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IMPROVED OIL RECOVERY IN FLUVIAL DOMINATED DELTAIC RESERVOIRS OF KANSAS – NEAR TERM

Final Report
June 18, 1993-September 30, 1999

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Lawrence, Kansas

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Chapter 1

Introduction

ABSTRACT

Common oil field problems exist in fluvial dominated deltaic reservoirs in Kansas. The problems are poor waterflood sweep efficiency and lack of reservoir management. The poor waterflood sweep efficiency is due to 1) reservoir heterogeneity, 2) channeling of injected water through high permeability zones or fractures, and 3) clogging of injection wells due to solids in the injection water. In many instances the lack of reservoir management results from 1) poor data collection and organization, 2) little or no integrated analysis of existing data by geological and engineering personnel, 3) the presence of multiple operators within the field, and 4) not identifying optimum recovery techniques.

Two demonstration sites operated by different independent oil operators were involved in this project. The Stewart Field is located in Finney County, Kansas and is operated by PetroSantander, Inc. This field was in the latter stage of primary production at the beginning of this project and is currently being waterflooded as a result of this project. The Nelson Lease (an existing waterflood) is located in Allen County, Kansas, in the N.E. Savonburg Field and is operated by James E. Russell Petroleum, Inc. The objective was to increase recovery efficiency and economics in these types of reservoirs. The technologies applied to increase waterflood sweep efficiency were 1) in situ permeability modification treatments, 2) infill drilling, 3) pattern changes, and 4) air flotation to improve water quality. The technologies being applied to improve reservoir management were 1) database development, 2) reservoir simulation, 3) transient testing, 4) database management, and 5) integrated geological and engineering analysis.

The Stewart Field project results included 1) the development of a comprehensive reservoir database using personal computers, 2) the completion of a simulation study to history match the primary production, 3) the simulation of waterflooding and polymer flooding, 4) an economic analysis to assist in identifying the most economical waterflood pattern, 5) completion of laboratory analysis conducted on reservoir rock, 6) unitization of the field so that a field-wide improved oil recovery process could be implemented, 7) design and construction of waterflood facilities, and 8) initiation and operation of the waterflood utilizing improved reservoir management techniques.

Water injection began on October 9, 1995 in the Stewart Field. In March 1996 oil production in the field began to respond to the water injection. Oil production continued to increase and through December 1998 total incremental waterflood response was approximately 2900 BOPD. Total field production was over 3150 BOPD. Total incremental waterflood production through December 1998 was 1,634,782 BO.

The Stewart Field project's activities and plans consisted of the operation of the waterflood utilizing state-of-the-art technologies in an attempt to optimize secondary recovery. Production and reservoir data were analyzed using reservoir characterization techniques and by updating the existing reservoir simulation. The analysis of results was utilized to optimize the waterflood plan and flooding techniques to maximize secondary oil recovery. This project was awarded the "Best Advanced Recovery Project in the Midcontinent" for 1995 by Hart's Oil and Gas World.

The Savonburg Field project results were; 1) the installation and proving of the air flotation device to be effective in water cleanup in mid-continent oil reservoirs, 2) the development of a database which includes injection and production data, and reservoir data, 3) the development of a reservoir description, 4) the completion of a pattern volumetric study to select high potential areas, 5) completion of a streamtube waterflood simulation, 6) an analysis of injectivity on individual wells as a result of clean water/wellbore cleanups, and 7) the results of infill drilling and pattern changes.

EXECUTIVE SUMMARY

This project involved two demonstration projects, one in a Morrow reservoir located in the southwestern part of the state and the second in the Cherokee Group in eastern Kansas. Morrow reservoirs of western Kansas are still actively being explored and constitute an important resource in Kansas. Cumulative oil production from the Morrow in Kansas is over 400,000,000 bbls. Much of the production from the Morrow is still in the primary stage and has not reached the mature declining stage of that in the Cherokee. The Cherokee Group has produced about 1 billion bbls of oil since the first commercial production began over a century ago. It is a billion-barrel plus resource that is distributed over a large number of fields and small production units. Many of the reservoirs are operated close to the economic limit, although the small units and low production per well are offset by low costs associated with the shallow nature of the reservoirs (less than 1000 ft. deep).

Common recovery problems in both reservoir types include poor waterflood sweep efficiency and lack of reservoir management. The poor waterflood sweep efficiency is due to 1) reservoir heterogeneity, 2) channeling of injected water through high permeability zones or fractures, and 3) clogging of water injection wells with solids as a result of poor water quality. In many instances the lack of reservoir management results from 1) poor data collection and organization, 2) little or no integrated analysis of existing data by geological and engineering personnel, 3) the presence of multiple operators within the field, and 4) not identifying optimum recovery techniques.

The technologies being applied to increase waterflood sweep efficiency were 1) in situ permeability modification treatments, 2) infill drilling, 3) pattern changes, and 4) air flotation to improve water quality. The technologies being applied to improve reservoir management were 1) database development, 2) reservoir simulation, 3) transient testing, 4) database management, and 5) integrated geological and engineering analysis.

In the Stewart Project, the reservoir management portion of the project conducted during Budget Period 1 involved performance evaluation. This included 1) reservoir characterization and the development of a reservoir database, 2) volumetric analysis to evaluate production performance, 3) reservoir computer modeling and simulation, 4) laboratory work, 5) identification of operational problems, 6) identification of unrecovered mobile oil and estimation of recovery factors, and 7) identification of the most efficient and economical recovery process.

To accomplish these objectives the initial budget period was subdivided into three major tasks. The tasks were 1) geological and engineering analysis, 2) laboratory testing, and 3) unitization. Due to the presence of different operators within the field, it was necessary to unitize the field in order to demonstrate a field-wide improved recovery process. This work was completed and the project moved into Budget Period 2.

Budget Period 2 objectives consisted of the design, construction, and operation of a field-wide waterflood utilizing state-of-the-art, off-the-shelf technologies in an attempt to optimize secondary oil recovery. To accomplish these objectives the second budget period was subdivided into five major tasks. The tasks were 1) design and construction of a waterflood plant, 2) design and construction of a water injection system, 3) design and construction of tank battery consolidation and gathering system, 4) initiation of waterflood operations and reservoir management, and 5) technology transfer. All the tasks were completed and water injection began in October 1995.

The Stewart Field project results were 1) the development of a comprehensive reservoir database using personal computers, 2) the completion of a simulation study to history match the primary production, 3) the simulation of waterflooding and polymer flooding, 4) an economic analysis to assist in

identifying the most economical waterflood pattern, 5) completion of laboratory analysis conducted on reservoir rock, and 6) unitization of the field so that a field-wide improved oil recovery process could be implemented, 7) design and construction of waterflood facilities, and 8) initiation and operation of the waterflood utilizing improved reservoir management techniques.

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In the Savonburg Project, the reservoir management portion involved performance evaluation. This work included 1) reservoir characterization and the development of a reservoir database, 2) identification of operational problems, 3) identification of near wellbore problems such as plugging caused from poor water quality, 4) identification of unrecovered mobile oil and estimation of recovery factors, and 5) identification of the most efficient and economical recovery process.

To accomplish this work the initial budget period was subdivided into four major tasks. The tasks included 1) geological and engineering analysis, 2) waterplant optimization, 3) wellbore cleanup and pattern changes, and 4) field operations. This work was completed and the project has moved into Budget Period 2.

The Budget Period 2 objectives consisted of continual optimization of this mature waterflood in an attempt to optimize secondary and tertiary oil recovery. To accomplish these objectives the second budget period was subdivided into six major tasks. The tasks were 1) waterplant development, 2) profile modification treatments, 3) pattern changes, new wells and wellbore cleanups, 4) reservoir development (infill drilling), 5) field operations, and 6) technology transfer.

The Savonburg project results included a complete geological and engineering analysis and fieldwork. The geological and engineering analysis included, 1) development of a database which includes injection and production data, and reservoir data, 2) development of a reservoir description, 3) completion of a pattern volumetric study to select high potential areas, and 4) completion of a streamtube waterflood simulation. The field work completed included, 1) the installation of the air flotation device for improvement of water quality, 2) wellbore cleanups throughout the field, 3) completion of six in-situ permeability modification treatments, 4) three pattern changes, and 5) an in-fill well drilled and completed as an injection well.

Chapter 2

Stewart Field Project

OBJECTIVES

The objective of this project was to address waterflood problems in Morrow sandstone reservoirs in southwestern Kansas. The general topics addressed were 1) reservoir management and primary drive performance evaluation, and 2) the demonstration of a recovery process involving off-the-shelf technology which could be used to enhance waterflood recovery and increase reserves.

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BACKGROUND

History

The Stewart Field is located approximately 12 miles northeast of Garden City in Finney County, Kansas. The Field is about 1/4 - 1/2 mile wide, 4.5 miles long and is approximately 2400 acres. A location plat is shown in **Figure 1.**

In August of 1967, Davidor and Davidor drilled the Haag Estate #1 well in the NE NE of Section 12-T23W-R31W, attempting to extend Mississippian production found to the northeast in Section 6. This was the discovery well for the Stewart Field. The Haag Estate #1 well was completed from a basal Pennsylvanian Morrow sand from 4755-4767 ft. for 99 BOPD. Davidor and Davidor drilled two additional producers (Haag Estate #2 and Mackey #1) and one marginal well (Mackey #2) in Section 12 (refer to the well location plat in **Figure 2**).

In 1971, Beren Corporation acquired the lease and attempted to extend the field to the west with the Mackey #3 located in the NE NW of Section 12. The well was drilled in November 1971 and temporarily abandoned in June 1972 after minimal production.

In 1985, Sharon Resources, Inc. drilled the Sherman #1 located in C E/2 E/2 NE of Section 11 and penetrated 45 ft. of Morrow sand. This well was completed for 60 BOPD. This resulted in a more active development of the field. Sharon drilled four more producing wells in Section 11 through 1985 and early 1986, followed by two dry holes. Beren drilled two offset wells on the Mackey lease, both near the west line of Section 12. In 1986, Sharon extended the field north to Section 2 (four producers and two dry holes) on the Nelson and Carr leases. In 1987, Sharon continued a westward extension in Section 3 (four producers and two dry holes) and drilled the Bulger #7-1 east of the Haag lease in the C W/2 SW NW Section 7-T23S-R30W. Four producing wells were drilled on the Meyer lease in Section 10, around 1988, followed by wells on the Scott lease, in Section 4, in 1988 and 1989. North American Resources Company (NARCO) leased Section 9 and drilled a total of three producers and one dry hole in the north half of Section 9 during 1988. The eastern end of the field, the Bulger lease, was extended with two more Morrow producers, one St. Louis producer, and three dry holes in 1987.

Some locations were drilled during 1990 and 1991. Competitive forces resulted in development drilling with two additional wells in Section 12, one in Section 4 and three stepout wells in Sections 3 and 10. The Scott 4-8 was drilled in January 1992. During 1994, the final two wells, the Bulger 7-8 and 7-10, were drilled on the eastern end of the field.

The western extent of the field is currently defined by three tight Becker wells on the east edge of Section 5 and a wet Morrow test in Section 8. The eastern extent of the field is not as well defined with a suspected permeability barrier east of Bulger 7-10. Total primary field development resulted in 43 producers and 14 dry or abandoned wells.

All wells were drilled through the Morrow, cased with 4.5 or 5.5-inch production casing, perforated through a majority of the net pay interval and stimulated. Most wells utilized approximately 450 ft. of 8-5/8 inch surface casing and a DV or stage collar around 2050 ft. with top stage cement to surface. Early completion practices included acid or diesel breakdown jobs. Some wells were hydraulically fractured with gelled diesel. In 1990 and 1991, Sharon Resources implemented a field wide fracture program consisting of a water based gel with 3,000 to 43,500 lbs. of sand. All Morrow wells have currently been fracture stimulated, with the exception of Mackey #1. All wells during primary production were produced with pumping units and insert rod pumps.

Three wells within the Stewart Field were completed as St. Louis producers, namely Bulger #7-2, Sherman #5 and Nelson #2-3. The two latter wells have been recompleted into the Morrow, whereas the Bulger #7-2 remains a St. Louis producer with no Morrow sand present.

Pressure

The Stewart Field primary pressure history consisted of drill stem tests (DST's) on 31 producers drilled from August 1987 to October 1991, and two field-wide shut-in surface buildup pressure tests in September 1989 and November 1991. The average field pressure at the beginning of this project was estimated to be 100-150 psig.

The first well, the Haag Estate 1, was DST'd 8/14/67 with a final shut-in pressure of 1080 psig. The Haag Estate 2 was DST'd on 1/28/68 with a final recorded pressure of 1102 psig. No extrapolated pressures were available on these wells. Given the good permeability and no pressure depletion in the reservoir, the 1100 psig value was considered representative of an initial stabilized reservoir pressure. Subsequent extension wells proved the continuity of the reservoir over the 4.5-mile length of the field.

The initial two wells were drilled on the Mackey lease in 1968, on the west offset quarter section to the Haag wells. Only the Mackey 1 (SE NW Section 12) encountered productive Morrow sand. It tested with 1102-psig bottomhole pressure (BHP). No further Morrow wells were drilled until the Sherman 1 was DST'd on 7/10/85. This well is near the east line of Section 11 and showed depleted pressures of 847 psig measured shut-in and 862 psig extrapolated. In the 18 years between 1968 and 1985 the two Haag wells and the Mackey well produced 323,196 bbls of oil. The field was extended west with drilling from 1985 to 1992. In 1987 the initial wells were offset to the east with the Bulger 7-1 DST having a final shut-in pressure of 718 psig. The latest Morrow DST producer during primary was the Scott #4-8 which had a static BHP of 300 psig in January 1992. Two additional wells were drilled on the Bulger lease in the latter part of 1993 and early 1994. Pressure data on these wells were not available.

In September 1989, surface measured bottomhole pressure buildup tests were run on 12 wells after 2-6 days of shut-in (depending on the well) to obtain an average reservoir pressure. Bottomhole pressure calculations and an isobar map resulted in an average reservoir pressure of 575 psig.

In November 1991, the field was shut-in for 4 days and surface measured bottomhole pressure buildup tests (6 wells) and static fluid levels (31 wells) were used to calculate bottomhole pressures. Eliminating wells with high fluid levels due to St. Louis water communication, the field-wide average pressure was planimetered to be approximately 215 psig.

Production

Initially most of the wells in the Stewart Field were completed in the Morrow formation. Three wells were completed in St. Louis and Ste. Genevieve initially. Therefore, production was mainly from the Morrow. Production increased approximately 8 fold due to the fracture stimulation work in 1990-1991. There was also substantial increase in water production that is believed to be due to communication with the underlying St. Louis formation.

The Morrow wells produced approximately 3,365 Mbbl of oil and 1,143 Mbbl of water, through May 1994. Using decline curve analysis, extrapolation of this production data indicated estimated primary recovery to be 3.88 million barrels of oil. May 1994 average daily production was 600 BOPD.

Gas production from the field was used to power the pumping units and to fire the gun barrels and heater treaters. Gas volumes were insufficient to market and any excess gas not being used on the leases was vented. No gas volume measurements from the field were available.

Field Data Summary

General		
State:	Kansas	
County:	Finney	
Location:	Section 7, T23S - R30W and Sections 2,3,4,9,10,11,12, T23S - R31W	
Primary Well Count:	43 Producers	
Operators:	3	
Reservoir Data		
Formation	Morrow	
Elevation (Field Average KB)	2884 ft.	
Depth to Top of Morrow Sand	4764 ft.	
Temperature	125° F	
Original Pressure	1102 psig (estimated)	
Average Initial Water Saturation	32.2%	
Area within Zero Contour of Net Sand Map	1,356 Ac.	
Original Oil In Place (estimated)	22,653	MSTB
Cumulative Production (as of 6-1-94)	3,365.035	MSTB
Cumulative Recovery Factor	14.9%	
Estimated Ultimate Primary Reserves	3,881	MSTB
Primary Recovery Factor	17.1%	
Estimated Incremental Secondary Reserves	3,738	MSTB
Incremental Secondary Recovery Factor	16.5%	
Estimated Primary plus Secondary	7,619	MSTB
Primary plus Secondary Recovery Factor	33.6%	
Rock Properties		
Lithology	Sandstone	

Average Thickness	26 ft.
Average Porosity (11% cutoff)	16.5%
Arithmetic Average Permeability (from Cores)	138 md
Compressibility	10×10^{-6}
Archie Equation Parameters:	a = 1
	m = n = 2
Fluid Properties	
Crude Oil -	
API Gravity	28
Viscosity at P_i and T_{res}	12.1 cp
Initial Solution Gas-Oil Ratio	37 SCF/STB
Gas Specific Gravity	1.234
FVF at Pi	1.038 RB/STB
Bubble Point Pressure (P_{BP})	180 psig
FVF at P_{BP}	1.045 RB/STB
Compressibility at P_i	5.83×10^{-6} psi^{-1}
Avg. Compressibility above P_{BP}	7.88×10^{-6} psi^{-1}
Produced Water-	
Resistivity at 125° F	0.04 ohm-m
Chlorides	55,500 mg/l
Total Dissolved Solids	91,300 mg/l
Compressibility at P_i	3.07×10^{-6} psi^{-1}

BUDGET PERIOD 1 ACTIVITIES

Geological and Engineering Analysis

Geology Summary

The Stewart Field is situated on the northeastern edge of the Hugoton Embayment of the Anadarko Basin. Morrowan or Atokan aged sands filled an incised valley into the underlying Ste. Genevieve and St. Louis formation of the Mississippian age. This incision occurred from regressive sequences during the period of the Central Kansas Uplift. The incised valley is filled with at least three and as many as six stacked, partly eroded siliclastic sedimentary intervals. Each sequence represents a transgressive and regressive succession reflecting flooding and then reemergence of the shelf and valley system. Local erosion and reworking of the sediments is common. The sands may be at least partially sourced from erosion of a local sandy Ste. Genevieve limestone. It is believed that marine reworking of the sands from the west contributed to cleaning up the sands.

Log, core and dipmeter data indicate that the deposits prograded from east to west, landward to basinward. The channel thickens from around 20 ft. in the eastern end in Sec. 7-T23S-R30W to around 45 ft. in Sec. 9-T23S-R31W with a notable exception in the east half of Sec. 12-T23S-R31W, where a suspected karstic feature results in 61.5 ft. of gross sand. The lower half of this sand is poorly developed, possibly due to lack of marine reworking. The channel dips 3 to 5 degrees per mile until the paleogradient steepens in the western end of Sec. 3-T23S-R31W before emptying into a deltaic environment with shale and silty sandstones in Sec. 5-T23S-R31W. Deep fault planes or zones of weakness may have contributed to rapid directional changes of the center of the channel.

Sourcing of the reservoir is believed to have occurred along fault lines and porous reservoir rocks from the Woodford shale deep in the Anadarko Basin. A thick black oil stain is found in some of the core samples, possibly indicative of an earlier hydrocarbon migration. The Morrow reservoir was initially underpressured, but a higher pressure region was tested in the west end.

The lithology is described as glauconitic quartzarenite to quartzarenite with varying grain size distribution from very fine to medium sized grains. In some wells, a coarse grained conglomerate is reported at the base of the sand. Samples are typically subangular to subrounded, moderate to well sorted with intergranular to intercrystalline porosity development. Quartz overgrowths are abundant. X-ray diffraction indicates 0 - 6 % clay volume with a majority of smectite along with detrital chlorite and illite.

The fluvial influence of the channel is exemplified by the tributary channels and by the thickening and dipping sand strata towards the west. In addition, the cores show layers of coarse grains fining upwards with numerous instances of cross-bedding within the individual strata.

A strong marine influence is shown by numerous lime streaks. Even though individual lime streaks cannot be correlated across the whole length of the channel, the Pe curve identifies common no flow boundaries across 4-5 well distances. In actual core recovery, these lime streaks were tested impermeable with no oil saturation. An abundance of glauconite, pyrite, coals, shales, fossils, burrows and caliche zones are also found within the sand sequences.

Database Development

All the electric log data for the field were digitized into a computer database. The log data were analyzed by digitizing the Morrow interval of the printed logs using a commercial "Logdigi" computer program by "Logic Group". Existing core analyses and log data were analyzed to find a relationship between core porosity versus log porosity and porosity versus permeability. A cumulative porosity plot was used to determine a porosity cut-off as related to net pay. The porosity cut-off was determined to be 11%, which corresponds to about 8% of the total porosity feet. Net pay thicknesses for individual wells were completed using this porosity cut-off value. A net pay map was constructed for the purpose of the waterflood feasibility study. This map was planimetered to determine the reservoir volume of the Morrow and oil recovery factors.

Water saturation calculations from electric logs were done in order to be included in the database. The water saturations could not be calculated with sufficient accuracy to tabulate values for individual wells. Key problems identified were thin bed effects, thin conductive beds from pyrite cementation material, and conductive chloride clays. Capillary tests on cores were employed to estimate initial water saturation.

Production data for all wells in the Stewart Field was also entered into the computer database. Production data was tabulated by month since the discovery of the field. The wells were grouped by tank battery so that allocations for each well could be monitored. The production was allocated to each well by monthly barrel tests. Water production was estimated by applying the percent of water as determined by a grind-out test and relating that to the oil volume produced. The sales numbers for each tank battery were also listed to compare with the production numbers supplied by the operators. Production was divided between Morrow and non-Morrow for the wells that had produced from other zones. Gas production from the field was minimal and was used to power the pumping units or vented.

The Stewart Field primary pressure history, including drill stem tests (DST) conducted on 31 wells, two field wide shut-in surface pressure tests, and individual well fluid level tests was also tabulated into the database. Pressure tests indicated the continuity of the reservoir over the 4.5-mile length of the field. Isobar maps were constructed for the field. Pressure history of all DST's, shut-in pressures, bottomhole pressure (BHP) from fluid levels, and BHP versus cumulative production plots were made for each well and the entire field.

A log stratification study was completed which indicated the Morrow formation could be divided into as many as eight different flow units. Three main flow units were identified as separate depositional sequences that appeared to possess similar porosity and permeability characteristics. These three flow units correlate along the deepest parts of the channel, with some minor discrepancies within the thinner boundary wells. The three flow units were identified as the Red zone on top, Purple zone in the middle, and Yellow zone on the bottom. The depth and subsea elevation for the top and bottom of each zone was entered into the database for each well.

Porosity and resistivity log data (foot by foot) were cross-plotted on log-log paper (Pickett plot) keeping track of depth trends. The three primary zones in the Morrow formed distinct clusters of points on these plots indicating that the zonation identified nicely grouped the levels of heterogeneity. While most of the field is above the oil-water contact, several wells in the west half of the field indicate a transition zone and water leg.

Wettability tests, petrographic data, and standard core analysis were compared as series of plots with log analysis results to define correlations. In particular, relationships between bulk volume water (water saturation and porosity) and relative permeability data, grain size and sorting, and mineral composition (clays) were sought.

Permeability was estimated using different relationships utilizing porosity and water saturation. One method investigated was the Timor relationship. This empirical relationship provided only fair results when comparing measured core permeability versus estimated permeability.

The possibility of open fractures in the Morrow reservoir was evaluated through three potential sources of information:

1. 4-arm dipmeters from the reservoir to examine for borehole breakouts to establish minimum horizontal compressive stress direction.
2. Paleomagnetic measurements of core samples to orient the cores to define directions of any open fractures that might be present.
3. Examination of the oriented core from the Sherman #3.

The presence and characterization of fractures helped to define any anisotropy in the reservoir in addition to the influence of sedimentary structures on fluid flow.

Volumetric Analysis

Decline curve analysis from existing production data was completed for all the wells within the field. Utilizing a straight exponential decline analysis, calculated remaining primary reserves as of June 1, 1994 were 516,000 barrels of oil for an ultimate primary oil recovery of approximately 3,881,000 barrels. A plot of the field's primary production is shown in **Figure 3**.

Over the last year of primary production a substantial flattening of the production decline occurred for many leases, as more of the field was affected by gas expansion.

Material Balance

Material balance calculations were performed from initial pressure to the 1989 and 1991 field wide tests. Assuming no water influx and pressure above the bubble point, the fluid produced should have been due to fluid and rock expansion over the given pressure drop. These calculations gave original reserves in excess of 100 million barrels of oil in place. Volumetric mapping of the net sand indicated only 22 million barrels in place.

It was determined that uncertainties in fluid and rock properties would not resolve the difference in determining the original oil in place between volumetric mapping of the net sand and material balance calculations. Either a large volume of the reservoir was yet to be defined or a limited water influx (pressure support) existed within the field.

Development drilling and seismic data indicated that the reservoir boundaries were defined with reasonable certainty. Therefore, potential pressure support sources were investigated and identified. This was accomplished through the geological examination of well logs and drill stem test data from locations adjacent to the field. A complete collection of well logs from adjoining areas to the field was assembled.

Three potential sources of pressure support were identified. A water aquifer associated with the Morrow formation is present at the west end of the field. Underlying formations, the Ste. Genevieve and St. Louis, appear to be in communication with the Morrow reservoir in certain areas of the field.

Polymer Flood Analysis

Relative permeability tests were conducted on cores taken from the Stewart Field. Using the endpoints from the relative permeability curves, mobility ratios were calculated. All the mobility ratios calculated based on the average saturation behind the flood front were less than 1.0, which was highly favorable.

Analysis was conducted utilizing the Polymer Flood Predictive Model developed by Scientific Software-Intercomp for the National Petroleum Council's (NPC) 1984 survey of U.S. enhanced oil recovery potential (NPC, 1984). Using average reservoir properties the model did not predict significant incremental amounts of oil recovery for polymer flooding versus waterflooding. **Figure 4** is a plot illustrating the results of this analysis.

Based on these findings there was no justification for considering a polymer flood in this project.

Reservoir Modeling

Independent reservoir simulation studies were undertaken by Sharon Resources and the University of Kansas. Sharon Resources, located in Englewood, Colorado, was connected via Internet to the workstation at the University of Kansas. The studies were performed using a Silicon Graphics workstation with Western Atlas VIP Executive simulation software. The VIP simulator is a conventional black oil simulator, equipped with graphics interface. A major portion of the technology transfer associated with this budget period pertains to University personnel assisting Sharon Resources in their simulation efforts.

The objectives of each study consisted of: (1) the characterization and distribution of the various reservoir parameters, (2) a material balance model to establish a history match with the primary production, and (3) a waterflood predictive model to select the optimum waterflooding pattern for maximum economic oil recovery. The independent studies resulted in different models, however, the two models provided similar results.

Overview of Reservoir Simulation

A. Introduction

Reservoir simulation is a tool to increase profitability of a reservoir through proper reservoir management. Simulation can be a tool to determine optimum well pattern and spacing, design of a facility, optimum recovery method, optimum well completion, etc. Simulators can also be used to match the history of the reservoir with updated seismic and geological data. It can serve as a tool to judge the actual performance of the reservoir and also predict the future performance. Based on the predictions, proper reservoir management can be applied to reduce operating costs and thereby increasing profitability.

B. Data Requirements

The approach for reservoir description entirely depends on the available reservoir database. Data required for a reservoir description can be classified as follows:

1. Rock property data at initial static conditions.
    a. Formation structure: Tops and bottoms of the formation.
    b. Net pay thickness.
    c. Porosity at initial pressure.
    d. Drainage and capillary pressure data.
2. Fluid properties at static conditions.
    a. Oil, gas and water formation volume factors.
    b. Oil, gas and water densities at standard conditions.
3. Rock and fluid data for oil/gas displacement
    a. Absolute permeability of rock.

b. Gas and oil relative permeability curves.
c. Formation, oil and water compressibility.
d. Oil and gas formation volume factor as a function of pressure.
e. Gas in solution as a function of pressure.
f. Oil and gas viscosity as a function of pressure.

4. Rock and fluid data for water/oil displacement
   a. Oil and water relative permeability curves.
   b. Water formation volume factor as a function of pressure.
   c. Water viscosity as a function of pressure.

Porosity and permeability distributions are normally derived from core analysis, well-log, and well test data. The most difficult reservoir property to define is the permeability distribution areally and vertically between wells. Adequate knowledge of permeability distribution is more important than the porosity to understand the flow of reservoir fluids. Porosity can be measured by logging, but permeability cannot be measured reliably by logging. Thus, it is necessary to estimate the permeability from permeability/porosity correlations developed from core analysis data. Correlations will be most reliable if they are developed for each major rock type present in the reservoir.

After developing the reservoir description, it is necessary to test the description. This is carried out by matching the available history of the reservoir. Simulation of the past history can identify the weaknesses in the reservoir description and modifications to the description can then be implemented. In some cases the reservoir description is changed to match the history, considering that the changes should be rational and consistent. History matching can also be used to study the current status of the reservoir, to identify the depletion mechanism, and to determine the fluid distribution in the reservoir.

Simulation Conducted at the University of Kansas

A. Data Availability

Necessary data required for simulation was provided by Sharon Resources. The most important data for reservoir description was the porosity /permeability correlations for the three major zones within the Morrow. These correlations were derived by Sharon Resources and the results of the correlations were used in the simulation for distribution of properties in the reservoir. Relative permeability data representative of the field was also required. Sharon Resources also supplied this data.

B. Reservoir Description

The Stewart Field model was developed in stages. Sharon Resources initially identified the three major pay zones in the reservoir. Based on core/log and permeability/porosity correlations they assigned porosity and permeability values to the zones present in all the producing wells. Digitized logs were also provided to get the tops and bottoms of each zone. Initially it was decided to divide the field in four different sections, which were assumed to be isolated from each other. The first section of the field consisted of the Sherman, Nelson, Carr and Mackey leases. These leases comprise 912,000 barrels of oil production from the Morrow, which is approximately 35% of the total field production from the year 1985. The assumptions used to match the production history of this section were also used in the subsequent sections.

Initially it was necessary to assign X and Y coordinates to each well from a zero reference point. The NE corner of section 10 was chosen as the zero reference point.

To identify the distributions in the regions between the wells, it was necessary to contour the tops, bottoms, porosity, permeability and water saturations of each zone. Data files were created and CPS Radian software was used for contouring. Due to the absence of control points, other than the wells, CPS Radian mathematically extrapolated the reservoir boundaries. In order to get a more accurate reservoir description, about 100 Dry holes were introduced around the reservoir to force a NO FLOW boundary in the desired locations. The necessary files were converted to a format that was acceptable to the VIP black oil simulator's GRIDGENR, a preprocessor program to generate grids graphically for simulation purposes.

C. Reservoir Simulation using VIP Simulator

The VIP black oil simulator was developed by Western Atlas Inc. It is one of the most powerful commercial software packages available for reservoir simulation. Its graphic interface enables the user to import geological and other data from various engineering and geological software. GRIDGENR is a utility of VIP that allows the user to import reservoir parameters in the form of contours. Based on the grid system selected, it calculates and assigns values to each grid block.

Using the VIP PRCORE utility, all rock and fluid parameters were input and the necessary data files relating to the formation structure, porosity and permeability distribution were imported into GRIDGENR. The initial simulation grid of 150x20x3 blocks was created and the values were calculated using the program. This allowed creation of the VIP-CORE initialization module file.

Once the initialization file was created, the next step was to create the VIP-EXEC file. This file consists of the history of all the wells which includes location, date of completion, perforation intervals, wellbore radius, skin factor, stimulation history, production history, pressure constraints, and any other information related to the wells. Sharon Resources provided all relevant information. Using the VIP PREXEC utility, all data was imported and a recurrent run file was created. The field consisted of 44 producing wells.

D. History Matching of Primary Production

The model had the following initial assumptions:

1. Initial reservoir pressure was assumed to be 950-1000 psi (depending on the first date of production in the four sections). No external pressure support was provided.
2. The reservoir was under natural depletion drive.
3. There was no initial skin damage on the wells.
4. Based on the pressure buildup tests an average skin factor of -3 was assigned to each well after the fracture stimulation work.

Several cases were run to get an optimum history match of each section. The details of the simulation results for section "C" consisting of Sherman, Nelson, Carr and Mackey leases are described below. Similar assumptions were used for all the other three sections.

Details of the Simulation Conducted at the University of Kansas of Section "C" of the Stewart Field

The model had the following initial assumptions:

1. Initial reservoir pressure was assumed to be 950 psi and there was no external pressure support for the reservoir.
2. The reservoir was under natural depletion drive.
3. There was no skin damage on the wells.
4. Based on the pressure buildup tests an average skin factor of -3 was assigned to each well after the fracture stimulation work.

Several cases were run to get an optimum history match. Tables of all cases are included. During the initial run it was observed that the simulated production was much less than the actual production, especially during the period from 1989-1992 (Case 1). This was the period when Sharon Resources had conducted the field wide fracture stimulation program. The actual peak rate of production in this period was about 850 BOPD. The simulated results showed a peak rate of production of about 250 BOPD. During the analysis of the results it was observed that most of the wells became pressure limiting and were unable to produce the rates due to low pressures. These results lead to a hypothesis that there was a source of external pressure support. One possible scenario for providing pressure support was from the underlying St. Louis formation acting as an active aquifer. Based on various data available, the St. Louis formation was implemented into the model as a layer which was 95% water saturated and had a slightly higher pressure compared to that of the Morrow formation. The simulated results after the introduction of the St. Louis formation (at 1250 psi) increased, but were still below actual production (Case 2).

The St. Louis formation pressure was then increased to 1550 psi with a very low vertical permeability (Case 3). There was some increase in the production, but simulated results were still off in the post fracture production by a factor of 3.

In the next two runs, a skin factor of +1 was introduced during the pre-frac period and -3 in the post-frac period. Low vertical permeability of 0.002md and 0.0015 were introduced in all the layers (Case 4 and 5). In both the runs, there was substantial increase in post-frac production, but the pre-frac production was reduced by a factor of 3 due to the skin factor.

Vertical permeability was then increased by a factor of 10, i.e to 0.015 md (Case 6). It was observed that the initial simulated peak production during the pre-frac period was approximately 150 BOPD less than actual and the post-frac production was about half the actual production.

At this point the perforations were changed in the wells. It was assumed initially, all the wells were perforated in all the zones present in the wells. To maintain the reservoir pressure during the post-frac period and achieve the peak production rate, it was decided to have perforations only in the top two layers during the pre-frac period and have perforations in all the zones including the St Louis formation during the post-frac period (Case 7). Also, a -2 skin factor was implemented during the pre-frac period and a skin factor of -4 during the post-frac period (Case 8). The St. Louis formation pressure was also increased to 1750 psi. Simulated results were still much below the actual until the permeability of the system was increased by a factor of 2. In this model the initial peak production rate during the pre-frac period was off by about 30-40 BOPD and the post-frac rate was off by about 250 BOPD.

Analysis of each well's simulated production compared with the actual production history revealed that some of the edge wells did not have enough reservoir volume to produce properly. It was decided to extend the NO FLOW boundary and give these wells additional reservoir volume. This increased the original-oil-in-place-(OOIP) in the model by about 35%. The results of this model were 96.013% of the actual production from the wells in the section (Case 9). The match from this model was considered adequate for the reservoir section in question.

Conclusions

The following changes to the original description enabled the model to have a history match of the reservoir section chosen for simulation:

1. Permeability of the reservoir was increased by a factor of 2.
2. Reservoir volume had to be added to the northern portion of the simulated area. This leads us to question whether the reservoir boundaries have been properly defined in this area.
3. Outside pressure support had to be included. It appears most logical that this support was coming from the underlying St. Louis formation. This would result in the primary drive mechanism being a combination of depletion drive and water influx.

Results and Cases

Case 1

Layer #	Perf	KZ md	Sw %	P psi
1	Yes	0.002	31	950
2	Yes	0.002	31	950
3	Yes	0.002	31	950
4	No	0.0015	99	950

Pre-frac Skin = 0
Post-frac Skin = -3

Analysis: The prefrac results are about 100 BOPD less than the peak production and Post frac results are about 1/4th of the actual production.

Case 2

Layer #	Perf	KZ md	Sw %	P psi
1	Yes	0.002	31	950
2	Yes	0.002	31	950
3	Yes	0.002	31	950
4	No	0.002	95	1250

Pre-frac Skin = 0
Post-frac Skin = -3

Analysis: There was not much difference from the case one.

Case 3

Layer #	Perf	KZ md	Sw %	P psi
1	Yes	0.001	31	950
2	Yes	0.001	31	950
3	Yes	0.001	31	950
4	No	0.001	95	1550

Pre-frac Skin = 0
Post-frac Skin = -3

Analysis: The prefrac results are about 80 BOPD less than the peak production and Post frac results are about 1/4th of the actual production. Not much increase in cumulative production.

Case 4

Layer #	Perf	KZ md	Sw %	P psi
1	Yes	0.002	31	950
2	Yes	0.002	31	950
3	Yes	0.002	31	950
4	No	0.002	95	1550

Pre-frac Skin = +1
Post-frac Skin = -3

Analysis: There was decrease in pre-fracture production by a factor of three but increase in post fracture production by a factor of 2.

After this the permeability in x and Y direction were increased by a factor of 2, resulting in some major changes which are discussed in the cases below.

Case 5

Layer #	Perf	KZ md	Sw %	P psi
1	Yes	0.0015	31	950
2	Yes	0.0015	31	950
3	Yes	0.0015	31	950
4	No	0.0015	95	1550

Pre-frac Skin = +1
Post-frac Skin = -3

Analysis: Due to the low vertical permeability there was some pressure support but was not substantial to increase the cumulative production by factor of 2 to match the actual production.

Case 6

Layer #	Perf	KZ md	Sw %	P psi
1	Yes	0.015	31	950
2	Yes	0.015	31	950
3	Yes	0.015	31	950
4	Yes	0.015	95	1550

Pre-frac Skin = +1
Post-frac Skin = -3

Analysis: The vertical permeability was increased by a factor of 10, resulting in increase of the total production substantially. post fracture production by a factor of 2.

It was then decided to produce from Zone 1 & 2 to match the pre-fracture production and then open all the zones after the fracture job.

Case 7

Layer #	Perf	KZ md	Sw %	P psi
1	Yes	0.0	31	1000
2	Yes	0.09	31	1000
3	Yes	0.002	31	1000
4	Yes	0.002	60	1700

Pre-frac Skin = +1
Post-frac Skin = -3

Analysis: No substantial changes in production observed.

Case 8

Layer #	Perf	KZ md	Sw %	P psi
1	Yes	0.025	31	950
2	Yes	0.025	31	950
3	Yes	0.025	31	950
4	Yes	0.0095	95	1750

Pre-frac Skin = -2
Post-frac Skin = -4

Analysis: Initial peak production was about 30-40 BOPD less than the actual production, but the post fracture peak production was about 250 BOPD less than the actual production.

Reservoir Model OOIP:	7523.140 MSTB
Total production:	817757 STB
Actual production:	912540 STB
% of Actual Production:	88.846 %

It was found that the edge wells namely Nelson #2-2, Nelson #2-3, Sherman #4 and Carr #2-1 were not producing at the rate they should have been producing. Looking into the maps and contours, it was found that there was not enough reservoir volume in that area for the wells to produce. In order to increase the reservoir volume the no flow boundary was moved further outside. this increased the total reservoir OOIP by about 35%.

Case 9

Layer #	Perf	KZ md	Sw %	P psi
1	Yes	0.002	31	950
2	Yes	0.09	31	950
3	Yes	0.095	31	950
4	Yes	0.09	99	1650

Pre-frac Skin = -2
Post-frac Skin = -4

Analysis: Substantial changes in production observed. The final results gave us history match of about 99.013%

Reservoir Model OOIP: 100288 MSTB
Total production: 876153.9 STB
Actual production: 912540 STB
% of Actual Production: 96.013 %

Conclusions:
1. Permeability increased by factor of 2.
2. Increased reservoir volume at the edges.
3. Pressure support from the aquifer.

Case to prove aquifer support:

Case 10: No vertical permeability in either layer.

Layer #	Perf	KZ md	Sw %	P psi
1	Yes	0.0	31	950
2	Yes	0.0	31	950
3	Yes	0.0	31	950
4	Yes	0.0	95	1750

Pre-frac Skin = -2
Post-frac Skin = -4

Analysis: Initial peak production was about 60-80 BOPD less than the actual production, but the post fracture peak production was about 250 BOPD less than the actual production.

Reservoir Model OOIP: 10288 MSTB
Total production: 730160.2 STB
Actual production: 912540 STB
% of Actual Production: 80.01%

Case 11: No aquifer present in the model.

Layer #	Perf	KZ md	Sw %	P psi
1	Yes	0.002	31	950
2	Yes	0.09	31	950
3	Yes	0.0095	31	950

Pre-frac Skin = -2
Post-frac Skin = -4

Analysis: Initial peak production was about 60-80 BOPD less than the actual production, but the post fracture peak production was about 250 BOPD less than the actual production.

Reservoir Model OOIP:	10007 MSTB
Total production:	762144.7 STB
Actual production:	912540 STB
% of Actual Production:	83.51%

The following is a summary of the assumptions used and changes implemented to the field description in order to obtain a history match of the primary production for all four sections:

1. Permeability of the reservoir was increased by a factor of 2. Justifications for this could be that there was uncertainty in the porosity permeability correlations developed using the core/log data or damage to the cores during the drilling process.
2. Reservoir volume was added to the northern portion of the Nelson and Carr leases. This led us to question whether the reservoir boundaries had been properly defined in this area.
3. Outside pressure support was included. It appeared most logical that this support was coming from the underlying Ste. Genevieve/St. Louis formations. This would result in the primary drive mechanism being a combination of depletion drive and water influx.
4. The initial skin had to be changed to +1 and the average skin after fracture stimulation remained at -3 for all wells. This post fracture skin used in the simulator was in agreement with the pressure transient analysis where the post fracture stimulation skin was within the range of -2.8 to -3.6.
5. The initial reservoir pressure was 1200 psi and the pressure of the underlying formation was assumed to be 1500 psi. Initially it was assumed that the underlying formation was in pressure communication with the entire field, but based on the geological analysis and production history it was observed that the direct communication of the permeable underlying formation is in the area of the Mackey and Scott leases. This assumption was built into the model in order to describe the reservoir more realistically.

Based on the above assumptions the model was developed. An external aquifer, as described above in assumption 5, was included as the fourth layer in the model. None of the wells were perforated in the fourth layer.

A model of the entire field was developed. The model was built using a grid of 150x20x4. Each gridblock had average dimensions of 190 x 250 ft. The resulting model had about 2-3 gridblocks between each well. The model contained a total of 12000 gridblocks. The OOIP for this model was 25256 MSTB. This figure did not match with the estimated OOIP based on the net sand map provided by Sharon Resources. One reason for this discrepancy could have been the uncertainties associated with the reservoir boundaries. The following parameters were added to the reservoir description to obtain a history match.

1. Water saturations in the four layers:

Layer 1: 31 %
Layer 2: 31 %
Layer 3: 31 %
Layer 4: 99 %

2. Vertical permeability distribution within and between the layers.

Layer 1: $K_z = 0.05$ md
Layer 2: $K_z = 0.01$ md
Layer 3: $K_z = 0.05$ md, Only at the west end and in section 12.
Layer 4: $K_z = 0.05$ md, Only at the west end and in section 12.

The vertical permeability in the rest of the field in layers 3 & 4 was zero.

3. Initial pressure for the layers:

Layer 1: 1200 psi
Layer 2: 1200 psi
Layer 3: 1200 psi
Layer 4: 1500 psi

These values provided a primary history match in which the simulated production was 95.74% of the actual production. The actual and simulated results are plotted in **Figure 5**.

This was assumed to be a representative model of the field. This model looked different from the actual field in certain aspects, but it behaved similar to the actual reservoir in terms of the production and pressure history. One of the reasons for possible discrepancies could have been the description of the reservoir properties within the interwell region. Many different models were capable of producing a history match for the same field.

E. Waterflood Simulation

Reservoir simulators have served as an effective tool to predict and design the optimum recovery processes. The VIP simulator has the capability to simulate many of the enhanced oil recovery processes, including waterflooding. During the initial stages of this study it was observed that the mobility ratio was favorable for waterflooding. Thus, there was minimal incremental increase in oil production due to polymer flooding. Polymer flooding was analyzed using the DOE streamtube waterflood/polymer flood predictive model. Based on the results of the predictive model, it was decided to design an optimal waterflood recovery pattern.

F. Waterflood Patterns Investigated

Working Interest Owners (WIO) and University personnel proposed six different patterns. The injection rate was restricted by the water availability of about 6000 BWPD (as informed by Sharon Resources). Thus, in each case the total water of 6000 BWPD was distributed equally between each injection well within the waterflood pattern. The different waterflood patterns simulated were 3 line drive, 5 line drive, 7 line drive and three other line drive type patterns.

All the patterns were run for a waterflood period of ten years. The production wells were set to a watercut limit of 90%. **Figure 6** is a plot of cumulative oil production versus cumulative water injection for the different patterns investigated. During the waterflood predictive runs convergence failures were observed. To avoid excessive failures, timestep control was implemented in the simulation. Timestep control restricts the maximum change in the saturation profiles, pressure, etc, in order to avoid convergence failures by solving the fluid flow equations at small time intervals. This had no significant effect on the calculated results.

G. Conclusions of the Waterflood Simulation

The Stewart Field simulation indicated favorable results for waterflood. The following conclusions were derived for waterflood prediction based on the simulation results.

1. Based on the simulations, the cumulative oil production and the WOR for all the patterns varied by less than 10%.
2. Simulation results suggested that the total oil recovery was a function of the volume of water injected, but not a strong function of the injection pattern.

Simulation Conducted by Sharon Resources

The simulation conducted by Sharon Resources was designed in two phases. A two-dimensional (2D) study was done with radial and linear models using a range of reservoir characteristics and sensitivities. Also a three dimensional (3D) study was conducted to history match the Morrow production history and predict the optimum waterflooding pattern.

A. Two-Dimensional Study

The objectives of the 2D simulation were to study oil recovery changes as reservoir characteristics varied within a range of known field data. This would acquaint Sharon Resources personnel with the simulator, assist in the understanding of the reservoir, and would also help simplify history matching in the 3D simulation. The following objectives were stated:

1. In a radial model, history match a typical fracture stimulation response.

2. a. In a linear model, study the effect of layering and cross-flow between layers. Study oil recovery as a function of permeability variation and permeability ordering.

   b. Study the impact of wells with St. Louis communication. Study the effect of shutting in first line producing wells at various water cuts and converting them to injectors.

   c. Vary relative permeabilities and capillary pressures within known field parameters to ascertain their effect on oil recoveries.

1. Radial Model

Sherman #3 was selected as the well to model via radial simulation. This well had good logs with clearly identified flow units, core analysis, pre- and post-stimulation pressure transient analysis and was an excellent example of the increased production rates obtained from hydraulic fracture treatments. The purpose of the radial model was to history match the fracture results.

Core porosities and permeabilities were used to represent eight layers identified from the logs. Production declined from a peak rate of 47 BOPD in January 1986 to 3 BOPD in October 1990. The well was fractured in November, 1990 with 11,000 gallons of 40 lb. Boragel with 1,300 lbs. 100 mesh sand and 18,200 lbs. 20/40 sand. Production reached a stable rate of around 120 BOPD before declining to 13 BOPD in December 1993. This production response could not be explained by changing from a +1 pre-frac skin to a -2 post-frac skin factor, but was augmented by additional thickness opened at the wellbore. An eight layer radial model with 20 concentric cylinders with increasing radii away from the wellbore was used to match production from a 32-acre drainage area. The production could not be matched by depletion drive alone without substantial pressure support. This support was likely water influx, possibly from hydraulic fractures communicating with the St. Louis. It was also necessary to double the core permeabilities to match the actual flow rates.

The after-frac peak production rate was best modeled by adding a large outer cylinder of water reservoir, surrounding the drainage area, to represent an external pressure source. A no-flow boundary was needed to isolate half of the reservoir at original pressure. Half of the thickness was initially perforated, with the pressure support, and allowed to produce down to the pre-frac rate. The fracture was then responsible for opening up the other half of the thickness, releasing oil that was still at original pressure, matching the production increase. This was a plausible explanation, as several shale and limestone streaks were evident in the core and pressure support could be seen from different sources.

The external pressure source and isolation of part of the reservoir accomplished the goal of approximating the well's performance. The model did not sustain the peak rate for as long as the actual production, but this could be accomplished by increasing the drainage area. The model required a pressure constraint at the producing well. The well was allowed to produce at the actual rate if the BHP stayed above 50 psi. If the actual rate was too great and required a lower pressure than 50 psi, the pressure limit was invoked thereby reducing the rate at which the well could produce. The model performance showed that the well was able to produce at the actual rates while keeping the well essentially pumped off as evidenced by the pressure staying above 50 psi but not exceeding 200 psi. The only portion of the model where the well was unable to keep up with the actual production was the extended peak rate after the frac.

2. Linear Model

a. Layering, Cross-Flow, Permeability Variation and Ordering

The linear model was built using 25 x 5 x 8 gridblocks in the X, Y and Z directions, respectively. Each gridblock was 55 feet in the X and Y direction and 5 feet in the Z direction. One well at each end of the model approximates the 40-acre spacing seen across most of the field. (This is referred to as a 2D model since the purpose of including the Y-direction was to judge the directionality of the solution algorithm and not to describe the width of the channel.) The flow units were described by eight layers, two in the Red (top) and Purple (middle) and four in the Yellow (bottom). Eight layers represented the maximum amount of flow units identified in any well and were felt necessary to adequately describe the reservoir with a proper permeability variation. Since the permeability-porosity transforms were based on log analysis that averages data over several feet, the permeabilities calculated from the logs were too uniform. As an example, Sherman #3 plotted a permeability variation (V) = 0.7 from point specific lab measurements, but V=0.3 based on the log transforms. The linear model was run at V=0.3, 0.5 and 0.7 to quantify how much the log derived permeability transforms over-estimate waterflood performance. The recovery of reserves in the 2D model was very high as each layer will flood out eventually and areal sweep was complete for each case. Therefore, comparing ultimate recovery is not an indication of waterflood performance. The method chosen to compare waterflood performance in the 2D study was the number of months to recover 72,000 barrels of oil. The more efficient floods will have later water breakthrough, thereby recovering more reserves sooner and without the added operational cost of produced water. The V=0.7, 0.5 and 0.3 cases recovered 72,000 BO in 47, 28 and 24 months respectively. The 0.3 permeability variation case recovered the oil in almost half the time of the case with V=0.7.

The different permeability variation cases were all run with 1 md of cross-flow between layers. The effect of cross-flow on a reservoir with V=0.7 was studied at 0, 1 and 100 md. The model uses the vertical permeability as the permeability to flow between the gridblocks. The 0, 1 and 100 md cases recovered 72,000 BO in 48, 47 and 27 months, respectively. The no-flow barriers isolated the layers creating different pressure profiles in each layer. Cross-flow between layers allows the pressure to equalize so that a uniform pressure drop from the injector to the producer exists across all the layers. Based on these results, wells with low stratification would make better injection wells.

The impact of permeability ordering was seen to be negligible in the case of wells with no-flow boundaries. This was expected since cross-flow is not occurring and the pressure transients move through each zone individually with no effect of gravity. What was more surprising, however, was the small effect of permeability ordering in the presence of vertical permeability.

Sensitivity to number of layers was tested by comparing a three layer model with the eight layer model to see the validity of representing a V=0.7 with only three layers. Three layers recover 72,000 BO in 37, 31 and 24 months for the 0, 1 and 100 md cases, respectively. This was an improvement of 23%, 34% and 11% over the eight layer model with the same vertical permeability. The difference was caused not from the difficulty of representing a V=0.7 with three or eight data points, but from the vertical permeability. Seven no-flow barriers exist in an eight layer system as opposed to only two in a three layer. At low vertical permeability this causes considerable differences. Increasing vertical permeability reduces the contribution of the barriers and puts more priority on the permeability variations. At high vertical permeability a three layer system only differs from an eight layer model by 11%.

The continuity of layers must be considered. The low vertical permeability in the Stewart Field would suggest that more layers are required, but if the eight layers are of limited extent it may not be necessary to model that many layers. The following cases are defined as follows:

Case 8>3:	Eight layer model with seven no-flow barriers in the injector and two no-flow barriers in the producer.
Case 3>8:	Same as above, inject from the other direction.
Case 8:	Eight layer model, vertical permeability = 100 md with two no-flow barriers.
Case 3-0:	Three layer model with two no-flow barriers.
Case 8F:	Eight layers, vertical permeability = 100 md, communication in all layers near well-bore, two no-flow barriers.
Case 3F:	Three layers, vertical communication near wellbore (100 md), and two no-flow barriers.

Again, comparisons were based on time to breakthrough and time to recover 72,000 BO. Case 8>3, with the more stratified well used as the injector, showed water breakthrough in 12.6 months, two months sooner than Case 3>8. A well with more uniform stratigraphy makes a slightly better injector, but the two cases were not much different. Case 8 had slightly later breakthrough (15.7 months) and recovered the reserves in the same amount of time as Case 3>8. Therefore, it is not necessary to model eight layers if the no-flow barriers are discontinuous.

Case 8 was compared to Case 3-0 to see if a vertical permeability variation of 0.7 was better described with eight layers as opposed to three layers if only three continuous flow units exist in each well. The three layer case had water breakthrough in 15.2 months as compared to 15.7 months for the eight layer, but it recovered the reserves much faster than the eight layer model (35 months vs. 43.8 months). In comparing results with V=0.7, with three vs. eight layers, breakthrough occurred in the high permeability layer at about the same time. The three layer model was more efficient and resulted in more optimistic results regarding reserve acceleration.

Cases 8F and 3F were designed to study the same effects as above where fractures result in communication around the wellbores. Note, both cases have only two no-flow barriers. The results were similar to the comparison of Case 8 and 3-0 in the preceding paragraph. The eight layer model showed no difference between the fractured and non-fractured cases. The three layer model had a three month delay in breakthrough and recovered reserves three months sooner than the non-fractured. The three layer results were slightly optimistic as compared to the eight layer. Therefore, the configuration used in the 3F case was used in the 3D simulation.

b. St. Louis Communication

The effect of communication with the St. Louis in a linear model was duplicated by a thick, water aquifer underlying the Morrow. A third well was inserted between the two previous wells in the center block (20-acre spacing). No vertical flow was present between the Morrow and St. Louis except in the one gridblock containing the center well. A vertical permeability of 1.0 md was allowed in the 55 foot by 55 foot block containing the well to simulate the conductivity of a hydraulic fracture into the St. Louis. The pressures in the Morrow and St. Louis were 200 psia and 800 psia, respectively. The cases were run on a V=0.7 and kz=1 md in the Morrow. The center well was shut-in at different watercuts to determine the optimum time to shut-in the well and to observe any cross-flow into the St. Louis.

The first model had a fixed injection rate of 110 BWPD (approx. 1 ft/day advance rate in the reservoir). The center well was shut-in at 0 (not producing), 50, 80 and 98 percent watercut. The model showed that the center well accelerates recovery of reserves. The cumulative production after one year was 36,000 BO, 36,667 BO, 42,000 BO and 42,000 BO for the 0, 50, 80 and 98 case, respectively. Although producing the first well at high watercuts (80% and 98%) recovered more oil in the first year, producing the injection water is not cost effective as compared to keeping it in the ground. Shutting in the first line producer as soon as it begins to cut water allows the flood front to advance to the next well.

The model allowed for injection to be controlled by a constant rate or constant injection pressure. The bottomhole pressure in the 110 BWIPD case remained low enough that no cross-flow into the St. Louis occurred. Another case was run with the bottomhole pressure in the injection well held constant at 3000 psia. The rate was allowed to vary to accommodate the pressure. Again, the recoveries were accelerated by producing the center well with the added cost of handling more produced water. A producing well pressure limit of 400 psia on the 40 acre producer was able to keep the pressure low enough at the center well to prevent cross-flow. Therefore, it appeared that a communicated well might be shut in without the reservoir pressure building high enough to cross-flow into the St. Louis. This would need to be verified in the field with BHP tests in the communicated wells. Initial water influx from the St. Louis into the base of the Morrow was seen in both cases.

B. Three Dimensional Study

The 3D study was divided into a material balance (MB) study and a reservoir description study. The objective of the MB portion of the simulation study was to utilize the simulator as a volumetric tool to establish a history match with the primary production. More attention was paid to reservoir volumes and areas of influx than to detailed reservoir description.

The results showed that reservoir volume of the Morrow channel was insufficient to match produced volumes from depletion drive alone. The study identified three possible sources of influx that may contribute to the reservoir performance. These sources are 1) a Morrow or St. Louis reservoir communicated at the west end of the channel, 2) a juxtaposed productive Ste. Genevieve found in the E/2 of Section 11, Section 12 and the W/2 of Section 7 and 3) Mackey #3 (a temporarily abandoned well with fracture stimulation into the St. Louis, isolated behind a bridge plug).

The MB simulation was done with a two layer model to reduce computer run time associated with multiple layer models. The Morrow channel for the Stewart Field was represented by a single layer of varying thickness and average reservoir characteristics. The second layer served as the source for "other" zones that may provide pressure support.

A net sand map was digitized using GridGenerator software included in the VIP Program package. The Morrow interval was mapped on screen and included some dry holes within the area mapped. However, the volume of the map calculated a satisfactory 26,468 MSTB OOIP. The field was mapped to include the production from the Chief operated wells found in Section 8, T23S-R30W. These wells were drilled beginning in July of 1990 and had a discovery pressure around 700 psig. The less than original pressure found in this section may have been an indication of pressure communication with the Stewart Field, but this was later found to be questionable. The final match did not include the estimated 86,000 barrels of oil produced from the Chief wells as part of the MB. The volume mapped for the Chief wells was left in the model to compensate for additional Morrow reservoir beyond the Bulger 7-10 or in the N/2 of Section 7.

A thick (up to 100 feet) aquifer was modeled underlying the Morrow that represents multiple geologic intervals. This "influx" zone was divided into four sections, using zero permeability barriers around each section. This was done to prevent pressure communication between the influx zones and to reduce the number of gridblocks required studying three or four layers. The GridGenerator puts an overlying grid on the maps and assigns reservoir parameters to each gridblock including: structure top, gross and net thickness, porosity, water saturation and permeability in the X, Y and Z directions. The grid orientation chosen for this run had 100 blocks along the channel (east - west) and 15 blocks across the channel (north - south) approximately 320 by 320 feet. With 1,500 blocks for the Morrow and the influx zone, the entire model required 3,000 gridblocks.

The Stewart Field was divided by sections with reservoir parameters assigned to each as follows:

Section	kx-ky-kz	porosity
4 and 9	150 md	18%
3 and 10	120 md	17%
2 and 11	90 md	15%

12	80 md	16%
7	65 md	16%

These values were based on average log calculated data that showed an increasing trend in permeability toward the west. The initial pressure of the Morrow was set at 1200 psig and an initial water saturation of 31% was used across the field.

The initial run had no aquifer influx and represented a total depletion drive system in the Morrow. The field recovered 2.11 MMBO (including Chief) as compared to 3.23 MMBO actual production through 7/1/93 (including Chief), or a 65% match.

Due to an increase in water production in the Scott 4-4, 4-5 and on the Pauls lease along with the presence of a permeable, high pressured zone DST'd in the Scott 4-3, the west end was chosen as the first area to introduce water influx. The influx support was represented by a 100% water saturated zone with 5 md permeability in the X and Y directions with a pressure of 1400 psig. Communication between the Morrow and the aquifer was modeled with vertical permeability between the layers of 0.07 md over an area of approximately 40 acres on the west end of the field, south of the Scott 4-4 and 4-5 and west of the Pauls 9-3. After trying varying values of vertical permeability, 0.07 md was selected as the value providing the most pressure support without excessive water production.

The influx from the aquifer supported the early production from 1967 to 1985. In this time period only 3 wells in Section 12 were producing and the withdrawal from the Morrow was small compared to the size of the reservoir. From 1985 and forward, production increased sharply due to the drilling activity. As the production increased, the water influx becomes less adequate in supporting the producing wells.

Modeling wells fractured into the St. Louis was initially attempted, but water production from these wells caused the pressure in the aquifer to be drawn down too quickly. The influx from the west end was assumed to be from a different source than the St. Louis "C" zone in the fracture communicated wells. The water production from the St. Louis is from an independent zone and contributes little pressure support to the Morrow if the communicated wells remain on production or are only shut-in for short periods of time. Since only the Mackey #5 was shut-in for some of the recent months, modeling the water production from the St. Louis is unnecessary.

The west end influx increased the model recovery from 2.11 MMBO to 2.23 MMBO or 69% of actual. The model was still having trouble keeping up with the post 1985 drilling program. The pre-frac skin was then reduced from +3.0 to +1.5 and the producing BHP was reduced from 50 to 15 psi. The skin was lowered to reduce the severity of the pressure drop from the grid block to the wellbore. Since the wells had historically been "pumped off", the BHP could be lowered to allow for lower fluid levels. These changes increased the model production to 2.49 MMBO, a 77% match.

Having obtained the maximum benefit from the west end influx, the Ste. Genevieve was identified as another source of influx. Many well logs calculate a productive Ste. Genevieve interval underlying the Morrow channel, especially in an area extending from the east half of Section 11 to the west half of Section 7. A study map of the Ste. Genevieve resulted in 1.5 MMBO in place. One section of the influx layer was allocated to represent the Ste. Genevieve. An area extending from the Sherman #1 to the Bulger 7-1 on the south side of the channel was used as the Ste. Genevieve source in the model. It was necessary to use a porosity of 1% and 40% water saturation to obtain an oil volume approximating that of the study map. The low porosity was only a means of adjusting the storage volume in the model and does not affect the flow capacity of the reservoir. The saturation value means both oil and water will flow from the Ste. Genevieve. These values increase the oil volume of the model by 1,703 MSTB for an OOIP of 28,171 MSTB. The Ste. Genevieve was given 0.07 md communication with the Morrow channel. The Ste. Genevieve influx increased the model history match to 2.53 MMBO or 78% of actual.

In December 1971, the Mackey #3 was drilled and encountered 1 foot of Morrow sand. A fracture attempt communicated with the St. Louis, and the well tested 160 BWPD and was temporarily abandoned. In

1986, holes in the casing were repaired. Fluid levels after swab tests showed pressures to be 900-1100 psig. The well was again temporarily abandoned. Wells had been producing from Section 12 since 1967. In 1985, an offset well in Section 11 (Sherman #1) DST'd an extrapolated pressure (p*) of 862 psig, less than the original pressure. From 1972 to 1986 (and forward) the fracture in the Mackey #3 potentially allowed water influx from the St. Louis to cross-flow into the Morrow as the Morrow was being depleted. This represents the third source of pressure support used in the simulation.

Multiple runs showed that a high conductivity fracture between the Morrow and St. Louis in the Mackey #3 could be simulated by allowing 1 md of vertical permeability in the gridblock containing the well without watering out offset wells. Fluids were allowed to move between the zones due to the pressure differential. No fluids were produced from the well. The simulation of the Morrow channel with these three sources of influx produced 2.57 MMBO through 7/1/93 as compared to an actual 3.23 MMBO (including Chief), an 80% match. Even though oil production only increased 40 MBO, the pressure history match was improved.

Core work performed by TORP on extracted cores from the Sherman #3 and Scott 4-4 indicated sensitivity to water resulting in a reduction in permeability. Meyer 10-4 and Mackey #1 had exhibited lower production rates subsequent to being exposed to water from casing leaks. The coring procedure itself is likely to reduce the permeability found in the routine core analysis due to water and mud filtrate. For these reasons and the need to increase transmissibility along the length of the channel, the permeability in the Morrow was doubled. This brought the model results up to 2.98 MMBO produced, a 92% match.

The fine tuning of the MB simulation case included removing the Chief production from the match and updating the production data to 1/1/94. Adjustments were made to the skin of individual wells to improve each well's match. The final case had a 98% match with 3.19 MMBO (without Chief) compared to the actual production of 3.27 MMBO as of 1/1/94.

The pressure was evaluated visually in the 3-D graphical display. Particular attention was paid to reservoir pressure as wells were drilled westward. Although the model pressure of the Sherman #1 was higher than actual (1000+ vs. 862 psig), the majority of the wells in the model were drilled with reservoir pressure around 800 psig. The simulation also showed a reservoir pressure of approximately 800 psig at the time of drilling the western-most wells on the Scott lease. This coincides with the p* of 775 psig exhibited by the DST of Scott 4-4 in January 1989.

The final MB history match utilized the following parameters:

1. Three sources of water influx
   a. West end, kz=0.07 md, kx and ky = 5 md, Porosity = 12%, Sw = 100%, area of influx approximately 43 acres, pressure = 1400 psig.
   b. Ste. Genevieve, 1.7 MMB OOIP, kz = 0.07 md, kx and ky = 5 md, Porosity = 1%, Sw = 40%, pressure = 1400 psig.
   c. Mackey #3 cross-flow, one grid block with kz = 1.0 md, kx and ky = 5 md, Porosity = 12%, Sw = 100%.

2. A producing BHP of 15 psig.

3. A pre-frac skin = 1.5 and post-frac skin = -3.0 with the following exceptions:
   Bulger 7-4, 7-5 and Sherman 3-5 have post-frac skin = -4.5
   Sherman #5, Pauls 9-1 and Haag #4 have pre/post-frac skin =0.0/-4.5

4. Permeability and porosity values of:

Section	kx-ky	kz	porosity
4 and 9	300 md	150 md	18%
3 and 10	240 md	120 md	17%
2 and 11	180 md	90 md	15%

12	160 md	80 md	16%
7	130 md	65 md	16%

5. Morrow pressure = 1200 psig.

6. OOIP Morrow = 26,468 MSTB, Morrow and Ste. Genevieve = 28,171 MSTB

C. Waterflood Study

The 3D reservoir description study was used in a predictive mode to quantify secondary reserves and to select the best pattern for waterflood operations. The objective of the predictive portion of the simulation study was to create a model with the reservoir characteristics that would affect waterflood performance, yet simple enough to maintain the history match found in the material balance portion of the simulation study.

A net sand map for each flow unit (Red, Purple and Yellow) was drawn using GridGenerator. Each zone was mapped honoring all data, including dry holes surrounding the field. The Red and Purple intervals were mapped with a maximum thickness of 10 feet. The Yellow zone was mapped with a maximum net thickness of 30 feet with a 15 foot contour being carried the entire length of the field. At an initial water saturation of 31%, the field was calculated to contain 27.8 MMSTB OOIP. The OOIP includes approximately 1.7 MMSTBO from the Ste. Genevieve leaving 26.1 MMSTB of Morrow oil.

No vertical permeability was allowed for the three Morrow layers except at the wellbore. A vertical permeability of 1 md was assigned to each gridblock (approximately 300-320 feet square) containing a fracture stimulated well. Permeability was assigned to each zone so as to establish a 0.70 permeability variation. Utilizing the permeability-porosity transform derived from the core-log relationship, the most frequently occurring permeability ordering was the Yellow (bottom) zone with the highest permeability, the Purple (middle) zone with the lowest permeability and the Red (top) zone with the median permeability. The permeability distribution across the field was described as follows:

	Sec 4&9	Sec 3&10	Sec 2&11	Sec 12	Sec 7
Red (Top)	300	240	180	160	130
Purple (Middle) 130	105	79	70	58	
Yellow (Bottom) 680	550	400	350	285	

Vertical permeability allows cross-flow from the three sources of influx into the Yellow zone. The bottomhole pressure in each producer was reduced to 10 psig and all fractured wells were given a post-frac skin of -4.5. Increasing the post-frac skins on all wells in reality affected only a few wells, since most were limited by their actual producing rate. The pre-frac skins were retained from the material balance simulation study.

This predictive model was first run to compare the history match by using the same three sources of influx described in the material balance study. Ninety six percent of the historical production was matched with the new and more detailed model.

