Uniaxial Strain with Liquid Permeabilities

UNIAXIAL STRAIN TEST WITH LIQUID PERMEABILITIES

Figure 6-11B. Uniaxial Strain Test with Liquid Permeabilities

Figure 6-11C. Uniaxial Strain Test with Liquid Permeabilities

COMPRESSIBILITY CALCULATED FOR A UNIAXIAL STRAIN/PORE PRESSURE DRAW DOWN TEST

Figure 6-11D. Compressibility Calculated for a Uniaxial
Strain/Pore Pressure Draw Down Test

Figure 6-11E. Porosity Determined During Uniaxial Strain Test with Liquid Permeabilities

Figure 6-11F. Permeability Measured During Uniaxial Strain/Pore Pressure Draw Down Test

stress. Here the sample underwent large deformations at a relatively constant stress. There was a significant reduction in the permeability subsequent to this yielding. Figure 6-12 represents the effective stress/volumetric strain relationship observed in testing sample No. 5. The probable yield region is evident as the plateau immediately preceding point K1 on the graph.

Figure 6-11C is a plot of the pore volume strain as a function of pore pressure. The slope of this curve at any point is the formation compressibility. The pore volume strain is calculated from the expression:

$$\frac{\Delta V_p}{V_{p_0}} = \frac{1}{\phi_0} \left[\frac{\Delta V_b}{V_{b_0}} - \beta_g (P_c - \phi P_p) \right]$$

where: ϕ_0 = initial porosity

$\Delta V_b/V_{b_0}$ = bulk volume strain

β_g = grain compressibility (assumed
1.8x10⁻⁷ psi⁻¹)

P_c = confining pressure

P_p = pore pressure

Figure 6-11D shows the variation in the formation compressibility as a function of pore fluid pressure. The values of the

Figure 6-12. Uniaxial Strain with Liquid Permeabilities

formation compressibility were obtained by taking slopes of the pore volume strain, pore pressure curves. In all cases, the compressibility is shown to increase significantly as the pore pressure decreases. This phenomenon is particularly noticeable in samples #1 and #5 where the samples yielded. The compressibility then decreased as the pore fluid pressure was reestablished. The extreme increases in the compressibility shown in these graphs would likely not be as large in the field, where the compressibility is taken as an average over the formation. Locally yielded regions could, however, cause a noticeable increase in the compressibility.

Figure 6-11E shows the porosity as a function of pore pressure. These figures show that there is only a slight change in porosity at low effective stress. A significant porosity change can be observed on pore fluid pressure drawdown. In all three tests the linear portions of these curves are nearly parallel.

The permeability as a function of pore pressure is shown in Figure 6-11F. These plots show noticeable reductions in all samples during the pore pressure drawdown, particularly when the sample yielded. The permeability did not show corresponding recovery when the pore pressure was established to the initial reservoir pressure. Bars are included on this plot to show the

estimated range of error for each variable. In the case of the pore pressure, the points represent the target pressures and the bars show the range of pressures over which the permeability measurements were actually made.

6.5.3.2 Short Term Hydrostatic Compression Test

Short term hydrostatic compression tests were run on sample No. 2 and on two plugs cut from sample No. 3 (3A and 3B).

Sample No. 2 was a very friable sandstone. Figure 6-13A is a plot of the axial, radial and volume strains as a function of confining pressure. Compaction values are similar in all directions. Figure 6-13B shows the pore volume strain as a function of confining pressure.

In the case of samples 3A and 3B, axial strains are significantly larger than radial strains. A change in slope occurs in these tests at approximately 2000 psi, corresponding to the change in loading rate that occurred at 1870 psi.

6.5.3.3 Long Term Hydrostatic Compression

Samples for the long-term hydrostatic compression tests were taken from the same cores that were used to prepare samples for the short-term hydrostatic compression tests. These tests were

Figure 6-13A. Hydrostatic Compression 3600 PSI Confining Pressure

Figure 6-13B. Hydrostatic Compression 3600 PSI Confining Pressure

designed to help determine the role of creep in the change of compressibility.

The radial strain transducers drifted an unacceptable amount during the creep tests. The possibility of this occurring during the test had been anticipated based on prior experience with strain gauge transducers. Because of this, axial strain was measured using linear variable differential transformers (LVDT). LVDTs are known for long-term stability and are frequently utilized in creep experiments. Due to time and economic constraints, radial LVDT transducers could not be developed for this project.

The most accurate representation of the actual behavior of the sample can be determined by calculating the bulk volume change based on the axial strain measurement. The radial deformation was estimated by scaling the axial strain data. The amount of scaling was determined from the short-term hydrostatic strain data, which showed the radial strains to be qualitatively similar in samples No. 2 and No. 3 but approximately 6% and 57% smaller, respectively, in magnitude than the axial strains. Therefore, bulk volume strain was calculated as follows for the long-term hydrostatic compression tests:

$$\frac{\Delta V_b}{\Delta V_{b_0}} = \frac{\epsilon_a + 2(K)\epsilon_a}{3}$$

where: ϵ_a = axial strain

K = scaling constant

Sample No. 3 exhibited very little creep during the long term test, as shown in Figure 6-14. Supporting evidence from the Phase One rock mechanics testing indicates that the lack of creep response is atypical for this reservoir rock. The expected response is a fairly uniform rate of creep, as seen in sample No. 2, shown in Figures 6-15A and 6-15B. The slope of the curve in 6-15B represents the formation compressibility.

Figure 6-16 is a direct comparison between the short and long term response of the sample No. 2 core material. The magnitude of the pore volume strain is greater when the sample is stressed over an extended period. The majority of the difference in strain response occurs below 2000 psi confining stress. Above 2000 psi the compressibilities of the two samples are similar. No sample yielding was observed in any of the hydrostatic compression tests.

These results imply that time-dependent behavior should occur

Figure 6-14. Hydrostatic Compression 3600 PSI Confining Pressure

Figure 6-15A. Hydrostatic Compression 3600 PSI Confining Pressure

Figure 6-15B. Hydrostatic Compression 3600 PSI Confining Pressure

HYDROSTATIC COMPRESSION 3600 PSI CONFINING PRESSURE

Figure 6-16. Hydrostatic Compression 3600 PSI Confining Pressure

early in the pressure depletion history of a reservoir; after the first few thousand psi of drawdown, this effect should level off. This, in fact, was the observed case. Calculated compressibilities and productivity indices increased during the early depletion of the reservoir, and leveled off later, between Buildups No. 10 and No. 11, as the total reservoir depletion approached 2000 psi.

6.5.3.4 High Resolution Permeability Tests

The results of the permeability tests on the barrier material are shown in Table 6-9. These results show, as expected, that this barrier material was relatively impermeable to the synthetic formation brine. One sample, D-113, disintegrated during saturation, and as such no data is available for this sample. These data are consistent with other values from work performed on similar materials.

**TABLE 6-9 PERMEABILITY OF BARRIER SHALE TO
SYNTHETIC FORMATION BRINE**

Sample I.D.	Depth (ft)	Sample Length (in)	Sample Diameter (in)	Permeability (10 ⁻⁶ darcy)
D-113*	13430.8-13431.4	N/A	N/A	N/A
D-123	13439.7-13440.4	1.170	1.735	0.04±0.02
D-125	13441.9-13442.4	0.750	1.732	0.05±0.02
D-132	13448.0-13449.6	0.825	1.735	0.29±0.02
D-134	13450.8-13451.4	0.487	1.745	0.03±0.02

*Sample disintegrated during saturation.

6.6 Shale (Source rock) Geochemistry

Three shale samples were selected and sent to Geochem Laboratories, Inc., for geochemical analyses. The complete Geochem Laboratories report is attached as Appendix J.

Analyses included the following:

- a) Total organic carbon determination and gross lithological description,
- b) Pyrolysis analysis,
- c) C₁₅+ Soxhlet extraction, deasphalting and complete liquid chromatographic separation of hydrocarbon and non-hydrocarbon fraction,
- d) C₁₅+ paraffin-naphthene gas chromatography,
- e) Visual kerogen assessment,
- f) Vitrinite reflectance analysis,
- g) Palynological examination.

6.6.1 Sample Characterization

Lithological description and organic carbon analyses are given in Table 6-10.

TABLE 6-10

ORGANIC CARBON ANALYSES AND GROSS LITHOLOGICAL DESCRIPTION

Well Interval (Feet)	Gross Lithological Description	GSA Color Code	Total Organic Carbon (% of Rock)
13418.4	100% Shale, noncalcareous, very slightly silty, slightly micromicaceous, very slightly pyritized, subcentimetric silt intercalated, slightly bedded, chunky, moderately soft, olive gray.	5Y 4/1	0.24
13424	100% Shale, noncalcareous, very slightly carbonaceous, glauconitic, very slightly micromicaceous, massive, chunky, moderately soft, olive gray.	5Y 4/1	0.23; 0.24R
13448.5	100% Shale, noncalcareous, very slightly carbonaceous, glauconitic, very slightly micromicaceous, massive, chunky, moderately soft, olive gray.	5Y 4/1	0.27

6.6.2 Thermal Maturity of Sediments

Based on kerogen coloration, the thermal maturity of the two (2) core samples from this well is an immature Maturation Index Stage 1+ to 2- as shown on Table 6-11, Visual kerogen assessment worksheet. The results of the vitrinite reflectance analyses also indicate an immature thermal maturation of these sediments, with an average % Ro of 0.41% and 0.40%, respectively.

The high odd-carbon preference (C.P.I) exhibited in the

C₁₅+ parafin-naphthene gas chromatograms of these samples is further evidence of a thermally immature sedimentary sequence. Figure 6-17 is a gas chromatogram from C₁₇ to C₃₅ of the extracted bitumen from sample 1, showing the strong odd preference (high C.P.I.).

At this immature level of thermal maturation, the rocks from this well interval would be expected to have only generated varying amounts of biogenically-derived methane (C₁) gas. This is consistent with the fact that the reservoir water was found to be slightly undersaturated with respect to methane; however, it fails to explain the presence of condensate and oil in the reservoir.

Figure 6-18 illustrates the depth/temperature zones of hydrocarbon generation. The Parcperdue samples lie close to the zone of light oil and gas generation; perhaps past geologic influences were insufficient to generate a little oil and condensate.

6.6.3 Hydrocarbon Source Characterization of Sediments

The sediments analyses from this well interval (13418' to 13448') have an immature, poor hydrocarbon source character. Source rock characteristics are summarized in Table 6-12.

TABLE 6-12
 SHALE SOURCE ROCK CHARACTERISTICS
 DOW-DOE NO. 1 SWEEZY

	<u>SAMPLE No.</u>		
	<u>1</u>	<u>2</u>	<u>3</u>
DEPTH			
Total organic carbon	0.24	0.24	0.27
Extract Bitumen ppm	46		27
Free HC mg/g	0.13	0.04	0.11
HC Potential mg/g	0.26	0.07	0.11
% Paraffin	36.0		39.5
% Aromatic	63.6		59.8
% Isoprenoid	0.4		0.7
Pristane/Phytane	0.67		1.33
C.P.I.	1.29		1.70
Vitranite Reflect %	0.41		0.40
Maturation Index	1+		1+

These sediments are within the geopressured gas-saturated sands in South Louisiana. On the basis of the data presented in this study, these shales may not have been the source for the gas

FIGURE 6-18 HYDROCARBONS PRODUCED BY THERMAL DISINTEGRATION

in this geopressured zone. The palynological data presented on Table 6-13 indicates that these shales were deposited in a near shore environment, which apparently was void of large accumulations of organic matter. However, since these sediments were deposited near the coast line, it is likely that there are adjacent sediments, deposited in a marsh environment, wherein large accumulations of organic matter (lignite) exist.

Should this be the case, then these organic-rich sediments would be the probable source for the large concentrations of gas found in this geopressured zone.

Figure 6-19, Source Rock Quality shows the Parcperdue samples to fall in the region of "non oil sources"; again, however, slight variances in quality could place the samples in the regions of poor oil, gas, or condensante sources.

6.6.4 Palynological and Microscopic Analysis

The results of examination by Geochem palynologists are summarized in Table 6-13.

PERCENT C₁₅ + HYDROCARBON AS PERCENT OF TOTAL ORGANIC CARBON

FIGURE 6-19 SOURCE ROCK QUALITY

TABLE 6-13

Intepretation of Environment of Deposition

Sample Number	Depth (Ft.)	Environment of Deposition
1	13418	Near shore subaerial marine environment, in an area of rapid currents.
2	13448	Very near shore subaerial marine environment, in an area of quiet water.

The two samples contain similar kinds of organic material. While both samples are rich in fungal debris (spores and hyphae) indicating a source for organic material that is probably in a swamp, the presence of microforaminiferal linings is indicative of deposition in a marine environment. The distance from shoreline and relative current speeds are inferred from condition of preservation and particle sizes.

7. Pressure Transient Monitoring

All pressure testing, including downhole and surface measurements, operation of surface support equipment, and interfacing with the Otis well test analysis personnel in Dallas was conducted by Otis Engineering Co., based in Houma, La.

The original test plan was to run a series of four isochronal drawdown and buildup tests followed by periodic long-term buildup tests. Early problems with sand production, chokes, and downhole equipment prevented the execution of the isochronal tests; the short-term tests then being run as reservoir limits tests. A production interval of sixty days (at a rate of 10,000 BPD) was selected for the long-term buildups.

7.1 Downhole Equipment

The downhole equipment consisted of the electric line, the Hewlett-Packard quartz pressure gauge, and the Otis 4-channel temperature tool. Specifications are as follows:

1. Electric Line

Line: MP-35N Single Conductor, Size 7/32"

Depth of Line in Producing Well: - 13,435' W.L.M.

BHT: 228°F --- BHP: 11,428 PSI

Total Length of Line $\pm$ 16,960'

Line was used at time of purchase (Vector Cable Co.)

2. Hewlett-Packard Quartz Pressure Gauge

Calibrated Pressure Range = 200-11,000 PSIA (1.4 -- 75.8 MPA)

Operating Pressure Range = 0-12,000 PSIA (0 -- 82.7 MPA)

Operating Temperature Range = 32°F to 302°F

Resolution: 0.01 PSI (69A) when sampling for a 1 second period

Repeatability: ± 0.4 PSI (+2.76 KPA) over entire range

Sensitivity % of full scale: 0.00009

Accuracy % of full scale: 0.025 (If temperature is known within 1°C: ± 0.5 PSI to 2000 PSI, $\pm 0.025\%$ of reading above 2000 PSI)

Type of Pressure Element: Quartz

Test Start Delay: 0 to indefinitely

Read Time Interval: 1 second and up

Size: 1-7/16" OD by 39-3/8" long

3. Otis 4-Channel Temperature Tool

Mode of Operation: Multiplexed

Range: 0°F to 257°F

Pressure Rating: = 15,000 PSI max.

Accuracy: $\pm 1.0^\circ\text{F}$ (.36C)

Repeatability: $\pm 0.1^\circ\text{F}$ (.06C)

Sensitivity: 0.1°F (.06C)

H₂S Service

Size: 1.50" (38 mm) OD x 13.0" in length (330 mm)

Figure 7-1 illustrates the bottom hole assembly in the production well. An Otis BHP bomb latching nipple was installed at a depth of 13,549' to secure the H-P gauge in the hole. Attempts to latch into the nipple failed, so a tubing end locator with a shear pin was installed at the bottom of the H-P gauge, in order to lock onto the end of the tubing at 13,464'.

The Otis 4-channel temperature tool failed (loss of multiplexed signal) during the first series of drawdown and buildup tests. The tool was replaced with a conventional RPG-7 tool during the initial five drawdowns and buildups. An Otis team studied the problem and discovered that the buildup of impedance in the cable caused the failure to multiplex. The problem was solved by degaussing the cable before each use by connecting a load (light bulb) across the cable and passing a 120 VAC current through it.

On April 29, 1982, the electric line became knotted in the lubricator flow tubes. The wireline valves were closed and the electric line was stripped out of the lubricator, the knot cut out, the line spliced and reverse-spooled onto the wireline skid.

The splice functioned until Nov. 1, 1982, when signal was lost while attempting to run buildup No. 10. The splice was now in the flowstream due to shortening of the cable at the end of each previous run; the heat, temperature, pressure, and salt water had resulted in a short circuit.

16 7 5/8", 39#/ft, C-95 & P-110, LT&C Csg
10,484.18' to 13,608.96'.

GRAVEL-PACK

17	Dowell Model 16 GP Packer w/port-closing sleeve	6.437	3.25	8.03	13,143.16
18	6 jts. 4", 13.40 #/ft blank w/weld-on centralizers each 15'.	4.00	3.428	28.23 28.28 28.71 28.72 27.56 28.75	13,151.19
19	3 jts. 4", .012 gauge Stainless Steel All-welded screen (Howard Smith) w/weld-on Centralizers each 15'.	4.545	3.428	29.80 29.94 29.72	13,321.44
20	Wash Pipe Seal Bore Sub	4.75	2.78	1.30	13,410.90
21	Tattle-Tale screen 4", .012 gauge Stainless Steel All-Welded	4.545	3.428	8.52	13,412.20
22	X-Over 4", NU x 2 7/8, 8RD	4.47	2.44	.58	13,420.72
23	Locator		2.44	.70	13,421.30
24	Collet/Seal Assembly (4 seal units)	3.25		3.54	13,422.00
25	X-Over 2 7/8 FL x 2 7/8 DSS-HT	3.22	2.44	.50	13,425.54
26	1 jt., 2 7/8", 6.5#/ft, DSS-HT Tubing	3.22	2.44	32.69	13,426.04
27	Otis 'XN' Landing Nipple 2 7/8", DSS-HT, BXP	3.22	2.205	.93	13,458.73
28	Production Tube w/mule shoe End of Tubing	3.22	2.44	3.90	13,459.66 13,463.56
29	T.I.W. Model 'SS' Packer		3.25	3.00	13,422.00

'CIBB JEFF' SAND - Perforated 13,349'-388' & 13,395' - 406' DIL Run 5 dated 6-22-81
w/12 SPF w/ 4" Big Hole Jet. Gravel-Packed w/ 20/40 Mesh Sand -- 1330 lb. in
formation & 3040 lb. in Annulus

Final Completion & Packer Fluid -- 17.2 ppg @ 60°F CaBr₂/ZnBr₂

Minimum Restrictions: Tubing - 'RN' Nipple @ 10,444' - 3.986"
Gravel-Pack - 'XN' Nipple @ 13,459' - 2.205"

NOTE: Tubing has 4.313" 'DR' Plug set @ 383' and A 5" BPV set @ surface.

FIGURE 7-1 BOTTOM HOLE ASSEMBLY

The electric line was pulled out of the hole and a conventional Otis electric line truck was brought in to complete the test. The conventional E-line operated without problems, indicating that the expensive MP-35N cable may not be necessary where short-term or non-flowing pressure testing is desired.

The line was cut and re-spliced and an attempt was made to run the line during buildup No. 11. The splice, however, would not pass through the lubricator flow tubes. The splice was re-made; however, a conventional Otis electric line truck was again called out to perform buildup test No. 11.

7.2 Surface Equipment

Surface equipment consists of the following: lubricator control head, lubricator, wireline mast, electric line skid unit, and power unit. Figure 7-2 shows the lubricator rig-up on the wellhead.

The Bowen Control Head is composed of four flow tubes inside of four flow tube sleeves and joined together with three couplings. Packing and a packing nut are at the upper end. There is a bottom sub with appropriate threaded connection (2-3/8" EUE 8rd) for Otis quick union. A modification is made for dual injection on the control head for better sealing purposes. The injection modification is constructed of 20,000 lb. W. P. autoclave fittings with check valve.

**FIGURE 7-2 LUBRICATOR MAST WITH QUICK CONNECT
LUBRICATOR FLANGE ON WELLHEAD**

The control head is attached to the lubricator by means of an Otis Quick Union. The lubricator is as shown in figure 7-3, standard, except with one additional (for a total of two) Otis wireline valve. The specifications on the wireline valve are:

Otis Low and High Pressure Wire Line Valve (BOP) 46B07

10,000 lb. W.P. W/7-32" Sealing Rams

15,000 lb. Test

3.00" I.D. Seal Dia. 3.50"

Otis Quick Union Connections 5" - 4Acme

This is a standard service valve. The valve is used on both low and high pressure (0-10,000 lb.) wells. Most any diameter line may be run through the valve by merely changing the sealing rams to accommodate the particular line being used. All O-Rings and packing in the valve are rated for 300°F temperature.

While attempting to run flow test No. 2, on April 28, 1982, the disposal well became plugged. Investigation showed that "Honey Oil" (Lubri-Chem 272 wireline oil) had become emulsified in the flow stream and "plated out" on the walls of the disposal well and also coated the interior of the pipe and separator vessel. On all subsequent runs both wireline valves were closed once the H-P instrument was latched-in on bottom. This prevented the lubricator oil from mixing with the flow stream and eliminated this as a cause of disposal well plugging.

FIGURE 7-3 OTIS LUBRICATOR STACK

7.3 Data Acquisition System

The data acquisition system, in addition to the downhole H-P pressure gauge and Otis four-channel temperature tool, consists of the following:

Ametek 12,000 psi pressure gauge and Daniel 400°F temperature gauge on the lubricator; Ametek 5,000 psi pressure gauge on the casing; Daniel 400°F temperature gauge on the flowline, upstream of the manumatic valve; two Ametek 10,000 psi pressure gauges, one just upstream of the turbine total flow meter, one just downstream of the meter; a flow rate indicator on the meter board; a 3,000 psi Ametek pressure gauge and a 400°F temperature gauge on the disposal well. The pressure/temperature monitoring system is shown in Figure 7-4.

All data was monitored and recorded in the Otis data acquisition trailer. The heart of the system is a Hewlett-Packard model 9845T computer terminal. Visual display and hard copy printout was produced for each of the sensor inputs, while simultaneously recording the data on Hewlett-Packard tape cassettes. Figure 7-5 is a schematic of the data acquisition system, showing the component modules:

- Block "A" (Inputs A/D Converters),
- Block "B" (Control Unit and Processor),
- Block "C" and "C2" (On-site Reporting),
- Block "D" Mass Storage -- Tape and Diskette,

FIGURE 7-4 OTIS PRESSURE / TEMPERATURE MONITORING SYSTEM

OTIS SYSTEM FOR DATA ACQUISITION

BLOCK "A" - (INPUTS AND CONVERTERS)
BLOCK "B" (CONTROL UNIT AND PROCESSOR)
BLOCK "C" AND "Ca" (ON-SITE REPORTING)
BLOCK "D" MASS STORAGE
TAPE AND DISKETTE
BLOCK "E" AUDIBLE ALARM SYSTEM
BLOCK "F" TELEPROCESSING SYSTEM

FIGURE 7-5 SCHEMATIC DATA ACQUISITION SYSTEM

Block "E" Audible Alarm System,
Block "F" Teleprocessing System.

Figure 7-6 shows the actual arrangement of equipment inside the data acquisition trailer.

Sampling intervals varied slightly with the different tests; however, the general procedure was to sample at one second intervals for the first minute, two second intervals for the following two minutes, five second intervals for the next three minutes, fifteen second intervals for the next ten minutes, and one minute intervals thereafter.

When the data tapes were filled they were taken to the teleprocessing terminal, located in the living quarters trailer, for the transmission to Otis Engineering in Dallas for analysis. The teleprocessing terminal, shown in Figure 7-7, consists of an Hewlett-Packard model 9835T computer terminal with CRT, an H-P model 9278A plotter, and a telephone modem.

Various plots of the drawdown and buildup tests were produced on site at the teleprocessing terminal for a "quick look" at the test data and to make preliminary calculations. The plots produced include: linear plots, semi-log plots, log-log plots, and Hoerner plots.

**FIGURE 7-6 DATA ACQUISITION SYSTEM
IN OTIS TRAILER**

**FIGURE 7-7 TELEPROCESSING TERMINAL
WITH PLOTTER AND MODEM**

All additional data processing was done by Otis on their mainframe computer in Dallas. The results of the Otis analysis are presented in Section 8.0 and in Appendix B.

S-Cubed, of LaJolla, California, operating under separate contract to the DOE, was asked to perform a reservoir analysis and simulation of the Parcperdue reservoir. They were provided with all the pressure transient data and surface measurements on magnetic tape. The results of S-Cubed's analysis are presented in Appendix C of this report.

Other, equally valid techniques of reservoir analysis can be employed to analyze the data, possibly resulting in different conclusions. Further analysis is beyond the scope of this project; however, much information remains to be gained from the tremendous amount of data accumulated, and additional research is strongly encouraged.

8. Reservoir Testing and Analyses

Otis Wireline Services rigged up surface and downhole pressure monitoring equipment on 4/26/82. The downhole equipment included a Hewlett-Packard surface readout downhole pressure measuring sonde. Subsequently, the Hewlett-Packard sonde was lowered to a prescribed measuring depth of 13,395 feet, the L. R. Sweezy No. 1 Well was opened to flow at 1730 hours, 4/26/82 and the DOW/DOE geopressure-geothermal test was begun.

Originally, a short-term test scenario named for its short flow tests with rates ranging from 5000-20,000 SBBL/D and subsequent short buildup tests, were prescribed. It was concurred shortly after the start of the testing that produced water rates substantially higher than 10,000-11,000 SBBL/D would apparently cause decay or breakdown of the finer grained material in the aquifer rock. This fine grained sand suspended in the produced water was observed and was prevalent in all flow tests wherein rates exceeded 500-1000 SBBL/D. Ultimately, this sand production was instrumental in causing numerous delays and setbacks including: changing the overall short-term flow test procedure by mandatory rate reduction; cutting out and destroying chokes and choke seats; clogging the separator and tank which perhaps caused erroneous separator valve functions; plus clogging the filters upstream of the saltwater disposal well.

It is noted that the original short-term progressive increasing rate schedule was reduced from a range of 5000-20,000 SBBL/D to 5000-10,000 SBBL/D. Numerous automatic shut-ins during a measured flow test were triggered by the choke and choke seat damage due to the sand production. The filling of the main cylinder in the separation unit, by sand production, could have systematically reduced available space in the baffle type cylinder. This could have caused the automatic dump to activate more frequently. The clogging of the filters upstream of the disposal well was a frequent occurrence. A quantity of fine material smaller than the mesh size of the filters may have ultimately produced a minor clogging effect at the injection sandface of the disposal well. This, coupled with a residual gas buildup, might have contributed to the backpressure problem in that well forcing two stimulation treatments and subsequent delays.

The Hewlett-Packard quartz surface readout pressure instrument that was employed for this test is one of the most sensitive downhole pressure measuring devices available in field well testing. This particular test employed an electronic data gathering system coupled with the Hewlett-Packard instrument that could sample and record in a minicomputer up to 10 parameters such as: bottomhole pressure, bottomhole temperature, surface pressure and temperature, turbine meter flow rates, annulus pressure, disposal wellhead

pressure and temperature, etc. While this monitoring system adequately recorded and stored the sampled information, it was noted the Hewlett-Packard sonde itself was apparently transmitting erroneous downhole temperatures. A set of calibration coefficients correlating frequency, temperature and pressure are available for the quartz element. These coefficients are applied to obtain each simultaneous downhole pressure measurement on time modes as small as 1 second. The coefficients also serve to adjust the measured pressure to accommodate temperature changes. The sonde's self-adjusting temperature correction feature malfunctioned during early testing; therefore, all pressure data were adjusted where necessary by subsurface temperature measurements recorded with a RT-7 gauge.

Daily rates and cumulative totals for gas were measured by a Daniels orifice meter and a P.D. or positive displacement meter. The P.D. meter was ultimately considered more reliable but did suffer numerous malfunctions.

The long-term testing phase was begun on 6/2/82. This phase continued until the well sanded up in the period between 1/23 - 2/5/83. The test was terminated thereafter.

In general, mechanical malfunctions delayed and, in the

case of the short-term test phase, altered the procedures. The constant and relatively uniform sand production caused the majority of malfunctions and delays that eventually terminated the test prematurely.

Regardless of the noted mechanical and physical problems encountered, the data gathered, processed and displayed in various forms in the following text will show the results of the complex nature of the investigated system.

8.1 Objectives and Methods

Eleven pressure drawdown and buildup tests were conducted in the subject well from April, 1982 through January, 1983 to obtain adequate short-term and long-term pressure responses under variable flow rate conditions. As summarized by Table 8-1, the final four drawdown tests were conducted for relatively long durations ranging from 26 to 65 days.

Subsequently, a detailed description of the geopressured aquifer system was achieved from analytic regression analyses of measured subsurface pressure-rate-time behaviors.

The resulting aquifer description includes evaluations of impervious aquifer boundary distances from the well,

TABLE 8-1
SUMMARY OF EVENTS

TEST NO. DATE	TOTAL DURATION (HOURS)	Q _w AVERAGE FOR FLOW (BBL/D)	Q _w LAST PRIOR TO SHUT-IN (BBL/D)	CUMULATIVE TOTALS FROM RATE SCHEDULE WATER SEP BBL	GAS MSCF	FINAL MEASURED PRESSURE IN EVENT (PSIA)
DD1&2 4/26 & 4/28/82	5.72	1467	14,016	2843.35	58.88	10,548.178
BU2 4/28/82	7.25	-	-	2843.35	58.88	11,282.809
DD3 5/12-13/82	30.84	6449	6445	11,396.70	211.99	10,968.888
BU3 5/13-17/82	96.08	-	-	11,396.70	211.99	11,397.801
DD4 5/17-18/82	25.69	8562	8646	20,771.50	407.20	10,718.872
BU4 5/18-20/82	34.34	-	-	20,771.50	407.20	11,385.300
DD5 5/20-26/82	144.02	10,914	10,752	86,264.20	1,584.98	10,247.650
BU5 5/26-6/2/82	170.42	-	-	86,264.20	1,584.98	11,284.480
DD7&8 6/2-28/82	624.00	9491	9465	313,679.00	6,352.60	10,191.810
BU8 6/28-7/2/82	187.13	-	-	313,679.00	6,352.60	11,037.040
DD9 7/6-8/27/82	1,248.00	9353	9360	798,809.00	14,436.30	10,136.553
BU9 8/27-30/82	72.02	-	-	798,809.00	14,436.30	10,506.683
DD10 8/31-11/2/82	1,539.10	8434	8520	1,310,150.00	22,592.10	9,905.980
BU10 11/2-5/82	72.42	-	-	1,310,150.00	22,592.10	10,210.260
DD11 11/15/82-1/19/83	1,560.00	8346	8334	1,846,840.00	30,591.10	9,637.620
BU11 1/19-23/83	72.41	-	-	1,846,840.00	30,591.10	9,891.640

TABLE 8-1

approximate aquifer shape, initial aquifer volume, effective permeability to water, skin effects, turbulent flow constants, sources of aquifer energy, static aquifer pressure depletion history, time variant aquifer productivity and the hysteretic variation of aquifer rock compressibility during flow and shut-in. Additional energy sources such as vertical and peripheral water influx due to compaction of the aquifer or partially sealing faults were also investigated; and finally the aquifer depletion performance was predicted down to an abandonment bubble-point pressure of 8550 psia.

8.1.1 Discussion

The general engineering approach to the analyses problem consisted of analysing each long-term drawdown and buildup test separately to determine if acceptable consistency prevailed in calculated values of initial water in-place and boundary distances. This approach also allowed insitu determinations of the rock compressibility as a function of static aquifer pressure during the drawdown and buildup cycles. Because of the highly "sponge like" or compactive nature of the aquifer rock, it was necessary to apply different analysis procedures to the pressure drawdown data. Detailed engineering descriptions of the techniques used in this study for both drawdown and buildup analyses are presented in Appendix B.

Conventional pressure analysis techniques such as type curve, Horner plot and Y-function plot methods are not applicable to the test data of this project because they involve constant flow rate, constant aquifer fluid properties and in this case, a disastrous assumption of constant rock properties with time and pressure depletion. These methods are also one dimensional in regard to single parameter determinations such as permeability or aquifer volume. For this study, the more powerful analysis approach of simultaneously evaluating several aquifer parameters through a computerized nonlinear regression algorithm was adopted. Pressure variant aquifer fluid and rock properties and variable flow rate effects are included in the regression approach. The variation in rock compressibility with pressure is one of the unknowns solved by sequential analyses of the test data.

In so far as the aquifer fluid mechanics are concerned, a linearizing form of the normalized potential function, $m(p_w)$, is used as follows:

$$m(p_w) = \frac{(1-\phi(p_i))}{k(p_i)} \int_{p_{sc}}^p \frac{k(p) dp}{(1-\phi(p)) \mu_w B_{wf}} .$$

The water density term of this function has been deleted since lab measurements show that the water density only varies by 0.716 % over the pressure range of interest (8550-11,447 psia) at aquifer temperature of 237.4 °F. Normalizing this integral by $(1 - \phi(p_i))/k(p_i)$ is important since it allows the general shape of laboratory curves to be used but not explicit lab values of $k(p)$ and $\phi(p)$. Including the lab derived values of aquifer fluid and rock properties and performing the integration required by the above equation defines the desired relationship between $m(p_w)$ and the aquifer pressure as shown by Table 8-2 and the corresponding plot of Figure 8-1. Developments of the aquifer fluid and rock properties used above are discussed in Sections 8.1.2 and 8.1.3, respectively. The initial permeability-thickness, $k(p_i)h$, becomes one of the objective parameters of solution as shown by the following general form of the flow equation

$$m(p_w) = m(p_i) - \frac{70.6 q_w}{k(p_i)h} (PD(t_D) + 2s + 2Dq_w).$$

The academics of this potential function and the aquifer fluid mechanics are also discussed in Appendix B.

An additional technique was developed to analyse the pressure drawdown data for simultaneous aquifer volume and rock

TABLE 8-2

WATER POTENTIAL FUNCTION VS PRESSURE
 DOW/DOE PARC PERDUE PROJECT
 L. R. SWEET NO. 1 WELL

PRESSURE	WATER POTENTIAL
[PSIA]	FUNCTION
[PSIA]/(CP-RBBL/SBBL)]	
8564.948	10435.65
8687.629	10631.72
8810.309	10830.78
8932.990	11032.65
9055.670	11237.20
9178.351	11444.63
9301.031	11655.10
9423.711	11868.71
9546.392	12085.55
9669.072	12305.61
9791.753	12528.93
9914.433	12755.56
10037.11	12985.55
10159.79	13218.93
10282.47	13455.77
10405.15	13696.09
10527.84	13939.96
10650.52	14187.43
10773.20	14438.54
10895.88	14693.34
11018.56	14951.90
11141.24	15214.27
11263.92	15480.51
11386.60	15750.67
11509.28	16024.82
11631.96	16303.01
11754.64	16585.30
11877.32	16871.74
12000.00	17162.40

FIGURE 8-1

FIGURE 8-1

compressibility determinations. This technique is applicable to long-term drawdown data and it involves a coupling of material balance and certain aquifer fluid flow theory as shown by Appendix B.