Several injection patterns were modeled. Each pattern was modeled with 6,000 and 10,000 barrels of water injected per day (BWIPD) for the field. The two injection rates were chosen to see the effect of injection rate and to bracket the range of available source water, which was unknown until the waterflood, is implemented. The injection volume was equally distributed among the number of injection wells with a maximum allowable BHP of 3000 psig. A favorable mobility ratio allows oil to move more easily than the water. As the reservoir fills with water, the injectivity goes down. The field injection curves show that the maximum rate (6,000 or 10,000 BWIPD) is sustained for 2 to 4 years until injection wells become pressure limited. The three line drive pattern was not modeled with 10,000 BWIPD because of insufficient number of injection wells to allow such a large volume. The majority of the net present value of the waterflood occurred in the first five years. The predictive model was designed for a ten year life with all producing wells being shut in at an 80% watercut. Reserves are recoverable at a higher watercut, but would be recovered late in the life of the project having a small effect on the NPV. The 3, 5 and 7 line drive patterns were chosen in order to select the optimum number of line drives. An additional run was made on the 5 line drive pattern where the producing wells are shut in at a 20% watercut and then returned to production on 7/1/97 and produced to a 97% watercut (labeled 5 L-D 20/97). Each pattern was associated with a different oil and water production curve, capital requirement and operating expense. Once the optimum number of line drives had been established, the results of the 2D and the reservoir characteristics could be used in selecting individual wells in the final pattern.

The cases run with the high injection rate exhibit higher peak oil rates and earlier water breakthrough. The low injection rate cases break through later and recover more reserves. The ten year reserves and the recovery factors for the different cases were as follows:

	Waterflood Recovery	Recovery Factor
3 L-D	2,986,000	11.4%
5 L-D Lo	2,776,000	10.6%
5 L-D Hi	2,764,000	10.6%
7 L-D Lo	2,796,000	10.7%
7 L-D Hi	2,713,000	10.4%
Beren Hi	2,710,000	10.4%
5 L-D 20/97	3,622,000	13.9%

Economic Analysis

Cost estimates were prepared for the purpose of determining a waterflooding pattern that optimizes the net present value. Higher water injection volumes will recover secondary oil reserves sooner, but at higher capital and operating costs. Price quotes were obtained from supply and service companies on major items in order to approximate total costs. Extensive cost analyses was performed on injection lines, injection wells, potential water supply sources, waterflood plant, and tank battery consolidation.

Footages for the injection lines were estimated for the different patterns. Bids were obtained for different materials for injection line pipe and downhole tubulars in the injection wells. The three possibilities investigated were: (1) fiberglass, (2) coated steel line pipe, and (3) PVC lined tubing.

Extensive cost analyses were performed on potential source water for the waterflood. Six potential water sources were identified and are summarized as follows:

Ogallala - A fresh water formation 300 feet deep with an estimated potential of 10,000 barrels of water per day (BWPD). Positive aspects are cheap lifting costs and the Conservation Reserve Program may help make water available. Negative aspects include field cores have displayed sensitivity to fresh water and political issue with farmers concerning depletion of irrigation water source.

Glorietta - A saltwater formation 600 feet deep with an estimated potential of 1,500 BWPD. The formation is currently being used for saltwater disposal. Positive aspects are three existing saltwater disposal wells could be converted to supply wells, cheap lifting costs, this water was successfully used in the Ingalls Field and minimal capital costs. Negative aspects are sand production problems and the expense to treat this water.

Topeka - A saltwater formation 4,400 feet deep with an estimated potential of 1,000 to 1,500 BWPD.

Morrow/St. Louis - Approximately 670 BWPD is currently being produced from Morrow and Morrow/St. Louis commingled wells in the field.

St. Louis - Two production wells in the field are completed in the St. Louis. These wells produce approximately 200 BWPD. This formation is approximately 5,000 foot deep and the water is very corrosive.

Devonian/Ordovician - A saltwater formation 5,700 feet deep with an estimated potential of 10,000 BWPD. Water quality from this formation was unknown.

The maximum design rate of 10,000 BWPD injection could be met several ways. Total cost per barrel of water produced was calculated from the potential sources including capital and operating costs. These costs included drilling and completion, appropriate pump size, electrical usage, service life, chemical usage, etc. It was determined a deep water source that can deliver all the water required was more economic than drilling numerous shallow lower deliverability wells.

Cost estimates were conducted for the water injection plant. The cost estimates included supplying electricity to the plant site, plant costs and injection pumps. Plant costs included the plant building, filtration system, valves, gauges, emergency shut-off systems, alarms, etc.

The preliminary design called for the consolidation of the existing 19 tank batteries to three satellite batteries. Consolidation of the production facilities would result in the following benefits: (1) replacement of inefficient or inadequately sized equipment, (2) relocation of facilities to achieve operating and production data gathering efficiencies that will save on manpower and maintenance, (3) less potential for environmental damage, and (4) simpler produced water collection and handling.

Total capital costs used in the economic analysis for the installation of the waterflood ranged from approximately $1.4 to $1.7 million dollars. The range was due to variables associated with the different patterns investigated (length of line pipe, number of injection wells, etc).

Economic analyses were run on all the waterflood patterns investigated in the simulation study. The economics were run based on 100% working interest with an 80% net revenue interest. The price of oil was held constant at $18.00 per barrel. The lease operating expense was $1600 per well per month. The economics were run using six month time units instead of yearly production to more accurately reflect discounting of future production back to the initial time of investment.

The lease operating expense included a fixed cost for the water injection plant operation, a variable water handling expense and a fixed per well cost. Injection water was made up of both water supply and produced water. The early life of the project primarily uses injection water from the supply well. As the production wells began to produce water, this water was reinjected requiring less water from the supply well. The produced water was reinjected at one-third the cost of the water from the water supply well. Initially, all wells were shut in when they reached an 80% water cut. This prevents the producer from starving the flood front and allows the front to move to the next producer. Later, all the wells were reinstated to producing status and allowed to produce to a 97% water cut.

When the production profile of each pattern was subjected to the assumptions of the economic analysis, some of the production was below the economic limit. Thus, only economically recoverable reserves were used in the economic analysis. The net present value of the economic reserves was run at discount rates of 10 and 40 percent.

Due to the favorable mobility ratio, the reserves recovered were similar for most patterns. The different patterns recover oil reserves at different rates throughout the project, since oil recovery is primarily a function of the volume of water injected. The net present value of economic reserves at a discount rate of 10% for the different patterns ranged from approximately $23 to $27 million dollars and at a discount rate of 40% ranged from approximately $11 to $17 million dollars. The sensitivity of the net present value to oil price was also investigated.

LABORATORY TESTING

Commercial Laboratories

Cores were recovered on the following six producing wells: Meyer 10-1, Scott 4-4, Scott 4-8, Sherman #3, Sherman #5 and Pauls 9-2, with a directional whole core routine analysis performed on Sherman #3. The other five wells were analyzed with plug analysis.

A special core analysis was run by Core Laboratories on the Meyer 10-1 with steady state relative permeability tests on four extracted samples. The cores represent a slight water-wet condition. Connate water saturations ranged between 18 and 29%, whereas residual oil saturations varied between 33 and 42%. Formation compressibilities were measured over a range from 2400 to 800 psig to be $10X10^{-6}$ psi^{-1}. No apparent water sensitivity was experienced.

Laboratory tests were also conducted on preserved cores taken from the Stewart Field. These tests were conducted by Surtek, Inc. located in Golden, Colorado. The tests consisted of a fluid-rock linear core study to determine the relative permeability characteristics using reservoir fluids. Capillary pressure was determined by mercury injection method. The linear corefloods also defined the initial and residual oil saturation, effective and absolute permeability, fractional flow, wettability of the reservoir rocks and the mobility ratio between water and oil. The capillary pressure test results were used to calculate the pore size distribution and saturation data.

The average initial oil saturation from three linear corefloods using Scott 4-8 core was 71% and the average waterflood residual oil saturation was 44%. The average oil recovery was 38% OOIP.

The average initial saturation in the laboratory for two relative permeability determinations was at 0.67 PV, and the waterflood residual oil saturation was 0.48 PV for a recovery of 35% OOIP.

The mobility ratio averaged 1.0 using endpoint permeability and saturation values for water displacing crude oil. This indicated that water was a good fluid for displacing Stewart Field crude oil.

Fractional flow data from the two relative permeability tests indicated the producing water-oil ratio would be approximately 3.5 after water breakthrough. The average oil saturation at water breakthrough would be 0.62 for 7.5% OOIP recovery at breakthrough. Assuming an economic limit of 99% water, the average residual oil saturation would be 0.509 or a total of 24% OOIP recovered economically by waterflooding.

Total waterflood recovery in coreflood 2 was 40.6% OOIP, and in coreflood 3 was 30.1% OOIP for an average recovery of 35.4% OOIP. This indicated that approximately 11.4% of this waterflood oil couldn't be recovered economically.

Mercury injection capillary pressure curves generated on the Meyer 10-1 and Sherman #3 cores suggested that the average initial non-wetting phase saturation would be 76% of the pore volume. Using the imbibition curve, the change in oil saturation by both primary production and waterflooding processes would be about 31%.

University of Kansas Laboratory

The objective of the laboratory testing conducted at the University of Kansas was to analyze the water sensitivity of Stewart Field cores. Initially the testing was to be done to determine the reservoir sensitivity to the proposed injection water. However, in the early stages of the testing, it was determined that the reservoir rock displayed sensitivity to formation brine. The following summarizes the results of these experiments.

Introduction

Water sensitivity analysis of Stewart Field cores was conducted through permeability measurements of the cores. Core plugs of known dimensions were cut, evacuated and saturated. Permeability measurements were made on these cores using different solutions at room temperature (≈68°F) and reservoir temperature (125°F). Experiments were performed on the core plugs from the following wells:

(i) Scott 4-4 (depth 4796 ft.)
(ii) Sherman 3 (depth 4781 ft.)
(iii) Meyer 10-1 (depth 4800 ft.)

The following solutions were used for performing permeability measurements:

(a) 2.0% sodium chloride
(b) synthetic formation brine (composition given in **Table 1**)
(c) injection water (proposed)
(d) filtered produced water from Scott 4-5
(e) 3.0% potassium chloride
(f) 500 ppm aluminum (aluminum citrate)

Table 1: Composition of Synthetic Formation Brine

Salt	Concentration (mg/l)
$NaCl$	76,470
$NaHCO_3$	430
Na_2SO_4	1,700
$CaCl_2.2H_2O$	15,010
$MgCl_2.6H_2O$	9,930

pH adjusted to 6.5

Experimental Procedure

The core plugs were cut having approximate dimensions of 1" length and 1" diameter. The plugs were cut using fresh water unless specified otherwise. The core plugs were then evacuated and saturated with the desired solution. The experimental set-up consisted of placing the core plugs in a rubber sleeve within a metal casing. The rubber sleeve was subjected to a pressure of approximately 200 psi, which resulted in an airtight seal around the plug. This was done in order to ensure no bypassing of the plug by the injected fluid.

The injection fluid was pumped into the core and the flow rate was measured by collecting the fluid from the effluent line. The pressure drop across the core was measured using two pressure ports situated upstream and downstream of the core, which were connected to a transducer to measure the pressure differential. Experiments were performed at room temperature and reservoir temperature by placing the apparatus in a water bath maintained at 125°F. The procedure for calculating the permeability from these measurements is outlined in the following:

Calculations for Permeability Measurements Conducted at the University of Kansas

$$k = Q\mu L/(A\Delta p)$$

where: k = permeability, darcys
Q = flow rate, cc/sec

μ = liquid viscosity, cP
L = core length, cm
A = cross-sectional area of core, cm^2
Δp = pressure drop across the core, atmospheres

Core Dimensions:

Core	Average length (cm)	Average diameter (cm)
Berea	2.478	2.506
Scott	2.616	2.506
Sherman	2.908	2.504
Meyer #1	2.682	2.508
Meyer #2	2.533	2.505

Viscosity:

2.0% Sodium Chloride Solution: Viscosity assumed to be same as water

For distilled water,

$$= \exp(1.003 - 1.479*10^{-2}T + 1.987*10^{-5}T^2), \text{ viscosity in cp}$$

where: T is the temperature in degrees Fahrenheit

Synthetic Formation Brine:

Viscosity at 125°F = 0.67 cp
Viscosity at 77°F = 1.07 cp
Viscosity at 68°F ≈ 1.20 cp

Injection Water:

Viscosity assumed to be same as water

3.0% Potassium Chloride Solution:

Viscosity at 125°F = 0.66 cp
Viscosity at 77°F = 0.98 cp
Viscosity at 68°F ≈ 1.10 cp

Filtered Produced Water:

Viscosity assumed to be same as synthetic formation brine

500 ppm Aluminum (Aluminum Citrate) Solution:

Viscosity assumed to be same as water

Porosity:

Berea core: porosity = 20.0 %

Field cores: porosity assumed to be 16.0 %

Results of Permeability Measurements

This section gives a brief summary of the results obtained from the permeability measurements of the core plugs from the three wells. Preliminary experiments were performed on Berea core plugs to validate the measurements by the apparatus being used.

The experiments performed on core plugs from the wells are summarized in **Tables 2** through **5.** Data for all the measurements are also shown in the following.

Berea core: Experiments were performed on berea core using synthetic formation brine solution at room temperature (≈68°F) and reservoir temperature (125°F). Normally the injection was done at three different flow rates. The flow rate was measured from the effluent line and typical values were around 1.2 ml/min, 2.4 ml/min and 3.6 ml/min.

Scott 4-4: The core plug was cut from the rock sample using fresh water. The plug was then evacuated and saturated with synthetic formation brine. Injection was typically done at measured flow rates of about 1.2 ml/min, 2.4 ml/min and 3.6 ml/min.

The core plug was removed from the apparatus and on visual inspection no damage could be observed. The plug was stored in a bottle containing 3.0% potassium chloride solution. The history of the series of experiments performed on the core plug is summarized in chronological order in **Table 2.**

Table 2: History of experiments performed on Scott 4-4 core plug

Time	Experimental Process	Permeability (md)
Day 1	Core plug cut using fresh water. Core evacuated and saturated with synthetic formation brine (SFB). Permeability measurements performed using SFB at room temperature (≈68°F). Overnight the core was left in contact with SFB at room temperature.	189-187
Day 2	Injection started with SFB at room temperature and good reproducibility was obtained. Injection started with SFB at reservoir temperature (125°F). A decrease in permeability was observed and the behavior continued during the entire injection period of about 3 hours. Overnight the core was left in contact with SFB at room temperature.	184-140
Day 3	Permeability measurements performed with SFB at room temperature giving a value of about 139 md. Measurements were then performed at 125°F and further decrease in permeability was observed for the entire injection period of about 2 hours. Overnight the core was left in contact with SFB at room temperature.	139-107
Day 4	After an initial permeability measurement with SFB at room temperature (90 md), the direction of flow was reversed. No change in permeability was observed. Injection at 125°F yielded further reduction in permeability. Overnight the core was left in contact with SFB at room temperature.	90-70
Day 5	The direction of flow was reversed again and SFB was injected at 125°F. The decrease in permeability was observed for the entire injection period of about 2 hours. The core was left in contact with SFB overnight at room temperature.	70-59

Time	Experimental Process	Permeability (md)
Day 6-10	The core was left in contact with SFB at room temperature.	-
Day 11	The core was injected with injection water from the field. Permeability measurements at room temperature remained constant but injection at high temperature resulted in a further reduction in permeability. Overnight the core was left in contact with the injection water at room temperature.	65-40
Day 12	The core was injected with 3.0% KCl solution at room temperature. An increase in permeability was observed with KCl injection at various flow rates. The core was left in contact with KCl solution overnight.	43-94
Day 13	Further injection with KCl solution resulted in a decrease in permeability. Overnight the solution was left in contact with KCl solution at room temperature.	82-55
Day 14	Permeability measurements performed with 3.0% KCl solution at 125°F. A continuous decrease in permeability was observed for the injection period of about 6 hours. The core was left in contact with the KCl solution overnight at room temperature.	48-30
Day 15	Injection was started with KCl solution at 125°F. A further drop in permeability was observed. Injection was continued at a fixed flow rate for about 6 hours until the permeability reached a constant value. The flow rate was changed and the injection was continued overnight at 125°F.	30-21
Day 16	No further change in permeability was observed. Changing the flow rates did not show any significant change in the permeability values. The core plug was removed from the apparatus and on visual inspection, no damage could be observed. The core plug was stored in a bottle containing 3.0% KCl solution.	20-25

Sherman 3: The core plug was cut using fresh water. It was then evacuated and saturated with filtered produced water from the Scott 4-5. The produced water obtained from the field was filtered at atmospheric conditions and then used for saturation and injection.

The core plug was removed from the apparatus and no anomalies could be observed on visual inspection. The plug was stored in a bottle containing filtered produced water. The history of the series of experiments performed on the core plug is summarized in chronological order in **Table 3**.

Table 3: History of experiments performed on Sherman 3 core plug

Time	Experimental Process	Permeability (md)
Day 1-4	Core cut using fresh water. Evacuated and saturated with filtered produced water from Scott 4-5. Injection started with produced water at 125°F and was continued for a period of three days. A constant decrease in permeability was observed. At the end of three days, the flow rate was reduced by 50% and injection continued for another day. Decrease in permeability was still observed. The core	7-2

Time	Experimental Process	Permeability (md)
	plug was stored in a bottle containing filtered produced water.	

Meyer 10-1 Core #1: The core plug was cut using 3.0% potassium chloride solution. It was then evacuated and saturated with the same solution. Injection was typically done at the flow rates of 1.2 ml/min, 2.4 ml/min and 3.6 ml/min at reservoir temperature.

The core plug was left in contact with the salt solution at room temperature. The history of the series of experiments performed on the core plug is summarized in chronological order in **Table 4**.

Table 4: History of experiments performed on Meyer 10-1 core plug #1

Time	Experimental Process	Permeability (md)
Day 1	Core cut using 3.0% KCl solution, evacuated and saturated with the same solution. Injection started with 3.0% KCl solution at 125°F. Solution was injected at three different flow rates and a continuous decrease in permeability was observed. Overnight the injection was continued at the reservoir temperature.	30-16
Day 2	Injection was done at three different flow rates and the permeability values appear to have reached a constant value. Overnight the core was left in contact with the 3.0% KCl solution at 125°F.	9-12
Day 3	Injection was done at different flow rates and the permeability values did not show any change. Overnight the core was left in contact with the 3.0% KCl solution at 125°F.	9-12
Day 4	Injection was continued with the same solution and no change in permeability was observed. The core was left in contact with 3.0% KCl solution at room temperature.	10-12

Meyer 10-1 Core #2: The core plug was cut using 3.0% potassium chloride solution. It was then and evacuated and saturated with 500 ppm aluminum (aluminum citrate) solution. Injection was done at different flow rates for permeability measurements.

The core plug was left in contact with synthetic formation brine at room temperature. The history of the experiments performed on the core plug is summarized in a chronological order in **Table 5**.

Table 5: History of experiments performed on Meyer 10-1 core plug #2

Time	Experimental Process	Permeability (md)
Day 1	Core cut using 3.0% KCl solution. It was evacuated and saturated with 500 ppm aluminum (aluminum citrate) solution. Injection started with 500 ppm aluminum solution at 125°F. Solution was injected at three different flow rates and a continuous decrease in permeability was observed. After approximately 6 hours of injection the injection fluid was changed to synthetic formation	29-16

Time	Experimental Process	Permeability (md)
	brine. Overnight the core plug was left in contact with the synthetic formation brine at the reservoir temperature.	
Day 2	Injection was done at different flow rates. For all the different injection rates the permeability values appear to have reached a constant value. The core was left in contact with synthetic formation brine at room temperature.	6-5

Figure 7 shows the results of the experiment performed on a core plug from Scott 4-4. The core was injected with synthetic formation brine at 125°F. The results show the relative permeability as a function of the pore volumes injected. A continuous decrease in the permeability was observed for the entire injection period. **Figure 8** shows similar results for a core plug from Sherman 3 injected with filtered produced water from Scott 4-5 at 125°F. The plug was continuously injected with produced water for a period of four days and a continuous decrease in permeability was observed. **Figure 9** shows the results of the experiment performed on a core plug from Meyer 10-1. The core was injected with 3.0% potassium chloride solution at 125°F and for the entire injection period a continuous decrease in permeability was observed.

From the results obtained it was observed that there is a reduction in permeability for all the field cores. This behavior was observed with all the injection fluids at reservoir temperature, indicating a high sensitivity of the cores to the injection fluids.

Conclusions

Permeability reduction of at least 50% will occur in the immediate vicinity of the wellbore where large volumes of water flow through the porous rock. Consequently, there will be in an increase in the skin factor. Injection rates would be expected to decrease with time at constant pressure or injection prressure would be expected to increase with time at constant rate.

UNITIZATION

A critical task associated with the initial budget period of this project was the unitization of the field. Unitization needed to occur in order to implement a field-wide improved oil recovery process. Initially, there were three operators and multiple working and royalty interest owners owning production interests within the field. A minimum of 75% of all interest owners needed to be in agreement on equity issues in order for the field to be unitized.

The Kansas Corporation Commission is the governing body concerning unitization in the State of Kansas. If 100% of the working and royalty interest owners agree to a unit operating agreement, then formal unitization by the Kansas Corporation Commission for waterflooding operations is not required. If 100% agreement cannot be reached, then a minimum of 75% of both working and royalty interest owners would have to be in agreement prior to initiating forced unitization proceedings with the Kansas Corporation Commission.

A technical committee was formed in order to help resolve some of the equity issues. Regular meetings and correspondence took place between the technical committee members and the working interest owners throughout the duration of this project. Difficulties arose concerning resolving equity issues necessary for unitization, with one major issue being the selection of the unit operator.

North American Resources Company (NARCO) resolved the unitization issue by offering to purchase the working interest of the other operators in the field. NARCO purchased Sharon Resources et al working interest in the Stewart Field and took over operations of their properties effective February 1, 1995. NARCO was successful in purchasing 100% working interest in the Stewart Field and proceeded in implementing the waterflood.

BUDGET PERIOD 2 ACTIVITIES

Design and Construct Waterflood Plant

A centrally located area in the middle of the field was selected for the waterplant, central tank battery, and field office facilities. The area is located on the Sherman Lease and is approximately 2.5 acres in size. This area is leased from the landowner on an annual basis.

A pre-fabricated injection plant was purchased from Power Service, Inc. The injection plant is skid mounted and enclosed in an all weather insulated metal building. The building is 12 ft wide, 43 ft long, and 8 ft tall. The plant has a maximum design of 10,000 BWPD at 2000 psi. The plant consists of two quintiplex positive displacement pumps powered by two 200 Hp electric motors, filtering equipment, suction and discharge piping, pressure recorders, flowmeter, and control equipment. All internal piping and electrical wiring was included with the plant.

The filtering equipment consists of a two-canister system using standard bag type filters. Each canister contains three bag filters and total injection volume passes through one canister at a time. Flow is switched from one canister to the other at a pre-set pressure differential. All water injected during the waterflood has passed through 3-5 micron filters. There are two pressure recorders, one for each injection pump. One master Halliburton flowmeter indicates total injection volume leaving the plant. The controls consist of high and low pressure shutdowns for both discharge and suction.

The water supply tankage consists of three 1000 bbl and one 300 bbl fiberglass tanks. The first 1000 bbl tank is used as a separation tank or retention tank for water off the heater treater and source water from the supply wells. The 300 bbl tank is a slop tank coming off the separation tank. The two additional 1000 bbl tanks are source tanks from which the injection plant draws from. All the tanks are gas blanketed to keep oxygen out of the system to minimize corrosion. The water supply tankage is part of the central tank battery facility.

The waterplant is also equipped with a computerized emergency shutdown (ESD) and call out system. This is a part of the computerized monitoring system for the central tank battery facility. The majority of the central facility monitoring and control system is packaged by Remote Operating Systems (ROS). The system uses industry standard data acquisition and control techniques that provide the facility with state-of-the-art automation. The system consists of three basic components:

1. *Master Terminal* (computer workstation consisting of personal computer with Pentium 100+ MHz chip, 16 MB RAM, 800 MB hard drive, monitor, modem, tape backup, one color printer, and one dot matrix printer). The master terminal monitors the operation of the system and provides a man-machine interface for input of setpoints, printing of reports, and alarm notification. The master terminal is located in the field office at the central facility.
2. *Remote Terminal Unit (RTU)*. The RTU is similar to an industrial use computer. All control functions are programmed into the RTU that directly monitors all the measurable parameters and makes decisions based on those measurements. The RTU is located on the east wall of the injection building.
3. *End Devices*. Are used for measuring user parameters. End devices include level sensors for tank fluid levels and temperature measurement, flowmeters, status lights, etc. End devices are presently located as follows:
    a. 1000 bbl separation tank - oil and water level sensor
    b. 1000 bbl water suction tank - level sensor on closest tank to injection plant
    c. Two 1000 bbl oil stock tanks - level sensors
    d. Heater treater - oil and water dump line flowmeters
    e. Injection discharge line flowmeter
    f. Water source inlet line flowmeter
    g. Status light and ampmeter for each of the two quintiplex injection pumps
    h. LACT unit totalizer and BS&W

i. Heater treater overflow tank - level sensor
j. Filter bypass switch
k. Source water inlet valve (ESD)
l. East and west emulsion (flowline) inlet valves (ESD's)
m. Injection discharge valve (ESD)

The master terminal unit is equipped with the following primary software programs:

1. *ROSSERVER* - performs communication with the RTU
2. *InTouch* by Wonderware - provides the man-machine interface
3. *ROS VOICE* - provides a voice callout alarm system
4. *Remotely Possible* - enables remote access to the computer

The monitoring and control system provides the following main functions:

1. Automated monitoring which reduces safety risks.
2. Automated monitoring and corresponding automated emergency shut down in the case of a problem, thereby minimizing spill and/or environmental damage potential.
3. Call out via pagers in the case of an alarm.
4. Ease of operation and trouble shooting problems.
5. Cost effectiveness.
6. Data gathering and analysis.

After PetroSantander bought the Stewart Field waterflood they installed a horizontal injection pump to increase the injection capacity from approximately 10,000 to 15,000 BWPD.

Design and Construct Injection System

Two existing wells in the field were recompleted as water supply wells. The Carr 2-2, which was a temporarily abandoned well that tested uneconomical in the Morrow and the Sherman 3-9, which was an existing producing well. These wells were recompleted in the Topeka formation. The Topeka is a saltwater bearing dolomitic limestone formation at approximately 4400 ft. Each well was tested for water supply quantity and quality. Following the tests both wells were equipped with a 175 Hp electrical submersible pump with variable speed drive. The pumping equipment for each supply well was designed to produce approximately 3000 BWPD. The supply wells were plumbed into the central injection facility using fiberglass pipe and put into operation in October 1995. The running of the supply wells were alternated to test the productivity of each well for approximately the first four months of the waterflood.

The geometry of the Morrow reservoir at the Stewart Field lended itself to the design of a trunkline injection system along the length of the field with short laterals branching from the trunkline to the individual injectors. A 4 inch 2500 psi working pressure fiberglass injection trunkline was trenched and installed over 3.5 miles of the length of the field. Lateral lines off the trunkline were 3 inch fiberglass pipe to the injection wells.

Originally a modified six line drive pattern (**Figure 10**) was selected for waterflooding the field based on the geological and engineering analysis conducted in Budget Period 1. Six existing producing wells were selected to be recompleted as water injection wells. The original six injection wells were the Bulger 7-1, Mackey #6, Meyer 10-2, Scott 4-2, Sherman #3 and Sherman 3-1. Numerous items were considered in selecting the injection wells. The major selection criteria were based on good net pay characteristics throughout the Morrow interval, no evidence of communication to the underlying formations resulting from hydraulic fracturing, peak primary production rates, and cumulative primary production. Recompletion consisted of running PVC lined tubing and packer with corrosion inhibiting fluid in the annulus. Each injector was equipped with an injection meter and pressure recorder. New valves, chokes, and wellhead equipment were installed on each injector to enable adjustment or shut off of injection rates. Subsequently, after PetroSantander bought the Stewart Field, an additional six existing wells were converted to injection to improve the sweep efficiency in several areas of the waterflood. December 1997 conversions were:

Well	Previous Status
Scott 4-5	Producing approx. 10-12 BOPD

Sherman 3-8	Producing < 1 BOPD
Nelson 2-2	Shut-in

Downhole injection profiles were attempted on several injection wells during the latter part of 1997. Difficulties with the plastic coated tubing prevented completion of this program. Profiles were obtained on the Sherman 3-1, Mackey #6 and Meyer 10-2 to evaluate injection distribution. The vertical injection distribution for these three injectors was good.

March 1998 conversions were:

Well	Previous Status
Haag Estate No. 2	Shut-in
Bulger 7-5	Producing 4 BOPD
Bulger 7-10	Producing < 1 BOPD

Design and Construct Battery Consolidation and Gathering System

The existing 19 tank batteries were consolidated into one central tank battery facility. Benefits of consolidation of the production facilities were 1) replacement of inefficient or inadequately sized equipment, 2) relocation of facilities to achieve operating and production data gathering efficiencies that saves on manpower and maintenance, 3) less potential for environmental damage, and 4) simpler produced water collection and handling. All the old tank batteries were reclaimed.

A concrete foundation and dike was poured for the central tank battery. The battery consists of four 1000 bbl welded steel oil stock tanks, 8 ft by 20 ft horizontal heater treater, and a truck liquid automated control terminal (LACT). As stated earlier, two of the 1000 bbl oil tanks have level sensors as part of the computerized monitoring system. Additional computerized monitoring equipment in the tank battery are oil and water dump line flowmeters off the heater treater, a level sensor in the heater treater overflow tank, and LACT unit totalizer and BS&W. The totalizer monitors oil sales and the BS&W sounds an alarm if the basic sediments and water content in the oil are to high.

A 4 inch fiberglass gathering line was trenched and installed across the length of the field which tied all the producing wells into the central tank battery. Two computer controlled emergency shut down valves were installed on the inlet to the tank battery from produced fluids coming in from the east and west sides of the field.

Waterflood Operations and Reservoir Management

North American Resources Company (NARCO) was the operator who implemented the waterflood. NARCO entered into a sales agreement on the Stewart Field waterflood with PetroSantander, Inc. of Houston, TX in September 1997. PetroSantander took over operations on October 11, 1997. PetroSantander, as did NARCO, conducts the secondary field operations with a full-time company lease operator and a full-time contract lease operator. The company and contract lease operators are supervised by a company production foreman who coordinates and supervises all field operations. A company project engineer is responsible for the reservoir and production engineering, as well as operations supervision. A company geologist provides geologic support for the project. The project engineer, production foremen, and geologist comprises PetroSantander's reservoir management team who are responsible for monitoring, recommending, coordinating, and implementing the development and enhancement plans/work for the field. University of Kansas personnel, including engineers from the Tertiary Oil Recovery Project and geologists from the Kansas Geological Survey complemented NARCO's and PetroSantander's reservoir management team.

PetroSantander, as did NARCO, utilizes an in-house field data capture program which allows field employees to input tank gauges, produced water meter readings, water cuts, well tests, injection rates, pressures, and other vital field information into a computer. The data is transmitted via modem on a daily basis to the project engineer and production accounting system. This near instantaneous access to detailed production and operations information aids in efficiency of the overall waterflood operations and assists in preventing problems before they are compounded which could result in loss of production or expense.

Total oil and water production for the field is recorded daily. Daily injection volumes and pressure are monitored at each injection well. Portable well test trailers are used for production tests on individual producing wells. Individual well tests and fluid level measurements are normally run twice a month. Water supply volumes and fluid levels are monitored on both water supply wells.

Water injection began on October 9, 1995 into four injection wells. Water was being injected into the original six injection wells by the end of October. Initial injection rate was approximately one half the design rate of 6000 BWPD due to alternating production of the supply wells to test their productivity. The injection rate was increased to 5600 BWPD the first week in February 1996. December 1998 injection rate into twelve injection wells was approx. 9,800 BWPD. Both supply and produced water are being injected. Initially, all the injection wells were taking water with the surface pressure being a vacuum. Surface injection pressures in December 1998 ranged from a vacuum to 1080 psi. December 1998 injection pressures are shown in **Table 6.**

Table 6
December 1998 Stewart Field Surface Injection Pressures

Well	Surface Injection Pressure (psi)
Nelson 2-2	1080
Sherman #3	675
Haag Estate #2	820
Mackey #6	570
Sherman 3-1	520
Scott 4-5	460
Sherman 3-8	380
Meyer 10-2	280
Scott 4-2	430
Bulger 7-1	240
Bulger 7-5	vacuum
Bulger 7-10	170

Cumulative water injection in the field from flood startup through December 1998 was 7,781,980 BW. Monthly and cumulative injection volumes for the twelve injection wells are shown in **Table 7.**

Table 7
Stewart Field Water Injection Summary (all values in bbls of water)

Date	Bulger 7-1	Mackey #6	Meyer 10-2	Scott 4-2	Sherman #3	Sherman 3-1	Nelson 2-2	Sherman 3-8	Scott 4-5	Haag Est. #2	Bulger 7-5	Bulger 7-10	Total Injection
Oct '95	7026	9857	8561	9945	10008	9810							55207
Nov '95	15276	14301	13738	14091	14329	13912							85647
Dec '95	15657	14833	15237	14879	14849	14549							90004
Jan '96	14590	13822	14199	13865	13837	13558							83871
Feb '96	24850	24227	26030	24994	25198	24384							149683
Mar '96	28460	23410	34977	29205	28429	28516							172997
Apr '96	23618	19184	35069	34973	27575	28091							168510
May '96	27534	17056	34664	36381	31034	25792							172461
Jun '96	29382	17132	31117	34987	28904	22126							163648
Jul '96	33353	17439	31412	37216	30520	23356							173296
Aug '96	33277	17145	29430	36915	31909	23395							172071
Sep '96	28561	15055	22549	31826	28535	20513							147039
Oct '96	30884	16034	25275	35285	29858	20853							158189
Nov '96	33427	16341	28970	39391	30765	20681							169575
Dec '96	36044	17370	28205	43279	31429	21447							177774
Jan '97	35980	16826	30695	41950	30782	21043							177276
Feb '97	32862	15255	27909	38889	27553	16293							158761
Mar '97	37848	17212	32131	40647	30457	20169							178464
Apr '97	35374	17310	30874	37885	27194	21442							170079
May '97	36391	17944	31844	40300	30039	21985							178503
Jun '97	34775	17722	28592	38826	28367	21067							169349
Jul '97	39172	19320	30475	42271	30968	22979							185185

Aug '97	39721	19776	31016	42472	32151	23449							188585
Sep '97	39086	18710	30311	41122	30835	21811							181875
Oct '97	40363	19199	30314	42014	30856	22867							185613
Nov '97	41084	19965	27450	41716	30067	27627							187909
Dec '97	39953	21581	26121	40440	29456	22030	2304	2435	2409				186729
Jan '98	43203	25224	31069	42826	32778	33922	26802	29004	37310				302138
Feb '98	40513	25017	27958	40516	45716	38656	15752	21017	39183				294328
Mar '98	38811	25386	26958	39949	29894	39959	8703	9465	23494				242619
Apr '98	36051	24056	28954	39546	31009	32749	13860	20062	24204	13798	13645	12818	290752
May '98	44935	24051	29189	38724	31030	31235	13874	19952	24879	14089	17961	11287	301206
Jun '98	41404	24119	31305	38301	31459	31180	12540	19068	22900	11191	18057	10886	292411
Jul '98	40077	24692	34694	39686	32500	31602	12524	19645	26071	13358	23847	20592	319288
Aug '98	39450	24497	33629	39634	30750	30577	12823	20085	24703	14847	19961	18572	309528
Sep '98	38024	23660	32204	38851	29346	29986	14228	18996	24675	13928	24044	22677	310619
Oct '98	40152	25293	34142	40598	30779	31277	14478	19574	25408	14066	24779	22720	323266
Nov '98	39045	24453	33187	38932	29557	30197	14538	19488	24032	7841	20353	12131	293754
Dec '98	28445	17522	24050	28045	21398	21780	11304	14112	17407	9034	13360	7288	213745
Total	**1304664**	**762002**	**1104512**	**1391374**	**1112123**	**956867**	**173730**	**232903**	**316675**	**112152**	**176007**	**138971**	**7781980**

Individual well injection volume adjustments have been made based on response (both injection well pressure response and offset producing well response) and reservoir volume near each injector.

In March 1996 following the injection volume increase in February, oil production in the field began to respond to the water injection. Approximately 550,000 BW was injected prior to observing any increase in oil production. Oil production has continued to increase and as of December 1998 total incremental waterflood response is approximately 2900 BOPD. Total field production is over 3150 BOPD. Total incremental waterflood production through December 1998 was 1,634,782 BO. **Figure 11** is a plot showing average daily totals for injection and production data by month for the field since the initiation of the waterflood.

In April 1996 injection profile and channel indicator tests were run on 1) Mackey #6, 2) Sherman #3, and 3) Sherman 3-1. The tests indicated that all the injected water is going into the Morrow reservoir with no near wellbore channeling. Attempts to log the other three injection wells failed due to restricted internal diameter in the injection tubing resulting from the PVC lining which would not allow the logging tool to go down.

In May 1996 the Mackey #6 was shut-in for a pressure falloff test to evaluate reservoir properties. The well was selected for testing because it appeared pressure had begun to build up in the region around this well. The test was conducted for 72 hrs using Echometer's computerized Well Analyzer. This test was also conducted to evaluate the effectiveness of the fluid level instrument to obtain liquid levels inside the tubing string while the well was on a surface vacuum. Bottomhole pressures were computed from the fluid level data. The data were analyzed using PanSystem Version 2.3, a commercially available well test analysis program. **Figure 12** is a plot of pressure versus shut-in time. Also shown in Figure 12 is the match obtained by assuming the well had a vertical fracture of infinite conductivity which was confined on two sides by parallel faults each equidistant from the injection well, as shown in **Figure 13**. The analysis confirmed the existence of a vertical fracture, but the fracture half-length was estimated to be 855 ft. This is not consistent with an estimate of 100-150 ft calculated from a review of the hydraulic fracture treatment conducted in June of 1990. The distance to parallel faults (reservoir boundaries) of 1055 ft is approximately the distance from the well to the edges of the productive channel. Other parameters are summarized in **Table 8**.

Table 8 Summary of Reservoir Parameters Computed from Match of Mackey #6 Falloff Data		
C_s	0.2365	bbl/psi
k_w	49.9	md
S_f	2.37	
x_f	855	ft
L	1055	ft

Where C_s is the wellbore storage constant, k_w is the permeability to water, S_f is the skin factor on the fracture, x_f is the fracture half-length, and L is the distance to the reservoir boundary. These parameters are not unique, but with the exception of the fracture half-length, appear to be consistent with estimates of reservoir parameters.

Electrification of the producing wells in the field began in May 1996. Electrification of the field has provided a more reliable and lower maintenance power source that can be automated much easier. Electrification of the field was completed in November 1996. The only wells in the field that were not electrified are three current producers which are planned as future injection wells (Meyer 10-5, Carr 2-1, and Scott 4-7) and two temporarily abandoned wells the Haag Estate #1 and #2.

In January 1997 the Meyer 10-2 was shut-in for a pressure falloff test to evaluate reservoir properties. The test was conducted for 72 hours using Echometer's computerized Well Analyzer. Bottomhole pressures were computed from the fluid level data. This data was also analyzed using PanSystem Version 2.3. **Figure 14** is a plot of pressure versus shut-in time. Also shown in Figure 14 is the match obtained by assuming the well had a vertical fracture of infinite conductivity that was confined on two sides by parallel faults. The analysis confirmed the existence of a vertical fracture with the fracture half-length being 231 ft. Other parameters are summarized in **Table 9**.

Table 9 Summary of Reservoir Parameters Computed from Match of Meyer 10-2 Falloff Data		
C_s	0.1619	bbl/psi
K	4.97	md
S_f	0.1694	
X_f	231	ft
L_1	11637	ft
L_3	256	ft
P_i	376	ft

Workovers were attempted on the Haag Estate #1 and #2 wells to return both wells to production status (both wells have been temporarily abandoned since NARCO took over operations on 4-1-95). Due to downhole mechanical problems neither workover attempts were successful and the wells were shut-in.

The Sherman #5 (which had been shut in since late 1-96) was placed back on production with a progressive cavity pump. The Sherman #5 was producing 3 BOPD and 170 BWPD when it was shut-in. The high water production was due to fracture communication between the Morrow and primarily water producing Mississippian formation. The progressive cavity pump was designed to produce over 500 BFPD and was installed in an attempt to lower the fluid level to allow the Morrow to produce into the wellbore. The Sherman #5 was placed on production 11-26-96 at a rate of approximately 9 BOPD and 220 BWPD during the last 5 days of November. Production from the Sherman #5 tested at 330 BWPD and 14 BOPD at the beginning of December 1996 and was increased to a semi-stable near pumped-off rate of 385 BWPD and 25 BOPD at the end of December 1996. This well became inactive in 1997 due to its high water oil ratio.

Larger bottomhole pump, rods and larger pumping unit were installed on the Bulger 7-4 on 12-27-96 to lower the fluid level that had increased over the past few weeks. Production prior to installing the larger lift equipment was 135 BOPD and 8 BWPD and post installation tests have been as high as 240 BOPD and 15 BWPD.

Upgraded artificial lift equipment were installed on the following wells:

Mackey #4 - installed 456 pumping unit with 144" stroke length
Meyer 10-2 - installed low profile 320 pumping unit and 2" bottomhole pump
Sherman #2 - installed low profile 320 pumping unit and 2" bottomhole pump
Haag Estate #3 - installed 228 pumping unit with 74" stroke length
Scott 4-7 - installed low profile 160 pumping unit with 74" stroke length

Two additional pumping unit changes were made on the Scott 4-1 and Sherman 3-2, where it was necessary to install low profile units to accommodate new overhead farm sprinkler systems. A 640 pumping unit and 2-inch insert pump was installed on the Bulger 7-4 to replace a 320 unit and 1.75-inch pump. A 320 pumping unit was installed on the Meyer 10-1, also lowered the tubing and installed a 1.75-inch pump. The 320 unit replaced a 114 unit on the Meyer 10-1. These two artificial lift upgrades were performed as a result of rising fluid levels. Several additional pumping units were upsized to lower producing fluid levels. New units were purchased for the Scott 4-7, Carr 2-1, and the Haag Estate #5. Two of the pumping units released from these wells were transferred to the Sherman #4 and Haag Estate #4. Also four new progressive gravity pumps were installed on producing wells to increase fluid production.

Resizing pumping units, bottomhole pump upgrades and increasing strokes per minute on pumping units were performed as a result of the well testing program which assists in identifying wells with production problems such as: rising fluid levels, abnormal production trends, and low pump efficiencies. The artificial lift upgrades were performed to handle increasing fluid production, lower the producing fluid level to a near pumped off condition and to maximize oil production.

The Pauls 9-5 (infill well) located 355 ft FNL - 1400 ft FEL in Sec.9-23S-31W and the Haag Estate #6 (replacement well) located 920 ft FNL - 420 ft FEL in Sec.12-23S-31W were drilled during the Spring of 1997. The Haag Estate #6 did not encounter any Morrow sand and was subsequently plugged and abandoned. The Pauls 9-5 was completed with 27 ft of Morrow perforations. The perforations were broken down with diesel and the well was placed on production 6-5-97. The Pauls 9-5 was producing over 100 BOPD and 6 BWPD during the later part of June 1997.

Long term static fluid levels were taken (to estimate bottomhole pressure) on the Meyer 10-5 and Nelson 2-2. Also the bottomhole pressure of the Pauls 9-5 was measured on a drill stem test. The pressures were as follows:

Well	Date	Shut-in Time	Pressure
Meyer 10-2	6-9-97	6 days	1072 psi
Nelson 2-2	6-9-97	5 days	35 psi
Pauls 9-5	5-23-97	DST	307 psi

A pressure build-up test was performed on the Mackey No.1 that indicated positive skin damage. An acid treatment was performed that resulted in a minor increase in production. Subsequently, this well was hydraulically fracture treated in an attempt to remove skin damage and increase production. The treatment was unsuccessful, as post treatment production was the same as before.

The computer model developed at the Tertiary Oil Recovery Project at the University of Kansas was revised to history match waterflood production and injection. The availability of waterflood data necessitated these modifications to the model. The basic structure of the model, the four layers, was retained but changes in the petrophysical (skin, x and y permeability) properties were made to get a reasonable match in the oil and water production peaks and the arrival of the waterflood front. The fluid levels were maintained equal to the reservoir reported data and well production was predicted accordingly, i.e. the simulation was performed under bottomhole pressure as the limiting constraint.

To arrive at a reasonable value for the gas-oil ratio, a series of runs were performed by changing gas-oil ratios and the flood front arrivals were compared with the actual water front arrival in the field. The original ratio of 37 SCF/STB turned out to be the most reasonable value. A revised set of relative permeability data regressed from the old relative permeability data were used. Also, the relative permeability data were further adjusted to reduce water production and the early arrival of the water response to the flood. The vertical permeability of the fourth layer was adjusted to study the effect of the pressure support of the fourth layer on water and oil production and on the arrival of the flood response. It was found that a vertical permeability factor of 0.005 (0.5%) of the original core value gave adequate pressure support. Different simulation runs were performed by varying the permeability of the top three layers and observing its effect on the match. It was observed that permeability values of 67.5 % of the original core permeability values produced a reasonable match. This was acceptable and justified because the original core values were measured with respect to air, and a factor of 0.7 is generally used to get the permeability with respect to liquid phase.

To history match fluid production of individual wells, the skin values of each well were modified. The skin only modifies the permeability of the well grid block. In cases where the maximum negative skin was reached (the negative maximum skin is a function of the grid block size) local modifications to the permeability were made to get better history matches. The local modifications typically extended to a 3 X 3 grid, and in some instances to a 5 X 5 grid, with the well located at the center. These modifications were applied to all the layers and were done at the time of completion and when hydraulic fracturing occurred, if needed.

A few wells had their flood front arriving later or earlier than observed in the field. To correct this, the grid permeability between the injector and the producing wells was altered. The altered path was as narrow and direct as possible. These modifications were applied to individual layers as needed. A few wells showed both oil and water responses to the flood when there was none observed in the field. These wells were generally directly above or near the region in communication with the underlying Ste. Genevieve and St. Louis formations (the fourth layer in this model). The communication between the third and fourth layer near these wells was removed by closing the vertical permeability (i.e., K_z=0). In other instances, some wells did not show a response or the water response to the flood was not large enough. These wells had some surrounding grid blocks opened to the fourth layer to allow additional water influx. The grid blocks altered were usually a 5 X 5 grid with the well located at the center. A few wells had two to three distinct oil spike responses to the flood indicating that different layers had broken through at different times. These wells were modeled by altering the path permeability, as needed, of the individual layers.

The revised history match for the field is shown in **Figure 15**. There are three distinct peaks in oil production. The first is due to the field-wide development, the second due to the hydraulic fracturing of the field and the third peak is the response to the waterflood. The data points indicate actual production figures while the solid lines indicate the simulated values. The recent decline in actual oil production is due to excessive downtime due to workovers to upsize pumping equipment, rod parts, pump changes, water supply well downtime and work on the injection system. This temporarily effected the normal trend in production, which has since stabilized and is following the trend predicted by the simulation. Oil production rates, cumulative oil, and water production rates are presented in red, green, and blue, respectively. Field wide oil, water, and gas cumulative productions are reported in **Table 10**. There are three regimes of production. The first is the primary production match, the second is the matching of the waterflood period to date and the third is the prediction of the field performance through the year 2010.

Table 10
Fluid Production and Their Simulated Values for Different Regimes

	Primary Production through 9/1995		Production through 4/1998		Production through 12/2010	
	Actual	Simulated	Actual	Simulated	Actual	Simulated
Cumulative Oil (MSTB)	3.593	3.776	4.62	4.645	N/A	8.872
Cumulative Water (MMSTB)	1.348	1.186	2.51	2.026	N/A	38.06
Cumulative Gas (MMSCF)	N/A	814	N/A	841	N/A	848
Pressure Drop (psi)	~1000		N/A		N/A	

The prediction indicates additional production of approximately 4 million barrels of oil. **Figure 16** illustrates the oil saturation distribution of the field as of June 1998. The three layers are separated from each other to provide better visualization. The color scale can be seen at the bottom. The first layer clearly indicates the presence of large areas of unswept oil that should be considered for further exploitation. These regions are represented in blue.

A meeting between PetroSantander and University personnel was conducted in May 1998 to discuss the model behavior and the prediction. PetroSantander presented two locations that they suspected had potential for oil production. These sites corresponded with the regions that had unswept oil on the simulated oil saturation distribution. This provided additional support to the accuracy of the model. Two simulated wells were drilled in these areas and their combined output was estimated to be 300,000 barrels from October 1, 1998 through the year 2010. A few additional runs were performed by drilling new wells at other sites that the model indicated had potential. The model predicted economic wells could be drilled at these locations.

Technology Transfer

Technology transfer activities for this project includes the demonstration of data collection and analysis, the importance of a multi-disciplinary reservoir management team, and monitoring waterflood performance such that real-time changes can be made to optimize oil recovery. The following are the technology transfer activities conducted during this project:

1. A paper titled, "Stewart Morrow Field - DOE Class 1 Project" was presented in March 1995 at the TORP Oil Recovery Conference in Wichita, KS and was published in the conference proceedings.
2. The project was awarded the "Best Advanced Recovery Project" and was runner-up as the "Best Field Improvement Project" in the Midcontinent by Hart's Oil and Gas World for 1995.
3. Project information was presented as a poster session at the SPE Forum Series titled, "Multidisciplined Analysis and Solutions to Rejuvenating Old or Marginal Fields" in August 1995 at Snowmass Village, Colorado.
4. Methodologies used in this project were presented as a case study at seminars titled, "Increasing Profitability in Marginal Oil Fields" in August 1995 in Great Bend, Kansas and November 1995 in Wichita, Kansas.
5. Presentations were made on the Stewart Field as part of the Traveling Workshop Series for selected Class 1 near-term projects sponsored by BDM-OK and the Petroleum Technology Transfer Council. Presentations were made in Bartlesville, OK, Wichita, KS, Denver, CO, Billings, MT, Oklahoma City, OK, and Grayville, IL. A paper on the project was also published as part of the workshop proceedings.
6. A paper titled, "Evaluating Waterflood Potential in a Morrow Sandstone Reservoir" was presented at the SPE/DOE Tenth Symposium on Improved Oil Recovery in April 1996 at Tulsa, Oklahoma and was published in the conference proceedings.

7. A tour of the waterflood facilities was held in conjunction with the mid-year meeting of the Kansas Independent Oil and Gas Association in Garden City, Kansas in May 1996.
8. Articles pertaining to the increase in oil production due to waterflood response were published in Enhanced Energy Recovery News, Improved Recovery Week, and local newspapers throughout western Kansas.
9. An article on the Stewart Field waterflood was published in the University of Kansas Petroleum Technology Newsletter dated fourth quarter 1996.
10. Presentations on the Stewart Field project were made at the API Chapter meeting in Great Bend, Kansas on 1-8-97 and Society of Independent Professional Earth Scientists (SIPES) meeting in Wichita, Kansas on 2-19-97.
11. A paper titled "Implementation and Monitoring of the Stewart Field Waterflood" was presented and published as part of the proceedings for the Twelfth Oil Recovery Conference held March 19-20, 1997 in Wichita, Kansas.
12. A presentation on the Stewart Field waterflood was presented on August 25, 1997 at the annual meeting of the Kansas Independent Oil and Gas Association in Wichita, KS.
13. A presentation on the Stewart Field waterflood was presented on September 11, 1997 at the Noon Kiwanis Club meeting in Lawrence, KS.
14. A presentation titled, "Waterflooding Using Improved Reservoir Management: Stewart Field Case Study", was presented at a symposium sponsored by the University of Wyoming Enhanced Oil Recovery Institute on October 29-30, 1997 in Casper, WY.
15. Presentations on the Stewart Field waterflood were presented to the Tertiary Oil Recovery Project's advisory board meetings on November 7, 1997 in Lawrence, KS, April 7, 1998 in Wichita, KS and October 30, 1998 in Lawrence, KS.
16. Information pertaining to the Stewart Field waterflood was displayed on the exhibition booth for the Tertiary Oil Recovery Project at a workshop titled, "Horizontal Drilling Applications in Kansas", sponsored by the North Midcontinent Regional Lead Organization of the Petroleum Technology Transfer Council on June 16, 1998 in Wichita, KS. A brochure containing detailed information on the Stewart Field waterflood was developed, printed and distributed at the workshop.
17. Papers on the Stewart Field project were presented at the North American Prospect Expo (NAPE) in Houston, TX on January 27-28,1998; the Society of Independent Earth Scientists (SIPES) 1999 Annual Convention and Seminar in Wichita, KS on March 10-12, 1998; and the Tertiary Oil Recovery Project's 13th Oil Recovery Conference in Wichita, KS on March 17-18, 1998.
18. An article on the Stewart Field Waterflood was published in the 2nd Quarter 1999 University of Kansas Petroleum Technology Newsletter.
19. A presentation on the Stewart Field waterflood was conducted at the Department of Energy (NPTO and FETC) Oil and Gas Conference in Dallas, TX on June 29, 1999.
20. A paper titled "Waterflood in Kansas field should boost recovery by five million bbl" was published in the PTTC/World Oil Petroleum Technology Digest in September 1999.
21. Operators throughout the area continue to visit the field to view the state-of-the-art waterflood installation and computerized monitoring system.

CONCLUSIONS

A waterflood was designed and implemented for the entire field based on the geological and engineering analysis conducted in Budget Period 1. The waterflood installation includes state-of-the-art computerized monitoring and emergency shut down systems. The installation design places special emphasis on production, injection, and pressure data access and recording.

Water injection began in October 1995 and the field has responded favorably to waterflood operations. Through December 1998 a total of 7,781,980 BW had been injected resulting in an increase in oil production of approximately 2900 BOPD or 1,634,782 bbls of incremental secondary oil recovery through December 1998.

Stewart Field Figures

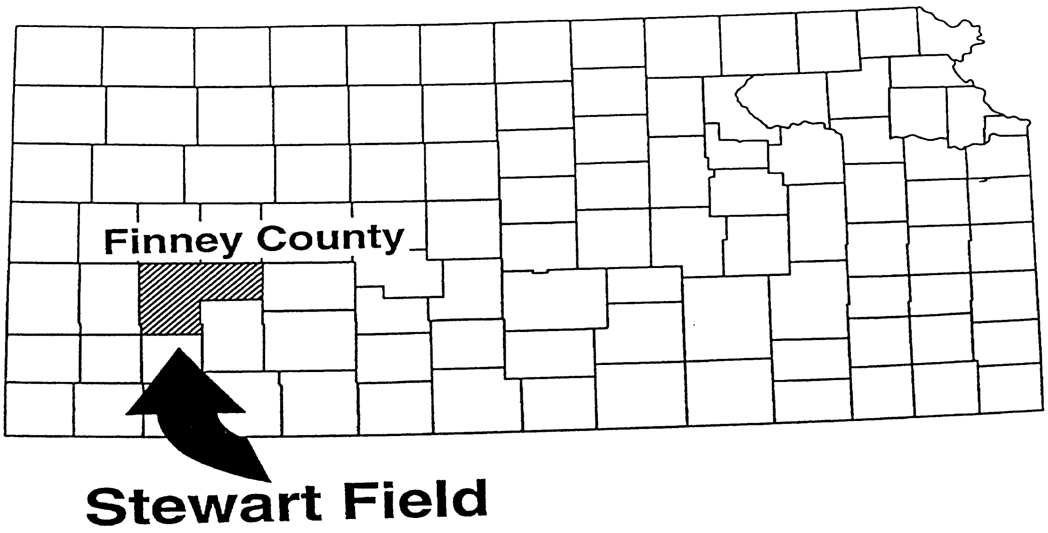


Figure 1 Location Plat for Stewart Field.

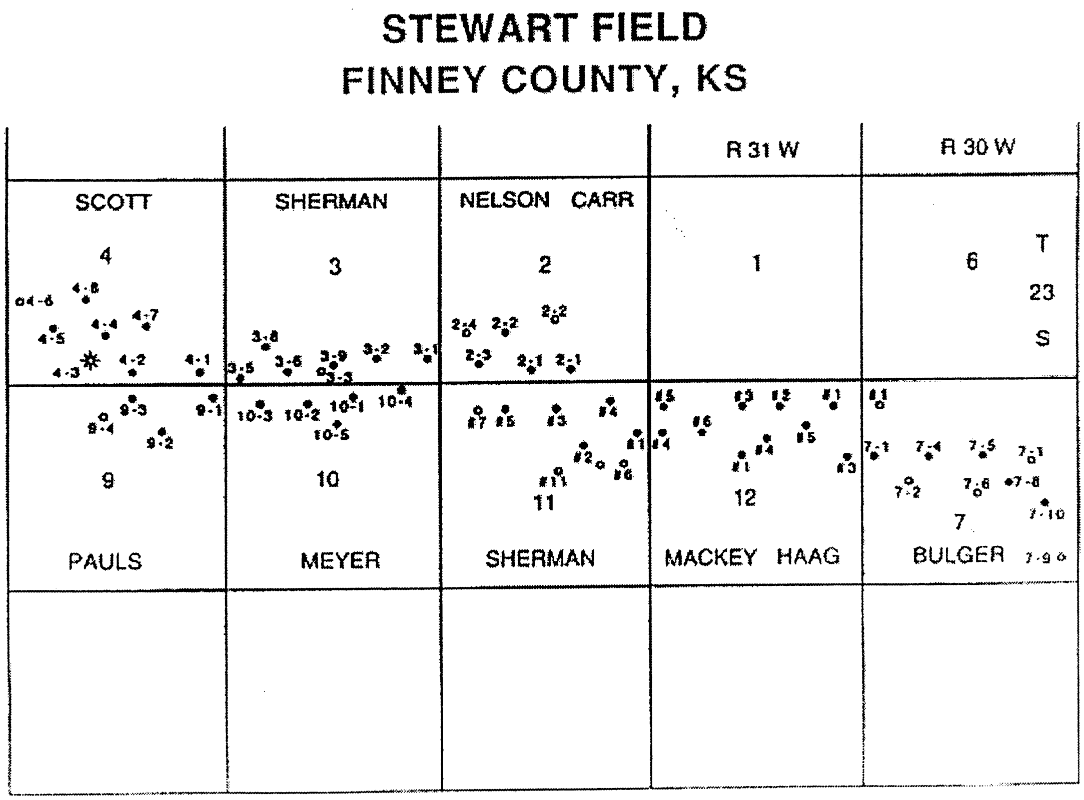


Figure 2 Stewart Field Well Location Plat.