In the discussions of the analyses, Section 8.2, it is well to keep in mind that the long-term buildup analyses were performed first and the long-term drawdown analyses second. The long-term buildup analyses yielded simultaneous evaluations of permeability-thickness, $k(p_i)h$; skin effect, s ; turbulent flow constant, D ; hydraulic diffusivity, $k/\phi\mu c_t$; and four boundary distances, d_1 - d_4 , comprising a rectangle shape approximation of the aquifer. From these results, the initial aquifer water volume, W ; the average rock compressibility, c_f ; and static aquifer pressure, p ; were determined. Long-term drawdown analyses were performed next to compute W , c_f and $\bar{p}$. With exception to c_f , reasonable comparisons were found between W and $\bar{p}$. Significantly different rock compressibility values were obtained from the buildup and drawdown analyses at essentially equal static aquifer pressures. Finally, it will be shown that relatively small volumes of vertical and peripheral water influx may have occurred during flow testing.

Development of the aforementioned aquifer fluid properties and core data are discussed in the following two sections,

respectively.

Nomenclature used in this report is as follows:

- A = equation constant
- B = equation constant
- B_{wfb} = water flash volume factor at bubble-point,
RBBL/SBBL
- B_{wf} = water flash volume factor, RBBL/SBBL
- B_t = two phase volume factor, water and free gas,
RBBL/SBBL
- B_t = relative volume factor, B_t/B_{wfb} , fraction
- B_g = gas volume factor, RBBL/Mscf
- c_t = total system compressibility, vol/vol/psi
= $c_w + c_f$
- c_w = water compressibility, vol/vol/psi
- c_f = rock compressibility, vol/vol/psi
- D = turbulent flow constant, per SBBL/D
- d_1-d_4 = boundary distances from well, feet
- h = net effective aquifer thickness, feet
- k = permeability, md (millidarcies)
- $k(p)$ = permeability at pressure, p, md
- $k(p_i)$ = permeability at initial pressure, p_i , md
- $m(p_w)$ = potential function at well pressure, p_w ,
psia-SBBL/cp-RBBL

- $\bar{p}$ = static aquifer pressure, psia
 p_i = initial static aquifer pressure, psia
 p_w = well pressure, flow or shut-in, psia
 p_b = bubble-point pressure, psia
 p_{sc} = pressure at standard conditions, psia
 $p_D(t_D)$ = dimensionless potential drawdown at t_D
 $\phi(p_i)$ = effective porosity at pressure, p_i
 $\phi(p)$ = effective porosity at pressure, p , pore volume fraction
 q_w = water flow rate, SBBL/D
 R_{sb} = solution gas water ratio at bubble-point pressure, scf/SBBL
 R_g = solution gas-water ratio, scf/SBBL
 R_i = instantaneous separator gas-water ratio, scf/SBBL
 s = skin effect, dimensionless
 t_D = dimensionless time, $0.0002637kt / c_t$
 t = time, hours
 μ_w = water viscosity, cp (centipoise)
 W = initial aquifer volume in-place, SBBLs

8.1.2 Aquifer Fluid Properties

Definitions of aquifer fluid properties such as water volume factor, B_w ; water viscosity, μ_w ; and solution gas-water

ratio, R_g ; as functions of pressure which include the bubble-point pressure, p_b ; are required before analyses of the pressure drawdown and buildup tests can be performed. These properties are obtained from recombined lab PVT analyses of separator gas and water samples after adjusting to field separator conditions and a produced gas-water ratio.

The recombined PVT analyses presented in Section 11 were available for the aquifer fluid property evaluations. Table 8-3 summarizes the evaluation results. This table shows a bubble-point pressure of 8550.15 psia and a corresponding solution gas-water ratio of 20.58 scf/SBBL (standard cubic feet of gas per separator barrel of water) at the aquifer temperature of 237.4 °F. In the undersaturated fluid region from bubble-point to the initial pressure of 11,447.1 psia the water volume factor ranges from 1.03139 to 1.02387 RBBL/SBBL, the water viscosity varies from 0.4268 to 0.4371 cp and the water density ranges from 65.041 to 65.510 lb/cf, respectively. All of the measured subsurface pressure drawdown and buildup test data are within this region.

Evaluations of the bubble-point pressure, p_b ; and solution gas-water ratio were made by correlating the lab measured bubble-points with separator wet gas-water ratios, R_i ; obtained from various recombinations and solving for p_b at the

reported field separator ratio of 17 wet scf/SBBL. The second degree polynomial fit of the correlation is given by the following relationship:

$$p_b = -898.341786 + 566.247088(R_i) - 0.614900171(R_i)^2, \pm 5.1391 \times 10^{-9} \text{ psia},$$

which yields $p_b = 8550.153$ psia at $R_i = 17$ scf/SBBL. Next, a second degree correlation of lab measured solution gas-water ratios with bubble-points yields

$$R_s = 10.7185378 + 8.33910337 \times 10^{-4}(p_b) + 3.73344907 \times 10^{-8}(p_b)^2, \pm 0.55114 \text{ scf/SBBL},$$

or $R_s = 20.58$ wet scf/SBBL at $p_b = 8550.153$ psia.

Lab flash gas liberations performed with different recombination gas-water ratios provided the data required to establish the following correlation between flash volume factor, B_{wfb} ; and bubble-point pressure:

$$B_{wfb} = 1.05188743 - 2.42795231 \times 10^{-6}(p_b) - 9.90321382 \times 10^{-12}(p_b)^2 + 5.40814837 \times 10^{-16}(p_b)^3, \pm 6.7585 \times 10^{-6} \text{ RBBL/SBBL},$$

which solves for $B_{wfb} = 1.031394$ at $p_b = 8550.153$ psia. Now the bubble-point pressure and corresponding values of solution gas-water ratio and flash volume factor are established. From these results and the lab relative volume, data evaluations of the volume factor at pressures above and below the bubble-point are performed.

Based on experience with oil PVT behavior, a known linear relationship furnishes correlations between relative volume, B_t and p , above and below the bubble-point pressure. This relationship has the following general form:

$$\log(1-B_t) = A + B \times \log(p-p_b);$$

or using the lab B_t data above bubble-point yields the following equation:

$$\log(1-B_t) = -5.57362743 + 0.991622635(p-p_b).$$

Solving this equation for B_t at pressures above bubble-point and using the relationship, $B_{wf} = B_t \times B_{wfb}$, yields the relevant water volume factors shown by Table 8-3. A similar fit having the minimum deviation of all below bubble-point cases was found using the 7780 psia bubble-point data as shown in Section 11.

TABLE 8-3

ADJUSTED LAB PVT DATA

<u>P</u> <u>(psia)</u>	<u>B_{wf}</u> <u>(RBBL/SBBL)</u>	<u>R_{sf}</u> <u>(scf/SBBL)</u>	<u>w</u> <u>(cp)</u>	<u>w</u> <u>(LBM/CF)</u>	<u>B_g</u> <u>(RBBL/Mscf)</u>
11447.1	1.02387	20.58	0.4371	65.510	-
11000.0	1.02502	20.58	0.4355	65.437	-
10500.0	1.02630	20.58	0.4337	65.356	-
10000.0	1.02758	20.58	0.4319	65.275	-
9500.0	1.02887	20.58	0.4302	65.195	-
9000.0	1.03016	20.58	0.4284	65.114	-
8800.0	1.03068	20.58	0.4277	65.081	-
<u>8550.15</u>	<u>1.03139</u>	<u>20.58</u>	<u>0.4268</u>	<u>65.041</u>	<u>BUBBLEPOINT</u>
8000.0	1.03264	20.04	0.4200	64.670	0.55305
7800.0	1.03320	19.87	0.4189	64.558	0.56056
7400.0	1.03424	19.19	0.4167	64.333	0.57691
7000.0	1.03518	18.56	0.4145	64.108	0.59535
6800.0	1.03579	18.10	0.4134	63.996	0.60550
6400.0	1.03659	17.08	0.4112	63.771	0.62803
6000.0	1.03742	15.84	0.4089	63.546	0.65411
5800.0	1.03772	15.20	0.4078	63.433	0.66873
5400.0	1.03814	13.74	0.4056	63.208	0.70175
5000.0	1.03854	12.21	0.4034	62.983	0.74071

RBBL = reservoir barrel

SBBL = separator barrel

scf = standard cubic feet

cp = centipoise

LBM = pounds of mass

cf = cubic feet

Mscf = thousand scf

This relationship is

$$\log(B'_t - 1) = -5.99814029 + 1.15702586 \log(p_b - p),$$

where $B'_t = B_t/B_{wfb}$;

and it provides a linear means to define B_t at pressures below the previously determined bubble-point of 8550.15 psia based on $B_t = 1.031394 B'_t$. The other relationship developed from lab data at this point is the fraction of water in the total stream below bubble-point or B_{wf}/B_t . This expression as developed from the lab 10,500 psia bubble-point case, as shown in Section 11 and normalized for the 8550.15 psia bubble-point, is

$$\begin{aligned} \log(1 - 0.999794 B_{wf}/B_t) &= -14.4433294 \\ &+ 3.26954747 \log(10500 - p). \end{aligned}$$

This equation coupled with the aforementioned B_t determination provides the B_{wf} values shown by the table below 8550.15 psia.

Next, it is necessary to compute the solution gas-water ratio, R_g , as the pressure decreases from bubble-point to 5000 psia. This is accomplished by using the two phase volume factor expression,

$$B_t = B_{wf} + B_g(R_{sb} - R_g),$$

or

$$R_g = R_{sb} - (B_{wf} - B_t) / B_g,$$

$$R_g = 20.58 - (B_{wf} - B_t) / B_g;$$

where

$$\begin{aligned} B_g &= 1000 p_{sc} T_z / 5.615 T_{sc} p \\ &= 1000 \times 15.025 \times 697.4 \times z / 5.615 \times 520 \times p \\ &= 3588.7509 \quad z/p, \text{ RBBL/Mscf.} \end{aligned}$$

The gas volume factor term is evaluated from the lab mole component analysis of separator gas, Section 11, and the Hall-Yarborough deviation factor, z , correlation. Table 8-4 shows the gas properties generated. A 5th degree polynomial fit of B_g as a function of pressure from 5000 to 11,800 psia produced the following expression:

$$\begin{aligned} B_g &= 2.55023654 + p(-8.22482489 \times 10^{-4} \\ &\quad + p(1.47102959 \times 10^{-7} + p(-1.41707635 \times 10^{-11} \\ &\quad + p(7.06283563 \times 10^{-16} + p(-1.43256921 \times 10^{-20}))))), \\ &\quad \pm 6.4324 \times 10^{-5} \text{ RBBL/Mscf.} \end{aligned}$$

This expression smoothes the B_g curve and it resulted in the calculated values shown by Table 8-3. The R_g values of this

TABLE 8-4

GAS PROPERTIES

GAS TYPE: MISC SPECIFIC GRAVITY: 0.5897

VISCOSITY:

HEPTANES+:

CO2 (CENTIPOISE):	0.00009	C7+ MOL. WT. :	0.00
N2 (CENTIPOISE):	0.00002	C7+ CRIT. PRESS. (PSIA):	0.0
H2S (CENTIPOISE):	0.00000	C7+ CRIT. TEMP (DEG R):	0.0

GAS ANALYSIS (MOLE PERCENTAGES):

N2	0.290	IC4	0.070
H2S	0.000	NC4	0.030
CO2	2.200	IC5	0.010
C1	95.240	NC5	0.000
C2	1.880	C6	0.000
C3	0.280	C7+	0.000

CALCULATED GAS PROPERTIES
(AT RESERVOIR TEMPERATURE)

PSEUDO CRIT TEMP(DEG R): 349.000 PSEUDO CRIT PRESS(PSIA): 674.741

PRESSURE (PSIA)	ZFACTOR (--)	GAS COMPR. V/MMV/PSI	VISCOSITY (CP)	BG (RB/MCF)	MP (PSIASQ/CP)
5000.00	1.03201	144.6476	0.02154	0.7408	0.14344096E 10
5200.00	1.04364	135.6524	0.02197	0.7203	0.15247690E 10
5400.00	1.05565	127.4734	0.02240	0.7016	0.16158013E 10
5600.00	1.06799	120.0206	0.02284	0.6845	0.17073792E 10
5800.00	1.08065	113.2178	0.02329	0.6687	0.17993869E 10
6000.00	1.09357	106.9955	0.02374	0.6541	0.18917204E 10
6200.00	1.10674	101.2923	0.02419	0.6407	0.19842858E 10
6400.00	1.12013	96.0559	0.02464	0.6281	0.20769995E 10
6600.00	1.13370	91.2376	0.02509	0.6165	0.21697867E 10
6800.00	1.14745	86.7964	0.02555	0.6056	0.22625813E 10
7000.00	1.16136	82.6943	0.02601	0.5954	0.23553250E 10
7200.00	1.17540	78.8991	0.02647	0.5859	0.24479668E 10
7400.00	1.18956	75.3810	0.02693	0.5769	0.25404626E 10
7600.00	1.20383	72.1139	0.02739	0.5685	0.26327745E 10
7800.00	1.21819	69.0750	0.02785	0.5605	0.27248703E 10
8000.00	1.23264	66.2433	0.02830	0.5530	0.28167230E 10

table were subsequently evaluated for the saturated region from 5000 to 8550.15 psia using the aforementioned R_g equation.

Other values of water viscosity and density appearing in the saturated pressure range of Table 8-3 were determined from the following polynomial fits of the lab data:

$$\mu_w = 0.375724956 + 5.53655329 \times 10^{-6}(p),$$

$$\pm 0.00364 \text{ cp},$$

and

$$\rho_w = 60.1717983 + 5.62309781 \times 10^{-4}(p),$$

$$\pm 0.10295 \text{ lb/ft}^3.$$

8.1.3 Core Data

Core data of the second Terra Tek report, Section 6.5, were used to define the normalized permeability, $k(p)/k(p_i)$; and normalized porosity, $(1 - \phi(p_i))/(1 - \phi(p))$; as required to develop the aforementioned $m(p)$ integral.

Permeability and porosity values for the pressure unloading cycles of Sample Nos. 1, 3 and 5 of the aforementioned report were used to establish the following relationships:

$$\log k = 2.330359 + 5.35118671 \times 10^{-5}(p)$$

$$\phi = 27.9140166 + 1.3459918 \times 10^{-4}(p)$$

where $k = \text{md}$

$\phi = \% \text{ pore volume}$

$p = \text{psig.}$

For the pressure range of interest from 11,447 to 8550 psia, the above correlations show a 30 % reduction in permeability and a 1 % decrease in porosity. The log-mean lab permeability of the three samples is 967.3 md and the math average porosity is 29.03 %. For Sample Nos. 1-5 corresponding average values of permeability and porosity are 1546 md and 30.0 %, respectively. Additional data measured during the loading cycles of these samples did not produce useable correlations.

Viable relationships of rock compressibility as a function of pressure were not achieved from the data of the aforementioned report. Significant and permanent deformation of the core plugs occurred during lab tests at high pressure. However, the degree of rock deformation in the actual aquifer system may be appreciably less as pressure depletion occurs over relatively longer periods of time.

Technical aspects of the lab permeability, porosity and

compressibility measurements and the various correlations developed are shown by Sections 6.4; 6.5 and Appendix B.

8.2 Summary of Drawdown and Buildup Tests

Composite plots of the measured drawdown and buildup tests are shown by Figures 8-2; 8-3 and Figures 8-4; 8-5, respectively. These plots illustrate the variation of subsurface pressure and corresponding potential function as the flow time increases from left to right for drawdown and as the shut-in time increases right to left for buildup. The X scale on each of these plots represents the sum of the products of the change in flow rate and the logarithm of incremental time of flow rate events occurring before and at the time of pressure measurement. Additional details of this well known superposition problem are shown in Appendix B.

In general, it is interesting to observe the progressively flattened trend in drawdown and buildup profiles on the composite plots as the aquifer pressure declines and rock compaction propagates through the aquifer. The late-time downward profile trends shown on Figures 8-2; 8-3 for drawdown plots and the late-time upward trends of Figures 8-4; 8-5 for buildup signify reflections of aquifer boundaries. The ensuing regression analyses of these late-time trends provided the

FIGURE 8-2

FIGURE 8-2

FIGURE 8-3

FIGURE 8-3

FIGURE 8-4

FIGURE 8-4

FIGURE 8-5

FIGURE 8-5

objective aquifer boundaries. The ensuing regression analyses of these late-time trends provided the objective aquifer description. Other analyses consisting of linear fits on the earlier time regions provided only approximations of the effective permeability and skin effect. A summary of the test events and highlights of the analyses are presented as follows.

8.2.1 Drawdown Nos. 1;2 and Buildup No. 1, 4/26-28/82

The initial bottomhole pressure testing was begun when the Hewlett-Packard, HP, quartz sonde was lowered into the producing well at approximately 1306 hours on 4/26/82. The HP instrument was allowed to stabilize at subsurface conditions prior to opening the well for the first pressure drawdown test. During this time, an initial aquifer pressure of 11,447.1 psia was measured at 13,395 feet. This instrument datum was maintained throughout the testing program. The producing well was opened to flow at approximately 1730 hours on 4/26/82. Numerous anticipated and unforeseen problems prohibited a stable pressure drawdown response for the 2.2-hour flow. The well was shut in automatically at 1955 hours and remained closed until 1020 hours on 4/28 when a second attempt to flow the well was made. Choke malfunctions and significant sand production caused an automatic shut-in after this 5.9-hour second flow period. The water flow rates were 6939 SBBL/D

during the first flow and they ranged from 4992 to 14,016 SBBL/D during the second flow.

The above events caused the drawdown profiles to be erratic and therefore not suitable for analyses. Subsurface pressure measurements were not obtained during the first shut-in, Buildup No. 1, because of wireline failure.

8.2.2 Buildup No. 2, 4/28/82

After the aforementioned automatic shut-in, the HP instrument remained at datum for an approximate 7.3-hour pressure buildup test. During this shut-in period, the measured subsurface pressure increased from 10,548 to 11,283 psia. It is noted that the well was shut in at the pneumatic valve and shortly after shut-in at the wellhead. The automatic shut-in on this buildup as well as Buildup No. 4 resulted in extended early time profile behaviors predominated by apparent storage and skin effects.

Due to the short flow duration prior to shut-in, this test only investigated the compacted or reduced aquifer permeability region around the wellbore and therefore it is not suitable for the aforementioned long-term aquifer boundary analysis. Short-term analyses of the data show reduced permeabilities

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ranging from 403 to 758 md and an apparent skin effect and turbulent flow constant of 8.36 and 0.000968/SBBL/D, respectively attributable to the impedance of the inner region of reduced permeability. The skin and turbulent flow values convert to equivalent pressure drawdowns of 215 and 345 psi, respectively or 62.3 % of a total 899 psi pressure drawdown.

A striking feature of this and the other buildup profiles, shown on Figure 8-5, is the rate-sensitive levels on the left side as shut-in time increases. As will be shown, this problem is apparently related to flow rate sensitive effects on rock compaction acting during flow and shut-in.

8.2.3 Drawdown No. 3, 5/12-13/82

An attempt was made to flow the well at 2113 hours, 5/4/82. Numerous choke problems caused an automatic shut-in at 0016 hours, 5/5/82. No bottomhole pressure measurements were made for this 3-hour flow period. The well was successfully opened on a 24/64 choke at 1155 hours, 5/12/82, after the HP instrument was lowered to datum. In general, this approximate 30.8-hour pressure drawdown test exhibited a relatively stable average rate of 6449 SBBL/D throughout the test.

The drawdown analysis shows a relatively low, compacted

permeability of 195 md and a negative skin effect of -6.18. A negative skin value usually indicates an improved flow environment at or near the wellbore and in this case, it is suspected that the wellbore has been effectively enlarged due to sand production.

The late-time region profile of this drawdown plot does show an approximate 2-fold increase in slope signifying a probable reflection of a nearby aquifer boundary.

8.2.4 Buildup No. 3, 5/13-17/82

The approximate 31-hour drawdown period previously described was terminated at 1954 hours on 5/13/82 when the well was shut in for a 36-hour pressure buildup test. Although the well remained shut in for 96 hours, the HP instrument was removed from the well shortly after 0730 hours, 5/15/82. During this test, the measured subsurface pressure increased from 10,969 to 11,398 psia and the extrapolated water potential function at infinite shut-in time converts to 11,403 psia. This value of extrapolated pressure is 44 psi lower than the measured initial aquifer pressure of 11,447 psia.

Again, as encountered in the previous shut-in, this buildup test shows progressively increasing values of calculated aquifer permeability ranging from 746 to 1477 md. The latter value of permeability appears to be too large and it

may be the result of a phenomenon known as negative departure due to at least one nearby aquifer boundary or additional energy influx due to compaction of shale and tighter rock. The late-time flattening of this profile shown on Figure 8-5 exhibits this trend and it possibly correlates with the aforementioned boundary reflection of the prior drawdown. As producing time increases, the negative departure reaction due to a boundary is known to translate into a positive upward departure. This event will be observed on the later buildups of longer duration.

8.2.5 Drawdown No. 4, 5/17-18/82

The HP gauge was set at gauge datum immediately following the aforementioned 96-hour pressure buildup test. The well was successfully opened to flow at 1926 hours, 5/17/82, on a 28/64 choke. The ensuing 26-hour drawdown period exhibited an average flow rate of 8896 SBBL/D and a pressure profile similar to Drawdown No. 3.

Analysis of the apparent straight line of the drawdown plot again gives a low, compacted permeability of 174 md and a corresponding skin effect of -6.08. The late-time region does show an initial downward departure due to a probable nearby boundary.

8.2.6 Buildup No. 4, 5/18-20/82

The previously described 26-hour flow period was terminated at 2110 hours on 5/18/82 when a mechanical malfunction activated an automatic shut-in. The ensuing pressure buildup test shows this reaction on Figure 8-5 by an early-time, prolonged "s" shape of the profile. Measured pressures ranged from 10,719 to 11,385 during this 24-hour shut-in.

The late-time profile of this test shows some erratic behavior which is probably due to a small decrease in the HP gauge datum. Intermediate data points of this profile exhibit normal behavior and they indicate two distinctive regions of reduced permeability ranging from 341 to 670 md. Late-time boundary reflections are not evident.

8.2.7 Drawdown No. 5, 5/20-26/82

Pressure buildup test No. 4 was terminated at 0728 hours, 5/20/82, when the well was opened to flow on a 32/64 choke. The ensuing 144-hour pressure drawdown test endured a relatively stable flow rate of approximately 10,800 SBBL/D water and +190 Mscf/D gas production.

The late-time profile of this longer drawdown test shows the first affirmative reflection of multiple aquifer

boundaries. The calculated aquifer permeability at earlier times again shows a low permeability value of 185 md and a corresponding negative skin effect of -6.03.

8.2.8 Buildup No. 5, 5/26-6/2/82

The previously described 144-hour drawdown test was followed by a 170.4-hour pressure buildup test beginning at 0730 hours on 5/26/82. The flow rate at shut-in of this test was 10,762 SBBL/D and the measured pressures ranged from 10,248 to 11,284 psia during the shut-in period.

The buildup profile shown by Figure 8-5 is similar to the aforementioned profile of Buildup No. 3 in regard to the late-time flattening on the left side of the plot. In view of the late-time reflection of boundaries on the previous drawdown profile, it is evident that the boundary reflections on the buildup profile are masked by a flattening effect. Two late-time linear regions are identifiable on the buildup profile and they yield apparent effective gradient permeabilities of 841 and 960 md, respectively. The corresponding skin effect and turbulent flow constant of the larger permeability value are +32.64 and 0.002242/SBBL/D, respectively.

8.2.9 Drawdown No. 7; 8, 6/2-28/82

After the 170-hour pressure buildup test described previously, the well was opened to flow at approximately 1547 hours on 6/2/82. Intermittent mechanical problems prevailed during this drawdown (No. 6) until the test was terminated on 6/9/82.

Drawdown No. 7 was started on 6/11/82 and continued till 0810 hours on 6/23/82. Mechanical problems frequently impaired continuous long term flow.

What was designated Drawdown No. 8 was begun at approximately 1026 hours, 6/23/82. The well flowed approximately 96 hours till it was shut in at 1203 hours on 6/28/82. This test is essentially a continuation of the previously designated Drawdown No. 7, but will henceforth be referred to as Drawdown Nos. 7 and 8.

The drawdown profile of this test shows a "text book", late-time reflection of aquifer boundaries on Figures 8-2 and 8-3. It is indicated to have achieved pseudosteady-state flow in the aquifer. Nonlinear regression analysis of this pseudosteady-state region yields the first rigorous calculations of aquifer volume, rock compressibility and static aquifer pressure. Regression convergence was achieved

at an initial in-place aquifer volume of 96.047 million separator barrels, a rock compressibility of 21.020×10^{-6} vol/vol/psi and a static aquifer pressure of 11,300.8 psia. This pressure value coupled with a cumulative production of 313,679 SBBL and the initial aquifer pressure of 11,447.1 psia indicates an aquifer productivity of 2144.08 barrels per psi depletion at termination of the test. A calculation of the aquifer energy indices indicates that 89.7 % of the total available energy is derived from compaction of the rock while only 10.3 % is attributable to insitu water expansion.

Again, the earlier, unsteady-state linear region of this profile indicated a reduced permeability of 117.3 md and a corresponding negative skin effect of -6.05.

8.2.10 Buildup No. 8, 6/28 - 7/6/82

The previously described drawdown test was terminated at approximately 1203 hours on 6/28/82. The ensuing 181-hour bottomhole pressure buildup test began at this time. At shut-in, the well was flowing at 9465 SBBL/D and 10,192 psia. At termination of this buildup, the pressure had increased to 11,037 psia.

The late-time upward departure region of this profile

exhibits the first affirmative reflection of aquifer boundaries during shut-in. A regression analysis of this region converged on four rectangle boundary distances of 275, 2678, 2436 and 10,272 feet from the wellbore. The first two boundaries are parallel sides on the major axis of the rectangle and the second two boundaries form parallel sides of the minor axis. These boundaries enclose a calculated initial aquifer volume of 96.127 million SBBLs.

Additional results of the regression analysis include a static aquifer pressure of 11,320.6 psia and a buildup rock compressibility of 5.768×10^{-6} vol/vol/psi. The calculated aquifer volume and static pressure compare reasonably well with the previous drawdown analysis results; however, the rock compressibility is appreciably less. This result is a first clue of the hysteretic effect of compactive and expansive forces acting during a flow - shut-in sequence.

The apparent linear region of this buildup profile prior to the boundary reflections indicates a permeability of 507 md. However, the aforementioned nonlinear regression analysis of the boundary departure region shows a higher permeability of 796 md, a skin effect of +17.89 and a turbulent flow constant of 0.002103/SBBL/D.

8.2.11 Drawdown No. 9, 7/6 - 8/27/82

The above pressure buildup test was terminated when the Hewlett-Packard instrument was removed from the well and the well was opened to flow at 1020 hours, 7/6/82. The ensuing 52-day drawdown period experienced water flow rates averaging 9353 SBBL/D and periodic short shut-in periods. The measured bottomhole pressure drawdown portion of the test began at 1808 hours, 8/26/82.

The drawdown profile of this test shows erratic behavior particularly during the latter portion of flow. The best regression results were found in a relatively short time span just before the late-time profile showed greater oscillations. Results of this analysis indicate an initial aquifer volume of 95.096 million SBBLs, a static aquifer pressure of 11,176.1 psia and a rock compressibility of 29.032×10^{-6} vol/vol/psi.

The cumulative production per psi depletion at termination of this test was 2946.6 SBBLs/psi, an increase of 803.5 SBBLs/psi when compared with the Drawdown No. 8 results. Correspondingly, the energy derived from rock compaction increased from 89.7 to 92.3 % as the aquifer pressure decreased.

8.2.12 Buildup No. 9, 8/27-30/82

Drawdown Test No. 9 was terminated at approximately 0920 hours on 8/27/82 when the ensuing 3-day shut-in pressure testing began. Final flow rate at shut-in was 9360 SBBL/D and the pressure ranged from 10,137 to 10,507 psia during shut-in.

Because the total buildup time was relatively short, acceptable regression results could only be obtained for the 3 nearest boundaries at calculated distances of 270, 2739 and 2498 feet, respectively. Calculated values of the furthest boundary and aquifer volume are 8181 feet and 82.3 million separator barrels, respectively. These values are low when compared with the analyses results of the other tests.

The calculated aquifer static pressure of 11,163.4 psia is only 12.7 psi less than the value calculated by the prior drawdown analysis. The calculated shut-in rock compressibility has increased from 5.768×10^{-6} vol/vol/psi during Buildup No. 8 to 8.598×10^{-6} vol/vol/psi due to pressure depletion.

The calculated aquifer permeability, skin effect and turbulent flow are 1023 md, +7.32 and 0.001101/SBBL/D, respectively. When compared with previous results, the skin effect and turbulent flow constant have significantly decreased.

8.2.13 Drawdown No. 10, 8/30 - 11/2/82

The Hewlett-Packard quartz pressure instrument was again removed from the well and Drawdown No. 10 was initiated on a 22/64 choke. Intermittent flow-shut-in events similar to the previous production problems delayed continuous long-term flow. During the final approximate 18 hours of drawdown, the choke was progressively changed causing the flow rates to range from 5000 to 9315 SBBL/D and average 8434 SBBL/D. In general, an erratic pressure drawdown profile was generated during this test because of choke changes and production problems.

After several regression attempts using different sets of data points, a convergence was found in a relatively small final region of the drawdown profile. Results of this analysis show an initial aquifer volume of 100.414 million separator barrels, a reduced static aquifer pressure of 11,109.2 psia and an aquifer rock compressibility of 36.305×10^{-6} vol/vol/psi. Considering 1,310,150 separator barrels produced at the end of this test and the pressure depletion leads to a water depletion index of 3877.3 bbls/psi, an increase of 929.7 bbls/psi when compared with the index calculated for Drawdown No. 9. The aquifer energy of this test is calculated to be comprised of 93.8 % rock compaction and 6.2 % water expansion.

The middle-time region of this drawdown profile indicates an effective aquifer permeability of 844.7 md and a negative skin effect of -6.23.

8.2.14 Buildup No. 10, 11/2-5/82

This 72.4-hour buildup test shows a flow rate at shut-in of 8520 SBBL/D and a pressure response increasing from 9906 to 10,210 psia at termination.

Regression analysis of the late-time region reflecting aquifer boundary effects resulted in an initial aquifer volume of 101.511 million separator barrels, a static aquifer pressure of 11,078.1 psia, a shut-in cycle compressibility of 8.916×10^{-6} vol/vol/psi and four boundary distances located at 285, 2900, 2397 and 10,049 feet from the well. The calculated static pressure compares with the pressure calculated for the companion drawdown test and the calculated boundary distances and volume compare with acceptable accuracy to the ones determined for the previous buildups.

Additional results of the analysis show an effective permeability of 993 md, a skin effect of 3.56 and turbulent flow constant of 0.001009/SBBL/D. The permeability compares with the value determined for the previous buildup test and the

skin effect and turbulent flow constant are significantly less.

8.2.15 Drawdown No. 11, 11/15/82 - 1/19/83

This 65-day flow test was started on 11/15/82 at approximately 1530 hours. As in prior tests, the producing well was shut in temporarily on 1/18/83 while the HP instrument was installed. Flow rates ranged from 3702 to 9406 SBBL/D and averaged 8346 SBBL/D during this test.

Regression analysis of the final portion of this drawdown provided 95.305 million separator barrels initially in-place, 10,964.8 psia static aquifer pressure and 38.009×10^{-6} vol/vol/psi rock compressibility. Examples of the computer output results are shown by Tables 8-5, 6; 7. Relatively small average deviations of ± 1.71 psi and ± 5609 SBBLs were computed for the regression matches of flowing pressure and cumulative production as shown by Tables 8-5 and 8-6.

At termination of this test, the production of 1,846,840 SBBLs caused the static aquifer pressure to decrease by 482.3 psi resulting in a depletion index of 3829.2 SBBLs/psi. This index compares closely with computed index of 3877.3 SBBLs/psi for the previous drawdown test. The rock compressibility of this drawdown increased by a relatively smaller amount.