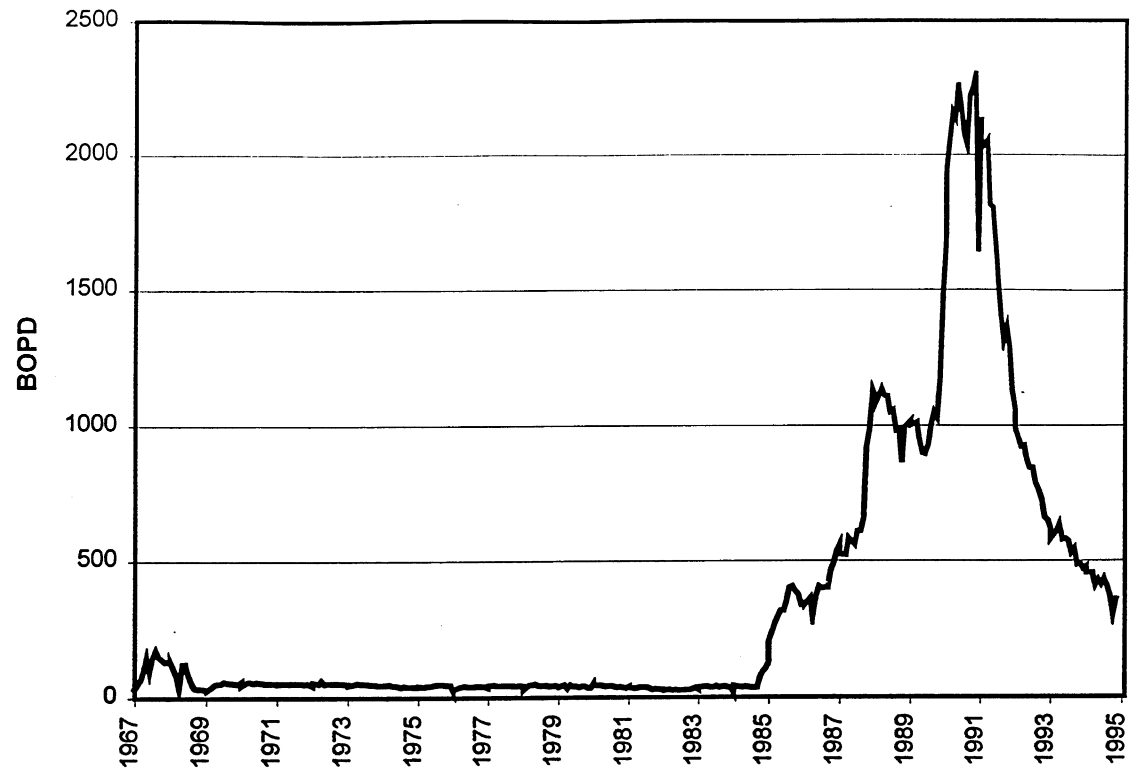


Figure 3 **Stewart Field Primary Production Curve.**

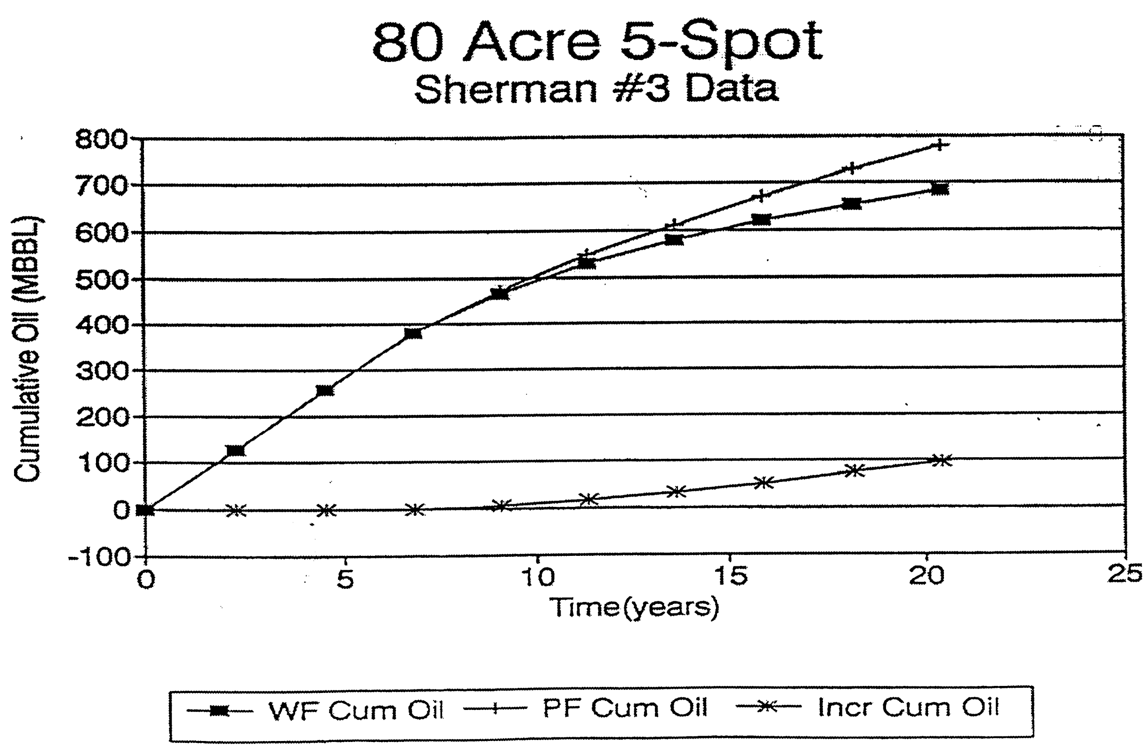


Figure 4 **Polymer Flooding versus Waterflooding Plot in the Stewart Field.**

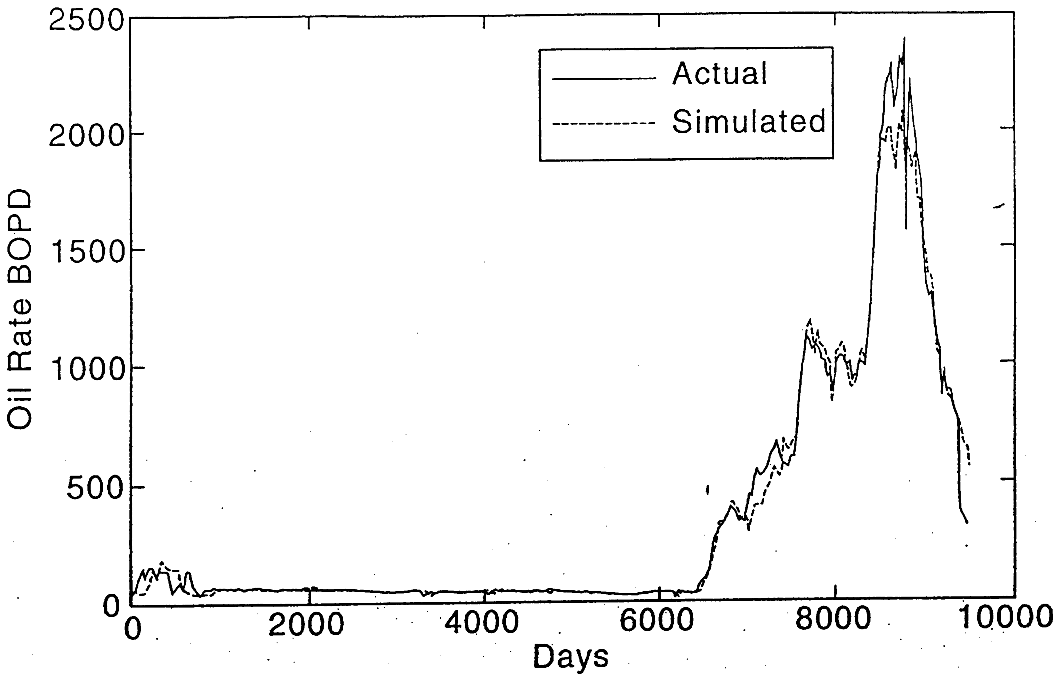


Figure 5 **Actual Versus Simulated Production for the Original Model of the Stewart Field.**

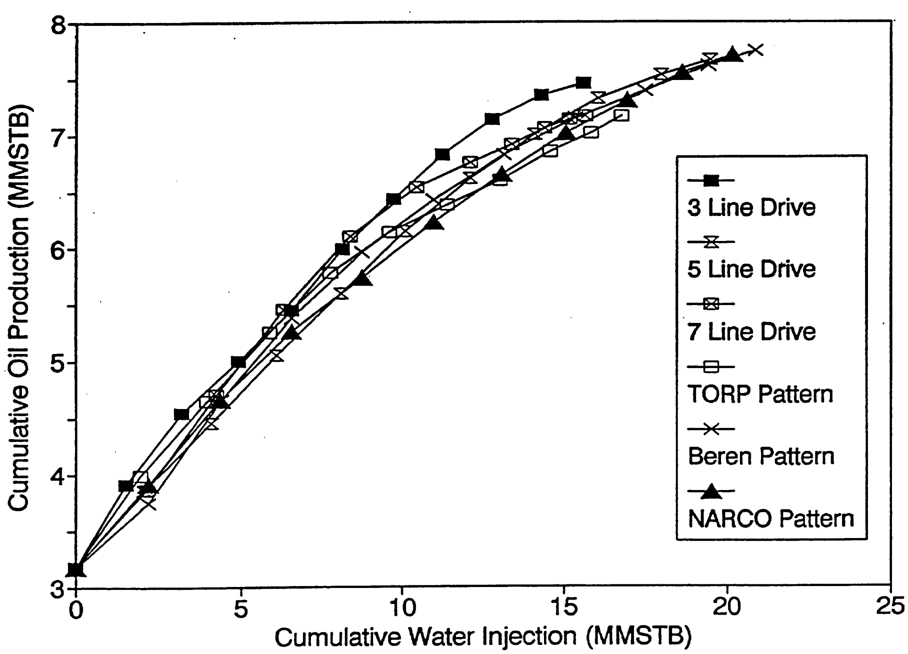


Figure 6 **Cumulative Oil Production versus Cumulative Water Injection for Waterflood Patterns Investigated for the Stewart Field.**

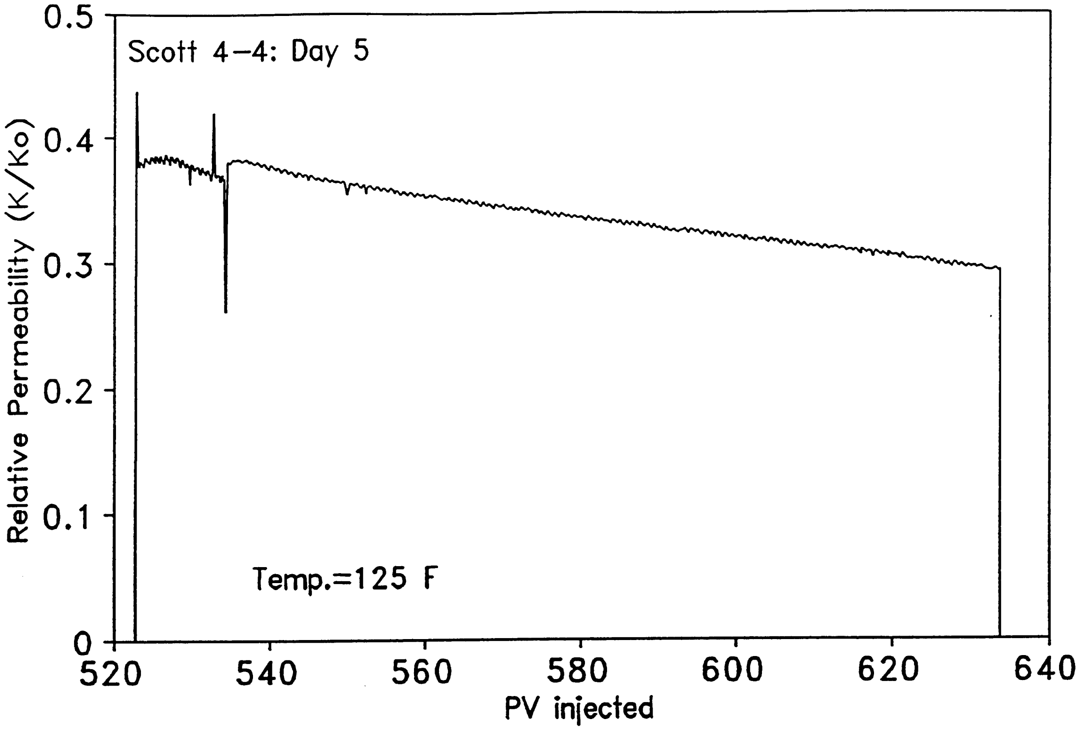


Figure 7 **Relative permeability versus pore volumes injected for synthetic formation brine.**

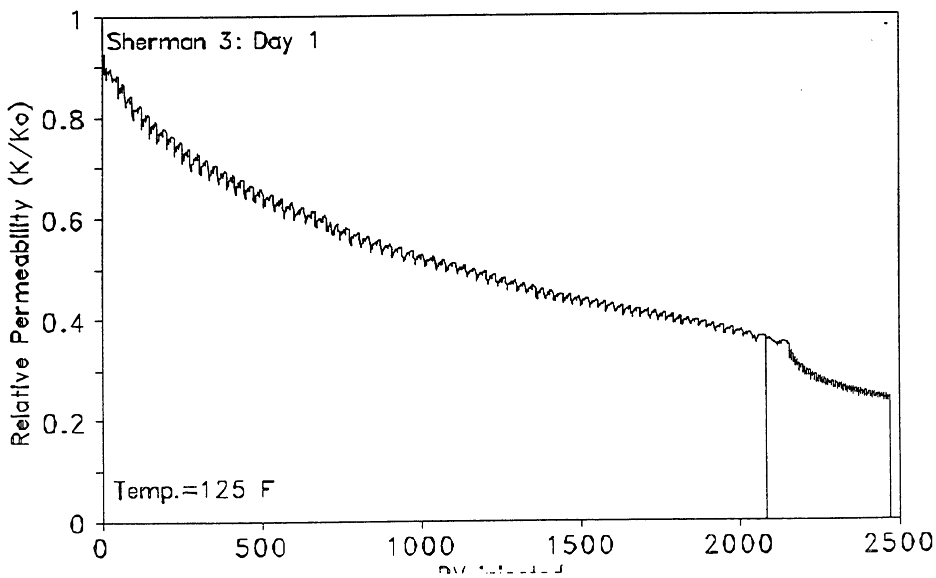


Figure 8 **Relative permeability versus pore volumes injected for filtered produced water.**

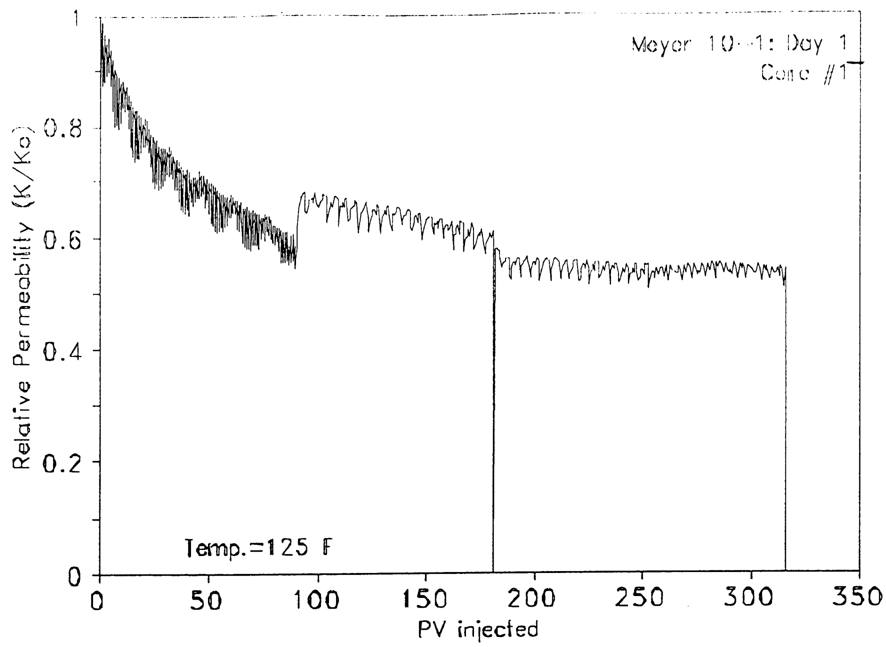


Figure 9 **Relative permeability versus pore volumes injected for 3.0% potassium chloride solution.**

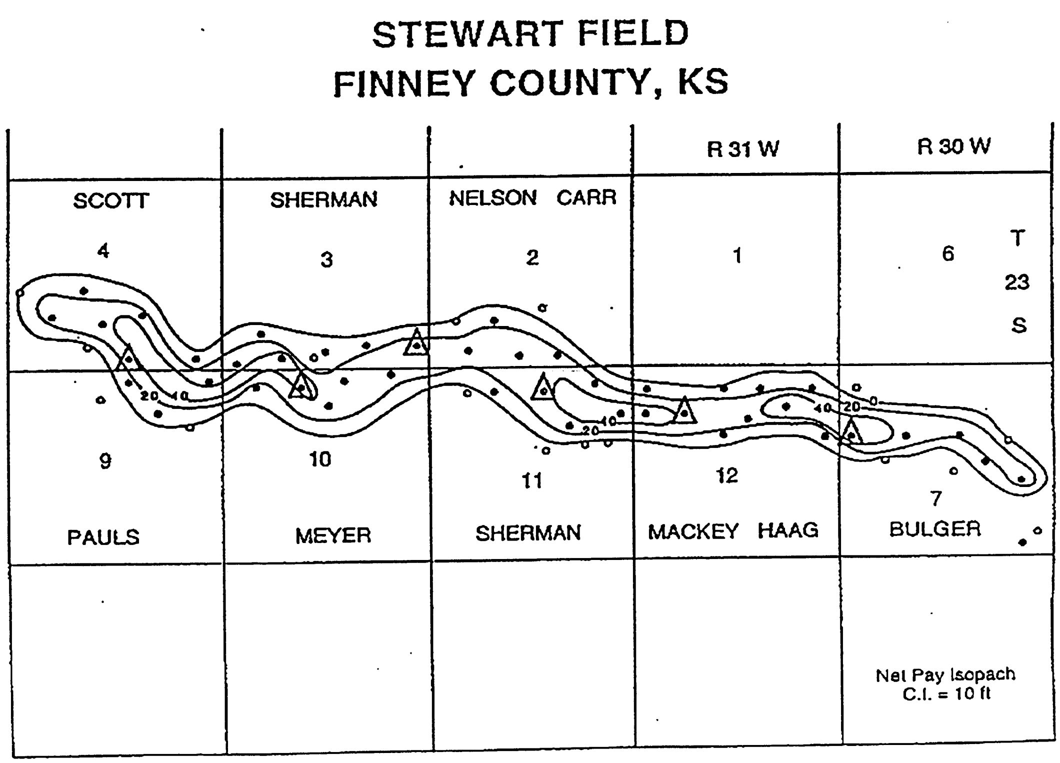


Figure 10 **Original Modified Six Line Drive Pattern Selected for Waterflooding the Stewart Field.**

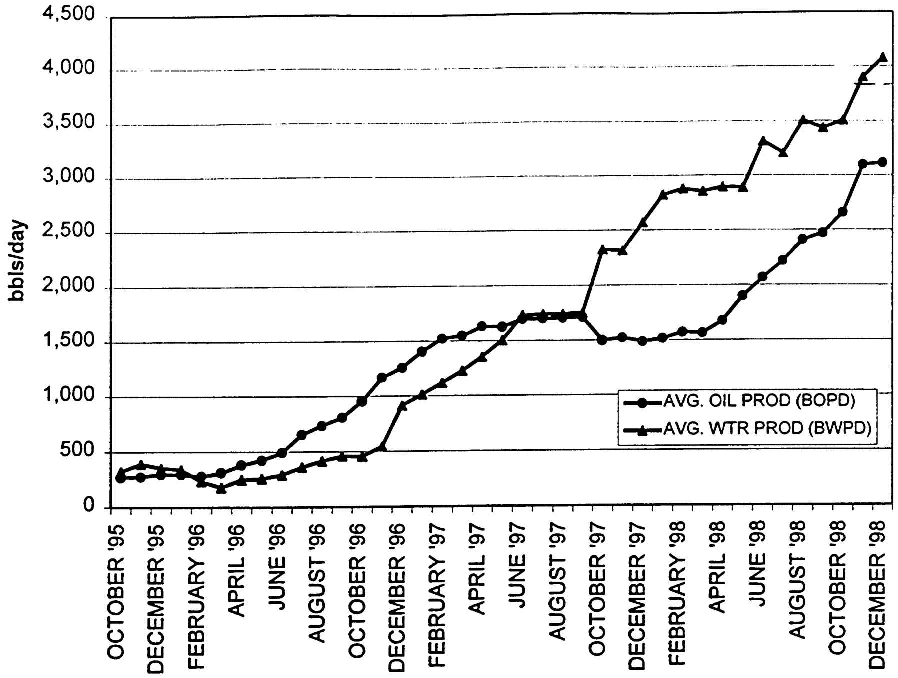


Figure 11 **Average Daily Totals for Injection and Production by Month for the Stewart Field.**

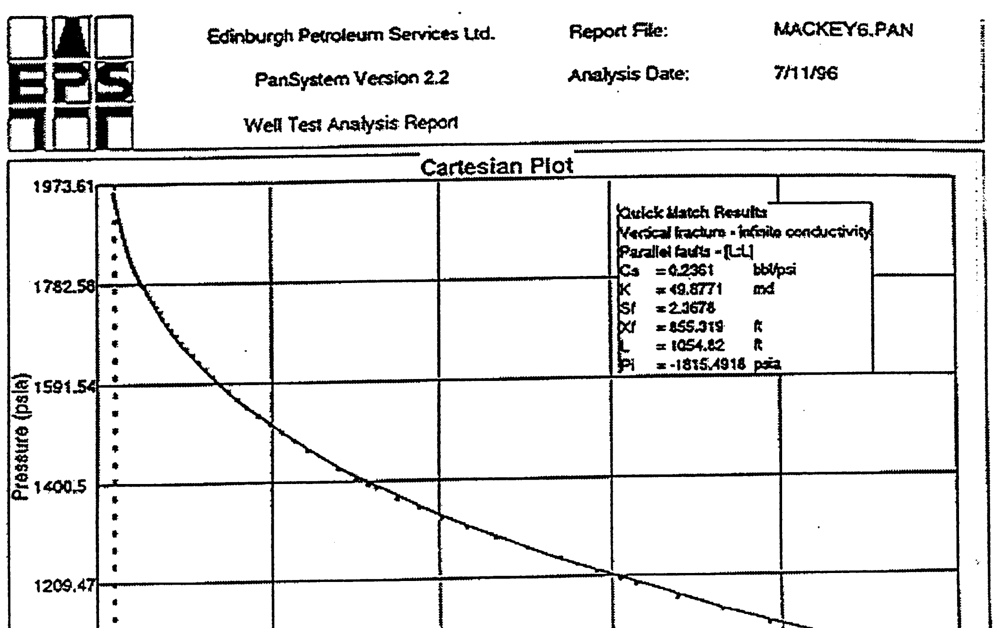


Figure 12 **Plot of Pressure Versus Shut-in Time for the Fall-Off Test Conducted on the Mackey #6.**

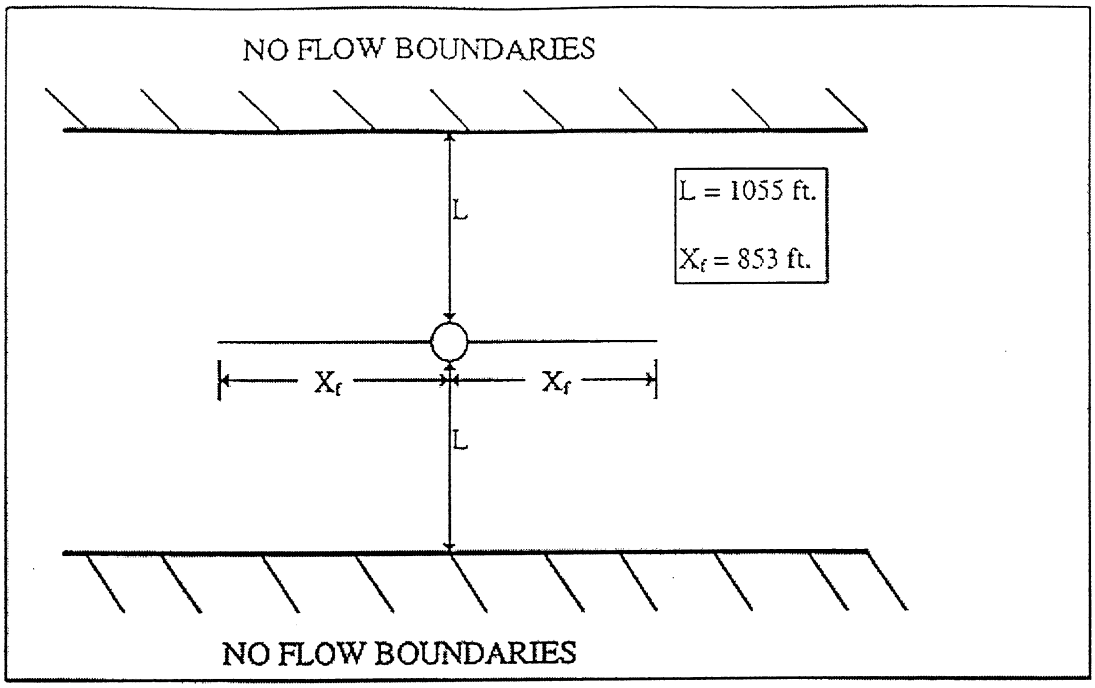


Figure 13 **A Schematic Illustrating a Vertical Fracture of Infinite Conductivity that is Confined on Two Sides by Parallel Faults Each Equidistant from the Injection Well**

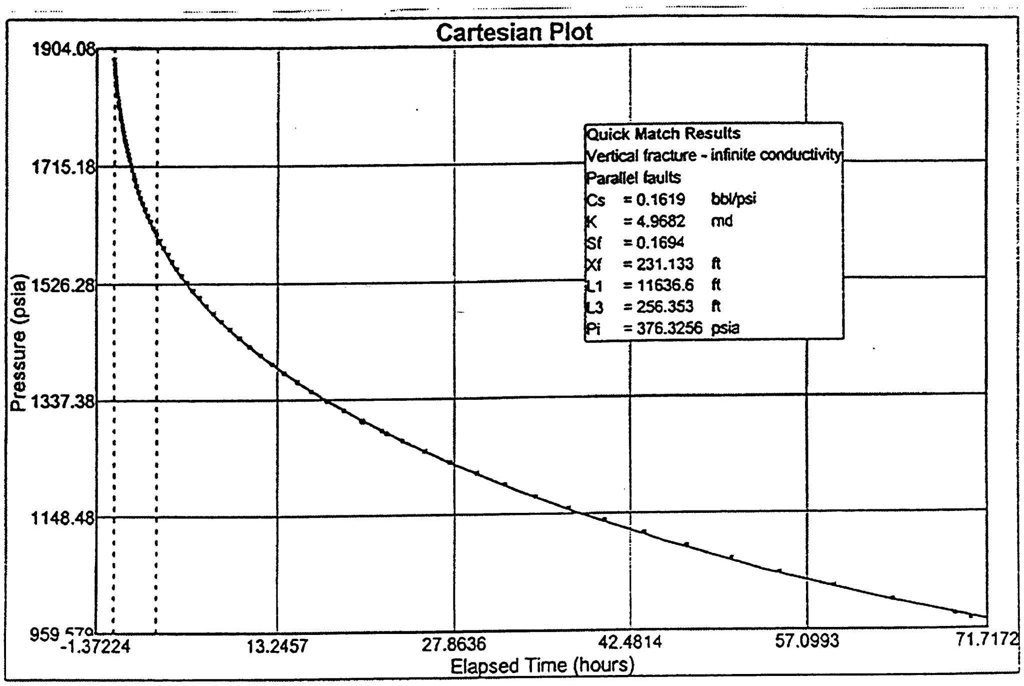


Figure 14 **Plot of Pressure Versus Shut-in Time for the Fall-Off Test Conducted on the Meyer 10-2.**

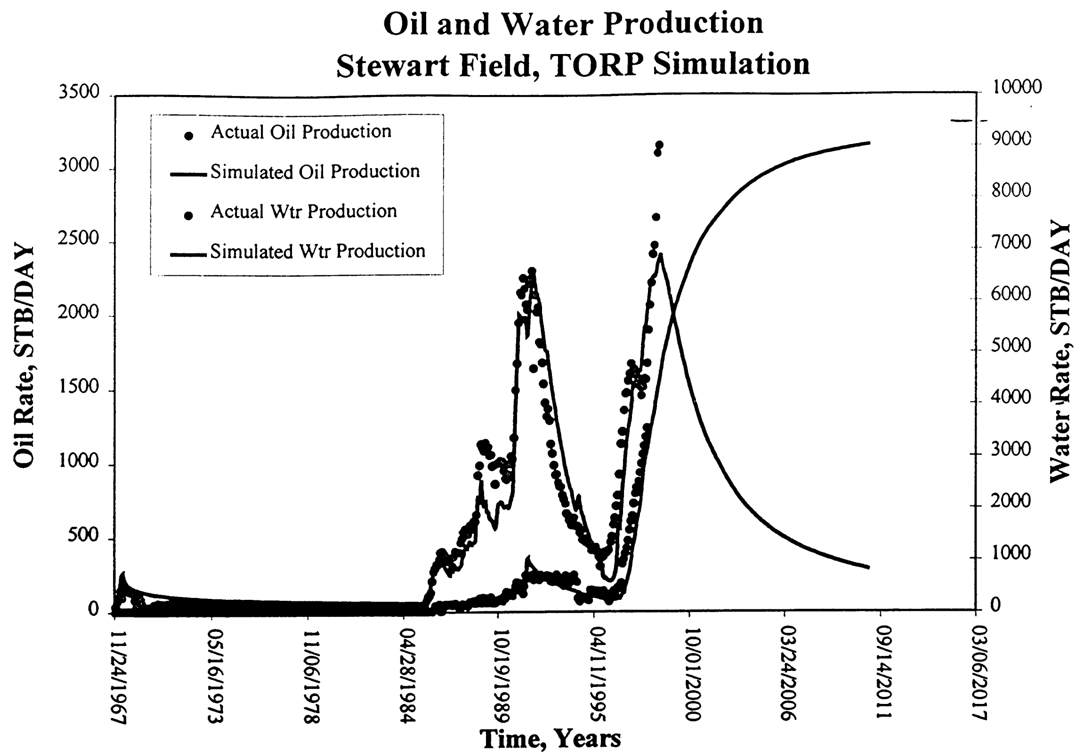


Figure 15 **Revised History Match for the Stewart Field**

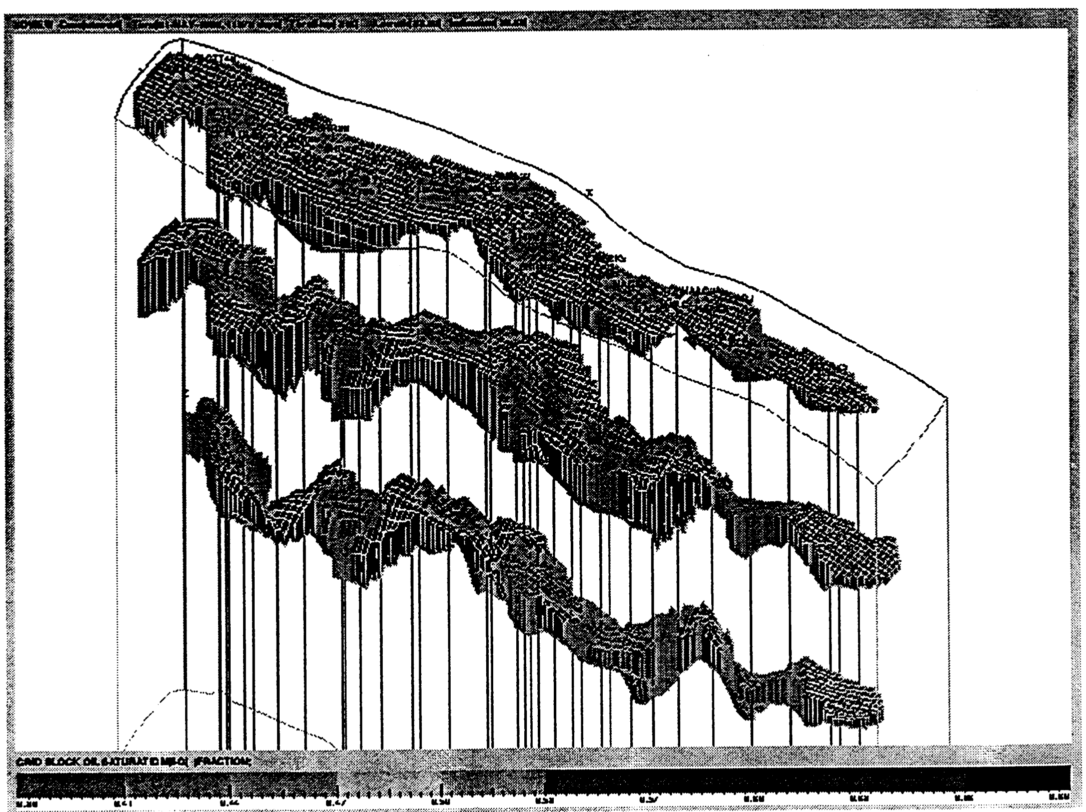


Figure 16 **Computer Model Illustration of Oil Saturation Distribution in the Stewart Field as of June 1998.**

Chapter 3

Savonburg Field Project

OBJECTIVES

The objective of this project was to address waterflood problems in Cherokee Group sandstone reservoirs in eastern Kansas. The general topics addressed were 1) reservoir management and performance evaluation, 2) waterplant optimization, and 3) demonstration of off-the-shelf technologies in optimizing current or existing waterfloods with poor waterflood sweep efficiency. It is hopeful that if these off-the-shelf technologies are implemented the abandonment rate of these reservoir types will be reduced.

The reservoir management portion of this project involved performance evaluation and included such work as 1) reservoir characterization and the development of a reservoir database, 2) identification of operational problems, 3) identification of near wellbore problems such as plugging caused from poor water quality, 4) identification of unrecovered mobile oil and estimation of recovery factors, and 5) preliminary identification of the most efficient and economical recovery process i.e., polymer augmented waterflooding or infill drilling (vertical or horizontal wells).

To accomplish these objectives the initial budget period was broken down into four major tasks. The tasks included 1) geological and engineering analysis, 2) waterplant optimization, 3) wellbore cleanup and pattern changes, and 4) field operations.

Budget Period 2 objectives consisted of the continual optimization of this mature waterflood in an attempt to optimize secondary and tertiary oil recovery. To accomplish these objectives the second budget period was broken down into six major tasks; 1) waterplant development, 2) profile modification treatments, 3) pattern changes, new wells and wellbore cleanups, 4) reservoir development, 5) field operations, and 6) technology transfer.

In Budget Period 1, it was determined that the lower B3 zone had not been flooded effectively and contained unswept mobile oil. The in-fill injection well drilled in December 1995 confirmed this assumption. The core results are presented in the July 1996 annual report, and included in this report as **Appendix B**. In the past few years, main emphasis of all tasks was to target water injection into this B3 zone.

BACKGROUND

The Nelson Lease is located in Allen County, Kansas in the N.E. Savonburg Field about 15 miles northeast of the town of Chanute and one mile northeast of Savonburg. The project is comprised of three 160-acre leases totaling 480 acres in Sections 21, 28, and 29, Township 26 South, Range 21 East.

The first well drilled in the location of this project was in 1962. Fifty-nine production wells and forty-nine injection wells have been drilled and completed since 1970. A pilot waterflood was initiated in March 1981 and expanded in 1983. Full development occurred in 1985.

Production of oil in the Nelson Lease in the Savonburg NE Oil Field is from a valley-fill sand in the Chelsea Sandstone member of the Cabaniss Formation of the Cherokee Group. This lease is similar to a large number of small oil fields in eastern Kansas that produce from long, narrow sandstones, "shoestring sandstones" (Bass, 1934), at shallow depth.

The most productive part of the reservoir sand in the lease lies in the eastern half of the SW/4 of Section 21 and is a narrow valley cut to a depth of up to 40 feet (12 m) through the Tebo and Weir-Pittsburg horizons into the Bluejacket A coal (Harris, 1984). The deepest part of the valley is less than 300 m wide. Wells that encountered the most sandstone in the valley are the most productive.

In 1986, eleven gel polymer treatments were implemented successfully on the Nelson Lease. Overall incremental oil recovery was 3.5 barrels per pound of polymer placed which totaled 12,500 barrels. The production increase was not sustained due to wellbore plugging as a result of poor water quality.

Cumulative production through December 1998 has been 393,511 barrels. Of this production, 131,530 barrels were produced by primary depletion. Water injection began in March 1981 and over 261,000 barrels have been produced under waterflood operations. Cumulative water injection is 5,628,660 barrels. The graph of waterflood production and injection data is presented in **Figure 17**. Water-oil ratio since waterflood start-up is presented in **Figure 18.**

In 1993, this Class 1 project started Budget Period 1. The tasks included 1) geological and engineering analysis, 2) waterplant optimization, 3) wellbore cleanup and pattern changes, and 4) field operations, which have been completed and are presented in the 1994 annual report. In that report, the high potential areas for development were defined.

BUDGET PERIOD 1 ACTIVITIES

GEOLOGICAL AND ENGINEERING ANALYSIS

Database Development

Due to the abundance of data on the field, a computer database was set up to make data easily accessible. Spreadsheets were utilized in the development of the database. The computer database included, 1) reservoir properties from core analysis on a well basis, 2) production and injection data on a well basis since waterflood start up, and 3) lithology picks on a well basis.

This study used materials provided by J.E. Russell Petroleum Inc., including cores, unscaled gamma ray-neutron logs and core data. While cores collected before 1983 were discarded after description and analysis, cores were available for 23 wells drilled since Russell became operator of the field. Russell cores are simply designated by their well number, either RW-n (n=1 through 19) or O-n (n=1 through 4). The Russell cores were described and were the basis for much of the depositional interpretation of the reservoir rocks and associated strata. Core data provided was collected by Oil Field Research in Chanute, Kansas, except for two descriptions carried out by CoreLab. Core data included a text and graphic description, measurements of porosity, permeability, and fluid saturation for nearly all wells, and, for the Russell cores, recoverable oil and effective permeability at residual oil saturation.

Zone Description and Mapping Methods

Sandstone was mapped and identified utilizing two methods, 1) core reports to determine net floodable sand for volumetric analysis, and 2) gamma-ray logs to determine sand thicknesses and differences in lithologies for geological analysis. Both methods proved valuable.

In the volumetric study, net pay was determined from core analysis utilizing a porosity cut-off of 13% and effective water permeability cut-off of 1 md.

In the geological study, a shale line and a sand line were drawn on the g-ray log. The shale line was drawn at a deflection which was consistently reached by beds which did not appear to be anomalously radioactive. The sand line was drawn at the gamma-ray reading in the Cherokee Group. Rocks with a deflection greater than 1/2 of the difference between the sand and shale lines were considered to be shale and those with a smaller deflection were considered to be sandstone.

Reservoir Parameters

The reservoir characteristics were defined from log and core analyses. Average porosity and permeability are 18.4% and 27 md respectively. Average residual oil saturation, based on laboratory flood pot tests was 34.9 percent. Connate water saturation of 24 percent was estimated from core data and by applying an empirical relationship using permeability data. The gravity of the crude oil is 31.2 degrees API at 60° F. The viscosity of the reservoir crude oil at reservoir temperature is 15.4 cp.

Volumetric Analysis

A pattern volumetric analysis was conducted to determine recovery factors in BBL/Ac-ft for given segments of the field. Net pays were determined from flood pot data. From the database three grids and maps were developed; 1) net pay, 2) porosity, and 3) water saturation. The net pay grid was multiplied with the porosity grid to develop a porosity-foot grid for the field. Each segment or pattern was then integrated to determine acre-ft. The patterns or reservoir segments are presented in Figure 15. Areas of high potential are also presented in the figure.

Initial-oil-in-place at waterflood start up was determined by multiplying the porosity-ft with the initial oil saturation of 24%. A formation volume factor (FVF) of 1.06 was included in the calculations.

A simulation study was conducted to determine waterflood and polymer flood recoveries. The study (along with input parameters) is presented in the following section. It was found that the recovery factor for waterflood and polymer flood were 255 and 335 BBL/Ac-ft respectively. Table 3 presents the remaining waterflood and polymer flood reserves remaining per segment. It also presents volumetrics for the B2 and B3 zone, and (oil & water) production by segment.

Estimates of oil recovery by polymer injection were computed by assuming that the polymer flood started at the same time and same initial saturations as the waterflood. Producing water-oil ratios in the field (Figure 18) were in excess of 30 during the waterflood. The model used to simulate polymer flooding does not account for the fact that a substantial portion of the reservoir was waterflooded when the polymer flood was initiated. Polymer injected into these portions of the reservoir will displace large amounts of water with additional oil and the response to polymer injection will be delayed when compared to the simulated response. Consequently, polymer flood estimates were considered optimistic.

FIGURE 17: NELSON LEASE PRODUCTION & INJECTION

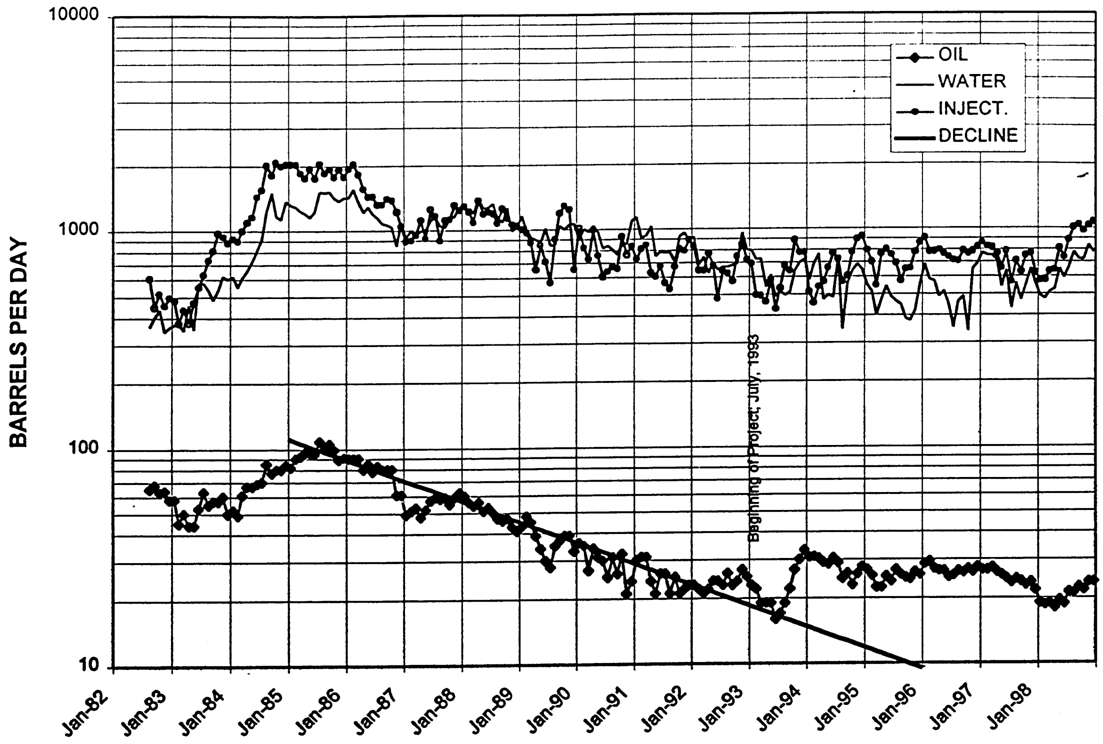
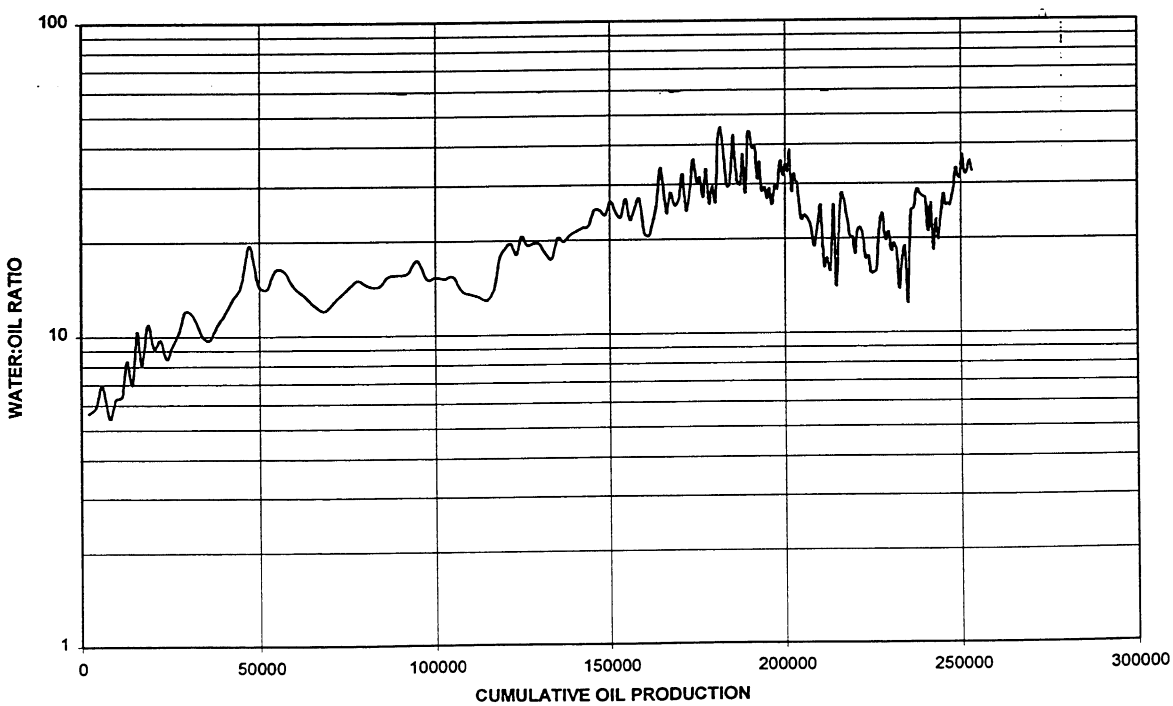


FIGURE 18: NELSON LEASE WATER:OIL RATIO



B2 Net Pay

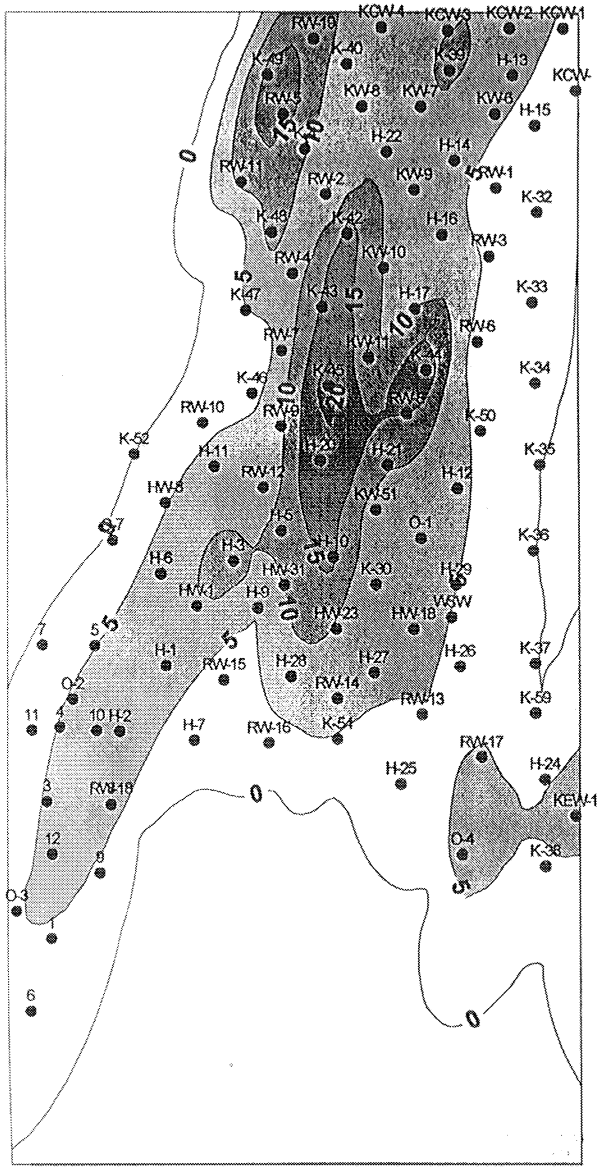


FIGURE 19

B3 Net Pay

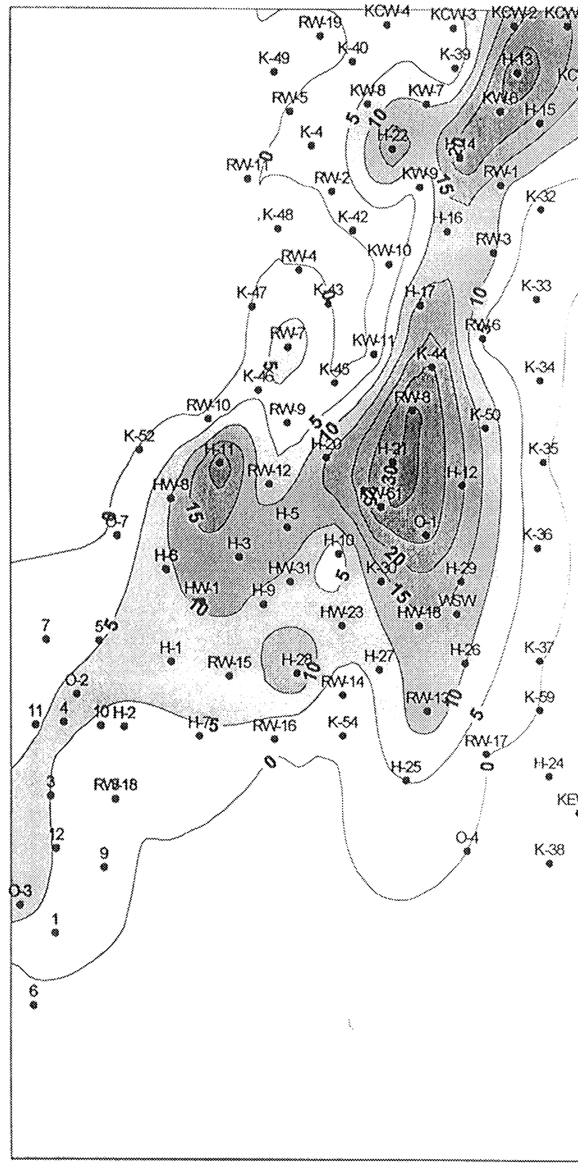


FIGURE 20

Table 11: Pattern Volumetric Analysis

Well	Oil Prod. BBL/ Ac-ft	Oil Left BBL/ Ac-ft	Remaining Sec. Oil	Remaining Poly Oil	Remaining Tot. Oil	Segment Acres	B2 Vol. Ac-ft	B3 Vol. Ac-ft	Total Vol. Ac-ft	Oil Prod. June 94	Water Prod. June 94
H-1	117	138	9,149	5,298	14,447	4.09	33.89	32.34	66.23	7,740	113,625
H-11	75	180	9,708	4,304	14,012	2.47	19.81	33.99	53.80	4,012	92,014
H-14	259	(4)	(274)	5,504	5,231	2.51	18.72	50.09	68.81	17,819	192,372
H-15	184	71	2,043	2,312	4,355	1.01	4.56	24.34	28.90	5,327	58,965
H-16	226	29	1,990	5,398	7,388	3.32	20.54	46.94	67.48	15,217	202,476
H-17	127	128	12,377	7,709	20,086	3.82	40.13	56.24	96.37	12,196	203,703
H-20	144	111	24,216	17,504	41,720	6.74	94.10	124.70	218.80	31,579	221,003
H-22	134	121	6,656	4,389	11,046	2.49	23.22	31.65	54.87	7,335	101,718
H-26	236	19	602	2,480	3,082	1.34	9.40	21.59	31.00	7,302	63,697
H-27	21	234	10,430	3,568	13,999	2.57	19.98	24.62	44.60	944	76,606
H-28	69	186	9,304	4,000	13,305	2.96	23.12	26.88	50.01	3,447	144,798
H-3	65	190	30,164	12,681	42,846	6.46	79.33	79.19	158.52	10,258	169,577
H-30	220	35	5,968	13,731	19,700	6.75	67.24	104.41	171.64	37,801	310,339
K-36	35	220	9,401	3,415	12,816	2.83	11.65	31.04	42.69	1,485	34,205
H-9	82	173	9,931	4,591	14,522	3.02	25.87	31.51	57.38	4,701	101,352
K-39	153	102	16,361	12,880	29,242	6.69	56.04	104.97	161.01	24,695	345,730
K-40	21	234	6,250	2,133	8,383	2.10	24.38	2.27	26.66	547	30,563
K-41	129	126	4,256	2,694	6,950	2.55	31.71	1.97	33.67	4,331	131,973
K-42	75	180	8,207	3,645	11,852	2.78	38.05	7.51	45.56	3,410	98,335
K-43	178	77	4,115	4,280	8,394	3.08	49.52	3.98	53.50	9,527	107,389
K-44	144	111	10,101	7,260	17,362	2.72	35.72	55.03	90.75	13,041	188,887
K-45	85	170	12,295	5,773	18,068	3.01	55.02	17.14	72.17	6,107	130,939
K-47	36	219	12,901	4,717	17,618	7.27	46.73	12.23	58.96	2,134	36,524
K-49	112	143	1,460	815	2,275	0.31	9.88	0.31	10.19	1,137	18,253
K-54	184	71	2,182	2,450	4,632	3.09	15.11	15.51	30.62	5,626	127,719
TOTALS			219,793	143,531	363,331	85	856	942	1,794	237,812	3,302,856

Simulation Study

To determine the potential recovery from waterflooding in the Savonburg Field, a streamtube simulator was utilized. The following input parameters were used in the simulation:

Table 12: Input Parameters for Streamtube Simulator

FORMATION PROPERITIES AND PATTERN VOLUMES

FORMATION DEPTH	620.0 FT
FORMATION TEMPERATURE	70.0 DEG.F
FORMATION AVE. PERMEABILITY	27.0 MD
FORMATION POROSITY	0.2
TOTAL NET THICKNESS	17.2 FT
TOTAL PORE VOLUME	61.4 MBBL
ORIGINAL OIL IN PLACE	45.8 MSTB
OIL IN PLACE AT START OF FLOOD	42.2 MSTB
DYKSTRA-PARSONS COEFFICIENT	0.63 VDP
PATTERN AREA	2.50 ACRE
WELLBORE RADIUS	0.50 FT
INJECTIVITY COEFFICIENT	1.00 PSI/FT
INJECTION RATE OVERRIDE	40.0 RB/D
WATER-OIL MOBILITY RATIO	7.38
POLYMER-OIL MOBILITY RATIO	1.00
POLYMER CONCENTRATION	500.0 PPM
POLYMER ADSORPTION	200.000 LB/AC FT
POLYMER ADSORPTION PARAMETER	0.147 VOL SLUG/PV
POLYMER VISCOSITY	12.700 CP
RESISTANCE FACTOR	7.40
RESIDUAL RESISTANCE FACTOR	2.000
POWER-LAW COEFFICIENT	4.774 CP*SEC**(N-1)
POWER-LAW EXPONENT	0.600
POLYMER SLUG SIZE	0.300 PV
MAXIMUM INJECTED PV, POLY+CHASE WAT	2.000 PV

FORMATION PROPERTY TABLE

DISCRETE LAYER CALCULATION OPTION	1 LYROPT
NUMBER OF LAYERS	5 NLAYER OR NLDP
AVERAGE POROSITY	0.1840
AVERAGE PERMEABILITY	27.0 MD
TOTAL NET THICKNESS	17.2 FT
AVERAGE INITIAL WATER SATURATION .	0.30

LAYER NO.	PHIL	PERML MD	PAYL FT	SWIL
1	0.18	75.69	3.44	0.30
2	0.18	28.35	3.44	0.30
3	0.18	16.64	3.44	0.30
4	0.18	9.84	3.44	0.30
5	0.18	4.48	3.44	0.30

RELATIVE PERM CURVES

IRREDUCIBLE WATER SATURATION .	0.240	SWC
RESIDUAL OIL SATN AFTER WATER	0.349	SORW
OIL RELATIVE PERM END-POINT	0.800	XKROE
WATER RELATIVE PERM END-POINT	0.300	XKRWE
OIL RELATIVE PERM CURVATURE	2.00	XNO
WATER RELATIVE PERM CURVATURE	2.00	XNW

RELATIVE PERMEABILITY TABLE

WATER SATURATN	OIL KRO	WATER KRW	FRACTION WATER	FRACTION POLYMER
0.2400	0.8000	0.0000	0.0000	0.0000
0.2811	0.6480	0.0030	0.0835	0.0038
0.3222	0.5120	0.0120	0.3157	0.0190
0.3633	0.3920	0.0270	0.5755	0.0539
0.4044	0.2880	0.0480	0.7664	0.1211
0.4455	0.2000	0.0750	0.8807	0.2367
0.4866	0.1280	0.1080	0.9432	0.4109
0.5277	0.0720	0.1470	0.9757	0.6280
0.5688	0.0320	0.1920	0.9916	0.8322
0.6099	0.0080	0.2430	0.9983	0.9617
0.6510	0.0000	0.3000	1.0000	1.0000

WATERFLOOD REPORT PATTERN PRODUCTION SUMMARY

PATTERN LIFE RATIO	10.80
PATTERN AREA .	2.50 ACRE
PATTERN PORE VOLUME	61.4 MBBL
ORIGINAL OIL IN PLACE	45.8 MSTB
OIL IN PLACE AT START OF FLOOD	42.2 MSTB
TOTAL OIL PRODUCTION	11.0 MSTB
OIL RECOVERY	255 BBL/AC-FT @ WOR - 25

POLYMERFLOOD REPORT PATTERN PRODUCTION SUMMARY

PATTERN LIFE RATIO	10.80
PATTERN AREA	2.50 ACRE
PATTERN PORE VOLUME	61.4 MBBL
ORIGINAL OIL IN PLACE	45.8 MSTB
OIL IN PLACE AT START OF FLOOD	42.2 MSTB
TOTAL OIL PRODUCTION	15.1 MSTB
OIL RECOVERY	335 BBL/AC-FT @ WOR - 60
TOTAL POLYMER INJECTED	3.2 MLB
OIL/POLYMER RATIO	4.67 STB/LB

The simulation run indicates that the recovery factors for waterflood and polymer flood are 255 and 335 BBL/Ac-ft respectively. This recovery factor is larger than most of the recovery factors in the volumetric pattern study. This would indicate that many of the patterns have a high potential for incremental oil if the continued development was optimized.

Geological Analysis

The primary zone of oil production is a sandstone that is part of the Chelsea Sandstone of the Cabaniss Formation, Cherokee Group. The sandstone, with associated mixed lithology (rippled sandstone, wavy- and linsen-bedded sandstone, siltstone and shale) and shale, fills a valley that was cut during a low stand of sea level. The low stand occurred after deposition of the Tebo Coal and some overlying strata but before deposition of the Scammon Coal. The most productive reservoir is a structureless, fine-grained sandstone associated with the first stage of filling this valley, called the B_3 zone in this report. Rippled sandstones of the overlying interval, the B_2 zone, are potentially productive in the NW part of the lease, but are generally either saturated with dead oil, have low initial oil saturations, or are thin and discontinuous, making poor reservoirs.

Geological understanding of this reservoir results from two factors. One is the availability of good data. The operators, J.E. Russell Petroleum, Inc. provided cores, core descriptions and analyses, and logs. The other factor was the application of sedimentologic and stratigraphic principles that have emerged in the past few years, especially sequence stratigraphy and the understanding of the features of sediments deposited by tidal currents.

The stratigraphic framework of the Cherokee Group in the field area is a series of regional marker intervals that consist (ideally) of an underclay, a coal, a caprock of marine sandstone or limestone, and a dark gray or black shale. In terms of sequence stratigraphy, the boundary of the underclay and coal represents a sequence boundary, a surface of subaerial exposure. The boundary between the coal and the caprock represents the initial surface of marine transgression, with the caprock representing a lag deposit on a ravinement surface cut during transgression. The surface of maximum transgression lies in the overlying dark gray or black shale or in the medium gray shale that gradationally overlies it. These strata thus reflect the effects of rise and fall of sea level relative to the area of deposition of these sediments. Regional marker intervals extend across the Cherokee basin of southeastern Kansas and into the Forest City and Sedgwick basins (northeastern and south-central Kansas, respectively). They may continue into Iowa and southwestern Kansas.

Locally, the regional marker intervals are missing, notably in the vicinity of the Nelson Lease. The pattern of their absence in the field area suggests a valley eroded into underlying deposits; this is the valley referred to above. The sediments that fill this valley appear to carry indications of deposition by tidal currents. The sediments show gradational changes from shale to wavy- and linsen-bedded sandstone and mudrocks to rippled sandstone on a dm scale. The gradational nature of these changes suggests no little erosion between depositional events. The changes of grain size suggest frequent changes of current intensity, from essentially no current, when mudstone and macerated plant material accumulated in wavy- or linsen-bedded successions to times of current when ripples or sand or silt accumulated. This may correspond to currents during individual tidal cycles. The dm-scale gradation of shale to mudrocks to sand may reflect changes in intensity of ripple-forming episodes of the kind that would result from the neap-spring cycles of tidal activity. Because the mixed lithologies of the B_2 and B_3 zones suggest tidal activity, the sandstones and shales of these zones may also have formed in tidal environments. Tidal sandstones occur in mounded masses, convex upward, rather than in the convex-downward patterns of fluvial channels.

Planning for further development of this field should take into account the linear nature of the primary reservoir, the lower (or B_3) sandstone, and the sheet-like nature of the upper sand (B_2) in the northwestern part of the field, if that area is developed further. Additional drilling for improved waterflood recovery may be warranted in the central part of the deep valley and in the northwestern part of the lease. Several wells are completed in sandstones where petrophysics, saturations, and continuity of beds are unfavorable for either injection or production. Each well should be evaluated in view of current subsurface information, and those that are not likely to be productive should be abandoned. The field contains substantial amounts of dead oil, which not only cannot be produced but which act as a barrier to flow of fluids thought the reservoir. Wells drilled during further development the wells logged at least with g-ray--neutron logs. The wells should be cored and the cores analyzed for normal petrophysics, fluid saturations, recoverable oil and effective permeability. Cores should be described geologically and their character used to improve knowledge of the distribution of rocks in the field.

The geological study identified two sandstones, B_2 and B_3, which have potential for additional oil recovery. The study utilized regional marker horizons to form the basis for correlation of Cherokee Group rocks over the Cherokee Basin and to adjacent basins. East-West cross sections were developed on nearly all the wells identifying the continuity of the B_2 and B_3 pay zones. The cross sections are presented in Appendix E. Isopach maps were developed for the B_2 and B_3 sandstones.

It was concluded that the sandstones of the B_3 zone of the Chelsea valley fill in the eastern 1/2 of section 21 may not be completely drained by the current arrangement of wells. Specifically, injection wells may be needed between wells H-14 and H-16, between H-16 and K-44, between H-20 and H-21, and between H-30 and H-27. These locations lie along the trend of thickest sandstone in the axis of the Chelsea valley fill and adjacent injection wells are on the margins of the sandstone. While these steps would reduce spacing substantially, very high original oil saturations along the valley (as high as 5000 bbls/acre recoverable oil) and the potential for improved recovery may justify the step.

Cores of the B_2 zone in the northwest part of the Nelson Lease indicate recoverable oil averaging 2000 Bbls/acre, but production from that area has been low. Recompletion, additional development drilling, or some expansion of the field in this direction may be desirable, under the right economic conditions.

The complete geological analysis of the field is included as **Appendix A.**

Discussion of Field Recommendations

As part of the Phase 1 work, selected field testing of the waterflood was completed. Based on the volumetric pattern study and geological evaluation, several recommendations were made. Field recommendations included well cleanups. Recommendations were based on zone potential. From examining the geological report, Zone B-3 is of better quality and of higher potential than Zone B-2. As a result, it was suggested that initial work be conducted on Zone B-3 in Phase 1. Once these recommendations were implemented, areas of high potential would be identified in Zone B-2 and work continued.

The following injection wells had gel polymer treatments conducted, and wellbore cleanups occurred.

Well RW-8 - The original differential survey indicated that the fluid was entering above the oil producing horizon. A gel polymer treatment was conducted to plug the thief zone. A wellbore cleanup was conducted on the oil producing horizon with success. The final differential survey indicated that the water was entering the B3 zone, which was the targeted formation. After treatment, approximately 60 B/D was being injected at a pressure of 460 psi.

Well RW-3 - A gel polymer treatment was implemented to plug the channel to H-17. The wellbore was cleaned and a differential temperature survey indicated the water was being injected into the B2 and B3 oil zones.

Well RW-6 - A gel polymer treatment was implemented to plug the channel to K-44.

The following injection wells were cleaned to improve injectivity.

Well KW-51 - Placed on injection in September 1994, utilizing 1-inch pipe and a packer. The wellbore was cleaned within the following two weeks. Injection later averaged 50 B/D.

Wells (KW-6, KCW-1, RW-7, RW-9, RW-12, RW-13, RW-1, HW-23) were cleaned and reactivated as injectors.

The following producing wells were cleaned and remediated: H-17, H-21, K-44, H-13, H-26, H-22, H-30, H-5, H-14, and O-1.

Producing Wells H-5 and H-14 were converted to injection wells in the April 1995, and July 1995, respectively.

Conclusions and Summary

An engineering and geological study was conducted on the Savonburg Field with many conclusions and findings to date. Also a water cleanup process was selected to cleanup the low quality injection water in the field.

Air flotation was selected as the process to improve water quality. The air flotation unit was installed along with additional tanks and lines needed for proper installation. Steady-state operation was achieved. A flocculation chemical was selected to aid in the performance of the air flotation unit. Economics looked favorable.

Results from the engineering study included, 1) a volumetric study of selected patterns throughout the field, and 2) a waterflood and polymer flood simulation study of a five-spot with average properties of the Nelson Lease. The volumetric study provided waterflood efficiencies on a pattern basis to determine patterns of highest potential for additional recovery. The simulations indicated that a total recovery factor of 225 BBLS/Ac-ft could be achieved through continued operation of the waterflood and if a polymer flood was installed 335 BBLS/Ac-ft could be achieved. These recovery factors are larger than most of the recovery factors in the volumetric pattern study. This would indicate that many of the patterns have a high potential for incremental oil if the waterflood were optimized. If a polymer flood is installed incremental oil is estimated at 363,000 barrels.

BUDGET PERIOD 2 ACTIVITIES

Waterplant Development

The water supply for the Nelson Lease is a mixture of produced water from the Bartlesville formation and makeup water from the Arbuckle formation. The produced water contains barium and soluble iron, whereas, the make-up water contains sulfate and sulfide. The combination of the two waters causes barium sulfate and iron sulfide to precipitate from solution. Depending on the ratio of the two waters the resulting water is either black due to the iron sulfide or red due to the formation of insoluble iron oxide. Prior to the Department of Energy Project, these waters were mixed in a single tank. The produced water was filtered through a 75-micron bag filter. This water was pumped into the supply tank where the make-up water was added. The mixed water was black and contained iron sulfide, iron oxide, barium sulfate, and oil. This black water was then pumped to the injection wells. Barium sulfate scale and particulate matter collected in the flow lines and in the injection wells, creating continual injectivity problems and workover expense. Various scale inhibitors, detergents, and other chemicals were added at the produced water tank to reduce the scaling and plugging problems experienced.

The water supply system was redesigned. An air flotation unit was added to improve the quality of the injection water by removal of oil and suspended solids. Flotation was selected over sand filtration in order to demonstrate available technology not used by Kansas operators. The premise for selecting the flotation unit was that it would be easier to operate than a sand filtration system, and the chemical treatment costs per barrel of water would be less than the prior system used. A 1000 barrel per day unit was purchased from Separation Specialists, Inc. of Bakersfield, California in June of 1994. The flotation unit was designed for off-shore operations for the removal of oil to less than 30 ppm for water discharged to the ocean. The flotation unit was installed and began operation on July 13, 1994. A complete write-up on the water quality improvement by air flotation on the Savonburg project is included in **Appendix D.**

Permeability Modification Treatments

Phase I analysis indicated that numerous channels exist in the reservoir between injection and producing wells. Profile modification treatments were designed and implemented to plug the channels so water will be injected in oil bearing porous media. A variety of gel systems was considered

During 1997 two wells on the Nelson lease were subjected to permeability modification treatments. In September 1997 a channelblock treatment was performed on well No. H-14. A sixty-barrel batch of freshwater polymer solution was prepared with salts and thiosulfate added while agitating and hydrating the polymer. Sodium dichromate was added during the treatment at a concentration from 650-750 ppm. The injection treatment lasted slightly less than six hours.

Initial Pressure	450 PSI
Maximum Pressure	662 PSI
Final Pressure	620 PSI
Average Pressure	625 PSI
Polymer Injection Rate	3.64 BPH
Treatment Volume	60 Bbls.
pH of Solution	5.8-6.3
Viscosity	36.0-43.5 cp
Temperature	26.5-29.5° C
Polymer Alcoflood 935	137.5 lbs.
Sodium Dichromate	14.2 lbs.
Sodium Thiosulfate	10.5 lbs.
Sodium Chloride	100.0 lbs.
Calcium Chloride	65.0 lbs.

Offset producers were sampled throughout the treatment for evidence of polymer breakthrough. All tests were negative. The wellhead pressure increased well above prior levels when the well was placed on injection, indicating that the primary water channel was plugged. However, a tracer test conducted five weeks after the treatment indicated communication with H-15 in 23 hours and H-16 in 24.5 hours.

In October a 62 barrel channelblock treatment was performed on well RW-8 due to the injection entering only the B2 perforations. After setting a sand pack over the B3 zone the polymer solution was injected at 41 barrels per day and 540 psi. Sodium dichromate was added continuously at concentrations of 650-750 ppm.

Initial Pressure	420 psi
Final Pressure	500 psi
Average Pressure	500 psi
Polymer Injection Rate	3.68 bbl/hour
Treatment Volume	62 bbls
pH Solution	5.4-6.2
Viscosity	49.5-52 cp
Temperature	27.5° C
Polymer Alcoflood 935	137.5 lbs
Sodium Dichromate	14.2 lbs
Sodium Thiosulfate	10.5 lbs
Sodium Chloride	100.0 lbs
Calcium Chloride	65.0 lbs

A second channelblock treatment was performed six weeks later on November 19. The well was treated with two batches of polymer solution.

	FIRST BATCH	SECOND BATCH
Initial Pressure	335 psi	755 psi
Final Pressure	490 psi	590 psi
Average Pressure	480 psi	585 psi
Polymer Injection Rate	3.6 BPH	3.7 BPH

Treatment Volume	32.6 bbls	31.8 bbl
pH Solution	5.7	5.8-4.4
Viscosity	No measurements taken	
Temperature	51-43° F	11.8-9.3° C
Polymer Alcoflood 935	70 lbs	84 lbs
Sodium Dichromate	6.8 lbs	7.4 lbs
Sodium Thiosulfate	5.25 lbs	5.25 lbs
Sodium Chloride	50.0 lbs	50.0 lbs
Calcium Chloride	32.5 lbs	32.5 lbs
28% HCL Acid	None	2 quarts

Actual injected volume in batch two was reduced to 28.1 bbl.

A month later, on December 18, the well was washed to the plugged back total depth of 675'. An injection test of 3.68 BPH @ 550 psi indicated the treatment did not hold. Subsequently, about four weeks later, injection was again attempted and, although pressures were in excess of 700 psi, no water could be injected into the B2 zone. The well was then washed out and injection resumed in the B3 zone through tubing under a packer.

Pattern Changes and Wellbore Cleanups

Pattern Changes. Since the geological and engineering analysis conducted in Budget Period 1 indicated that the B3 zone had not been waterflooded completely and that unrecovered oil existed, pattern changes were implemented to increase the volume of water injected into the B3 zone. Since production wells H-14 and H-5 showed good continuity in the B3 zone, these two wells were converted into injectors in 1995. Well O-1, also recommended to be converted to injection in the Budget Period 1 analysis was converted to injection in late 1998.

Injection well KW-51 and producer H-9 were plugged in February 1998 as both wells were in serious communication with other wells on the lease. During late 1998 many of the comparatively poor quality wells were also plugged – Wells 2, 6, 7, K-32, K-33, K-34, K-35, K-36 and Cox 1, 5 and 502.

Wellbore Cleanups. 1997 was a period of relatively clean injection wells, but in 1998 a large number of wellbore cleanouts were required due to the inconsistency of injection water quality. Prior to the cleanouts, the injection volumes were much lower than normal, resulting in lower total fluid and oil producing rates. A series of mid-year 1998 wellbore cleanouts coupled with the development of excellent injection water resulted in an increase in injectivity to over 1000 BWPD.

Injectivity improvement was obtained by wellbore cleaning. Clean-up treatments have involved acid and a wide variety of additives. Techniques include hydraulic jetting, jetting with air and foam, placement with a coiled tubing unit, and simply lubricating in the treatments. The principal functions of the acid additive are to remove wellbore emulsion, sludge and deposits, prevent iron precipitation, prevent clay swelling, and the attendant migrations of clays and fines.

A typical treatment involves the following chemicals: 1) 50 gallons of 28% hydrochloric acid, 2) two gallons of an iron control additive (ESA-91), 3) one-half gallon of clay stabilizer (ESA-50), and 4) two gallons of micellar acidizing additive (ESA-96).

Reservoir Development

In 1996 an infill injection well was drilled to further develop the reservoir. **Figure 19** presents the location of the in-fill well. The core analysis showed a watered out B2 zone at an approximate depth of 646-661 ft. and appreciable mobile oil in the B3 zone at an approximate depth of 678-715 ft. This can be qualified with measuring the core water saturations and chloride content in the brine. **Table 13** presents the core analysis measurements and the B2 and B3 zones. Since the injected water is of much lower concentration chloride, any watered out zones will show lower concentrations of chloride in the brine from core analysis. **Figure 20** presents this phenomenon with footages (647-660) showing low concentrations of chlorides. **Figure 21** presents water saturation in the core verifying the watered out zone in the upper B2.

Figure 22 presents porosity measurements that are somewhat uniform averaging approximately at 18%. **Figure 23** presents the permeability to air measurements that identifies the permeable sandstones. This plot presents the separation of the B2 and B3 sandstone reservoirs. There is an eight-foot impermeable barrier between the zones. This is also presented in **Figure 24** presenting the effective permeability to water in millidarcys.

On March 13, 1996, the well was perforated from 678 to 688 ft. A 3 1/8" diameter hollow steel carrier casing jet gun was utilized. Waterflood injection was initiated on April 11, 1996.

The original proposal included evaluation of the possibility of installing a polymer flood in the Savonburg Field. Until the latest months of operations a consistently clean water supply was not available (a necessity in polymer flooding), plus, the producing water/oil ratio is becoming critically high.

FIGURE 21: LOCATION OF RW-20

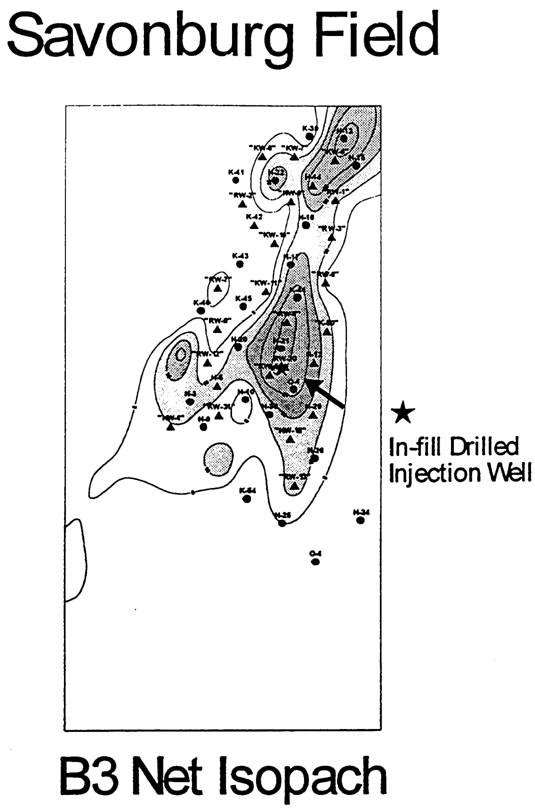


FIGURE 22: RW-20 CORE CHLORIDE CONTENT

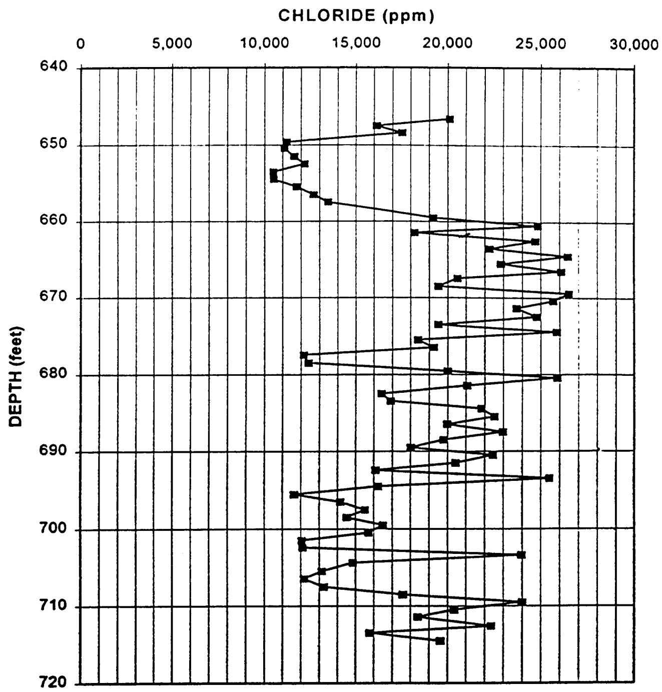


FIGURE 23: RW-20 CORE WATER SAT'N

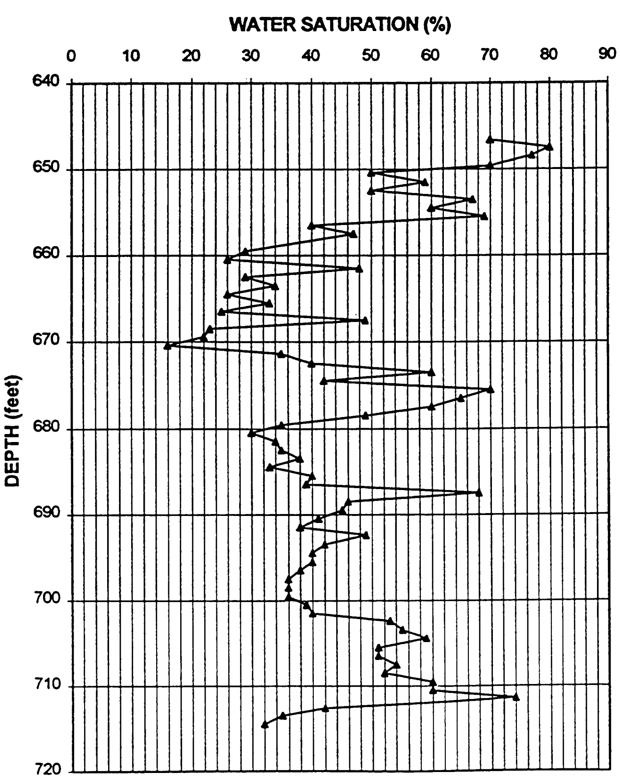


FIGURE 24: RW-20 POROSITY

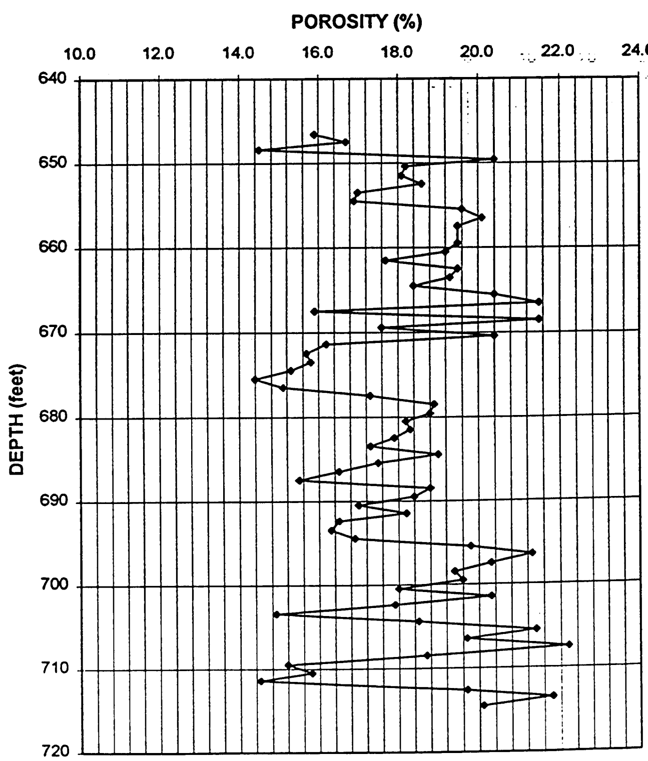


FIGURE 25: RW-20 PERMEABILITY (air)

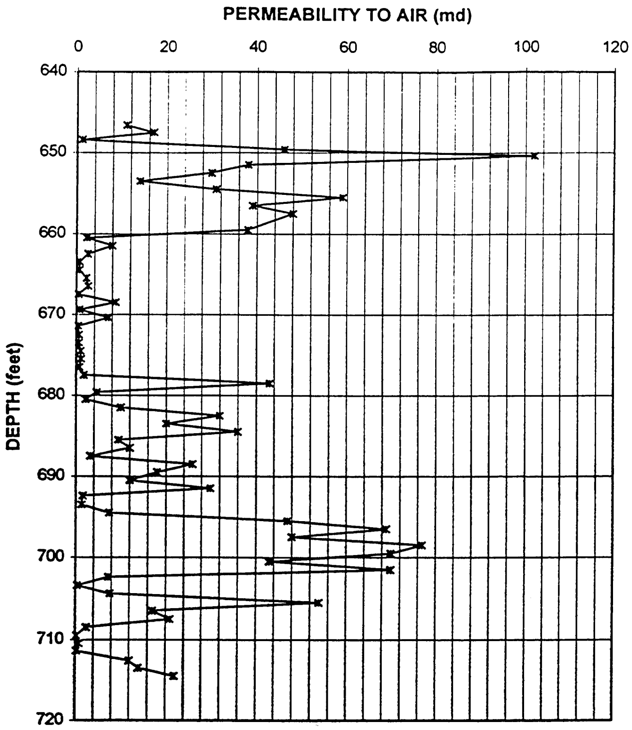


FIGURE 26: RW-20 PERMEABILITY (water)

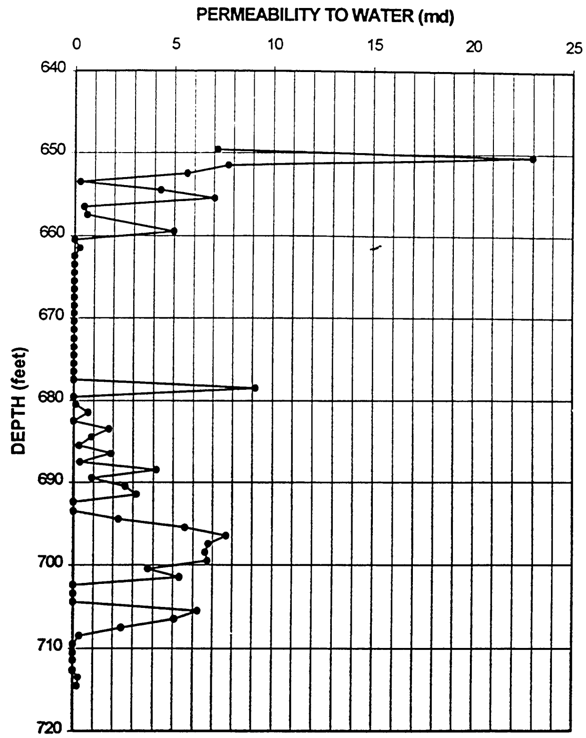


FIGURE 27: RW-20 RESIDUAL OIL SAT'N.

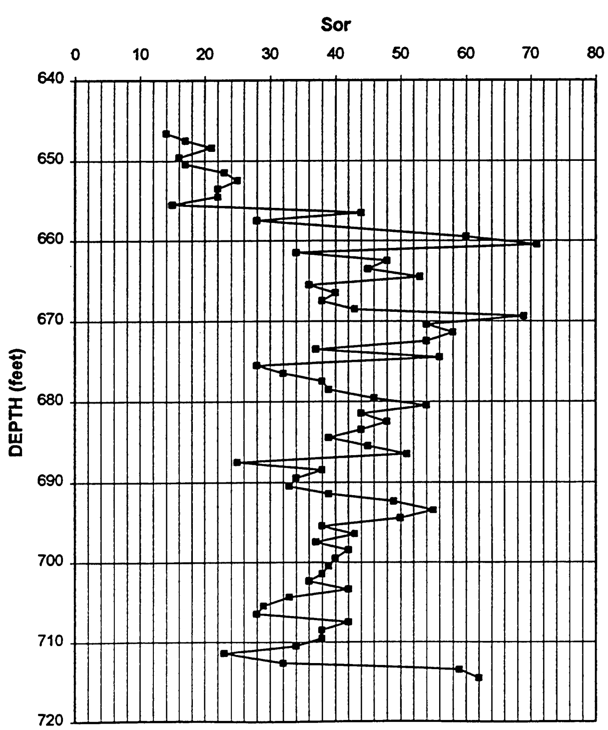


Table 13

RW-20 **BASIC CORE ANALYSIS DATA**

Sample #	Depth Feet	Eff. Porosity Percent	Percent Oil Saturation Oil	Water	Total	Perm. Mill
1	646.6	15.9	14	70	84	11
2	647.5	16.7	17	80	97	17
3	648.4	14.5	21	77	98	1.1
4	649.6	20.4	16	70	86	46
5	650.4	18.2	17	50	67	102
6	651.5	18.1	23	59	82	38
7	652.5	18.6	25	50	75	30
8	653.5	17.0	22	67	89	14
9	654.5	16.9	22	60	82	31
10	655.5	19.6	15	69	84	59
11	656.5	20.1	44	40	84	39
12	657.5	19.5	28	47	75	48
13	659.5	19.5	60	29	89	38
14	660.5	19.2	71	26	97	2.2
15	661.5	17.7	34	48	82	8
16	662.5	19.5	48	29	77	2.5
17	663.5	19.3	45	34	79	0.72
18	664.5	18.4	53	26	79	0.66
19	665.5	20.4	36	33	69	2.2
20	666.5	21.5	40	25	65	2.6
21	667.5	15.9	38	49	87	0.47
22	668.5	21.5	43	23	66	8.8
23	669.4	17.6	69	22	91	0.71
24	670.4	20.4	54	16	70	7.2
25	671.4	16.2	58	35	93	0.43
26	672.5	15.7	54	40	94	0.63
27	673.5	15.8	37	60	97	0.6
28	674.5	15.3	56	42	98	1
29	675.5	14.4	28	70	98	1.1
30	676.5	15.1	32	65	97	0.79
31	677.5	17.3	38	60	98	1.7
32	678.5	18.9	39	49	88	43
33	679.6	18.8	46	35	81	4.6
34	680.5	18.2	54	30	84	2.1
35	681.5	18.3	44	34	78	10
36	682.5	17.9	48	35	83	32
37	683.5	17.3	44	38	82	20
38	684.5	19.0	39	33	72	36
39	685.5	17.5	45	40	85	9.5
40	686.5	16.5	51	39	90	12
41	687.5	15.5	25	68	93	3.2
42	688.5	18.8	38	46	84	26
43	689.5	18.4	34	45	79	18
44	690.5	17.0	33	41	74	12
45	691.5	18.2	39	38	77	30
46	692.4	16.5	49	49	98	1.5
47	693.5	16.3	55	42	97	1.3
48	694.5	16.9	50	40	90	7.5
49	695.5	19.8	38	40	78	47
50	696.5	21.3	43	38	81	69
51	697.5	20.3	37	36	73	48
52	698.5	19.4	42	36	78	77
53	699.5	19.6	40	36	76	70
54	700.5	18.0	39	39	78	43
55	701.5	20.3	38	40	78	70
56	702.4	17.9	36	53	89	7.3
57	703.4	14.9	42	55	97	0.35
58	704.4	18.5	33	59	92	7.7
59	705.5	21.4	29	51	80	54
60	706.5	19.7	28	51	79	17
61	707.5	22.2	42	54	96	21
62	708.5	18.7	38	52	90	2.4
63	709.5	15.2	38	60	98	0.28
64	710.5	15.8	34	60	94	0.81
65	711.4	14.5	23	74	97	0.23
66	712.6	19.7	32	42	74	12
67	713.5	21.8	59	35	94	14
68	714.5	20.1	62	32	94	22

Table 13

RW-20

BASIC CORE ANALYSIS DATA

Sample #	Depth Feet	Eff. Porosity Percent	Percent Oil Saturation Oil	Water	Total	Perm. Mill
1	646.6	15.9	14	70	84	11
2	647.5	16.7	17	80	97	17
3	648.4	14.5	21	77	98	1.1
4	649.6	20.4	16	70	86	46
5	650.4	18.2	17	50	67	102
6	651.5	18.1	23	59	82	38
7	652.5	18.6	25	50	75	30
8	653.5	17.0	22	67	89	14
9	654.5	16.9	22	60	82	31
10	655.5	19.6	15	69	84	59
11	656.5	20.1	44	40	84	39
12	657.5	19.5	28	47	75	48
13	659.5	19.5	60	29	89	38
14	660.5	19.2	71	26	97	2.2
15	661.5	17.7	34	48	82	8
16	662.5	19.5	48	29	77	2.5
17	663.5	19.3	45	34	79	0.72
18	664.5	18.4	53	26	79	0.66
19	665.5	20.4	36	33	69	2.2
20	666.5	21.5	40	25	65	2.6
21	667.5	15.9	38	49	87	0.47
22	668.5	21.5	43	23	66	8.8
23	669.4	17.6	69	22	91	0.71
24	670.4	20.4	54	16	70	7.2
25	671.4	16.2	58	35	93	0.43
26	672.5	15.7	54	40	94	0.63
27	673.5	15.8	37	60	97	0.6
28	674.5	15.3	56	42	98	1
29	675.5	14.4	28	70	98	1.1
30	676.5	15.1	32	65	97	0.79
31	677.5	17.3	38	60	98	1.7
32	678.5	18.9	39	49	88	43
33	679.6	18.8	46	35	81	4.6
34	680.5	18.2	54	30	84	2.1
35	681.5	18.3	44	34	78	10
36	682.5	17.9	48	35	83	32
37	683.5	17.3	44	38	82	20
38	684.5	19.0	39	33	72	36
39	685.5	17.5	45	40	85	9.5
40	686.5	16.5	51	39	90	12
41	687.5	15.5	25	68	93	3.2
42	688.5	18.8	38	46	84	26
43	689.5	18.4	34	45	79	18
44	690.5	17.0	33	41	74	12
45	691.5	18.2	39	38	77	30
46	692.4	16.5	49	49	98	1.5
47	693.5	16.3	55	42	97	1.3
48	694.5	16.9	50	40	90	7.5
49	695.5	19.8	38	40	78	47
50	696.5	21.3	43	38	81	69
51	697.5	20.3	37	36	73	48
52	698.5	19.4	42	36	78	77
53	699.5	19.6	40	36	76	70
54	700.5	18.0	39	39	78	43
55	701.5	20.3	38	40	78	70
56	702.4	17.9	36	53	89	7.3
57	703.4	14.9	42	55	97	0.35
58	704.4	18.5	33	59	92	7.7
59	705.5	21.4	29	51	80	54
60	706.5	19.7	28	51	79	17
61	707.5	22.2	42	54	96	21
62	708.5	18.7	38	52	90	2.4
63	709.5	15.2	38	60	98	0.28
64	710.5	15.8	34	60	94	0.81
65	711.4	14.5	23	74	97	0.23
66	712.6	19.7	32	42	74	12
67	713.5	21.8	59	35	94	14
68	714.5	20.1	62	32	94	22

Table 13

RW-20 CORE FLOODPOT DATA

Sample #	Residual Sat. % Oil	% Water	Bbls./A.Ft.	Vol of Water Rec. cc.	Effective Perm. Millidarcys	I.F.P. #/Sq.	Chloride Content of Brine, ppm
1	14	82	178	124	0.94	25	20,094
2	18	80	236	216	1.5	15	16,131
3	21	77	235	0	imp	-	17,526
4	16	80	248	440	7.2	5	11,196
5	17	78	245	288	22.99	5	11,093
6	23	73	318	528	7.73	5	11,616
7	25	73	367	516	5.66	15	12,181
8	22	76	295	26	0.27	35	10,487
9	23	74	302	550	4.33	15	10,492
10	15	81	225	464	7.06	10	11,742
11	44	52	686	30	0.48	40	12,674
12	28	69	417	40	0.63	40	13,466
13	60	38	908	608	5	25	19,204
14	71	26	1041	0	0	-	24,838
15	34	63	456	30	0.28	40	18,180
16	48	29	722	0	0	-	24,695
17	44	35	649	0	0	-	22,248
18	53	26	757	0	0	-	26,433
19	36	34	564	0	0	-	22,862
20	39	27	647	0	0	-	26,079
21	38	49	469	0	0	-	20,525
22	43	24	717	0	0	-	19,484
23	68	24	918	0	0	-	26,477
24	54	17	846	0	0	-	25,643
25	58	35	729	0	0	-	23,696
26	54	40	649	0	0	-	24,774
27	38	60	469	0	0	-	19,477
28	56	42	665	0	0	-	25,835
29	29	68	315	0	0	-	18,371
30	32	65	375	0	0	-	19,235
31	38	60	498	0	0	-	12,137
32	29	69	432	282	9.16	10	12,418
33	46	35	657	0	0	-	19,997
34	54	44	750	8	0.11	50	25,883
35	40	56	562	52	0.72	40	21,045
36	48	35	655	0	0	-	16,414
37	40	58	549	134	1.78	40	16,906
38	39	57	584	64	0.89	40	21,799
39	45	53	604	20	0.28	45	22,501
40	42	56	548	170	1.89	35	19,984
41	25	71	301	18	0.33	50	22,961
42	36	60	536	342	4.16	20	19,792
43	32	65	456	82	0.94	35	17,997
44	29	69	391	288	2.61	20	22,429
45	33	65	469	282	3.16	30	20,432
46	49	49	627	0	0	-	16,083
47	55	42	687	0	0	-	25,464
48	37	61	494	212	2.28	35	16,214
49	36	62	553	442	5.61	25	11,632
50	32	66	523	212	7.7	20	14,169
51	34	65	543	298	6.79	25	15,497
52	37	60	566	382	6.65	25	14,510
53	37	61	572	480	6.77	20	16,493
54	37	60	517	344	3.78	30	15,692
55	36	62	575	452	5.33	30	12,057
56	36	53	500	0	0	-	12,084
57	42	55	479	0	0	-	23,967
58	33	59	474	0	0	-	14,838
59	29	69	490	262	6.26	15	13,136
60	28	68	434	518	5.11	15	12,176
61	42	54	720	298	2.44	20	13,247
62	38	58	563	36	0.33	35	17,570
63	38	60	442	0	0	-	23,996
64	34	60	417	0	0	-	20,342
65	22	75	246	0	0	-	18,381
66	32	43	484	0	0	-	22,336
67	59	38	989	22	0.28	40	15,760
68	62	34	981	28	0.22	35	19,581

Field Operations
Field operations consisted of 1) monitoring and modifying the waterplant, 2) monitoring all wells and lines in field, and 3) testing each well at least on a monthly basis. Russell Petroleum supplied monthly reports, which consist of monthly activities and barrel test/meter reading on active wells.

Producing wells were tested and the data were posted to a computer and updated monthly. The data consisted of oil and water volumes produced, pumping unit stroke length, net effective stroke length, pumping speed (strokes per minute), and general comments. These data were utilized to estimate oil and water production for each well.

Russell Petroleum has been responsible for all field activities, 1) plant development, 2) wellbore cleanups, and 3) permeability modification treatments.

Technology Transfer
A mid-year 1997 test on Well No. RW-20 proved that successful pressure transient tests could be performed in shallow, slim-hole wellbores utilizing a computerized Echometer (fluid-level detector).

POST-PROJECT DEVELOPMENTS

Observations from the Field

During the eight months immediately following the end of the project, the operator's field personnel have experienced a noticeable decrease in the frequency of certain maintenance obligations which at one time were very time consuming.

In order to prepare for the polymer injection the operator implemented in the summer of 1999, all the injection wells were acidized, jetted and cleaned. In only two wells was any "fill-up" detected, and then only minor amounts. Most of the wells exhibited a very clean wellbore with little or no filtrate or particulate matter accumulated. It is the opinion of the field personnel that the ability of the air-flotation unit (AFU) to maintain the clean water for an appreciable period of time has resulted in the clean wellbores in the injection wells.

In previous years, each flow meter on the wells needed to be removed approximately once per month for maintenance and/or cleaning. For the first eight months of 1999 this maintenance requirement has become almost non-existent. In each occasion to work on a meter, the problem was not related to scale accumulation or corrosion, but the fact that the meters had worn out.

Prior to the clean water era, the 75-micron filters used in the field required changing an average of once each week. Now, using 10-micron filters, changes occur about once every sixty days. This level of filter maintenance has been prevalent for all of 1999.

Basically, the advent of consistently clean injection water has 1) increased injectivity, 2) reduced downtime, 3) lowered well servicing costs, 4) reduced meter maintenance, 5) reduced filter changes, 6) reduced chemical requirements, and 7) allowed personnel labor to be applied to other functions.

Experience is a good teacher and the Russell field personnel are good students. Much was learned utilizing the AFU, but improvements on future applications can be made. Future AFUs need not be built above ground, but can be set lower, if not level with the ground surface, and still perform its functions. The tank does not need to be but a few feet deep to accomplish its purpose, rather than ten foot tall as in the Savonburg setup. The building housing the AFU at Savonburg has suffered from serious corrosion to the exposed steel, wood and electrical components. Future designs should be built with more corrosion proof materials, better ventilation and placement of electrical boxes, etc. away from the corrosive elements.

For small operations where iron compounds are a problem, an AFU may not be justifiable, the air-injection system used to pretreat the water may be all that is needed. Field personnel noted significant water improvement by virtue of this application alone, possibly even a greater impact than that of the AFU.

CONCLUSIONS

Obviously, the initial estimates of waterflood recovery were too optimistic, evidently because mobile oil saturation estimates were too high. Despite the concentrated effort to sweep the B_3 reservoir, the operator was unable to mobilize significant quantities of oil – much less than originally anticipated. Occasional limited production surges or slight prolonged increases were witnessed at individual producing wells, however, field wide, the responses were only capable of stabilizing the producing rate and decreasing the rate of production decline. Only one well (H-17) experienced an appreciable, sustained increase in production. This well went from 2.5 BOPD to 8 BOPD then produced with a shallow decline for several years. In most cases, when an increase was detected, it was only an increase of 1-3 BOPD and lasted but a few months. Although simulations performed in Budget Period I indicated appreciable oil reserves would be produced by polymer augmented waterflooding, polymer applications were never utilized during the project period due to 1) inability, until late in the project, to process clean water, 2) performance of waterflood suggested lower residual oil saturation than originally thought - consequently, less reserve potential -, and 3) very high producing water/oil ratio (> 30:1).

Throughout the life of the project numerous wellbore cleanouts were necessary due to the inconsistency of injection water quality. Only in the most recent months has the water quality been consistently acceptable. The included Hall Plots of certain injection wells graphically indicate the response of well treatment. After performing a cleanout the plot usually returns to its historical slope, indicating the removal of damage and a return to the well's normal injectivity.

Operation of the air flotation unit was improved. Solids content of 10 mg/L appears to be attainable in the injected water during continuous operation with proper maintenance and supervision

Chemical costs for water treating were reduced to \$4.50/day or about 0.5 cents/barrel of water.

Permeability profile treatments on two wells were successful in deterring interwell communication and improving wellbore injection profiles within the scope of this project.

The operator concludes the property currently requires less maintenance and is operating more efficiently than in prior years, particularly pertaining to the water injection system. However, sufficient cost data histories are not available to quantify this conclusion.

Individual producing well and injection well performance curves are included in **Appendices B and C.**

Appendix A

APPENDIX A

Geological Description of the Savonburg Field

Correlation of the well logs provided the stratigraphic framework of the field and the basis for interpreting lithology in wells or parts of wells where no core description was available. Stratigraphic markers, either regional or local, were traced through the field area to provide detailed correlation on a scale of 10 to 40 feet. Some of the markers, which are designated "marker intervals" can be tied into the regional stratigraphic correlation previously developed by Harris (1984) and applied by Staton (1987) and Huffman (1991). Where such correlations could be made, the marker intervals were referred to by the name of the associated coals, either those that have been formally recognized (Weir-Pittsburg, Tebo, Scammon, etc.) or those that Harris (1984) informally named (Fig. D-2). A few markers, especially those that are only of local significance, are still designated by the color of the press-on dots that were used to identify them on logs during the phase of the study when the internal stratigraphy of the field was being worked out (red, brown, dark blue, silver, etc.). Others, below the silver marker, were referred to by the letters A, B, C, and D because no additional colors were available to differentiate them. Traces of this usage remain in this report. Names of sandstones are based upon Jewett et al. (1968), as modified by Hulse (1978), Ebanks (1979), Staton, and Huffman.

Nomenclature of Mudrocks

The geological study uses *shale* in an informal sense that is common both in the oil industry and among professional geologists. Usage here does not differentiate between fissile or laminated rocks, which are strictly called clay- or mud shales, and non-fissile, non-laminated rocks which are given the suffix -stone. Clay and mud differ in particle size. Claystones and clay shales consist dominantly of clay (particles less than 4mm), whereas mudstones and mud shales consist of sub equal mixtures of clay particles and silt particles (4 to 62mm).

Contouring

Isopach maps of good quality reservoir sandstone, especially that in the B_3 and B_2 zone, were contoured to represent the geological interpretation of them as the result of deposition in a tidal estuary. These maps are presented in Figure D-6 and D-7, respectively.

Regional Geology

The valley-fill deposit that is productive on the Nelson Lease is in the Chelsea Sandstone member of the Cabaniss Formation (Jewett, et al., 1968), the lower part of the Skinner interval (younger than the Tebo Coal and older than the Scammon Coal; Staton, 1987), or the informal Cattlemans interval (Hulse, 1978). Rocks of the Cabaniss Formation are assigned to the Desmoinesian stage of the Middle Pennsylvanian Series. The Nelson Lease includes the SW/4 of Section 21, and the NW/4 of Section 28, Township 26 South, Range 21 East (Fig. D-1, D-2) and lies on the SW flank of the Bourbon Arch, a subtle structure that separates the Cherokee basin to the south from the Forest City basin to the north.

Both of these shallow basins lie in the marginal part of the craton of North America, on the shelf north of the Arkoma Basin, a foreland basin that, in turn, lies north of the Ouachita Tectonic Belt. The Ouachita belt was most active in the early and middle Pennsylvanian, with orogeny climaxing in Desmoinesian time, simultaneous with deposition of the Cherokee Group. Deposition in the Arkoma basin began in early Middle Pennsylvanian time (Atokan). Despite intense contemporary tectonic activity a few hundred kilometers to the south, sediments for the Cherokee Group appear to have come from sources that lay to the north and east.

The Cabaniss Formation consists mostly of shale, but includes beds of sandstone, coal, and limestone. In the area of the Nelson Lease, only the sandstones reach large thickness, with single sandstone lenses making up to 10 to 25 percent of the entire thickness of the Cabaniss Formation in many wells. Shale intervals are broken up by marker intervals, which are described below, into sequences 10 to 40 feet thick.

Previous descriptions

Operators of this field have divided the reservoir into informal A, B and C sandstone intervals (named from top to bottom). These intervals were defined primarily upon their depth, and the boundaries were drawn between them on the basis of shale interbeds that were approximately at the same elevation in adjacent wells. The A sand was not present in all parts of the field and was not productive of where it was found. The B sandstone was traced throughout the field and is perforated in most, if not all, productive wells. The C sandstone, as defined by the operators, is best developed in the eastern part of the northern 1/4 section lease, but was correlated over the entire field area. The operator's C sand is the major productive sands in the most productive wells, and intervals that appeared to have C sand in them were perforated in many wells throughout the field.

Results of restudy of the field

The analysis presented below has used the same designations for the intervals containing sandstone in the reservoir (A, B, and C), but has defined them according to their age with respect to regional stratigraphic marker intervals, described below, which are more continuous than the shale breaks used by the earlier analysis. The C sandstone, as used in this study, is older than the Tebo marker interval and younger than the Weir-Pittsburg marker interval, although it locally is deposited in a valley that was eroded through the Weir-Pittsburg marker interval. The B interval post-dates the Tebo marker interval and predates the Scammon marker interval, but includes a valley-filling succession that is lower in elevation than the projected position of older markers down as far as the Abj coal (Harris, 1984). The most productive sandstones in the field, which were designated C by the operators, have been reassigned to the B interval, based upon their situation as part of the fill of that valley. The B interval has been subdivided into B_3, B_2, and B_1 zones (listed from bottom to top) to differentiate sandstones that formed during different parts of the history of valley filling. All of the oil production in the field comes from beds designated as part of the B_2 and B_3 zones, according to revised correlations. Sandstones of the A interval are younger than the Scammon marker interval and older than the Mineral marker interval. Locally A sandstone beds are deposited in a shallow valley that cuts through the Scammon marker interval.

Regional marker intervals of the Cherokee Group

Regional marker intervals are characteristic of the Cherokee Group and other dominantly siliciclastic Pennsylvanian strata of eastern Kansas. Where these marker intervals are completely developed, they include, in ascending order, an underclay or paleosol, a coal bed, an argillaceous limestone or shelly sandstone, and a dark gray to black shale (Fig. D-3). Commonly small concretions of siderite, called "birdshot siderite" are found in the strata just below the underclay. The strata containing siderite may be very light gray claystone or siltstone that has a bleached appearance and is tightly cemented.

Marker intervals can be correlated for distances of hundreds of kilometers, and from basin to basin on the shelf of the US interior. Some of those in the Cherokee can be correlated into Iowa and, across the Mississippi River Arch, into the Illinois Basin (Brenner, 1989; Coveney et al., 1987). Regional marker intervals may also correlate with markers that divide the Atokan and Desmoinesian succession in southwestern Kansas (Youle, 1993). Marker intervals have been successfully used to subdivide the Cherokee Group of Kansas, especially the Cabaniss Formation, and traced over southeastern and south-central Kansas (Killen, 1986; Staton 1987; Huffman, 1991) and into the Kansas City area. They are generally the stratigraphically equivalent to the coal beds used by Hulse (1978), Ebanks (1979), and Harris (1984), but are easier to correlate because they consist of a suite of lithologies, not all of which need to be present to establish the position of the marker interval. In characterizing reservoirs, as well as in other geological activities in the Cherokee section, these markers make possible a detailed stratigraphy and fine subdivision of the section into temporally distinct units (Fig. D-2, D-4). Marker intervals are 10 to 40 feet apart, for the most part, they are thus the most precise basis for correlation of Cherokee successions.

Marker intervals are remarkably recognizable in gamma ray-neutron logs. The underclay commonly washes out, which can be reflected in the caliper log. Underclays may also be depleted of potassium, compared to other shales, and resemble shaley sandstone on the gamma ray log, while the neutron log shows a "high porosity" response (leftward deviation) to bound water in the clay. Underclays are almost invariably present beneath Pennsylvanian coals in Kansas, and commonly beneath dark shales where no coal is present. A gamma ray low and a neutron deflection toward the right (low apparent porosity) is common just below the underclay. This corresponds to the tightly cemented, apparently bleached shales or siltstones that contain birdshot siderite.

Coal beds by themselves have leftward neutron responses to the left because they contain abundant water and hydrogen. Coal has low gamma ray intensities, but the gamma ray response is commonly masked by overlying highly radioactive dark gray or black shales, which are actually more common and continuous than the coals.

Argillaceous limestone and sandstone beds are not common in the Savonburg NE Field area, and are generally very thin, so that their log response is masked. They are common in other parts of the Cherokee elsewhere in SE Kansas. Harris (1984) reports that about 50% of coal occurrences have overlying limestones in the Krebs Formation (lower Cherokee Group) in cores and in natural and artificial outcrops in Cherokee, Crawford, and Bourbon counties.

Dark shales, either dark gray or black and either massive or fissile, are the fourth member of the complete marker interval. They contain a concentration of uranium and organic matter, which makes their response strong on both the gamma ray and neutron sides, although the gamma ray response is the most marked. Dark shales of one type or the other are almost invariably present above thin limestones or sandstones, above coal where the limestones are not present, or above underclay, where both coal and thin limestones and sandstones are missing. In the Nelson lease, such shales were the most recognizable unit of marker intervals.

Sequence Stratigraphy

The paleosols and underclays of the marker successions represent subaerial exposure of the succession during periods of low relative sea level. Thus they meet the definition of boundaries of stratigraphic *sequences* (Van Wagoner et al., 1990). The overlying part of the marker successions (coal, limestone or sandstone, if present, and dark gray or black shale; Fig. D-3) are probably the result of deposition during a rise in relative sea level with accompanying landward shift of adjacent depositional environments. The successive environments would be subaerial coal swamp, erosional region (associated with passage of the shoreline and shoreface across the area, which may leave residual deposits), and deposition in a shelf environment in a stratified water column, respectively. Between the coal (or underclay if no coal is present) and the next overlying bed is a surface of initial transgression, marking the passage from non-marine to marine deposition. The dark gray shale or a gradationally overlying medium gray shale would represent the surface of maximum transgression for each sequence.

Strata in the interval between marker successions reflect filling of available accommodation space (space beneath local base level that is not already filled with sediment) during conditions of rising, steady, or falling sea level. All of the sediment above a particular marker interval is younger than all of the sediment beneath that marker interval, e.g. all of the sediments between the Tebo and Scammon marker intervals are older than all beds between the Scammon and Mineral markers, so that temporal ordering of inter marker intervals is unequivocal.

In the valley region in the eastern part of the NW/4 of Section 21, T26S R21E (filled by Chelsea Sandstone; Fig. D-2, D-4), and elsewhere wherever erosion has removed the sequence boundary, the boundary lies at the base of the erosive cut, commonly just below a sandstone or a conglomerate. The depth of incision of the Chelsea valley is sufficient to indicate that sea level fell below a shelf edge during its incision (van Wagoner et al., 1990).

Marker intervals in the Nelson Lease

In the lower and middle Cabaniss of the Nelson Lease, six regional marker intervals are present, correlated (from top to bottom) to "V" Shale -Croweburg Coal, the Mineral Coal, the Scammon Coal, the Tebo Coal, Weir-Pittsburg Coal, and the Bluejacket "A" coal (Fig. D-2, D-4). In addition, several characteristic kicks of the gamma-neutron logs carry across the field, or parts of it, and are useful as additional stratigraphic markers (Fig. D-4). The following section of the report describes the individual marker intervals present close to the reservoir sandstones in the Savonburg Field and correlates them into a regional framework developed by Harris (1984). The correlation is based upon a study of the Cherokee Group in the Bourbon Arch region by Huffman (1991). While this report uses a nomenclature for the marker intervals based upon existing correlations, it does point out a few places where correlations are questionable and possibly subject to revision. This section also describes other stratigraphic markers in the field, the stratigraphic position of sand bodies, including the reservoir sand body in the Chelsea Sandstone, and non-reservoir rocks between markers in the Nelson Lease.

Stratigraphic Succession in the Nelson Lease - Bluejacket A marker interval

The Bluejacket A marker interval consists of the Bluejacket A coal bed ("A" coal bed on logs used in this study) and overlying dark shale. The coal bed itself was penetrated in the core from well RW-8, where it was 0.8' thick. The presence of this coal bed is inferred from a spike of low gamma ray intensity and high neutron porosity occurs in all other wells that penetrate deeply enough . The designation of the Bluejacket A coal bed was introduced informally by Harris (1984) to distinguish one of several previously unrecognized coal beds between the Weir-Pittsburg and Dry Wood coals. Staton (1987) and Huffman (1991) did not find the Bluejacket A coal easy to correlate across the Cherokee basin and Bourbon arch areas.

The coal of the Bluejacket A marker is underlain by a poorly developed underclay that is the lowest 3.1' of core RW-8. The underclay grades from laminated mudrock at the base, with vertical fractures filled with siderite and some slickensides, to mottled claystone with slickensides at the top. Above the Bluejacket A coal is less than 0.1' of very fine sandstone with pebbles of shale, siderite, and carbonaceous material, and medium gray streaked, burrowed shale that forms a small gamma peak. This shale bed was penetrated by the core of well O-1 (Fig D-5C), where it consisted of 3' of dark gray laminated shale. This dark gray shale is overlain directly by the silver marker.

Silver marker

The silver marker is a distinct kick to the right on the neutron log and moderate kick toward lower gamma ray values, compared to shales above and below. The top of this marker is 6 feet above the top of the Bluejacket A coal. The silver marker is present in the core RW-15, and its lower part is present in core O-1 (Fig. D-5C),. In RW-15, it consists of 3.7' of near white, light gray and dark gray mudstone that is firmly cemented. Siderite concretions of mm-scale ("birdshot siderite") are common in it. It was originally wavy bedded or laminated, but has since been disturbed by the action of organisms. Its boundaries with dark gray clay beneath (part of the Bluejacket A marker interval) and medium gray claystone above are sharp.

In core RW-12, light gray shales of the silver marker are overlain by just over 1' of siltstone and very fine sandstone with disturbed bedding. This bed grades into 1.1' of poorly stratified, dark gray silty shale. In RW-15, the silver marker is again overlain by light to medium gray shale, here 0.5' of laminated clayey mudstone below and 0.8' of blocky, slickensided clay above. The upper contact of the slickensided clay is gradational with laminated olive medium gray claystone that becomes light gray at the top.

The succession from the silver marker to the dark gray or olive clay above it appears to be a marker interval that lacks a coal at this locality. It differs from the normal marker interval in that its dark gray clay overlies the underclay or paleosol component gradationally, rather than sharply. Correlation of this horizon, referred to below as the Silver marker interval, is problematical and is discussed further below.

Silver marker to light blue marker

Dark clays at the top of the silver marker interval grade into a succession characterized by decreasing gamma ray intensity and rightward-shifting neutron values upwards, followed by sharper shifts of the gamma ray and neutron curves toward values characteristic of shales. The succession is about 14' thick. In part this sequence reflects a coarsening- then fining-upward succession of dark gray to light gray, weakly laminated shale, light gray streaked and linsen-bedded shale, and light gray linsen- to wavy-bedded silty shale. The shaley part of the succession may contain a few fossils of fragmented plants, especially 1/4 of the way up.

Some of the log deflections may be related to tight cementation and presence of siderite, like those of the silver marker. Several parts of the upper 6.5' of this interval have beds with moderate to high concentrations of birdshot siderite. In such beds, disruption of bedding by root marks or brecciation is common, especially in the upper part of the bed, where it grades into the underclay beneath the overlying Weir-Pittsburg marker. Maximum deflection of gamma ray and neutron curves corresponds to a light gray or light olive gray, cemented layer with red, birdshot siderite concretions in cores O-2, RW-7, RW-9 (Fig. D-5B), RW-10, RW-12, RW-15, and RW-16. The peak of this apparently upward coarsening upward succession lies about 16 feet above the top of the silver marker and was correlated as the dark blue marker. The topmost part of this sequence decreases in grain size to shale and changes from linsen-bedded to streaked with thin laminae of silt. It has higher gamma ray values and deflection to the left of the neutron curves.

Weir-Pittsburg marker interval

The Weir Pittsburg marker appears in logs as a prominent gamma-ray peak and the immediately underlying peak of a neutron deflectionto the left; both have a sharp deflection below and a gradational one above, unless the overlying succession has been removed by erosion and the marker is overlain by a valley-filling succession. This marker is partially or completely present in cores from wells O-3, RW-3, RW-6, RW-7, RW-9 (Fig. D-5B), RW-10, RW-12, and RW-16. This marker is very persistent, Harris (1984), Staton (1987) and Huffman (1991) were able to trace it across southeastern Kansas. It is absent in part of the Nelson Lease where it is apparently truncated by erosion before deposition of the B or C sandstones. The Weir-Pittsburg marker generally lies a few feet above the dark blue marker and is 21 feet above the silver marker.

Generally, the Weir-Pittsburg marker consists of an underclay overlain by a dark gray shale. Coal, limestone, and sandstone are not present in any of the cores from this field, but bleached, sideritic, cemented light gray shale and siltstone is present in the dark blue marker beneath. The correlation with the Weir-Pittsburg Coal is based upon the work of Huffman (1991). Reasons why this correlation is only tentative are discussed below.

The underclay of the Weir-Pittsburg marker interval grades from the light gray, cemented, sideritic mudrocks of the underlying dark blue marker. No bedding is preserved in the underclay, but it is friable and breaks into chunks that are slickensided and show root marks. The clay has a waxy appearance. Fractures are filled with brecciated fragments of the bed itself. This bed is 3.3' thick where completely preserved in core RW-7. The dark gray to black shale (actually claystone) bed in the Weir-Pittsburg marker is 0.75' to 2' thick and is laminated. It includes some phosphatic concretions and, at least in one well, a bed of fossil shells and shell fragments. Dark gray to black shale grades into overlying beds of medium gray or olive medium gray shale of the Weir-Pittsburg--Tebo interval.

Weir-Pittsburg--Tebo interval and C Sandstone

Dark gray, fissile, phosphatic shales of the Weir-Pittsburg marker interval grade into medium gray shales then into an upwards-coarsening mudrock sequence that has birdshot siderite and disturbed bedding as widespread features. This sequence is remarkably like the silver and dark blue markers and like the development between the Tebo marker interval and the brown marker outside the channel area, as described below. It is present in cores O-3, RW-6, RW-7, RW-10, RW-11, RW-16, and RW-17. Core descriptions from Oil Field Research commonly describe the top of this succession as "light gray sandstone". The total CU succession is about 6 feet thick. The shale bed is about two feet thick and is generally of an olive medium gray color. It is laminated and fissile. The coarser beds are shale and siltstone, apparently structureless, well indurated, and of light gray or perhaps olive light gray to very light gray color. They have disturbed bedding, root marks, and birdshot siderite in their upper part. Calcite cements may also be present. The top of this siltstone interval grades into the underclay at the base of the Tebo interval.

In the southeast corner of the southwest corner of section 21, T26S R21E, the interval between the base of the Tebo marker and the top of the Weir-Pittsburg marker includes a sandstone bed up to 11 feet thick. It has an erosional base and cuts through the Weir-Pittsburg marker interval into the dark blue marker below. According to the usage in this report, this sandstone is the C sandstone. The C sandstone has a upward-fining log pattern on the gamma ray-neutron log. This sandstone was encountered in only a few wells and no cores are available. Some sandstone assigned to the Chelsea valley fill that postdates the Tebo marker interval might actually be older than the Tebo marker interval and actually part of the C sandstone. Only where the Tebo marker is present is it possible to differentiate the B and C sandstones unequivocally. Sandstone in deep part of the valley fill (wells H-27, H-30, KW-51, H-21, RW-8, K-44, H-16, KW-6, H-13) was mapped as part of the B_3 zone, rather than being incorporated into the laterally adjacent C sandstone because the trend of the valley, as defined by the truncations of markers was at right angles to that apparent trend of the C-sandstone.

Tebo Marker Interval

In cores RW-16 and RW-17, the Tebo marker interval is a coal bed about six inches thick that overlies a poorly developed underclay. This marker was also encountered in cores RW-4, RW-5, and RW-11. In all of these cores, the coal was overlain by sandstone or conglomerate, rather than black shale. Despite the lack of a dark shale in those wells, the Tebo marker interval is marked on their logs by a distinct kicks, with the neutron peak just above the gamma ray peak. In wells on the east bank of the Chelsea erosional valley, the Tebo appears to be overlain by a black shale that grades up into a upward-coarsening succession, because logs of those wells display a sharper gamma ray peak than the Tebo marker interval does in other wells on the Nelson lease.

The underclay is at least 1.3' thick in the cores of the Tebo marker interval, and is a mottled, medium to very light gray, very friable claystone that gradationally overlies the sideritic upward-coarsening succession described above. The coal is less than one foot thick. In one well, the coal is split by layer of sandstone 0.3' thick, in another, by a shale bed. In the core from RW-16, the Tebo coal is overlain by a thin (0.4") limy sandstone interval with rip ups and other intraclasts that passes up into medium gray laminated mudstone. The mudstone passes, over a thickness of a foot, to medium gray siltstone and then into wavy-bedded mudrock or very fine sandstone. The log from this well shows a stronger gamma ray peak than other occurrences of the Tebo marker interval.

Bluejacket A Coal through Tebo Marker Interval

Correlation. The Weir-Pittsburg and Tebo marker intervals, as defined above, correlate exactly to markers Huffman (1991) identified in the Yemon #54 Dotson well in the NW SW of Section 26, T26S R21E, about 2 miles east of the Nelson Lease in the Savonburg NE Oil Field. Huffman (1991) and Staton (1987) had correlated their nets of wells back to the Pittsburg and Midway #20 core (SE NE NE Section 8, T32S R22E in Cherokee County, Kansas), which includes all of the Cherokee except the few feet above the Breezy Hill Limestone (Fig. D-2). Harris (1984) described this core and identified several key beds in it. Because Huffman's and Staton's correlations appear consistent and are already available, they are used in this report.

However, it is suspected that the correlation is incorrect with regard to the Tebo and Weir-Pittsburg coals. The marker called Weir-Pittsburg in this study normally has a phosphatic dark gray to black shale, similar to the shale assigned to the Tebo marker interval elsewhere, but no coal, whereas the Weir-Pittsburg is dependably a mineable coal with no black shale just 30 miles to the east, near the outcrop in Crawford County. It is suspected that the marker called "Weir-Pittsburg" in this study is actually includes the horizon of the Tebo Coal Bed.

If this is true, the identity of the marker called Tebo (i.e. the green marker) in this study then becomes a problem. However, Harris (oral comm., 1983) found that the Tebo coal is commonly split into two beds. For an example of this, see Harris's (1984, p. A-45) description of the P&M #21 core. It is possible that both markers (Weir-Pittsburg and Tebo, as referred to in this study) should be correlated with the Tebo. Unfortunately, where the Tebo is split into two beds elsewhere, the beds are generally not separated by as much section, 13 feet, as they are here.

Making the light blue marker part of the Tebo requires that another bed be the Weir-Pittsburg. It is possible that the silver marker is actually the Weir-Pittsburg horizon, with a well-developed paleosol and underclay, but no coal and little black shale. Final judgment on exact identity of beds awaits re-evaluation of Huffman's (1991) and Staton's (1987) correlations with the P&M 20 core. For the meantime, I have used their nomenclature.

Spacing between the Marker Intervals

Generally the spacing between the markers, especially the upper markers in the succession, vary from well to well. That is not true of the spacing between the Tebo marker interval, the Weir-Pittsburg marker interval, and silver marker and the Bluejacket A coal bed. Wherever the Bluejacket A coal bed and the silver markers are both present in a well, it is six feet from the top of the A bed to the top of the silver marker. The Weir-Pittsburg marker (defined as the cross-over from high neutron values (leftward deflection) to high gamma values) lies 21 feet above the top of the silver marker. Thirteen feet separates the Weir-Pittsburg marker from the Tebo marker, again defined as the crossover from high neutron to high gamma values. These distances serve as very reliable guides in reconstructing the depth of erosion of the valley now filled by the B_2 and B_3 sands and to projecting the depth of an underlying marker not penetrated by the drill.

The Reservoir Interval, the B_2 B_3 Interval

The reservoir interval is younger than the Tebo marker interval and older than the brown marker. It appears to be part of the fill of a valley cut through the Tebo and Weir-Pittsburg marker intervals, the dark blue marker, and, in places, the silver marker into the top of the Bluejacket A coal bed (Fig. D-2, D-4). Lithology of the valley-filling succession is complex. It consists of three basic lithologies: sandstones; interbedded sandstones, siltstones, and shales; and shales. It can be divided into two separate units, referred to here as the B_2 and B_3 zones. Stratigraphy and lithology of the reservoir interval are described below.

At places along the eastern side of the Nelson lease, the wall of the valley is preserved. Beds that predate cutting of the valley, but post -date the Tebo marker interval, are encountered in wells K-34, K-35, K-36, and K-37 (Fig. D-2, D-4). The succession in these wells has a log character like that of the coarsening upward successions between the Silver and Weir-Pittsburg markers and the Weir-Pittsburg and Tebo markers. No cores penetrate these rocks, but they are believed to be similar to the other successions with the same log character. If so, they would consist of medium gray shale and streaked shale grading into medium to light gray shale and siltstone, with linsen-, wavy- and ripple bedding. Their log character suggests that they have the same kind of siderite cement as the upper parts of the similar successions. While these beds lie between the Tebo marker interval and the brown marker, it may be interpreted as being slightly older than the valley-filling succession that lies between the same markers and is the main reservoir interval in the field. The western edge of their distribution marks the eastern margin of the valley succession.

East - West cross sections were developed presenting the B_2 and B_3 zones and their continuity. These cross sections are presented in Appendix D.

Brown Marker

The brown marker overlies the reservoir interval. Of the markers recognized in this field, this is the most difficult to identify and trace. It was recognized as a distinct, but neither sharp nor very high, gamma ray maximum that occurs below the Scammon marker interval and above reservoir sandstones and interbedded sandstones, siltstones and shales of the B_2 and B_3 intervals. However, this marker is not identifiable on logs from all wells and is well developed in only a few. In many wells, the brown marker was placed at the top of a sequence of interbedded sandstones, siltstones, and shales, and below a sequence of shale several feet thick. The brown marker was identified in cores O-1 (Fig. D-5C), RW-6 and RW-7. In those cores, it consists an interval of gray shale, which may contain pyrite concretions or plant fragments and is distinctly darker than overlying or underlying shales, although not very dark gray or black. It lacked any hint of development of coal, underclay, limestone, dark gray to black shale, or siderite-cemented, upward-coarsening sequence, which are all parts of the regional marker intervals as described in this report, and it is not known to extend beyond the boundaries of this field. It does, however, extend into wells along the east side of the Nelson lease where the valley-fill succession is not present and the interval above the Tebo marker interval has upward-coarsening character. This provides precise age control on the valley fill.

Brown Marker to Scammon Marker Interval, the B_1 Zone

The interval between the brown and Scammon markers contains light gray to medium gray shale at most places with moderate to extensive development of birdshot siderite and an underclay beneath the Scammon Coal Bed. The interval is 5 to 20' thick and is especially well developed above the deepest part of the Chelsea valley in the eastern part of the SW/4 of section 21. In RW-6, shales in this interval are at least 9.9 feet thick and consist of an upward-coarsening succession of clayshale and mudshale, with intense mottling and slickensides at the top. Shales contain pyritized plant remains and birdshot siderite. Siderite commonly is associated with near-vertical features that may be rhizocretions or expansion-contraction cracks related to drying during exposure at the earth's surface and soil formation. In RW-8, 20 feet of shale are present above the top of interbedded sandstone, siltstone, and shale of the B_2 zone, including a well developed underclay that probably is part of the Scammon marker interval. All of this shale has been assigned to the B_1 zone. The remarkable feature of this zone in RW-8 is the vertical fracture lined with birdshot siderite that reaches 20 feet down from the pre-Scammon underclay.

There is little development of sandstone between the brown marker and the Scammon marker interval, except in the southwestern part of the field. In the northwest corner of section 28, T26S R21E, sandstone reaches a thickness of over 10' between these markers. No preserved cores contain this sandstone. It does not appear to be productive.

Scammon Marker Interval

The Scammon marker interval includes the Scammon coal, an underlying underclay and an overlying dark shale. Birdshot siderite is common in the shales beneath the underclay, but the underlying succession does not display the nicely defined decrease in natural gamma-radiation and rightward deflection of the neutron log. However, a sharp, but low, rightward neutron kick in logs of some wells between the coal and overlying dark gray shale probably indicates a limestone. Many of Harris's (1984) descriptions of cores from the upper Cherokee in Crawford and Cherokee counties, Kansas, show a limestone above the Scammon Coal.

The Scammon marker interval is present in cores O-1 (Fig. D-5C), RW-4, and RW-8. The Scammon Coal Bed is the among the thickest cored in the Nelson leases, reaching 1.5' in core RW-4. The Scammon marker interval is present in most wells, but has been partly to completely removed by erosion preceding deposition of the overlying "A" sandstone in one well, H-17, in the center of the E 1/2 of the SW 1/4 of section 21, and the coal has been removed in both RW-4 and RW-8, where underclay is overlain by sandstone. Dark shale of the Scammon marker interval is rather thin and not highly radioactive. It is commonly a foot or less thick.

The Overlying Section - Scammon-Mineral Interval

Between the Scammon marker interval and the overlying Mineral marker interval is a sequence of shale, with some sandstone. This interval was designated as the "A" sandstone by the operators of the field. It contains sand along the eastern margin and in the center of the field, both in the SW 1/4 of section 21. This sand shows a distinct upward-fining pattern where it is thick enough that the gamma ray curve can be interpreted to show a pattern. In this interval, core RW-8 encountered 3.7' of light olive tan, fine, structureless sandstone, with a few inches of very fine to fine sandstone at the base. No other cores sampled this interval. This sandstone fills a shallow valley eroded through the Scammon marker in well H-17, and sandstone overlies the sub-Scammon underclay in several wells in the valley region in the east or southeast center of the SW/4 of section 21, T26S, R21E.

Mineral Marker Interval

The Mineral marker interval includes the Mineral Coal and an overlying dark shale. In many wells the dark shale is not present, so the Mineral coal is marked by a kick to the left on both the neutron and gamma logs. In other wells, it has a thin dark shale immediately above it. The dark shale may have additional spikes of high gamma count, making a gamma kick up to about five feet thick. This marker lies 15 to 30 feet below the "V" shale marker and is present in nearly all wells in the Nelson Lease. In core RW-6, the Mineral marker interval included 2.3' of coal overlain by 2' of fissile, very dark gray claystone with streaks of silt in places and 0.5' of light gray, laminated shale.

Red marker

The red marker is a sharp neutron kick to the right and lower gamma kick about 10 to 20 feet below the "V"-shale marker. In some wells, the red marker appears to be similar to, but not as well developed as, the dark blue marker, which is an upward-coarsening succession with siderite cement in the upper part. In some wells, one or more sharp kicks on gamma-ray or neutron are present above and below the red marker. The red marker is a persistent, but is not attributable to any horizon previously identified regional marker, although Jewett et al. (1968) and Harris (1984) have identified the Flemming and Robinson Branch coals between the Mineral Coal and the "V" shale.

"V" Shale marker interval

The most persistent and easily identified marker in the upper Cherokee is the "V" shale marker, which includes the associated beds of the Croweburg Coal, with its underclay and a very persistent black shale. This succession is overlain by the Verdigris (or Ardmore) Limestone, which occupies the position of a regressive limestone in limestone-shale cyclothems of the later Desmoinesian, Missourian, or lower Virgillian. Brenner (1989) referred the interval between the Croweburg Coal and the top of the Verdigris (Ardmore) Limestone to the Verdigris Formation. This marker succession is easily correlated into Iowa, where the black shale is called the Oakley Shale and the coal is called the Whitebreast Coal (Brenner, 1989). Schlinsog and Angino (1983) called this dark shale the "V" shale in southeastern Kansas.

Extent of Marker Intervals in the Nelson Lease

The Tebo and Weir-Pittsburg marker intervals and the dark blue and silver markers do not extend all the way across the Nelson Lease (Fig. D-2, D-4). Because some of these markers are regional in their extent, their local absence must be explained. The absences of marker beds form a pattern in which the lowest one, the silver marker, has a small area from which it is absent and subsequent overlying markers have progressively greater areas of absence. The most consistent interpretation of this pattern is that an erosional valley that developed after deposition of the Tebo marker interval, and cut through to the level of the silver marker or below (in places).

As pointed out above, the brown marker extends on to the bank of the valley, as defined by the presence of the Tebo marker and an upward-coarsening succession above it, which implies that the cutting took place before deposition of the brown marker. Sand and mud filled the valley before accumulation of the brown and younger markers, although a depression may have been left or developed by differential compaction after deposition of the brown marker.

Valley-fill Succession and Reservoir Sandstones

Reservoir sandstones of the Nelson Lease are part of a lithologically complex interval that lies stratigraphically between the Tebo marker interval and the brown marker (Fig. D-4). It includes a valley fill that is set into the underlying beds as far down as the Bluejacket A coal, but not the upward-coarsening succession of slightly older (but still post-Tebo) age found in wells K-34-37, in the bank of the valley. In addition to sandstones ranging from a few cm to over 10 m thick, this succession includes interbeds (called mixed lithologies or interbedded lithologies) of shale, siltstone, and sandstone on a scale of mm to dm, and beds of shale that are up to a few meters thick.

This interval can be divided fairly unequivocally into B_2 and B_3 zones, because a discontinuous horizon of conglomerate or a sharp increase of grainsize can be correlated from well to well across the lease, marking the base of the upper, or B_2 zone (Fig. D-4, D-5). In most wells, an interval of shale or mixed lithology lies at the top of the B_3 zone. This change is noted in preserved cores, and can be inferred in several of the core descriptions prepared by Oil Field Research. The B_3 zone fills the deepest part of the erosional valley in the eastern 1/2 of the SW/4 of section 21 and extends westward and southwestward across much of the lease. The B_3 zone includes the thickest and most productive sandstones in the study area. Thickness of the entire B_3 interval ranges up to 54 feet. The B_2 zone is more sheet-like and sandstone bodies in it are also thinner and more laterally extensive. However, they have distinctly less productive capability than the B_3 sandstones, although a small area in the NW part of the field in section 21 has recoverable oil results suggesting possible future development may be warranted.

Component Lithologies - Sandstone

Two types of sandstone that may have good reservoir properties are present in the Chelsea Sandstone, reservoir interval in the Nelson leases. Generally, structureless sandstones, with some rippled or laminated intervals, are present in the B_3 zone and B_2 sandstones are structured with ripples and some laminated intervals. Some B_2 sandstones do contain structureless intervals. Not all such sandstones are good reservoir, however, because some contain dead oil with initial saturations of greater than 50%, but no recoverable oil and zero effective permeability at residual oil saturation.

It is possible to recognize sandstone with good reservoir properties in the B_3 and B_2 intervals from the gamma ray pattern developed on logs, even on the unscaled logs available for this study (Fig. D-4). Good reservoir quality sandstones had sharp deflections and did not appear to be broken into thinner intervals by shale, because the gamma ray curve was consistently below the 50% deflection line that differentiated sandstone and shale. Mixed lithologies, such as those described below, have higher and more irregular gamma ray readings than the good reservoir sandstone. This difference permitted differentiation of good reservoir sandstones in logs of wells for which cores are no longer available.

Both structureless and structured sandstone commonly have conglomerates or conglomeratic sandstone at their base and may have one or more conglomeratic horizons above the base. Thickness of conglomeratic beds ranges from a few inches to several feet. Pebbles, cobbles and boulders are intraclasts of siltstone and concretions, with coalified fossil wood also present.

Structureless Sandstone

Structureless sandstones are especially common in the B_3 interval, in the paleovalley in the eastern part of the SW/4 of section 21. These sandstones are displayed in cores O-1 (Fig. D-5C), RW-1, and RW-8. Good quality B_3 sandstone is up to 35 feet thick in the core from well RW-8, which is in the valley center. Thickness decreases rapidly to the east and west of the axis of the valley and varies somewhat along the valley trend. The rock is heavily oil stained. For the most part, bedding is absent or so subtle that it is not detectable during description of core that has not been slabbed. Broken surfaces of the core are irregular or hackly with no tendency to have smooth, angled, or undulating surfaces, as beds with sedimentary structures would. Mica flakes show neither strongly preferred orientation nor concentration into zones. A few intervals of this sandstone, a few feet thick at most, do display ripples and lamination. The sandstone contains a few plant fossils.

The base of the good, structureless sandstone, although sharp and apparently erosive, is not necessarily the base of the erosional valley. In cores from both RW-8 and O-1 (Fig. D-5C), which are the best ones from the deep valley fill, the base of such sandstone lies several feet above the base of the valley fill, above a conglomerate bed and an interval of mixed lithology. The top of the good structureless sandstone of the B_3 interval in the valley fill grades into overlying successions of mixed lithology.

In the NE/4 of the NW/4 of section 28, the deep channel of the eastern part of the SW/4 of section 21 broadens, becomes less deeply incised, and contains thinner, less productive sandstones. Cores RW-13, RW-14, and RW-17 are from this area. B_3 sandstone reaches 16 feet thick in this area, and is mostly not structured, although beds do contain intervals of rippled, laminated, or cross-bedded sandstone. The base of sand beds and intervals within them contain mud intraclasts, in some places these are common enough to make the rock a conglomerate. Beds of structureless B_3 sandstone in this area have sharp, possibly erosive bases and gradational tops. They are overlain by interbeds of sandstone, siltstone, and shale.

West of the deepest part of the valley, in the center and south center of the SW/4 of section 21 and extending into the NW/4 NW/4 of section 28, B_3 sandstones are thinner, more laterally extensive, and not as productive. Cores are available from wells O-2, RW-7, and RW-15. Sandstone beds in this region is up to 15 feet thick and generally very fine grained and structureless. Sand beds may have coarser intervals with sharp bases at the base and within them, dividing the overall succession into units 5 to 10 feet thick. Coarser intervals at the base of units of the succession may be coarser sand (fine or on the border of fine and medium) or they may be conglomerates containing intraclasts of granule to boulder size. Conglomerates are up to 2.5 feet thick and may contain siderite cement. Coalified wood fragments are common in conglomerates and in parts of the section immediately overlying conglomerates but are scattered throughout sandstone beds. Some relatively thin intervals of the sandstone are laminated or rippled. Calcite cement is present in a few places.

Rippled Sandstone

Sandstones of the B_2 zone, in contrast, generally display clear ripple cross-lamination, plane lamination, small-scale to medium-scale cross-bedding, or other sedimentary structures. They have sharp bases and their lower few feet are commonly conglomeratic or slightly coarser grained--fine to very fine sandstone as opposed to the very fine sandstone above. Conglomerate clasts are intraclasts of mudrock. Internally, structured sandstones of the B_2 zone are very fine micaceous sandstones. B_2 sandstones grade upward into interbeds of sandstone, siltstone, and clay. Beds of sand range up to nearly 17 feet thick, but generally are thinner, commonly less than 10 feet thick. Layers of wavy-bedded sandstone and mudrock may break them into packages a few feet thick. Coalified wood fragments are present and may be common in B_2 sandstones; macerated plant debris commonly defines bedding in ripple marked or plane laminated intervals. Birdshot siderite is present in bands and layers in many occurrences of B_2 sandstone.

Structured sandstones of the B_2 zone are thickest, up to nearly 17 feet, in the valley region in the eastern part of the SW/4 of section 21. Cores O-1 (Fig. D-5C), RW-1, RW-3, RW-6, and RW-8 are all that part of the field. Several of the sandstones in the B_2 interval in the valley region are partially to completely saturated with "dead" oil. These beds have no recoverable oil, despite measured saturations of over 50%, and no permeability to water at residual oil saturation. Not only are they not reservoir, but they are barriers to movement of fluids through the sand.

In the NW/4 SW/4 of section 21, west of the main valley trend and in the northwest corner of the Nelson Lease, several wells encountered thick, potentially productive sandstone in the B_2 interval. Average recoverable oil saturations reach 2000 bbls per acre in wells RW-4, RW-5, RW-7, and RW-11, for which cores are available. Sandstones in this region may exceed 15 feet in thickness, but are commonly less than 10 feet thick. They are rippled very fine sandstones with a few silty partings. Macerated organic debris and mica fragments mark bedding surfaces. Some intervals, up to a few feet thick, are actually wavy-bedded intercalations of sandstone and mudrocks. Intervals of parallel-laminated intercalations of macerated plant debris and sandstone and intervals of wavy bedded sandstone and shale divide thicker sand-rich successions into intervals a few feet to several feet thick. Such intercalations have gradational bases and tops.

Sandstones are also found in the B_2 zone in the center of the SW/4 of section 21 and in the northern part of the NW/4 of section 28. Cores RW-9 (Fig. D-5B) and RW-12 represent the center of the SW/4 of section 21 while cores from wells O-2, O-3, RW-13, RW-14, RW-15, and RW-17 are from the northern part of the NW/4 of section 28. Cores RW-16 and RW-18 represent accumulation of the B_2 zone in a erosional remnant left between arms of the Chelsea valley.

In the RW-8 core, B_3 sandstone had recoverable oil of a few hundred barrels per acre-foot and total recoverable oil of 5500 bbls per acre, according to core analyses conducted by Oil Field Research in Chanute, Kansas. Wells developed in this sand where it lies in the paleovalley of the E 1/2 of the SW 1/4 of Section 21 have produced 10,000 to over 20,000 bbls of oil during water flood operations and may have produced for long periods before the water flood was installed in the area.

Interbedded sandstone, siltstone, and shale (mixed lithologies)

A characteristic suite of lithologies in the B_2 and B_3 zones of the Chelsea valley fill of the Nelson Lease comprises rippled very fine sandstones and siltstones, linsen- and wavy-bedded sandstones and mudrocks, and shale, including structureless mudrock, laminated shale, and streaked shale. In such sequences, the predominant lithology is wavy-bedded sandstone, siltstone, and shale, with linsen-bedded shale and siltstone second in importance. Burrowing is common but by no means sufficient to destroy the primary lamination of the sediment. Sandstone beds in most such successions are subordinate in abundance, but they are a plurality or a majority of the beds in some wells. They can be described as very fine grained, rippled, and tan, although some sandstone beds are apparently structureless or contain parallel lamination. Some sandstones contain a few shaley intraclasts or mud flasers. Sandstones commonly contain carbonaceous debris on lamina surfaces and may be sparsely burrowed.

In this suite, lithologies are interstratified at two scales. At the larger scale, the sequence is thin to medium bedded, with beds a several cm to a few dm thick. Rippled very fine sandstone and siltstone in beds several cm to a few tens of cm thick alternate with similarly thick beds of either interbedded shale and wavy- or linsen-bedded siltstone or beds of shale alone. At the smaller scale of interstratification, in wavy or linsen-bedded sequences, laminae of silt, sand, or shale are less than one mm to one cm thick and form coarse-fine alternations.

Characteristic of these rocks are gradational boundaries between beds in which rocks of different grain size prevail. This describes the beds at the several cm to a few dm scale, not the mm to cm laminations within wavy-bedded successions or streaked shales. Examples of such changes are from a bed where sandstone or siltstone predominates to one where linsen or wavy bedding is common or from a linsen- and wavy-bedded interval to shale. It is important to note that sharp-based sequences, progressively grading from coarse lithology (fine sand or conglomerate) to finer grained lithology (very fine sandstone to siltstone to mudrocks) are not common in interbedded intervals, although they are present.

Interbeds of sandstone, siltstone, and shale are found in both the B_2 and B_3 zones. Wells O-1 (Fig. D-5C), RW-3 and RW-8 represent the B_3 zone in the valley fill of the eastern part of the SW/4 of section 21. Commonly, a zone of interbeds overlies a thin sandstone or conglomeratic bed at the base of the valley fill. Such intervals are a few feet thick. In well RW-8 for example, the interbedded succession, 9 feet thick, at the base of the valley fill is overlain by structureless reservoir sandstone of excellent quality. Elsewhere, notably in wells KW-10, KW-11, RW-9 (Fig. D-5B), and RW-12, the entire B_3 zone is composed of such interbeds. The B_3 zone is 28 and 21 feet thick, respectively, in KW-10 and KW-11 which lie in the Chelsea valley. Logs of wells containing mixed lithologies show an irregular pattern, indicating interbedding at about the scale of resolution or finer. Cores from RW-9 (Fig. D-5B) and RW-12 confirm the lack of good quality sand in the B_3 interval, but they lie on an erosional remnant between the eastern valley and the western patch of B_3 sand. A similar set of thin to medium interbeds of sandstone, siltstone, and shale occurs in core RW-14 from along the western side of the eastern branch of the Chelsea valley in the NE/4 of the NW/4 of section 28 and in the core from well O-2 in the NW/4 of the NW/4 of section 28. Log patterns indicate that the upper 5 to 15 feet of the B_3 zone throughout its extent is composed of interbeds of sandstone, siltstone, and shale.

Interbedded successions of sandstone, siltstone, and clay are common in the B_2 zone as well, but they are generally absent from the bottom of that succession, because the base of the B_2 zone was generally placed at a sharp increase in grain size from the underlying B_3 zone. Some B_2 successions, however, consist of a thin conglomerate and a few feet (1 or 2 feet) of fine to very fine sandstone above it with and then interbedded successions above that range to over 20 feet thick. Elsewhere, the bulk of the B_2 succession is rippled sandstone, as described above, and only the upper few to several feet is interbedded lithologies. Contacts between thick beds of rippled sandstone and overlying interbedded successions are gradational in all occurrences.