TABLE 8-5

DRAWDOWN TEST NO. 11
 11/15/82-1/19/83
 DOW/DOE NO. 1 L. R. SWEETZ WELL
 CIB JEFF SAND
 PARCERDUE PROJECT
 VERMILION PARISH, LOUISIANA

DATA FILE: DD11
 WASP FILE: BDD11

AQUIFER PERFORMANCE HISTORY ANALYSIS

FLOW DATA AS OF 01/19/83
 NO INFLUX

AVG. DEV., CALC. VS MEAS. PRES. PSI - - - - -	1.7062974
AVG. DEV., CALC. VS MEAS. CUM. WATER, BBLS - - -	5608.6928
INITIAL WATER IN-PLACE, BARRELS - - - - -	95305033.
ROCK COMPRESSIBILITY, V/MMV/PSI - - - - -	38.008948
M(PW) CORRECTION CONSTANT, PSI/BARREL - - - - -	0.3104411

AQUIFER INPUT DATA

INITIAL AQUIFER PRESSURE, PSIG - - - - -	11432.075
AQUIFER TEMPERATURE, DEG. F - - - - -	237.00000
AVERAGE ATMOSPHERIC PRESSURE, PSIA - - - - -	15.025000
INITIAL PERMEABILITY, MD - - - - -	875.21000
INITIAL POROSITY, PERCENT - - - - -	29.450000
INITIAL ROCK COMPRESSIBILITY, VOL/MMVOL/PSI - -	3.8860000

TABLE 8-6

DRAWDOWN TEST NO. 11
 11/15/82-1/19/83
 DOW/DOE NO. 1 L. R. SWEETZ WELL
 CIB JEFF SAND
 PARCERDUE PROJECT
 VERMILION PARISH, LOUISIANA

DATA FILE: DD11
 WASP FILE: BDD11

OBSERVED PRODUCTION HISTORY AND CALCULATED MATCHES

PROD. BEGAN 04/26/82 HRS. 17.657

DATE MO/DA/YR	TIME OF DAY HOURS	TEST RATES			CUM. WATER PROD., BBLs.			CALC'D WATER N PLACE MMBBLs	BOTTOM HOLE FLOW PRES., PSIG.			AVERAGE AQUIFER PRESS. PSIG.
		GAS MCF/D	COND. BBL/D	WATER BBL/D	MEASURED	CALC'D	DIFF.		MEAS'D	CALC'D	DIFF.	
01/18/83	15.267	THIS POINT DELETED										
01/18/83	15.767	THIS POINT DELETED										
01/18/83	16.267	THIS POINT DELETED										
01/18/83	16.767	THIS POINT DELETED										
01/18/83	17.267	THIS POINT DELETED										
01/18/83	17.767	THIS POINT DELETED										
01/18/83	18.267	THIS POINT DELETED										
01/18/83	18.767	THIS POINT DELETED										
01/18/83	19.267	THIS POINT DELETED										
01/18/83	19.767	THIS POINT DELETED										
01/18/83	20.267	THIS POINT DELETED										
01/18/83	20.767	THIS POINT DELETED										
01/18/83	21.267	THIS POINT DELETED										
01/18/83	21.767	THIS POINT DELETED										
01/18/83	22.267	THIS POINT DELETED										
01/18/83	22.767	THIS POINT DELETED										
01/18/83	23.267	THIS POINT DELETED										
01/18/83	23.767	THIS POINT DELETED										
01/19/83	0.517	THIS POINT DELETED										
01/19/83	1.517	124.6	0.0	8322.0	1852750.	1852364.	386.	95.	9626.8	9626.7	0.1	10950.5
01/19/83	2.517	124.6	0.0	8322.0	1853097.	1852364.	733.	95.	9626.8	9626.6	0.2	10950.5
01/19/83	3.517	125.2	0.0	8344.0	1853444.	1843973.	9471.	95.	9625.6	9622.7	2.9	10950.4
01/19/83	4.517	125.2	0.0	8344.0	1853792.	1845715.	8077.	95.	9625.0	9622.6	2.5	10950.3
01/19/83	5.317	125.2	0.0	8344.0	1854070.	1846340.	7730.	95.	9624.9	9622.5	2.4	10950.2
01/19/83	6.317	125.0	0.0	8331.0	1854417.	1861663.	-7246.	95.	9622.4	9624.6	-2.2	10950.1
01/19/83	7.317	125.0	0.0	8331.0	1854764.	1856304.	-1540.	95.	9624.1	9624.5	-0.5	10950.0
01/19/83	8.317	125.0	0.0	8331.0	1855111.	1858310.	-3198.	95.	9623.5	9624.4	-1.0	10949.9
01/19/83	9.017	125.0	0.0	8331.0	1855354.	1859000.	-3646.	95.	9623.2	9624.4	-1.1	10949.9
01/19/83	9.517	125.0	0.0	8331.0	1855528.	1860118.	-4590.	95.	9622.9	9624.3	-1.4	10949.8
01/19/83	9.583	125.0	0.0	8331.0	1855551.	1861137.	-5586.	95.	9622.6	9624.3	-1.7	10949.8

TABLE 8-6

DRAWDOWN TEST NO. 11
 11/15/82-1/19/83
 DOW/DOE NO. 1 L. R. SWEETZ WELL
 CIB JEFF SAND
 PARCERDUE PROJECT
 VERMILION PARISH, LOUISIANA

DATA FILE: DD11
 WASP FILE: BDD11

CALCULATED AQUIFER ENERGY INDICES

DATE	TIME OF DAY	WATER EXPANSION	ROCK COMPACTION	VERTICAL INFLUX	PERIPHERIAL INFLUX	SUM INDICES
01/18/83	15. 267	THIS POINT DELETED				
01/18/83	15. 767	THIS POINT DELETED				
01/18/83	16. 267	THIS POINT DELETED				
01/18/83	16. 767	THIS POINT DELETED				
01/18/83	17. 267	THIS POINT DELETED				
01/18/83	17. 767	THIS POINT DELETED				
01/18/83	18. 267	THIS POINT DELETED				
01/18/83	18. 767	THIS POINT DELETED				
01/18/83	19. 267	THIS POINT DELETED				
01/18/83	19. 767	THIS POINT DELETED				
01/18/83	20. 267	THIS POINT DELETED				
01/18/83	20. 767	THIS POINT DELETED				
01/18/83	21. 267	THIS POINT DELETED				
01/18/83	21. 767	THIS POINT DELETED				
01/18/83	22. 267	THIS POINT DELETED				
01/18/83	22. 767	THIS POINT DELETED				
01/18/83	23. 267	THIS POINT DELETED				
01/18/83	23. 767	THIS POINT DELETED				
01/19/83	0. 517	THIS POINT DELETED				
01/19/83	1. 517	. 05961	. 94039	. 00000	. 00000	1. 00000
01/19/83	2. 517	. 05961	. 94039	. 00000	. 00000	1. 00000
01/19/83	3. 517	. 05961	. 94039	. 00000	. 00000	1. 00000
01/19/83	4. 517	. 05961	. 94039	. 00000	. 00000	1. 00000
01/19/83	5. 317	. 05961	. 94039	. 00000	. 00000	1. 00000
01/19/83	6. 317	. 05961	. 94039	. 00000	. 00000	1. 00000
01/19/83	7. 317	. 05961	. 94039	. 00000	. 00000	1. 00000
01/19/83	8. 317	. 05961	. 94039	. 00000	. 00000	1. 00000
01/19/83	9. 017	. 05962	. 94038	. 00000	. 00000	1. 00000
01/19/83	9. 517	. 05962	. 94038	. 00000	. 00000	1. 00000
01/19/83	9. 583	. 05962	. 94038	. 00000	. 00000	1. 00000

Aquifer energies as summarized by Table 8-7 are evaluated to be 94 % rock compaction and 6 % water expansion, respectively, about the same as determined for Drawdown No. 10.

8.2.16 Buildup No. 11, 1/19-22/83

Drawdown No. 11 was terminated at about 0935 hours on 1/19/83 and followed by a 72-hour buildup test. The flow rate at shut-in was 8334 SBBL/D and the pressures ranged from 9638 to 9892 psia during this shut-in.

Nonlinear regression analysis of the late-time boundary reflection region of this profile shows an initial aquifer volume of 95.974 million separator barrels, a static aquifer pressure of 10,988.9 psia, a shut-in rock compressibility of 11.299×10^{-6} vol/vol/psi and aquifer boundary distances at 265, 2642, 2281 and 10,605 feet, respectively. Table 8-8 is an example output summarizing the regression analysis results and Table 8-9 presents a comparison of calculated and measured pressure data after converting the calculated potential function to pressure. With exception to the pressure variant rock compressibility, these results are comparable with the results obtained from analyses of Buildup Nos. 8-10.

Additionally, a comparable aquifer permeability of 1090

TABLE 8-8

BUILDUP TEST 11 OF 1/19 - 23/83
 DOW/DOE GEOPRESSURE - GEOTHERMAL TEST
 L. R. SWEETZ NO. 1 WELL
 PERFS: 13342 - 13406 FEET
 PARC PERDUE FIELD
 VERMILION PARISH, LA.

DATA FILE: M-B11
 WASP FILE: BF-B11B

REGRESSION ANALYSIS RESULTS GEOPRESSURED AQUIFER

AVG. DEVIATION BETWEEN MEAS. & CALC. PRESSURES, PSI	- -	0.32
INITIAL WATER PERMEABILITY, MD	- - - -	1090.185
APPARENT SKIN EFFECT, DIMENSIONLESS	- - - -	3.72
TURBULENT FLOW CONSTANT, 1/SPBPD	- - - - -	0.000727127
INITIAL PRESSURE OR P*, PSIA:		
AT GAUGE DATUM	- - - - -	11447.10
AT RESERVOIR DATUM	- - - - -	11447.10
SLOPE CONSTANT, 141.268/KI*H	- - - - -	0.0025916
AVG. HYDRAULIC DIFFUSIVITY, MD-PSI/CP	- - - -	616453136.13
AVG. ROCK COMPRESSIBILITY, V/V/MMPSI	- - - -	13.819
AQUIFER AREA INVESTIGATED, ACRES	- - -	860.22
AQUIFER THICKNESS, FT.	- - - - -	50.0
CLOSED RECTANGLE BOUNDARY DISTANCES FROM OBS WELL:		
D1, NO FLOW BOUNDARY, FT.	- - - - -	265.4
D2, NO FLOW BOUNDARY, FT.	- - - - -	2642.5
D3, NO FLOW BOUNDARY, FT.	- - - - -	2281.1
D4, NO FLOW BOUNDARY, FT.	- - - - -	10605.0
VOLUMES OF WATER INITIALLY IN-PLACE:		
SBBL PER ACRE-FOOT	- - - - -	2231.40
TOTAL MMBBLS	- - - - -	95.974
STATIC AQUIFER PRESSURE AT TEST DATE, PSIA	- - - -	10988.85

BUILDUP TEST 11 OF 1/19 - 23/83
 DOW/DOE GEOPRESSURE - GEOTHERMAL TEST
 L. R. SWEETZ NO. 1 WELL
 PERFS: 13342 - 13406 FEET
 PARC PERDUE FIELD
 VERMILION PARISH, LA.

DATA FILE: M-B11
 WASP FILE: BF-B11B

PRESSURE HISTORY MATCH

POINT NO.	TIME HOURS	MEAS. PRES. PSIA.	CALC. PRES. PSIA.	DIFFERENCE PSI.
1	5580.343	0.000	9983.544	0.000
2	5604.343	0.000	9993.196	0.000
3	5628.343	0.000	9895.394	0.000
4	6204.343	0.000	9654.564	0.000
5	6376.759	0.000	9647.515	0.000
6	6380.759	0.000	9867.147	0.000
7	6398.593	0.000	9646.438	0.000
8	6403.993	0.000	9866.731	0.000
9	6423.929	9637.620	9637.622	-0.002
10	6423.931	0.000	9807.151	0.000
11	6423.932	0.000	9808.334	0.000
12	6423.957	0.000	9821.493	0.000
13	6424.026	0.000	9828.674	0.000
14	6424.097	0.000	9831.993	0.000
15	6424.176	0.000	9834.508	0.000
16	6424.276	0.000	9836.925	0.000
17	6424.459	0.000	9840.258	0.000
18	6424.643	0.000	9842.799	0.000
19	6425.043	0.000	9846.875	0.000
20	6425.376	0.000	9849.390	0.000
21	6425.726	0.000	9851.506	0.000
22	6426.076	0.000	9853.275	0.000
23	6426.343	0.000	9854.435	0.000
24	6426.843	0.000	9856.309	0.000
25	6427.343	0.000	9857.876	0.000
26	6427.843	0.000	9859.210	0.000
27	6428.343	0.000	9860.408	0.000
28	6428.843	0.000	9861.442	0.000
29	6429.593	0.000	9862.763	0.000
30	6430.093	0.000	9863.575	0.000
31	6430.593	0.000	9864.298	0.000
32	6431.093	0.000	9864.950	0.000
33	6431.593	0.000	9865.548	0.000
34	6432.093	0.000	9866.108	0.000
35	6432.593	0.000	9866.645	0.000
36	6433.093	0.000	9867.132	0.000
37	6433.593	0.000	9867.579	0.000
38	6434.093	0.000	9867.994	0.000
39	6434.843	0.000	9868.619	0.000
40	6435.343	0.000	9869.010	0.000
41	6435.843	0.000	9869.401	0.000
42	6436.343	0.000	9869.805	0.000
43	6436.843	0.000	9870.181	0.000
44	6437.343	0.000	9870.532	0.000

TABLE 8-9
(CONTINUED)

BUILDUP TEST 11 OF 1/19 - 23/83
DOW/DOE GEOPRESSURE - GEOTHERMAL TEST
L. R. SWEETZ NO. 1 WELL
PERFS: 13342 - 13406 FEET
PARC PERDUE FIELD
VERMILION PARISH, LA.

DATA FILE: M-B11
WASP FILE: BF-B11B

PRESSURE HISTORY MATCH

POINT NO.	TIME HOURS	MEAS. PRES. PSIA.	CALC. PRES. PSIA.	DIFFERENCE PSI.
45	6437.843	0.000	9870.863	0.000
46	6438.343	0.000	9871.175	0.000
47	6438.843	0.000	9871.472	0.000
48	6439.343	0.000	9871.755	0.000
49	6440.093	0.000	9872.121	0.000
50	6440.593	9872.580	9872.348	0.232
51	6441.093	9872.850	9872.590	0.260
52	6441.593	9873.160	9872.854	0.306
53	6442.093	9873.410	9873.108	0.302
54	6442.593	9873.660	9873.352	0.308
55	6443.093	9873.900	9873.586	0.314
56	6443.593	9874.120	9873.813	0.307
57	6444.093	9874.330	9874.034	0.296
58	6444.843	9874.690	9874.354	0.336
59	6445.343	9874.820	9874.562	0.258
60	6446.343	9875.250	9874.968	0.282
61	6447.343	9875.580	9875.366	0.214
62	6448.343	9875.940	9875.759	0.181
63	6449.343	9876.320	9876.216	0.104
64	6450.343	9876.690	9876.689	0.001
65	6451.343	9877.060	9877.191	-0.131
66	6452.843	9877.600	9877.953	-0.353
67	6453.843	9877.960	9878.428	-0.468
68	6454.843	9878.240	9878.878	-0.638
69	6455.843	9878.670	9879.233	-0.563
70	6456.843	9878.970	9879.533	-0.563
71	6457.843	9879.340	9879.829	-0.489
72	6458.843	9879.750	9880.124	-0.374
73	6459.843	9880.050	9880.446	-0.396
74	6460.843	9880.400	9880.804	-0.404
75	6462.343	9880.920	9881.320	-0.400
76	6463.343	9881.240	9881.651	-0.411
77	6464.343	9881.590	9881.972	-0.382
78	6465.343	9881.920	9882.285	-0.364
79	6466.343	9882.310	9882.590	-0.280
80	6467.343	9882.640	9882.890	-0.250
81	6468.343	9882.990	9883.184	-0.194
82	6469.376	9883.340	9883.483	-0.143
83	6470.876	9883.900	9883.912	-0.012
84	6471.843	9884.220	9884.185	0.035
85	6472.843	9884.550	9884.465	0.085
86	6473.843	9884.860	9884.797	0.063
87	6474.843	9885.180	9885.127	0.053
88	6475.909	9885.510	9885.509	0.001

TABLE 8-9
(CONTINUED)

BUILDUP TEST 11 OF 1/19 - 23/83
DOW/DOE GEOPRESSURE - GEOTHERMAL TEST
L. R. SWEETZ NO. 1 WELL
PERFS: 13342 - 13406 FEET
PARC PERDUE FIELD
VERMILION PARISH, LA.

DATA FILE: M-B11
WASP FILE: BF-B11B

PRESSURE HISTORY MATCH

POINT NO.	TIME HOURS	MEAS. PRES. PSIA.	CALC. PRES. PSIA.	DIFFERENCE PSI.
89	6476.859	9885.830	9885.864	-0.034
90	6477.843	9886.150	9886.219	-0.069
91	6478.893	9886.520	9886.548	-0.028
92	6480.343	9887.050	9886.951	0.099
93	6481.843	9887.510	9887.352	0.158
94	6483.343	9887.950	9887.738	0.212
95	6485.343	9888.480	9888.302	0.178
96	6487.343	9889.040	9888.886	0.154
97	6489.343	9889.580	9889.377	0.203
98	6491.343	9890.130	9889.804	0.326
99	6493.343	9890.760	9890.223	0.537
100	6496.343	9891.640	9890.842	0.798

md, a skin effect of 3.72 and a turbulent flow constant of 0.000727/SBBL/D are also indicated.

8.3 Results and Conclusions

A meaningful aquifer description has been obtained from analyses of the late-time drawdown and buildup behaviors after sufficient flow time was achieved for all aquifer boundaries to influence the pressure response at the well. Other analyses results such as permeability, skin effect and turbulent flow constant obtained from linear profile trends at earlier test times appear to be influenced by the propagation of rock compaction. This early-time transient nature of rock compaction coupled with its relatively large magnitude causes a gradient permeability to develop around the wellbore. The region of reduced permeability prior to stabilization of the pressure responses significantly reduces the flow efficiency of aquifer fluids into the wellbore.

The analyses results discussed for each test in Section 8.2 are summarized by Table 8-10. Certain results and aspects of the analyses are discussed in the following sections.

8.3.1 Boundaries

The average calculated boundary distances of the

TABLE 8-10

SUMMARY OF DRAWDOWN AND BUILDUP ANALYSES
DOW/DOE NO. 1 L. R. SWEETZ WELL

TEST TYPE; NO.	S _y (±psi)	S _y (±B)	k(p _i) (md)	s (-)	D (1/SBPD)	W (MMB)	$\bar{p}$ (psia)	C _f (v/v/MMpsi)	D ₁ (ft)	D ₂ (ft)	D ₃ (ft)	D ₄ (ft)
BU2	0.73	-	402.6	2.25	0.000447	-	-	-	-	-	-	-
	0.09	-	758.4	8.36	0.000968	-	-	-	-	-	-	-
DD3	0.70	-	195.4	-6.18	0.000000	-	-	-	-	-	-	-
BU3	0.03	-	746.0	16.25	0.002039	-	-	-	-	-	-	-
	0.06	-	1477.1	34.50	0.004923	-	-	-	-	-	-	-
DD4	1.20	-	174.2	-6.08	0.000000	-	-	-	-	-	-	-
BU4	0.32	-	341.1	-4.05	0.001782	-	-	-	-	-	-	-
	0.05	-	669.7	12.09	0.002003	-	-	-	-	-	-	-
DD5	3.36	-	185.0	-6.03	0.000000	-	-	-	-	-	-	-
BU5	0.01	-	840.5	30.52	0.001689	-	-	-	-	-	-	-
	0.04	-	959.8	32.64	0.002242	-	-	-	-	-	-	-
DD7&8	0.42	-	117.3	-6.05	0.000000	-	-	-	-	-	-	-
	3.57	7040	-	-	-	96.047	11300.8	21.020	-	-	-	-
BU8	0.17	-	264.5	0.74	0.000762	-	-	-	-	-	-	-
	0.05	-	507.0	10.49	0.001218	-	-	-	-	-	-	-
	1.27	-	796.4	17.89	0.002103	96.127	11320.6	5.768	275	2678	2436	10272
DD9	2.30	-	379.7	-8.75	0.000000	-	-	-	-	-	-	-
	3.64	9645	-	-	-	95.096	11176.1	29.032	-	-	-	-
BU9	0.03	-	857.1	7.14	0.000760	-	-	-	-	-	-	-
	0.10	-	1410.4	15.18	0.001483	-	-	-	-	-	-	-
	0.38	-	1022.7	7.32	0.001101	82.300	11163.4	8.598	270	2739	2498	8181
DD10	0.95	-	844.7	-6.23	0.000000	-	-	-	-	-	-	-
	0.82	2764	-	-	-	100.414	11109.2	36.305	-	-	-	-
BU10	0.09	-	398.3	-1.55	0.000466	-	-	-	-	-	-	-
	0.32	-	1204.3	6.68	0.001314	-	-	-	-	-	-	-
	0.52	-	993.2	3.56	0.001009	101.511	11078.1	8.916	285	2900	2397	10049
DD11	0.08	-	652.7	-6.06	0.000000	-	-	-	-	-	-	-
	1.71	5609	-	-	-	95.305	10964.8	38.009	-	-	-	-
BU11	0.03	-	669.1	-0.77	0.000497	-	-	-	-	-	-	-
	0.11	-	1368.2	6.64	0.001095	-	-	-	-	-	-	-
	0.32	-	1090.2	3.72	0.000727	95.974	10988.9	11.299	265	2642	2281	10605

TABLE 8-10

approximate rectangle aquifer shape are 274, 2740, 2403 and 10,309 feet, respectively, from the wellbore. These boundaries enclosed an aquifer area of approximately 880 acres in an elongated rectangle shape. A reasonable comparison of this shape with the geologic results is shown as superposed on the structure map of Figure 8-6. It is possible that part of the closing geologic fault shown in Section 34 on this map is nonsealing due to sand thickening and a relatively small fault throw.

8.3.2 Permeability

The average effective permeability to water computed at initial aquifer pressure for the last three late-time buildup analyses is 1037 md based on an average aquifer thickness of 50 feet. Core analysis data discussed in Section 8.1.3 calculates an initial permeability of 875 md; however, it is well to keep in mind that the core data relative to buildup analyses is only a statistical "pinpoint" and it should not be expected to yield comparable permeability values unless the aquifer is ideally homogeneous.

8.3.3 Skin Effect and Turbulent Flow

The calculated skin effect appeared to increase from 3.56

to 3.72 during the last two buildup tests while the turbulent flow constant decreased from 0.001009 to 0.000727/SBBL/D. Comparisons with analysis results of earlier tests indicate that significant decreases in skin effect and turbulent flow constant occurred as the aquifer was produced. It is suspected that unsteady-state rock compaction at earlier times caused a significant gradient permeability reduction in the vicinity of the wellbore and a corresponding loss in flow efficiency. This is implied by the analyses results of test Nos. 2-8.

Converting the skin effect and turbulent flow values calculated for Buildup No. 11 to equivalent pressure drops gives 45 and 73 psi, respectively. Thus, for a total pressure drawdown of 1327 psi (10,965-9638) incurred by Drawdown Test No. 11, only 3.4 % is due to the skin effect of permeability reduction around the wellbore and 5.5 % is attributable to the increased water velocity as it approaches the wellbore. Earlier in the discussion of Buildup No. 2, Section 8.2.2, it was found that 62.3 % of the total pressure drawdown was caused by skin effect and turbulent flow.

It appears that the flow efficiency of the aquifer system improved after the propagation of pore volume relaxation and permeability reduction became stabilized. Other factors such as the gravel pack and/or perforation cleanup with flow time could also have caused the observed improvement in flow efficiency.

8.3.4 Rock Compressibility

In magnanimous fashion, the primary energy drive mechanism of this geopressured aquifer is derived from rock compaction. Ultimately, it contributes about 94 % of the total available subsurface energy to expulse water. The rock compressibility values derived from analyses of the drawdown and buildup tests exhibit the typical hysteretic envelope as plotted on Figure 8-7. For comparison purposes, the unloading rock compressibility curve obtained from special core analyses, Section 6.5, is also shown on this plot. The rock compressibilities obtained from core data did not adequately describe the rock compaction process during flow or shut-in.

As shown by Table 8-10 and Figure 8-7, the rock compressibility of the pressure depletion cycle increases from an initial extrapolated value of about 2.4×10^{-6} vol/vol/psi at 11,447.1 psia to a calculated value of 38.009×10^{-6} vol/vol/psi at 10,964.8 psia static reservoir pressure. This rapid increase in rock compressibility to relatively large values appears reasonable. For comparison purposes Hammerlindl's⁽¹⁾ reservoir engineering study of the North

(1) Hammerlindl, D. J.: "Predicting Gas Reserves in a Abnormally Pressured Reservoir", SPE 3850, presented at the Abnormal Subsurface Pore Pressure Meeting, Baton Rouge, Louisiana, 1972.

FIGURE 8-7

ROCK COMPRESSIBILITY VS. STATIC AQUIFER PRESSURE

DOW/DOE PARC PERDUE PROJECT
L.R. SNEEZY NO.1 WELL

FIGURE 8-7

Ossum field, in Lafayette Parish, Louisiana shows a rock compressibility increasing from an initial value of about 7.9×10^{-6} to a maximum value of 32×10^{-6} vol/vol/psi as the static reservoir pressure decreases from 8921 to approximately 8000 psia. It is also interesting to note from this study that the rock compressibility decreases after the aforementioned peak value to 6×10^{-6} vol/vol/psi at the normal hydrostatic gradient pressure of approximately 5600 psia and remains essentially constant thereafter.

8.3.5 Initial Water In-Place

The calculated water initially contained in the aquifer ranges from 95.096 to 101.511 million separator barrels and averages approximately 97.211 million separator barrels within the aforementioned area of 880 acres. When based on an estimated average aquifer thickness of 50 feet, the average water volume initially in-place is 2209 separator barrels per acre-foot.

8.3.6 AOF, PI and Depletion Performance

The drawdown and buildup analyses of test Nos. 7-8, 9, 10 and 11 furnished certain results which are translated into graphical representations of absolute open flow (AOF), productivity index (PI) and depletion performance as shown by Figures 8-8,9 and 10, respectively. A stabilized AOF of 40,083

FIGURE 8-8

ABSOLUTE OPEN FLOW POTENTIAL PLOT

DOE/DOW PARC PERDUE PROJECT
L.R. SWEETZ NO. 1 WELLD7-8, AOF=34120 SBBL/D --- Δ x --- D11, AOF=40083 SBBL/D

FIGURE 8-8

FIGURE 8-9

FIGURE 8-9

FIGURE 8-10

DEPLETION INDEX PLOT

DOE/DOW PARC PERDUE PROJECT
L.R. SWEETZ NO. 1 WELL

FIGURE 8-10

SBBL/D is indicated in the presence of turbulent flow in the aquifer as of 1/19/83. The undersaturated productivity index is truly linear on Figure 8-9 and it shows a PI of 6.2794 barrels per day per psi drawdown at termination of testing. The depletion performance of Figure 8-10 exhibits an essentially constant value of approximately 3853 barrels cumulative per psi depletion after approximate steady state flow conditions were achieved in the aquifer.

8.3.7 Additional Energy Mechanisms

The existence of possible additional energy mechanisms in the aquifer were also investigated using Drawdown No. 11 data. Results of the investigation show that no significant additional aquifer energy was available from vertical or lateral fluid influx.

Relatively small volumes of fluid influx resulting from shale and tight rock compaction appear to be possible. A case study wherein a shale dewatering process occurs is summarized by Tables 8-11, 12 and 13. The regression fit of this data is no better than the aforementioned ones of Tables 8-5, 6 and 11, the case without energy influx. The calculated shale water influx constant shown by Table 8-11 is only 22.2585+ SBBL/psi as compared with the total depletion performance index of

DRAWDOWN TEST NO. 11
 11/15/82-1/19/83
 DOW/DOE NO. 1 L. R. SWEETZ WELL
 CIB JEFF SAND
 PARCERDUE PROJECT
 VERMILION PARISH, LOUISIANA

DATA FILE: DD11
 WASP FILE: BDD11

AQUIFER PERFORMANCE HISTORY ANALYSIS

FLOW DATA AS OF 01/19/83
 SHALE WATER INFLUX

AVG. DEV., CALC. VS MEAS. PRES. PSI - - - - -	1.7061048
AVG. DEV., CALC. VS MEAS. CUM. WATER, BBLs - - -	5606.6053
INITIAL WATER IN-PLACE, BARRELS - - - - -	94537161.
ROCK COMPRESSIBILITY, V/MMV/PSI - - - - -	38.096765
M(PW) CORRECTION CONSTANT, PSI/BARREL - - - - -	0.3104081
VERTICAL INFLUX CONSTANT, BBL/PSI - - - - -	22.258533

AQUIFER INPUT DATA

INITIAL AQUIFER PRESSURE, PSIG - - - - -	11432.075
AQUIFER TEMPERATURE, DEG. F - - - - -	237.00000
AVERAGE ATMOSPHERIC PRESSURE, PSIA - - - - -	15.025000
INITIAL PERMEABILITY, MD - - - - -	875.21000
INITIAL POROSITY, PERCENT - - - - -	29.450000
INITIAL ROCK COMPRESSIBILITY, VOL/MMVOL/PSI - -	3.8860000

TABLE 8-12

DRAWDOWN TEST NO. 11
 11/15/82-1/19/83
 DOW/DOE NO. 1 L. R. SWEETZ WELL
 CIB JEFF SAND
 PARCERDUE PROJECT
 VERMILION PARISH, LOUISIANA

DATA FILE: DD11
 WASP FILE: BDD11

OBSERVED PRODUCTION HISTORY AND CALCULATED MATCHES

PROD. BEGAN 04/26/82 HRS. 17.657

DATE MO/DA/YR	TIME OF DAY HOURS	TEST RATES			CUM. WATER PROD., BBLs.			CALC'D WATER N PLACE MMBBLs	BOTTOM HOLE			AVERAGE AQUIFER PRESS. PSIG.	VERTICAL WATER INFLUX BBL.
		GAS MCF/D	COND. BBL/D	WATER BBL/D	MEASURED	CALC'D	DIFF.		FLOW	PRES., PSIG.			
										MEAS'D	CALC'D	DIFF.	
01/18/83	15.267	THIS POINT DELETED											
01/18/83	15.767	THIS POINT DELETED											
01/18/83	16.267	THIS POINT DELETED											
01/18/83	16.767	THIS POINT DELETED											
01/18/83	17.267	THIS POINT DELETED											
01/18/83	17.767	THIS POINT DELETED											
01/18/83	18.267	THIS POINT DELETED											
01/18/83	18.767	THIS POINT DELETED											
01/18/83	19.267	THIS POINT DELETED											
01/18/83	19.767	THIS POINT DELETED											
01/18/83	20.267	THIS POINT DELETED											
01/18/83	20.767	THIS POINT DELETED											
01/18/83	21.267	THIS POINT DELETED											
01/18/83	21.767	THIS POINT DELETED											
01/18/83	22.267	THIS POINT DELETED											
01/18/83	22.767	THIS POINT DELETED											
01/18/83	23.267	THIS POINT DELETED											
01/18/83	23.767	THIS POINT DELETED											
01/19/83	0.517	THIS POINT DELETED											
01/19/83	1.517	124.6	0.0	8322.0	1852750.	1852385.	364.	95.	9626.8	9626.7	0.1	10950.4	10720
01/19/83	2.517	124.6	0.0	8322.0	1853097.	1852385.	711.	95.	9626.8	9626.6	0.2	10750.3	10722
01/19/83	3.517	125.2	0.0	8344.0	1853444.	1843999.	9446.	95.	9625.6	9622.7	2.9	10750.2	10724
01/19/83	4.517	125.2	0.0	8344.0	1853792.	1845740.	8052.	95.	9625.0	9622.6	2.5	10950.1	10726
01/19/83	5.317	125.2	0.0	8344.0	1854070.	1846364.	7706.	95.	9624.9	9622.5	2.3	10950.1	10728
01/19/83	6.317	125.0	0.0	8331.0	1854417.	1861683.	-7266.	95.	9622.4	9624.6	-2.2	10950.0	10730
01/19/83	7.317	125.0	0.0	8331.0	1854764.	1856326.	-1561.	95.	9624.1	9624.5	-0.5	10949.9	10732
01/19/83	8.317	125.0	0.0	8331.0	1855111.	1858330.	-3219.	95.	9623.5	9624.4	-1.0	10949.8	10734
01/19/83	9.017	125.0	0.0	8331.0	1855354.	1859021.	-3666.	95.	9623.2	9624.4	-1.1	10949.7	10736
01/19/83	9.517	125.0	0.0	8331.0	1855528.	1860138.	-4610.	95.	9622.9	9624.3	-1.4	10949.7	10737
01/19/83	9.583	125.0	0.0	8331.0	1855551.	1861157.	-5606.	95.	9622.6	9624.3	-1.7	10949.7	10737

TABLE 8-12

DRAWDOWN TEST NO. 11
 11/15/82-1/19/83
 DOW/DOE NO. 1 L. R. SWEETZ WELL
 CIB JEFF SAND
 PARCERDUE PROJECT
 VERMILION PARISH, LOUISIANA

DATA FILE: DD11
 WASP FILE: BDD11

CALCULATED AQUIFER ENERGY INDICES

DATE	TIME OF DAY	WATER EXPANSION	ROCK COMPACTION	VERTICAL INFLUX	PERIPHERIAL INFLUX	SUM INDICES
01/18/83	15. 267	THIS POINT	DELETED			
01/18/83	15. 767	THIS POINT	DELETED			
01/18/83	16. 267	THIS POINT	DELETED			
01/18/83	16. 767	THIS POINT	DELETED			
01/18/83	17. 267	THIS POINT	DELETED			
01/18/83	17. 767	THIS POINT	DELETED			
01/18/83	18. 267	THIS POINT	DELETED			
01/18/83	18. 767	THIS POINT	DELETED			
01/18/83	19. 267	THIS POINT	DELETED			
01/18/83	19. 767	THIS POINT	DELETED			
01/18/83	20. 267	THIS POINT	DELETED			
01/18/83	20. 767	THIS POINT	DELETED			
01/18/83	21. 267	THIS POINT	DELETED			
01/18/83	21. 767	THIS POINT	DELETED			
01/18/83	22. 267	THIS POINT	DELETED			
01/18/83	22. 767	THIS POINT	DELETED			
01/18/83	23. 267	THIS POINT	DELETED			
01/18/83	23. 767	THIS POINT	DELETED			
01/19/83	0. 517	THIS POINT	DELETED			
01/19/83	1. 517	. 05915	. 93521	. 00564	. 00000	1. 00000
01/19/83	2. 517	. 05915	. 93521	. 00564	. 00000	1. 00000
01/19/83	3. 517	. 05915	. 93521	. 00564	. 00000	1. 00000
01/19/83	4. 517	. 05915	. 93521	. 00564	. 00000	1. 00000
01/19/83	5. 317	. 05915	. 93521	. 00564	. 00000	1. 00000
01/19/83	6. 317	. 05915	. 93521	. 00564	. 00000	1. 00000
01/19/83	7. 317	. 05915	. 93521	. 00564	. 00000	1. 00000
01/19/83	8. 317	. 05915	. 93520	. 00564	. 00000	1. 00000
01/19/83	9. 017	. 05915	. 93520	. 00564	. 00000	1. 00000
01/19/83	9. 517	. 05915	. 93520	. 00564	. 00000	1. 00000
01/19/83	9. 583	. 05915	. 93520	. 00564	. 00000	1. 00000

3829-3877 SBBL/psi. The corresponding shale water influx volume is evaluated to have been only 10,737 BBLS at termination of the drawdown as shown on Table 8-12. Energy wise this shale water influx amounts to only 0.564 % of the available energy shown on Table 8-13.

The other case study comprises a finite linear influx problem wherein additional energy is derived from a more remote source such as peripheral shale and rock compaction or a leaky fault. Results of this case are summarized by Tables 8-14, 15 and 16. The statistical diagnostic shown by Table 8-14 for the average deviation between calculated and measured water production is a little better than the ones obtained for the aforementioned cases but not significantly on a percentage basis. A relatively low influx constant of 184.23+ BBLS/psi is also computed for this case and the last influx volume of 86,658 barrels shown by Table 8-15 is insignificant when compared with a cumulative production of 1,855,551 barrels. Table 8-16 shows a corresponding 4.556 % of the total energy attributable to lateral or peripheral influx.