Cores from wells RW-3, RW-6, and RW-8 contain interbedded lithologies in the B_2 zone from the region where the Chelsea valley is best developed, in the eastern half of the SW/4 of section 21. Interbedded sequences in the B_2 zone range from 4 to 18.9 feet thick in these wells, and are divided into beds 0.1 to 2.6 feet thick. Some of the thicker sandstone beds have scoured bases.

RW-2, RW-4, RW-10, and RW-19 display interbedded lithologies from the west part of the productive area in the SW/4 of section 21. Interbedded successions range from 9.5 to 16 feet. Sandstone occurs in beds from a few tenths of a foot to 6 feet thick, with thickest beds at the base of the B_2 zone. The thicker of these sandstone beds, over about 2-3 feet thick, might be separated from the mixed lithology successions and considered as individual sandstones. Sandstone is very fine grained, except at the base of the B_2 zone, where conglomeratic sandstone or conglomerate up to 0.9 feet thick may be present. Sandstone layers are rippled, inter laminated with mica and macerated organic matter, or structureless. Shale strata range from laminae to over 1 foot thick. They are streaked with sand or silt and may be burrowed. Large plant fragments are present in some beds.

The main Chelsea valley occupies two branches in the northern part of the NW/4 of section 28. Cores from wells O-2, O-3, and RW-15 contain interbedded lithologies in the B_2 zone above western branch, while O-4, RW-13, and RW-14 sample that zone overlying the eastern branch. In this area, interbedded lithologies may reach a total thickness of 8 to 21 feet, including beds of shale up to 1.8 feet thick and wavy- or linsen-bedded sandstone and siltstone up to 5.7 feet thick. Wavy- or linsen-bedded successions display variation in the proportion of sandstone or siltstone ripples to intervening mudstone drapes on a scale of several inches to a foot. Shale beds are commonly laminated, or contain streaks or lenses of sand or silt. Interbedded sequences in this part of the field contain sparse burrows, large plant fossils, and macerated plant debris, which is common on bedding surfaces. A series of upward fining beds of siltstone and shale, including linsen-bedded and streaked shale is present in RW-15. In O-2, an associated bed four feet thick consists of inter laminations of fine sandstone and macerated organic matter with mica.

RW-16 represents deposition of interbedded lithologies on the divide between the two branches of the Chelsea valley in the NW/4 of section 28. The B_2 zone is 17 feet thick and contains at least 5 feet of good sand at the top. The basal foot is pebbly sandstone, and the overlying 9 feet is interbedded sandstone, sandstone, siltstone and shale. Wavy-bedded sandstone is in beds some 2 feet thick, streaked shales are in beds 0.6 to 1.5 feet thick, laminated shales in beds 0.5 to 0.8 feet thick, and rippled sandstones in beds some 0.5 feet thick. Siderite is present in some beds.

Parallel-Bedded Sandstone and Organic Matter

Several cores from the B_2 zone (O-2, RW-6, and RW-8) contain distinctive successions of parallel stratified inter laminations of fine to very fine sand and organic matter, with mica. Laminae are on the mm scale. Sand laminae either display little in the way of sedimentary structures or the inter laminations may be wavy-bedded. Parallel-bedded sandstone and organic matter may be interbedded with rippled successions. Interlaminated successions range up to 6.7 feet thick.

Shale

Shale is a common component of the fill of the Chelsea valley in both the B_2 and B_3 zones. Much of it occurs intimately interstratified with silt and sandstone or as flasers or other inclusions in coarser rocks, as described above. In addition there are beds of shale about 2 feet to 11 feet thick in the succession. Such beds are most common in the upper part of either of the two zones, where they represent the culmination of gradational sequences from conglomerate or sandstone through interstratified lithologies. Shale beds are thickest in the area of the deep part of the Chelsea valley fill in the eastern part of the SW/4 of section 21.

Shale ranges over the gamut from mudstone and mudshale, which have subequal amounts of silt and clay, through claystone and clayshale. Shales in the B_2 and B_3 zones range from very light gray to dark gray, in places with an olive cast to the color. The range of shale lithologies includes laminated or bedded shales, structureless shales, streaked shales, with laminae of silt or sand as thin as a grain or two thick, and linsen-bedded shales, with scattered lenses of silt or sand. Generally, shale intervals at the top of both the B_2 or B_3 zones of the valley fill grade finer upwards, from linsen-bedded to streaked to laminated or structureless. Some cores of apparently structureless shale break easily along planar surfaces that parallel bedding in nearby rocks and indicate that the shale is stratified, although layering may not be visible because of fine grain size and little or no contrast between adjacent beds.

Shales contain fossilized plant material, either macerated or as pieces that may be larger than the diameter of NX core. Shale beds are commonly bioturbated normally in particular zones. Rarely are primary bedding structures in them completely destroyed by burrowing. Shale commonly contains pyrite, especially in the form of pyritized plant remains, and birdshot siderite, which may be in beds or may follow vertical structures that appear to be related to soil formation in overlying strata.

Tidal Features

Intervals of interbedded sandstone, siltstone, and shale display several features indicative of deposition by tidal currents. The most prominent is gradational alternations of thickness of sand laminae in wavy- and linsen-bedded intervals. These variations occur over intervals of several centimeters. Detailed counting of beds has not been attempted, and none of the intervals of wavy- and linsen-bedded siltstone and shale that have been examined had obvious periodicity of bed thickness of 14 or 28, which may form from diurnal or semi-diurnal tidal frequencies. Despite the lack of the compelling periodicity in thickness variation, the interval shows repeated rapid variations of current intensity, both fine-coarse alternations at the scale of mm to one cm and bed thickness variations at the scale of several cm it a few dm. Such variations are characteristic of tidal environments.

The sequences of varying thickness of bedding are also unlike wave-rippled sequences because they do not have scoured basal surfaces and thin dm-scale fining-upward sequences that are produced by storms. Individual thin laminae in linsen-bedded intervals can be traced across the entire width of the core, which is also a common feature of tidal deposition during the neap part of the tidal cycle, when deposition takes place from suspension and each successive current from the rising and falling tide does leads to accumulation without erosion of previous deposits. Boundaries between laminae are commonly thin, continuous layers of mica and carbonaceous trash, which imply cessation of current activity between depositional events. Current ripples from river deposits or other sites of activity of unidirectional currents, on the other hand, have macerated plant debris in troughs and part way up the foresets, where they are trapped in eddies rather than deposited during pauses of current activity.

Interbeds of wavy- and linsen-bedded sandstone, siltstone, and shale with shale, of possible tidal origin, are common in the B_2 zone. As a result, the B_2 zone is interpreted as a series of tidal sand bars with intervening tidal flat or mud bank deposits. Tidal indicators are also present in the mixed lithologies of the B_3 zone.

Another characteristic lithology in the Nelson Lease is best understood if it is assigned to formation by tidal activity. Sandstone interlaminated with organic matter and mica, which may make up units a few m thick, are unlikely to be the result of accumulation in flow-regime bed forms, because the rapid fluctuation from conditions where plant debris and mica would accumulate to those where plane beds of very fine sand are deposited seems unlikely, especially with no evidence of erosion between depositional events. Tidal ebb and flood cycles, with periods of slack water, seem to be a more likely explanation. Again, no obvious 14- or 28-bed cyclicity was noted during core description. Tidal deposits of interlaminated sandstone and organic matter, like tidal deposits of very fine sandstone, siltstone, and shale, are not rocks of reservoir quality.

Shapes of Sand Bodies

In drawing cross sections of the B_3 and B_2 intervals, it was necessary to depict the shape of the sandstone bodies. They could be either channels, which are convex downward with a broad, relatively flat top, or bars, with a convex upward top and a bottom conforming to the pre-existing surface. Which configuration one chooses has considerable significance in terms of the continuity of the reservoir. In this report, sandbodies in the B_2 interval are depicted as bars for several reasons. First, the B_2 interval commonly overlies a rather flat, apparently erosional surface, and the sand accumulations are of smaller scale than the width of the valley (Fig. D-4, D-7). Above this apparent erosion surface, even where thick sandstones were absent, thin layers of conglomerate and sandstone are present at the base of the interval. Tidal features, listed above, in the mixed lithology intervals suggest tides were important processes in depositing these sediments. The shape of the sediment accumulation in the B_2 zone is similar to an estuary, which is a common environment where tidal processes are important today. Tidal estuaries often contain convex upward sand bars, which form elongate, irregular mounds. Choosing to make the accumulations of sand in the B_2 interval convex-upward bars avoided the necessity of inferring large quantities of sand in areas between wells, where no available evidence bore on the shape of sand bodies.

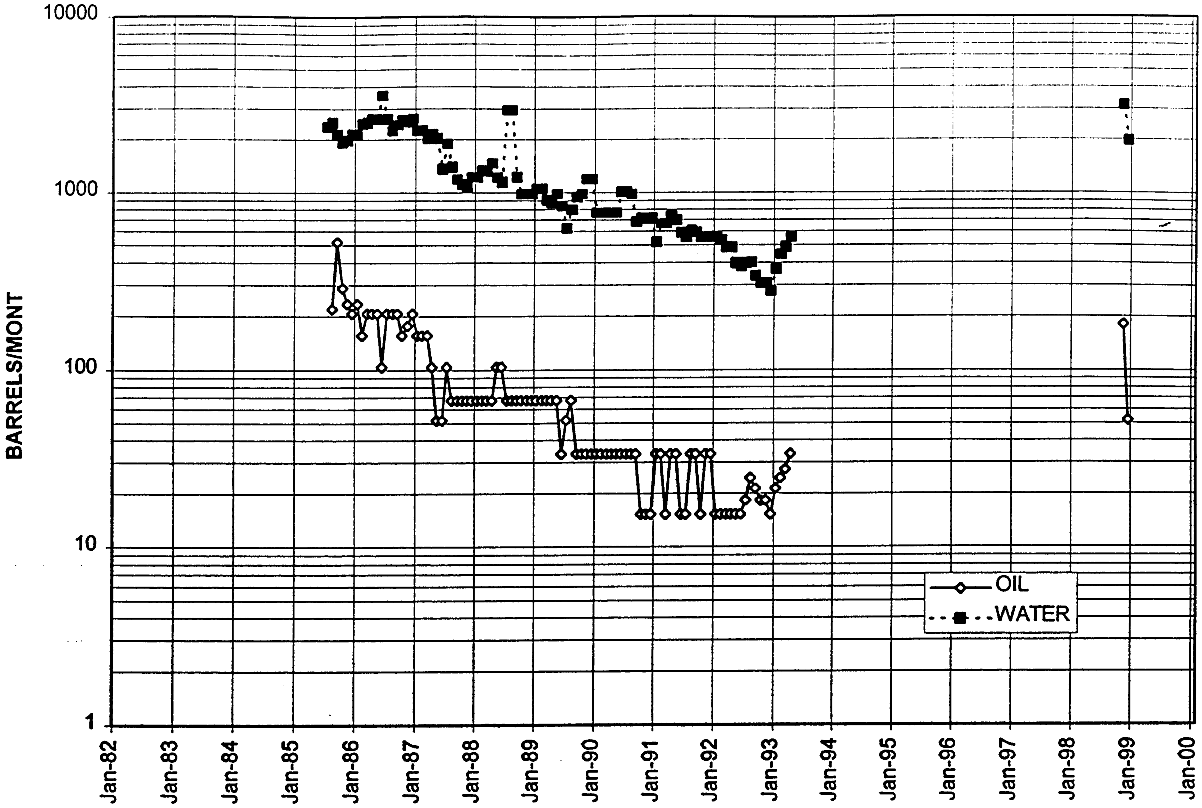
Diagenesis

Ten thin sections were cut from several different layers of the B sandstone interval. These have been only cursorily examined. They show development of three minerals that are of significance for recovery efforts in the Nelson Lease. Two of these are iron carbonates, siderite ($FeCO_3$) and ankerite $Ca(Mg,Fe)(CO_3)_2$. Iron may be released from these minerals during acidification of wells or other recovery operations, and be oxidized to form iron hydroxide, an insoluble precipitate. Particles of iron hydroxide may migrate to pore throats, where the plates of iron hydroxide can be trapped, blocking the pore.

The other mineral is kaolin, $Al_2Si_2O_{10}(OH)_8$. Kaolin is a clay mineral that forms accumulations of flaky particles in pores. During recovery operations, the clay particles may be moved to pore throats, blocking them. The sandstone also contains pyrite, which may oxidize during recovery operations and provide an important source of iron.

Appendix B

H-1



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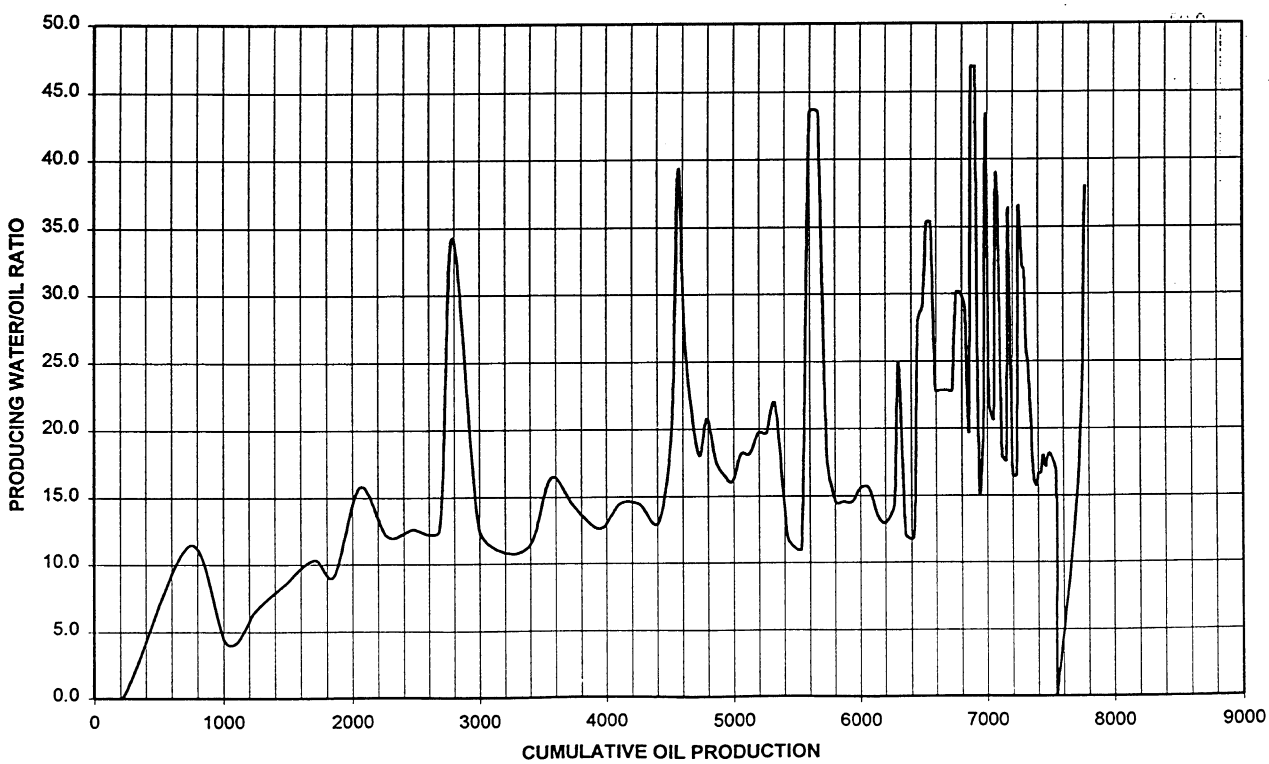
Jan-99
Jan-00

H-1



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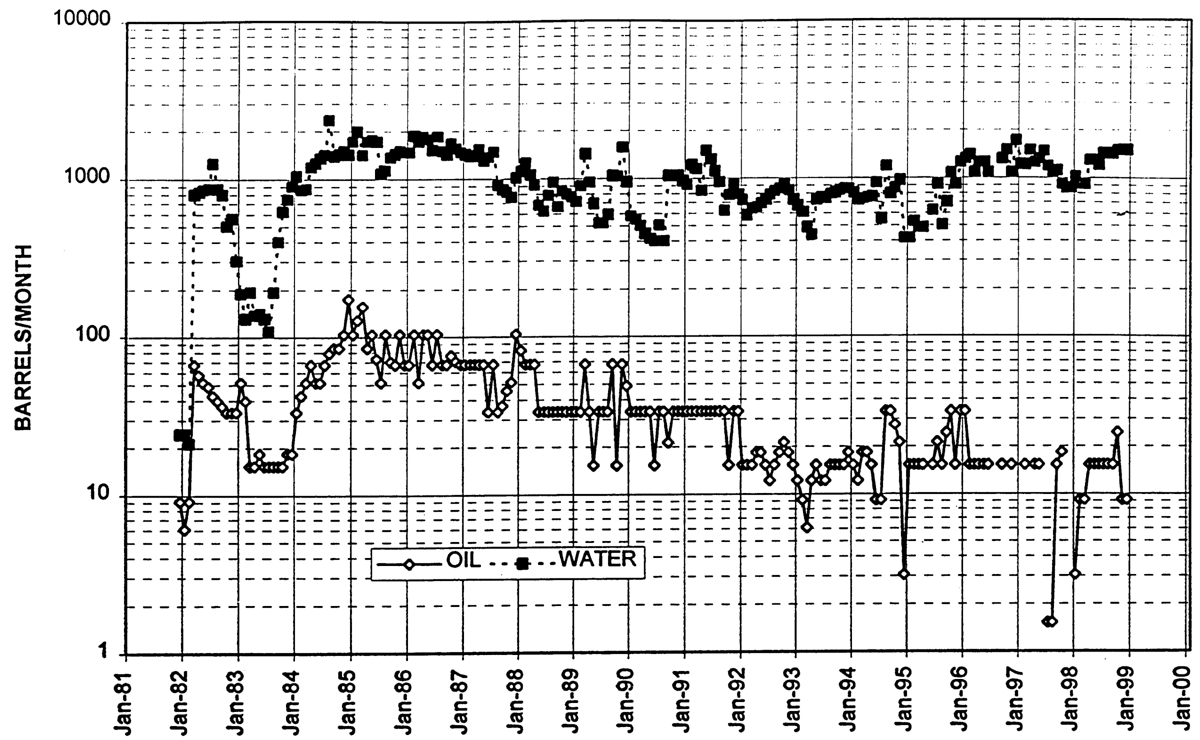
5000
6000
7000
8000
9000
CUMULATIVE OIL PRODUCTION

H-3



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WATER
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Jan-87
Jan-88
Jan-89
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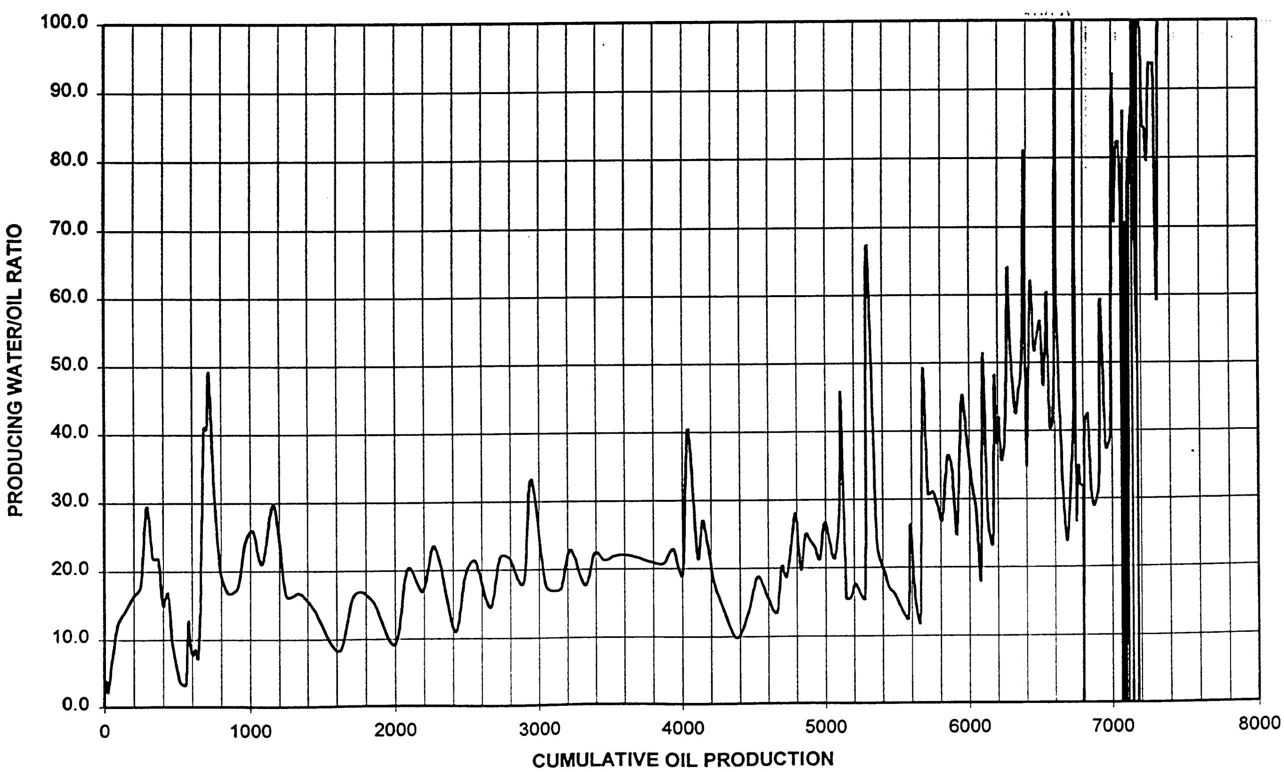
Jan-99
Jan-00

H-3



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5000
6000
7000
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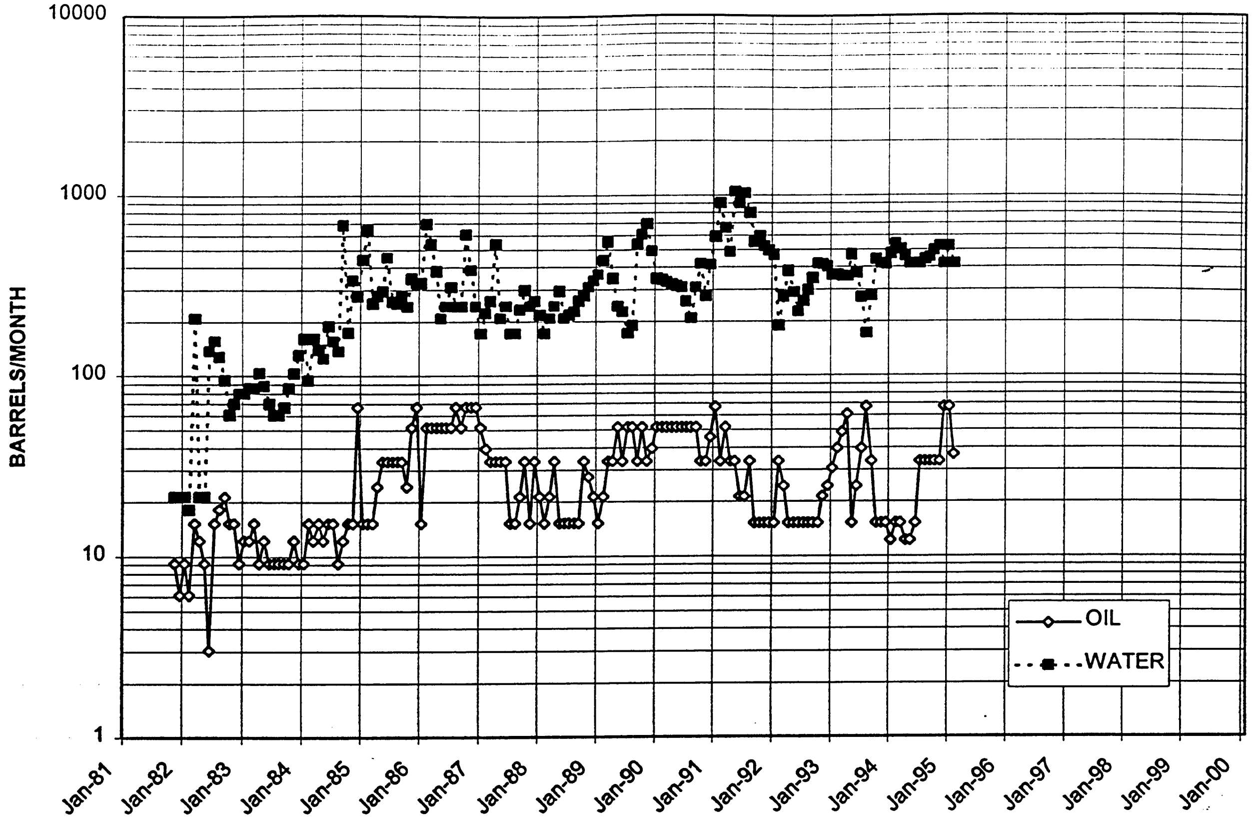
CUMULATIVE OIL PRODUCTION

H-5



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Jan-89
Jan-90
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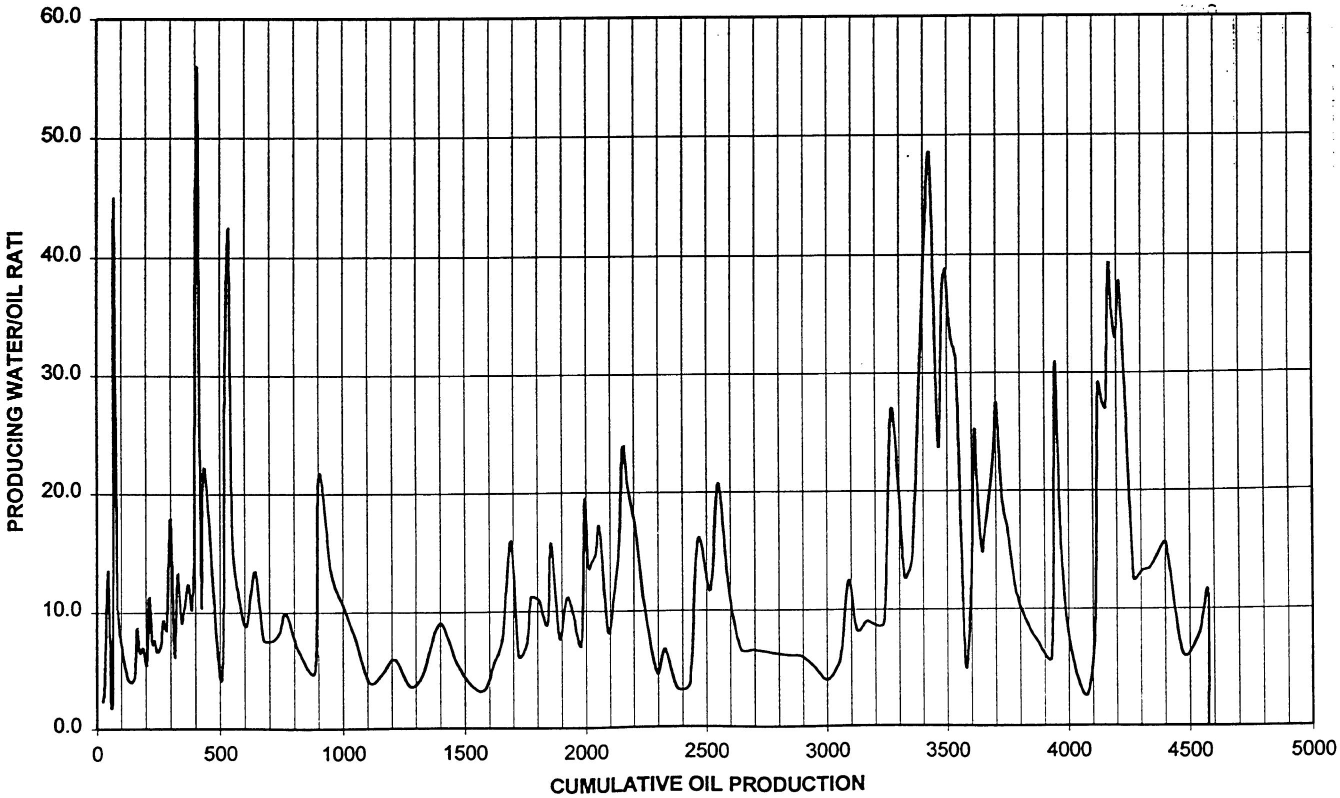
Jan-97
Jan-98
Jan-99
Jan-00
OIL
WATER

H-5



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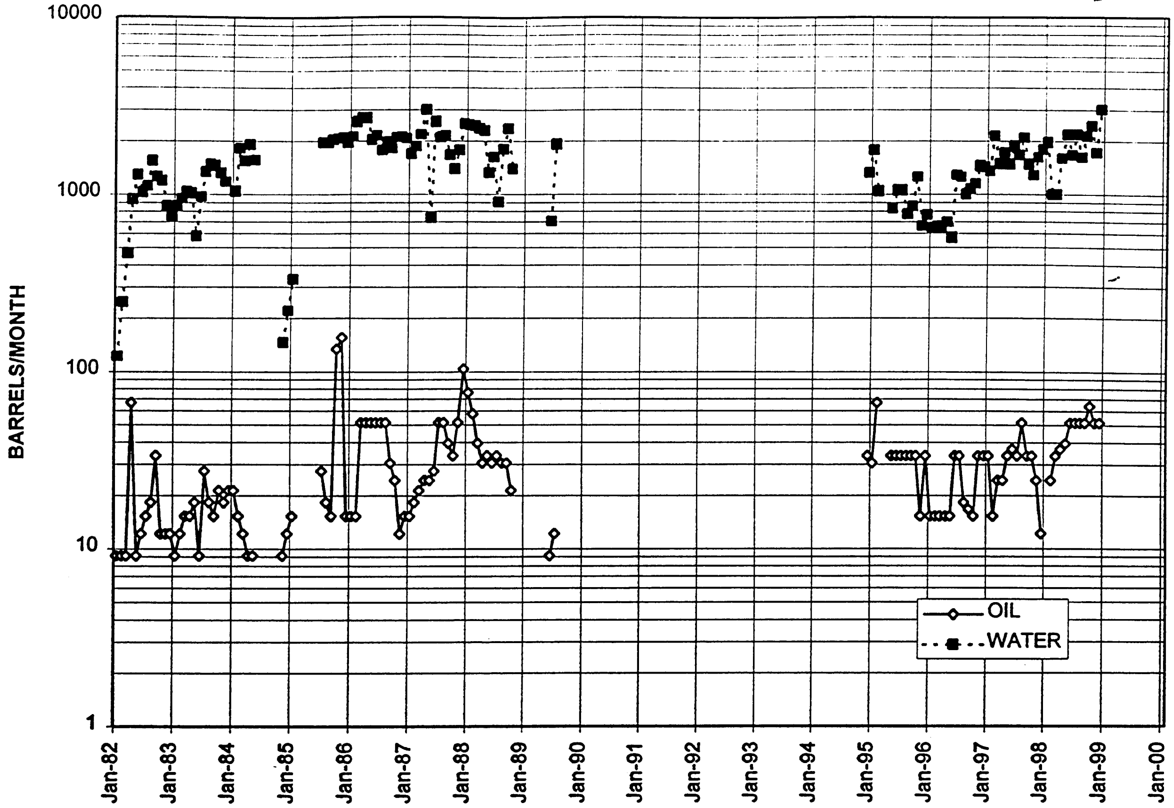
2000
2500
3000
3500
4000
4500
5000
CUMULATIVE OIL PRODUCTION

H-10



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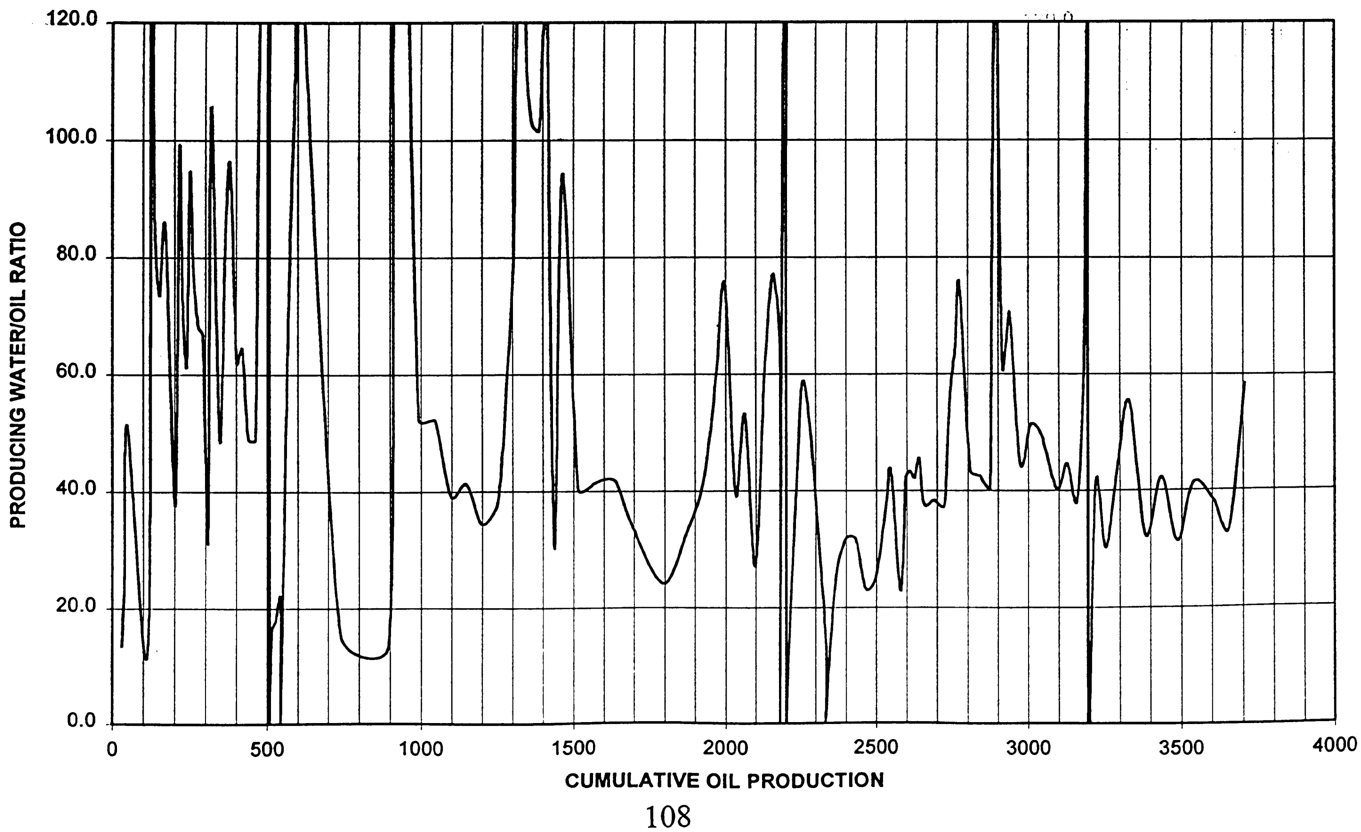
OIL
WATER

H-10



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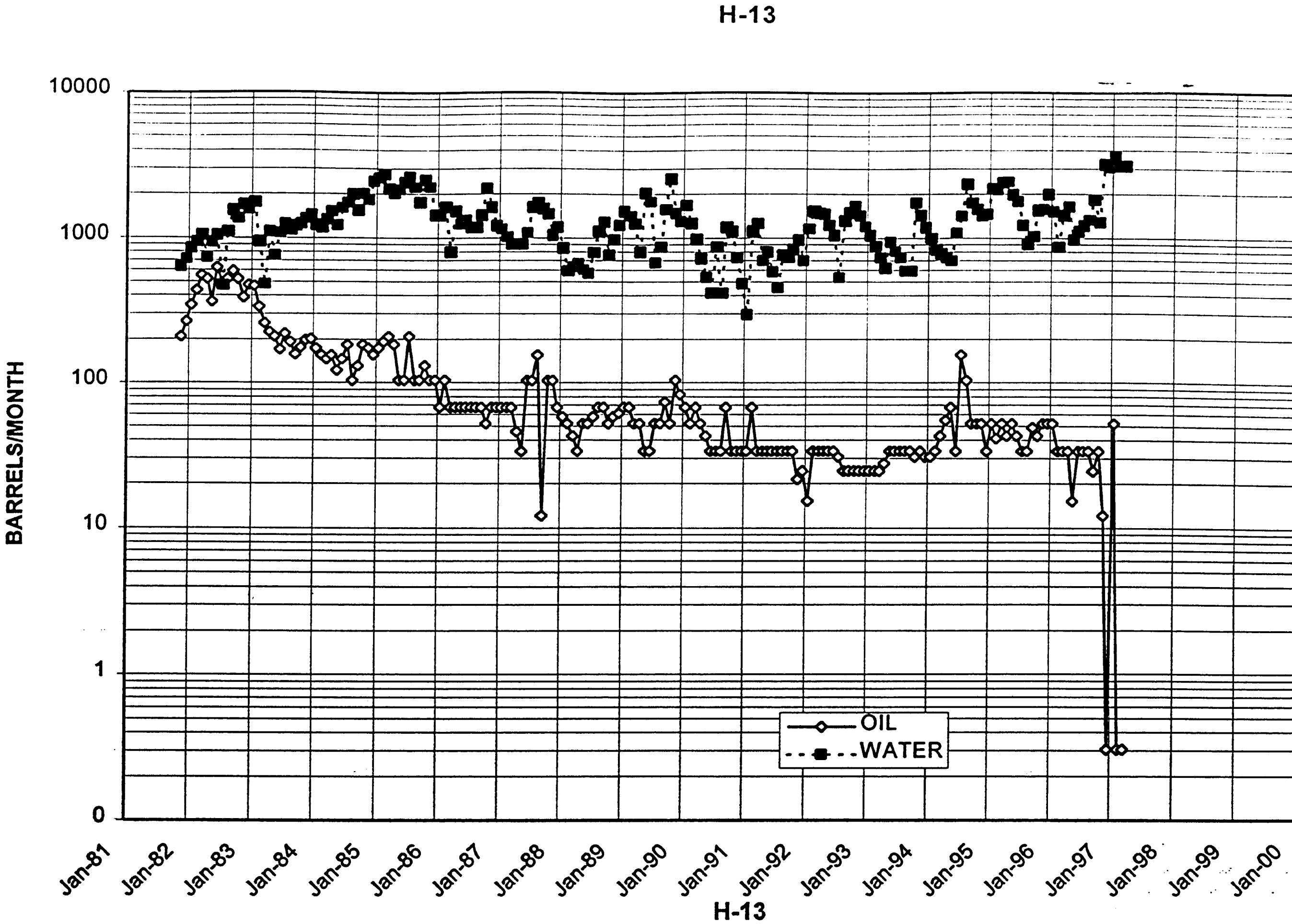
2000
2500
3000
3500
4000
CUMULATIVE OIL PRODUCTION



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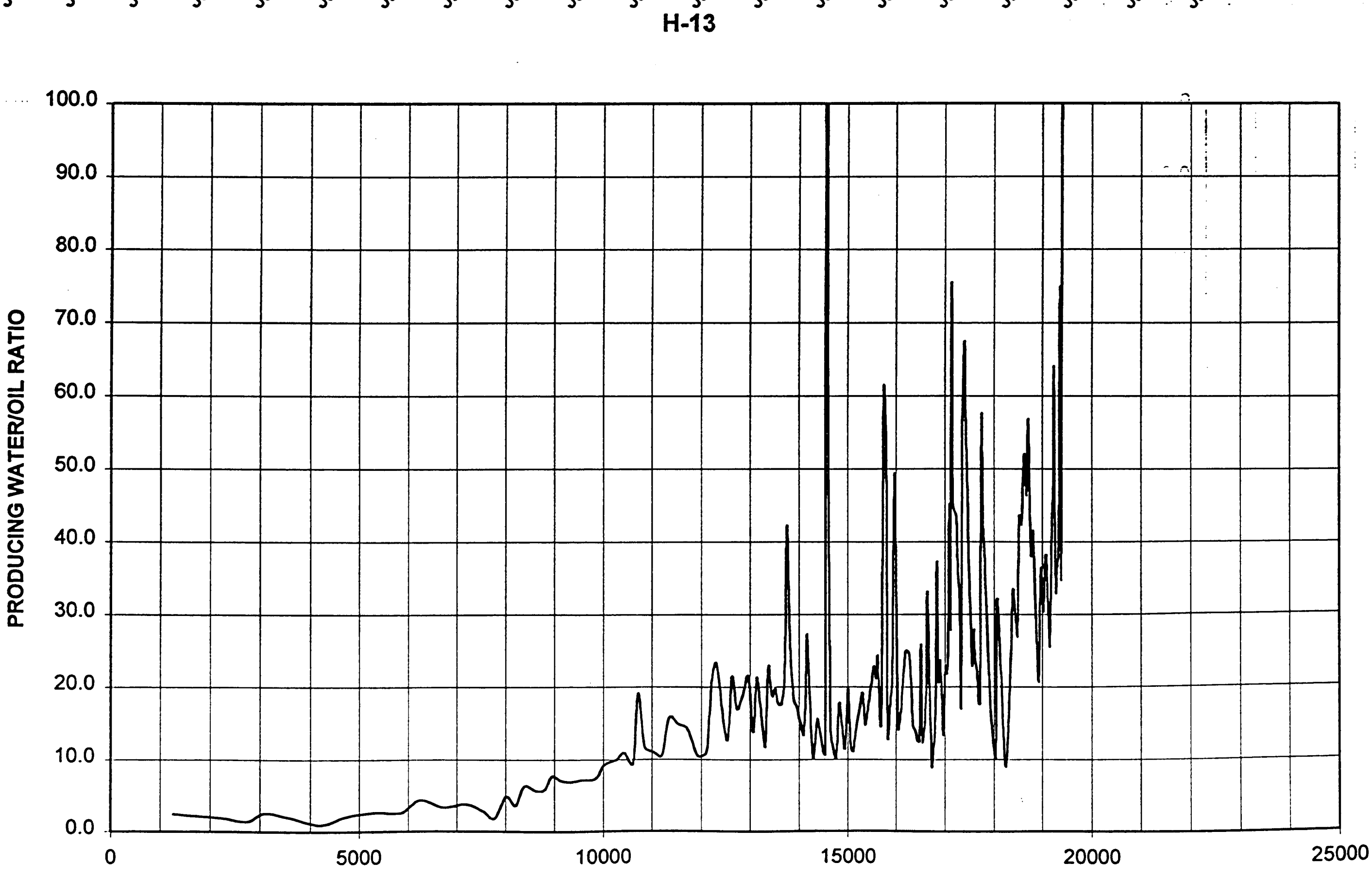

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10000
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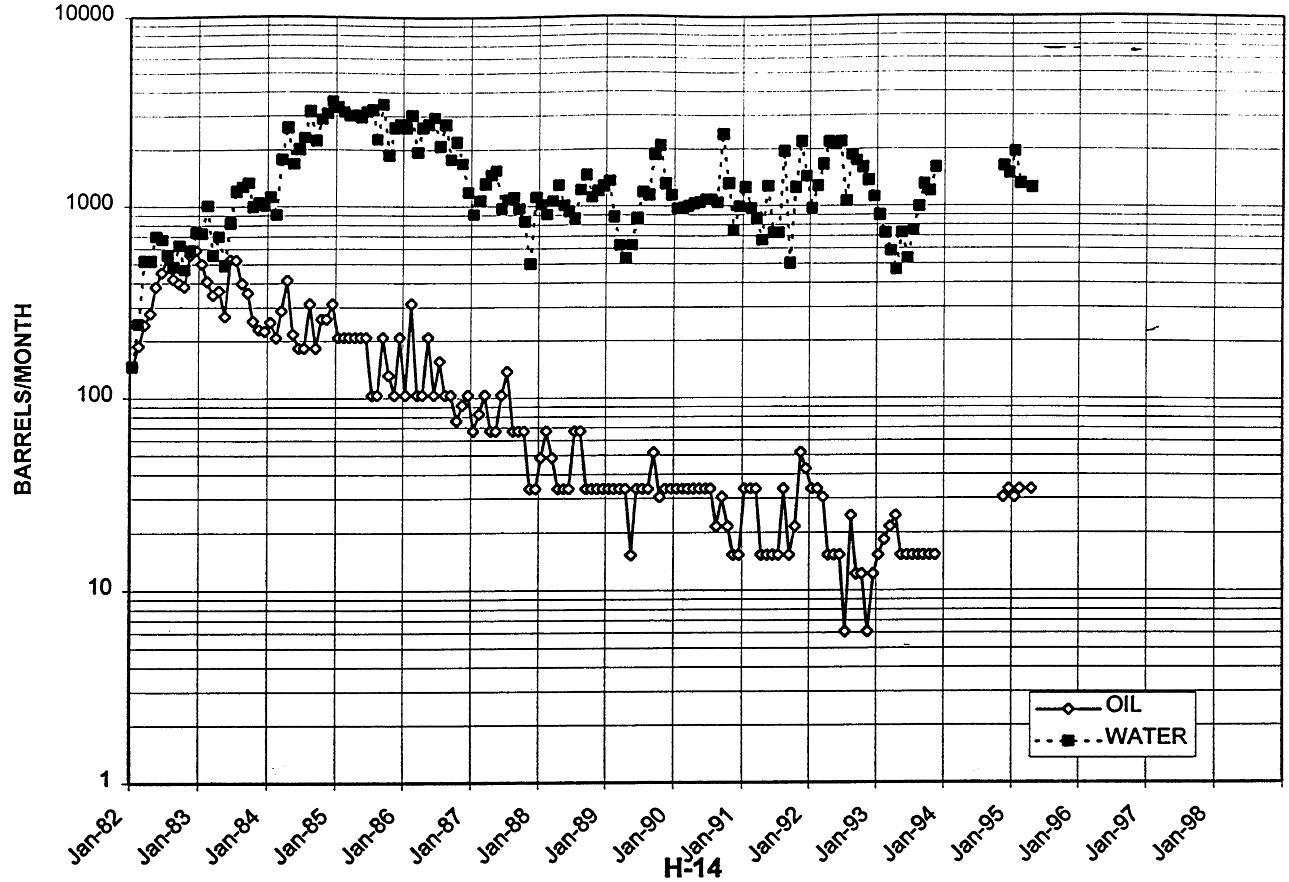
20000
25000
CUMULATIVE OIL PRODUCTION

H-14



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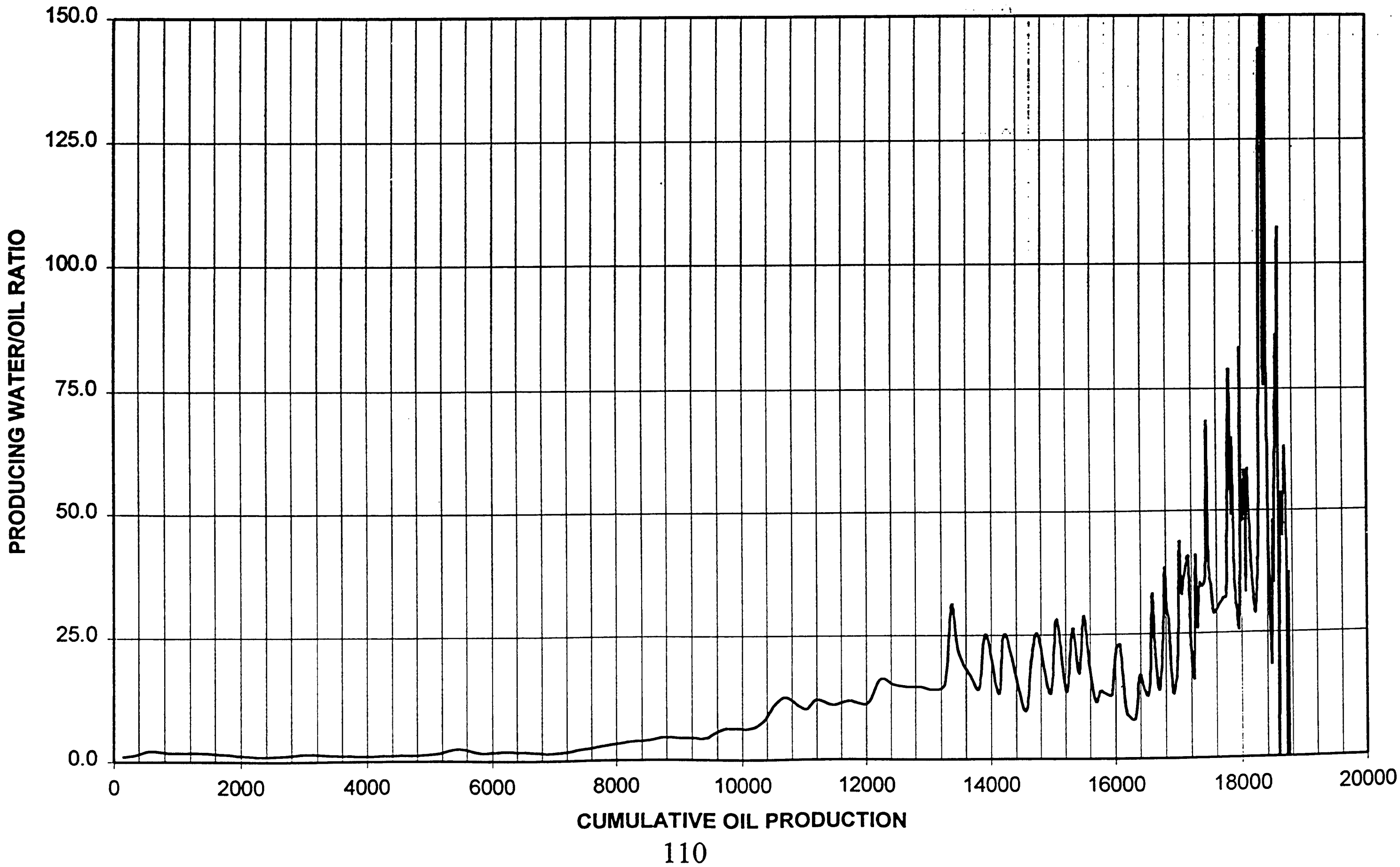
H-14



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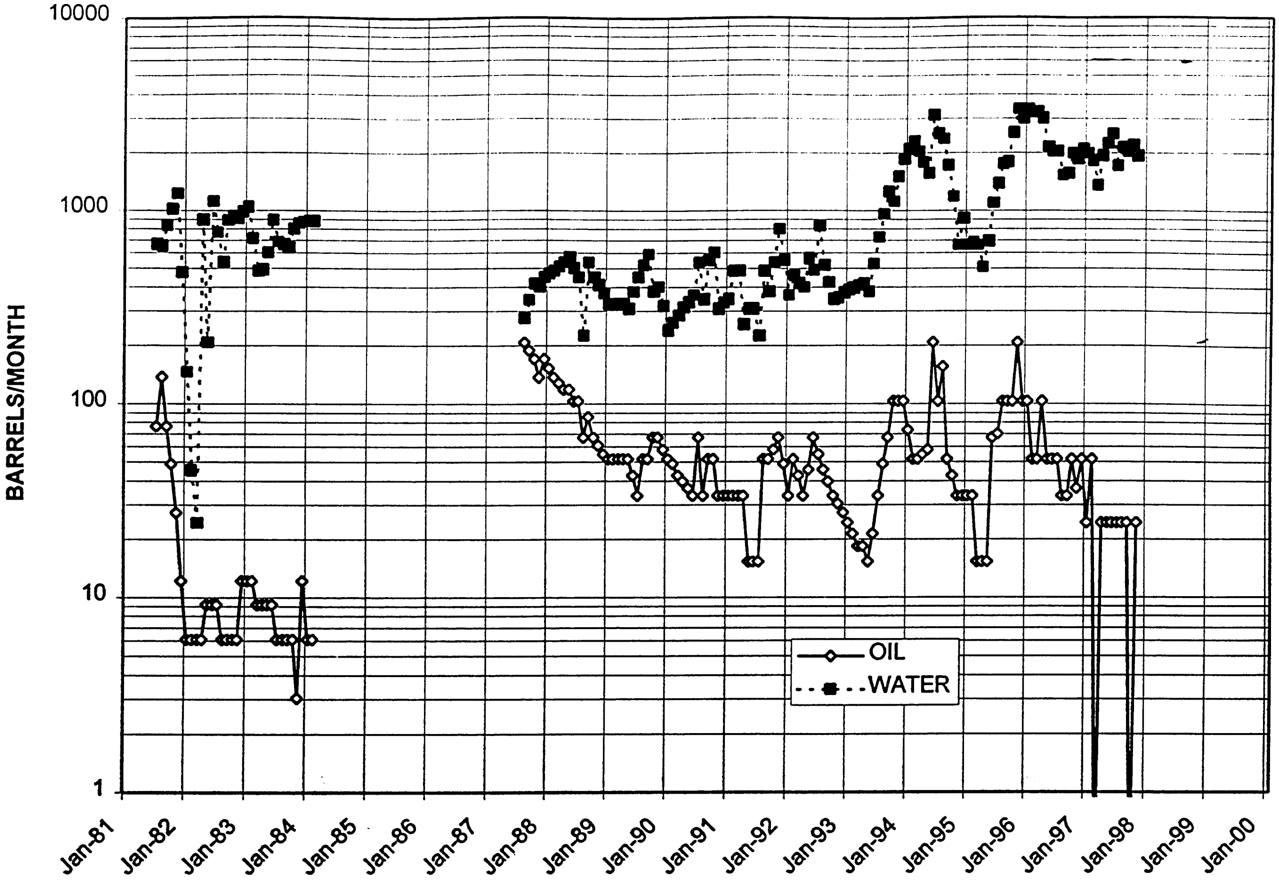
CUMULATIVE OIL PRODUCTION



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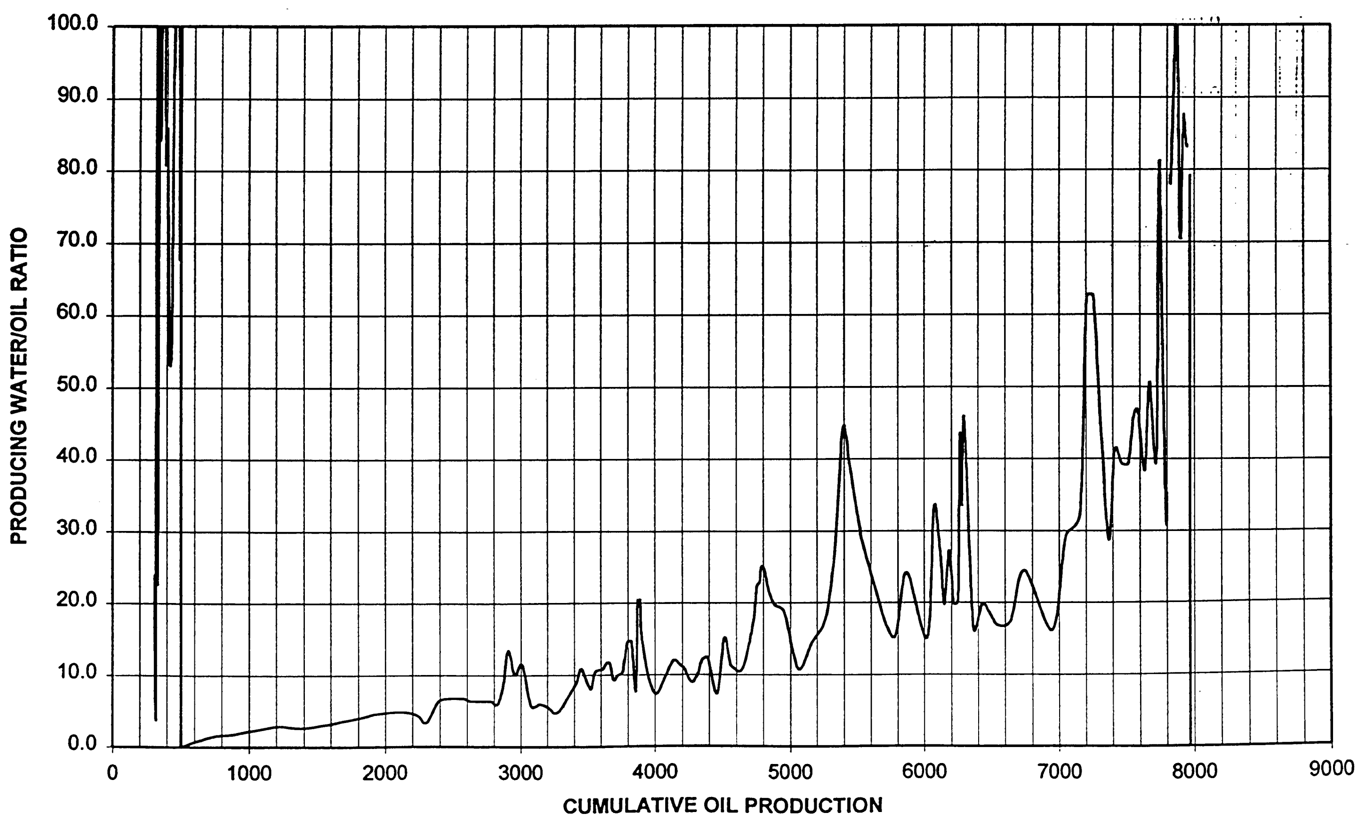
H-15



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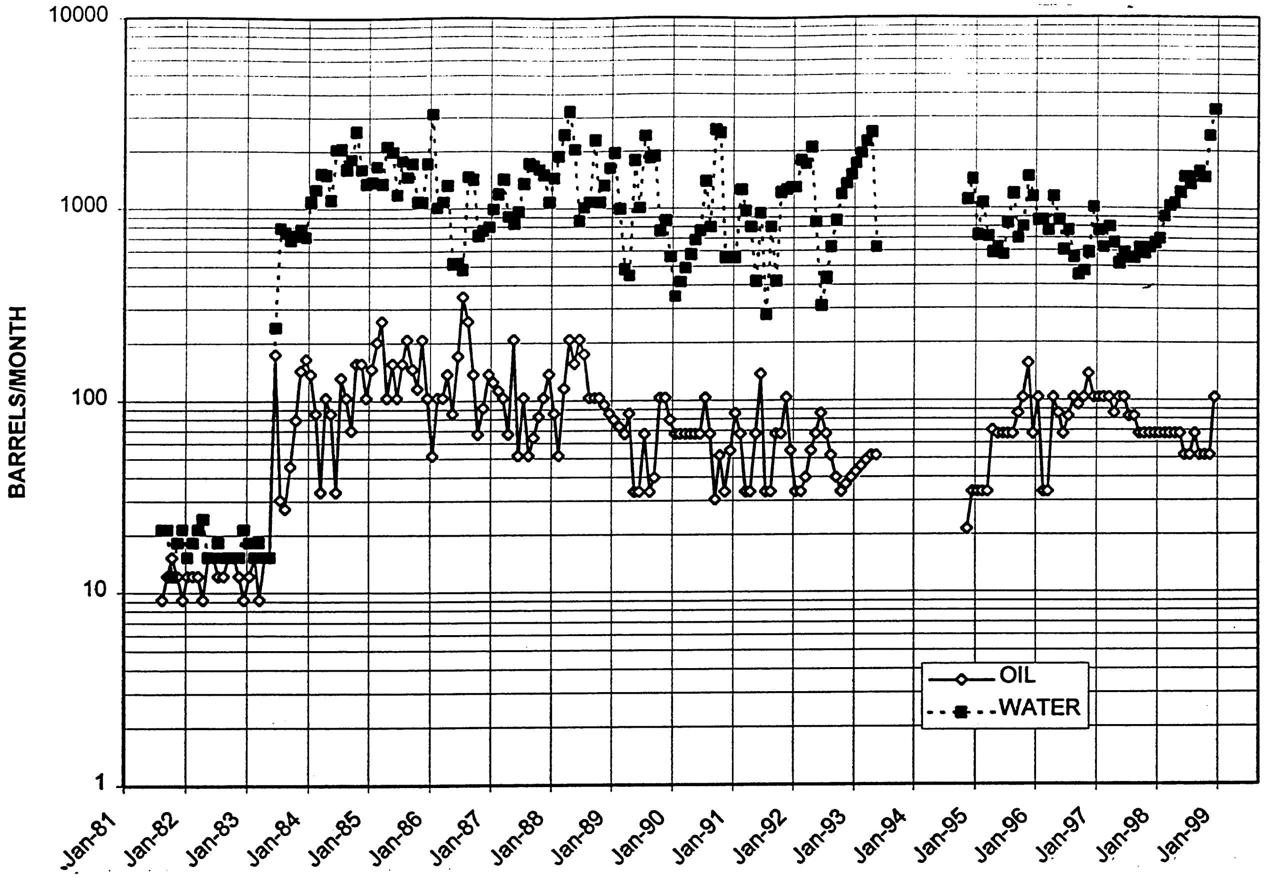
CUMULATIVE OIL PRODUCTION

H-16



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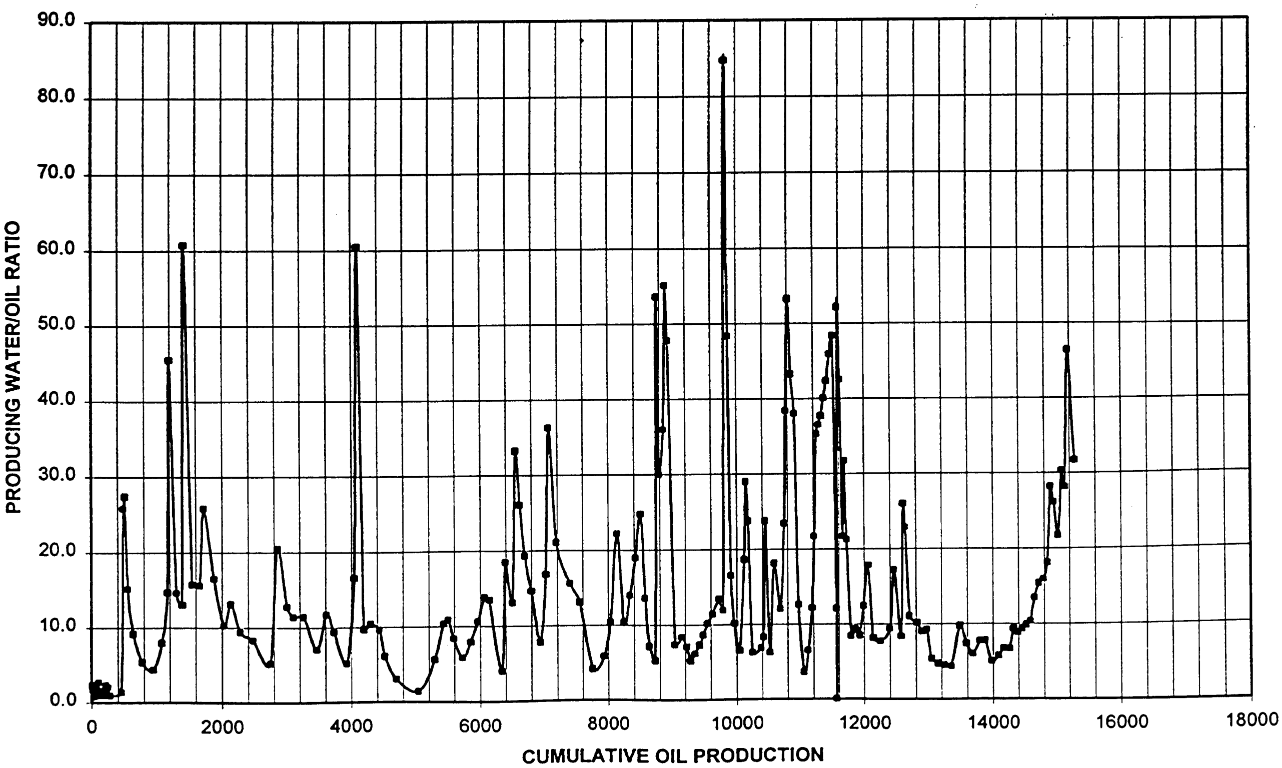
H-16



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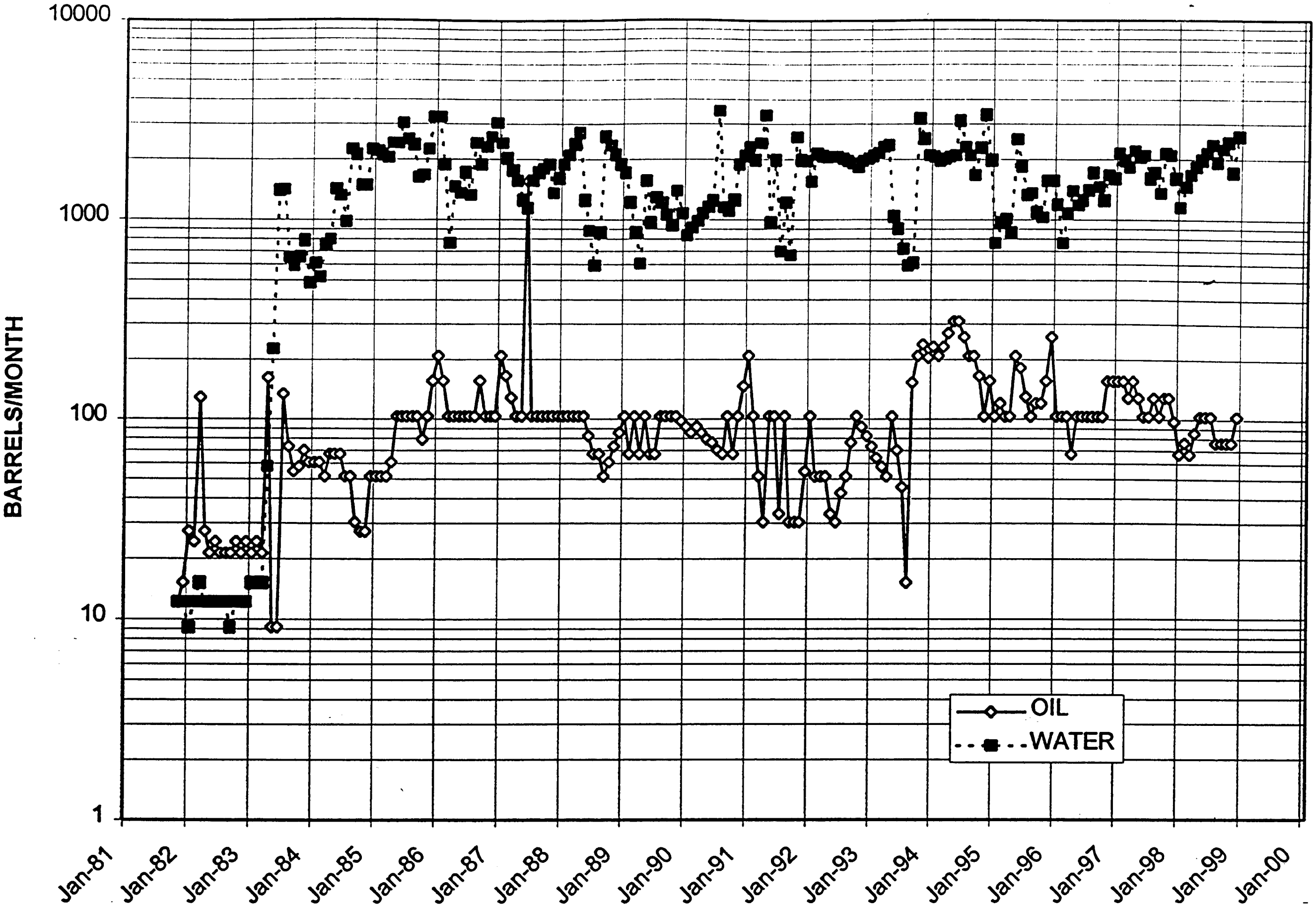
8000
10000
12000
14000
16000
18000
CUMULATIVE OIL PRODUCTION

H-17



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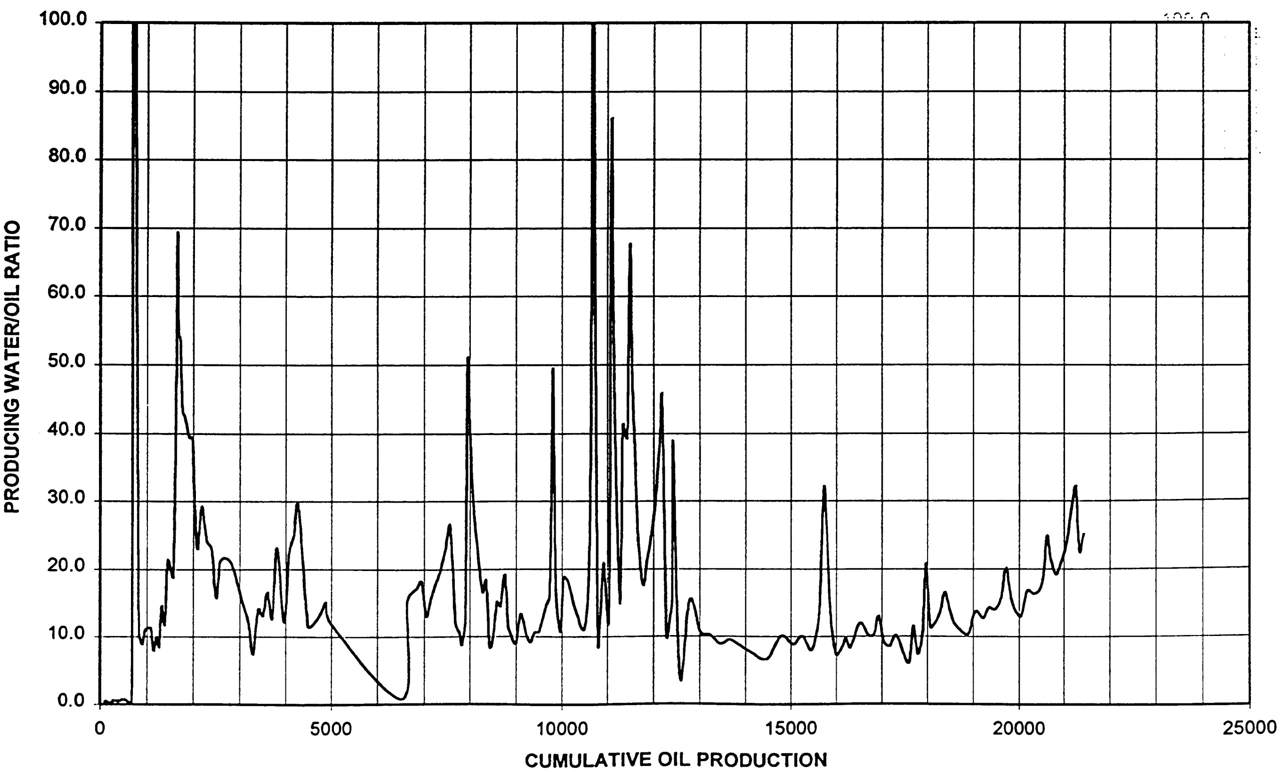
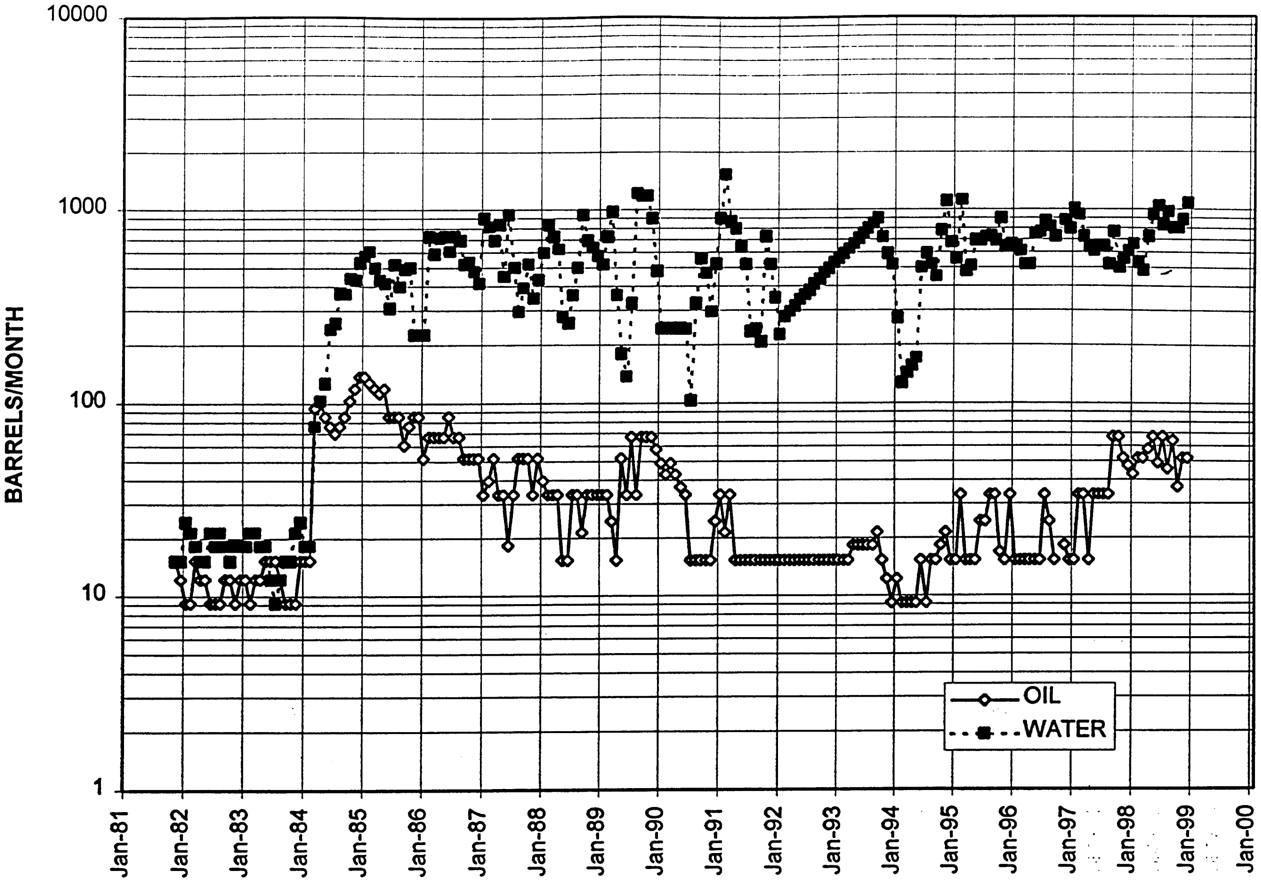
Jan-90
Jan-91
Jan-92
Jan-93
Jan-94
Jan-95
Jan-96
Jan-97
Jan-98
Jan-99
Jan-00

H-17



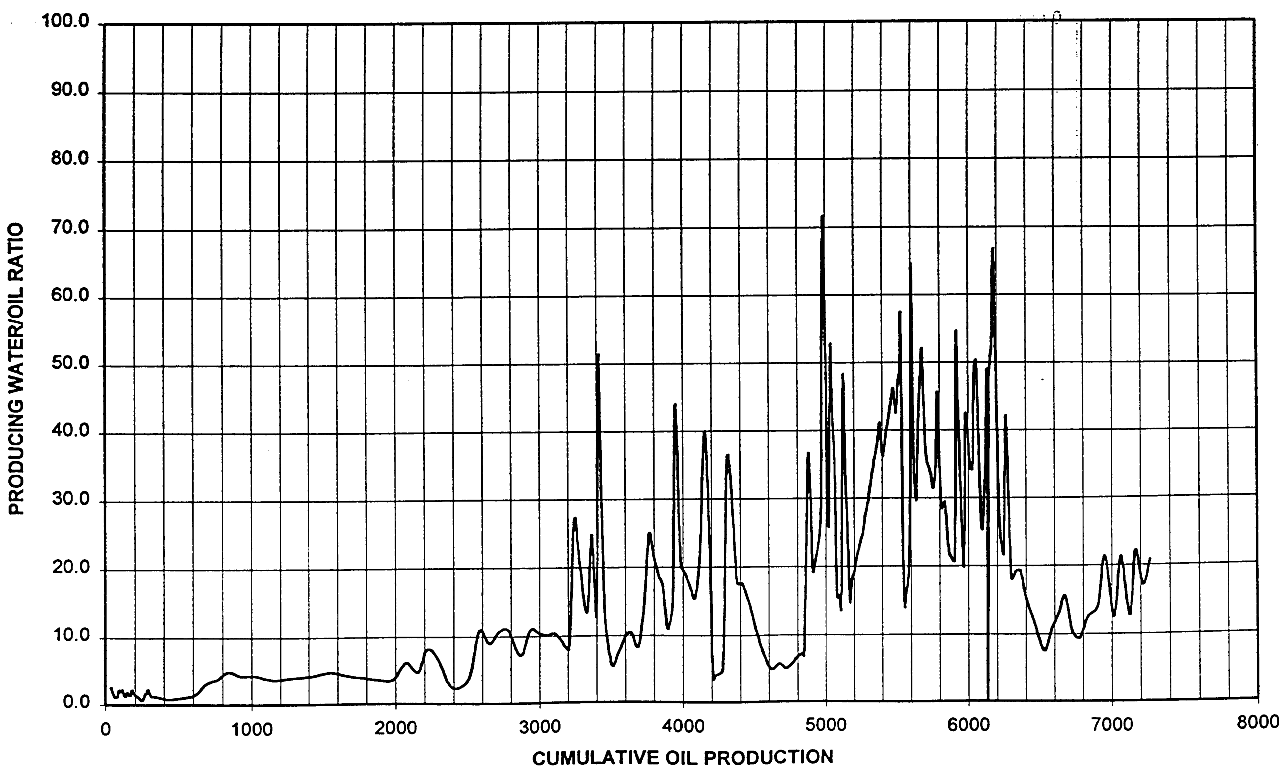
100.0
90.0
80.0
70.0
60.0
50.0
40.0
30.0
20.0
10.0
0.0
PRODUCING WATER/OIL RATIO
0
5000
10000
15000
20000
25000
CUMULATIVE OIL PRODUCTION

H-20



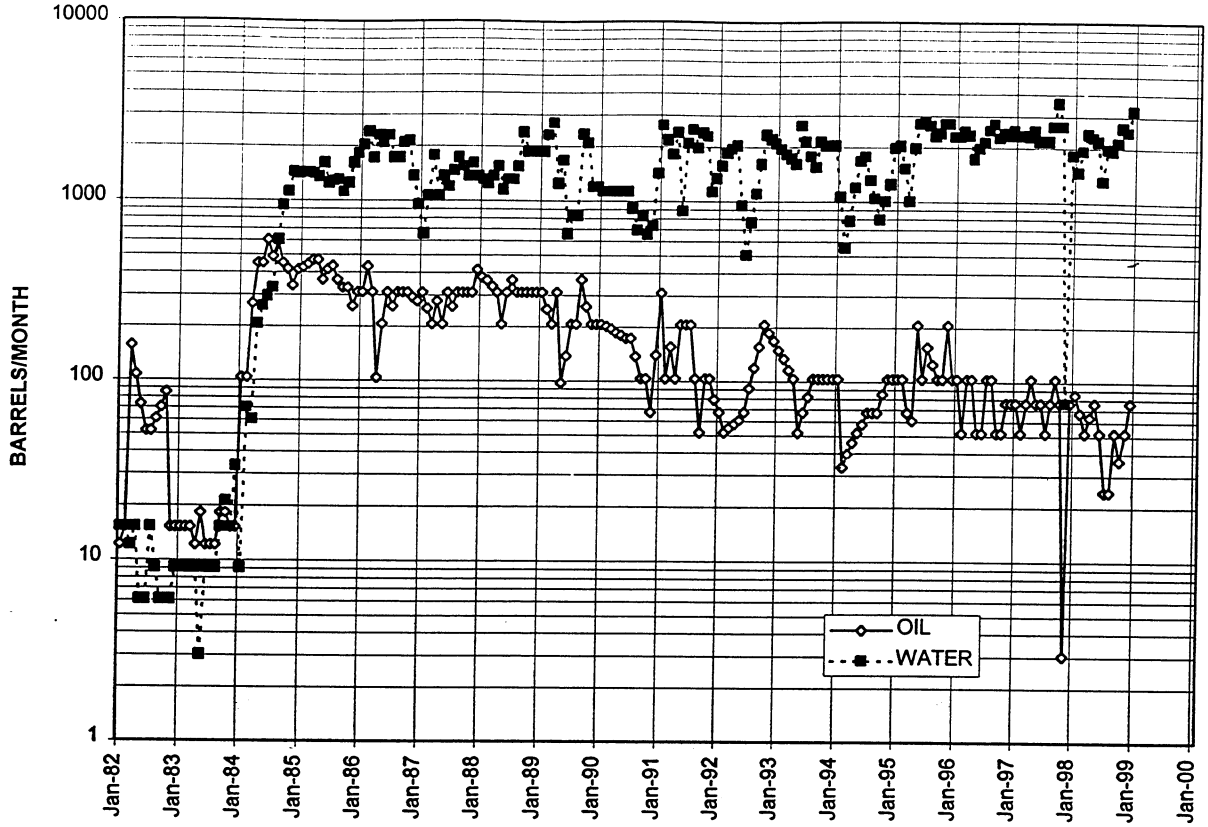
10000
1000
100
10
1
BARRELS/MONTH
OIL
WATER
Jan-81
Jan-82
Jan-83
Jan-84
Jan-85
Jan-86
Jan-87
Jan-88
Jan-89
Jan-90
Jan-91
Jan-92
Jan-93
Jan-94
Jan-95
Jan-96
Jan-97
Jan-98
Jan-99
Jan-00

H-20



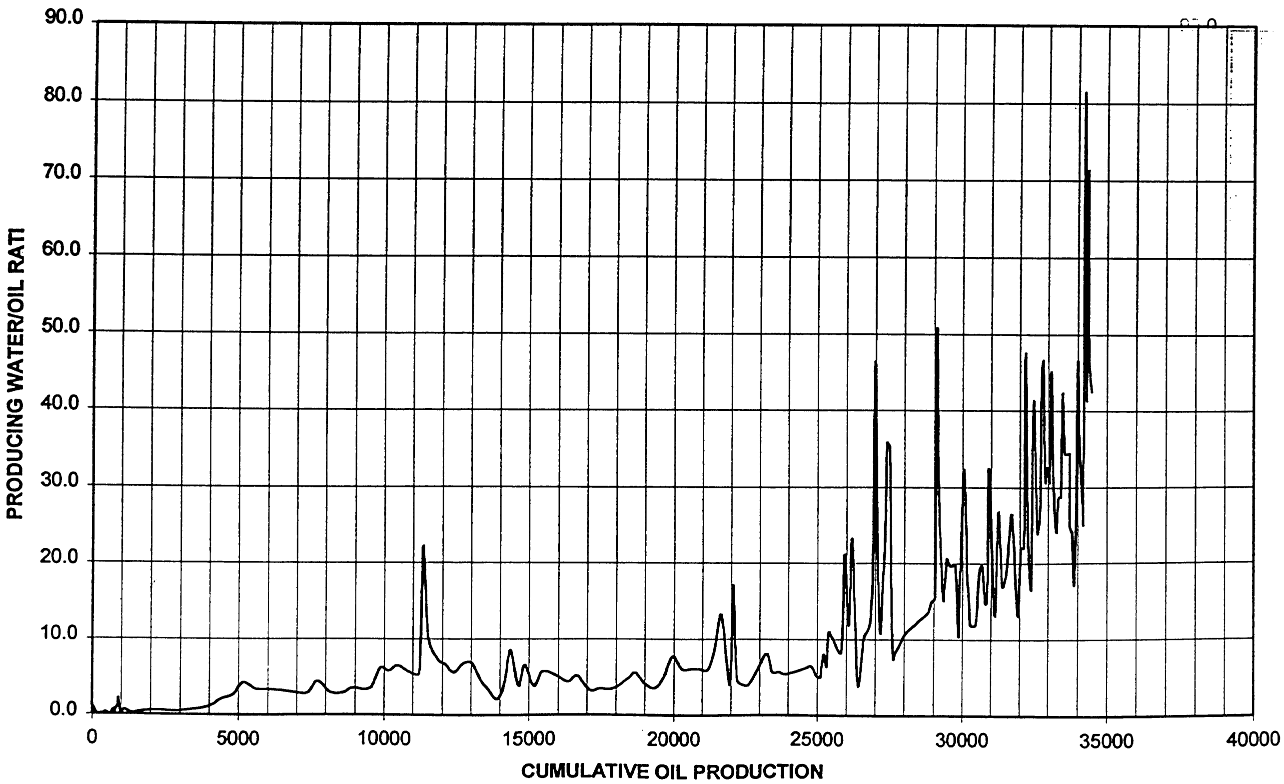
100.0
90.0
80.0
70.0
60.0
50.0
40.0
30.0
20.0
10.0
0.0
PRODUCING WATER/OIL RATIO
0
1000
2000
3000
4000
5000
6000
7000
8000
CUMULATIVE OIL PRODUCTION

H-21



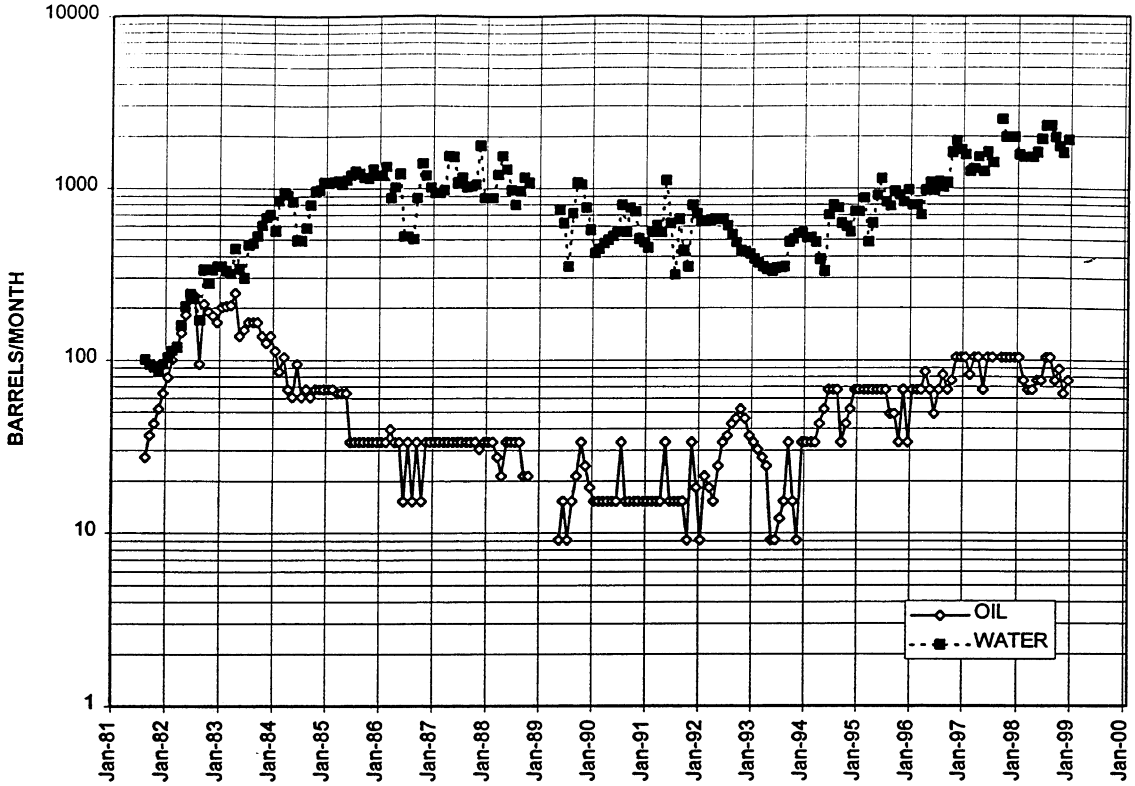
10000
1000
100
10
1
BARRELS/MONTH
OIL
WATER
Jan-82
Jan-83
Jan-84
Jan-85
Jan-86
Jan-87
Jan-88
Jan-89
Jan-90
Jan-91
Jan-92
Jan-93
Jan-94
Jan-95
Jan-96
Jan-97
Jan-98
Jan-99
Jan-00

H-21



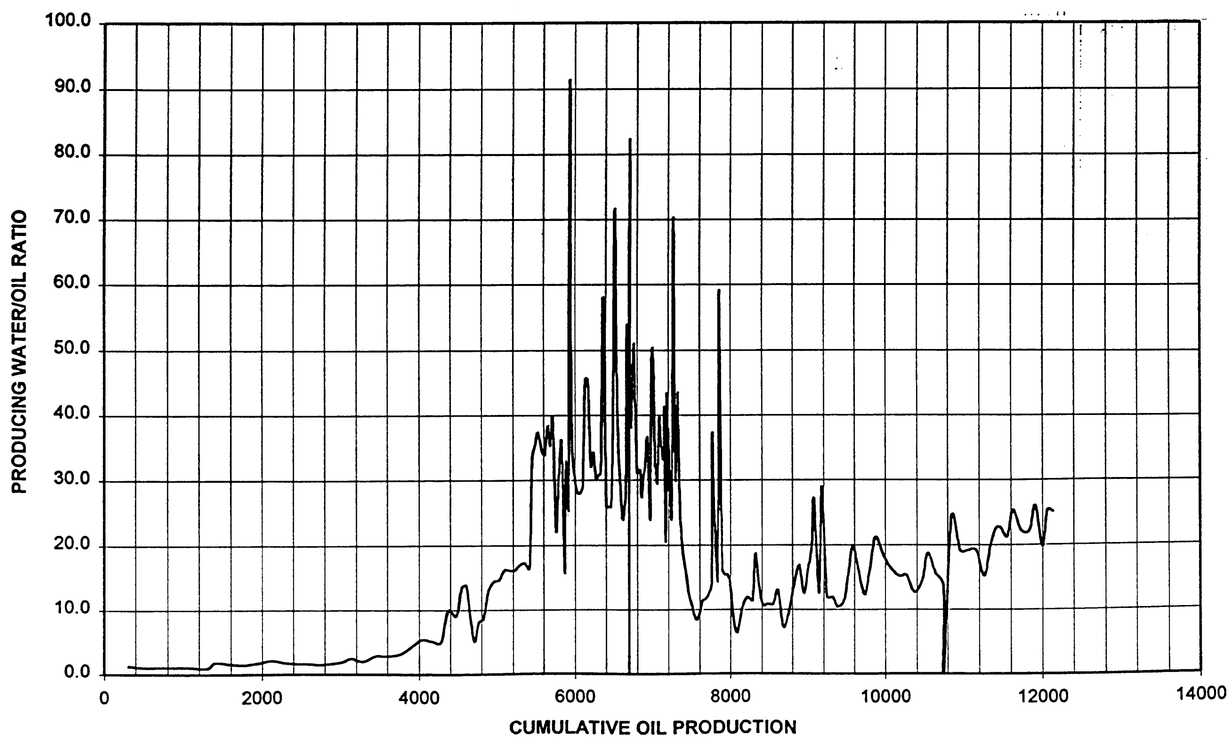
90.0
80.0
70.0
60.0
50.0
40.0
30.0
20.0
10.0
0.0
PRODUCING WATER/OIL RATI
0
5000
10000
15000
20000
25000
30000
35000
40000
CUMULATIVE OIL PRODUCTION

H-22



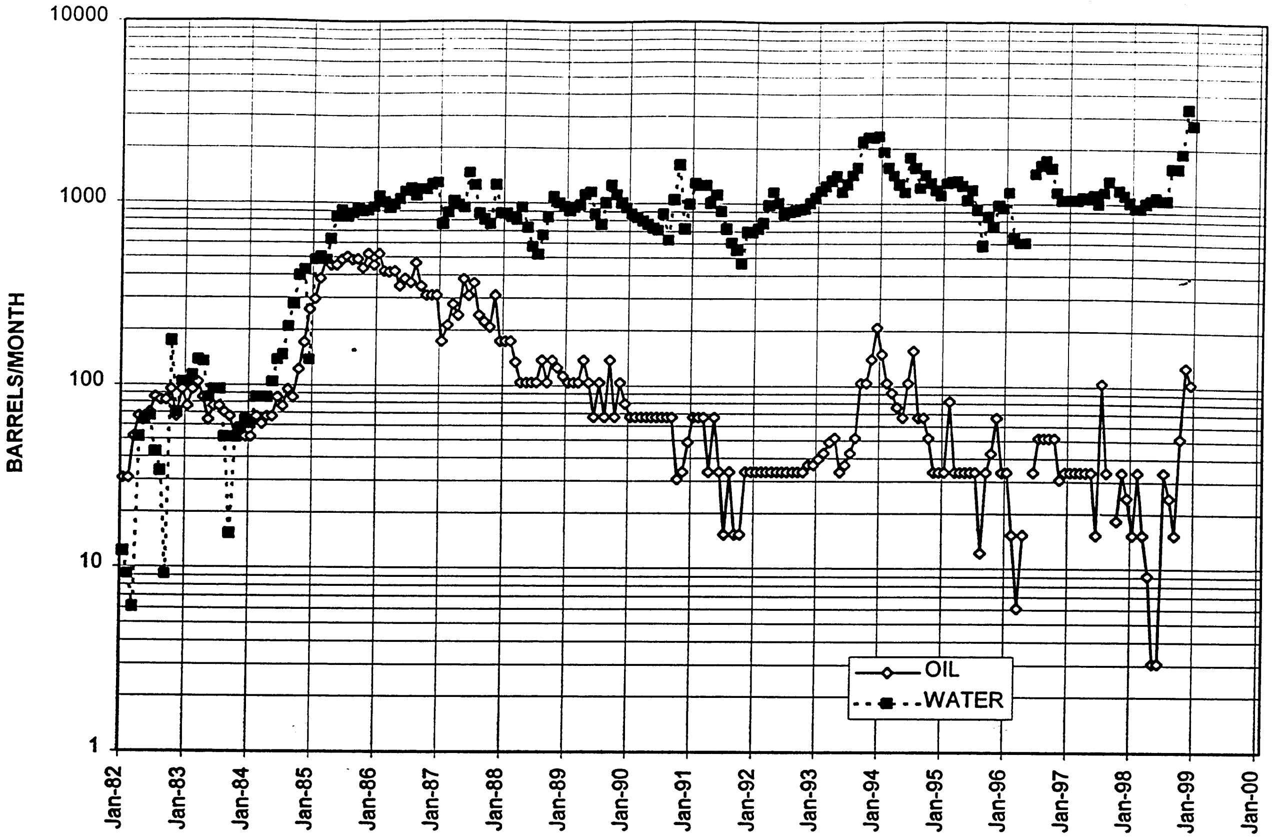
10000
1000
100
10
1
BARRELS/MONTH
OIL
WATER
Jan-81
Jan-82
Jan-83
Jan-84
Jan-85
Jan-86
Jan-87
Jan-88
Jan-89
Jan-90
Jan-91
Jan-92
Jan-93
Jan-94
Jan-95
Jan-96
Jan-97
Jan-98
Jan-99
Jan-00

H-22

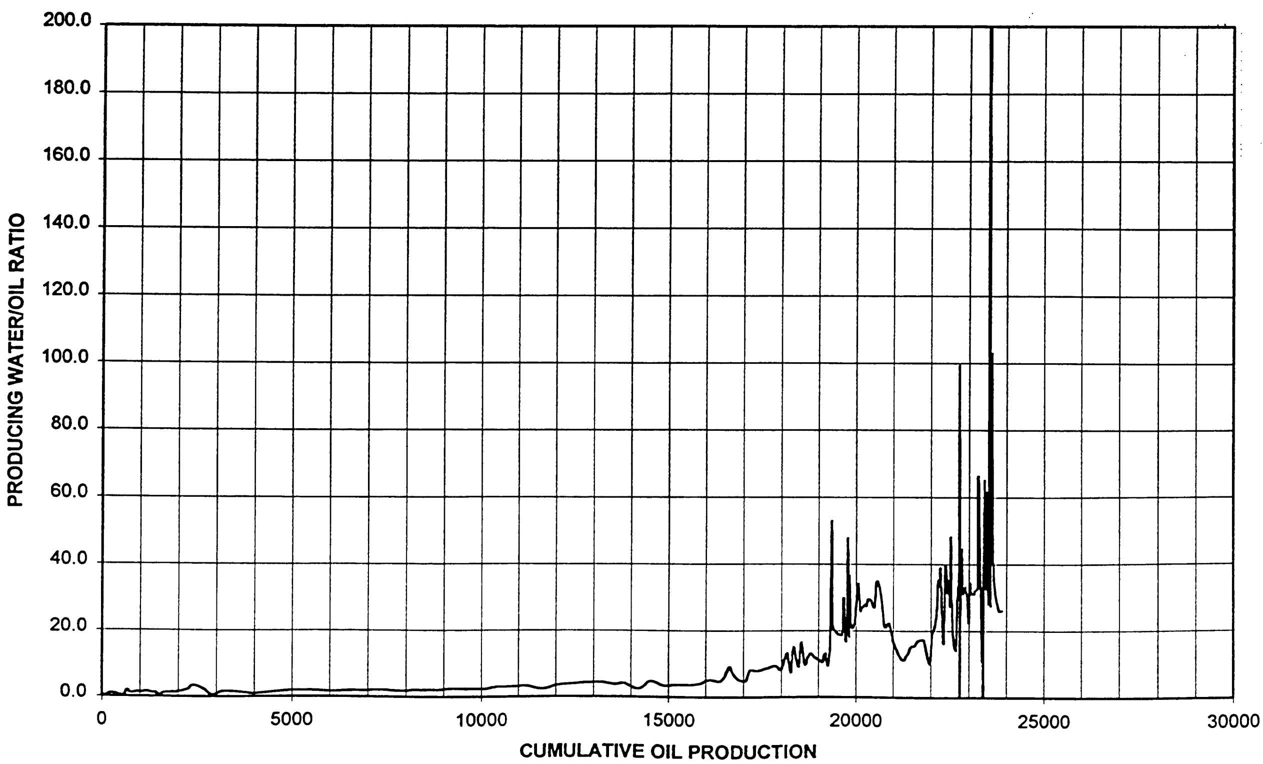


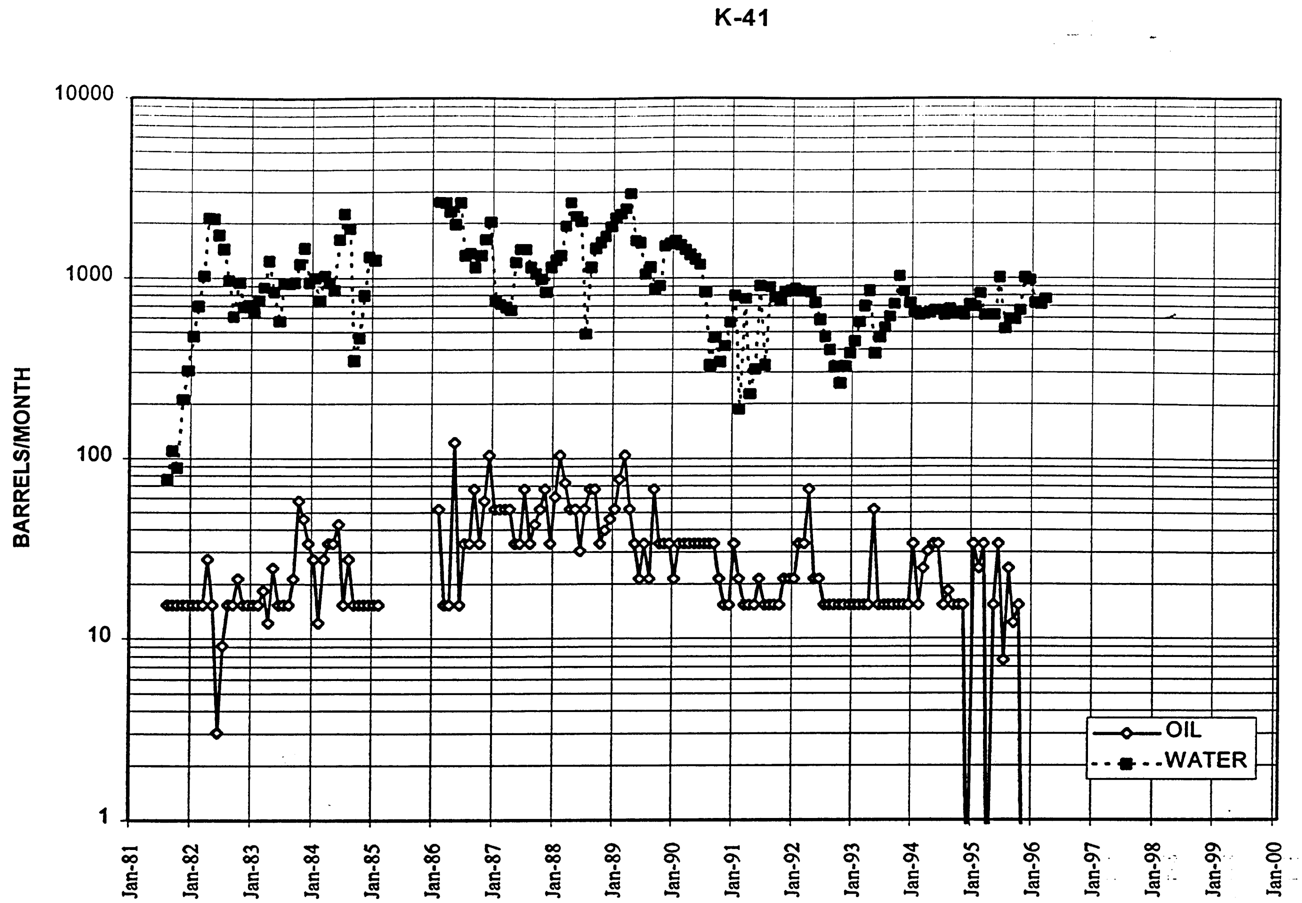
100.0
90.0
80.0
70.0
60.0
50.0
40.0
30.0
20.0
10.0
0.0
PRODUCING WATER/OIL RATIO
0
2000
4000
6000
8000
10000
12000
14000
CUMULATIVE OIL PRODUCTION

H-30


10000
1000
100
10
1
BARRELS/MONTH
Jan-82
Jan-83
Jan-84
Jan-85
Jan-86
Jan-87
Jan-88
Jan-89
Jan-90
Jan-91
Jan-92
Jan-93
Jan-94
Jan-95
Jan-96
Jan-97
Jan-98
Jan-99
Jan-00
OIL
WATER

H30


200.0
180.0
160.0
140.0
120.0
100.0
80.0
60.0
40.0
20.0
0.0
PRODUCING WATER/OIL RATIO
0
5000
10000
15000
20000
25000
30000
CUMULATIVE OIL PRODUCTION


K-41
10000
1000
100
10
1
BARRELS/MONTH
OIL
WATER
Jan-81
Jan-82
Jan-83
Jan-84
Jan-85
Jan-86
Jan-87
Jan-88
Jan-89
Jan-90
Jan-91
Jan-92
Jan-93
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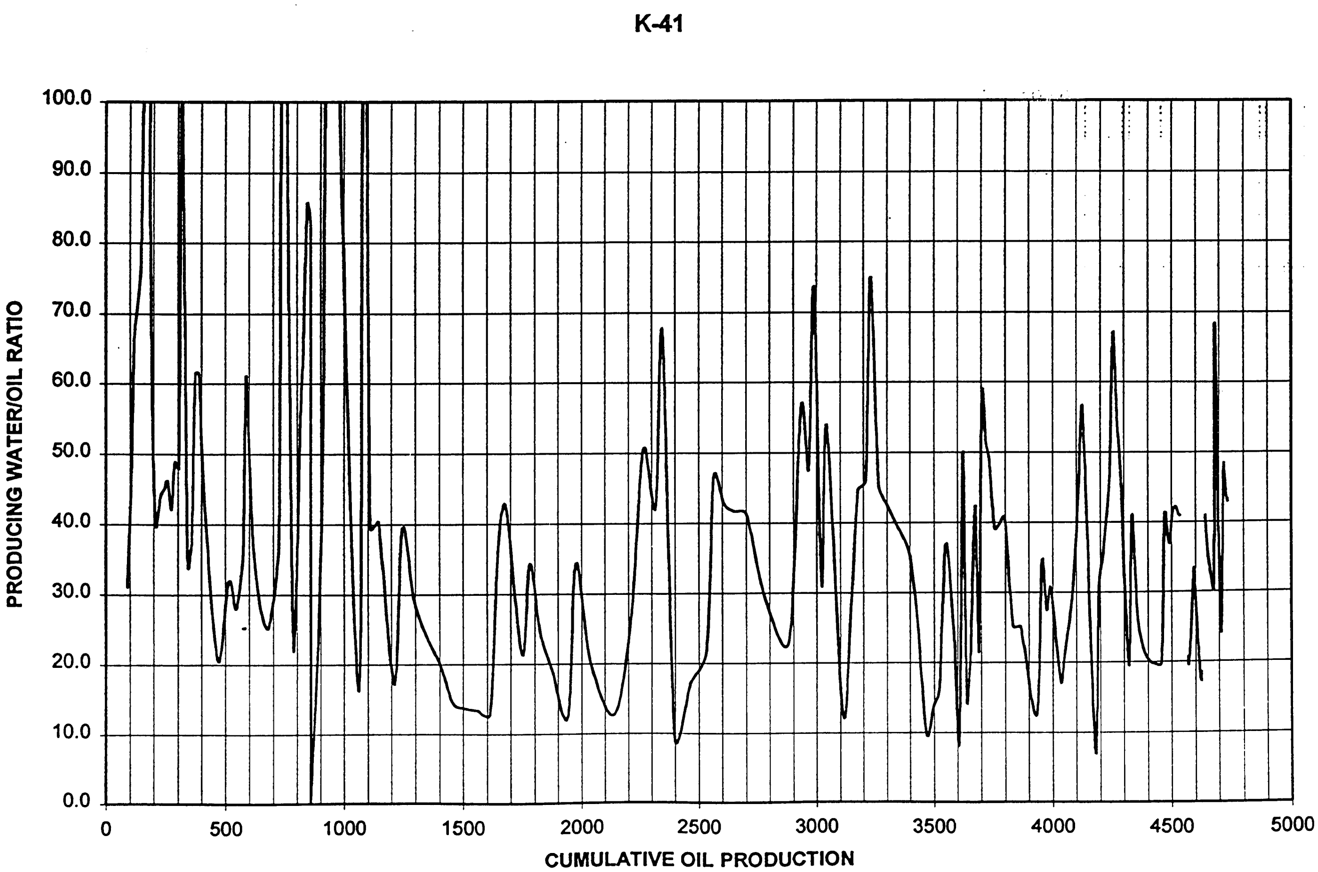
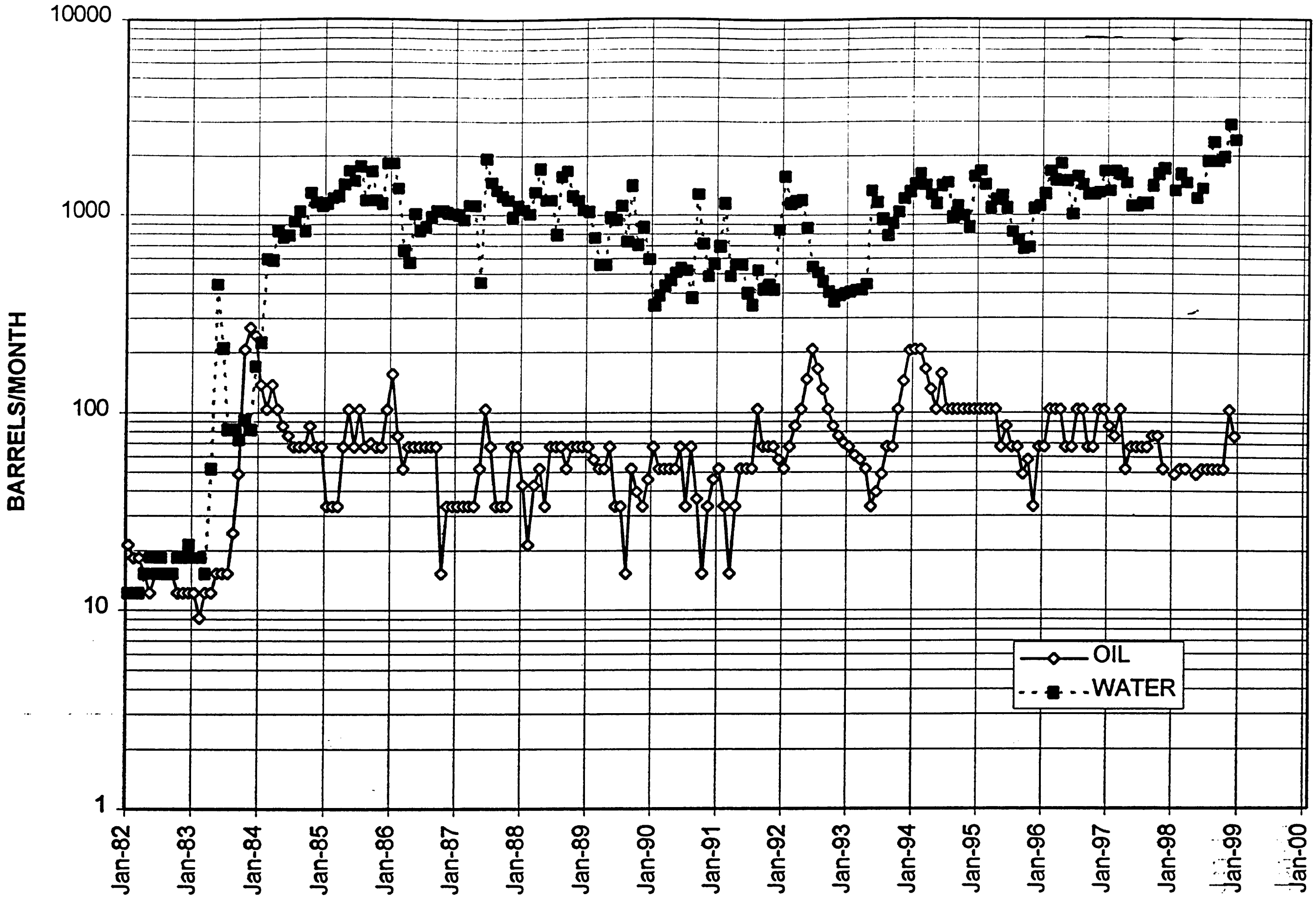
Jan-95
Jan-96
Jan-97
Jan-98
Jan-99
Jan-00

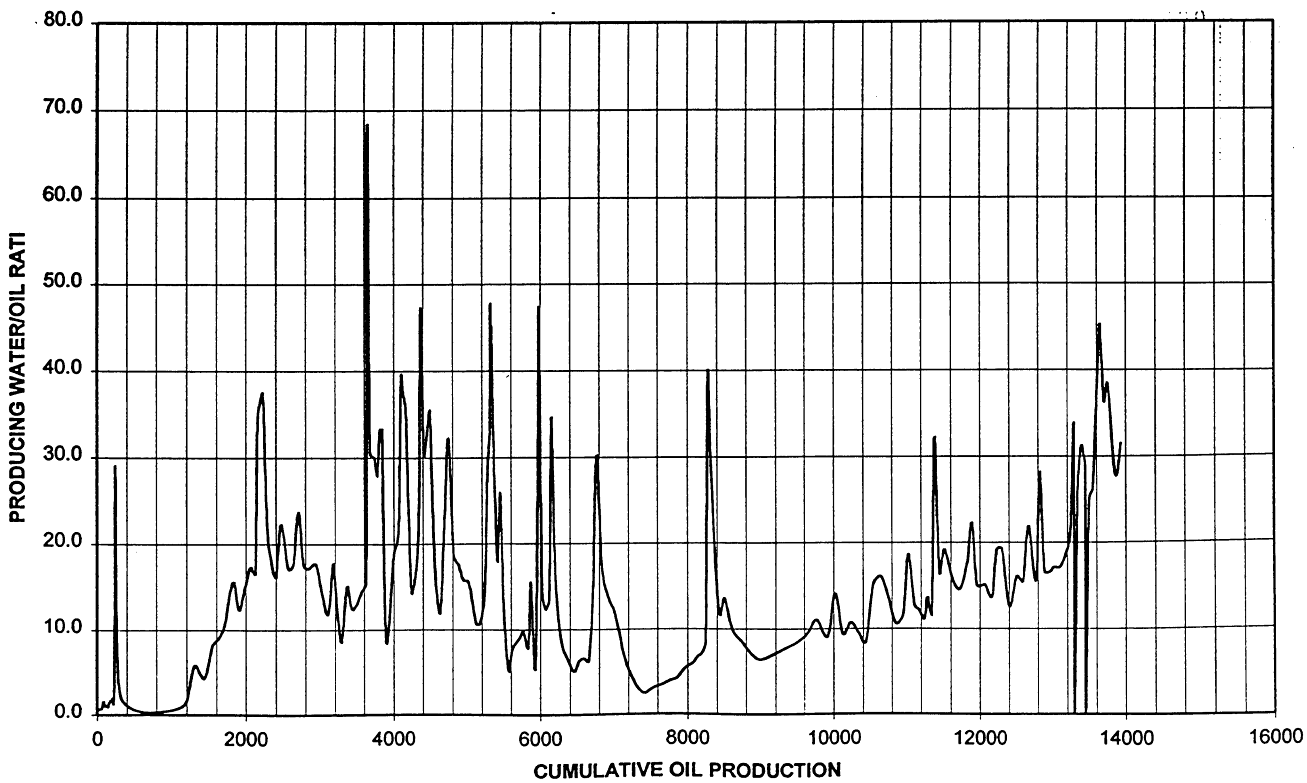

K-41
100.0
90.0
80.0
70.0
60.0
50.0
40.0
30.0
20.0
10.0
0.0
PRODUCING WATER/OIL RATIO
0
500
1000
1500
2000
2500
3000
3500
4000
4500
5000
CUMULATIVE OIL PRODUCTION

K-43



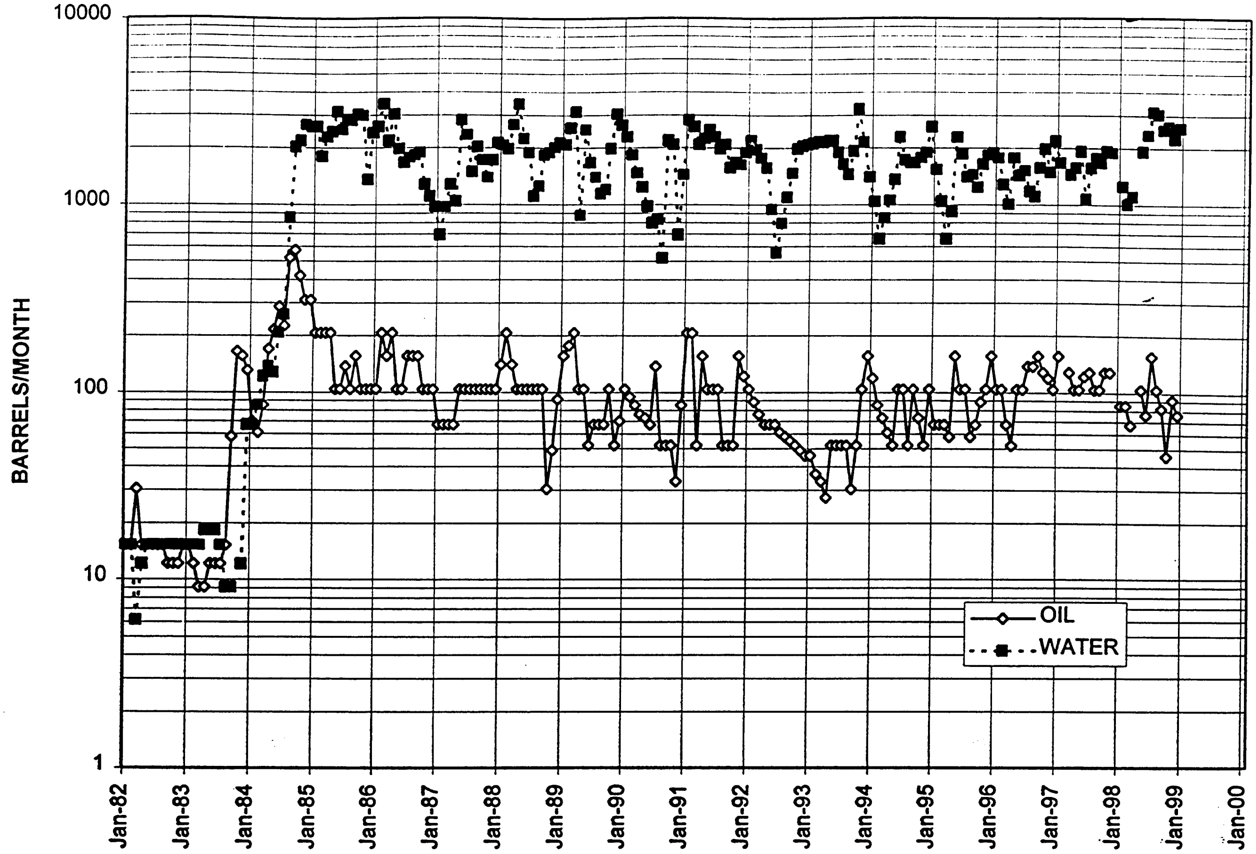
10000
1000
100
10
1
BARRELS/MONTH
Jan-82
Jan-83
Jan-84
Jan-85
Jan-86
Jan-87
Jan-88
Jan-89
Jan-90
Jan-91
Jan-92
Jan-93
Jan-94
Jan-95
Jan-96
Jan-97
Jan-98
Jan-99
Jan-00
OIL
WATER

K-43



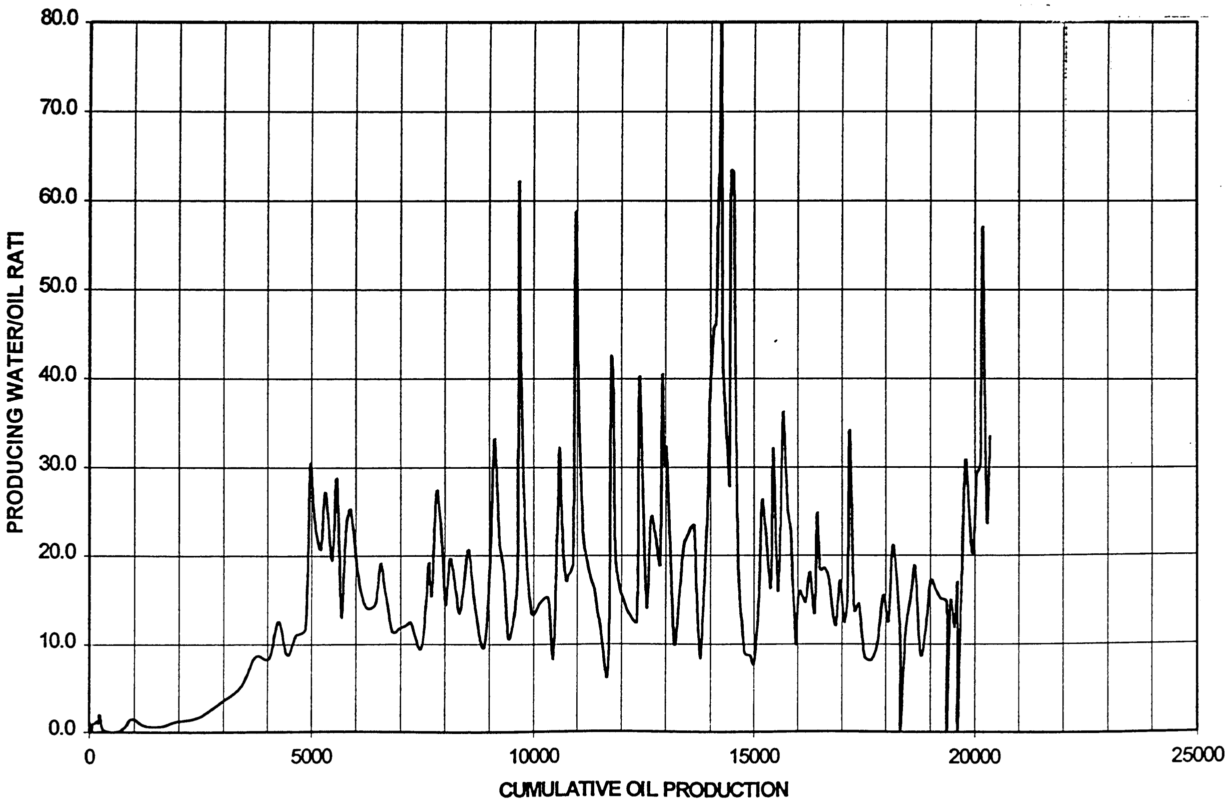
80.0
70.0
60.0
50.0
40.0
30.0
20.0
10.0
0.0
PRODUCING WATER/OIL RATI
0
2000
4000
6000
8000
10000
12000
14000
16000
CUMULATIVE OIL PRODUCTION

K-44



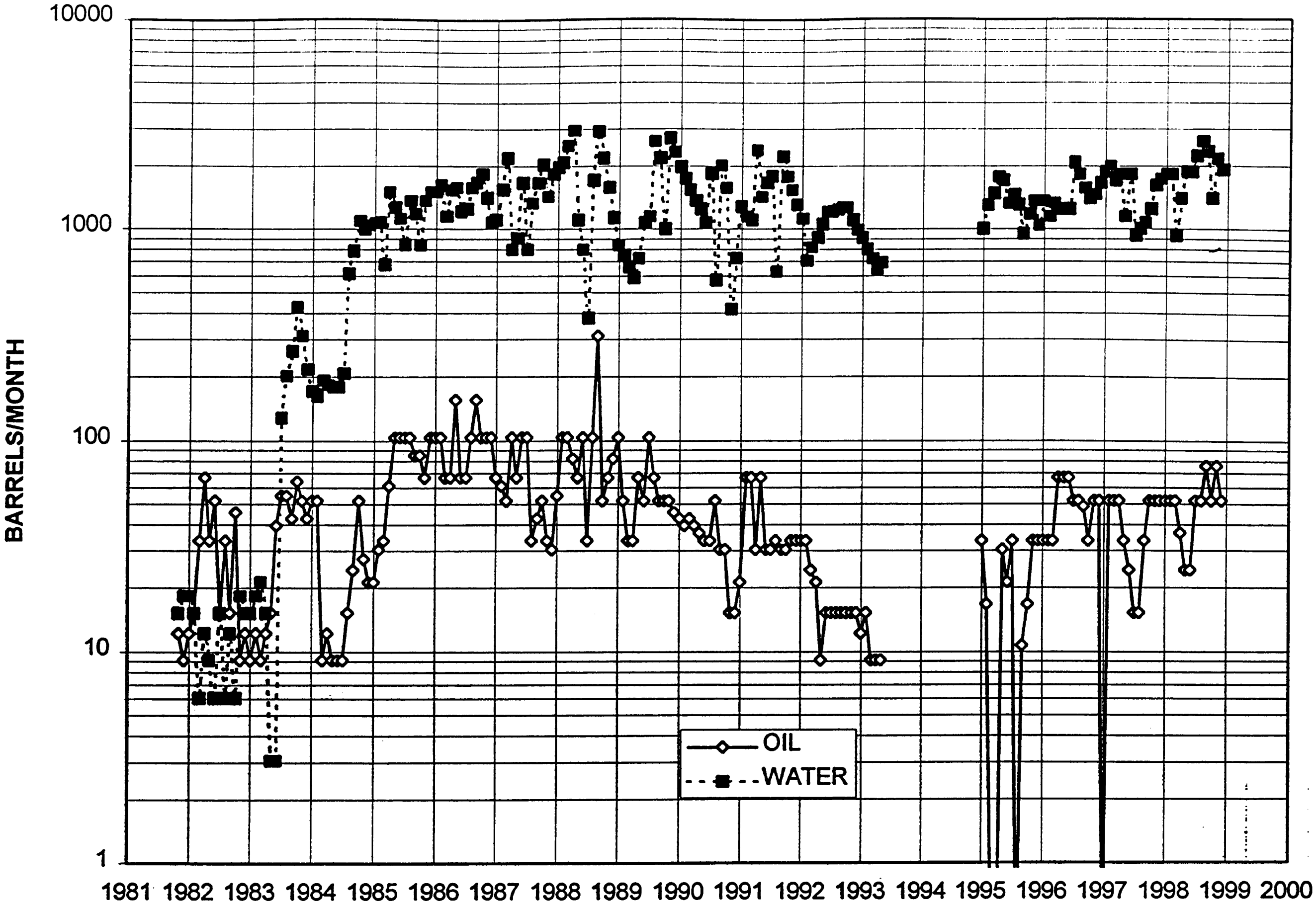
10000
1000
100
10
1
BARRELS/MONTH
Jan-82
Jan-83
Jan-84
Jan-85
Jan-86
Jan-87
Jan-88
Jan-89
Jan-90
Jan-91
Jan-92
Jan-93
Jan-94
Jan-95
Jan-96
Jan-97
Jan-98
Jan-99
Jan-00
OIL
WATER

K-44



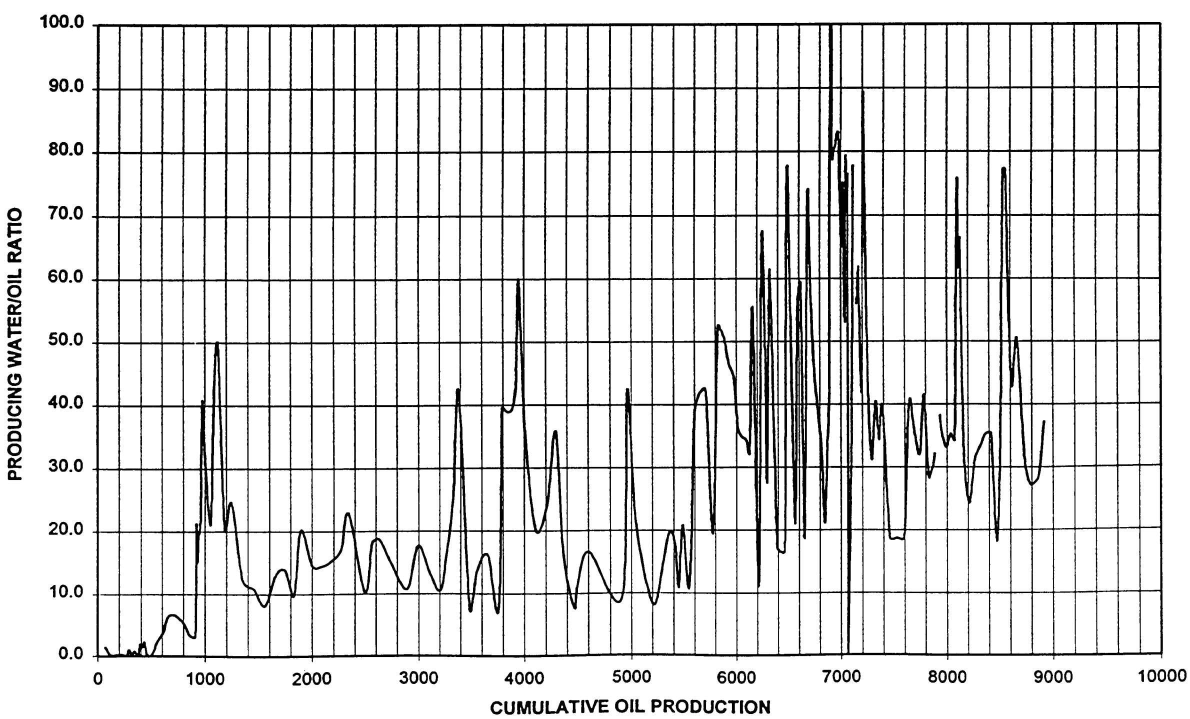
80.0
70.0
60.0
50.0
40.0
30.0
20.0
10.0
0.0
PRODUCING WATER/OIL RATI
0
5000
10000
15000
20000
25000
CUMULATIVE OIL PRODUCTION

K-45



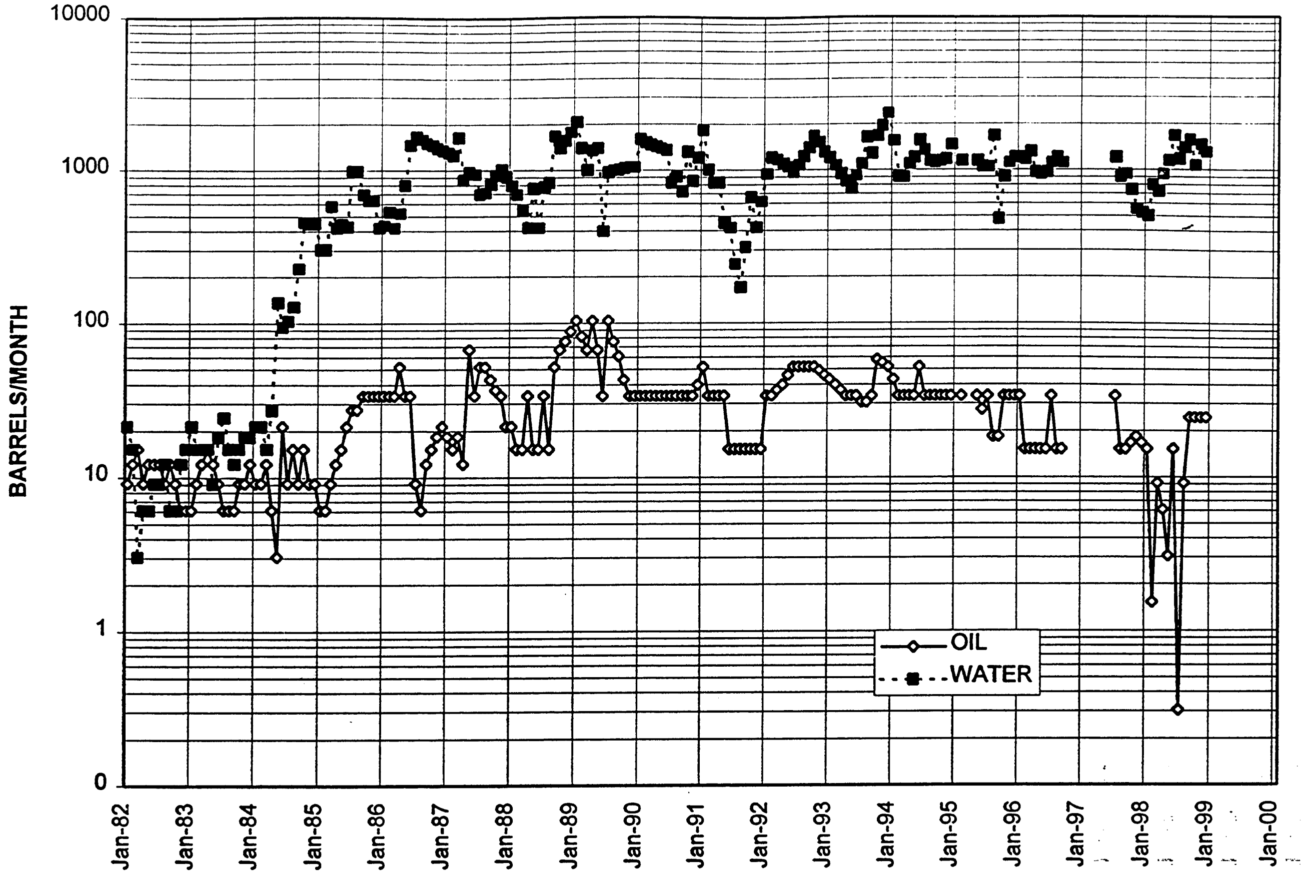
BARRELS/MONTH
10000
1000
100
10
1
1981 1982 1983 1984 1985 1986 1987 1988 1989 1990 1991 1992 1993 1994 1995 1996 1997 1998 1999 2000
OIL
WATER

K-45

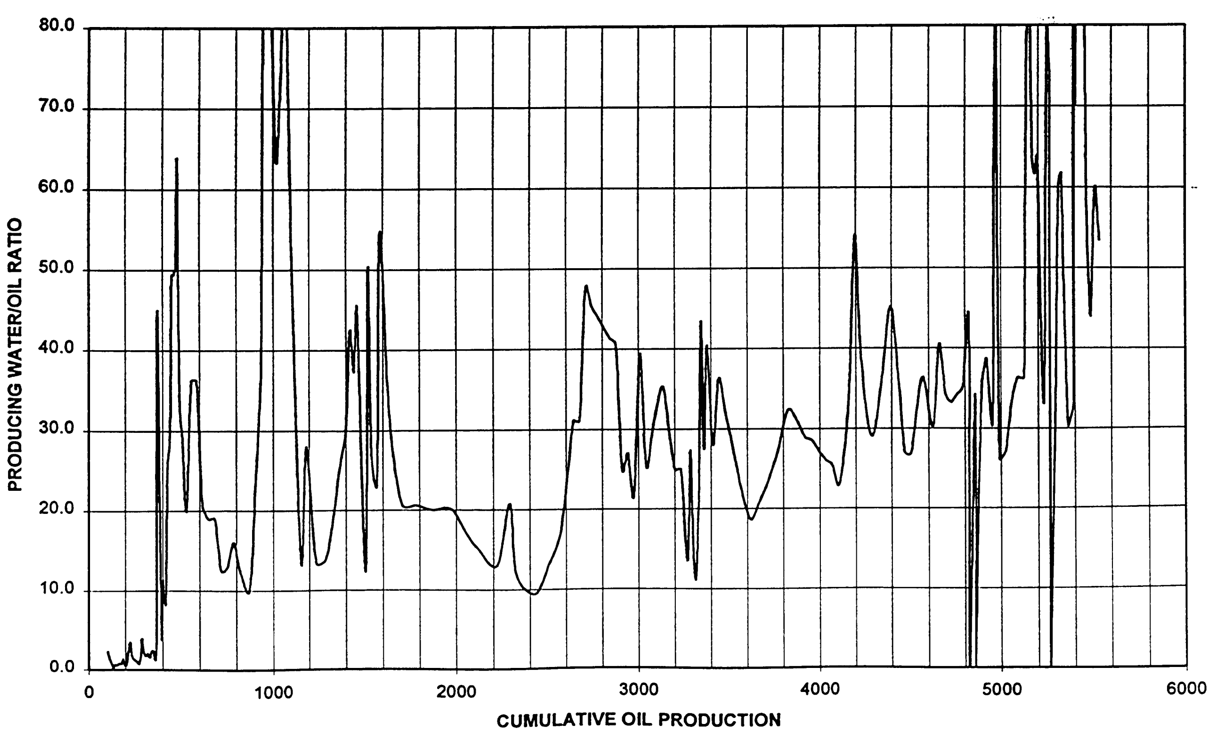


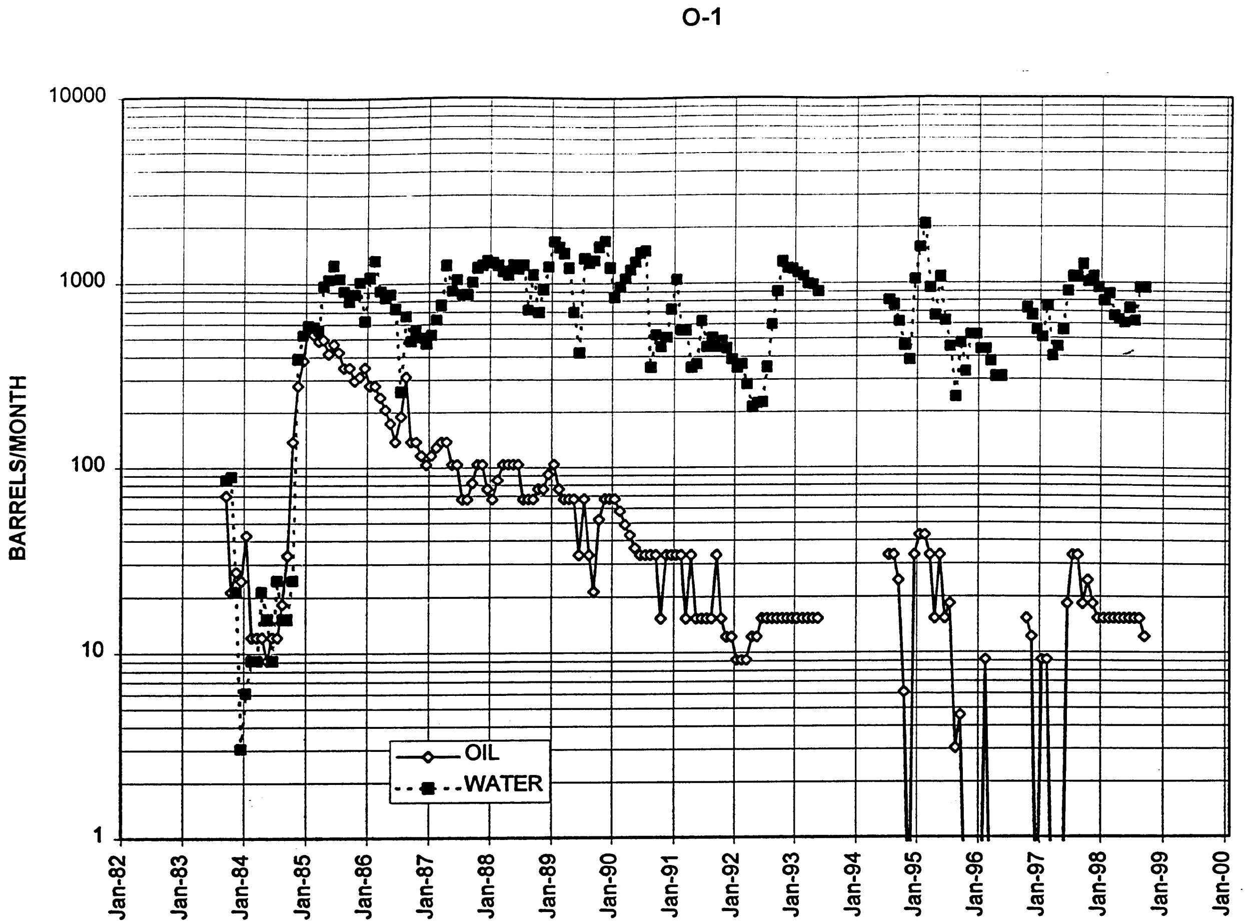
PRODUCING WATER/OIL RATIO
100.0
90.0
80.0
70.0
60.0
50.0
40.0
30.0
20.0
10.0
0.0
0 1000 2000 3000 4000 5000 6000 7000 8000 9000 10000
CUMULATIVE OIL PRODUCTION