8.3.8 Predicted Recovery

The aquifer performance was predicted based on the Drawdown No. 11 analysis results without additional energy

DRAWDOWN TEST NO. 11
 11/15/82-1/19/83
 DOW/DOE NO. 1 L. R. SWEETZ WELL
 CIB JEFF SAND
 PARCERDUE PROJECT
 VERMILION PARISH, LOUISIANA

DATA FILE: DD11
 WASP FILE: BDD11

PAGE:

AQUIFER PERFORMANCE HISTORY ANALYSIS

FLOW DATA AS OF 01/19/83
 FINITE LINEAR SHALE WATER INFLUX

AVG. DEV., CALC. VS MEAS. PRES. PSI - - - - -	1.7662135
AVG. DEV., CALC. VS MEAS. CUM. WATER, BBLS - - -	5521.7074
INITIAL WATER IN-PLACE, BARRELS - - - - -	87378787.
ROCK COMPRESSIBILITY, V/MMV/PSI - - - - -	39.515956
M(PW) CORRECTION CONSTANT, PSI/BARREL - - - - -	0.3099831
PERIPHERIAL INFLUX CONSTANT, BBLS/PSI - - - - -	184.23782
PERIPHERIAL DIFFUSION CONSTANT, K/(PHI*U*C*L*L) -	260.61171
AQUIFER PRESSURE CORRECTION CONSTANT, PSI/BBL -	0.0000000

AQUIFER INPUT DATA

INITIAL AQUIFER PRESSURE, PSIG - - - - -	11432.075
AQUIFER TEMPERATURE, DEG. F - - - - -	237.00000
AVERAGE ATMOSPHERIC PRESSURE, PSIA - - - - -	15.025000
INITIAL PERMEABILITY, MD - - - - -	875.21000
INITIAL POROSITY, PERCENT - - - - -	29.450000
INITIAL ROCK COMPRESSIBILITY, VOL/MMVOL/PSI - -	3.8860000

TABLE 8-15

DRAWDOWN TEST NO. 11
 11/15/82-1/19/83
 DOW/DOE NO. 1 L. R. SWEETZ WELL
 C1B JEFF SAND
 PARCERDUE PROJECT
 VERMILION PARISH, LOUISIANA

DATA FILE: DD11
 WASP FILE: BDD11

PAGE:

OBSERVED PRODUCTION HISTORY AND CALCULATED MATCHES

PROD. BEGAN 04/26/82 HRS. 17.657

DATE MO/DA/YR	TIME OF DAY HOURS	TEST RATES			CUM. WATER PROD., BBLs.			CALC'D WATER N PLACE MMBBLs	BOTTOM HOLE FLOW PRES., PSIG.			AVERAGE AQUIFER PRESS. PSIG.	EDGE WATER INFLUX DBL.
		GAS MCF/D	COND. BBL/D	WATER BBL/D	MEASURED	CALC'D	DIFF.		MEAS'D	CALC'D	DIFF.		
01/18/83	15.267	THIS POINT DELETED											
01/18/83	15.767	THIS POINT DELETED											
01/18/83	16.267	THIS POINT DELETED											
01/18/83	16.767	THIS POINT DELETED											
01/18/83	17.267	THIS POINT DELETED											
01/18/83	17.767	THIS POINT DELETED											
01/18/83	18.267	THIS POINT DELETED											
01/18/83	18.767	THIS POINT DELETED											
01/18/83	19.267	THIS POINT DELETED											
01/18/83	19.767	THIS POINT DELETED											
01/18/83	20.267	THIS POINT DELETED											
01/18/83	20.767	THIS POINT DELETED											
01/18/83	21.267	THIS POINT DELETED											
01/18/83	21.767	THIS POINT DELETED											
01/18/83	22.267	THIS POINT DELETED											
01/18/83	22.767	THIS POINT DELETED											
01/18/83	23.267	THIS POINT DELETED											
01/18/83	23.767	THIS POINT DELETED											
01/19/83	0.517	THIS POINT DELETED											
01/19/83	1.517	124.6	0.0	8322.0	1852750.	1852478.	272.	87.	9626.8	9626.7	0.1	10948.8	86343
01/19/83	2.517	124.6	0.0	8322.0	1853097.	1852399.	698.	87.	9626.8	9626.6	0.2	10948.6	86262
01/19/83	3.517	125.2	0.0	8344.0	1853444.	1844241.	9204.	87.	9625.6	9622.6	2.9	10948.5	86062
01/19/83	4.517	125.2	0.0	8344.0	1853792.	1845743.	8049.	87.	9625.0	9622.5	2.6	10948.4	85903
01/19/83	5.317	125.2	0.0	8344.0	1854070.	1846392.	7678.	87.	9624.9	9622.4	2.5	10948.3	85960
01/19/83	6.317	125.0	0.0	8331.0	1854417.	1861327.	-6910.	87.	9622.4	9624.6	-2.2	10948.3	86341
01/19/83	7.317	125.0	0.0	8331.0	1854764.	1856463.	-1699.	87.	9624.1	9624.6	-0.5	10948.3	86579
01/19/83	8.317	125.0	0.0	8331.0	1855111.	1858292.	-3181.	87.	9623.5	9624.5	-1.0	10948.2	86499
01/19/83	9.017	125.0	0.0	8331.0	1855354.	1859012.	-3657.	87.	9623.2	9624.4	-1.2	10948.1	86564
01/19/83	9.517	125.0	0.0	8331.0	1855528.	1860117.	-4589.	87.	9622.9	9624.4	-1.5	10948.1	86607
01/19/83	9.583	125.0	0.0	8331.0	1855551.	1861136.	-5585.	87.	9622.6	9624.4	-1.8	10948.1	86658

TABLE 8-15

DRAWDOWN TEST NO. 11
 11/15/82-1/19/83
 DOW/DOE NO. 1 L. R. SWEETZ WELL
 CIB JEFF SAND
 PARCERDUE PROJECT
 VERMILION PARISH, LOUISIANA

DATA FILE: DD11
 WASP FILE: BDD11

PAGE:

CALCULATED AQUIFER ENERGY INDICES

DATE	TIME OF DAY	WATER EXPANSION	ROCK COMPACTION	VERTICAL INFLUX	PERIPHERIAL INFLUX	SUM INDICES
01/18/83	15. 267	THIS POINT DELETED				
01/18/83	15. 767	THIS POINT DELETED				
01/18/83	16. 267	THIS POINT DELETED				
01/18/83	16. 767	THIS POINT DELETED				
01/18/83	17. 267	THIS POINT DELETED				
01/18/83	17. 767	THIS POINT DELETED				
01/18/83	18. 267	THIS POINT DELETED				
01/18/83	18. 767	THIS POINT DELETED				
01/18/83	19. 267	THIS POINT DELETED				
01/18/83	19. 767	THIS POINT DELETED				
01/18/83	20. 267	THIS POINT DELETED				
01/18/83	20. 767	THIS POINT DELETED				
01/18/83	21. 267	THIS POINT DELETED				
01/18/83	21. 767	THIS POINT DELETED				
01/18/83	22. 267	THIS POINT DELETED				
01/18/83	22. 767	THIS POINT DELETED				
01/18/83	23. 267	THIS POINT DELETED				
01/18/83	23. 767	THIS POINT DELETED				
01/19/83	0. 517	THIS POINT DELETED				
01/19/83	1. 517	. 05486	. 89967	. 00000	. 04546	1. 00000
01/19/83	2. 517	. 05487	. 89972	. 00000	. 04541	1. 00000
01/19/83	3. 517	. 05487	. 89983	. 00000	. 04530	1. 00000
01/19/83	4. 517	. 05488	. 89991	. 00000	. 04521	1. 00000
01/19/83	5. 317	. 05488	. 89989	. 00000	. 04523	1. 00000
01/19/83	6. 317	. 05487	. 89971	. 00000	. 04542	1. 00000
01/19/83	7. 317	. 05486	. 89960	. 00000	. 04554	1. 00000
01/19/83	8. 317	. 05486	. 89965	. 00000	. 04549	1. 00000
01/19/83	9. 017	. 05486	. 89962	. 00000	. 04551	1. 00000
01/19/83	9. 517	. 05486	. 89960	. 00000	. 04553	1. 00000
01/19/83	9. 583	. 05486	. 89958	. 00000	. 04556	1. 00000

influx and assuming continued flow at 8500 separator barrels per day. At an assumed abandonment static aquifer pressure of 8550 psia, the bubble-point pressure, a cumulative water production of 11,078,051 SBBLs is realized at a flowing pressure of 6834 psia after approximately 3.71 total years of flow. The associated total gas recovered during this period is 183,563 thousand standard cubic feet (Mscf) when based on a cumulative measured separator ratio of 16.57 standard cubic feet of gas per separator barrel of water produced.

Table 8-17 summarizes the predicted performance generated on a future 7-day time mode.

8.4 Summary and Discussion

Overall, the well testing and pressure analyses efforts were successful in producing a reliable aquifer description.

An important insight has been gained in regard to the predominate influence of rock compressibility on aquifer fluid displacement and ultimate recovery. In geopressured systems having this degree of pore volume relaxation, it is doubtful that viable rates could be sustained for pressure depletion below the hydrostatic pressure gradient or at pressures less than approximately 6000 psia. This result in turn leads to

abnormally low recoveries ranging from 10-15 % of the water and solution gas initially in-place. Similar situations of abnormally low recovery efficiencies in geopressured oil and gas reservoirs have been experienced in several geographic areas.

DRAWDOWN TEST NO. 11
 11/15/82-1/19/83
 DOW/DOE NO. 1 L. R. SWEETZ WELL
 CIB JEFF SAND
 PARCERDUE PROJECT
 VERMILION PARISH, LOUISIANA

DATA FILE: DD11
 WASP FILE: BDD11

PREDICTED PERFORMANCE AS OF 01/19/83

BASED ON A CONSTANT RATE OF 8500. BBLS/DAY
 FROM AS OF DATE TO BUBBLE POINT PRESSURE OF 8535.13 PSIG

TIME DAYS	CUM. WATER BBLS	BH FLOW PRESS. PSIG	RES. STATIC PRESS. PSIG
274.7	1915051.	9576.9	10934.4
281.7	1974551.	9558.8	10918.9
288.7	2034051.	9540.6	10903.5
295.7	2093551.	9522.4	10888.0
302.7	2153051.	9504.2	10872.6
309.7	2212551.	9486.0	10857.1
316.7	2272051.	9467.8	10841.7
323.7	2331551.	9449.6	10826.2
330.7	2391051.	9431.4	10810.8
337.7	2450551.	9413.2	10795.3
344.7	2510051.	9395.0	10779.9
351.7	2569551.	9376.7	10764.4
358.7	2629051.	9358.5	10749.0
365.7	2688551.	9340.2	10733.6
372.7	2748051.	9322.0	10718.1
379.7	2807551.	9303.7	10702.7
386.7	2867051.	9285.4	10687.2
393.7	2926551.	9267.1	10671.8
400.7	2986051.	9248.9	10656.3
407.7	3045551.	9230.6	10640.9
414.7	3105051.	9212.3	10625.4
421.7	3164551.	9193.9	10610.0
428.7	3224051.	9175.6	10594.5
435.7	3283551.	9157.3	10579.0
442.7	3343051.	9139.0	10563.6
449.7	3402551.	9120.6	10548.1
456.7	3462051.	9102.3	10532.7
463.7	3521551.	9083.9	10517.2
470.7	3581051.	9065.6	10501.8
477.7	3640551.	9047.2	10486.3
484.7	3700051.	9028.8	10470.8
491.7	3759551.	9010.4	10455.4
498.7	3819051.	8992.0	10439.9
505.7	3878551.	8973.6	10424.4
512.7	3938051.	8955.2	10408.9
519.7	3997551.	8936.8	10393.5

TABLE 8-17
(CONTINUED)

DRAWDOWN TEST NO. 11
11/15/82-1/19/83
DOW/DOE NO. 1 L. R. SWEETZ WELL
CIB JEFF SAND
PARCERDUE PROJECT
VERMILION PARISH, LOUISIANA

DATA FILE: DD11
WASP FILE: BDD11

PREDICTED PERFORMANCE AS OF 01/19/83

BASED ON A CONSTANT RATE OF 8500. BBLS/DAY
FROM AS OF DATE TO BUBBLE POINT PRESSURE OF 8535.13 PSIG

TIME DAYS	CUM. WATER BBLS	BH FLOW PRESS. PSIG	RES. STATIC PRESS. PSIG
526.7	4057051.	8918.4	10378.0
533.7	4116551.	8900.0	10362.5
540.7	4176051.	8881.6	10347.0
547.7	4235551.	8863.2	10331.5
554.7	4295051.	8844.7	10316.1
561.7	4354551.	8826.3	10300.6
568.7	4414051.	8807.9	10285.1
575.7	4473551.	8789.4	10269.6
582.7	4533051.	8771.0	10254.1
589.7	4592551.	8752.5	10238.6
596.7	4652051.	8734.1	10223.1
603.7	4711551.	8715.6	10207.7
610.7	4771051.	8697.1	10192.2
617.7	4830551.	8678.6	10176.7
624.7	4890051.	8660.1	10161.2
631.7	4949551.	8641.6	10145.7
638.7	5009051.	8623.1	10130.2
645.7	5068551.	8604.5	10114.7
652.7	5128051.	8586.0	10099.2
659.7	5187551.	8567.5	10083.7
666.7	5247051.	8548.9	10068.2
673.7	5306551.	8530.4	10052.7
680.7	5366051.	8511.8	10037.2
687.7	5425551.	8493.3	10021.7
694.7	5485051.	8474.8	10006.2
701.7	5544551.	8456.3	9990.6
708.7	5604051.	8437.8	9975.1
715.7	5663551.	8419.4	9959.6
722.7	5723051.	8401.0	9944.1
729.7	5782551.	8382.6	9928.6
736.7	5842051.	8364.2	9913.1
743.7	5901551.	8345.9	9897.6
750.7	5961051.	8327.5	9882.1
757.7	6020551.	8309.2	9866.5
764.7	6080051.	8291.0	9851.0
771.7	6139551.	8272.7	9835.5

TABLE 8-17
(CONTINUED)

DRAWDOWN TEST NO. 11
11/15/82-1/19/83
DOW/DOE NO. 1 L. R. SWEETZ WELL
CIB JEFF SAND
PARCERDUE PROJECT
VERMILION PARISH, LOUISIANA

DATA FILE: DD11
WASP FILE: BDD11

PREDICTED PERFORMANCE AS OF 01/19/83

BASED ON A CONSTANT RATE OF 8500. BBLs/DAY
FROM AS OF DATE TO BUBBLE POINT PRESSURE OF 8535.13 PSIG

TIME DAYS	CUM. WATER BBLs	BH FLOW PRESS. PSIG	RES. STATIC PRESS. PSIG
778.7	6199051.	8254.5	9820.0
785.7	6258551.	8236.3	9804.5
792.7	6318051.	8218.1	9788.9
799.7	6377551.	8200.0	9773.4
806.7	6437051.	8181.8	9757.9
813.7	6496551.	8163.7	9742.4
820.7	6556051.	8145.6	9726.8
827.7	6615551.	8127.6	9711.3
834.7	6675051.	8109.5	9695.8
841.7	6734551.	8091.5	9680.2
848.7	6794051.	8073.5	9664.7
855.7	6853551.	8055.6	9649.2
862.7	6913051.	8037.6	9633.6
869.7	6972551.	8019.7	9618.1
876.7	7032051.	8001.8	9602.6
883.7	7091551.	7983.9	9587.0
890.7	7151051.	7966.0	9571.5
897.7	7210551.	7948.2	9555.9
904.7	7270051.	7930.4	9540.4
911.7	7329551.	7912.6	9524.8
918.7	7389051.	7894.8	9509.3
925.7	7448551.	7877.1	9493.7
932.7	7508051.	7859.4	9478.2
939.7	7567551.	7841.7	9462.7
946.7	7627051.	7824.0	9447.1
953.7	7686551.	7806.4	9431.6
960.7	7746051.	7788.7	9416.0
967.7	7805551.	7771.1	9400.5
974.7	7865051.	7753.6	9384.9
981.7	7924551.	7736.0	9369.4
988.7	7984051.	7718.5	9353.9
995.7	8043551.	7700.9	9338.3
1002.7	8103051.	7683.4	9322.7
1009.7	8162551.	7666.0	9307.2
1016.7	8222051.	7648.5	9291.6
1023.7	8281551.	7631.1	9276.1

TABLE 8-17
(CONTINUED)

DRAWDOWN TEST NO. 11
11/15/82-1/19/83
DOW/DOE NO. 1 L. R. SWEETZ WELL
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VERMILION PARISH, LOUISIANA

DATA FILE: DD11
WASP FILE: BDD11

PREDICTED PERFORMANCE AS OF 01/19/83

BASED ON A CONSTANT RATE OF 8500. BBLS/DAY
FROM AS OF DATE TO BUBBLE POINT PRESSURE OF 8535.13 PSIG

TIME DAYS	CUM. WATER BBLS	BH FLOW PRESS. PSIG	RES. STATIC PRESS. PSIG
-----	-----	-----	-----
1030.7	8341051.	7613.7	9260.5
1037.7	8400551.	7596.3	9245.0
1044.7	8460051.	7578.9	9229.4
1051.7	8519551.	7561.6	9213.8
1058.7	8579051.	7544.2	9198.2
1065.7	8638551.	7526.9	9182.7
1072.7	8698051.	7509.6	9167.1
1079.7	8757551.	7492.4	9151.5
1086.7	8817051.	7475.1	9135.9
1093.7	8876551.	7457.9	9120.4
1100.7	8936051.	7440.7	9104.8
1107.7	8995551.	7423.5	9089.2
1114.7	9055051.	7406.3	9073.6
1121.7	9114551.	7389.1	9058.0
1128.7	9174051.	7372.0	9042.4
1135.7	9233551.	7354.8	9026.8
1142.7	9293051.	7337.7	9011.2
1149.7	9352551.	7320.6	8995.6
1156.7	9412051.	7303.5	8980.0
1163.7	9471551.	7286.4	8964.4
1170.7	9531051.	7269.4	8948.7
1177.7	9590551.	7252.3	8933.1
1184.7	9650051.	7235.3	8917.4
1191.7	9709551.	7218.2	8901.8
1198.7	9769051.	7201.2	8886.2
1205.7	9828551.	7184.3	8870.5
1212.7	9888051.	7167.3	8854.9
1219.7	9947551.	7150.4	8839.3
1226.7	10007051.	7133.4	8823.7
1233.7	10066551.	7116.5	8808.0
1240.7	10126051.	7099.7	8792.4
1247.7	10185551.	7082.8	8776.8
1254.7	10245051.	7066.0	8761.3
1261.7	10304551.	7049.3	8745.7
1268.7	10364051.	7032.5	8730.1
1275.7	10423551.	7015.8	8714.5

TABLE 8-17
(CONTINUED)

DRAWDOWN TEST NO. 11
11/15/82-1/19/83
DOW/DOE NO. 1 L. R. SWEETZ WELL
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PARCERDUE PROJECT
VERMILION PARISH, LOUISIANA

DATA FILE: DD11
WASP FILE: BDD11

PREDICTED PERFORMANCE AS OF 01/19/83

BASED ON A CONSTANT RATE OF 8500. BBLS/DAY
FROM AS OF DATE TO BUBBLE POINT PRESSURE OF 8535.13 PSIG

TIME DAYS	CUM. WATER BBLs	BH FLOW PRESS. PSIG	RES. STATIC PRESS. PSIG
1282.7	10483051.	6999.1	8699.0
1289.7	10542551.	6982.4	8683.4
1296.7	10602051.	6965.8	8667.9
1303.7	10661551.	6949.2	8652.3
1310.7	10721051.	6932.6	8636.8
1317.7	10780551.	6916.0	8621.3
1324.7	10840051.	6899.5	8605.7
1331.7	10899551.	6883.0	8590.2
1338.7	10959051.	6866.5	8574.7
1345.7	11018551.	6850.1	8559.2
1352.7	11078051.	6833.6	8543.6

9. Production Testing

Production testing of the Dow/DOE L. R. Sweezy No. 1 was performed by Johnston-Macco/Schlumberger (now Flopetrol-Johnston). Two men were on site at all times, working 12 hour rotating shifts. The work included: installation, operation, and maintenance of all surface equipment from the Manumatic valve to the disposal well; metering gas and water flow rates; recording data at 1/2 hour intervals; operation of the emergency shut-down system; operation of the filter unit; and monitoring the disposal well. The Johnston-Macco daily production reports are presented in Appendix A, Volumes I to IV (limited distribution).

9.1. Production History

A graphic representation of gas and brine production, from start-up in April, 1982, to shut-down in February, 1983, is presented in Figure 9-1. The major shut-in events, buildup tests and equipment repairs, are labeled.

A descriptive monthly summary of the production history follows:

FIGURE 9-1

Production History - Monthly SummaryApril, 1982

Testing began April 26, 1982. The Hewlett-Packard gauge was installed, but the signal failed. A flow rate of 17,000 bpd was achieved, the highest rate of the entire test. A mis-adjusted separator control caused an emergency shut down which terminated flow test 1.

The Otis temperature tool was replaced with an RPG-7 tool. Low flow rates could not be maintained due to plugging of the adjustable choke. Flow rate was taken up to 15,000 bpd. Back pressure rose quickly in disposal well to over 400 psi, which triggered an ESD. Inspection of the choke showed that it had been severely cut by fine grained sand. The electric line became knotted in the lubricator while coming out of hole. The line had to be cut to remove it from the lubricator. It was subsequently spliced and reverse-spooled onto the drum so the splice would not have to be run in the hole.

May, 1982

Disposal well was plugged with honey oil from lubricator and fine sand. Well was flushed with HCL, xylene, and mud acid using a coil tubing unit. Future electric line operations were done with lubricator wireline valves closed to minimize honey oil in

the flowstream. Ultrasonic inspection of flow lines showed no damage due to sand.

The well was reopened on May 4. The choke slammed into the seat immediately and broke. The choke was replaced, the well re-opened, and the new choke broke in the same manner. Flow was finally established at a rate of 3700 bpd. Differential pressure of 1400 psi suddenly appeared across the turbine meter. The well was shut in; examination of the choke showed it to be full of an unusual blue grease of an unknown origin. The color, an odd shade of turquoise, was similar to that of the hydraulic fluid used to open the upper master valve; however, there was no apparent channel of communication between the hydraulic cylinder and flow stream. The grease may have been packed in the valves originally, although this could not be documented.

A three pod filter unit was added downstream of the separator. The well was re-opened and another choke broke. After repair, flow was re-established at approximately 8500 bpd on a 28/64" choke.

Gas volumes being measured on a Daniels Sr. orifice meter were erratic due to surging, and indicated a GWR of only 10 or 12. A Rockwell P.D. gas meter was installed which indicated a GWR of approximately 20. The well was shut in May 18 due to compressor failure in the ESD system, and a buildup was run.

The well was reopened on a 32/64" choke at a rate of approximately 11,000 bpd. Intermittant sand production was detected in shake-outs, estimated to be 50 to 100 lb/day.

On May 20, the ESD was triggered twice when the polyflow tubing used in the ESD system burst. The well was shut in for a six-day buildup on May 26. The filter unit was repaired and polyflow tubing was replaced with stainless steel. The adjustable choke on the manifold was replaced with a positive choke and an adjustable choke was added downstream of the manifold.

June, 1982

The well was reopened but the new adjustable choke quickly broke. The stem was removed and the choke body was capped. The bellows on the Rockwell gas meter burst. The well slugged sand and mud for two days, then tapered off to a trace of sand. Water production was approximately 10,000 bpd on a 30/64" choke. Both the Daniels and the Rockwell gas meters appeared to be out of calibration. The well was shut in to allow Otis to test the pressure/temperature tool to determine why multiplexed temperature reading could not be obtained. Degaussing the cable before running in the hole solved the problem.

The well was re-opened on a 30/64" choke; however, a gas vortex resulting from gas which had separated in the well bore during shut in unscrewed the choke adaptor. The carbide

Section 9

adaptor was exchanged for a stainless steel adaptor. Flow was re-established on a 30/64" choke.

Gas metering continued to be a problem. Bellows broke again on the Rockwell meter and surging made reading of the Barton recorder on the Daniels meter difficult. Shut in well on June 23 for buildup test No. 7.

The well was re-opened for flow test No. 8 on a 30/64" choke. After re-calibrating both gas meters, a fairly consistent GWR of approximately 20 was indicated. Buildup No. 8 was successful.

July, 1982

The well was re-opened for flow test 9 on July 7, on a 30/64" choke. Sand production was 50 lb/day to 100 lb/day with occasional slugs. The GWR apparently dropped to 15-17. Trouble was experienced with the wellhead chemical injection pump due to the very corrosive nature of the "Dequest"® inhibitor. The disposal well was acidized with HCL and mud acid on July 21, which dropped the back pressure from 320 psi to 68 psi. The well was shut in for a short time on July 27 to replace a faulty dump valve on the separator. Average flow rate during July was 9500 bpd.

August, 1982

Choke was changed to 32/64" and flow rate increased to 10,500 bpd.

Sand increased dramatically, from $\pm$ 30 lb/day to 800 lb/day with some slugs as high as 25,000 lb/day; filters began to plug and flowing tubing pressure jumped 200 psi, probably due to partial plugging of the choke. The choke was changed back to 30/64" and flow cleaned up although some sanding occurred at irregular intervals. A Corrotor® electronic corrosion probe was installed in the filter unit. Black smoke from the flare stack was noted for the first time on August 22. Back flushing of disposal well was found to significantly lower injection pressure. The well was shut in on August 26 for buildup test No. 9. Approximately 25 gallons of sand was cleaned out of the separator.

September, 1982

The well was re-opened on a 30/64" choke. It was discovered that the master valve leaked. The well was shut in and Otis installed a retrievable wireline plug. The christmas tree was removed and all valves were repaired and pressure tested by FMC, and the tree re-installed. Flow was resumed on 30/64" choke on September 9. Sand was constant in trace amounts with occasional minor slugs. One million barrels total brine production was achieved September 27.

October, 1982

Flow continued with sand production erratic. The disposal well was acidized on October 2. Valves were installed on the filter unit to allow back washing of filter, thus extending their useful life. Citric acid was added to the filter cannisters when changing filters in order to lower back pressure in the disposal well. Nevertheless, injection pressure continued to rise and another acid job was performed on October 20. Back pressure problems continued in spite of backflushing and citric acid procedures.

November, 1982

The well was shut in for buildup test No. 10. The electric line had been shortened such that the splice had to be run in the hole. The line shorted out and had to be removed. The test was run with a conventional electric line truck.

The disposal well was allowed to backflow to the pit. It flowed gas and water for over a day and was still degassing when it had to be shut in due to lack of pit capacity. This indicated that a large part of the backpressure was due to gas breakout in the disposal formation after injection.

100 gallons of sand were cleaned out of the separator. Choke manifold valves were repaired. Rips were discovered in the

salt-water pit liner. The disposal well was treated with citric acid and bactericide, using a coil tubing unit.

Frac tanks were installed to hold salt water until the pit liner could be replaced.

Flow test No. 11 began November 15. The chemical inhibitor was changed from Dequest® to Nalco 2VV-419. Choke size was brought up slowly to 30/64". GWR apparently dropped to below 15. An injection fall off test was run November 23, which showed high permeability and very high damage (skin) in the disposal well.

The well consistently produced trace quantities of sand.

December, 1982

We began treating the disposal water with Nalco 1111 surfactant to reduce surface tension.

Several ESD's occurred due to air compressor failure. The well was restarted without problems. The disposal well was acidized on December 9 with HCl and mud acid.

Choke size was increased to 31/64", which increased flow rate to 9500 bpd. Sand production was erratic during the month.

Section 9

January, 1983

Production continued on 31/64" and 30/64" chokes. Buildup test No. 11 was attempted on January 17, however, the new splice would not pass through the lubricator flow tubes. The back-up electric line truck was called out to run the buildup.

Condensate had been noted in the gas line drip pot and samples collected since January 8. A quantity of dark, parrafinic oil was recovered when cleaning out the separator.

The 3" Daniels gas meter run was exchanged for a 2" meter run to improve accuracy.

The well was re-opened for flow test No. 12 on January 24 on a 31/64" choke.

The disposal well was acidized on January 31 with HCl and mud acid.

February, 1983

On February 2, flowing tubing pressure began to drop rapidly, accompanied by a slight increase in gas production. No increase in flow rate was noted.

Tubing pressure eventually stopped dropping, but remained erratic.

On February 5, at 0803 hours, a massive sanding incident occurred. The sand detector was pegged and the manifold shakeout valve immediately plugged. The separator and filter unit were found to be full of sand, mud, and fine clay.

Bailers tagged and recovered sand from the production well at 12,999 feet, 351 feet above perforations; and from the disposal well at 4448 feet, 72 feet above perforations.

Completion Technology, Inc., was called in to study the sanding situation, and they concluded that massive failure of the gravel pack had occurred, with formation collapse and probable collapse of the casing. The production well was beyond any practical method of salvage, and, after discussion and consultation, a decision was made to plug and abandon the well.

9.2 Surface Equipment

Production surface equipment consists of the following items:

- Wellhead
- Data header
- Tejas 3" turbine meter (total flow)
- Expansion loop
- Choke manifold
- Separator
- Filter unit
- Chemical injection pump
- Turbine meter (brine)
- Daniels Sr. orifice meter (gas)
- Rockwell positive displacement meter (gas)
- Emergency shut-down system (ESD) w/compressor
- Gas flare stack

A diagram of the site layout showing the locatin of the various equipment is presented in Figure 9-2. Figure 9-3 is a schematic showing the detailed assembly of the equipment.

9.2.1 Wellhead

The wellhead consists of four, 5-1/8", 10,000 psi, stainless steel gate valves, manufactured by FMC Co.; a 10,000 psi "Y"

FIGURE 9-2 PARCERDUE GEOTHERMAL PROJECT SITE LAYOUT

FIGURE 9-3 SURFACE EQUIPMENT-SCHEMATIC

block with a special flange and 3-1/8" protector sleeve to shield the electric line from erosion; a 3-1/16" 10,000 psi manumatic pneumatic safety valve; associated casing head spools and valves. The upper master valve is hydraulic actuated and is tied into the safety system, along with the manumatic. A schematic of the wellhead is shown in Figure 9-4. A picture of the wellhead and data header is shown in Figure 9-5.

On September 1, 1982, a leak was observed in a grease zert on the lower master valve. We were unable to shut off flow through the valve. A temporary plug was set and all valves were removed. The lower master valve had no grease and contained approximately two cups sand; the gates of all the valves were slightly warped. New gates with high temperature overlays were installed, the tree re-assembled and tested, and replaced on the wellhead.

9.2.2 Flow Line and Expansion Loop

The flow line and expansion loop were fabricated of 3-inch double x heavy flow line. The down-drop from the manumatic valve contained the data header with 1/2" ports for measuring temperature, pressure (gauge), pressure (dead weight tester), sonic sand detection. Also in the flow line was a high-low pressure pilot for the ESD system and electronic pressure and temperature monitors used in conjunction with the downhole data gathering system. The expansion loop is shown in Figure 9-7.

FIGURE 9-4 WELLHEAD AND X-MAS TREE

FIGURE 9-5; WELLHEAD
XMAS TREE AND DATA
HEADER

FIGURE 9-6; CHOKE MANIFOLD-SAMPLE STATION
(LEFT)-TURBINE METER BOARD (RIGHT)

FIGURE 9-7; EXPANSION LOOP

FIGURE 9-8; TOTAL FLOW TURBINE METER,
PRESSURE SENSORS, BARTON RECORDER (DWT),
HI-LO SAFETY PILOT

**FIGURE 9-9: SEPARATOR SHOWING CONTROLS;
HI-LO SAFETY PILOT ON TOP**

FIGURE 9-10: FILTER UNIT

**FIGURE 9-11: DANIELS SR ORIFICE GAS METER;
BARTON RECORDER; ESD BOARD
(FOREGROUND); WATER KNOCKOUT
(BACKGROUND)**

**FIGURE 9-12: ROCKWELL POSITIVE DISPLACEMENT
GAS METER**

**FIGURE 9-13: CORRATOR
CORROSION PROBE AND
METER**

**FIGURE 9-14: DISPOSAL WELLHEAD-PRESSURE,
TEMP. SENSORS ON TOP.**

9.2.3 Choke Manifold

The choke manifold consists of five, 3" WKM Co., 10,000 psi gate valves, and two Best Co. choke bodies. Originally, both chokes were adjustable, tungsten carbide, and of stem and seat design.

The force of the water flowing past the stem invariably caused the carbide cone to slam into the seat and fracture. Some cutting by sand was also experienced with the adjustable chokes. After repeated experiences of this nature, the adjustable chokes were removed and replaced with positive chokes of the bean type. The parallel arrangement of chokes allowed changing flow rate by opening one side of the manifold while simultaneously shutting in the other side. Usually, several choke changes were used in bringing the well up to the full flow rate. A third adjustable choke was added downstream of the manifold; however, it failed immediately and was not used again. Three of the valves were damaged during production by sand and corrosion. Repairs were made to the gates and seats and the valves replaced.

A picture of the choke manifold is shown in Figure 9-6.

9.2.4 Total Flow Sampler

Water samples were taken from a 3/8" tubing connection at the back of the choke manifold, through two, 10,000 psi needle valves.

The tubing was coiled and the coil placed in a vessel made from half a 55 gallon drum and filled with water. Ice was added to the water for cooling when sampling for chemical analysis.

The sampling port was also used for sand shake-out sampling at half hour intervals. The valve was opened and allowed to flow for a few seconds to clear out the line. A one-liter bottle was then filled approximately half-full. The water was swirled to concentrate the sand at the bottom of the bottle and the rate of sand production was then determined either by visual estimation, or the water volume was measured and the sand filtered and weighed to allow accurate calculation of the sand rate.

The cooling drum with 3/8" sampling line can be seen to the left of the choke manifold in Figure 9-6.

9.2.5 Separator

The brine/gas separator vessel is a horizontal cylindrical vessel with an O.D. of 48 inches and a length of 12 feet 6 inches headseam. The separator system was designed for a 20,890 bbl per day brine flow rate, and a 5.0 MMSCF/D gas rate. The vessel is also equipped with a 2-foot baffle plate for the separation of oil. The design operating pressure and temperature were 1,000 psig and 300°F, respectively. The maximum working pressure is 1440 psig at 105°F; 1290 psig at 350°F.

Pressure control on the separator was maintained by a back pressure regulator which controlled the gas flow to the flare system and by a brine liquid level indicator/controller, which controlled the rate of brine flow to the disposal well.

The separator operated with a minimum of problems; the greatest problem was sand filling from the test well. The separator is shown in Figure 9-9.

9.2.6 Filter System

The need for water filtration became apparent with the early sand production. A Nowata (Model No. 6FH6OC-600) filter system belonging to the Department of Energy was brought in and installed after the separator. The system was a skid-mounted three-cannister, cartridge type unit in which either 50, 25, 10, or 5 micron filters were used. The unit was rated at 600 psig at 300°F. The frequent plugging of filters necessitated changing cartridges at short intervals. In order to minimize this, the cannisters were plumbed such that water could be backflowed through them for short intervals, thus greatly extending the life of the filters. Examination of material caught on the filters showed material in the sub-two micron range; however, most of the sand was larger than five microns.

Three and six inch Rockwell plug valves were used as the principal valves on the filter unit. Leakage and grease washout were constant problems; even frequent greasing with high temperature grease did not solve the problem. Two of the plug valves were replaced with Orbit 600 psig, 300°F ball type valves, which were a great improvement over the plug valves.

Operation of the filters was to flow through either one or two cannisters, keeping one cannister in reserve for the changing out of cartridges when necessary. When required, the filters could be bypassed and flow re-directed to the salt water pit.

The filter unit is shown in Figure 9-10.

9.2.7 Disposal Wellhead

The disposal wellhead was composed of three, McEvoy Super Mudwonder 6", 2000 psi gate valves and swab flange on top with temperature and pressure gauges. The disposal wellhead is pictured in Figure 9-14.

9.3 Emergency Shut Down System (ESD)

The emergency shut down valves were the hydraulically actuated upper master valve and the pneumatically operated manumatic wing valve. The remainder of the ESD system consists

of a Hi-Lo flowline pressure pilot seen in Figure 9-8 , a Hi-Lo separator pressure pilot seen at top of the separator in Figure 9-9, and a Hi-Lo separator liquid level pilot.

There were two ESD boards in the system; one located at the choke manifold, one at the separator. The ESD boards and the pilots are of block-and-bleed design.