K-54


BARRELS/MONTH
10000
1000
100
10
1
0
OIL
WATER
Jan-82
Jan-83
Jan-84
Jan-85
Jan-86
Jan-87
Jan-88
Jan-89
Jan-90
Jan-91
Jan-92
Jan-93
Jan-94
Jan-95
Jan-96
Jan-97
Jan-98
Jan-99
Jan-00

K-54


PRODUCING WATER/OIL RATIO
80.0
70.0
60.0
50.0
40.0
30.0
20.0
10.0
0.0
0
1000
2000
3000
4000
5000
6000
CUMULATIVE OIL PRODUCTION


O-1
10000
1000
100
10
1
BARRELS/MONTH
OIL
WATER
Jan-82
Jan-83
Jan-84
Jan-85
Jan-86
Jan-87
Jan-88
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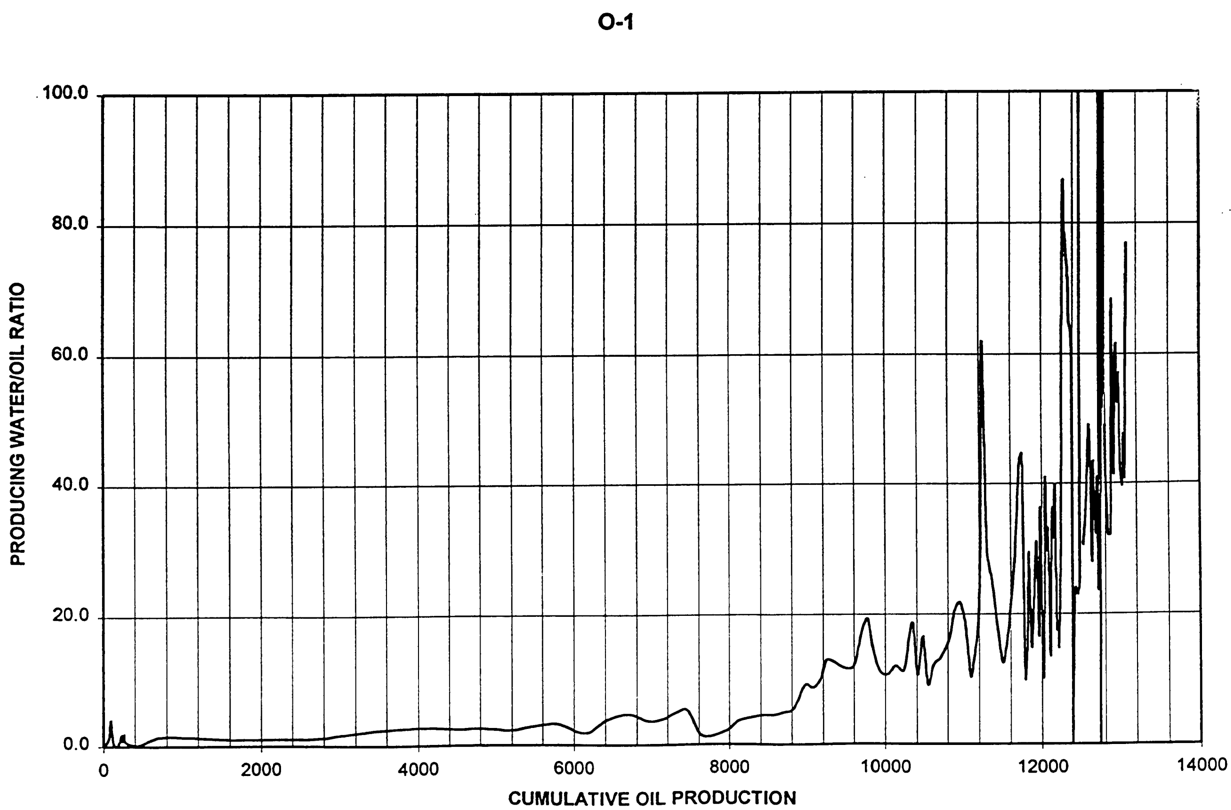
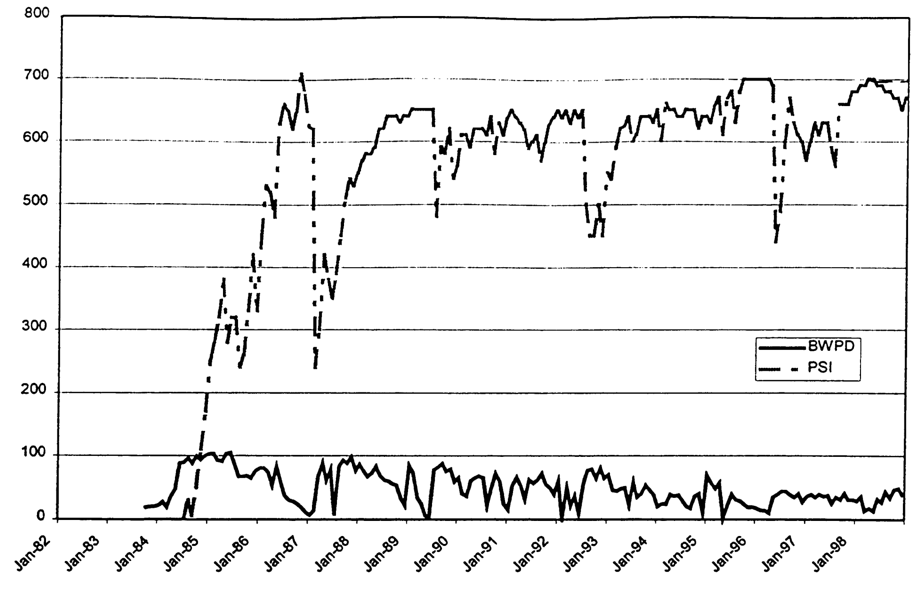
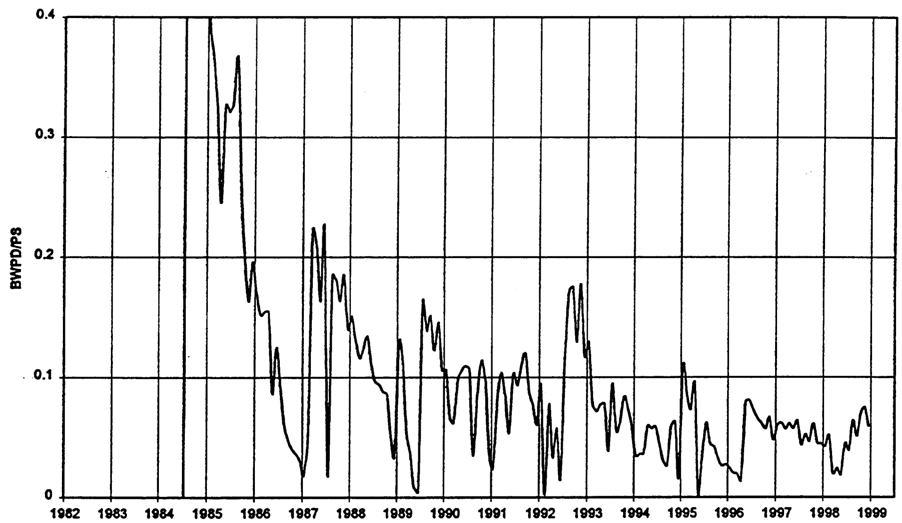
Jan-98
Jan-99
Jan-00


O-1
100.0
80.0
60.0
40.0
20.0
0.0
PRODUCING WATER/OIL RATIO
0
2000
4000
6000
8000
10000
12000
14000
CUMULATIVE OIL PRODUCTION

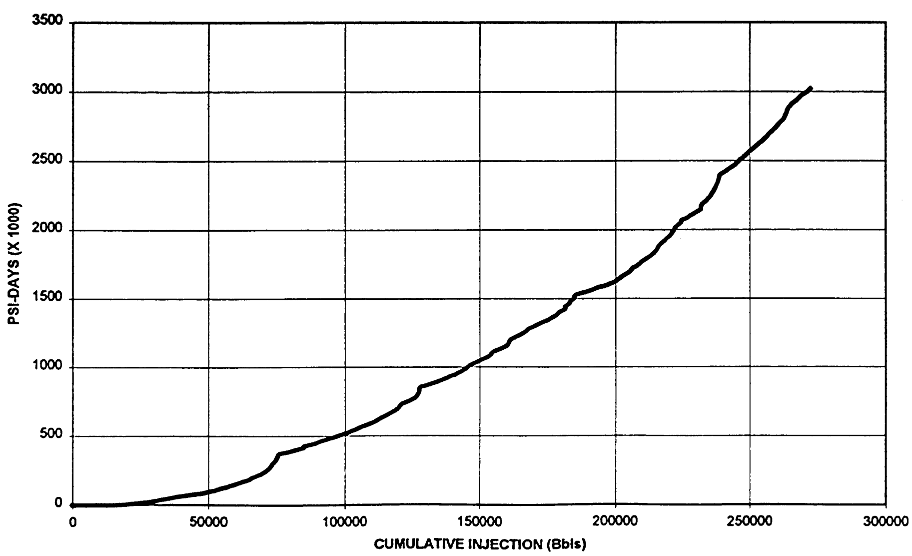
Appendix C



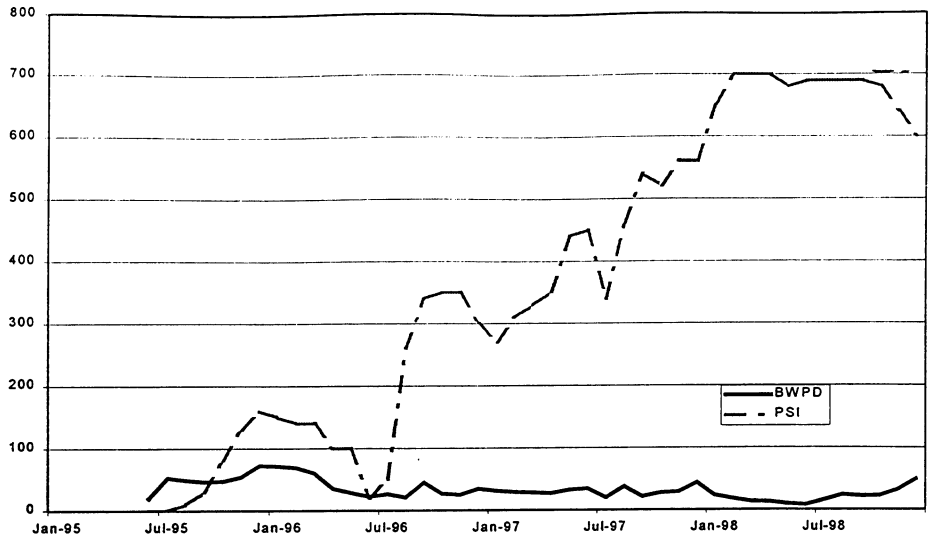
H-12 INJECTIVITY INDEX



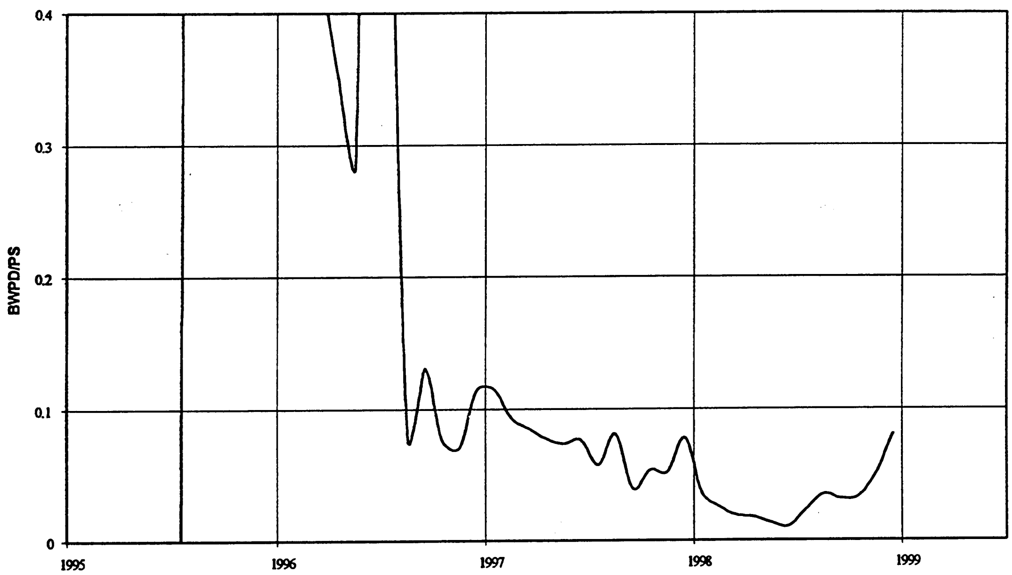
H-12 HALL PLOT



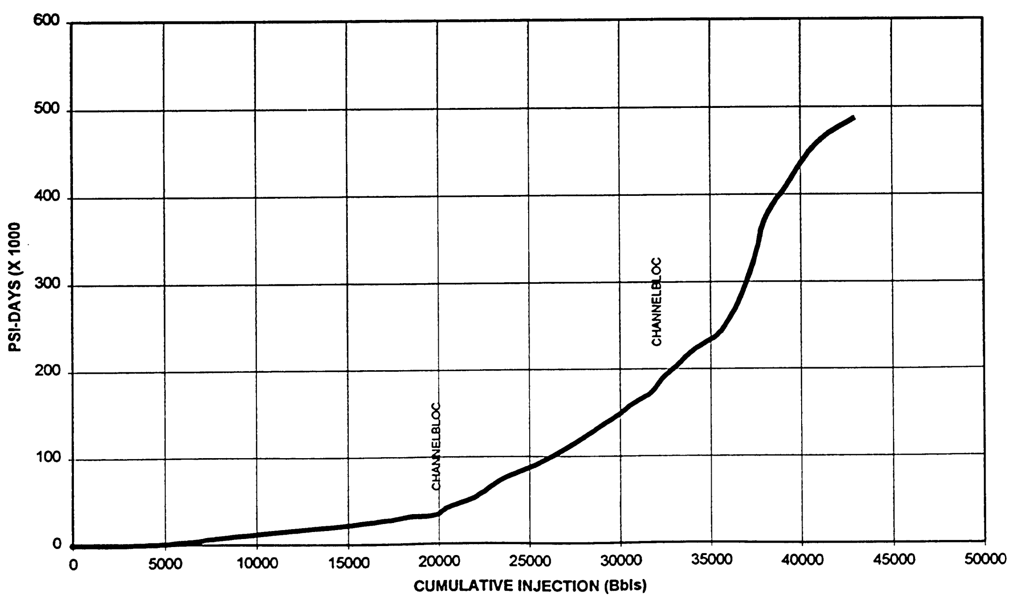
H-14 INJECTION HISTORY



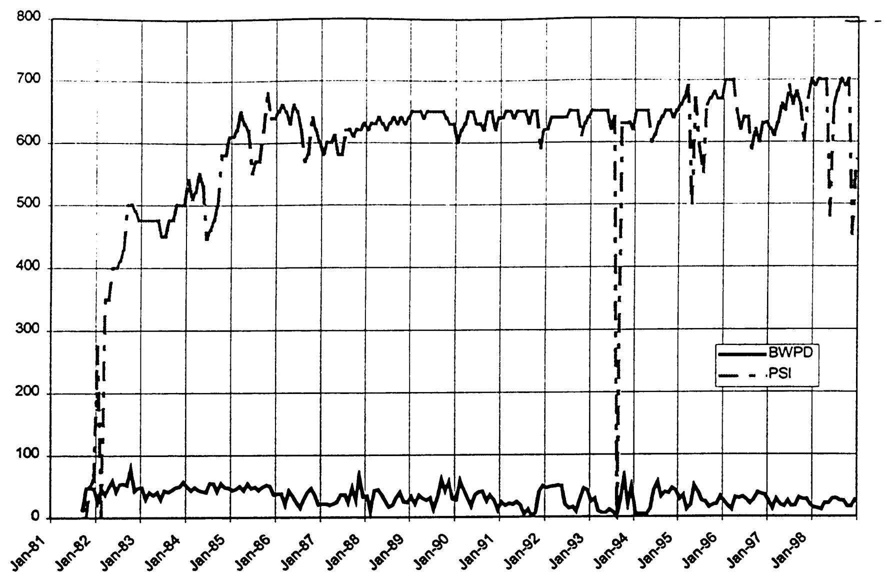
H-14 INJECTIVITY INDEX



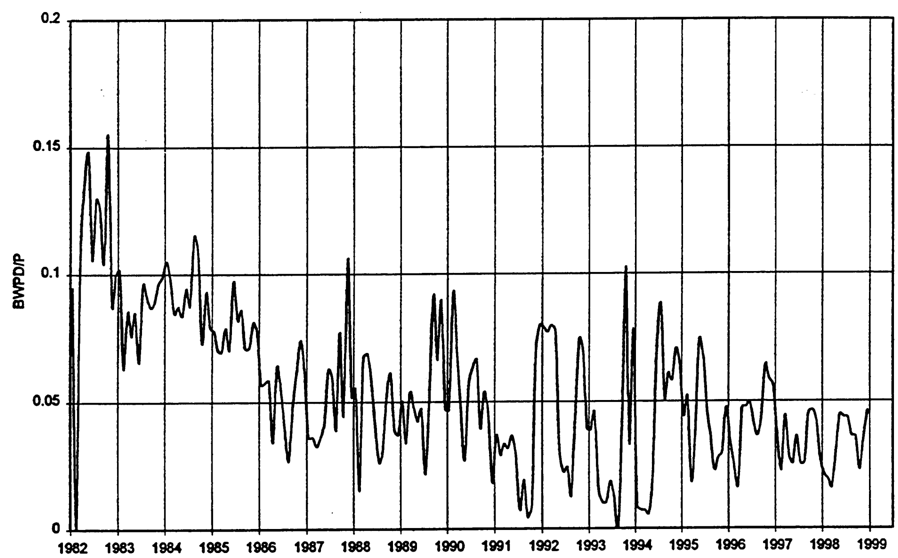
H-14 HALL PLOT



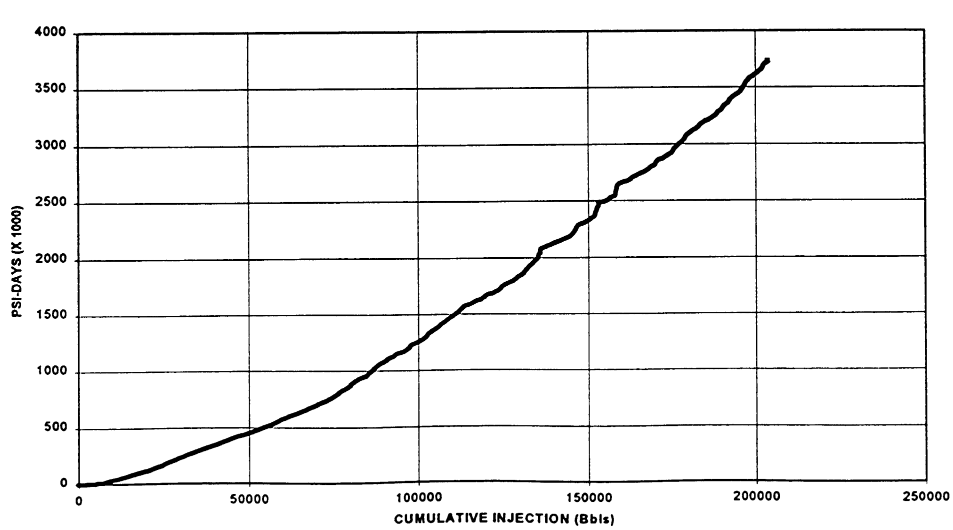
KW-7 INJECTION HISTORY



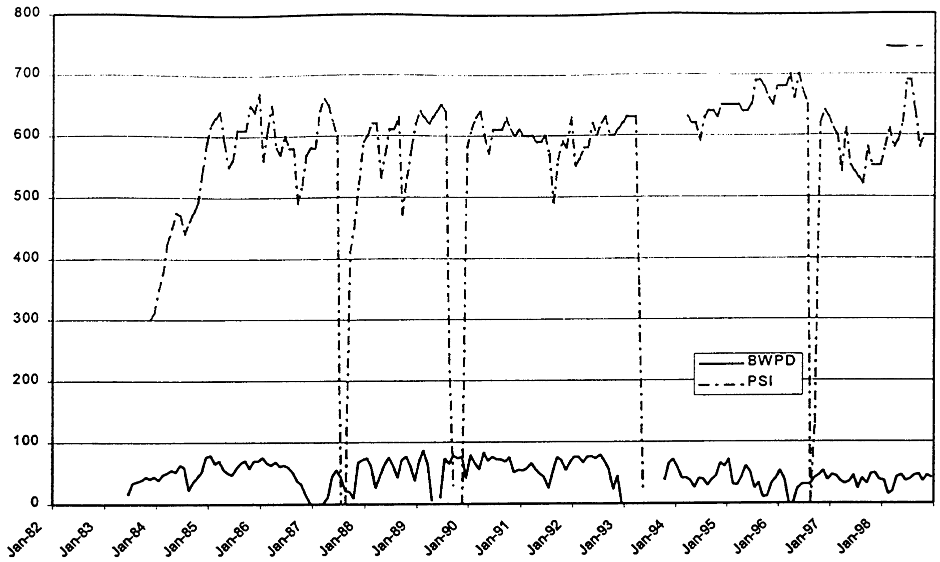
KW-7 INJECTIVITY INDEX



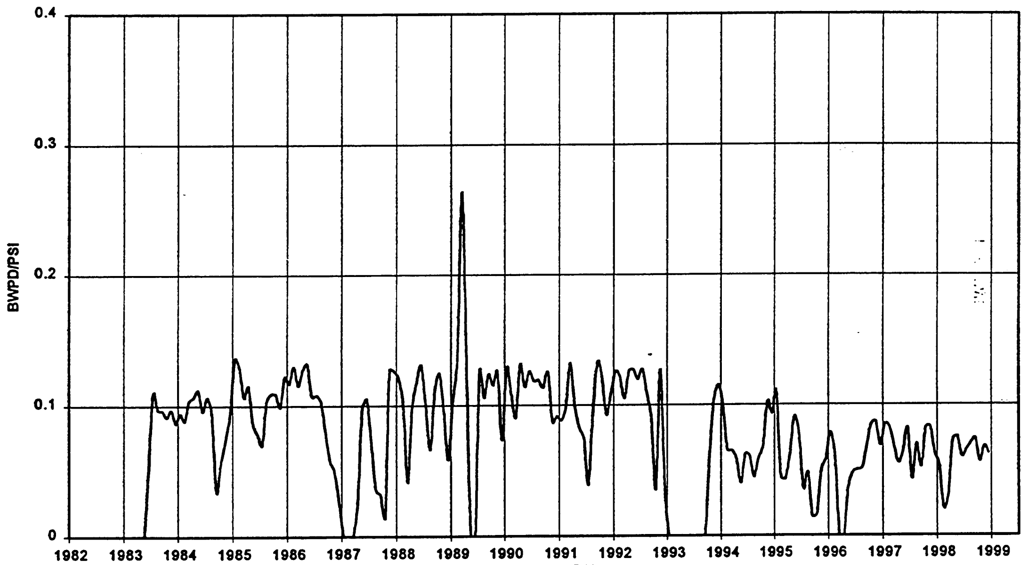
KW-7 HALL PLOT



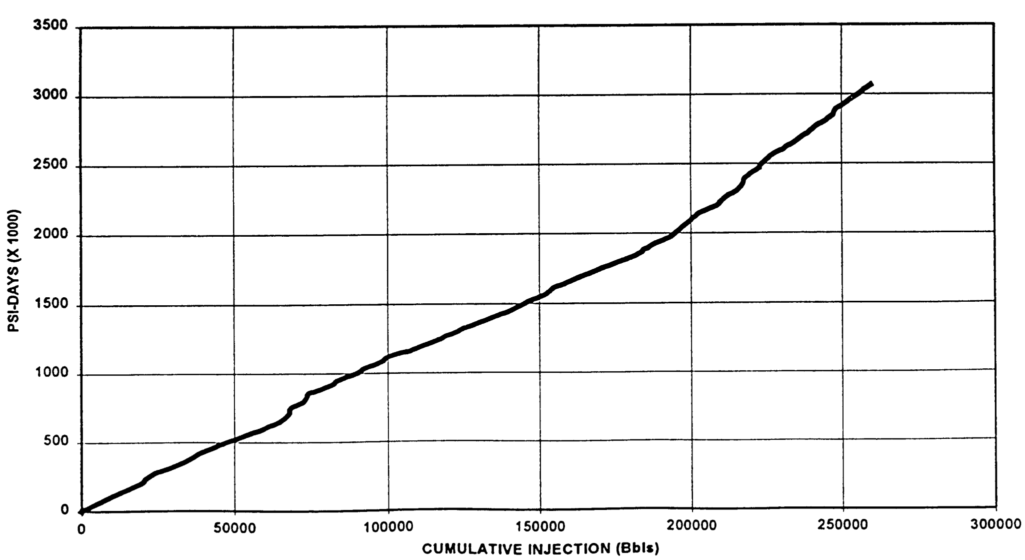
KW-9 INJECTION HISTORY



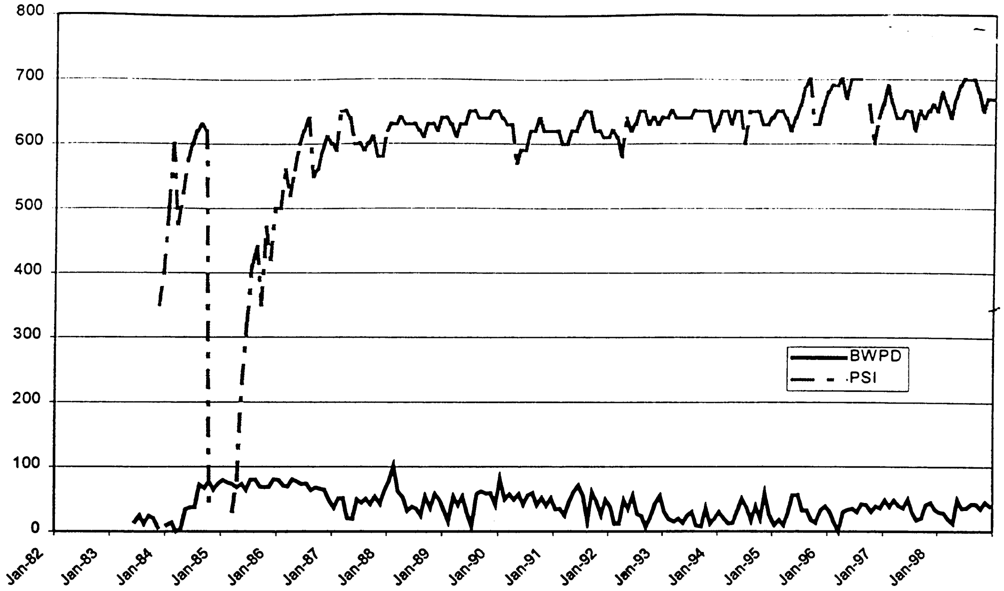
KW-9 INJECTIVITY INDEX



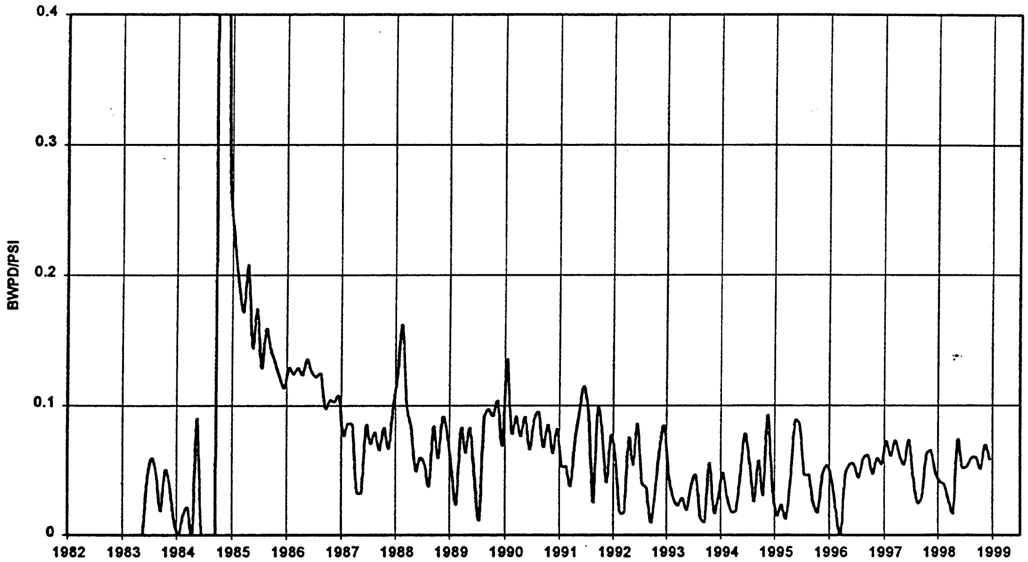
KW-9 HALL PLOT



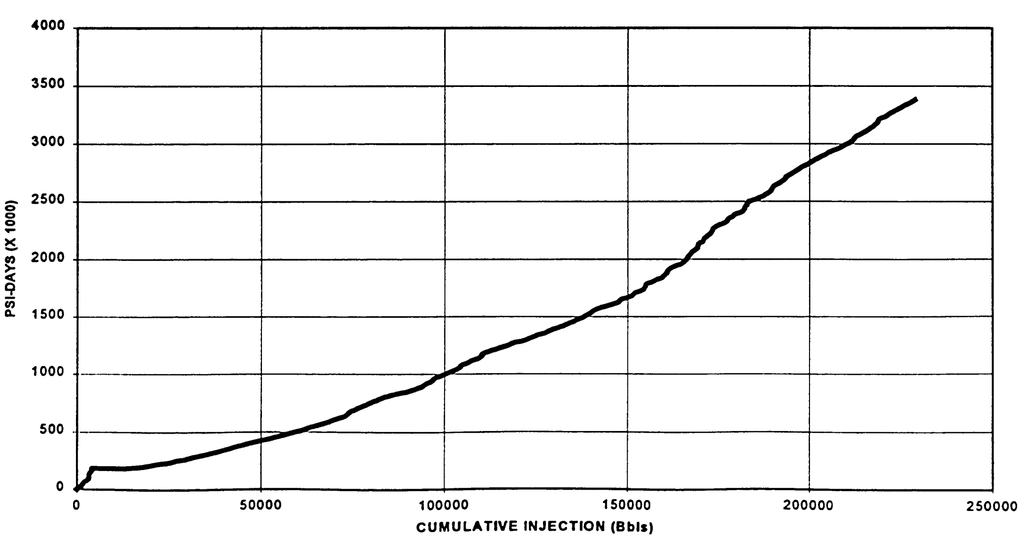
KW-11 INJECTION HISTORY

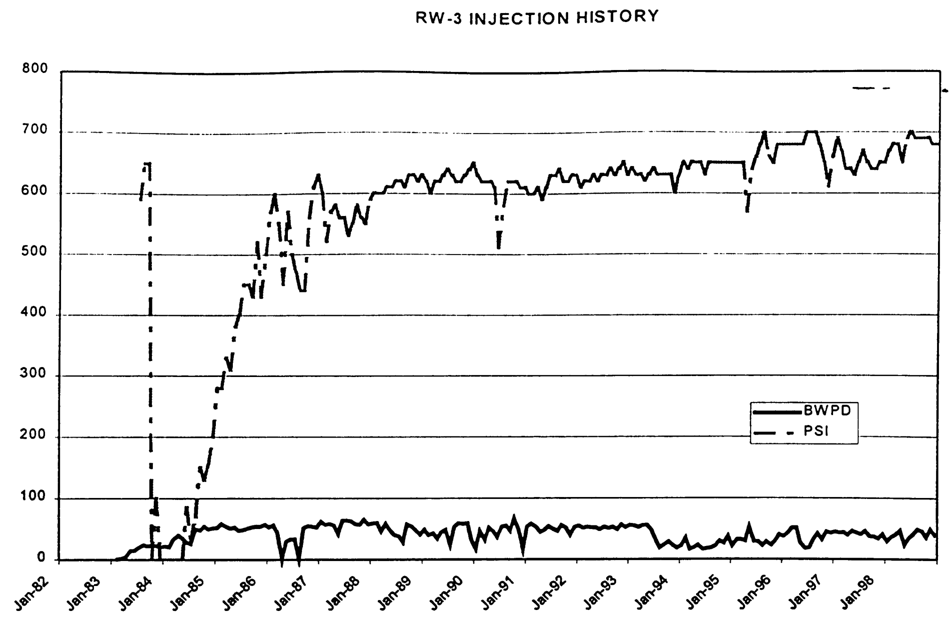


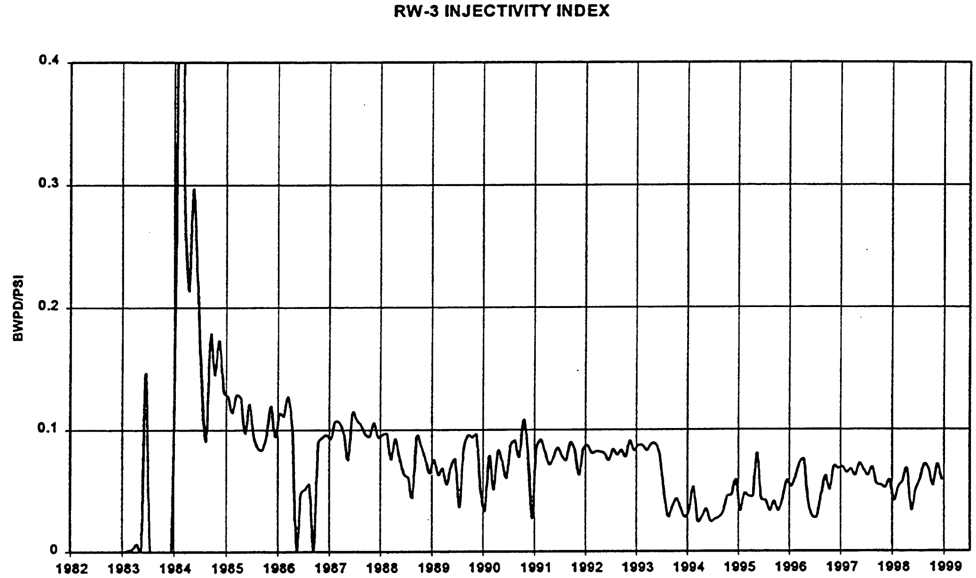
KW-11 INJECTIVITY INDEX

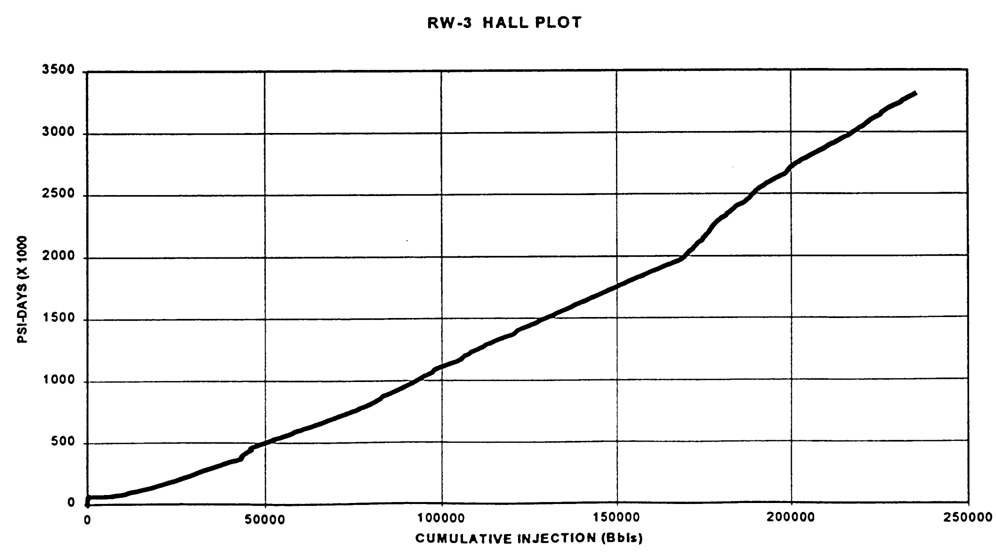


KW-11 HALL PLOT

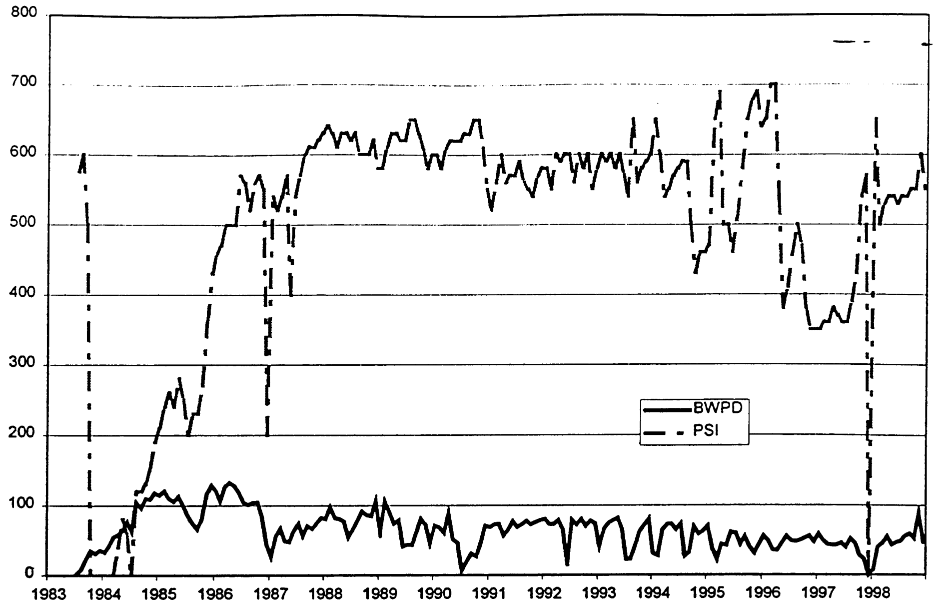



RW-3 INJECTION HISTORY
800
700
600
500
400
300
200
100
0
Jan-82
Jan-83
Jan-84
Jan-85
Jan-86
Jan-87
Jan-88
Jan-89
Jan-90
Jan-91
Jan-92
Jan-93
Jan-94
Jan-95
Jan-96
Jan-97
Jan-98
BWPD
PSI

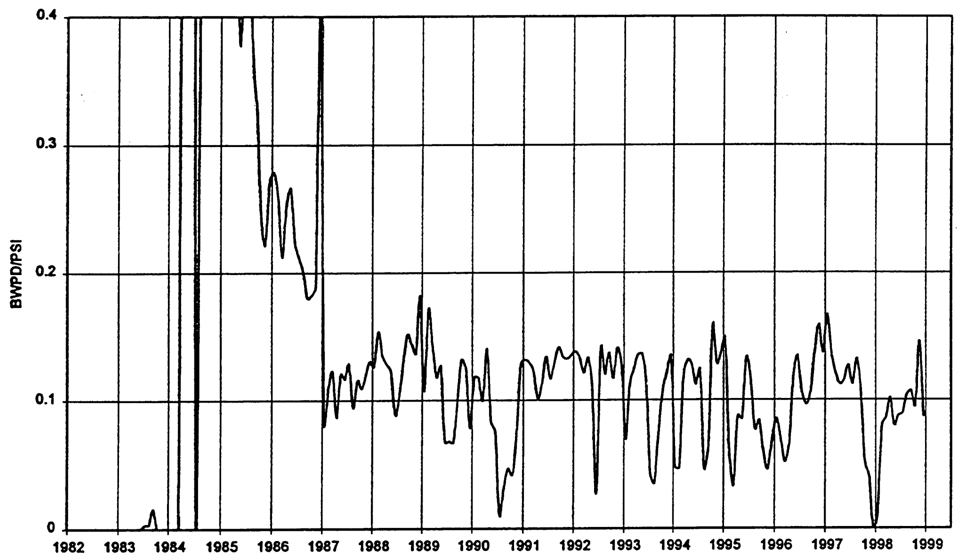

RW-3 INJECTIVITY INDEX
BWPD/PSI
0.4
0.3
0.2
0.1
0
1982 1983 1984 1985 1986 1987 1988 1989 1990 1991 1992 1993 1994 1995 1996 1997 1998 1999


RW-3 HALL PLOT
PSI-DAYS (X 1000
3500
3000
2500
2000
1500
1000
500
0
0
50000
100000
150000
200000
250000
CUMULATIVE INJECTION (Bbls)

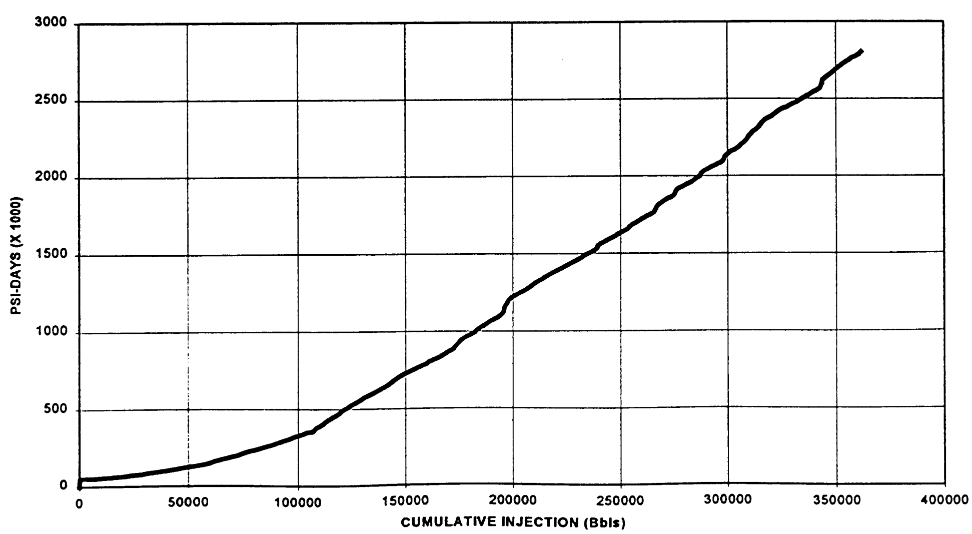
RW-8 INJECTION HISTORY



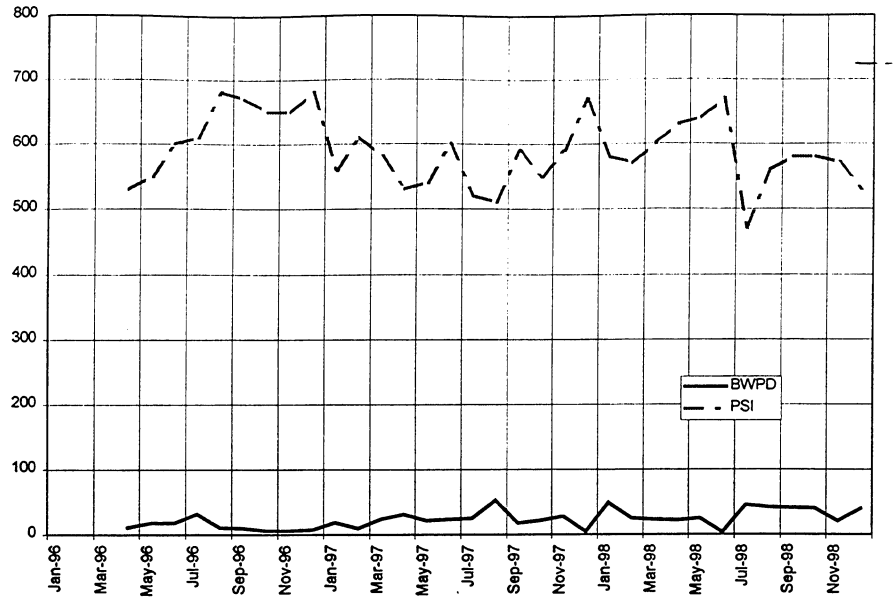
RW-8 INJECTIVITY INDEX



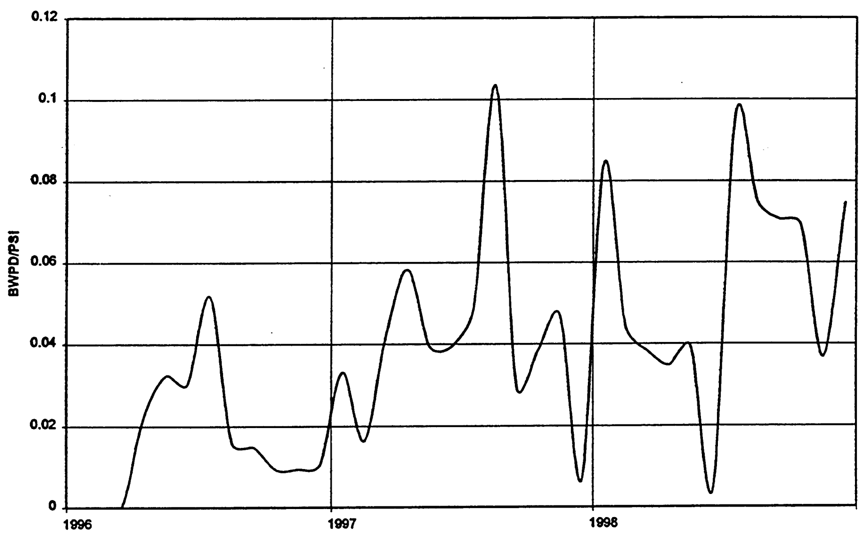
RW-8 HALL PLOT



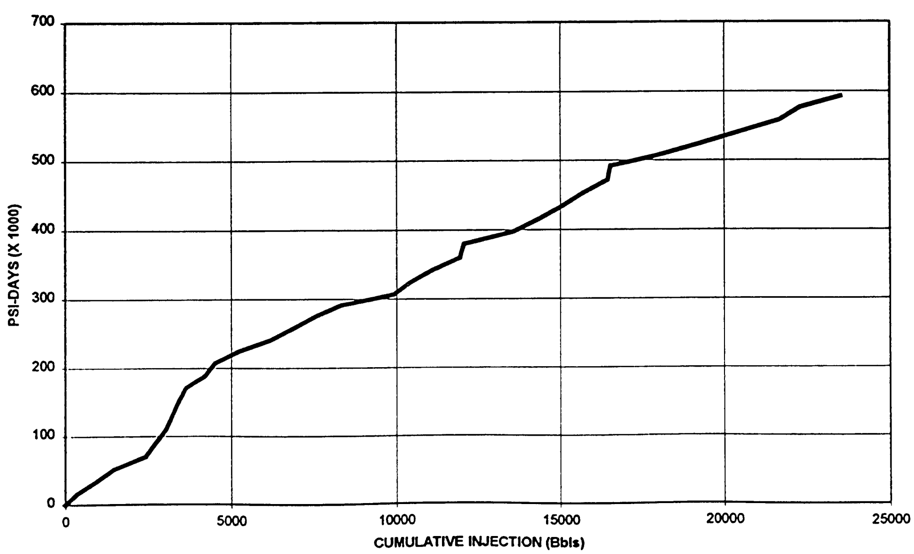
RW-20 INJECTION HISTORY



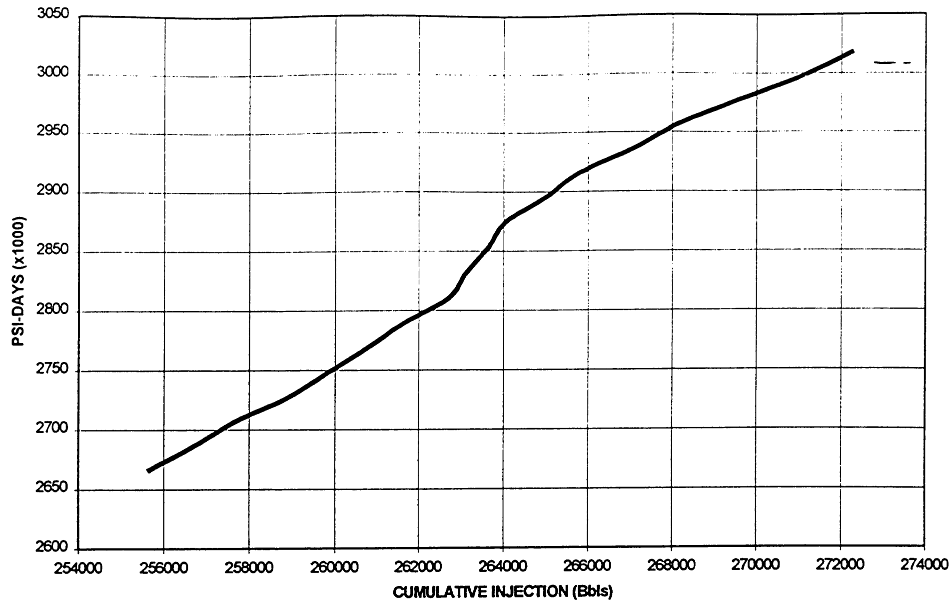
RW-20 INJECTIVITY INDEX



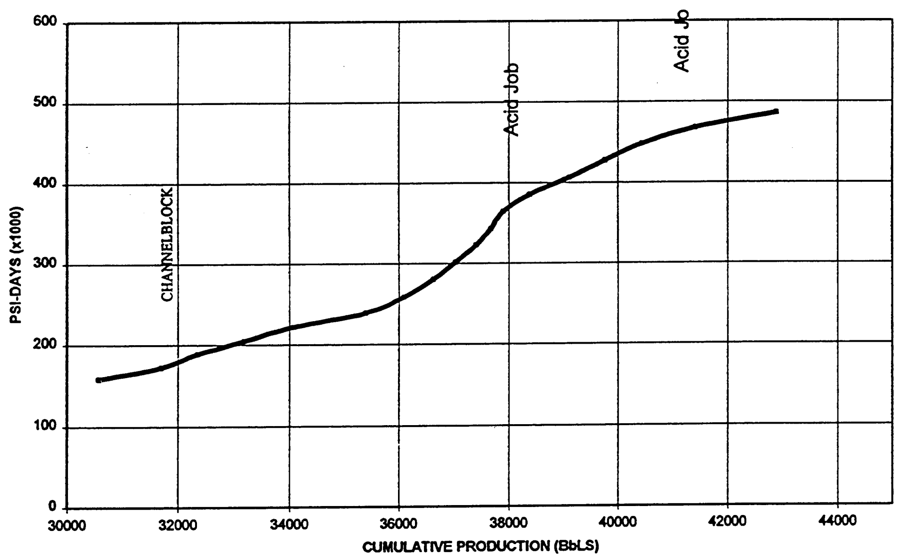
RW-20 HALL PLOT



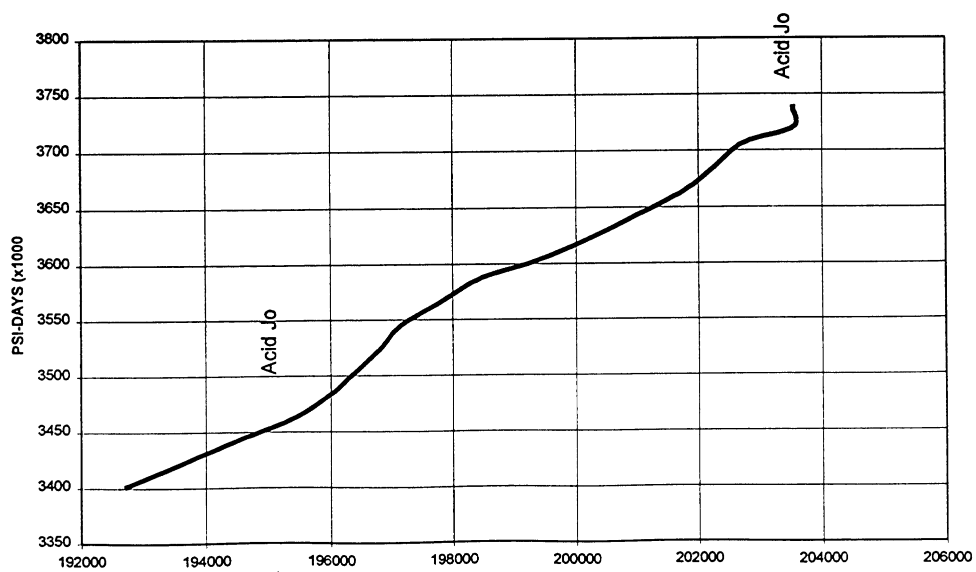
H-12; LATE-TIME HALL PLOT

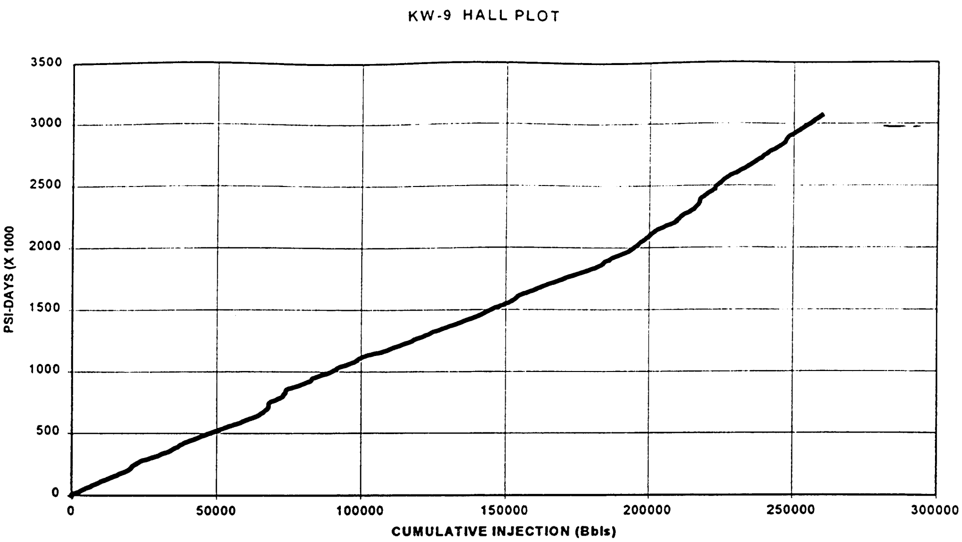


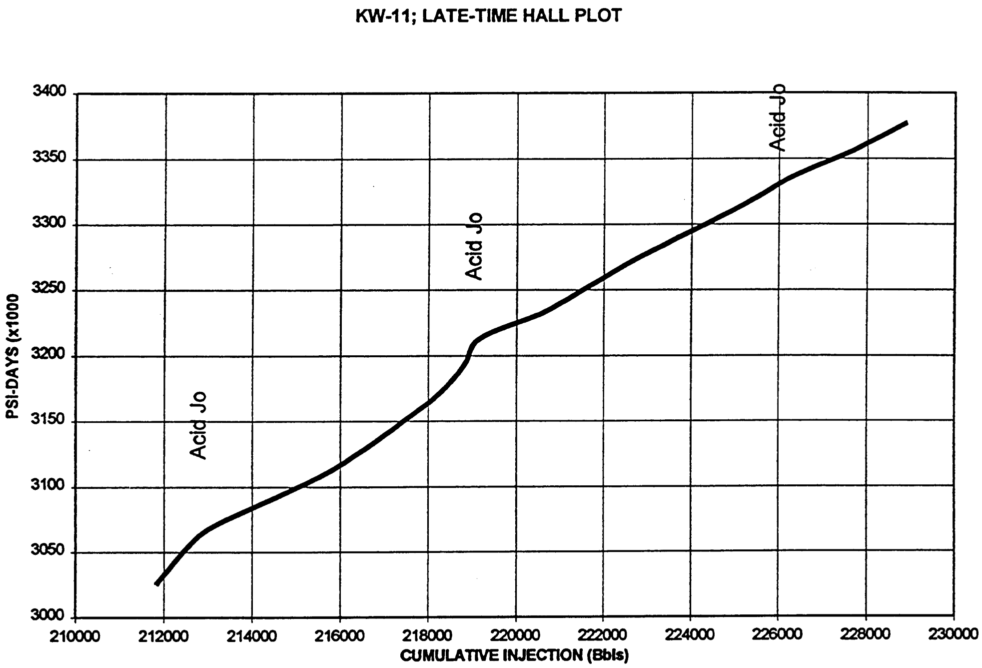
H-14; LATE-TIME HALL PLOT



KW-7; LATE-TIME HALL PLOT




KW-9 HALL PLOT
PSI-DAYS (X 1000
0
500
1000
1500
2000
2500
3000
3500
0
50000
100000
150000
200000
250000
300000
CUMULATIVE INJECTION (Bbls)


KW-11; LATE-TIME HALL PLOT
PSI-DAYS (x1000
3000
3050
3100
3150
3200
3250
3300
3350
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Acid Jo
Acid Jo
Acid Jo
210000
212000
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216000
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224000
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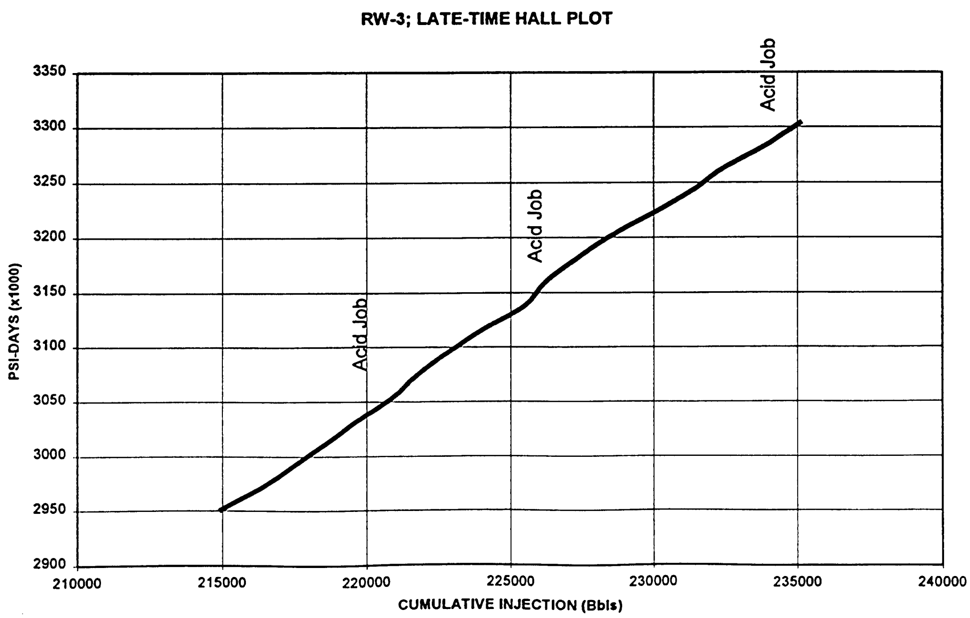
RW-3; LATE-TIME HALL PLOT
PSI-DAYS (x1000)
2900
2950
3000
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3100
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3200
3250
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Acid Job
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Acid Job
210000
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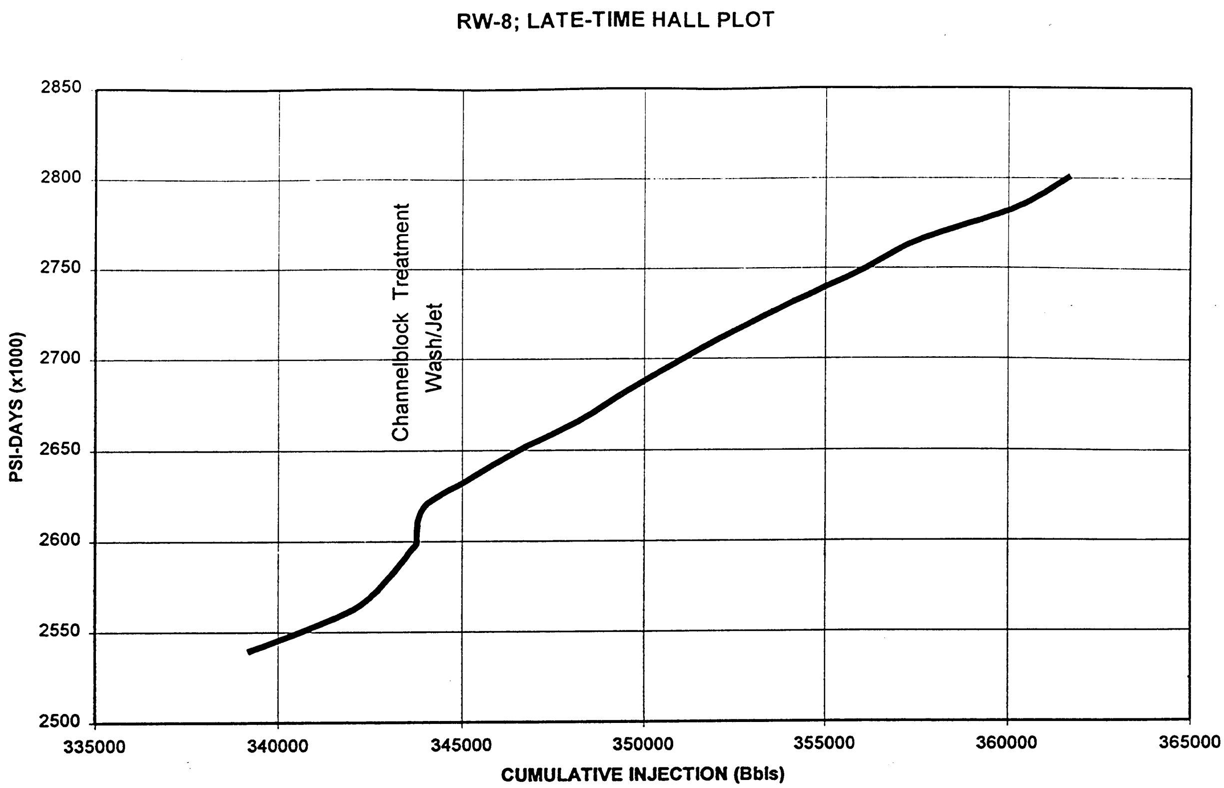
240000
CUMULATIVE INJECTION (Bbls)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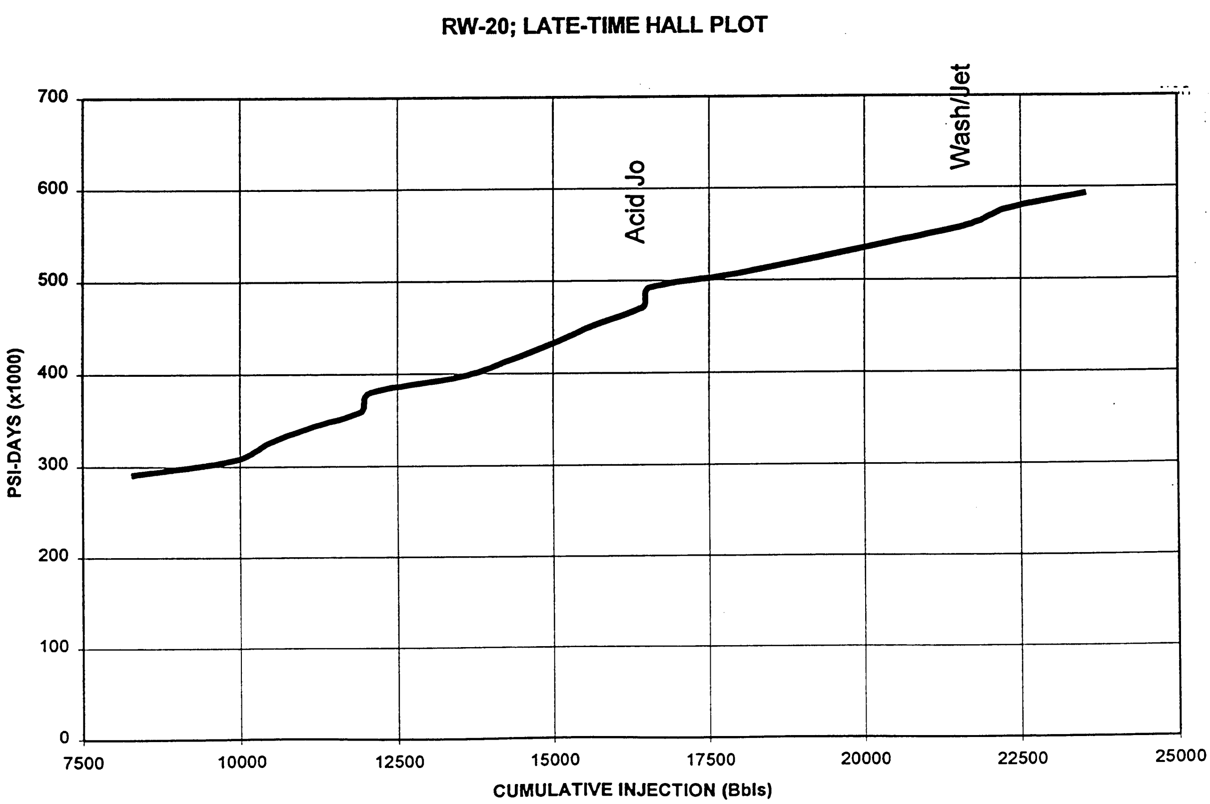
2800
2750
2700
2650
2600
2550
2500
PSI-DAYS (x1000)
Channelblock Treatment
Wash/Jet
335000
340000
345000
350000
355000
360000
365000
CUMULATIVE INJECTION (Bbls)


RW-20; LATE-TIME HALL PLOT
700
600
500
400
300
200
100
0
PSI-DAYS (x1000)
Acid Jo
Wash/Jet
7500
10000
12500
15000
17500
20000
22500
25000
CUMULATIVE INJECTION (Bbls)

Appendix D

Water Quality Improvement by Air Flotation
Savonburg Project, Nelson Lease

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Tertiary Oil Recovery Project
University of Kansas

The success of a waterflood for the recovery of petroleum from a reservoir depends on the quality of the water injected into the reservoir and the path the water takes between injection and production wells. The injection water will take the path of least resistance through the formation. Imbibition of water by the rock and the pressure gradient from injection to production well allows the flood water to contact a greater area of the reservoir than just close to natural and man caused fractures. Water quality can affect and alter the water path. The five harmful constituents in flood water, in order of importance are; (1) dispersed oil; (2) bacteria and algae; (3) suspended solids; (4) dissolved solids; and (5) dissolved gases. Both oil and solids plug the entrance to the pores at the well bore or fracture face near the well bore, and thus, diminish the water volume that can enter the pores of the reservoir rock. An attempt is made periodically to remove this accumulation of debris by treating the well with hydrochloric acid and other cleaning chemicals. Removal of dissolved and suspended solids is generally incomplete, even when the injection well is back flowed after an acid–chemical treatment. Insolubility of oil, silica, clay, bacterial and algae debris, and scale deposit such as barium sulfate in hydrochloric acid prevents the restoration of the injection well to its full potential.