Primary supply air was provided by a diesel powered compressor rated at 5 CFM at 100 psi. Back up air supply was a bank of four air cylinders connected in series and tied into the system through a 3-way block and bleed valve. All hook up was done with 3/8 inch stainless steel tubing after an initial hook up with plastic polyflow tubing failed. A schematic of the system is shown in Figure 9-15.

The ESD system operated perfectly on several emergency shut downs. Time to close on the manumatic valve is 4 seconds; slightly longer on the hydraulic master valve.

9.4 Water Measurement

Fluids were measured using two turbine meters. A Tejas "Big Tex" 3-1/16 inch, 5,000 psi meter was installed upstream of the choke manifold to monitor total flow. Two pressure sensors were installed in the flowline, one upstream and one downstream of the

FIGURE 9-15: EMERGENCY SHUT DOWN SYSTEM (ESD)

meter, to measure pressure drop across the meter. The meter, with pressure sensors, is shown in Figure 9-8. Readout was at a meter board located adjacent to the meter. The board had both a totalizer and rate readout, and was powered by a battery which was trickle charged by solar cells located on the top of the meter box. The meter box, battery box, and solar cells can be seen on the right side of the picture in Figure 9-6. The flow rate readout was electronically monitored and recorded during pressure transient testing. No repair of the "Big Tex" was required during the test period.

The downstream meter, located on the separator dump line, was a Tejas model 111, 3-inch, 3500 psi meter, with a self contained, battery powered meter board mounted directly on the meter itself. The 111 meter had to be repaired once during the testing, to replace a bearing.

The two meters generally agreed within ± 2 percent. Meter calibration was accomplished by hooking up a commercial meter prover across the filter outlet flow lines, and calculating a new meter factor. Except in the case where the bearing failed in the separator water meter, meters proved to be accurate to water within ± 1 percent at the normal flow rates.

9.5 Gas Metering

The accurate metering of gas rates was one of the most difficult tasks encountered during production testing. The original metering system was a Daniels Sr. orifice meter in a 3-inch meter run and a Barton differential pressure recorder, as shown in Figure 9-11. Gas-water ratios obtained shortly after start-up of the test were in the range of 9-12 SCFG/BBL. Because this GWR appeared to be much lower than expected for this brine, a Rockwell model 3000 positive displacement (PD) meter was installed, as shown in Figure 9-12. Initial results with the PD meter indicated a GWR of approximately 20 SCFG/BBL. Subsequently, modifications were made to the system to improve accuracy: the 3-inch Daniels meter run was replaced with a 2-inch run; a surge bottle and water knock-out pot were added in front of the PD meter; additional back-pressure maintenance devices were added to the gas discharge line.

The net result of these modifications was convergence of the results from the two meters toward a GWR of 17 SCFG/BBL. Nevertheless, this value is considered to be only an approximation, due to a number of factors impeding accurate gas measurement:

1. Separation equipment was designed for much higher gas flows - up to 25 MMCFGPD.

2. Constant back pressure was impossible to maintain. Because of low gas volume, when the water dump valve would open, the gas back-pressure valves would close in trying to maintain a constant separator vessel pressure. The result would be surging in the gas line and a pressure chart composed of a series of spikes, impossible to read accurately for calculations.
3. Continuous temperature monitoring was equally difficult, due to gas surging and climatic variations. The magnitude of the variation was, of course, far less than the pressure variation.
4. The Daniels meter was too large for the application. Even the 2-inch meter run was rated for 1 MMSCFGPD. Condensation would sometimes collect outside the orifice plate, causing inaccuracy in the data.
5. PD meter calculations were subject to the same inaccuracy as the Daniels meter due to lack of constant back pressure. The bellows and the meter case were both prone to filling with condensation or water carry-over from the separator, and had to be kept drained. On two occasions, the bellows burst, and had to be removed and repaired.

6. Calibration on the Barton recorder and PD meter was checked periodically.

9.6 Scale and Corrosion

Corrosion and scale coupons were found to be unsatisfactory for use in the production system due to high fluid velocities and entrained sand abrasion.

A Corrator® model 1172 corrosion measuring instrument was used to determine corrosion rates. The probe was installed on the outflow line of the filter unit and readings were taken either daily or every other day. Two readings were taken: a corrosion rate and pitting index. The Corrator® and probe are shown in Figure 9-13.

Initial corrosion rates measured 40 mils per year, but readings decreased daily, approaching zero. Pitting index began at 1.5 and rapidly approached zero. Examination of the probe showed a deposit of scale over the electrodes. The scale inhibitor was adjusted and no further scale problems were encountered. Corrosion readings stabilized at 10 mils per year, with a very low pitting index. Final examination of the probe, however, did reveal significant pitting of electrodes.

Ultrasonic thickness checks were made on the flowlines at approximately 60 day intervals. The only areas where thinning was significant were one 45° elbow and the 6" x 3" reducer at the separator. This was initially thought to be due to sand abrasion; however, examination of the pieces revealed pitting due to high fluid velocity and a corrosive solution of carbon dioxide. Some pitting was noted at the valves and choke cage on the choke manifold and at the separator dump valve.

The only scaling was the small deposit of calcium carbonate on the corrosion probe and a 1/32 inch buildup downstream of the separator dump valve. Both these minor incidents occurred during a period when chemical scale inhibitor injection was suspended. With inhibitor, no scale was detected. It is felt that the fairly low salinity plus the abrasion factor of the sand helped keep scaling from becoming a problem.

9.7 Chemical Treatment

Initial chemical treatment was Dequest® 2000 at a concentration of 1 ppm, injected at the data header (close to the manumatic valve), using a Texsteam chemical injection pump (compressed air). Numerous problems developed with the pump; including pitting of the balls and seats, and decomposition of the packing. After forty days of intermittent operation, the Texsteam pump was replaced with a Milton-Roy chemical injection pump (electric), in August, 1982.

Similar problems continued with the Milton-Roy pump. In November, 1982, the scale inhibitor was changed to Nalco 2VV419 at a concentration of 3 ppm. No further problems were experienced.

The only scale buildup detected was 1/32-inch in the flowline downstream of the separator dump valve, after a prolonged period of chemical pump down time. Both inhibitors appeared to be effective; however, the Nalco was far easier to handle. Sand abrasion probably helped to prevent scaling in the flow system. The buildup of back pressure in the disposal well and the amenability to acidization indicate that some precipitation was taking place in the disposal formation.

9.8 Disposal Well Management

Separator back pressure was used as the energy source to re-inject the brine into the disposal well. The separator operated at 650 psig pressure, and initially, 300 psig was selected as the maximum back pressure in the disposal well. It was later determined that 400 psig back pressure was acceptable.

The first plugging incident occurred in April, 1982, at the start-up of the short term testing, when sand and honey oil from the lubricator carried over into the disposal well. A coil

tubing unit was used to wash the screen with 2,500 gallons 15% HCl acid, 20% xylene, circulated out of the hole. The formation was then acidized with 2,500 gallons 15% HCl, 5,000 gallons mud acid (HF), followed by 1,000 gallons 7-1/2% HCl. Clean-up was completed May 3, 1982, and the filter unit was installed at this time. Electric line procedures were modified to prevent honey oil entering the flow stream.

A total of five acid jobs were performed during the test period, using mixtures of HCl and mud acid. Various techniques were used, including pumping acid directly, use of a coil tubing unit, and use of diverting agents. The results of these techniques did not vary significantly.

During the period from May 5, 1982, until July 21, 1982, a total of 467,000 barrels of brine were disposed. Injection pressure rose to 320 psi. After acidization, back pressure dropped to 68 psi.

From July 21, 1982, to October 2, 1982, 590,000 barrels brine were disposed. The well was acidized at 370 psi, which was reduced to 35 psi.

From October 2, 1982, to October 20, 1982, back pressure rose faster than normal. The well was acidized at 395 psi, which was reduced to 50 psi.

From October 20, 1982, to December 9, 1982, 296,000 barrels of water were injected. Maximum back pressure rose to 480 psi, which decreased to 110 psi after acidization.

From December 9, 1982, to January 31, 1982, a total of 393,000 barrels brine were disposed. The well was acidized at 420 psi, which declined to 110 psi. No further acidization was performed before the well sanded in on February 5, 1983.

During production, three techniques were developed to help manage disposal well back pressure and prolong the interval between major acid jobs.

1. In October, 1982, 25 to 100 pounds dry citric acid was added to the filter pods, when indicated, during filter changes. This small amount of citric acid was very effective in reducing back pressure, which typically dropped by 50 psi to 200 psi. It was generally discovered that, as the interval from the last major acid job increased, the effectiveness of the citric acid decreased until it no longer produced a significant pressure reduction.
2. As back pressure would rise at periodic intervals, flow would be diverted from the disposal well to the salt water pit for a short period of time, usually 30 seconds

to one minute. This allowed the well to back-flush itself, and usually resulted in pressure reductions of 50 to 150 psi. Again, effectiveness decreased with time since the last major acid job.

3. In November, 1982, the disposal well was opened and allowed to flow to the salt water pit. It flowed brine and gas for 24 hours, producing over 10,000 barrels brine, and was shut in only due to lack of pit capacity. The conclusion is that the approximately 3 SCF/BBL of gas remaining in solution at separator dump pressure was breaking out of solution in the formation around the wellbore, thereby decreasing the relative permeability to water.
4. Also in November, 1982, trace amounts of oil began to be detected in the brine. On December 2, 1982, we began injecting a surfactant, Nalco 1111 in the flow, down-stream of the filters. This proved effective in reducing the rate of back-pressure buildup.

The factors contributing to back-pressure buildup in the disposal well can be summarized:

1. Formation pressure increase due to water injection,
2. Sand and fine particulate matter,
3. Chemical precipitation in the formation, probably calcium carbonate,

4. Gas breakout in the formation,
5. Oil in the flow stream, either from the formation, or introduced through the production system.

9.9 Sand Detection and Control

Two methods of sand detection were employed. A Johnston-Macco acoustic flowline sand detector, model FSD-100 was installed in the flowline at the data header. The detector is theoretically much more sensitive than erosion detectors or cyclone detectors, able to detect sand concentrations in the range of .01% to .001%. This sensitivity applies to sand in a gas stream; in practice, the water generated background noise, and acted as a cushion to the sand grains, such that the sensitivity was greatly diminished. Large sandings were detectable; however, the "normal" sanding rate of 50-75 lbs/day was not easily detectable, nor were small variations in rate.

The sonic sand detector was in operation at all times during production, and continuous recordings of sand measurements were made on a strip chart recorder.

Sand shake outs were taken at 1/2 hour intervals through a 3/8-inch line at the choke manifold. A description of the technique is given in section 9.2.4 - Total Flow Sampler. In a typical shakeout, a dime-sized concentration of sand in a

half-liter of water was normal, and equated to approximately 50 to 75 pounds of sand per day. During serious sanding incidents, surges of sand equivalent to rates as high as 25,000 pounds per day were observed for short periods.

The only effective method of sand control was to keep flow rates below 10,000 barrels per day. Choke sizes were increased slowly when opening the well, in order to minimize shock to the formation; a minimum of two well bore volumes were flowed on each choke before increasing to the next size.

9.10 Brine Bypass Line

A six-inch flowline bypass was installed from the separator to the salt water disposal pit. The purpose of the bypass line was threefold:

1. To divert water to the pit should the burst plate on the separator give way.
2. To bypass flow to the pit when backflushing the disposal well.
3. As an emergency bypass, should the disposal well become plugged.

9.11 Completion Procedures and Analysis of Gravel Pack Failure

The Dow/DOE L. R. Sweezy No. 1, located at Parcperdue, Louisiana, (south of Lafayette) was a research and development well designed to study the feasibility of producing geopressured energy.

The Cib jeff interval includes approximately 50 net feet of permeable formation having an average porosity of 29%. The reservoir volume is approximately 70 million barrels. Original reservoir pressure was approximately 11,423 psig. Production of the reservoir was planned at 20,000 bbls of brine per day to allow complete depletion in a short interval of time. Core data indicated permeability of the very clean Cib jeff sand approaching 3,000 md. A sand of this vertical extent and permeability can easily produce at this rate. However, the Cib jeff sand is unconsolidated and sand control measures were required to limit sand production. Using present technology, gravel packing is the most practical method of controlling sand in an interval of this vertical extent, allowing production rates of 20,000 bbls per day. A gravel pack was installed in the L. R. Sweezy No. 1, but it was not possible to produce at 20,000 bbls per day without producing large quantities of formation sand. In fact, the well produced sand from a very early point in its life and produced large quantities of sand; even when the production rate was restricted

to less than 10,000 bbls/day, until the gravel pack failed catastrophically, February 5, 1983.

9.11.1 Need for Sand Control

In the U.S. Gulf Coast and other geologically similar areas, many of the young, deltaic deposited sand formations are either unconsolidated or are weakly consolidated by clays. The unconsolidated formations usually produce sand even at low oil production rates. The weakly consolidated formations may produce sand-free at restricted production rates.

Most of these sands are water wet. The interfacial tension of residual water helps to keep the formation consolidated. However, if the formation begins water production, the wetting phase moves and disturbs the cohesive forces of interfacial tension and the clay bonding. Sand production may begin at this point and increase with increased water saturation and production rate. The Cib jeff sand in the Sweezy No. 1 is an extremely clean, unconsolidated sand, saturated with the brine wetting phase.

9.11.2 Gravel Packing

Gravel packing has been in use for several hundred years. Its use accelerated in the late 1960s and 1970s when sizing

techniques were improved and with the advent of clean fluids and improved placement techniques. At the present time, the success ratio of gravel packing exceeds 90 percent.

There are two types of wells that demand close attention to design and procedural techniques. These are wells requiring very small gravel (US 40-60 or smaller) and high rate wells. Experience by field technicians in wells of these types is limited and the principles are not always understood. As a result, many of the gravel pack failures are in wells falling in these categories. This report will outline the process used in designing and performing gravel packs in wells requiring high performance efficiency. The design procedure starts after casing is set and assumes that the producing interval has been well isolated by a primary cement job.

9.11.3 Design Procedure

The design procedure includes the following steps:

Gravel sizing,

Selection of completion method (open hole or perforated),

Selection of screen,

Completion fluid consideration,

Gravel placement techniques.

Section 9

Smaller gravel results in decreased permeability and increased pressure loss. Most sand producing formations can be controlled with US 20-40 gravel. However, some of the younger sands are much finer and require finer gravel. Permeability of some of the commonly used gravels are listed below.

US 20-40	121 darcies
US 40-60	45 darcies
US 50-70	30 darcies

Equations used in making the pressure loss calculations in perforated gravel packs are shown below.

Packed Perforation Pressure Loss Equation

$$\Delta P_1 = \frac{0.888 L \mu Q}{KA} + 9.1 \times 10^{-13} \beta \frac{Q^2}{A^2}$$

Where ΔP_1 = Pressure loss through perforation pack, psi

Q = Flow rate, bbls/day

μ = Viscosity, centipoise

K = Gravel permeability, darcy

A = Perforation area, feet²

β = Drag coefficient,
 $10^{(6.5 - .95 \log K)}$

This equation should be applied when selecting the completion method.

The original gravel pack design for Sweezy No. 1 used twelve 3/4-inch perforations per foot and a total of 288 perforations. At 20,000 bbls/day, the pressure drop was predicted by a predesign calculation to be 31 psi with gravel having a permeability of 90 darcies. The calculations appear to have been in error and the calculated pressure loss should have been 231 psi.

The actual diameter of the perforations used was 0.68 inches but there were 600 perforations. Table 9-1 shows calculated pressure loss for rates up to 20,000 bbls/day for 600 perforations and gravel only 60 darcies permeability. At these conditions, pressure losses were borderline acceptable for 12 holes/foot.

Calculations in Table 9-1 also show the pressure loss expected if the perforations were filled with 2 darcy formation sand. An open hole pack has much lower pressure losses, but a perforated completion, even with gravel having 60 darcies permeability, is acceptable if all perforations are packed; however, if a high percentage are filled with formation sand, the pressure loss would not be acceptable.

TABLE 9-1Gravel Pack Pressure Loss

Produced Fluid Density - 1.09 kg/liter or 68.01 lbs/ft³

Produced Fluid Viscosity - 0.5 centipoise; Screen OD - 4-1/2"

Perforation Tunnel Length - 2 inches; Perforation Diameter -
0.68 inches

Producing Interval - 50 feet

<u>Production Rate (BPD)</u>	<u>Gravel Permeability (darcies)</u>	<u>Open Hole Completion (psi)</u>	<u>Perforated Completion</u>	
			<u>8 holes/ft (psi)</u>	<u>12 holes/ft (psi)</u>
5,000	60	0.08	22.5	11.3
10,000	60	0.16	77.8	37.2
15,000	60	0.24	165.8	77.8
20,000	60	0.32	286.7	132.8
5,000	2	2.4	598	306
10,000	2	4.9	2,026	981
15,000	2	7.3	4,283	2,026
20,000	2	9.8	7,370	3,439

Figure 9-16 was developed to visually indicate the minimum number of gravel packed perforations required for a given production rate. It is a series of production rate curves plotted versus pressure loss and number of perforations. These curves were developed using the Packed Perforation Pressure Loss Equation. This series of curves allows a quick estimate of the number of perforations required to produce at a certain rate under the conditions stated on the figure. For example, if the pressure loss at the perforations is to be limited to 100 psi, there must be approximately 508-0.68" diameter perforations packed with gravel having a permeability of 120 darcies producing at 20,000 bbls/day. And if only 33% of the perforations (153) are packed, the differential pressure will be at an unacceptable level of 865 psi.

In the Sweezy No. 1 a 4" OD wire-wrapped screen with .012 wire spacing was in 7-5/8" casing. This screen allowed approximately 1.4" of gravel around the screen and maximum slot area.

Ordinarily, Type 304 stainless steel wire is used with J55 base pipe in the construction of wire-wrapped gravel pack screens. Type 304 wire was used in the Sweezy No. 1, and based on well performance, the completion consultant does not believe that chloride stress cracking contributed to the failure of the well to perform properly.

FIGURE 9-16

Clean fluids are necessary to prevent deposition of solids in the perforation tunnels and mixing with the gravel. Both of these conditions result in productivity impairment.

When using clean brines and after purging the perforations, loss of fluid to the formation is increased. For this reason, use of a minimum overbalance to control the well is recommended, while keeping safety in mind. An overbalance of 150 psi is commonly used. Brine density must be adjusted to compensate for the well temperature effect.

In perforated completions, gravel placement must be performed in a manner that will assure maximum number of perforations filled with gravel. Perforations filled with formation particles will be restricted severely. Restriction of perforations diverts production through the remaining perforations at increased velocity and differential pressure. If the velocity and differential pressure are high, further restricting the productivity and increasing the rate at which complete plugging of the pack will occur. There is evidence from well test data in the Dow/DOE Sweezy No. 1 that +500 psi skin leads to increased formation particle production.

9.11.4 Gravel Pack Efficiency Improvement

Prior to injecting gravel the perforations must be purged of formation particles. In addition, the formation matrix must be permeable so that the gravel carrier fluid can be squeezed into the matrix, leaving the gravel in the perforation tunnel.

9.11.4.1 Perforation Purging

There are at least three methods used to purge perforations. The most commonly used is the washing technique using opposed swab cups to circulate between perforations. This may result in purging less than half the perforations as the fluid will follow the path of least resistance. Surging and underbalanced purging subject all the perforations to instantaneous pressure differential.

Surging was developed by Shell and is used extensively in the Gulf Coast.

Underbalanced purging is an emerging technique and has become more widely used in the past three years. Industry is divided on which method of perforation purging is best. At the present time, the majority of operators use the perforation wash technique.

9.11.4.2 Acidizing

Acidization of the perforations is extremely beneficial to proper placement of gravel. As slurry is injected into perforations, the carrier fluid must be squeezed out of the slurry, leaving gravel in the perforation tunnels. For this to occur, the formation matrix near the perforations must be permeable. Matrix acidization is normally applied to remove formation permeability damage and improve matrix fluid injectivity.

The acid treatment normally consists of three stages. A preflush of 7-1/2% hydrochloric acid is injected to remove calcium carbonate and to flush brines away from the wellbore. Following the weak acid, a mixture of hydrochloric/hydrofluoric acid is injected to remove clay and silt particles that were not soluble in the 7-1/2% hydrochloric. And because hydrochloric/hydrofluoric acid is not compatible with brines, a spacer of 7-1/2% acid is injected following the hydrochloric-hydrofluoric acid.

9.11.4.3 Stage Packing

In high rate wells, it is necessary that most if not all of the perforations are filled with gravel. This is difficult in long perforated intervals. The problem lies in non-uniform effective permeability. The gravel slurry enters the

perforations opposite the highest matrix permeability and dehydrates, leaving gravel in the perforations and a sand bridge in the screen/casing annulus. Perforations opposite less permeable matrix below this point will not be fully packed, allowing formation sand invasion of the tunnel.

Matrix acidization has been used in conjunction with diverting agents to obtain uniform permeability. This approach has only limited success and is not a solution to the problem.

One approach that has been used very successfully is to perforate a series of short intervals (10-15 feet) then purge, acidize, and pack in stages. This is an expensive approach because multiple perforation runs, purge procedures and pack procedures are required. This, coupled with the rig time, sometimes appears to be an unjustified expense. It is, however, the only effective approach to maximize the number of packed perforations. This was the approach originally recommended in the Sweezy No. 1 by Dowell.

9.11.5 Failure of Sweezy No. 1 Gravel Pack

There may have been several possible causes or contributing factors to the failure, including:

1. Perforations not prepacked
2. Single stage pack rather than three-stage (original Dowell recommendation proposed four stages)
3. Inability to bring the well in slowly during initial production stages
4. Perforating the more unconsolidated portion
5. Possible improper sizing of gravel
6. Oil coning

The analysis of the well test data indicates that factors 1, 2, and 3 could have had a severe impact. Factor 5 is a possible cause but gravel was sized using sieve analysis from whole cores and Sauciers criteria. Pack failure began prior to oil coning, so while it may have caused additional problems, it probably did not cause initial failure.

9.11.6 Analysis of Data

Well test data was taken at intervals during the producing life of the Sweezy No. 1. The test data (summarized in Table 9-2) shows skin factor, reservoir permeability, and differential pressure due to skin calculated at a given flow rate. The differential pressure due to skin was similar to measurement of the pressure loss of brine flowing through the gravel and formation-filled perforations.

Completion Technology Co. (CTC) has prepared a series of pressure loss versus perforation flow rate plots for perforations filled with materials of various permeability. These plots are in Figure 9-17. The conditions used to prepare the plots were similar to those in Sweezy No. 1.

Perforation Diameter	- .68 inches
Perforation Length	- 2 inches
Brine Specific Gravity	- 1.09
Brine Viscosity	- 0.5 centipoise

Several different packing material permeabilities were used, starting with permeability plots of 1,000 and 2,000 millidarcies that may be used to simulate perforations filled with formation materials. Then followed a series of plots with permeabilities varying from 40 to 120 darcies. These plots represent gravel filled perforations. The gravel used on the Sweezy No. 1 was US Mesh 20-40. Laboratory measurements indicated a permeability of 121 darcies for US 20-40. Field testing has indicated that the permeability of the gravel is considerably less after placing in a well. One test series indicated 80,000 millidarcies after being pumped around a screen using filtered water and a triplex pump. The permeability is further damaged when mixed with dirtier water and displaced to the bottom of a well.

FIGURE 9-17

Using these plots and permeabilities conditions, it is possible to calculate the number of perforations filled with gravel and the number filled with formation material. Gravel permeability for these calculations was estimated to be 60,000 millidarcies. Laboratory data indicated formation permeability of 2,000 to 3,000 millidarcies. However, well tests by Otis (Table 9-2) indicated permeability in the range of 476 to 1,246 millidarcies. CTC selected 1,000 millidarcies to represent permeability of the formation material filling the perforation.

The number of gravel and formation packed perforations was calculated for the differential pressures due to skin in each of the Otis tests. An explanation of the calculations follows.

Buildup Test No. 2 (April 28, 1982) was the first recorded test after production was started on April 26, 1982. This test indicated a skin of 544.7 psi when calculated at a flow rate of 13,826.8 BWPD. Figure 9-17 shows that the flow rate through a single perforation filled with 1 darcy material is 8 BWPD at 544.7 psi differential; and through a gravel filled perforation with 60 darcy permeability, the rate is 70 BWPD.

It is possible to write two simultaneous equations to solve for the number of perforations of each permeability. These equations assume that all perforation charges effectively penetrated the formation and a total of 600 perforations were present.

$$x + y = \text{Total perforations}$$

Where: x = the number of gravel filled perforations
 y = the number of formation filled perforations
 and

$$Q_{gp}x + Q_{fp}y = Q_{total}$$

Where: Q_{gp} = Flow rate BWPD through gravel filled perforation
 at a given pressure loss
 Q_{fp} = Flow rate BWPD through formation filled perforation
 at the same given pressure loss
 Q_{total} = Total flow rate from well tests at the pressure
 (P skin) Table 9-2

Using Buildup Test No. 2 data, the equations then are:

$$x + y = 600 \text{ perforations}$$

$$70x + 8y = 13826.8 \text{ BWPD}$$

Solving then shows 145 perforations filled with gravel and 455 perforations filled with formation material.

Table 9-2 shows the calculated data for each of the Otis well tests. The columns labelled "Calculated Number of Perforations" shows the number of formation filled and gravel filled perforations. While the data is indicative of probable perforation condition, it should not be interpreted as literal fact.

TABLE 9-2

CALCULATED NUMBER OF GRAVEL FILLED & FORMATION SAND FILLED PERFORATIONS

Test	Skin Factor	Reservoir Perm md	ΔP Skin psi	Flow Rate bpd	PI (Skin) bpd/psi	Calculated Rate per Perf-bpd		Calculated No. of Perfs	
						Gravel Filled	Fmt. Filled	Gravel Filled	Fmt. Filled
Build Up Test #2 4/28/82	22.7	732	544.7	13826.8	25.38	70	8	145	456
Build Up Test #3 5/13-17/82	31.7	764	335.08	6361.8	18.95	62.5	6	57	543
Build Up Test #4 5/18-20/82	36.18	749	528.26	8608.7	16.29	68.75	7.75	65	535
Build Up Test #5 5/26-6/2/82	48.19	763	863.42	10766.8	12.47	88.5	10.5	58	542
Build Up Test #8 6/28-7/6/82	23.83	476	593.95	9363.1	15.76	73	8.3	67	532
Build Up Test #9 8/27-30/82	29.47	1246	277.92	9257.4	33.31	49.4	5	141	459
Build Up Test #10 11/2-15/82	18.02	1015	188	8350	44.41	40.2	3.8	167	433
Build Up Test #11 1/19-23/83	16.3	1150	148.77	8270.2	55.59	35	3.25	199	401
Draw Down Test #11 11/15/82-1/19/83	104	656	1614.51	8017	4.96	122	15.5	-	612+

Conditions: Total Perforations - 600 Diameter - .68 in Length - 2 in
 Perforations Filled with FMT Sand - Perm = 1000 md Perforations Filled with Gravel - Perm = 60000 md
 Produced Brine - Viscosity - 0.5 cps Brine Density - 1.09 Kg/liter

In figure 9-18, the production rate per psi pressure loss due to skin, PI (skin), is plotted for each of the buildup tests shown in Table 9-2. This plot illustrates the decreasing PI (skin) through Buildup Test No. 5. After Buildup Test No. 5, there was an increasing PI (skin). This is a good indication that the formation sand and gravel were being purged from the perforations. If the screen had not already failed, flow may have been going up the annulus of the screen assembly and back into the tubing through the open crossover ports of the Model 16 packer. Sand production was controlled only by the cohesiveness of the formation from this point in time.

9.11.7 Conclusions

Analysis of data in this table leads to the following conclusions:

1. Due to prepack in one stage, there were only ± 150 perforations filled with gravel initially.
2. Due to the high skin created by poor packing, gravel was flowed out of some of the perforations and replaced by formation sand causing an increased differential skin pressure of 863.42 psi and a skin factor of 48.19 in Build-up Test No. 5. This is also reflected by reduced Productivity Index (Skin), plotted in Figure 9-18.

PRODUCTIVITY INDEX OF SKIN VERSUS TIME

FIGURE 9-18

3. Increased differential pressure probably completely purged some of the perforations and most of the flow was coming from only a few perforations, after Buildup Test No. 6.
4. During Drawdown Test No. 11, all perforations filled with sand, causing almost complete plugging.
5. Production after that date probably came from only a few perforations until the screen was blasted through. A complete failure occurred on February 5, 1983.
6. There is evidence that the well was in trouble from the initial test. However, a rework at that time would have been very expensive and involved, because it would have been virtually impossible to have effected a complete pack of all the perforations without stage packing.
7. Casing may have buckled in the producing zone due to reduced reservoir pressure and lack of lateral support resulting from voids around the wellbore.
8. Workover of the production well would have been impractical due to high risk and high expense.

10. Chemical Analyses

The chemical and physical analyses of fluids from the L. R. Sweezy well were carried out by the University of Southwestern Louisiana (USL) in Lafayette, Louisiana.

10.1 Facilities

The analyses were performed at two of the University's Laboratories and at an on-site laboratory trailer. The laboratory trailer contained the following major items of analysis equipment:

Varian	Gas Chromatographic System
Varian	Atomic Absorption Spectrometer
Bausch & Lomb	Spectrophotometer
Beckman	Conductivity Bridge
Orion	Ion Selective Electrode System
Corning	pH meter

The University preparatory laboratory provided:

- wet chemistry facilities
- solvent extraction system
- sample dryers
- sample mounting

USL's Acadiana Research Laboratory provided the
3MV van de Graaff accelerator and its
associated proton beam handling equipment
sample irradiation chambers
x-ray detection equipment
-ray detection equipment
data link to USL's Multics computer

10.2 Laboratory Procedures

The various procedures used will be discussed in the sections dealing with particular fluids.

10.3 Sampling Procedures

Three different fluids were sampled: the brine, the exsolved gas and the condensables from the gas stream. The sample points are shown in Figure 10-1.

10.3.1 Brine Sampling

The brine samples were removed from the brine stream through a sampling point just downstream from the choke system. The hot brine, normally about 96°C was passed slowly through a coil of 3/8" stainless steel tubing immersed in an ice bath to reduce its temperature. This cooling was designed to reduce the loss of

FIGURE 10-1 CHEMICAL SAMPLING POINTS

volatile compounds. This procedure is a standard one suggested by several authors. Normally about eight (8) liters of brine was taken on the sampling schedule shown in Table 10-1 which included both the early short term flow tests and long term tests. Table 10-1 also lists the cumulative brine production on the sample dates. Some large volume samples were also taken for extraction of trace materials in the brine.

TABLE 10-1

BRINE SAMPLING SCHEDULE

SAMPLE #	DATE (Time)	CUMULATIVE BRINE VOLUME in kilobarrels
1.	5-12-82 (1258)	-
2.	5-12-82 (1700)	4
3.	5-12-82 (0902)	8
4.	5-13-82 (1717)	11
5.	5-17-82	15
6.	5-18-82	18
7.	5-18-82	20
8.	5-20-82	23
9.	5-21-82	37
10.	5-22-82	47
11.	5-23-82	58
12.	5-24-82	70
13.	5-25-82	80
14.	6- 8-82	135
15.	6-11-82	160
16.	6-14-82	187
17.	6-17-82	216
18.	6-21-82	255
19.	6-25-82	309
20.	7- 7-82	329
21.	7-14-82	395
22.	7-19-82	442
23.	7-26-82	507
24.	8- 2-82	567
25.	8- 9-82	636
26.	8-16-82	701
27.	8-23-82	767
28.	9- 1-82	825
29.	9-13-82	868

30.	9-27-82	996
31.	10-4-82	1060
32.	10-11-82	1123
33.	10-18-82	1186
34.	10-25-82	1248
35.	11- 2-82	1300
36.	11-16-82	1320
37.	11-22-82	1360
38.	11-29-82	1421
39.	12- 6-82	1481
40.	12-20-82	1585
41.	12-27-82	1652
42.	1- 3-83	1718
43.	1- 10-83	1783
44.	1- 16-83	1840
45.	1- 25-83	1856
46.	2- 2-83	1928

The regular samples were divided into five (5) parts as follows:

TABLE 10-2

Brine Samples

1. Raw, unacidified (RU)
2. Raw, acidified (RA)
3. Filtered, unacidified (FU)
4. Filtered, acidified (FA - HNO_3)
5. Filtered, acidified (FA - HCl)

The various sample fractions were used as listed in section 10.4.

10.3.2 Gas Sampling

A standard double-valved, teflon-lined gas sampling bomb was attached to a gas sampling port at the top of the gas-brine separator and both inlet and outlet valves opened. After a time long enough to insure that the sampler was flushed by the gas flow, the outlet valve was closed and after a moment, for the pressure to equilibrate, the inlet valve closed. The gas from the separator was sampled on essentially the same schedule as brine samples.

10.3.3 Condensable Hydrocarbon Sampling

The condensable materials in the gas stream were collected seven times during the course of testing the well. The apparatus used to collect these samples consisted of a two stage regulator which reduced the pressure and a series of traps and a flow meter. The gas stream passed through an ice-water cooled trap to remove some moisture from the stream. The stream then passed through two "dry ice" - acetone traps and finally through a wet test meter to record the total volume of gas which passed through the system.

10.4 Brine Analysis

Brine analysis included both physical and chemical testing.

10.4.1 Physical Methods - Procedures

A. Density

The density of the brine was determined by weighing a standard volume (usually 50 ml) contained in a pycnometer which was equilibrated in a constant temperature bath at 25.0°C.

B. Viscosity

The viscosity of the brine was determined by timing the flow of a standard volume brine through the calibrated orifice of a Oswald viscosimeter maintained at 25.0°C. The equation used was

$$\text{viscosity} = 0.8928 \rho_x \left(\frac{t_x}{t_{H_2O}} \right)$$

ρ_x = density of the brine

t_x = flow time for the brine

t_{H_2O} = flow time for H_2O

C. Conductivity

The conductivity of the brine was measured directly using a Beckman conductivity bridge and a calibrated immersion-type conductivity cell. The cell and the brine were maintained at 25.0°C in a constant temperature bath.

D. pH

The pH of the brine was measured directly using a standard pH meter and a combination pH electrode. The pH was measured soon after the sample was taken and the value reported is the equilibrium value, i.e., when no further change was observed.

10.4.2 Chemical Methods - Procedures

A. Chloride

The chloride ion concentration was measured by titration; the Mohr method.

B. Sulfate

The sulfate ion concentration was determined turbidimetrically using FA-HCl brine. Comparison was made to matrix-matched standards.

C. Hydrogen Carbonate

Hydrogen carbonate was determined using a specific ion electrode and a fresh sample of RU brine.

D. Fluoride

Fluoride was determined using a specific ion electrode. A sample of FU brine was compared to matrix-matched standards.

E. Alkalinity

The total alkalinity was determined by potentiometric titration of an RU brine sample using standard HCl solution.

F. Hardness

The total hardness of the brine was determined by titration with ethylenediaminetetracetic (EDTA) acid to an Erichrome Black-T end point.

G. Dissolved Solids

A sample of FA-HCl brine was evaporated to dryness and the residue weighed.

H. Dissolved Silica

Silica was determined using the spectrophotometric molybdate method on an RU brine sample.

I. Ammonia

Ammonia was determined using a specific ion electrode. A sample of FU brine was compared to matrix-matched standards.

J. Boron

Boron was determined using the spectrophotometric curcumin method.

K. Atomic Absorption Methods

The following elements were determined using atomic absorption spectrometry. Except for sodium all determinations were in comparison to matrix-matched standards.

- a. zinc
- b. sodium
- c. potassium
- d. magnesium
- e. iron
- f. calcium

L. Bromine

Bromine was determined using proton induced x-ray emission.

M. Strontium

Strontium was determined using proton induced x-ray emission.

10.4.3 Results of Brine Analyses

Several parameters and constituents changed during the course of the sampling. The results reported in Table 10-3 are the asymptotic ones; the average of many essentially unchanging values. The values which changed with time are reported graphically in Figures 10-3 through 10-5. For reference, the unchanging values of total solids and chloride are shown in Figure 10-2. The analysis of the changes are discussed in Section 10.8. The standard deviation, $\sigma_{\bar{x}}$ reported in Table 10-3 is calculated by the expression.

$$\sigma_{\bar{x}} = \sqrt{\frac{\sum (x_i - \bar{x})^2}{n(n-1)}}$$

where x_i is a particular value of a set of n values and $\bar{x}$ is the mean value of the set.

TABLE 10-3
Brine Analysis

<u>DETERMINATION</u>	<u>MEAN VALUE</u>
Density @ 25°C	1.062 $\pm$ 0.000 g/mL
Conductivity @ 25°C	121,700 $\pm$ 641 mhos/cm
Viscosity @ 25°C	1.045 $\pm$ 0.001 ep
pH (equilibrium)	6.37 $\pm$ 0.02
alkalinity	1540 $\pm$ 23 mg/L
total dissolved solids	99,700 $\pm$ 240 mg/L
total hardness (as CaCO ₃)	5410 $\pm$ 140 mg/L
sodium	33,890 $\pm$ 170 mg/L
potassium	176 $\pm$ 4 mg/L
magnesium	262 $\pm$ 3 mg/L
boron	60.2 $\pm$ 0.6 mg/L
manganese	1.1 $\pm$ 0.09 mg/L
silica	68.4 $\pm$ 1.1 mg/L
ammonia	48.0 $\pm$ 0.8 mg/L
iron	2.10 $\pm$ 0.09 mg/L
zinc	1.92 $\pm$ 0.16 mg/L
calcium	1710 $\pm$ 30 mg/L
strontium	245 $\pm$ 11 mg/L
chloride	55,720 $\pm$ 140 mg/L
hydrogen carbonate	380 $\pm$ 13 mg/L
sulfate	522 $\pm$ 4 mg/L
carbonate	0.04 $\pm$ 0.003 mg/L
fluoride	1.65 $\pm$ 0.07 mg/L
bromide	110 $\pm$ 15 mg/L
iodide	36.3 $\pm$ 1.6 mg/L

10.5 Gas Analyses

A small portion of the gas sample was removed through a fixed volume sampling loop and injected into the gas chromatograph equipped with a seven foot PORPAK-Q column. The sample was carried by chromatographic grade helium. The column was heated and its temperature varied in a programmed sequence. The mole percent of each component is calculated in the following manner.

$$N_i = \frac{A_i R_i}{\sum A_i R_i} \times 100$$

N_i = the normalized (mole) percent of component i

A_i = the integrated peak area for component i

R_i = the relative response factor for component i

The mean results and the standard deviations of the mean are given in Table 10-4.

TABLE 10-4
Gas Analyses

<u>DETERMINATION</u>	<u>MOLE PERCENT</u>
N ₂	0.39 ± 0.03
CO ₂	2.45 ± .12
C ₁	94.17 ± .16
C ₂	2.48 ± .02
C ₃	.35 ± .02
i - C ₄	.09 ± .003
n - C ₄	.03 ± .003
i - C ₅	<.01
N - C ₅	<.01
C ₆ +	<.01

FIGURE 10-2 VARIATIONS OF TOTAL DISSOLVED SOLIDS AND CHLORIDES

FIGURE 10-3 VARIATION OF IRON

FIGURE IO-4 VARIATION OF CALCIUM

FIGURE 10-5 VARIATION OF ZINC

10.6 Trace Elements

The trace element concentration of the samples was measured using a technique which used solvent extraction to isolate elements or groups of elements from the brine; then analysis of the group by proton induced x-ray emission (PIXE). It was hoped that these trace indicators would provide information concerning changes in the source of the waters sampled.

In the PIXE method of analysis, a proton beam with an energy of about 2 MeV is directed into a sample. The proton beam has quite sufficient energy to remove the innermost electrons around the atoms of the sample. When an electron vacancy is created in a particular shell of an atom, the excited atom may stabilize by filling the vacancy with an electron from a higher shell and the emission of a photon of electromagnetic radiation. When the vacancies occur in the K or the L shell the photons are usually in the x-ray region. The designation of these x-rays are as follows

Vacancy In ___ Shell	Electron Filling The Vacancy From ___ Shell	X-Ray Designation
K	L	K
K	M	K
L	M	L
L	N	L
L	O	L

The energies of the x-rays from particular elements are known from atomic physics calculations. The observation of particular x-ray energy groups provides a unique means of identifying the presence of elements in a sample. See for example Figure 10-6; the abscissa is proportional to x-ray energy. This is an energy spectrum from the bulk solids from the brine. The germanium peaks result from a standard added to the samples. Quantitative measurements of elemental concentrations can be accomplished by comparison to standard samples or by such techniques as standard addition.

Interfering background, the generally unstructured events of Figure 10-6, which tend to obscure smaller x-ray peaks, results primarily from three sources: Compton scattering of higher energy gamma rays produced from proton-nucleus reactions, pile-up of signals in the detection electronics when two x-rays arrive at the detector at essentially the same time and bremmstrahlung (German for breaking radiation) x-rays which are produced in the deceleration of electrons in the sample which were ejected by the proton beam. The second source can be reduced by simply counting for a longer time at a slower rate and by electronically rejecting some pulses which occur too close together in time. Of the other two sources, the last is the most serious, best dealt with by using thin samples so that the electrons produced do not decelerate in the sample but pass through. Solvent extraction of complex ions of various elements is a technique long employed for

FIGURE 10-6 X-RAY ENERGY SPECTRUM FROM THE BULK SOLIDS FROM A BRINE SAMPLE

separation. Since PIXE can detect the presence of many elements simultaneously, techniques which extract groups of elements leaving behind the bulk of a sample are particularly useful.

To accomplish this extraction, brine samples were adjusted to a pH of 4 and a small amount of sodium diethyldethiocarbamate (NaDDTC) added. The metal complexes produced were extracted into a few milliliters of chloroform. This chloroform was evaporated, leaving a very thin sample containing the trace elements of interest. The bulk of the sample-sodium, potassium, calcium and magnesium salts is not extracted. Pixie results are listed in Table 10-5.

TABLE 10-5

<u>ELEMENT</u>	<u>CONCENTRATION</u>	
	Brine Sample:	
	<u>8-2-82</u>	<u>2-2-83</u>
V	< 5 ppb	< 5 ppb
Cr	<10 ppb	<10 ppb
Mn	1.1 ppm	1.0 ppm
Fe	2 ppm	1.6 ppm
Ni	< 5 ppb	< 5 ppb
Cu	<10 ppb	<10 ppb
Pd	<10 ppb	<10 ppb
Pb	50 ppb	40 ppb

Figure 10-7 is a portion of an x-ray energy spectrum of a thin sample extract described above. The peaks corresponding to vanadium, manganese, iron, nickel, copper and zinc are shown. Vanadium and nickel are not found in the brine. This particular spectrum represents a sample to which 100 parts per billion (ppb) of each of vanadium and nickel was added. Further, an addition of as little as 5 ppb produced a peak which was discernable above the background events. Not all of the elements of interest are extracted efficiently into NaDDTC, however cupferron is an excellent agent for Cr, Cu and Pd among others. Table 10-5 lists the results of the extraction/PIXE measurements for two representative brine samples.

10.7 Hydrocarbon Production

Early in our testing of the fluids from the DOW-DOE L. R. Sweezy #1 geopressured well in Vermilion Parish, Louisiana, we detected the presence of a small amount of condensable hydrocarbons in the separator gas from the well. These hydrocarbons were trapped from a small amount of the separator gas by means of a series of "dry ice" -- acetone traps. Analysis of this condensate showed it to be largely aromatic in nature. The production of this primarily aromatic condensate continued over the lifetime of the well. Furthermore, the production of

FIGURE 10-7 X-RAY SPECTRUM OF SOLVENT EXTRACT

hydrocarbons increased during the lifetime. A "drip pot" trap in the gas line from the separator to the flare began to collect a light oil, where before only water had been present. About one month before the demise of the well due to excessive sand production, the well began to produce heavy oils. The production of these hydrocarbons could inject a new dimension into the economic equation for geopressured-geothermal brine production.

The presence and significance of this aromatic condensate in the L. R. Sweezy well generated interest in determining if similar condensates could be obtained from the Pleasant Bayou #2 geopressured-geothermal well in Brazoria County, Texas, and/or from the Gladys McCall #1 geopressured-geothermal well in Cameron Parish, Louisiana. An attempt was made to correlate any hydrocarbons collected from these wells with that already obtained from the L.R. Sweezy well.

Experimental Results

The three wells sampled all contain very similar, primarily aromatic, hydrocarbons in the gas exsolved from the brine. Figure 10-8 shows gas chromatographs of these condensates. The six major components are labeled: B = benzene, T = toluene, E = ethylbenzene, and O, M, and P, for ortho-, meta-, and para-xylene

Figure 10-8 Gas Chromatographs of Hydrocarbons Condensed from the Gas Streams from three Geopressed Wells.

respectively. Table 10-6 gives the mole percents of the six compounds from each of the three wells. Our early semiquantitative results indicated that the amount of condensate in the separator gas from the wells are: L. R. Sweezy #1 = 15ml/MCF, Gladys McCall #1 = 86ml/MCF, and Pleasant Bayou #2 = 123ml/MCF. It was noted the condensates from the sampled wells are very much different in character than a condensate sample taken from a producing gas well whose producing zone is in the same sand as the L. R. Sweezy #1 well, but across a fault.

TABLE 10-6

COMPOUND	MOLE PERCENT		
WELL:	Sweezy	Gladys McCall	Pleasant Bayou
Benzene	32.96	66.94	51.05
Toluene	36.04	23.44	33.91
Ethylbenzene	7.53	2.51	2.96
o-Xylene	11.19	2.62	4.07
m-Xylene	10.39	3.85	6.87
p-Xylene	1.89	0.65	1.14

10.8 Discussion of Results

The detailed analytical chemistry, both inorganic and organic, that was performed on the L. R. Sweezy well, provided the basis for the understanding of some of the processes which were active during the production of the well.

10.8.1 Elution of completion fluids from the formation.

The several brine samples from the early short term flow tests of the well and the weekly samples of the long term tests revealed a sharp decrease in concentration of calcium and zinc (Figures 10-4, 10-5). Subsequent bromine analysis yielded a similar pattern.

A reasonable explanation for this phenomenon lies in the fact that the Dowell Hevi-water® completion fluid was left standing in the well for about 2-1/2 months. The well was left in this condition while repairs were being made to the special "christmas tree" which failed due to a valve malfunction on initial installation. The Hevi-water® is a solution of calcium bromide (CaBr_2) and zinc bromide (ZnBr_2) in proportions to provide the desired density - which varied during the completion of this well. This solution is assumed to have diffused into the formation.

The elution of the $\text{CaBr}_2\text{-ZnBr}_2$ from the formation does not follow a pattern indicative of simple diffusion into the formation. If only one, simple diffusion process was involved, one would expect the concentrations eluted would decrease in a simple exponential fashion, and a graph of the logarithm of the concentration as a function of elution volume would then be a straight line. Figure 10-9 shows that this is not the case. However, as analysis of this graph reveals, it can be decomposed into three straight line components representing three separate diffusion rates.

The equation for the elution (chi-squared) in mixed units is:

$$C_{\text{Zn}} = 208.6e^{-0.54V} + 162.0e^{-0.0099V} + 18.3e^{-0.0027V}$$

The concentration of zinc, C_{Zn} is in units of mg/L and V is the cumulative volume produced in thousands of barrels (42 gallons per barrel). A background of 2 mg/L of zinc, determined from the long term limit of the concentration, was subtracted from all the data to account for the natural zinc in the formation.

FIGURE 10-9 LOGARITHM OF THE ZN CONCENTRATION AS A FUNCTION OF PRODUCTION VOLUME.

The coring from the sand showed that the production formation was separated into two distinct zones, the upper and lower. Further, the upper zone is cut by siltstone "stringers". The average permeability of the lower zone is 20 millidarcies, while that in the middle of the upper zone ranges from about 100 millidarcies to about one darcy. The upper portion of the upper zone was sparsely measured and only one figure of 44.8 millidarcies is reported. It is suggested that the Hevi-water® standing in the well diffused at different rates into the different regions of the production zone and the elution function reflects this fact.

The elution function was integrated over the total volume removed and it was found that 4.3×10^3 kilograms (9540 pounds) of zinc was removed from the formation; as zinc bromide 1.5×10^4 kilograms were removed. The Hevi-water® was on the average about 10% ZnBr_2 (weight-weight), so about 1.5×10^5 kilograms of solution were removed. Separate calcium analysis confirms this number to within 10%. Furthermore this amount of Hevi-water® corresponds to about 130 barrels which is in satisfactory agreement with the "somewhat over 100 barrels" reported lost during completion operations.

10.8.2 Analytical Methodology

Most of the analytical methods chosen in this work were standard and taken from Hankins and Watson. Analytical chemistry is not, however, a static and unchanging science, and better methods and/or techniques can often be developed. Two such developments need to be stressed here:

A. Ion selective electrode analysis for:

1. Fluoride

Although ion-selective electrode analysis is a recommended procedure for fluoride ion, there are no details for a proper methodology available for use of this type of electrode in brine.

2. Ammonia and Carbon Dioxide

Methods have been developed to utilize these gas-sensing, ion-selective and bicarbonate ions in brine. The use of reconditioning buffers is the key to reproducibility.

B. Proton Induced X-ray Emission (PIXE) Analysis of Strontium and Bromine

The PIXE analysis technique described in Section 10.6 for determining trace elements proved also to be an excellent technique for determining bromine and strontium. Dried samples of the solids from measured amounts of brine containing a reference element were bombarded with protons and characteristic x-rays measured. An x-ray energy spectrum for these elements appears as Figure 10-6 in this report. Here the reference element is germanium to provide consistency from sample to sample.

Quantitative results were obtained using the method of standard additions. In most methods the large excess of chloride and calcium ions would interfere with the bromide and strontium ion analysis; this poses no problem in this method.

10.8.3 Trace Chemistry

It has been found in this work that the already very sensitive technique of proton induced x-ray emission can be greatly facilitated by combining it with solvent extraction of groups of elements. The methods developed proved very useful for brine

samples where the overwhelming bulk of sample interferes with the elements of interest. Sensitivity of a few parts per billion were achieved.

It was hoped to use changes in the trace element inventory of the brine to shed light on the intrusion of other waters into the production formation. If these waters came from the surrounding shales one would expect that the different chemical history of these waters would cause changes in composition of the produced brine. No changes were observed in the trace elements which were followed in this work.

Increases in the trace content would have been taken as evidence for the intrusion of new waters. The lack of change does not support the counter point since less than 2% of the estimated volume of the formation water was removed during the production period. Further, there is no direct information concerning the shale water composition, nor is there any idea as to the degree to which other waters would mix with those in the formation and find their way to the well bore.

10.8.4 Hydrocarbon Condensates and Oils

It is impossible to unequivocally determine the source of the observed condensates. Several hypotheses are presented which are consistent with the following chemical facts:

1. At a given temperature and pressure, aromatic hydrocarbons, in general, are more soluble in water (or brine) than are aliphatic compounds of equal numbers of carbon atoms (eg: benzene, C_6H_6 vs. hexane, C_6H_{14}).
2. At a given temperature and pressure, if two or more phases of a multicomponent system remain in contact (ie: share a common interface) for a sufficient period of time, then the components must partition themselves between these phases so as to give the overall system a minimum Gibbs Free Energy. This is the thermodynamic requirement for equilibrium in such a system.

With only these facts and the observations of the behavior of the L. R. Sweezy #1 well (This is the only well to date which has flowed over a substantial portion of its possible lifetime.); two simple hypotheses (ie: models) that are consistent with the above scientific facts and the observations to date are proposed.

Hypothesis 1. In this model system, excluding sand structure; the formation brine is still in contact with either a liquid petroleum phase, or a petroleum-rich gas phase, or possibly both. Furthermore, the contact between the phases has existed for a sufficient period of time for the components that comprise the condensate to be in a state of equilibrium partition between the two or more phases.

Hypotheses 2. In this model system, again excluding sand structure; either liquid petroleum, or a petroleum-rich gas phase, or possibly both at some point in geologic time contacted the formation brine and allowed for partition of the components that comprise the exsolved condensate. (Note: Equilibrium partition is not a requirement of this model, but in view of movement restrictions imposed by porosities and permeabilities we would tend to believe it was at least approximated.)

Hypothesis #1 probably offers the best explanation of the events at the L. R. Sweezy #1 well. It was not until after the production of large quantities of brine, that dramatic changes occurred in the hydrocarbon production. Since the hydrocarbon production was rather small (estimated at a few gallons/day) compared to the brine production (approximately 8,000 bbls/day), a

liquid hydrocarbon phase or a petroleum-rich gas phase is unlikely as the source. The petroleum rich gas phase referred to could be similar to that observed by Price, et.al., in laboratory studies.

For the Pleasant Bayou #2 and the Gladys McCall #1 wells, either hypothesis is a plausible model at this point in time. Both wells are producing essentially the same kind of condensate as did the L. R. Sweezy #1 well prior to the onset of oil production. However, as was previously stated, the condensate yield per MCF of gas varies in amount by a factor of eight between the 15ml/MCF of the L.R. Sweezy #1 well and the 123ml/MCF of the Pleasant Bayou #2 well. There are a number of possible explanations of the variation in condensate yield. Assuming a relatively constant aromatic content in the original oils, then the implication is that a greater relative amount of oil is now, or was, in contact with the brine in the Pleasant Bayou #2 production zone.

11. PVT Analysis

Surface separator water samples were taken by a representative of Weatherly Laboratories, Inc. on May 12, 1982.

The gas-liquid ratio measured on this test, 10.01 cubic feet of separator gas per barrel of separator liquid, was used as the basis for one recombination. The resultant reservoir fluid exhibited a bubble point of 5037 psia at the reservoir temperature 237.4°F.

Subsequent tests indicated that a gas-liquid ratio of 17.0 SCF/Bbl. is more representative of the reservoir fluid. This reservoir fluid would exhibit a bubble point of 8870 psia at 237.4°F. This interpolated bubble point pressure has a possible error of $\pm 0.4\%$.

The reservoir fluid exists as undersaturated brine at reservoir conditions (11,408 psia and 237.4°F).

The complete Weatherly report, with numerical data is presented in Appendix K.

11.1 Sampling and Laboratory Procedure

1. Water vapor content of separator gas:

Determined by flowing gas from a metering valve on the

meter run through a weighing tube (indicator Drierite (CaSO_4) weighed to 0.1 milligram) to a G.C.A./Precision Scientific wet test meter. Separator gas samples were taken from the same place into evacuated 1 gallon stainless steel cylinders after thorough purging of transfer line at separator pressure. Separator liquid sample cylinders (500 ml. S.S.) were first charged with separator gas to full separator pressure. The liquid cylinders were then connected to the separator water sampling point by a S.S. tube long enough to loop through a cooling bath. The water transfer line was then slowly and thoroughly purged at the cylinder. Separator water was let into the cylinder by slowly bleeding gas from top valve. At no time was the water caught in the cylinder allowed to drop below separator pressure.

2. Flash liberation of gas from separator water:

Accomplished by using a weighed separator flask. This separator flask was connected to the outlet of a separator water cylinder by a short capillary line. Gas from the separator flask passed through a weighed drying tube through a glass cylinder (300 ml.) to a Ruska Gasometer. A vacuum valve and a mercury manometer were connected to the gas manifold between the drying tube and the

gasometer. Before commencing the flash, the entire flash gas manifold was evacuated and then filled with helium to atmospheric pressure. A known volume of separator water was pushed out of the sample cylinder at a pressure slightly above field separator pressure by use of a calibrated mercury pump. The volume of stock tank water produced was determined by its weight and density. The volume of dry gas evolved was determined with the gasometer. This gas volume was subject to $\pm 2\%$ error due to the very small amounts measured. The gas was charged from the glass cylinder to a chromatograph for analysis.

3. Physical recombination of separator effluents:

Dry separator gas was charged into a temperature controlled cell. The volume of this windowed cell is known for any pressure and temperature. The pressure of the gas in the cell was measured with a mercury manometer and a barometer. This calculated gas volume was subject to a $\pm 1\%$ error due to the small amount charged to the cell. A volume of separator water was charged into the windowed cell by use of a calibrated mercury pump. The water was metered and measured at a pressure slightly

above field separator pressure. Four recombinations were done in order to produce a saturation pressure-vs-gas-water ratio curve. A fifth recombination was done using the produced gas-water ratio at the time of sampling.

4. Pressure-volume relations of recombined reservoir fluid at reservoir temperature:

Each datum of pressure-volume relations was corrected for mercury pump calibration, manifold expansion, cell expansion, mercury compressibility and mercury thermal expansion. Liquid volume percent was determined by calibrated cathetometer and by data interpretation.

5. Differential liberation of reservoir fluid at reservoir temperature:

Gas from each pressure decrement of the differential liberation was analyzed in the same manner as described in 2, (flash liberation). Differential liquid changes were noted.

6. Viscosity of reservoir fluid:

Geothermal water viscosities were measured using an E.L.I. Rolling Ball Viscometer with an electronic detection system to prevent electrolysis. The detection system consists of a sensitive audio amplifier with a

positive feedback adjusted just below oscillation. Feedback was turned on by an automatic switch as the viscometer was inverted at the beginning of the cycle and turned off when the ball made contact. Part of the signal was used to turn the digital timer on and off. Times were measured to 1/100th of a second and averaged. The viscometer was calibrated at each of the three angles using several known viscosity standards which were checked against Cannon-Fenske Viscometers and the results ($t\Delta\rho$ vs. μ) plotted. The viscometer was recalibrated using distilled water at several temperatures. These results were used along with previous results to obtain new calibration curves.

t = roll time, (second)

$\Delta\rho$ = density difference between ball and
reservoir fluid, (gm./ml)

μ = viscosity, (centipoise)

The viscometer was charged with reservoir fluid and run at 237.4°F at 1000 lb. intervals. The viscosities had a probable error of ± 0.002 centipoise.

11.2 Field Data for Weatherly Laboratory Investigation**11.2.1 Well Record**

Company	Dow Chemical U.S.A
Well	L. R. Sweezy No. 1
Field	Parcperdue
Parish and State	Vermilion, Louisiana

11.2.2 Field Characteristics

Formation Name	Anahuac
Sand Name or Designation	Cib jeff
Date Completed	August 1981
Original Reservoir Shut In Pressure (5-12-82)	11,408 psia

11.2.3 Well Characteristics

Original Produced Gas-Liquid Ratio	17:1 (est)
Perforations	13,349-388'; 13,395-406'
Elevation	17'
Total Depth	13,600'
Last Reservoir Flowing Pressure (5-12-82)	11000 psia
Reservoir Temperature	237.4°F

11.2.4 Sampling Conditions

Date Sampled (on 24/64" choke)	5-12-82
Tubing Pressure, Flowing	5013 psig
Primary Separator Temp.	122 °F
Primary Separator Pressure	614 psig
Primary Separator Gas Rate	64,259 SCF/day
Separator Liquid Rate (2nd. Stage @ 60 psig)	6417.6 Bbls/day
Gas-Liquid Ratio	10.013 SCF/Bbl 60#L
Shrinkage Factor (Vol.60#Liq.@122°F/Vol.614#Liq. @122°F)	1.001
Gas-Liquid Ratio	10.014 SCF/Bbl. 614#Liq.
Shrinkage Factor (Vol.S.T.Liq.@60°F/Vol Sep.Liq. @614#&122°F)	0.9865
Gas-Liquid Ratio	10.151 SCF/Bbl.S.T.Liq.
Pressure Base	15.025 psia @ 60°F
Gas Rate	64,259 SCF/day @ 15.025 psia @ 60°F

11.3 Reservoir Fluid Summary

Reservoir Temperature	237.4°F
Saturation Pressure at 237.4°F	5037 ± 23 psia
Compressibility of Reservoir Water at 237.4°F Vol. per Vol. per Psi x 10 ⁶	
From 5037 Psia to 7000 Psia	2.55
From 7000 Psia to 9000 Psia	2.46
From 9000 Psia to 11,408 Psia	2.43

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Saturated Water at 5037 Psia, 237.4°F		<u>Diff. Lib.</u>
Density, Gms. per Ml.		1.0327
lbs. per Bbl.		361.96
Specific Volume, Cu. Ft. per Lb.		0.015511
Viscosity, Centipoise		0.415
Formation Volume Factor, Bbls. per Bbl.		
"Residual Stock Tank Water" at 60°F	1.0539*	1.0491
Solution Gas-Water Ratio, Cu.Ft. per Bbl	14.1*	17.1 Wet
"Residual Stock Tank Water" at 60°F	13.5*	13.5 Dry
Reservoir Water at 11,408 Psia 237.4°F		
Density, Gms. per Ml.		1.0492
Lbs. per Bbl.		367.74
Specific Volume, Cu.Ft. per Lb.		0.015267
Viscosity, Centipoise		0.437
Formation Volume Factor, Bbl. per Bbl.		
"Residual Stock Tank Water at" 60°F		1.0326

*Based on separator water flash.

Figures 11-1 thru 11-6 summarize the results of the laboratory tests. Bear in mind that it was learned after sampling was completed that the GWR was closer to 17 SCF/bbl than the 12 SCF/bbl originally measured. This results in a revised bubble point of 8800 psia, as indicated on Figures 11-1 and 11-3 (and implied but not shown on 11-2).

11.4 Adjusted PVT Data

PVT data used in reservoir calculations were adjusted to account for changes in bubble point pressures and for wet gas. The adjusted data is presented in Table 11-1.

TABLE 11-1

ADJUSTED LAB PVT DATA DOW/DOE NO.1 L.R. SWEETZ WELL

<u>P</u> (psia)	<u>Bwf</u> (RB/SB)	<u>Rsf</u> (SCF/SB)	<u>μ_w</u> (CP)	<u>ρ_w</u> (LBM/CF)	<u>Bg</u> (RB/Mscf)
11447.1	1.02387	20.58	0.4371	65.510	--
11000	1.02502	20.58	0.4355	65.437	--
10500	1.02630	20.58	0.4337	65.356	--
10000	1.02758	20.58	0.4319	65.275	--
9500	1.02887	20.58	0.4302	65.195	--
9000	1.03016	20.58	0.4284	65.114	--
8800	1.03068	20.58	0.4268	65.081	--
8550.15	1.03139	20.58	0.4279	65.041	(Bubble Point)
8000	1.0326	20.04	0.4200	64.670	0.55305
7800	1.0332	19.87	0.4189	64.558	0.56056
7400	1.0342	19.19	0.4167	64.333	0.57691
7000	1.0352	18.56	0.4145	64.108	0.59535
6800	1.0358	18.10	0.4134	63.996	0.60550
6400	1.0366	17.08	0.4112	63.771	0.62803
6000	1.0374	15.84	0.4189	63.546	0.65411
5800	1.0377	15.20	0.4178	63.433	0.66873
5400	1.0381	13.74	0.4156	63.208	0.70175
5000	1.0385	12.21	0.4134	62.983	0.74071

RB = reservoir barrel

SB = separator barrel

SCF = standard cubic feet

CP = centipoise

LBM = pounds of mass

CF = cubic feet

Mscf = thousand SCF

FIGURE 11-1 EFFECT OF GAS-WATER RATIO ON BUBBLE POINT PRESSURE AT 237.4°F

FIGURE 11-2 LIQ. VOL. % VS. PRESSURE-RES. WATER AT 237.4° F

FIGURE II-3 DIFF. LIBERATION OF RESERVOIR WATER AT 237.4°F

FIGURE II-4 FORMATION VOLUME FACTOR & SOLUTION GAS-WATER RATIO (BASED ON SEP. WATER FLASH) AT 237.4°F

FIGURE 11-5 SPECIFIC VOLUME OF SATURATED (BUBBLE POINT) WATER AT 237.4° F

FIGURE 11-6 VISCOSITY OF RESERVOIR WATER AT 237.4°F

12. Drilling, Completion, Abandonment

12.1 Dow/DOE L. R. Sweezy No. 1 Production Well

Drilling operations commenced January 2, 1981, and were completed August 14, 1981. A summary description of those operations through completion and abandonment follows.

12.1.1 Test Site Layout and Drilling Rig

The test site is located on the L. R. Sweezy lease in the North Parcperdue field in Vermilion Parish, Louisiana. The Sweezy property consists of 37.5 areas of pasture land with a surface elevation of approximately 20 feet.

Test well location was 1800 feet from the south line and 1350 feet from the west line of Section 26, Township 11 South, Range 4 East. Location of the site and the wells on the Sweezy property are shown in Figure 12-1.

The drilling rig, designated Welsh No. 17 and rated at 18,000 feet, was contracted through competitive bidding with Welsh Drilling and Services, Inc., Houston. The contract was a Daywork Drilling Contract and included drill crews, drill pipe, and fuel furnished for a constant 24-hour day rate.

FIGURE 12-1 REVISED SITE LAYOUT (9-10-81)

All equipment, labor, and expense to move-in, rig up, rig down, and move-out were covered by a one-time mobilization fee.

The rig inventory and specifications were:

Draw-works and Engines

National 110-M with 1-3/8" Lebus grooving powered by 3 Caterpillar D-398 turbocharged diesel engines and C300-64FH National torque converters. Parkersburg V200 hydromatic brake.

Mud System

(2) National 10-P-130 triplex w/6" x 8" charge pumps, 1400 bbl. capacity tanks, clevander, desilter and double screen shale shaker.

Derrick and Substructure

Skytop 142'; 1,000,000 lb. hook load capacity. Model D-192 7-sheave, grooved for 1-3/8" line. Stepdown 18-1/2'H x 29'W x 38'L substructure.

Traveling Equipment

National block/hook 650-G-500. National P-300 swivel. Varco 6500 kelly spinner.

Rotary

Ideco 37-1/2", w/27-1/2" split master bushings.

12.1.2 Well Design

The final well plan approved by the D.O.E. with schematic of of the wellhead (Figure 12-2), casing detail (Figure 12-3) and wellbore (Figure 12-4) follows:

L. R. Sweezy No. 1 General Well Plan

Proposed Total Depth: 13,600'
Projected Spud Date: Nov. 1980, Actual 1/2/81
Objective Zone of Interest: "Cib jeff"
Conductor Casing: 30" (with sub-sea type hanger ring)
driven to 150' $\pm$ penetration. 30" to be Grade
B with a wall thickness 1.5" on top. Equipped
with guide shoe and each joint to be welded.

Hole Size: 17-1/2", to be opened to 24"

Surface Casing: 16" set at 5000'. Cement back to surface.

Hole Size: 14-3/4"

Protection Casing: 10-3/4" set at 12,600' $\pm$ (or in a 12.5 #/gal
equivalent pore pressure). Cement back to
7600' $\pm$ (or 5000' fillup).

FIGURE I2-2 WELLHEAD AND X-MAS TREE

DOW CHEMICAL / D.O.E.
L.R. SWEETZ NO.1
CASING DETAIL

Rotary Table

25.67'

BHF - 16", 5,000 PSI

FIGURE 12-3. L.R. SWEETZ NO.1 CASING DETAIL

DOW CHEMICAL/D.O.E.
L.R. SWEETZ NO. 1
WELLBORE AND COMPLETION SCHEMATIC

**FIGURE 12-4. L.R. SWEETZ NO.1 WELLBORE AND
COMPLETION SCHEMATIC**

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Hole Size: 9-1/2"

Completion Casing: Combination 8-5/8" / 7-5/8" to be set at 13,600'.

Inclination Surveys:

<u>Interval</u>	<u>Maximum Deviation</u>
0 - 5000'	Every 500' - Maximum allowable deviation from vertical 1°.
5000'-12,600' ±	Every 500' - Maximum allowable deviation from vertical 5°.

Multishot Surveys:

- 1st Survey from surface to 5000'
- 2nd Survey from 5000' to 12,600'
- 3rd Survey from 12,600' to 13,600' ±

Coring: 120' ± from 13,350' to 13,470' ± utilizing a conventional core barrel assembly.

Special Drilling Fluid Considerations:

1. Maximum mud weight anticipated - 17.2#/gal.
2. API fluid loss to be maintained at no higher than 2cc - 3cc below 10-3/4" casing setting depth.

Logging:

<u>Interval</u>	<u>Log</u>
0 - 5000'	Gamma Ray/ISF Sonic - other as directed.
5000' - 12,600'	Gamma Ray/ISF Sonic - others as directed. Temperature Survey (after 10-3/4" casing set to determine top of cement and recalculate required overpull)
12,600' - 13,600'	ISF/Sonic - others as directed.

Completion: Gravel pack with a screened liner.

Blowout Prevention Equipment:

Minimum Configuration Blowout Preventers.

Surface Casing (16")

- 3 - 16-3/4" 5000 psi Ram Type Preventer
- 1 - 16-3/4" 5000 psi Bag Type Preventer
- 1 - Remote Control HCR Type valve on choke line
- 1 - Drilling Spool oriented as surface casing
- 1 - Full opening safety valve to fit drill pipe and drill collars
- 1 - Inside blowout preventer to fit drill pipe and drill collars

Intermediate Casing (10-3/4")

- 3 - 11", 10,000 psi Ram Type Preventer
- 1 - 10", 5000 psi Bag Type Preventer
- 1 - Remote Control HCR Type valve on choke line
- 1 - Drilling Spool oriented on intermediate casing
- 2 - Full opening safety valve to fit drill pipe and
drill collars
- 1 - Inside blowout preventer to fit drill pipe and
drill collars

Choke and Manifold

A remote-control, hydraulic choke and manifold connected to surface and intermediate casing as appropriate.

Casing Specifications:

16" Casing Design

Interval

0 - 5000'

Specifications

16", 109#/ft, K55, Buttress
Regular clearance couplings R-3,
Amalog IV Inspected.

10-3/4" Casing Design

<u>Interval</u>	<u>Specifications</u>
0 - 5500'	10-3/4", 55.5#/ft, S95, Buttress Thread
5500' - 8400'	10-3/4", 55.5#/ft. P110, Buttress Thread
8400' - 12600'	10-3/4", 55.5#/ft, S95, Buttress Thread, Amalog IV Inspected

8-5/8" / 7-5/8" Casing Design

<u>Interval</u>	<u>Specifications</u>
0 - 11000'	8-5/8", 44# P110 ABCFL4S
11000' - 13600' <u>±</u>	7-5/8", 39# P110 LT&C

5-1/2" Tubing Design

5-1/2" O.D., 23#/ft, S-95, LT&C ABC modified, internally coated with Tube Kote TC-2c.

The actual "as built" configuration of the well is shown in Figures 12-2 through 12-4 and in Figure 12-5, the deviation survey; and is explained in the Drilling History which follows.

DOW CHEMICAL CO.
L. R. SWEEZY WELL NO. 1
PARC PERDUE FIELD
EASTMAN WHIPSTOCK, INC.

12-5 DEVIATION SURVEY

12.1.3 Drilling History

Welsh drilling rig No. 17 commenced day rate operations on January 2, 1981. Thirty inch conductor casing was driven to 268 ft.*, and drilling with 14-3/4 inch mill tooth bit commenced on January 6, 1981. The 14-3/4 inch hole was drilled to 5,203 ft. and opened to 20 inches in 16 days. Sixteen inch, 109 lb/ft, K-55, BTRC casing was set at 5,048 ft. and cemented by January 31, 1981. After a remedial cement squeeze the 16-inch casing shoe was successfully pressure tested on February 7, 1981.

A 13-3/4 inch hole was started on February 9, 1981, and drilled from 5,203 ft. to 12,712 ft. in 52 days; and 10-3/4 inch 55 lb/ft combination P-110 and AR-95, BTRC casing was run and cemented from 12,712 ft. to 6,300 ft. to complete the intermediate casing string installation. After a remedial cement squeeze the 10-3/4 casing shoe was successfully pressure tested on April 2, 1981.

A 9-1/2 inch hole was next drilled from 12,712 ft. to original total depth of 13,600 ft. with cores cut from 13,340 ft. to 13,400 ft. and 13,400 ft. to 13,460 ft. in 10 days. The total depth was reached on April 11, 1981, producing an average penetration rate (including logging and coring; and running and

*Depths are with reference to the Rotary Drive Bushing located 26 feet above ground level.

cementing conductor, surface and intermediate casing strings) of 136 ft. per day over 100 days.

Major problems were encountered after reaching total depth and conditioning the hole in preparation for running the production casing string. That portion of the drilling history directly reproduced from Dow to DOE correspondence dated July 7, 1981, follows:

1. Dropped String Incident

a. While pulling out of hole and laying down drill string on 4/14/81, tongs caught and broke drill pipe. Dropped 2463' of drill string. Top of fish 11,136'. Required 98 bbls of mud to initially fill hole and another 30 bbls to reach stable condition.

b. Remedial efforts left a fish of

1 crossover

9 8" spiral drill collars

3 9-1/2" x 8" body stabilizers

1 bit sub

1 9-1/2" bit

Top of fish at 13,301'

2. First Side Track Attempt

- a. 4/26/81-Cement 13,301' to 13,100' with 160 sacks class 'H' containing 10 sacks of sand at 17.5 ppg.
- b. 4/27/81-Cement did not set - Second plug of 200 sacks (36 bbls) with 10 sacks of sand at 13,301 to 13,059'.
- c. 4/29/81-Tagged firm cement at 13,155'. Drilled to 13,189' found soft cement. Wait.
- d. Go in hole with 2-1/2° bent sub, tag cement 4/30/81 at 13,189'. Time drill to 13,215' - hard cement to 13,194', soft cement to 13,213', hard cement to 13,215. Direction survey at 13,185' - survey 3/4° N 65° W, at 13,165' - 3/4° N 55° W. Drill to 13,266'. Survey at 13,224' - 2-1/2° S 48 W. Re-orient tool to North and drill to 13,328'. Survey at 13,291' - 7° S 37° W. Kicked off at 13,215' - TD 13,328'. Go in hole with 9-1/2" bit - on top of fish at 13,301'.

3. Second Sidetrack (First Sidetrack Hole)

- a. Cement with 500 sacks, estimated top of cement 12,700'. Firm cement found at 13,064'.

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b. Drilled to 13,605'. Directional Surveys at 13,156' - 6° N, 13,427' - 6-3/4° N.

c. Ran 8-5/8" - 7-5/8" tapered casing string. Threads parted with 267 joints in hole, between joints 262 and 263. Fell to bottom. Top of fish 547' (5/16/81).

4. Parted Casing Incident

a. Fishing casing 547' to bottom. Cut 7-5/8" casing at 12,683' and pulled fish.

b. Recut 7-5/8" casing at 12,792' and pulled out casing. Top of fish at 12,800.

5. Third Sidetrack (2nd Sidetrack Hole)

a. Cement from 12,797' with 260 sacks - est. top 12,400'.

b. Cement tagged at 12,390'. Sidetrack off at 12,721' with 2° bent sub.

c. Surveys at 12,760' - 1-1/2° N 1° W; 12,776' - 2-3/4° N 11° W; 12,824' - 4° N, 10° E; 13,060' - 5° drift; 13,252' - 5-1/2° drift; and 13,600' - 4-1/2° drift.

- d. Ran Gamma Ray/Dual Induction Log w/Long Spaced Sonic and Gamma Ray/Compensated Neutron Log w/Formation Density Curve 13,612' to 12,712' on 6/22/81.
- e. Ran 8-5/8" - 7-5/8" tapered string 13,608' to surface. Lost returns at 120 joints in hole. Float collar at 13,534'.
- f. Cemented through casing with following sequence:
70 bbls Dowell spacer	17.2 ppg
370 sacks "H" cement	17.4 ppg
728 bbls mud	17.0 ppg (5 bbls over)
- Plug did not bump, floats did not hold. Trapped 500 psi on casing. Lost 408 bbls of 17.0 ppg mud from returns.* In place 1700 hours 6/25/81.
- g. Intent was to do top cement job forcing mud through fracture near 10-3/4' shoe so 60 bbls of 17.0 ppg mud was pumped down annulus at 3 BPM and 1800 psi to clean fractured area of cement. Pressure at surface bled into formation to 300 psi on annulus.

*Note: Returns loss experienced on all side tracks at pump pressure of 300 psi to 400 psi. Loss near shoe of 10-3/4" string.

h. Top Job Cementing

Cementing sequence into annulus, 2200 psi.

15 bbls Dowell spacer 17.3 ppg

330 sacks "H" cement w/35% No.1 sand mixed to 17.4 ppg

330 sacks "H" cement w/35% No. 1 sand mixed to 16.8 ppg

220 sacks "H" cement w/35% No. 1 sand mixed to 16.8 ppg

91 bbls mud 17.0 ppg

6. Sequence of Events after Casing Cement Job

DATE	TIME	ACTION	CONSEQUENCE OR RESULT
6/27	1030	Bleed 1450 psi off annulus	No flow 0 psi Open
	1300		Well started flowing
	1330	Closed Hydril	1550 psi @ 1345 to 2035 psi @ 1730 hours. Estimated maximum flow of 40 bbls (basis-mud tank).
	2000-	Ran temperature log # 1 -	Tag cement @ 13,389', annulus
	2230	10,500' to 13,389'	pressure at 2300 psi
6/28	0100	Started Pumping mud w/1/2 BPM @ 3900 psi, Pumped 34 bbls of 17.1 ppg mud in 3 stages	Pressure stabilized at 2300 psi
	0500-	Ran temperature log # 2-	
	1130	surface to 13,389'	
	1200	Bled pressure to 1500 psi	Slight build-up
	1300	Bled pressure to 1000 psi	Build-up to 1700 psi in 20 min.
	1330	Pumped mud to 2200 psi & shut-in well, observed	Slow build-up of pressure

DATE	TIME	ACTION	CONSEQUENCE OR RESULT
6/29	0600		Pressure at 2300 psi
	0930-1000	Bled 2 bbls mud to 1500 psi, stable, bled 1/2 bbl mud.	0 pressure for 20 minutes Well started flowing-flowed 12 bbls (rate at end 2 bbls/min.)
		Shut in	Pressure to 3000 psi in 3 minutes
	1015	Pumped 14 bbls 17.2 ppg mud 1/4 bbl/min at 4200 psi	
	1100	Shut down pump.	Pressure stabilized @ 3300 psi.
	1230-2400	Pumping with truck (a) 15 bbls 17.6 ppg mud at 1/4 - 1/2 bbl/min 4200 psi	Pressure backed to 4000 psi
		(b) 20 bbls 17.6 mud at 3/4 bbl/min 4200 psi	Pressure backed to 3600 psi
		(c) 25 bbls 17.6 mud at 1 bbl/min 4200 psi	Pressure backed to 3800 psi
		(d) Shut down pump	Pressure bled to 1200 psi
		(e) Pumped 30 bbls 17.6 mud at 1 bbl/min 3800 psi. Shut down pump.	Pressure bled to 700 psi
6/30	0000-0600	(f) Pumped 102 bbls 17.6 mud at 1 bbl/min 3800 psi. Shut down pump.	Pressure bled to 650 psi
		(g) Pumped 130 bbls 17.8 mud at 1 bbl/min 3800 psi Shut down pump.	Pressure bled to 600 psi
6/30	0600-1200	Ran Noise Log - No Noise Pumped 15 bbl 17.8 mud at 1 bbl/min with noise tool at 12,850' and 12,675' - No noise Ran temperature log # 3 - 11,500' to 13,420'	Pressure stable at 600 psi

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<u>DATE</u>	<u>TIME</u>	<u>ACTION</u>	<u>CONSEQUENCE OR RESULT</u>
6/30	1200- 2400	Run gamma ray and cement bond logs 13,420' to 12,500' at zero pressure on 8-5/8" casing, rerun 13,420' to 12,000' with 600 psi pressure on 8-5/8"	No apparent difference in rerun. Poor cement bonding. Pressure on annulus 650 psi
7/1	0100- 0600	Observe pressure	Increased to 750 psi at 0600
	0600- 1630	Wait on orders	
	1630- 2400	Prepare to run "barite pill" with radioactive tracer in front and behind. Locate gamma ray/casing. Collar log tool at 12,704' to see radioactive tracer.	
7/2	0600- 1500	Pumped "barite pill" 30 bbls 17.8 ppg mud mixed with 4.5 millicuries of Iridium 192 coated on sand pellets pumped at 1.0 bbl/min. 3800 psi	Annular pressure 700 psi
		20 bbls 17.8 ppg mud same rate	
		70 bbls 22.0 ppg barite pill with 1.5 millicuries of IR-192 in last 5 bbls.	
		185 bbls 17.8 ppg mud at 1 bbl/min and 4000 psi to 330 psi	No signal seen on gamma ray tool.
7/2	1500	Ran gamma ray tool 12,704' to 9,600'	No signal
	2100	Ran tool 13,430' to 12,200'	Strong signal at 12,845' to 12,867' (lesser signal 12,815' to 12,822' due to poor depth calibration)
		Attempted temperature log	Tool failed repeatedly.
	2100 2400	Observed well	Taking fluid in annulus at 1-1/2 bbls/hr.

<u>DATE</u>	<u>TIME</u>	<u>ACTION</u>	<u>CONSEQUENCE OR RESULT</u>
7/3	0000-0100	Observe and fill	Static level at 0100
	0800-1100	Pumped 1-1/2 bbls 17.8 mud	Pressure to 1000 psi, bled down to 500 psi in 7 min.
		Pumped 1/2 bbls	Pressure 500 psi to 1000 psi, bled to 500 psi in 5 min.
		Pumped 1/2 bbls.	Pressure 500 psi to 1000 psi, bled to 500 psi in 6 min.
		Pumped 3-1/2 bbls	Pressure 500 psi to 2000 psi, bled to 500 psi in 5 min. Stabilized at 250 psi.
		Opened and bled to surface to 0 psi	No change or flow. Well dead.
	1100-1500	Stretched 8-5/8" casing by easing and stretching in increments	Calculated free point 660'.
7/5	0830-1200	Lift BOP Stack, Pull 8-5/8" with 505,000 lbs. Set slips in head, set casing with 475,000 lbs after 1/2" lost to set slips	Well head squatted 3 ± inches under load.
	2200	Set BOP. Tested 8-5/8" casing at 5000 psi for 30 min.	Held pressure.

12.1.4 Gravel-Pack Completion

After a cement bond log indicated sufficient production zone isolation, the block squeezes were pressure tested and differentially tested. The drilling mud was then displaced with a calcium bromide/zinc bromide completion fluid. The wellbore was circulated and cleaned until all particles, 5 microns and larger, were filtered out. The "Cib jeff" Sand was perforated at 12,349' to 388' and 13,395' to 406' (dual induction log). The zone was perforated with 12 shots per foot with Schlumberger's 4" Big Hole casing jet. A T.I.W. Model 'SS' packer with a knockout plug was set at 13,422'. The perforations were successfully washed with a Dowell cup-type perforation washing tool. However, several drag springs off the wash tool were lost in the hole.

The perforated interval was acidized with 3000 gallons of 15 percent HCl and 6000 gallons of regular mud acid. The planned pre-pack gravel-pack was not attempted because of severe lost returns following the acid. A mule shoe with collet and seal unit were run to push the drag springs lost earlier and knock-out plug through the packer at 13,422 feet. The packer was tested to 100 psi.

The gravel-pack assembly w/BHP bomb latching nipple, 4", .012 gauge screen and Dowell Model 16 GP Packer was run in the hole. The packer was set at 13,143 feet and tested with 3500 psi. The "Cib jeff" Sand was gravel-packed with 20 barrels Dowell Water Pack slurry with 7600 lbs., 20/40 mesh re-sieved Ottawa sand. Final sand out was at 5000 psi. Reversed with 8.5 barrels of slurry leaving 1330 pounds of 20/40 mud sand in the formation and 3040 lbs. in the annulus between screen and casing.

The polished bore receptacle (PBR) run previously with the 8-5/8" / 7-5/8" casing was honed and tested at 4000 psi. The PBR location seal assembly and other completion equipment was run into hole with 262 jts. of 5 1/2", 23#/ft, S-95, LT&C modified and internally coated tubing. All connections were internally tested at 9000 psi prior to running. See Figure 12-5 for completion details.

The seals were located in the PBR at 10,451 feet and tested to 5000 psi. After testing, the seals could not be pulled out of the PBR. A special wireline standing valve was built and set in the Model 16 packer at 13,143 feet and the seals hydraulically pumped out of the PBR. After circulating the well, the seals were worked into the PBR and tested with no problems. The tubing was spaced out, the FMC tubing hanger installed and the hanger landed in the tubing head at 2130 hours on August 14, 1981. The seals were again tested to 5000 psi.

The polished bore receptacle (PBR) run previously with the 8-5/8" / 7-5/8" casing was honed and tested at 4000 psi. The PBR location seal assembly and other completion equipment was run into hole with 262 jts. of 5 1/2", 23#/ft, S-95, LT&C modified and internally coated tubing. All connections were internally tested at 9000 psi prior to running. See Figure 12- 6 for completion details.

The seals were located in the PBR at 10,451 feet and tested to 5000 psi. After testing, the seals could not be pulled out of the PBR. A special wireline standing valve was built and set in the Model 16 packer at 13,143 feet and the seals hydraulically pumped out of the PBR. After circulating the well, the seals were worked into the PBR and tested with no problems. The tubing was spaced out, the FMC tubing hanger installed and the hanger landed in the tubing head at 2130 hours on August 14, 1981. The seals were again tested to 5000 psi.

The special standing valve was removed from the packer at 13,143 feet and an Otis 'DR' plug set at 383 feet. An FMC 5" back pressure valve was installed in the tubing hanger and the 10,000 psi blow-out preventors were nipped down. A temporary FMC 3-1/16", 10,000 psi, dry hole tree was installed and tested to 9000 psi.

**DOW CHEMICAL/D.O.E.
L. R. SWEETZ NO. 1
GRAVEL-PACK AND COMPLETION DETAIL**

ITEM	DESCRIPTION	O.D. (IN)	I.D. (IN)	LENGTH (FT)	TOP (FT)
TUBING					
	Elevation (Rotary to THF)			20.75	00
1	PMC 9" x 5 1/2" TCH Tubing Hanger			.88	20.75
2	1 Jt. 5 1/2", 23#/ft. S-95, LT&C Mod. Tbg. Internally coated w/TK-2C	5.50	4.54 (drift)	39.80	21.63
	5 Pup Jts., 5 1/2", 23#/ft. S-95, Mod. Tbg. Internally coated w/TK-2C	5.50	4.54	10.05 8.09 6.07 4.10 2.52	61.43
	7 Jts. 5 1/2" tbg. as above	5.50	4.54	281.13	92.26
3	Otis Flow Coupling 5 1/2", BXB LT&C Mod.	6.10	4.78	10.00	373.39
4	Otis 'R' Landing Nipple, PXP	5.50	4.313	1.03	383.39
5	254 Jts., 5 1/2" Tbg. as above			10,049.42	384.42
6	Otis Flow Coupling, 5 1/2", BXB LT&C Mod	6.10	4.78	9.98	10,433.74
7	Otis 'RN' Landing Nipple	5.50	3.986	1.15	10,443.72
--	T.I.W. Seal Ass. Serial No. 14553				
8	Locator	7.00		1.02	10,444.87
9	Spacer	5.50		3.43	10,445.89
10	Seals-T.I.W. Riton Packing (15 units)	6.75		25.90	10,449.32
11	Mule Shoe	6.68	4.68	1.40	10,475.22
	End of Tubing				10,476.62
NOTE: Locator is spaced-out 5' above PBR.					
12	8 5/8", 44#/ft. P-110, FL-45 casing surface to 10,450.89'.				
--	T.I.W. Polished Bore Receptical Serial No. 14812				
13	X-Over 8 5/8", 44#, FL-45 x 7 5/8", LT&C PIN.	5.625	6.81	4.25	10,450.89
14	Polished Bore Receptical	8.00	6.75	27.64	10,455.14
15	Extension 7 5/8" LT&C	8.25	6.75	1.40	10,482.78
16	7 5/8", 39#/ft. C-95 & P-110, LT&C Csg 10,484.18' to 13,608.96'.				
GRAVEL-PACK					
17	Dowell Model 16 GP Packer w/port- closing sleeve	6.437	3.25	8.03	13,143.16
18	6 Jts. 4", 13.40 #/ft blank w/weld-on centralizers each 15'.	4.00	3.428	28.23 28.28 28.71 28.72 27.56 28.75	13,151.19
19	3 Jts. 4", .012 gauge Stainless Steel All-welded screen (Howard Smith) w/ weld-on Centralizers each 15'.	4.545	3.428	29.80 29.94 29.72	13,321.44
20	Wash Pipe Seal Bore Sub	4.75	2.78	1.30	13,410.90
21	Tattle-Tale screen 4", .012 gauge Stainless Steel All-Welded	4.545	3.428	8.52	13,412.20
22	X-Over 4", NU x 2 7/8, BRD	4.47	2.44	.58	13,420.72
23	Locator		2.44	.70	13,421.30
24	Collet/Seal Assembly (4 seal units)	3.25		3.54	13,422.00
25	X-Over 2 7/8 FL x 2 7/8 DSS-HT	3.22	2.44	.50	13,425.54
26	1 Jt., 2 7/8", 6.5#/ft. DSS-HT Tubing	3.22	2.44	32.69	13,426.04
27	Otis 'XN' Landing Nipple 2 7/8", DSS-HT, BXP	3.22	2.205	.93	13,458.73
28	Production Tube w/mule shoe End of Tubing	3.22	2.44	3.90	13,459.66
29	T.I.W. Model 'SS' Packer		3.25	3.00	13,463.56 13,422.00

'CIBD JEFF' SAND - Perforated 13,349'-388' & 13,395' - 406' OIL Run 5 dated 6-22-81
w/12 SPF w/ 4" Big Hole Jet. Gravel-Packed w/ 20/40 Mesh Sand -- 1,330 lb. in
formation & 3040 lb. in Annulus

Final Completion & Packer Fluid -- 17.2 ppg @ 60°F CaBr₂/ZnBr₂

Minimum Restrictions: Tubing - 'RN' Nipple @ 10,444' - 3.986"
Gravel-Pack - 'XN' Nipple @ 13,459' - 2.205"

9/5/81

**FIGURE 12-6 L.R. SWEETZ NO.1 GRAVEL-PACK AND
COMPLETION DETAIL**

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The special standing valve was removed from the packer at 13,143 feet and an Otis 'DR' plug set at 383 feet. An FMC 5" back pressure valve was installed in the tubing hanger and the 10,000 psi blow-out preventors were nipped down. A temporary FMC 3-1/16", 10,000 psi, dry hole tree was installed and tested to 9000 psi..

The drilling rig, Welsh Rig 17, was released by Dow Chemical at 0800 hours August 16, 1981. Rig down and move out was complete on August 26, 1981. An overall drilling progress chart is presented in Figure 12-7.

12.2 Dow/DOE L.R. Sweezy No. 2 Salt Water Disposal Well

The salt water disposal well was drilled from February through March of 1982. The well is designated by the State of Louisiana as "Dow/DOE L.R. Sweezy No. 1 SWD", but is referred to in this report as the "Dow/DOE L.R. Sweezy No. 2", to avoid confusion.

12.2.1 Well Site and Drilling Rig

The salt water disposal (SWD) well was located 1840 feet from the south line and 1160 feet from the west line of Section 26, Township 11 South, Range 4 East. Location is noted on Figure 12-1.

12-7 DRILLING PROGRESS CHART

The drilling rig, designated WellTech No. 330, was contracted through competitive bidding from WellTech, Inc., Lafayette, Louisiana. The contract was a day work drilling contract, including drill crews, but did not include drill pipe nor fuel. All equipment, labor, and expense to move-in, rig up, rig down, and move-out were covered by a one-time mobilization fee.

A revised subcontract agreement was negotiated for reuse of the WellTech rig and crews when it became necessary to rework and gravel-pack the disposal well.

The rig inventory and specifications follow:

WellTech Rig No. 330 is a Ideco 7525 Rambler back-in unit, equipped with H44 draw-works powered by two (2) 3408 turbo Caterpillar Detroit engines rated at 475 HP each with CLBT 5860 Allison transmission, torque converter combination; which can be operated independently or together through a selective control gear box. The V80 Parkersburg hydromatic brake is water cooled. Ideco combination hydraulic- and wireline-raised 117' derrick has hook load capacity of 341,000#, 8 line or 358,000#, 10 line string up. Drill line is 1-1/8". Racking capacity is 20,000' of 2-7/8" drill pipe, or 28,000' of 2-3/8" tubing. Unit is also equipped with one crown-o-matic.

12.2.2 Well Design

The salt water disposal well was designed to dispose of 20,000 barrels per day of salt water for a period of at least one year. Wellbore and completion details of the finished well are shown in Figure 12-8.

L. R. Sweezy No. 2 General Well Plan

Proposed Total Depth: 5000 feet

Objective Zone: 4,533 feet to 4,685 feet

Conductor Casing: Drive 16" O.D., 1/2" Wall

Hole Size: 13-3/4"

Surface Casing: 10-3/4" Cemented back to surface.

Hole Size: 9-1/2"

Completion Casing: 7-5/8" Cemented back to surface

Completion: Gravel-packed with 4" O.D. screened liner set across perforations in 7-5/8"

Casing Specifications:

16" Casing Design

Interval
0 - 180'

16" O.D., 1/2" Wall, Grade B,
Welded

10 3/4" Casing Design

Interval
0 - 1650'
1650' - 2700'

10-3/4" O.D., 40.5#/ft, K-55,
ST&C
55.5#/ft, AR-95, BTRC

DOW CHEMICAL/D.O.E.
L. R. SWEETZ SWD NO. 2
WELLBORE AND COMPLETION DETAIL

Elevations:
RT to THF - 15.3'
RT to BHV - 17.1'

16", 1/2" wall, Grade B, welded
Driven to 185' (168' penetration w/147 BPF w/D-22 hammer)

Tubingless Completion - Injection Down 7 5/8" Casing

10 3/4" casing @ 2721'
0' - 1650' 40.5#/ft., K-55, ST&C
1650' - 2721' 55.5#/ft., AR-95, BTNC
Cemented w/1200 SXS Dowell Light Wate @ 12.5 ppg +
1050 SXS Class 'H' w/.5% CaCl₂ + .2% D-46 mixed @ 15.6 ppg.
Had 44 bbls cement returns @ Surface.

ITEM	DESCRIPTION	O.D. (IN)	I.D. (IN)	LENGTH (FT)	TOP (FT)
1	Dowell Model 16E G. P.	6.437	3.25	7.90	4,337.60
2	Packer w/part closing sleeve				
	5 Jts. 4", 11.60#/ft Blank	4.0	3.428	31.83	4,345.50
	w/ weld-on centralizers			31.82	
	each 15'.			31.83	
				31.85	
				8.60	
3	5 JTS. 4", .012 gauge stain-	4.545	3.428	23.20	4,513.25
	less steel all-welded screen			31.80	
	(Howard Smith) w/weld-on			32.80	
	centralizers each 15'. Blank			31.80	
	on each jt. - .90" bottom,			31.60	
	1.20' top.				
4	Wash Pipe Seal Sub	4.00	2.750	1.35	4,664.45
5	Tattle-Tail Screen 4",	4.545	3.428	6.15	4,665.80
	.012 gauge stainless				
	steel all-welded				
6	X-over 4", NU x 3 1/2", 8RD	4.688	3.428	.55	4,671.95
7	Baker Model 'E' Locator/	5.00	3.00	.50	4,672.50
	snap-latch				
8	with Baker 91-40 seals	4.00	3.00	3.22	4,673.00
	w/mule shoe				
	End of Tubing				4,676.22
9	Baker Model 'F' Packer	6.50	4.00	2.10	4,673
	(size 91-40) Set w/elect.				
	line @ IEL measurements.				

Brine Disposal Sand - Perforated: 4520' - 4560' w/4 SPF
4560' - 4607' w/8 SPF
4607' - 4640' w/12 SPF
4646' - 4660' w/12 SPF

All perforations IEL measurements w/5" Big Hole Jet.
Gravel-packed w/20-40 mesh sand--4,425 lbs in annulus and
3,450 lbs in formation.

Minimum Restrictions: 3.25" @ 4,337' - Top of G. P. packer
2.75" @ 4,664' - Seal Bore Sub.

7 5/8", 26.4#/ft., J-55, LT&C Casing @ 5001' cemented with
250 SXS Dowell Light Wate @ 12.5 ppg + 1000 SXS Class 'H'
w/.5% D-65 + .2% D-46 mixed @ 16.2 ppg. Had 63 bbls cement
returns to surface.

**FIGURE 12-8 L.R. SWEETZ NO. 2 WELLBORE AND
COMPLETION DETAIL**

7 5/8" Casing Design
Interval
 0 - 5000'

7-5/8" O.D., 26.4#/ft, J-55,
 LT&C

Completion:
Interval Perforated:
 4520' - 4660'

4" O.D., 11.60#/ft liner with
 .012 gauge stainless steel
 screen set across
 perforations.

12.2.3 Drilling History

The L. R. Sweezy No. 2 was drilled without incident by WellTech Rig No. 330. The rig was accepted at 1700 hours on February 5, 1982. Conductor casing was driven to 185 feet and the 13-3/4" hole spud at 1130 hours on February 8, 1982. A 10-3/4" surface casing string was then cemented to surface from 2721 feet. A total depth of 5011 feet was reached on February 21, 1982. The completion casing string of 7-5/8" was run and cemented from 5001 feet to surface. After changing out the drilling fluid the casing was tested satisfactorily for completion. Completion was attempted in the interval 4520 feet to 4660 feet; however, after perforating, sand entry was excessive for good disposal operation. The rig work was then temporarily suspended and the rig released on March 1, 1982.

12.2.4 Gravel Pack Completion

Completion work was resumed on March 18, 1982. A casing scraper was run on drill pipe. The perforated interval 4520 feet

- 4660 feet was cleared of tight spots and sand was circulated out to plug back total depth of 4956 feet until hole would stay sand free. A Baker model "F" packer was set by wire line at 4,673 feet for gravel-pack assembly.

The gravel-pack assembly consisting of Baker mule shoe seal and latch, 4" O.D. liner with .012 stainless steel welded screen and Dowell model 16E packer was set from 4,673 feet to 4,337 feet. The interval 4,520 feet to 4,660 feet was gravel-packed with 36 barrels of Dowell water-pack slurry and 13,500 pounds of 20-40 mesh re-sieved Ottawa sand. Final sand out was at 4,000 psi leaving 3,450 pounds of sand in the perforations and 4,425 pounds of sand in the screen and casing annulus.

The well fluids were then circulated out and replaced with filtered fluids. Dowell then acidized gravel-pack with 5,000 gallons of 15 percent HCl. Acid was pumped to the formation and overflushed with a final pressure of 250 psi at a 10 barrel per minute rate. Work was completed on March 25, 1982.

12.3 Abandonment and Site Restoration

After catastrophic sanding of the production well, surface equipment, and the disposal well on February 5, 1983, it was decided to plug and abandon the two wells.

12.3.1 Plug and Abandon Plan

Dow's original plan to retrieve the production tubing and all possible casing for inspection, and erosion and corrosion evaluation, was discarded. The Department of Energy decided to abandon all downhole tubulars in-place for economic reasons.

Plugging and abandonment procedures were conducted in strict compliance with all State of Louisiana and Federal regulations, and with constant adherence to the best safety considerations. Permit and report requirements are noted in Section 12.4.

12.3.2 Plug and Abandon Test well.

Following the plan to plug the test well, Gearhart Industries, Inc., moved equipment to location and set up on February 28, 1983. A collar log was run for correlation. The sand plug was found to be at 12,968 feet and the 5-1/2" tubing bottom at 10,469', by wire line measurements. A Gearhart two inch O.D. vented thru tubing bridge plug was then set at 12,900 feet. Well head pressure at this time was 3,500 psi. Lead shot and cement were then dumped to cover the plug up to the vent tube. The cement was allowed to set and attempts to close the vent tube

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were unsuccessful due to fill. The well head tubing pressure remained at 3,400-3,700 psi. Additional cement was dumped and allowed to set.

On March 6, 1983, well head pressure was 3,700 psi. The well head pressure was released on March 7, 1983, and bled to a slight gas and brine flow in 9-1/2 hours. The well was then shut in. Overnight the shut in well head pressure increased to 1,400 psi. In 1-1/2 hours the pressure was reduced to a slight gas and brine flow and continued for another 1-1/2 hours until the well was shut in for further evaluation.

On March 16, 1983, Otis Hydraulic workover unit No. 2 and equipment was moved to location. The shut in well head pressure was 3,800 psi. The pressure was bled off and 2-3/8" tubing with a back pressure valve 30 feet from the end was started in the hole.

Circulation with field brine was established over 1,000 feet until one half of the tubing was in the hole. At this point circulation could not be obtained. The tubing was run in to a depth of 12,809 feet RKB without further circulation.

At this point several attempts were made to retrieve or reach the back pressure valve with Otis wire line tools. All attempts were unsuccessful due to tight spots in the tubing or scale. The tubing was then perforated at 12,765 to 12,771 feet with

Schlumberger's 1-3/8" O.D. steel carrier tubing puncher. Tubing pressure and annulus pressure were less than 5 psi at this point. Schlumberger was rigged down and reverse circulation started out the tubing using the Otis rig pump. Larger amounts of scale and heavy oil from the tubing were being reversed out when the tubing plugged. The 2-3/8" tubing and 2-3/8" tubing X 5-1/2" annulus were alternately pressured and bled off in an attempt to remove the tubing plug. During this process the tubing and the annulus started flowing at 3,600 psi pressure. Reverse circulation was established with the rig pump and the well bore fluid was allowed to circulate until free of sand and scale. Dowell pumped and reversed out brine with 14.8#/gallon mud. Sixty barrels of mud was lost below the tubing. At this point both tubing and annulus were at -0- psi surface pressure. The well was allowed to stabilize overnight. The tubing and annulus surface pressure remained -0- psi. Dowell then spotted cement plug No. 1, with 125 sacks class H cement. Top of the plug should have been at 12,188 feet. The cement was allowed to set 24 hours. Top of cement plug was found to be at 12,823 feet or 635 feet low. A second 125 sack cement plug was set and the top confirmed at 12,251 feet. Plug No. 2 is from 12,251 to 12,741 feet.

The 2-3/8" tubing was pulled to 10,504 feet and 14.8#/gallon oil base mud was spotted over the interval 10,504 feet to 10,092

feet. All the work string was then pulled and the Otis Hydraulic workover unit was released on March 27, 1983.

On March 28, 1983 an Otis wire line truck was moved to location to set a 4.31 inch O.D. Otis type "RN" plug in the "RN" nipple at 10,434 feet. The plug was worked to position two times with difficulty, but it would not set. The plug was modified to hold pressure from above only and set at 10,434 feet. Otis moved off location on March 30, 1983.

On April 4, 1983, Gearhart and Dowell moved to location to recover calcium bromide/zinc bromide completion fluid from 5-1/2" x 8-5/8" annulus and set a top cement plug. The 5-1/2" tubing was perforated from 10,400 feet to 10,406 feet. Dowell then displaced 230 barrels of calcium bromide/zinc bromide fluid with 14.7#/gallon mud. Oil base mud had been spotted over this interval to prevent contamination to the bromide solution, but did not perform as expected. Although the primary objective of removing the bromide solution from the wellbore was accomplished, the solution did become contaminated. The fresh water mud also was contaminated and became very viscous and hard to circulate. The interval from 406 feet to 400 feet was then perforated and 90 sacks of class H cement were placed in the 5-1/2" tubing and the 5-1/2" x 8-5/8" annulus from 406 feet to 50 feet.

The 10-3/4" x 8-5/8" annulus was pressured to 3,500 psi to confirm cement integrity; could not pump into the annulus.

The 10-3/4" x 16" annulus would not hold pressure and was cemented with 235 sacks class H cement. All plugs were in place on April 7, 1983.

On April 8, 1983, the cement integrity of the 10-3/4" x 16" annulus was confirmed.

The wellhead was then removed, casing strings cut off, and plates welded over all casing strings at six feet below ground level. Abandonment of the L. R. Sweezy No. 1 well was completed on April 14, 1983. Figure 12-9 shows details of the plugs in place.

12.3.3 Plug and Abandon Disposal Well

The L. R. Sweezy No. 2 salt water disposal well became plugged with sand at 4,448 feet when the test well sanded up.

A permit was obtained from the State of Louisiana Department of Conservation to place bottom and top cement plugs.

On March 29, 1983, a Dowell coil tubing unit was moved to location and set up. Tubing was run to 4,337 feet or to the top of screened liner, and the well bore fluid displaced with 9.3#/gallon mud. The bottom cement plug was then set with 50 sacks class H cement from 4,337 feet. The cement was allowed to cure overnight and the plug was confirmed at 4,151 feet. The

**DOW / DOE NO. 1 L.R. SWEETZ
GEOTHERMAL WELL
PLUG AND ABANDON SCHEMATIC**

FIGURE 12-9 PLUG AND ABANDON SCHEMATIC

bottom plug is from 4,337 to 4,151 feet. The coil tubing was pulled to 250 feet and the top plug was set with 50 sacks class H cement from 250 feet to 50 feet. Dowell moved off location on March 30, 1983.

The well head was removed, the casing cut off six feet below ground level and steel plates were welded on all casing strings.

The L. R. Sweezy No. 2 salt water disposal well was abandoned on April 13, 1983.

12.3.4 Site Restoration

Site restoration work began in March, 1983, when a final decision was made to plug and abandon the wells, and was completed, except for re-seeding, by June, 1983.

12.3.4.1 Reserve Pit Fluids

Laboratory analysis of reserve pit fluids in February, 1983, indicated that total dissolved solids and chloride content were high for release of the water to the environment.

After competitive bidding, a contract was awarded to Water & Industrial Waste Laboratories, Inc., Lafayette, Louisiana, to treat reserve pit liquids and release the treated effluent to the site drainage ditches.

State of Louisiana run-off standards were easily met after treatment; and the contractor metered, treated, and released 20,977 barrels of reserve pit fluids to the ditch.

12.3.4.2 Salt Water Storage Pit

Rising chloride content in the site ring ditch in November, 1982 led to the discovery that the 36-mil reinforced chlorinated polyethylene salt water pit liner was leaking. The pit was pumped down to reveal torn seams resulting from large gas bubbles gathering under the liner. After removing approximately 3,420 barrels of brine and sludge with vacuum trucks; a consultant, Gulf Coast Agricultural Associates, Lafayette, Louisiana, was contracted to take soil samples and recommend proper abandonment of the salt water pit area.

The agricultural consultant made the following recommendations:

1. Remove the free water from the brine pit and dispose of it other than on the land.
2. Remove no less than one foot of soil material from the bottom of the brine pit and dispose of it off the premises.
3. Remove the north levee and dispose of it off the premises.
4. Back-fill with other levees and level and pack before adding top soil.

5. Bring in top soil to finish filling the brine pit area.
6. Fertilize, disc and reseed.

These recommendations were closely followed and 4,025 barrels water (mostly rainwater) and sludge were removed by vacuum trucks. The site restoration contractor removed 2,198 cubic yards of polluted soil from the north levee and bottom of the pit. This soil was hauled to a disposal site and 2,524 cubic yards of fill and top soil was hauled in and spread over the pit area.

12.3.4.3 Site Renovation

Site restoration work was competitively bid and a contract awarded to the low bidder, Central Industries, Inc., Scott, Louisiana.

The statement of work for site renovation specified the contractor was to furnish all labor, equipment, and materials to accomplish the following:

- Item #1 Dispose of all boards.
- Item #2 Cut 28 wood pilings and all well casing at least 4 ft. below ground surface. Cap casing and backfill. (Casing cut 6 ft. below surface.)
- Item #3 Pick up and load approximately 1,800 tons of limestone and haul to on-site area designated by the landowner.
- Item #4 Remove all piping for water and sewage systems. Backfill over all underground piping areas.

Section 12

- Item #5 Clear out and backfill ring levee ditch. Push up 3 foot high levee around entire location to contain all drilling mud and solids.
- Item #6 Dip mud and solids out of reserve pit, and backfill reserve and saltwater pits.
- Item #7 Clean up location of all pieces of scrap, cans, trash and nails. Particular effort required to pick up all board road nails with magnet.
- Item #8 Remove two 4-inch and one 2-inch water wells. remove all piping and plug the three wells. (This work not performed at request of landowner.)
- Item #9 Disc entire location and pick up black visqueen and nails while discing. Re-disc with farm tractor and harrow for seeding.
- Item #10 Reroute drainage ditch to original location.
- Item #11 Remove top part of old pit liner in salt water pit. (Top part of liner was anchored in pit levee).
- Item #12 Take down all fencing around location, roll up barbed-wire, stack fence posts on location at direction of landowner.
- Item #13 Remove rental cattleguard from location and return to the supplier's yard at Scott, La.
- Item #14 Remove all electrical poles, wiring boxes and telephone lines from site. Set one pole adjacent to 2-inch water well at Northwest corner of site, place meter base on pole and hook up wiring to well.
- Item #15 Fertilize and spread grass seed over entire location.
- Item #16 Furnish necessary trucks and trailers to move in six (6) pieces of equipment and attachments.

Note: It is understood that all fluids in the reserve and salt-water pits and ditches are to be disposed of by Dow. All salvageable board road lumber, telephone and light poles, electrical lights and trash to be hauled from location at no additional cost to Dow.

The above work was essentially complete by June 15, 1983, except final discing and seeding which was delayed due to excessive rain.

12.4 Permits

The following permit and report forms are applicable to the drilling, completion, and plugging of Dow/DOE Sweezy No. 1 and the salt-water disposal well in the State of Louisiana. All were submitted as required.

1. Work Permit (Figure 12-10)
2. Application for Permit to Drill (Figure 12-11)
3. Weekly progress or Drill Reports (Figure 12-12)
4. Permit Plat--Well No. 1 (Figure 12-13)
5. Permit Plat--Well No. 2 (Figure 12-14)
6. Well History and Work Resume Report (Figure 12-15)
7. Well Completion or Recompletion Report (Figure 12-16)
8. Affidavit of Test of Casing in Well (Figure 12-17)
9. Plug and Abandon Report (Figure 12-18)

GEOHERMAL RESOURCE WORK PERMIT
STATE OF LOUISIANA OFFICE OF CONSERVATION

Well Name & No. Lee Roy Sweezy #1 Sec. 26 T. 11S R. 4E
Field Parcperdue 7213 Parish Vermilion 057
Permit Serial No. 172445 Work Permit No. GR #2, 1981

Description of Work Sidetrack around fish. Top of fish 12,797.
Set cement plug in open hole from 12,390 to 12,797 and drill to
original T.D. of 13,600'.

Sand & Reservoir To Be Tested Cib-Jeff TD 13,600

Operator The Dow Chemical Co. - DOE
Address P. O. Box 51188
City, State & Zip Lafayette, LA 70505

Permit Requested By [Signature] Date 6/10/81
Permit Authorized By [Signature] District Lafayette Date 6-12-81

See Instructions On Reverse Side Form GR-4 ('79)

FIGURE 12-10

ORIGINAL TO OPERATOR

FORM MD 13-R
STATE OF LOUISIANA
DEPT. OF CONSERVATION

PERMIT TO DRILL FOR MINERALS

PERMIT\$100.00
Multiple Zone Processing

Att
Send To Lafayette/5 Date December 1, 1980
Serial No. Ser#172445 APAPI#1711321087
Parish Vermilion 057 Field Parcperdue 7213

Operator The Dow Chemical Co-DOE
Address P.O. Box 51188
City & State Lafayette, LA 70505
Well Name Lee Roy Sweezy No.1
Location Sec 26, T11S, R4E
1800' N & 1350' E fr SW/cor of Sec 26.

PTD 14,000

Zone or Reservoir of Proposed Completion Cibb-Jeff
Applicable Department of Conservation Order 29P

COMMISSIONER

ISSUING AUTHORITY

157004

FIGURE 12-11

WEEKLY PROGRESS OR DRILL REPORT

Department of Conservation District: _____ DATE _____

PARISH	FIELD	WELL NAME & NO.	CONDITION OF WELL, ACTIVITY AND DEPTH

Person to contact if additional
information is needed: Name _____ Phone _____

By _____ Title _____

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FIGURE 12-13 L.R. SWEETZ NO.1 LOUISIANA DEPT. OF
CONSERVATION PERMIT PLAT

FIGURE 12-14 L.R. SWEETZ NO. 2 LOUISIANA DEPT. OF CONSERVATION PERMIT PLAT

OFFICE OF CONSERVATION WELL HISTORY AND WORK RESUME REPORT		Geothermal Test Well FIELD Parc Perdue SERIAL NO. 172445 PRODUCING INTERVAL 13,349'-388' & 13,395'-406' DIL RESERVOIR (COMPANY SAND IDENTIFICATION) Cibb Jeff Sand								
Three typewritten copies of this report must be filed with the District Office of the Office of Conservation in which the well is located within twenty (20) days of the date of completion. NOTE: If not properly completed and signed this report will be returned.										
LEASE AND WELL DATA										
CHECK APPROPRIATE BOXES ☒ NEW WELL ☐ RECOMPLETION ☐ P & A		☐ 31 INACTIVE DRY HOLE FUT. UTIL. ☐ 32 INACTIVE DRY HOLE NO FUT. UTIL. ☐ 36 INACTIVE WAITING ON PIPELINE ☒ 37 INACTIVE WAITING ON tree								
		PRODUCT ☐ OIL ☐ GAS ☒ OTHER	IF RECOMPLETION ☐ SAME RESERVOIR ☐ DIFFERENT RESERVOIR							
		DATE COMP. RECOMP. OR P & A M D Y 8/16/81								
OPERATOR Dow Chemical USA/ US Department of Energy		CODE 0	ADDRESS P. O. Box 53073 - Lafayette, La. 70505							
WELL NAME L. R. Sweezy		WELL NO. 1								
PARISH Vermilion		SEC 26 TWP. 11 S RGE. 4 E	DATE PERMIT ISSUED December 1, 1980							
DATE SPUNDED 1/02/81	DATE READY TO PRODUCE* Wait on tree	TOTAL DEPTH 13,612'	PBD. 13,532'							
GROUND ELEVATION N/A		CASING HEAD FLANGE ELEVATION N/A	DISTANCE FROM RKB TO CNF 26.67'							
DATE WELL TURNED INTO TANKS Suspended		SINGLE, DUAL OR TRIPLE COMPLETION? single	NOTE: IF THIS IS A MULTIPLE COMPLETION, FURNISH A SEPARATE REPORT FOR EACH COMPLETION							
WAS WELL DIRECTIONALLY DRILLED? No	WAS DIRECTIONAL SURVEY MADE? Yes	WERE 3 COPIES FILED WITH THE OFFICE OF CONSERVATION? yes	DATE FILED enclosed							
TYPE OF ELECTRICAL OR OTHER LOSS RUN (CIRCLE LOSS FILED WITH OFFICE OF CONSERVATION) GR/DIL-LSS GR/CNL-FDC Dipmeter, CEL, Temperature Log			DATE FILED Enclosed							
CASING, LINER AND TUBING RECORD										
C	CASING SIZE	HOLE SIZE	CASING WEIGHT	DEPTH SET		SACKS CEMENT	TEST PRESSURE	HOURS UNDER PRESSURE	DATE TESTED (MM DD YY)	NAME OF TEST WITNESS - STATE IF CONSERVATION AGENT OR OFFSET OPERATOR
				FROM	TO					
101	30"	driven	1" wall	0		driven	N/A			
102	16"	20"	109#	0	5,048'	10,000	1,000	1/2	02-06-81	C. A. Bell/C. Yates
103	10 3/4"	13 3/4"	55.5#	0	12,712'	3118	3,000	1/2	04-01-81	C. A. Bell/C. Yates
104	8 5/8"	9 1/2"	44#	0	10,451'		4,800	1/2	07-05-81	C. A. Bell/T. Broussard
105	7 5/8"	9 1/2"	39#	10,451'	13,608'	370	4,800	1/2	07-05-81	C. A. Bell/T. Broussard
TUBING SIZE		5 1/2"		DEPTH OF TUBING		10,477'		DEPTH OF PACKER		Polished Bore receptical @ 10,451'
INITIAL COMPLETION OR RE-COMPLETION DATA										
INITIAL PRODUCTION			GAS VOLUME			GOR		CHOKE SIZE		PRODUCING METHOD
BOPD			MCF/DAY			CF/BSL		/64"		
FLOWING TUBING PRESSURE		SHUT-IN TUBING PRESSURE		CASING PRESSURE		WATER PRODUCTION		BS&W		%
PSIG		PSIG		PSIG		BPD				
GRAVITY		BHP (SHUT-IN)		COMPANY REPRESENTATIVE		DATE GAUGED				
°API @ 60° F										
PLUS AND ABANDON (P & A) DATA										
CASING SIZE	AMOUNT PULLED	CEMENT PLUGS				DATE WORK PERFORMED	NAME OF TEST WITNESS - STATE IF CONSERVATION AGENT OR OFFSET OPERATOR			
		FROM	TO	SACKS	HOW PLACED					
CERTIFICATE: I, the undersigned, state: That I am employed by Dow Chemical USA and that I am authorized to make this report, and that this report was prepared under my supervision and direction and that all facts stated herein are true, correct and complete to the best of my knowledge.										
Signature: John S. Wilson						Title: Project Manager				

*Data well is equipped to produce, but due to no available market, no pipe line connection, etc., the well has been shut-in.

FIGURE 12-15

WORK RESUME			
List below all work performed under Office of Conservation Work Permits while drilling and completing well.			
WORK PERMIT NO.	DATE WORK PERFORMED	SERVICE COMPANY	DESCRIPTION OF WORK
	1/2/81 thru 8/16/81	Welsh Drlg. & Services & others GR L#1, 1981 GR L#1, 1981	Rig up Rig. Drive 30", 1 1/2" and 1" wall conductor to 247' penetration w/248 BPF. RU Diverter. Drill 14 3/4" hole to 5200'. Log open hole to 20" to 5060'. Set 16" 109#/ft casing @ 5048'. Cement w/9500 sxs cmt. top out w/500 sxs. NU 16 3/4", 5000 BOP. Drill 13 3/4" hole to 12,712'. Log. Set 10 3/4", 55.5# casing @ 12,712'. Cement w/3118 sxs cement. WOC. Stretch casing to offset thermal expansion. Hang & NU 11", 10,000 BOP. Drill 9 1/2" hole to 13,600' w/ 17.2 ppg mud. Log. While POOH w/wiper trip dropped drill pipe. Fished w/o success. Spot cmt plug & side track #1 @ 13,215'. Drill to 13,328'. Lost sidetrack #1. Spot cmt. Plug & sidetrack #1A @ 13,064'. Drill to 13,196'. Open hole. Drill 9 1/2" hole to 13,605'. Log. While running 8 5/8" / 7 5/8" casing. 8 5/8" parted below rotary. Fishing recovered 8 5/8" & 7 5/8" to 12,800'. Spot cement plug & sidetrack #2 @ 12,721'. Drill 9 1/2" hole to 13,612'. Set 8 5/8" / 7 5/8" casing @ 13,608'. Cement w/370 sxs plus top job w/850 sxs class H. After WOC well flowed on annulus. Killed, stretched, hang & NU. CEL & block squeezed. Tested csg. 5000 psi. Dry tested. Displace mud w/17.4 ppg CaBr ₂ /ZnBr ₂ completion fluid. Perforated 13,349'-388' & 13,395'-406' w/12 SPF w/4" big hole. Wash perforations. Acidize & gravel pack w/4", .012 ga screen w/20-40 sand. Ran 5 1/2", 23#, P-110 tubing. Tested each connection w/9000 psi. Install dry-hole tree.
List below all important Paleofaunal or Geological Formation tops, Cap Rock and Salt Overhang bottoms.			
FORMATION	DEPTH	FORMATION	DEPTH

FIGURE 12-15 (CONT.)

FIGURE 12-16

STATE OF LOUISIANA
OFFICE OF CONSERVATION

AFFIDAVIT OF TEST OF CASING IN WELL

DATE WORK DONE February 6, 1981 WELL SERIAL NO. 172445

Lafayette DISTRICT
(One copy to be filed with District Office)

NOTE: This Report Will Be Returned If Not Properly Completed and Signed

Field Parc Perdue Parish Vermilion Sec. 26 Twp. 11S Rge. 4E

Operator Dow Chemical USA Well Name L.R. Sweezy Well No. 1

Size of casing 16" Weight 109# Make U.S. Steel

No. of threads per in. Butt. Grade K-55 Seamless X New ☒ 2nd ☐

If second hand, was pipe tested _____ Describe _____

Depth casing shoe landed below derrick floor 5048 Ft. Sacks of cement 10,000

Size of hole 20" Ins. _____ Amount of cement left in pipe 50 Ft³

Method of cementing Stab-in Cement set in 12 hrs., under Floats psig.

Total depth 5060' Total time set 120 hrs.

DETAIL OF PRESSURE TEST BEFORE DRILLING PLUG

Date of test February 6, 1981 Gauge pressure of casing 1,000 psig.

Pressure at end of 30 minutes 1,000 Pressure drop 0 psig.

Test fluid: Water Mud Weight 8.9 Viscosity 38

Remarks: Top 200' Casing filled with Drill Water

This work was done according to the Rules and Regulations of the Department of Conservation.

Cecil Yates
WITNESS

Dow Chemical USA
OPERATOR

(SIGNED) C. Allen Bell
REPRESENTATIVE

Form - Csg. T

FIGURE 12-17A

STATE OF LOUISIANA
OFFICE OF CONSERVATION

AFFIDAVIT OF TEST OF CASING IN WELL

DATE WORK DONE April 1, 1981

WELL SERIAL NO. 172445

Lafayette

DISTRICT

(One copy to be filed with District Office)

NOTE: This Report Will Be Returned If Not Properly Completed and Signed

Field Parc Perdue Parish Vermilion Sec. 26 Twp. 11 S Rge. 4E

Operator Dow Chemical USA Well Name L.R. Sweezy Well No. 1

Size of casing 10 3/4" Weight 55.5[#] Make Armco

No. of threads per in. Butt. AR-95 Grade P-110 Seamless X New ☒ 2nd ☐

If second hand, was pipe tested _____ Describe _____

Depth casing shoe landed below derrick floor 12,712 Ft. Sacks of cement 3,118

Size of hole 13 3/4" Ins. _____ Amount of cement left in pipe 44 FT³

Method of cementing Two-plug displacement. Cement set in 48 hrs., under _____ Floats _____ psig.

Total depth 12,712'. Total time set 72+ hrs.

DETAIL OF PRESSURE TEST BEFORE DRILLING PLUG

Date of test April 1, 1981. Gauge pressure of casing 3000 psig.

Pressure at end of 30 minutes 3000 psi Pressure drop 0 psig.

Test fluid: Water Mud _____ Weight _____ Viscosity _____

Remarks: Top 100' Casing Filled with Water.

This work was done according to the Rules and Regulations of the Department of Conservation.

Cecil Yates
WITNESS

Dow Chemical USA

OPERATOR

(SIGNED)

C. Allen Bell

REPRESENTATIVE

Form - Csg. T

FIGURE 12-17B

STATE OF LOUISIANA
OFFICE OF CONSERVATION

AFFIDAVIT OF TEST OF CASING IN WELL

DATE WORK DONE July 5, 1981 WELL SERIAL NO. 172445

Lafayette DISTRICT
(One copy to be filed with District Office)

NOTE: This Report Will Be Returned If Not Properly Completed and Signed

Field Parc Perdue Parish Vermilion Sec. 26 Twp. 11S Rge. 4 E

Operator Dow Chemical USA Well Name L.R. Sweezy Well No. 1

Size of casing 8 5/8" / 7 5/8" Weight 44# / 39# Make Armco

ABC FL-4S

No. of threads per in. 8 RD Grade P-110 Seamless ☒ New ☒ 2nd ☐

If second hand, was pipe tested _____ Describe _____

Depth casing shoe landed below derrick floor 13,608' Ft. Sacks of cement 370

Size of hole 9 1/2" Ins. _____ Amount of cement left in pipe 16.5 Ft 3

Method of cementing Two-plug Displacement Cement set in 18 hrs., under 500 psig.

Total depth 13,612' Total time set 48+ hrs.

DETAIL OF PRESSURE TEST BEFORE DRILLING PLUG

Date of test July 5, 1981 Gauge pressure of casing 4800 psig.

Pressure at end of 30 minutes 4800 psi Pressure drop 0 psig.

Test fluid: Water Mud _____ Weight _____ Viscosity _____

Remarks: Top 100' of Casing Filled w/ Water. Tested thru Kill Line w/

Blind Rams closed.

This work was done according to the Rules and Regulations of the Department of Conservation.

Thomas Broussard
WITNESS

Dow Chemical USA
OPERATOR
(SIGNED) C. Allen Bell
REPRESENTATIVE

Form - Csg. T

FIGURE 12-17C

GEOHERMAL WELL
STATE OF LOUISIANA
OFFICE OF CONSERVATION
PLUG AND ABANDON REPORT

WORK PERMIT NO. L#180,1983 WELL SERIAL NO. 172445
DATE WORK FINISHED (MM-DD-YY) 4/7/83

LAFAYETTE DISTRICT
(Three Copies to be Filed with the District Office)

NOTE: This Report Will Be Returned If Not Properly Completed And Signed.

Field PARC PERDUE Parish VERMILION Sec. 26 Twp. 115 Rge. 4E
Operator DOW CHEMICAL/DOE CODE Well Name L. R. SWEETZ Well No. 1
Total Depth 13,534' Condition of Well PLUGGED AND ABANDONED

CHECK APPROPRIATE BOX:

☐ 29 DRY HOLE

☒ 30 FORMERLY PRODUCTIVE WELL GEOTHERMAL TEST WELL - DEPT. OF ENERGY

	CASING SIZE	AMOUNT PULLED	CEMENT PLUGS			
			FROM	TO	SACKS	HOW PLACED
301	5 1/2" (8 5/8)	NONE	406'	50'	90	CIRCULATED
302	7 5/8"-8 5/8"	NONE	13,534 12,741	12,823 12,251	125 125	SPOTTED W/2 7/8" WORK STRING
303	10 3/4"	NONE	COULD NOT PUMP DOWN ANNULUS			
304	16"	NONE	5,000'	SURF	235	BULLHEAD DOWN ANNULUS

Mud Record: Weight 14.8 ppg Viscosity _____

Remarks: SEE DIAGRAM - VENTED BRIDGE PLUG FAILED AT 12,900'. OTIS "RN" BRIDGE PLUG AT 10,434'

This work was done according to the Rules and Regulations of the Office of Conservation.

WITNESS

DOW CHEMICAL COMPANY
OPERATOR

(Signed) REPRESENTATIVE
J. R. HAMILTON

Form P & A (1-78)

FIGURE 12-18

13. Environmental Considerations

The environmental concerns for the Parcperdue research site involved endeavors by Louisiana State University (LSU), Oak Ridge National Laboratory (ORNL) and The Dow Chemical Company. Environmental mitigation and monitoring commitments were outlined by ORNL in an Environmental Assessment (EA) prepared for this project. To insure implementation and compliance to the EA, ORNL personnel periodically visited the site throughout all phases of the project.

13.1 Environmental Monitoring - LSU

Air, water, seismic and subsidence monitoring at the research site were conducted by LSU personnel under separate contract to DOE. Detailed results of this project are published by LSU. This monitoring program consisted of three phases:

1. baseline monitoring before drilling to establish background data,
2. monitoring during drilling and testing the wells,
3. monitoring after project completion for consequences of the research.

13.1.1 Air

Ambient air quality and meteorology were monitored from a mobile monitoring station located about one-half mile northwest of the Parcperdue well. The LSU subcontractor provided continuous records of H₂S, SO₂, nonmethane hydrocarbons, total hydrocarbons (THC), wind speed, wind direction, temperature, and precipitation. These readings were recorded from July 1, 1980, through October 31, 1981.

No significant air quality impacts were detected during this period which covered preconstruction, well drilling, and short term flow testing of the production well.

13.1.2 Water Run-Off

Surface water flow through the Parcperdue site is generally southward toward Leblanc Ditch which is hydraulically connected to the Vermilion River to the west and Bayou Parcperdue to the east. Three surface water sampling stations were located radially south of the site at distances of 1-1/2 to 3 miles. One station was on Bayou Parcperdue below the ditch entry, one on the ditch SSE of the test site, and one on the ditch near the Vermilion River.

Sampling from the three stations was set-up on a monthly basis beginning in January 1980. Then because of funding cutbacks and the small changes noted in monthly samples, the frequency was changed to quarterly in 1981.

The sampling program indicated seasonal variations in surface water quality but no significant alteration was attributable to testing activity.

13.1.3 Ground Water

Sampling of ground water at the site was first accomplished from two existing domestic wells, 50 and 100 feet deep, located approximately 500 feet west of the Parcperdue production well. As development of the site continued, four water wells were drilled to 180, 90, 130, and 130 feet in close proximity to the test well.

Monthly sampling began in January 1980, and was changed to quarterly in 1981. As with surface water, some seasonal variation in water quality was noted, but no significant alteration was attributable to testing activity.

13.1.4 Seismic

The Louisiana Geological Survey and LSU conducted base-line seismic studies at Parcperdue to investigate microseismicity associated with geopressured-geothermal fluid production.

The microseismic survey consisted of five continuous recording seismograph stations located around the test site at distances of 1-1/2 to 4 miles. These stations were on-line from November 1981 through the completion of project field work.

Results of these investigations and detailed analyses of seismic events are published by LSU.

13.1.5 Subsidence

A first order leveling survey was conducted at the Parcperdue site prior to drilling. Then, more than a dozen benchmarks in the vicinity of the well were releveled between the drilling and testing phases of the production well.

The object of the subsidence detection system is to permit comparisons of relative elevations before and after reservoir drawdown.

Minor subsidence, if it occurs, will be detected by the monitoring system. Final conclusions are published by LSU.

13.2 Environmental Considerations On-site

At the well site, precautions to preclude adverse environmental impact to the research area included: 1. ring levee and ditch around the entire research area, 2. lined brine holding pit for emergencies, 3. lined reserve pit for drilling mud, well tailings and fresh water, 4. lining underneath boards around production and disposal wells, 5. flaring of geopressured gas stream. Verification of all monitoring commitments in the Environmental Assessment (EA) for this site was accomplished through onsite inspections by Oak Ridge National Laboratory (ORNL) personnel. ORNL staff made three visits to the site: during site development, testing, and restoration phases.

13.2.1 Ring Ditch

A ring ditch was formed at the base of a three foot earthen levee which surrounded the entire research site. The site sloped to the NW corner, where drainage to the environment was controlled through a six-inch valved plastic pipe. All surface drainage from the site collected in the ring ditch and passed through this pipe.

Periodic samples of the ditch water were analyzed to insure compliance with state regulations. Additionally, minnows and other aquatic life living in the ditch served as a monitor for water suitability to flow into surrounding streams. A water level of approximately eight inches was maintained in the ditch at the outfall to keep the minnows alive.

Water in the ditch determined to be unsuitable for release into the environment was pumped into the brine pit and either injected into the site disposal well or hauled by tank to an approved disposal site.

13.2.2 Reserve Pit

The reserve pit was located adjacent to both the production and disposal wells. The capacity of the pit was approximately 100,000 bbls. It was lined with standard visqueen plastic. Water-based drilling mud, drilling tailings and fresh water were the only materials stored in the reserve pit.

By rigid segregation of materials stored in this pit, the water was kept fresh and sustained aquatic life, minnows, snakes and frogs.

At the end of the project, only clarification treatment was necessary to meet state specifications for flowing the reserve pit water into the environment, during site restoration.

13.2.3 Brine Pit

For emergency storage of production well brines, a 30,000 bbl earthen pit was constructed beside the reserve pit. The pit was lined with a 36-mil reinforced chlorinated polyethylene liner. During interruptions to the disposal well operation, production well flow was diverted to the brine pit for temporary storage. Whenever water in the ring ditch failed to meet state specifications for release, it was pumped into the brine pit.

Brine from the pit was pumped down the disposal well during periods when the production well was out of service. The brine pit was an invaluable aid in continuing production while maintenance problems around the filters and disposal well were being resolved.

13.2.4 Liner Under Boards

A large boarded area surrounded both the disposal and production wells. A polyethylene liner was placed on the ground, under the boards to aid in preventing brine spills from contaminating the topsoil. This preventative measure proved very beneficial when re-establishing vegetation on the research site.

Section 13

13.2.5 Miscellaneous Waste Handling

All sanitary sewage from the trailers on-site was collected in septic tanks. Weekly, these tanks were emptied into vacuum trucks and hauled to approved disposal sites.

Any liquids which could not be stored in the brine or reserve pits was hauled off-site to state approved disposal sites.

Scrap metal was sold at the end of the project to a local scrap dealer.

13.3 Environmental Conclusions

Most environmental endeavors on-site proved very successful. Two problems arose near the end of the project concerning liners in both the reserve and brine pits.

13.3.1 Brine Pit Problem

In early November 1982 minnows in the ring ditch moved from the northern section around to the west perimeter ditch. Water in the northern ditch changed color and analyses indicated brine contamination. Further investigation showed the liner in the

brine pit had separated in numerous places. Principal separations occurred at field installed seams; however, several separations were found in the fabric itself. An estimated 5-10,000 bbls brine leaked through the liner into the surrounding soil.

To monitor the movement of the brine in the soil, six sampling points (4-6 ft. deep) were dug around the perimeter of the research site. Water from the sampling points was tested for chlorides over a four month period. Water that accumulated in the perimeter ditch was pumped into the disposal well with the remaining brine pit water. All brine liquids were kept inside the perimeter lines. Vegetation damage was confined inside the research site perimeter.

Soil testing around the brine pit was conducted by an independent consultant as the site was being restored. The results of this testing dictated the removal of 2,198 cubic yards of soil. During site restoration the soil was removed and replaced with clay and topsoil.

After site restoration was completed, vegetation grew profusely throughout the research location.

To prevent future problems with such liners, field seam installations must be improved. Additionally, provisions must be included in the installation for venting gas build-up from underneath the liner.

13.3.2 Reserve Pit Liners

The 100,000 bbl reserve pit was lined with 5-mil polyethylene ("Visqueen") plastic. After approximately 10 months this liner deteriorated and separated in numerous places above water level. Winds blew underneath the separations and tore the liner further.

Future liners for such pits should be a heavier material, or no liner at all should be used. Packed clay is adequate for the pond bottom.

14. Observations and Recommendations

14.1 Drilling and Completion

1. Two incidents are responsible for most of the drilling problems: the dropped drill string, and parted casing. The dropped drill string was the result of tongs accidentally latching about drill pipe while pulling string. The casing threads which parted were Atlas-Bradford ABFL-4S threads. Possible causes were a defective box, slow taper on the pin, and ovalities in both members.
2. Excess retardant is sometimes added to cement to prevent premature setting while pumping slurries. Care should be taken that sufficient time is allowed for complete setting of cement when cementing casing strings.
3. Gravel-packing was necessary to minimize sand production. The ultimate gravel-pack failure might have been avoided by employing certain techniques: smaller gravel sizing, wash and prepack perforations, stage-pack perforations, bring well on slowly, avoid perforating most unconsolidated zones.

4. The mechanical properties log gave results which contradicted the core examination, mechanical testing, and reservoir analysis. The use of a mechanical properties log as the sole criterion as to whether or not to gravel pack a well could result in failure to gravel pack when necessary, and the loss of the well. When possible, whole core should be obtained for formation evaluation.
5. Disposal well injection formations should be cored, if possible. Water compatibility studies of disposal formations should always be performed.

14.2 Production

1. A regular lubrication program should be established for all above ground equipment. Insure the lubricant is appropriate for the application (compatible with temperature, pressure, brine).
2. Stem-and-seat type chokes should not be used with high velocity brine, because fluid pressure against the flange of the stem can force it into the seat, shutting off flow and sometimes causing damage to the choke. Adjustable chokes should be of "double bean" design, such as the Willits choke. Choke manifolds should provide for at least one, bean-type positive choke.

3. Plug-type valves are poor choices for brine applications, because the hot brine tends to wash out the grease necessary for the tapered plug to seal. Ball valves or gate valves are preferable.
4. Flow lines should be checked regularly for corrosion/erosion using x-ray and ultrasonic methods, particularly at bends or areas of turbulent flow.
5. Scale was not a problem due to the relatively low salinity (100,000 ppm) of this brine. Inhibitor should be aimed at reducing precipitation in the disposal formation.
6. Dequest® 2000 was unsatisfactory as an inhibitor due to difficulty in handling and corrosion of pump parts. Nalco 2VV419 worked as well and was easier to handle.
7. A system to inject acid (citric or inhibited hydrochloric) directly into the disposal well brine stream, continuously or in slugs, would be valuable.
8. Back pressure in the disposal well was reduced using various types of acid jobs, backflowing the well, and the addition of a surfactant.

9. The sensitivity of acoustic sand detectors is severely reduced in a brine stream.. They should be employed as emergency warning devices, but sand monitoring should be done by shakeout.
10. All lined pits should be adequately vented to prevent the accumulation of air underneath the liner.

14.3 Pressure Transient Testing

1. Lubricator wireline valves should be closed in as soon as the instrument is on bottom in order to prevent the injection of honey oil into the flow stream.
2. MP-35N electric line is subject to buildup of magnetic impedance and should be degaussed prior to each usage.
3. The use of MP-35N electric line probably is not necessary unless extended flowing conditions are contemplated.
4. Surface equipment should be instrumented to electronically record data continuously - not just during pressure transient testing.

14.4 Geology - Chemistry

1. Predicted resevoir properties - size, thickness, depth, temperature, pressure, salinity - were very close to those actually measured.
2. Reservoir brine is undersaturated with respect to gas. PVT physical properties are close to predicted.
3. The well produced hydrocarbons - an aromatic condensate trapped out of the gas line and a paraffinic oil removed from the separator. The relative volume of hydrocarbons appeared to be increasing with cumulative production. The source of the hydrocarbons is uncertain, although several theories have been proposed. More research is needed.
4. The surrounding shale has a low petroleum maturation index and may not be the only source of hydrocarbons produced from the Cib jeff zone in Parcperdue field.
5. No geochemical evidence of shale de-watering was observed.

6. Mechanical deformation testing of core material is extremely important - especially in light of the results of the reservoir analysis. The limited amount of data answered some questions but raised others. Whole core material is obtained at great risk and expense, and affords the only opportunity to actually test and observe rock behavior. Much work needs to be done, and where core is available, the data should be maximized.

14.5 Reservoir Analysis

1. A water potential function, which uses non-linear regression to generate various parameters as a function of pressure, was used to analyze the data. Other methods of analysis may yield different results.
2. Unusually high rock compressibility is the primary reservoir drive mechanism. The subject of rock compressibility in geopressured systems is not well known and deserves much more research. The high rock compressibility may increase the ultimate recovery from the reservoir by a factor of 2 to 3.
3. The calculated reservoir volume is approximately 100 million barrels over 880 acres, larger than the 70 million barrels over 660 acres interpreted from the geology. One corner of the fault block may be slightly leaky.

4. No significant aquifer energy was available from shale de-watering or from edge water influx.
5. The absolute open flow of the well is 40,000 bbls per day. Recoverable water is 11,000,000 barrels; however, damage to flow efficiency with pressure depletion will preclude full recovery at feasible rates.
6. Much knowledge remains to be gained from the Parcperdue data. The next step is to take the data developed in this study and perform a rigorous numeric simulation.

14.6 Environmental

1. No negative environmental effects were observed as a result of the production of geopressured water.
2. Leakage of brine from the lined pit into the soil did occur. Where brine holding pits are in use, a system of shallow wells should be located on the periphery of the site to monitor possible seepage.