Typical waterflood operations and problems

When an operator decides to start a waterflood to prolong the economic life of the lease, three questions need to be answered. First, where can the flood water be obtained on or near the lease? The source of the flood water is generally from a saline zone other than the oil zone. This water zone must supply a sufficient quantity of water to meet the needs of the waterflood. This water is generally of excellent quality and causes no problems at the injection wells, unless the source zone contains traces of oil or has been contaminated by the disposal of water into the zone. Bacteria are always a problem in all wells. Chemical incompatibility between the injected and connate waters can lead to serious formation plugging and is discussed below.

Second, what will be done with the produced water when it appears at the production wells? The operator of the lease has three choices. The first choice is that all the produced water is sent to a disposal well(s) on or near the lease. The second choice is that the produced water is re-injected into selected injection wells. This requires two water handling systems on the lease. The third choice is that the produced water is combined with the injection water before the water is sent to the injection wells. This latter practice commonly occurs in waterflood operations, especially by the small independent operators, and leads to major problems in the injection wells. Precipitation of minerals when incompatible waters are combined and the carryover of oil from the produced water eventually plugs the injection wells.

Third, how will the injection water affect the properties of the reservoir? Each zone in a reservoir is from a different geological era, and therefore, the water frequently has a different dissolved mineral content. When incompatible waters are mixed, precipitation of barium and calcium sulfate, calcium carbonate, and iron sulfide or oxide commonly occurs. A check for compatibility of the proposed injection water with the connate water in the oil reservoir, if considered, is frequently ignored because of a limited source of supply water or immediate economic needs. Many oil operators will inject an incompatible flood water into the oil reservoir based on the assumption that the damage in the mixing zone will be small, or treatment of the injection well with acid and/or chemicals will restore the capability of the well to take water, or that any future problems will not be their concern.

The Proposal to the Department of Energy

The Tertiary Oil Recovery Project at the University of Kansas, in cooperation with several independent oil operators, submitted a proposal to investigate typical problems faced by operators in Kansas in response to a Department of Energy notice. The following excerpts, taken from the proposal submitted to the Department of Energy on January 10, 1992, describe the problem and the solution to the water quality problem.

"**Project Overview** — The major emphasis of this project will be to address waterflood problems of the type found in Cherokee Group reservoirs in southeastern Kansas. General topics addressed will be (1) reservoir management and performance evaluation, (2) waterflood optimization, and (3) the demonstration of a recovery process involving off-the-shelf technology . . . (page 47)."

"**Phase II - Processes to be Implemented** — The implementation phase will be conducted in two stages, (1) the waterflood optimization stage, and (2) the reservoir development stage . . . (page 58)." "The waterflood optimization will consist of, (1) the development of a water plant, and (2) profile modification treatments to reduce channeling of injected water, (3) well bore cleanup treatments and, (4) pattern changes . . . (pages 58-59)." "A water plant will be designed and constructed which is capable of producing high quality brine continuously. The water plant will be monitored daily for water quality. Five-micron filters will be placed at each well to act as monitoring devices. If the 5-micron filters plug, the water plant will be redesigned until acceptable water quality is achieved . . . (page 59)."

From this broad statement in the proposal, one goal of the Savonburg Project was to improve the quality of the injection water with the premise that cleaner water would reduce the cost of injection well operations. The equipment and chemicals were to be "off the shelf technology" and require no long term support from Tertiary Oil Recovery Project personnel after installation and startup of the equipment.

This report describes the water problem at the Nelson Lease, the choice of using air flotation to clean the water, the principles of air flotation, and the installation of the equipment into the then current water plant. Next the "off the shelf technology" approach is covered with its achievement and failure. A description follows of the necessary changes needed in the flotation equipment, the water handling practices, the need for flow meters, and the analytical measuring equipment with the training of field personnel in the use of the equipment.

Nelson Lease Water Plant

The Nelson Lease that is in Allen County, Kansas in the N. E. Savonburg Field is operated by Russell Petroleum, Incorporated. The projects consist of three 160-acre leases in Sections 21, 28, and 29, Township 26 South, Range 21 East. The lease is 1.5 miles east of the county road that connects the towns of Elsmore and Savonburg both which are 1 mile east of US 59. The first well was drilled in 1962. A pilot waterflood was initiated in March 1981, expanded in 1983, and a full waterflood was started in 1985. The water plant currently consists of a single triplex pump to pump water at sufficient pressure and volume to the individual injection wells via a pipe–manifold system. Water for two to six individual injection wells are supplied from a single manifold. Control valves, flow meter, and filter are installed at the manifold in the flow line to each well.

At some point in the waterflood operations, Russell Petroleum decided that the produced and supply (makeup water) waters would be mixed before re-injection into the reservoir. Figure 1 is a schematic of the water flow through the plant in early 1993. All the produced water was reused. This water was passed through a 7×32 inch, 75-micron bag filter and sent to the clean water tank. The additional water needed for the flood was obtained from the supply well that was also sent to the clean water tank. The water in the clean water tank was grayish-black to reddish-brown in color depending on the ratio of produced and supply water, and the oxygen in the water.

The produced water contained oil and solids smaller than 75 microns that passed through the bag filter. Additional solids formed when the two incompatible waters were mixed. Bacteria and algae in the clean water storage tank added to the problem. Each injection well was protected with 75-micron cartridge filters. A significant quantity of solids would pass through the cartridge filters and eventually reduce the water flow at the injection well to the point that the well had to be cleaned. The removal of solids from the well bore by periodic cleaning with hydrochloric acid with or without addition chemicals would partially restore the injection well capability to take water. The net results of the solids in the injection water were an increase in pressure on the formation at the injection wells, decrease in injection water volume, and an increase in frequency of well cleaning.

Water flow through the plant was controlled by three water level switches in the clean water tank. The out-of-water switch shuts off the injection system to protect the triplex pump. The high water switch at the top and the low switch found two feet lower in the clean water tank controlled the transfer of water from the produced water tank or supply well. The low water switch began the pump to transfer produced water to

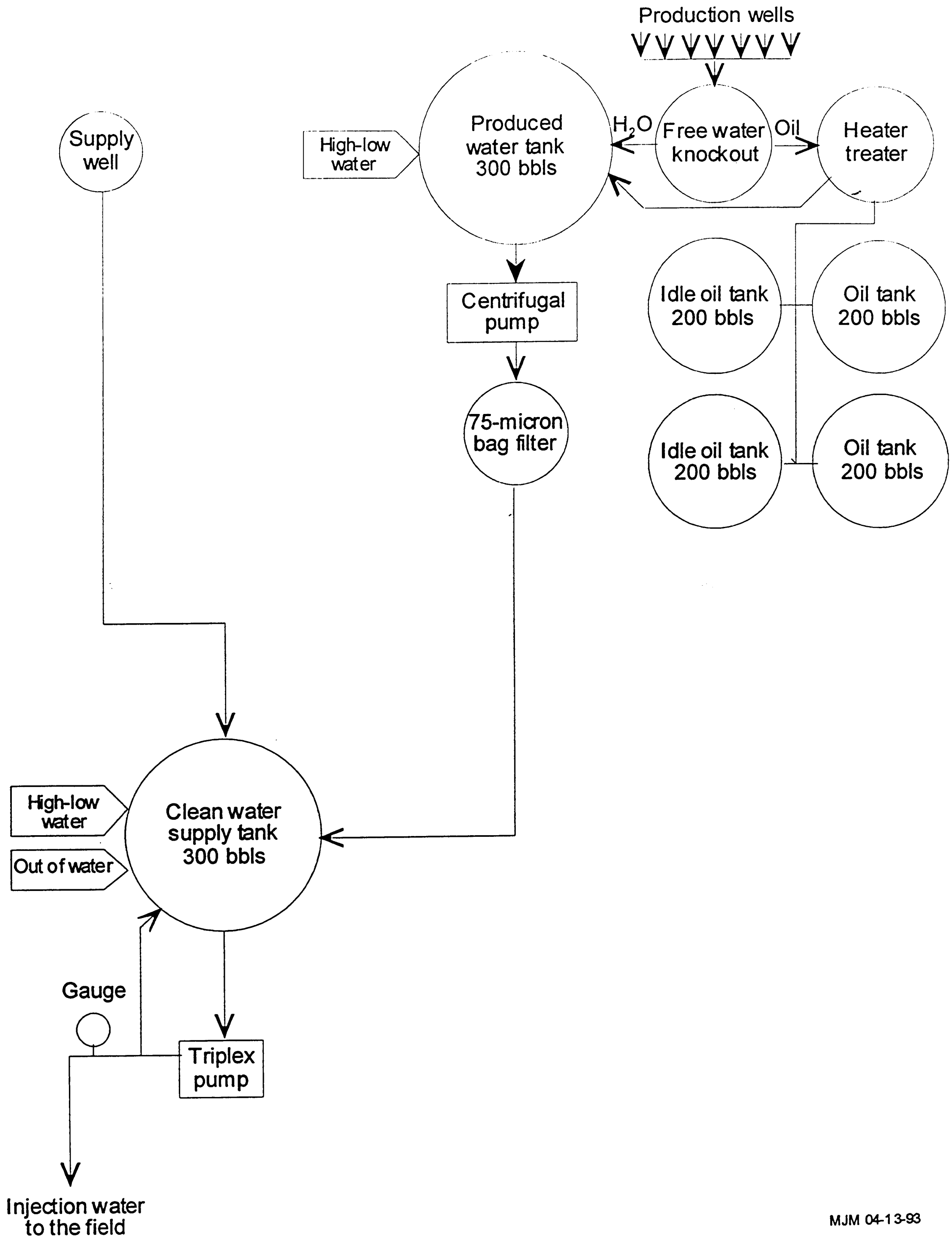


Figure 1. Flow of water through the Nelson Lease water plant before the installation of the air flotation unit in 1994.

the clean water tank. If water level in the produced water tank was low then a low water switch would shutoff the transfer pump and start the supply well pump that sent water to the clean water tank. The high water switch in the clean water tank would shut off the supply well or the produced water transfer pumps. Various treatment chemicals were added at the produced water tank in an attempt to alleviate the filter plugging in the plant and at the injection well by scale formation and aggregation of suspended solids.

Russell Petroleum and Tertiary Oil Recovery Project personnel meet several times in early 1992 to discuss the potential and value of submitting a proposal to the Department of Energy as a Class I PON demonstration project. One facet of the proposal would be to improve the quality of the injection water used for the waterflood. The premise being, that removal of oil and solids from the injection water would reduce the costs of operating the injection well system. The proposal would most likely require modification of the water plant and a change in the operational procedures for the water plant.

The Nelson Lease Water Problem

The injection water for the Nelson Lease consists of a mixture of produced water and make-up water. Production water comes from three sandstone beds from the 630 to 700-foot depth of the Chelsea Sandstone, a member of the Cabaniss Formation of the Cherokee Group. Makeup water is obtained at 1475 foot depths of the Arbuckle Formation that is 700 feet below the Cherokee formation. The two waters have a different chemical composition that leads to precipitation of solids on mixing. Injection well problems arose when the mixed supply-produced water was used in the waterflood operation. The use of 75-micron cartridge filters at the wellhead permitted sufficient quantity of suspended solids to reach the well bore. This required an increase in pressure to maintain water volume in the injection wells. As pressure increased and water volume decreased, the need to treat the injection wells with acid increased in frequency.

The water injection problem arose from the incompatibility between the produced and supply waters. Factors identified was (1) carryover of 300 mg/L or greater of disbursed oil in the produced water, (2) the precipitation of barium sulfate and iron sulfide on mixing of the two waters, and (3) the clay, sand, organic solids, and bacterial debris in the mixed water. The presence of iron sulfide and oil are known to cause problems in the injection wells. The removal of the oily solids from the well bore required frequent treatment with hydrochloric acid along with other treatment chemicals. In an attempt to alleviate the injection well plugging problem various treatment chemicals were added to the mixed water at the plant. A typical daily cost for these chemicals was approximately $35.00 per day to treat 1000 barrels of water in 1992. The 21 and 20 injection wells required 24 and 21 extensive clean outs in 1992 and 1993, respectively.

Difficulty was experienced in filtering 700 to 1000 barrels of supply–produced water per day through a 75-micron bag filter. Eventually, the supply water was added to the filtered produced water in which case the barium sulfate and iron sulfide formed in the water in the tank feeding the water injection pump. The mixed water generally varied from reddish-brown to gray or black in color. Table 1 lists the ion analysis as reported by Oil Field Research of Chanute, Kansas.

Table 1. Water analyses for produced, supply, and combined waters at the Nelson Lease, October 28, 1993

Ion	Produced mg/L	Makeup mg/L	Combined mg/L	Produced meq/L	Makeup meq/L	Combined meq/L
Sodium	3924	1247	3157	170.68	54.24	137.32
Iron	0	0	3	0.01	0.00	0.16
Barium	145	6	82	2.11	0.09	1.19
Calcium	200	116	152	9.98	5.79	7.58
Magnesium	101	46	79	8.31	3.79	6.50
Chloride	6241	1986	4964	176.04	56.02	140.02
Bicarbonate	920	429	776	15.08	7.03	12.72
Sulfate	0	42	0	0.00	0.87	0.00
Total	11531	3872	9213			
Cation meq/L				191.10	63.91	152.76
Anion meq/L				191.11	63.92	152.73
Difference meq/L				-0.01	-0.02	-0.03

From the analyses in Table 1 the ratio of produced to supply waters was estimated at 7 to 3. From this ratio, 30 mg/L of barium sulfate precipitated on combining the two waters. The black color of the water is typical of oil field waters in which iron sulfide has precipitated. Insufficient information was available to estimate iron sulfide in the water. Sulfide analysis was not reported and the iron values are low due to oxidation of ferrous ion and the precipitation of iron oxide before soluble iron analysis was done.

Potential solutions to the water quality problem at the Nelson Lease consisted of three approaches:

1. Keep the produced water separate from the supply water and divide the field into two injection systems. This would require two injection pumps and water distribution lines.
2. Install a better filtration system than the current 75-micron cloth bag filter.
   a. A sintered metal filter was considered. The sintered metal filter unit is automatically back washed when the pressure reaches a set limit. The problems with a sintered metal filter system were the disposal of the backwash water, what size a system would be required, the cost for equipment, and could the manufacture assure successful operation in the oil field.
   b. Install a graded sand filtration system. Sand filtration systems have been used in the oil field and Russell Petroleum had experience. The problems with a graded sand filter system were the disposal of the backwash water, and the failure of sand to resettle properly when oil causes the sand grains to agglomerate. These clumps of sand disrupt the sand bed and reduce the filtration capability of the sand.
3. Install an air flotation unit to remove oil and solids from the water. Air flotation has been used in cleaning water in the oil field. An air flotation system would not be new technology, but would be new to Russell Petroleum and to the oil operators in Kansas. The air flotation system would test the concept of rapid assimilation of a "new method" for Kansas independent oil operators by using "Off the Shelf Technology".

Choice of Air Flotation

An air flotation unit was selected as the process to remove oil and solids from the mixed produced-supply water used as source water for the waterflood at the Nelson Lease. The principal reasons for selecting air flotation were; (1) air flotation has been used in the oil field for the removal of oil and solids from produced water before disposal of the water, particularly in California and offshore in the gulf of Mexico; (2) air flotation is not used by the oil operators in Kansas and would serve as a demonstration site; and (3) air flotation would be a test of assembling "Off the Shelf Technology" to serve a need in the production of oil and reduce the problems and cost of operating a waterflood. The equipment would be installed and operated by professional personnel from Russell Petroleum and the Tertiary Oil Recovery Project. Then the operation would be turned over to field personnel for daily operation and maintenance under the supervision of an engineer from Russell Petroleum.

The Principles of Air Flotation

Oil is insoluble in water. That is, oil is hydrophobic and will float to the surface of the water. When the oil is dispersed as small droplets or emulsified, and especially in the presence of solids such as iron sulfide to which the oil will adhere, then the individual droplets will not coalesce and will not float to the surface of the water. Air bubbles, which are also insoluble in water, rapidly rise to the surface of the water. Air, being hydrophobic, will stick to an oil drop. This combination of air bubble and oil drop increases the effective size and decreases the effective density that aids in the flotation of the oil. The steady stream of rising, minute air bubbles bouncing off the oil droplet helps to move the oil to the water surface. The same is true for suspended solids in the water. If the solid can be made hydrophobic by adsorption of an appropriate chemical then an air bubble will attach itself to the solid particle. Specific minerals have been separated from ores by this process. The problem is to find a chemical formulation that will make all solids hydrophobic in the produced–supply water mixture. A hydrophobic wetting agent that imparts a charge to the particle can also aid in the removal of dirt from the water. In this case, a hydrophobic flocculation material that has a charge opposite of the wetting agent is used. The solid particles are attracted to the flotation agent by coulombic force. The principles are simple, but finding the correct formulation that works well with the specific water in the field is the problem.

Air flotation works well for the removal of solids between 10 and 100-microns in size. The surface of the particle is important in that it must be hydrophobic or made hydrophobic by adsorption of a chemical. The adsorption of a hydrophobic chemical on the particle surface depends on the zeta potential of the solid, i.e., whether the particle carries a positive, negative, or no charge. Zeta potential depends on the pH of the water that affects the isoelectric point of the solid. The isoelectric point is the pH of the system in which the particle such as iron oxide has a zero charge. The pH of the system also affects interaction between solid(s) and chemical(s) and between two or more chemicals used in the flotation process.

The air or gas bubble size is also important. Smaller bubbles are more effective than larger bubbles. Air is commonly used as the gas, but natural gas, nitrogen, and other gases have been used. The bibliography contains a selected list of references that describe in greater detail the process of air flotation overall and the use of air flotation in the cleaning of produced water in the oil field before reuse or disposal.

Methods of Generating Small Air Bubbles

The generation of air bubbles in an air flotation unit is accomplished by one of two principal methods, dissolved air and induced air. The dissolved air method requires air to be dissolved in the water by increasing the air pressure above the water to 50 or greater pounds per square inch. When the pressure of the system is reduced to atmospheric pressure, then the air comes out of solution forming small bubbles. A variation of the induced air system is a vacuum desorption process. The water is saturated with air at atmospheric pressure and then the water is placed under a vacuum that causes the dissolved air to come out of solution forming small bubbles. In the induced air system, the bubbles are generated by a high speed rotating impeller. The rapid rotation of the impeller creates a low pressure area at the center of the hollow shaft that sucks in air. The air is then forced against a perforated shroud by the impeller where small bubbles are formed. A venturi tube has also been used to generate small air bubbles. As the water flows through the constriction of the tube, air is sucked into the tube at the low pressure location and the flow of water provides the shearing force to generate the small air bubbles. The electrolysis of water to form oxygen and hydrogen has also been used to form the gas bubbles.

Purchase and description of the air flotation unit.

Four potential suppliers were invited to submit bids for an air flotation unit to clean the produced water at the Nelson Lease. Two companies responded with information and prices; two of the companies no longer produced air flotation equipment. A flotation unit from Separation Specialists Incorporated of Bakersfield, California was selected based on the best price and was the only company to send a system engineer to the site. The systems engineer tested the proposed feed water in February 1994 in a bench model flotation unit. The results showed promise even with the limited chemicals in his test kit. The unit was ordered in March and delivered in June 1994.

The unit was designed to remove oil from produced water in offshore operations in the Gulf of Mexico. The unit was guaranteed to reduce the oil in water to less than 30 mg/L. No other warranty of specifications were implied as to removal of solids from the water.

The flotation vessel is a 4-foot diameter by 4-foot tall with a top and bottom dome, epoxy coated, enclosed tank. Figure 2 is a photograph of the flotation unit as received. The working volume of the tank is 375 gallons. Air bubbles are generated by impeller–air turbines mounted tangentially at one, two, and three feet below the surface of the water. Figure 3 is an exploded drawing of an impeller–air turbine assembly. The impeller forces water past the edge of the air turbine where the velocity of the water shears off small air bubbles as air exits the turbine. The air turbine is a closed impeller for a centrifugal pump. The lip of the inlet for the impeller fits into a plastic block which serves as a bearing and seal between the water and air inlet. The plastic bearing block is held in place by a retainer bar that also aligns the impeller–air turbine shaft through a water seal at the tank wall and then connects to the shaft of the motor.

The impeller–air turbine units cause a counterclockwise rotation of the water in the tank. This rotation of the water is the only mechanism to sweep the oil and dirt at the surface of the water into the waste water weir mounted at the water surface. The waste weir is pie shaped and mounted at the side and extending to the center of the tank at the water surface. Feed water enters just below the water surface in the tank and clean water exits from the center bottom of the tank. Treatment chemicals are added to the feed water before it enters the tank or at the air turbine–impeller ports.

Clean water exits the flotation unit at the bottom center and rises in a pipe to a 12x12x12-inch weir box on the side of the tank. The clean water weir is set to maintain a fixed height of water in the flotation tank. Water exits the clean water weir box and flows by gravity into a water storage tank. As the flow of feed water increases, the clean and waste water flow also increases. For steady-state operation of the flotation unit the feed water rate needs to be held constant.

Figure 2. Photograph of the air flotation unit as received from Separation Specialist of Bakers-field, California, June 1994. Two of the air turbine mounts are visible on left and lower front. The clean water exit weir is on the top right. Note the tank is enclosed for off-shore application.

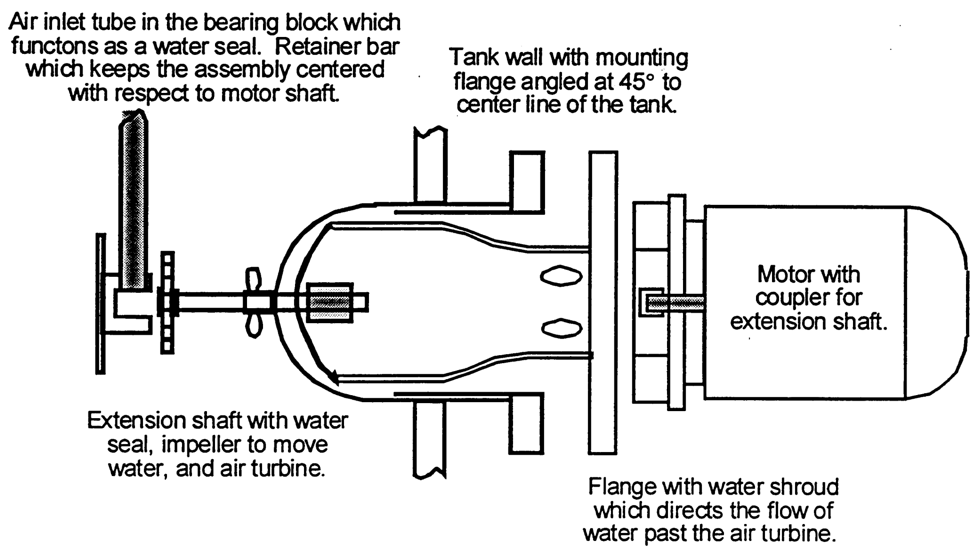


Figure 3. View of components which constitutes the impeller–air turbine assemble for the generation of air bubbles in the flotation unit. Each component is shifted to the left with respect to the motor to more clearly show the various parts.

Air Flotation Chemical Formulations

Before the installation of the air flotation unit, various chemical vendors were invited to test the combined supply–produced water for potential chemical formulations to be used with the flotation unit. Only Petrolite Corporation responded. The field engineer tested 30 formulations that Petrolite supplied as floatation aids and recommended two formulations in June 1994. The best formulation, FLW-162, is a high molecular weight cationic polymer prepared in an oil emulsion. This formulation, on contact with water releases the water soluble cationic polymer along with a surfactant and/or wetting agent. However, shear is needed to disperse the polymer into the water.

In early 1996 a water soluble anionic flocculation polymer was recommended by field engineer from Separation Specialists. This material is used in water clarification and is not a formulation for air flotation. Additional chemicals are required with the anionic polymer. Details of the use of the anionic polymer with other chemicals are described later. The anionic polymer was tried when the water plant ran out of the FLW-162 and a new supply could not be obtained in time.

Installation of the Air Flotation Unit

The flotation unit was placed in operation at the Nelson Lease water plant on July 13, 1994. The FLW-162 flotation chemical was started at one pint per day, the slowest feed rate on the chemical pump, and added to the water inlet line just before the flotation tank. All previously used water treatment chemicals was stopped. Instructions from the manufacture as to the operation of the flotation unit were a minimum. Engineers from the Tertiary Oil Recovery Project and Russell Petroleum directed the installation and startup of the equipment. Two 200-barrel fiberglass tanks and one 50-barrel steel tank were added to the water plant tankage. One 200-barrel fiberglass tank served as a feed tank to the flotation unit and the second served as the receiver of the clean water from the flotation unit. The 50-barrel steel tank received the froth from the top of the flotation tank. The flotation unit was mounted on a 7-foot high platform with no protection from the elements. A corrugated metal and fiberglass shed was constructed around the flotation unit to protect the unit in the winter. Figure 4 is a schematic of the flow of water from the field and supply well, through the air flotation unit, and then back to the field.

Water flow through the plant is controlled by water level switches in the clean water and the produced water tanks. An out-of-water switch near the bottom of the clean water tank shuts off the triplex pump to protect the pump. A pair of switches about two feet apart near the top of the clean water tank begins the transfer of water from the produced water tank to the air flotation supply tank. A low water switch on the produced water tank shuts off the produced water pump and starts the supply well pump. The high water switch on the produced water tank will reverse the source of water sent to the air flotation supply tank. The high water switch in the clean water tank shuts off all water transfer. Activation of the air turbines in the flotation unit is also controlled by the high–low water switches on the clean water supply tank. Water from either the produced water tank or supply well enters at the bottom the flotation supply tank and exits by gravity to the air flotation unit via a 2-inch PVC pipe. This arrangement of water transfer caused the flow rate through the flotation unit to fluctuate with the level in the flotation supply tank.

Initially, water flowed through the air flotation by gravity from the 200-barrel fiberglass air flotation supply tank via a 2-inch PVC line. The feed water entered the flotation unit 3-inch below the surface of the water. Water from the produced water tank was transferred to the feed tank by a centrifugal pump using a buried flow line that had been in place between the produced water tank and the clean water tank. When the produced water tank was empty, then water was obtained from the supply well. This configuration was changed in September 1994 when the feed water transfer pump was used to sent produced water directly to the air flotation unit. The air flotation supply tank was no longer used. This eliminated the surge of water through the unit experienced in the gravity flow feed. The supply water was rerouted from the air flotation feed tank to the produced water tank. The waste water that was initially sent to the air flotation tank was rerouted to the produced water tank when use of the air flotation supply tank was abandoned in September 1994. The reason for the change was that a chemical feed rate could not be established for the flotation chemical when the flow rate varied through the flotation unit. Starting in September, the specified feed rate for FLW-162 was one pint per day, the lowest feed rate of the chemical pump. However, the flotation polymer feed rate varied widely as the field personnel adjusted the rate as they thought best. The FLW-162 was initially feed directly from the 55-gallon drum and then later from a five-gallon plastic tank. Difficulty was experienced with the chemical feed pump. A small amount of moisture from the air would interact with the oil emulsion allowing lumps of the cationic polymer to form which would plug the check valves on the chemical pump. This would require frequently cleaning of the chemical pump.

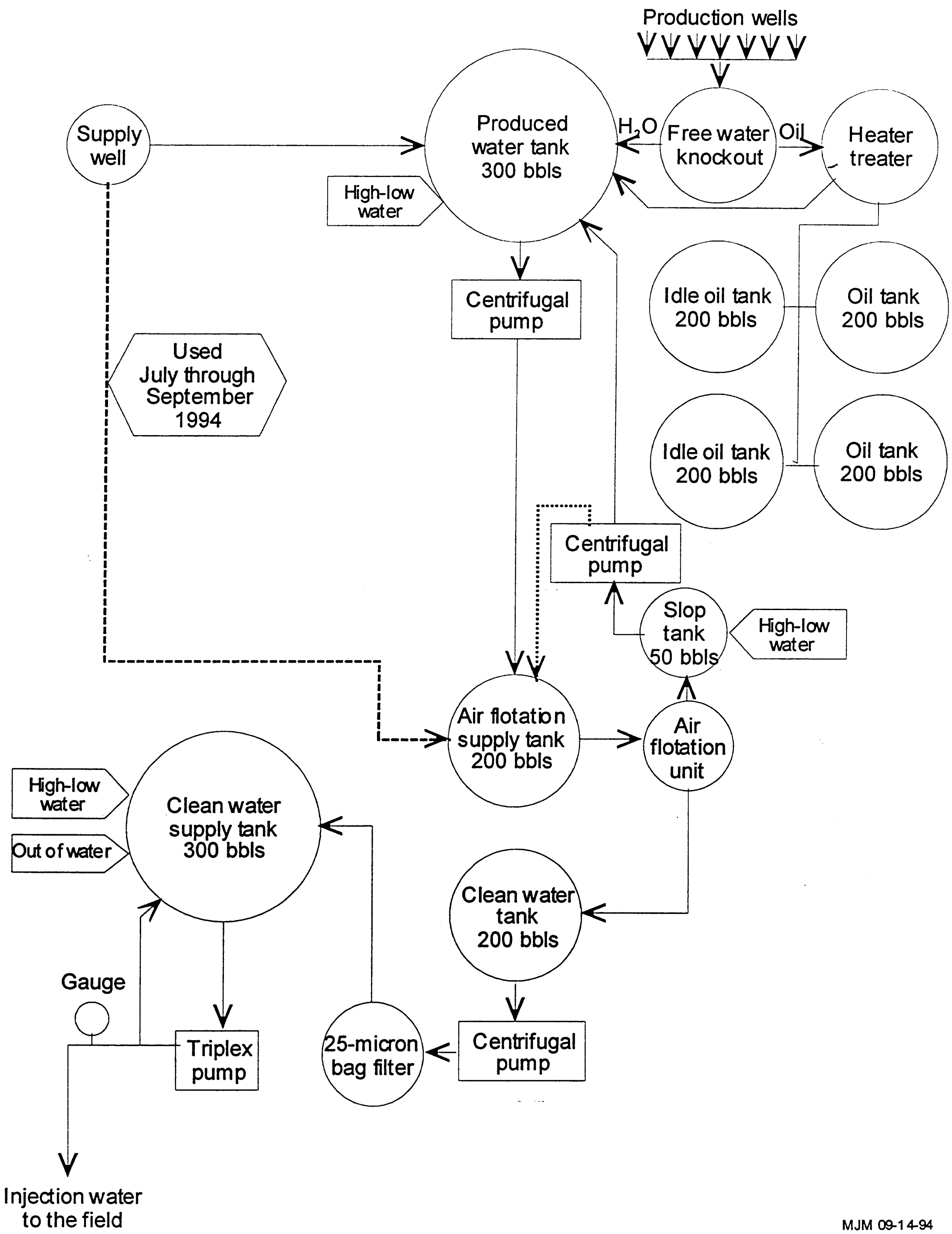


Figure 4. Flow of water through the Nelson Lease water plant after the installation of the air flotation unit in July 1994.

The quality of the water exiting the flotation unit was better than the feed water, however, no test equipment was available to evaluate water quality other than the ASTM D-4189 "Silt Density Index for Water. A modified version was adapted to measure water quality. One liter of water was passed through a 0.5-micron, 47-mm diameter fiberglass filter using a 10 psi pressure from an air pump. The square root of time versus cumulative volume generally results in a straight line. The slope of the line times 100 was used as a water quality index. The filter can be dried and weighed to measure the suspended solids in the water. This filtration test will give a water quality index of 0.5 for pure water. Before the startup of the flotation unit the water quality index for the flood water was 26.4. The first water from the flotation unit had a water quality index of 2.62. However, this tenfold improvement could not be maintained consistently. The fluctuation in water flow through the flotation unit, the frequent stop and start of the unit as controlled by the need for water, and the varying composition of the feed water all affected the water quality from the air flotation unit. Nevertheless, the daily operation of the flotation unit was turned over to Russell Petroleum field personnel in September of 1994.

Initial problems with the air flotation unit

After seven and one-half months the air flotation unit stopped working, the air turbines produced no bubbles. On March 2, 1995, the field engineer from Separation Specialties arrived and the three air turbines were removed from the flotation unit and found completely plugged with solids. The tank was cleaned and three new air turbines were installed. Difficulty was experienced with the alignment of the air turbines since the plastic bearing block had to have the mounting holes drilled and tapped in the field. This caused some misalignment of the air turbine to the water seal. The air turbines started failing within weeks and required constant cleaning of the solids that would accumulate in the turbine.

The black to brown water fluctuation requires a different concentration of flotation chemical. This observation leads plant personnel to adjust the chemical feed rates to the unit frequently. The result was either over or under treatment with flotation chemical. Under treatment would result in minimum removal of suspended solids in the feed water. Over treatment would result in a sticky froth that would not flow into the waste weir at the surface of the water. The solids would build on the surface of the water and then be drawn into the air inlet tubes for the air turbines. This was thought to be part of the problem in plugging of the air turbines with solids. Extension of the tubes through the manhole of the closed tank where solids could not be sucked back into the air turbines did not relieve the plugging of the air turbines.

An in depth evaluation was undertaken by the engineers from Russell Petroleum and the Tertiary Oil Recovery Project in early 1995 as to operational parameters that affected the quality of water from the air flotation unit. Thus, begun a study of the equipment, waters, and chemicals used in the air flotation unit. The results are summarized in the following sections. Ten problems were identified. The problems are discussed as individual items but in reality are interrelated and cover the time from late 1995 through the end of 1998 when a viable air flotation unit requiring minimum attention was in operation.

The first problem was the frequent start and stopping of the air flotation unit. The second problem was the appearance of a hard barium sulfate scale on the injection well meters. The third problem was the fluctuation in the supply to produced water ratios that caused the feed water color to vary from black, containing iron sulfide, to reddish-brown, containing iron oxide. This variation in solids composition required a different concentration of flotation chemical. The fourth problem was the flotation chemical and the plugging of the chemical metering pump. The fifth problem was finding the optimum location for the addition of the flotation chemical with respect to the flow of feed water to the flotation unit. The sixth problem was the constant failure of the air turbines and replacement with venturi tubes. The seventh problem was insufficient pump power to generate sufficient air volume from the venturi tubes. The eighth problem was the type and placement of the waste water weir. The ninth problem was the lack of measurement equipment to measure flow rates and water quality quantitatively, and a data base to identify causes and effects. The tenth problem was the need to keep water flowing to the field always, especially in winter months when freezing would become a problem in the pipes under no flow condition.

Problem One. Reduce the frequency of starting and stopping the air flotation unit.

Initially the quality of the water from the flotation unit would be poor and then improve as the unit ran. With each stoppage of the flotation unit it was observed that some solids in the water would sink to the bottom of the tank and exit with the clean water. The length of stop time did not appear to relate to the solids that appeared in the clean water. To reduce the frequency of stopping and starting the air floatation unit, two 300-barrel fiberglass tanks were installed in September 1995 for the clean water that feeds the triplex pump. This increased the clean water storage capacity by 200 barrels. In addition, the high-low water switches were placed further apart, and thus, decreased the frequency of calling for water about one-half. This additional working volume in the clean water tanks allowed the air flotation unit to run for a longer time on each call for water. The decrease in the number of stops for the air flotation unit per day resulted in a small increase in the overall water quality of the clean water leaving the unit.

An additional benefit with the two clean water tanks was that it provided for a 50 percent increase in injection time before the out-of-water switch would shut down the injection system. This increase in storage capacity generally provided ample time to solve water plant problems. The two tanks were connected such that water from the filter could be sent to either tank and likewise water could be drawn by the triplex pump from either tank. The new arrangement of tanks permitted one water tank to be taken out of service at a time for cleaning. During the normal operation, the water levels in the two tanks are equalized by a direct connection between the tanks. With the two tanks connected the frequency in the call for water was reduced by one-half. Figure 5 illustrates the new arrangement of the flow of water through the Nelson Lease water plant.

Problem Two. Barium sulfate scale in the injection well meters and air turbines.

Before the start of the air flotation unit, the individual injection well meters had to be removed frequently and cleaned of scale deposits. This scale on the meters was soft and mushy and could be easily removed from the rotor and body of the meter. The scale consisted of a mixture of barium sulfate, iron sulfide, and iron oxide, all coated with oil. The deposit in the meters changed from a soft to a hard and very difficult to removal scale over a year after the startup of the flotation unit. Oil and iron sulfide was absent from the hard scale. Apparently it took almost a year to flush the accumulated solids and scale inhibitor from the flow lines.

The precipitation of barium sulfate past the air flotation unit was not expected. The precipitation of barium sulfate on combination of sulfate with barium, in salt water, is rapid in the laboratory, but with formation waters the precipitation of barium sulfate is much slower. The cause for the retarded precipitation of barium sulfate in the mixed waters is not known nor was any attempt made to study this phenomenon.

All the barium can be precipitated from the produced water by the addition of sulfate from sulfuric acid or sodium sulfate to the water in the supply water tank. However, this resulted in a serve scaling problem in the lines between the produced and supply tank and to the air flotation unit. The barium in the water leaving the plant was reduced to 0 ppm during this test period.

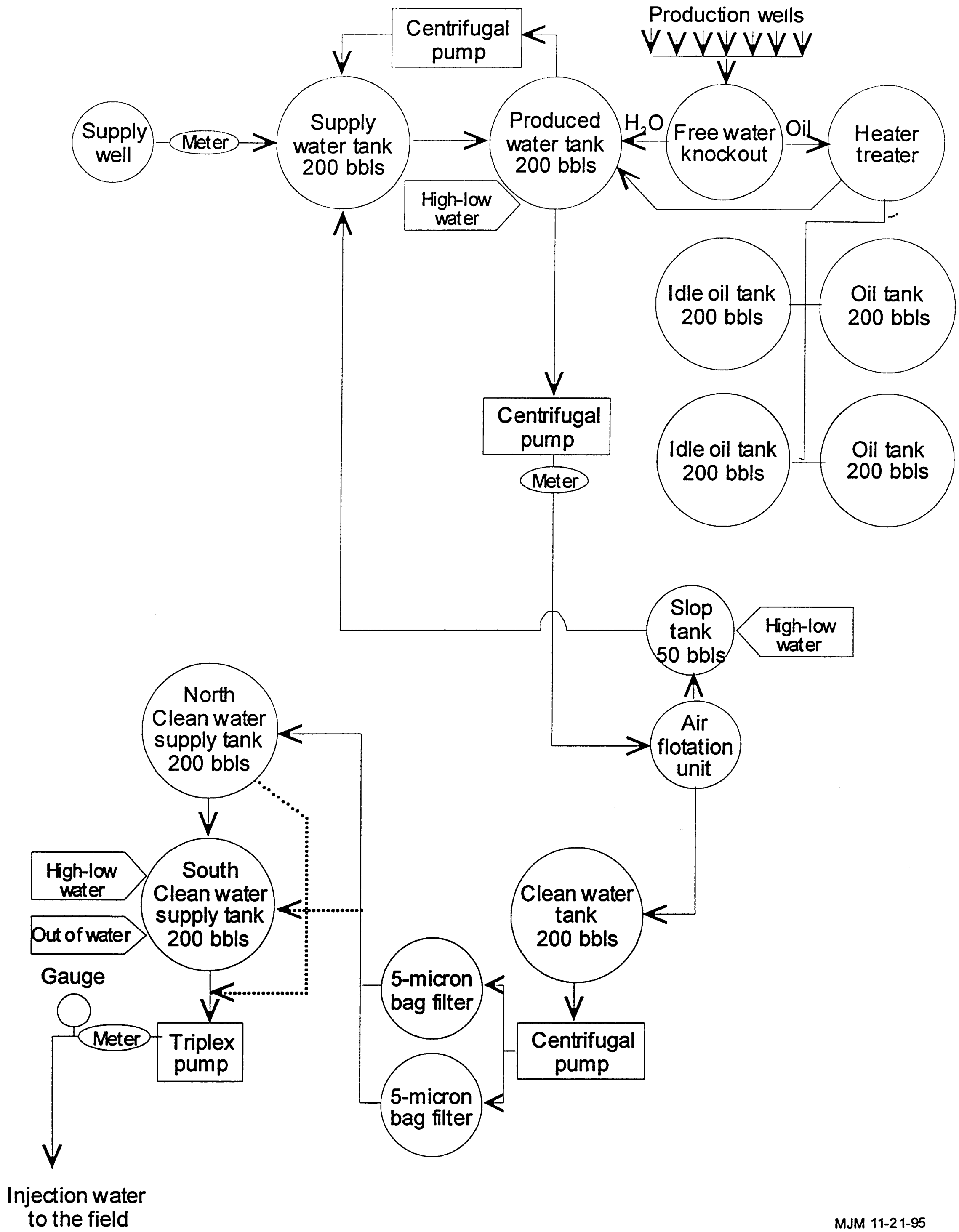
It was the consensus that a longer residence time for the feed water would allow the barium sulfate to form and thus not precipitate after the air flotation unit. Plans were made to increase the residence time of the mixed waters before transfer to the flotation unit. This is discussed in details in Problem Three.

The deposition of the hard barium sulfate at the meters on each injection well was remedied by restoration of a scale inhibitor to the clean water in November 1995. This was done as a precautionary measure until the residence time of the mixed waters could be increased. The addition of the scale inhibitor in the flood water immediately affected the injection well meters. No injection well meters have had to be replaced due to barium sulfate scale after December 1995. This rapid response is in contrast to the time for the hard scale to appear. This was an early indication that clean water was helping to clean the injection lines of solids.

The failure of the air turbines due to solids was also attributed to the barium sulfate scale problem. Thus, the location for injection of the scale inhibitor was moved from the clean water tank to the air flotation unit. Addition of the scale inhibitor to the water in the flotation unit did not affect the action of the flotation chemical nor on the quality of the water leaving the flotation unit. The scale inhibitor did not stop the solids accumulating in the air turbines. The cause is discussed in Problem Five. The addition of the scale inhibitor to the flotation unit did solve the problem of barium sulfate scale on the screens of the bag filter units. The filters are between the flotation water tank and the clean water tanks.

Problem Three. The varying composition of the feed water.

The feed water to the air flotation unit is a mixture of produced and supply water. Produced water on the Nelson Lease comes from three sandstone beds from the 630 to the 700-foot depth of the Chelsea Sandstone member of the Cabaniss Formation of the Cherokee Group. Makeup supply water is obtained at



1475-foot depth of the Arbuckle Formation that is 700 feet below the Cherokee formation. The two waters have a different chemical composition that leads to precipitation of solids on mixing. The produced water

Figure 5. Flow of water through the Nelson Lease water plant after addition of additional tanks for water storage in September 1995.

contains approximately 120 mg/L barium and 10 to 20 mg/L of ferrous iron. The supply water has approximately 40 mg/L sulfate and from 10 to 70 mg/L of sulfide. Barium sulfate forms a soft to hard scale depending on oil and other solids in the water. On exposure of the water to oxygen from the air the ferrous iron is converted to ferric iron and precipitates as brown ferric oxide or black iron sulfide, if sulfide is present. Oxidation of the ferric sulfide by oxygen slowly forms brown ferric oxide.

On startup of the flotation unit it was quickly observed that treatment of brown water, due to ferric oxide, required less flotation chemical than treatment of black water, due to ferric sulfide. Throughout the day the water would cycle between brown and black in color depending on whether the supply well was on or off. The produced water from the field for a given period is nearly constant. Variation of supply water depends on the pumping rate and the number of injection wells in operation.

The daily variation in the amount of produced water can be related to the temporary shutdown of one or more production wells. A long term change in the amount of produced water can be attributed to a change in pump size at one or more production wells, or the shutdown of a well for a prolonged period. In contrast, the supply water in the mixed feed water varies throughout the day. This variation in amounts of supply water is caused by the need for additional water and is controlled by the high and low water switches in the produced water tank. The amount of clean water needed depended on the number of injection wells in operation and the water scheduled for the flood. The produced water averaged 695 and the supply water averaged 245 barrels per day for 1998.

The produced water is separated from the oil in a gun barrel separator with the water going to the produced water tank. The water stream falls through the air, an average, about ten feet, before splashing into the water in the tank. This allows for the oxygenation of the water. During the period that no supply water is added to the produced water tank, the water becomes brown from the oxidation of ferrous hydroxide–oxide to insoluble ferric hydroxide-oxide. When the water level reaches the low water switch in the produced water tank, then the supply well pump is started and pumps water to the produced water tank. The supply water enters at the bottom of the tank. The sulfide in the supply water reacts with the iron in the produced water to form ferrous and ferric sulfides. Ferrous sulfide is oxidized to by the oxygen in the water to form insoluble ferric sulfide as the two waters mix. Likewise, the sulfate in the supply water reacts with the barium in the produced water to form insoluble barium sulfate as the two waters mix.

The approximate 100-barrel fluctuation in the produced water tank with the changing ratio of supply to produced water caused the over and under treatment with the flotation chemical in the flotation unit. The ratio of produced to supply water ranges from 100 to 50% during a water transfer cycle to the air flotation unit, and several transfer cycles occur in a 24-hour period. No provision was made to coordinate the feed rate of the chemical pump used for injection of the flotation chemical to the time when the supply well pump was in operation.

An attempt was made to oxidize the ferric sulfide in the produced water tank using 10% sodium hypochlorite. The supply water, at the start of pumping, contains 10 to 15 mg/L of sulfide. It was assumed that the initial water from the supply well would contain the highest concentration of sulfide. Test of the mixed water on startup of the supply well with sodium hypochlorite suggest that 3 to 4 gallons of 10% hypochlorite should be sufficient to oxidize all the ferric sulfide to ferric oxide. However, continuous injection of hypochlorite into the supply tank never solved the black water problem.

In September 1995 the tankage at the Nelson lease was increased in capacity and arrangement changed. Two 300-barrel fiberglass tanks were installed for clean water storage. This reduced the frequency of stop and start for the air flotation unit. A 300-barrel fiberglass tank was set to receive the supply well water. The deteriorating 300-barrel steel, produced, a water tank was replaced by a 200-barrel fiberglass tank. This increased the total water storage to 1000 barrels. In the replacement 200-barrel fiberglass tank the float switches were again placed to allow for about 100-barrel difference in water level. The water from the gun barrel separator was allowed to fall approximately ten feet through the air before splashing into the water surface in the tank. This again caused the produced water to be fully oxygenated. The supply and recycle water were diverted to the bottom of the new 300-barrel fiberglass supply water tank. Water from this tank flows by gravity to the 200-barrel produced water tank. This water is allowed to fall through the air again for approximately ten feet that oxygenates the water from the supply water tank.

The original plan was to add supply water to the produced water at a rate that provided a more consistent water composition. As the supply tank was filled the first time, it was found that the sulfide content increased from 15 to more than 80 mg/L in the first hour of pumping from the supply well. The sulfide slowly decreased to 40 mg/L after three hours of pumping. The high sulfide content of the water in the supply tank clearly showed that hypochlorite oxidation of sulfide to sulfur of sulfate was not economically feasible. Air sparging was tried and found to release hydrogen sulfide to the atmosphere. The hydrogen sulfide content in the free space in the tank posed an unacceptable environmental hazzard. The presence of hydrogen sulfide in the air space in the produced water tank was never a problem when the produced and supply waters were combined in the original produced water tank. Thus, a pump was installed between the supply and produced water tanks and the two tanks continuously circulated. This procedure reduced the hydrogen sulfide in the air space above the supply tank to less than 5 ppm and generally below detection limits (0.5 ppm) of the Drager sampling equipment used. The hydrogen sulfide in the water was essentially removed by reaction with ferrous and ferric ions in the produced water.

With no free hydrogen sulfide in the produced–supply water mixture, then air sparging of the supply tank water with air from a venturi tube in the line between the supply and produced tanks, or from an air compressor greatly reduced the presence of black water in the air flotation unit. Advantage was taken of the oxygen in the air to oxidize the ferric sulfide in the water to ferric oxide. The circulation of the supply and produced water tanks doubled the residence time of the feed water before transfer to the flotation unit. However, this increase in reaction time still does not prevent the formation of barium sulfate scale at and after the flotation unit. Thus, the water is currently treated at the air flotation unit with a scale inhibitor.

The elimination or reduction of the ferric sulfide in the water by air oxidation reduced the flotation chemical needed. This permitted the feed rate for the flotation chemical to be optimized, and eliminated the need for field personnel to change the feed rate constantly. The result was an improvement in the water quality from the flotation unit. A new chemical pump was obtained in July 1997 that allowed lower and more precise metering of flotation chemical.

Problem Four. The chemical pump for the flotation chemical.

Part of the problem with consistently obtaining clean water from the air flotation unit was related to the injection of flotation chemical into the feed water. Chemical metering pumps from Liquid Metronics Division of Milton Roy were available in the water plant for metering the various treatment chemicals. The first problem was the Model Z14 pump failed to deliver a constant amount of the cationic polymer to the flotation unit. The field engineer from Petrolite Corporation reported that 1 to 2 ppm FLW-162 would be needed to treat the feed water. For 1000 barrels of water per day at 2 ppm would require 0.08 gallons of chemical per day. The lowest setting on the Model Z14 pump is 0.08 gallons per day. However, at the lowest speed setting the flow rate becomes unreliable. The speed of the pump is controlled by adjusting a variable resistor. A small change in resistance caused by a change in temperature or humidity at the minimum setting caused the pump to stop pumping or to speed up. The speed rate was frequently increased by field personnel to insure chemical would be pumped, especially over night or weekends. This resulted in excess flotation chemical which caused problems in the flotation unit with the stiffness of the froth that would plug the waste weir.

The second and major problem was failure of the pump check valves. Sticky globs of the flotation chemical or flakes of a white solid would coat the balls of the check valves and stop the flow of chemical. This failure was attributed to the typical handling procedure of treatment chemicals by plant personnel. The chemical was pumped directly either from a drum or from a smaller container that is open to the atmosphere. For the cationic flotation formulation prepared as an oil emulsion a small amount of moisture would cause premature inversion of the emulsion. This resulted in a very viscous fluid that would not flow though the feed line or pump. Any emulsion on the surface of the container would dry and form a white flake that would also cause the check valves to malfunction. Thus, many pump failures occurred between July 1994 and April 1996.

In April 1996 a switch was made to a water solution of an anionic flocculation polymer. The reason for the change was (1) the plant was out of cationic polymer and immediate delivery was not possible, and (2) the desire of the plant personnel to have a chemical that would be easier to handle in the water plant. The field engineer from Separation Specialists suggested an anionic polymer from Rohm and Haas Company would be easier to handle in the water plant. The anionic polymer, ROMAX™ 7000, was supplied by Rohm and Haas Company as a 50% solution in water. This material was not formulated as a flotation agent and therefore required additional chemicals. A foaming agent was necessary to create a froth at the water surface that holds the solids until the froth reaches the waste weir. Various anionic and nonionic materials were tried. The nonionic materials, such as Triton X-100, worked best but created two problems. First, an excess of the Triton X-100 would generate too much foam that would plug the waste weir. Second, the waste water is recycled to the feed water and the buildup of nonionic surfactant caused excess foam at the flotation unit. In addition, the anionic polymer always removed fewer solids from the water than the cationic polymer. This was probably caused by part of the suspended solids that carried a negative charge and were not flocculated by the anionic polymer. The main advantage of the anionic polymer was that the material could be diluted with water and thus allow the metering pump to run at a faster speed and/or stroke length. This allowed the pump to be operated in a favorable speed and stroke range. However, the handling procedures in the plant still caused failure of the chemical pump due to solids in the check values. When the anionic polymer solution dried out on the upper portion of the reservoir, then flakes of an insoluble polymer would cause the check valves to fail. In addition, the use of the anionic polymer required a second metering pump for the injection of an additional chemical such as the nonionic or anionic surfactant tried. Combination of additional chemicals and pumps only compounded the problem with the operation of the flotation unit by plant personnel.

In December of 1997 the decision was to return to use of the cationic polymer and find a practical solution to the chemical pump plugging problem. The problem in handling the oil emulsion of the cationic polymer was twofold. The first problem was the plugging of the check valves on the Model Z14 metering pump when the FLW-162 emulsion was exposed to moisture. Elimination of moisture and dirt from the air eliminated the pump check valve problem

The second problem was the FLW-162 feed rate of 0.08 gallons per day required the Model Z14 pump be operated at the slowest speed and shortest pump stroke. At this setting the feed rate varied and the pump would fail to deliver chemical. For a period the FLW-162 emulsion was diluted 50 percent with kerosene. This allowed the chemical pump to be operated above the minimum speed and stoke which caused problems in the uniform delivery rate for the flotation chemical. The problem of moisture and failure of check values remained when an open container was used for the kerosene-diluted polymer. The collapsible plastic container solved the problem of moisture reacting with the oil emulsion polymer. However, a new problem appeared in the settling of the polymer rich phase to the bottom of the container. A heavy mineral oil as diluent was also tried. The FLW-162 diluted with mineral oil would still slowly settle into a polymer rich layer at the bottom of the container. This settling of the internal phase in kerosene or mineral oil would cause a slow decrease in the amount of polymer added to the water over a period of one week as fluid was withdrawn from the bottom of the container.

The problem of varying chemical feed was eliminated when a new metering pump, A model A971-151P pump that had digital controls for pump rates was purchased in July 1997. This pump provides a constant rate at the lowest pump setting. With the new chemical pump and the use of a collapsible container as polymer reservoir, no metering pump problems were encountered over a 12-month period. A preventive maintenance check on the pump showed no problems with the balls and seats of the check valves nor the accumulation of solids on the diaphragm of the pump after six months of operation. The Model A971-151P pump allows the plant personnel to increase the flotation chemical rate, if needed, and then return to the one stroke per minute, the minimum rate, which delivers the required 1 ppm FLW-162. The 1 ppm of flotation chemical was verified by preparing a 3 to 1 dilution of the FLW-162 in heavy mineral oil. The minimum amount of cationic polymer needed on 19 May 1998 was 0.37 pounds per day (0.34 pints, 0.8 ppm by volume). From July through November 1998 the flotation unit has performed well with the 0.5 pounds per day (1 ppm) of FLW-162. Occasionally, the flotation chemical needs to be increased to 2 or 3 ppm when the feed water composition is altered, due to return of treating fluids from a production well.

Problem Five. Location for the addition of flotation chemical to the feed water.

For the cationic flotation chemical to work it must be released from the internal phase of the oil emulsion and then the high molecular weight cationic polymer must be dispersed in the water. After inversion and dispersion is achieved the polymer can then start coagulation of the suspended solids and finally the flocculation of the polymer laden solids. Originally, the cationic polymer was injected into the 2-inch flow line as the feed water entered the flotation unit. A tap for a 1/4-inch valve was threaded into the 2-inch PVC pipe that connected the 1/4-inch feed line from the metering pump. This tap was 12-inches in front of the inlet to the flotation tank. The viscous polymer emulsion would flow along the surface of the pipe and slowly start to invert and release the cationic polymer on contact with water. This resulted in lumps of the polymer in the flotation tank. Moving the injection point to the flange that held the air turbine assembly provided better dispersion of the polymer as the lumps of the viscous polymer flowed past the impeller and across the lip of the air turbine. The best solution was to inject the polymer in front of the centrifugal pump that transferred the water to the flotation unit. The impeller in the centrifugal pump provides the shear needed to invert the emulsion and disperse the polymer in the feed water. The 2-inch feed line to the centrifugal pump was tapped and a 1/4-inch ball valve was installed. The valve was drilled to allow the 1/4-inch polypropylene feed line to be inserted through the ball valve and to the center of the 2-inch pipe. This injection of chemical into the water prevented the polymer from adhering to the pipe wall and provided a uniform feed rate of flotation chemical. The addition of the cationic polymer to the transfer line some 75 feet before the flotation unit provided additional time for the coagulation and flocculation of the solids before the water reached the flotation unit. Installation of a 1.5-inch venturi tube in the transfer line provided air for entrainment of the solids as they passed through the transfer line. This air also reduced the tendency of solids to accumulate in the transfer line. The addition of polymer and air in the transfer line improved the efficiency of the flotation unit since the air entrained solids remained in the top 6-inch of water in the flotation unit. Repeated water samples from 2-inches below the surface of the water in the flotation unit and from the bottom of the unit gave the same suspended solids values.

Problem Six. Failure of the air turbines and replacement with venturi tubes.

The sixth problem was the failure of the unit to generate air bubbles. After nine months of operation (27 February 1995) the generation of air bubbles ceased. The air turbines were completely plugged with solids. Initially, the cause was attributed to the formation of barium sulfate scale in the air turbines and throughout the flotation unit. Replacement of the impeller-air turbine units required two men for eight hours, and excessive time for repair. Each air turbine and plastic bearing block was replaced. The bearing blocks needed to have mounting holes drilled and taped in the field. The new impeller-air turbine units started to fail within weeks and lasted four months before bubble generation ceased. The air turbines were again plugged with solids.

In July 1995, the first air turbine-impeller assembly with the mounting flange and shroud was brought to the repair shop at the Tertiary Oil Recovery Project for evaluation and redesign of parts if necessary. The plastic bearing block from the February repair was found to be off-center which caused the water seal in the flange and the water seal between the air turbine and bearing block to fail. A new bearing block retainer was cut from stainless steel stock and aligned with the center of the motor shaft. A 1/4-inch hole was drilled in the retainer bar to aid the alignment of the plastic bearing block. A new bearing block was machined from 3-inch diameter, high density polyethylene. The new block had a 1/4-inch diameter by 1/4-inch heigh protrusion on the end that fit into the alignment hole on the retainer bar. The new bearing block also had a recess cut into the face for a spring-loaded lip seal to receive the lip of the air turbine. A 1-inch threaded hole on the side of the block for the 1-inch PVC air pipe completed the new design for the bearing block. The air turbine assembly with a new air turbine was installed in the air flotation unit on 27 July 1995. The second and third air turbine assemblies were removed and brought to the Tertiary Oil Shop for a similar repair with the new design for the bearing blocks. It was found that each assembly was customly built and the parts were not interchangeable with respect to retainer bars and bearing blocks. Thus, future repairs, if necessary, had to account for the difference in each part of the air turbine assembly.

The new water seals on the bearing blocks did not stop the water leakage problem of the seal. Field personnel reported that they thought the air volume was decreasing daily. Installation of air flow meters on each of the air turbines verified their observation. A representative of the seal manufacture stated that a watertight seal required no more than a 0.005-inch lateral movement and a 0.002-inch radius of gyration of the air turbine lip in the seal. The lip of a new air turbine, which is an enclosed impeller for a centrifugal pump, was found out-of-round and/or off-center by more than 0.009 inches. Thus, a watertight seal between the air turbine and bearing block could not be achieved by any commercially available seal. The evaporation of water in the air turbine would always lead to plugging by solids accumulation. Removal of the solids from an air turbine was impractical. This led to consideration of alternate methods for the generation of air bubbles in the flotation unit.

A porous plastic, muffler assembly was built in December 1996 in which air was pumped through the porous plastic and a centrifugal pump was used to pump water past the plastic muffler to shear off small air bubbles. This device showed promise, but was a custom build item in the shop at the Tertiary Oil Recovery Project. Two of the air bubble generators were installed and used for six weeks. The air bubble generators required an air compressor for air and a centrifugal pump. Clean water from the bottom the flotation unit was pumped to the bubble generators. Difficulty was experienced in regulating the flow of air and water to the two bubble generators using valves.

An advertisement for a high air volume venturi tube used to aerate sewage lagoons appeared as a potential solution to the air bubble problem in the air flotation unit. A 0.5 and a 1-inch venturi tube manufactured by Mazzi Injector Corporation were purchased and tested in the laboratory for bubble generation. A quick field test in the flotation unit revealed that the 1-inch venturi tube driven by a 5-gpm centrifugal pump generated as much air as one bubble generator. For the air bubble generators a mounting flange had been fabricated from 1-inch thick PVC sheet. This flange had a 1.5-inch mounting hole for the pipe that contained the outside pipe of the bubble generator. On 10 December 1997 the bubble generator was removed from the south air turbine port and the 1-inch venturi tube was installed in the flange using a 1.5 to 1-inch reducing nipple. The hose that supplied water to the bubble generator was used to power the 1-inch venturi tube. The pressure across the venturi was 9.5 psi against a hydrostatic head of 30 inches of water, the deepest air turbine port in the flotation unit. This venturi tube produced 15 SCFH air. The second 1-inch venturi tube was installed on 10 January 1997 in the west air turbine port located 20 inches below the water surface and 90° from the south air turbine port. The south and west venturi tubes showed no scale buildup after 75 and 29 days of operation, respectively. Later the west venturi tube was moved to the north air turbine port, 10 inches below the surface of the water, to get a better rotation of solids at the water surface.

The venturi tubes were inexpensive, easy to install, and performed better than the original impeller-air turbine equipment or the porous plastic air compressor system. In May 1997 flow meters for measuring air volume were installed and daily measurements of air were recorded. The south and north venturi tube each generated 20 SCFH air flow in the flotation tank. A portable third 1-inch venturi tube was installed in June 1997. This venturi was attached to 1-inch PVC pipe and a 90° elbow to allow the venturi to be placed horizontally at any depth and position in the flotation tank. This was done in an attempt to move the dirt to the waste water weir and away from the sides of the flotation tank. The three venturi tubes produced as clean a water as the three air turbines, however, judging water quality was difficult due to the lack of a simple method to measure suspended solid content. The cause of excess solids in the clean water was not apparent until later and is discussed below. The final locations of the venturi tubes in the air flotation unit are discussed in the next section.

Problem Seven. Pump power for the venturi tubes and location of the venturi tubes.
Originally one TEEL 2P377 centrifugal pump was used to power the two or three-venturi tube configuration. A set of valves was used to control the water to each venturi tube. This form was inadequate for two reasons. First, the flow rate to any venturi tube was difficult to control. Different water flow rates to the venturi tubes affected the water circulation at the water surface. When one venturi tube received more water, then the accumulation of solids at the water surface would move from the center toward the side of the tank, which affected removal of solids. Second, one centrifugal pump did not produce sufficient pressure across the venturi tubes to generate the needed air volume. This was discovered when a bench model air flotation unit was built. A sample of ~~water exiting~~ from the flotation unit would produce water of less than 10 mg/L solids without the addition of any flotation cationic polymer. All needed was the additional air volume in the bench unit. This was confirmed by testing the water at the top of the flotation unit when water transfer to the unit was stopped. The venturi tubes were kept operational during this stopped water transfer period.

The installation of a second TEEL 2P377 centrifugal pump, which is an open-face impeller pump, allowed each of the two venturi tubes to be powered by an individual pump. This allowed maximum water flow, i.e., a maximum pressure differential across each 1.5-inch Mazzi 1585-X venturi tube. The original 1-inch venturi tubes were replaced by 1.5-inch venturi tubes as the larger size provided more air. The cost per venturi tube increased from $59 to $83. At an inlet pressure of 20 psig, the air flow is 2.4 SCFM for each tube or 4.8 SCFM air to the flotation unit. It was found, from a test in the bench unit, that a minimum of 4 SCFM air was needed per 40 gpm of feed water to produce water with less than 10 mg/L solids in the clean water. This was also true in the plant air flotation unit. As indicated in Figure 6, the goal of less than 10 mg/L solids was approached when the second pump was installed in May of 1998.

The combination of the two venturi tubes, 180° apart, mounted at 45° to the center axis of the tank, and 1-foot from the bottom of the tank was the optimum location for the venturi tubes. The air from the venturi tubes sweeps the wall of the tank with the small rising bubbles and prevents solids from adhering to the wall of the tank. The placement of the venturi tubes at a 45° angle cause the water to rotate at 3 to 5 rpm. This top-to-bottom and tank wall-to-center circulation of the water moves the solids from bottom to top and from wall to the center of the tank at the water surface. Quality water of less than 10 mg/L was achieved starting in July with the new waste weir in the center of the tank and with a centrifugal pump for each 1.5-inch venturi tube.

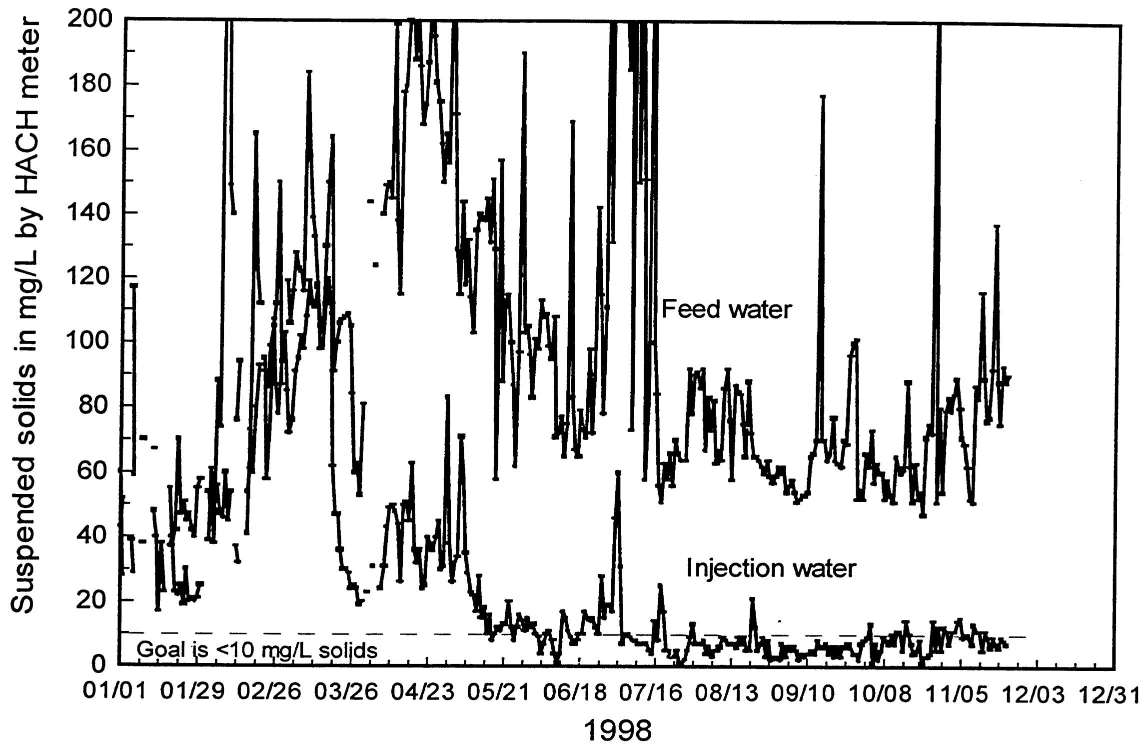


Figure 6. The successful removal of suspended solids from the mixed supply-produced water by air flotation. The goal of less than 10 mg/L of solids in the clean water as measured by HACH colorimeter was achieved in July and sustained when an air to water ratio of 4 SCFM air to 40 gpm water was attained. The air flotation unit was rebuilt with two 1.5-inch venturi tubes locatated 12-inches above the bottom of the tank and a 6-inch diameter waste weir located in the center of the tank at the water surface.

Problem Eight. Shape and placement of the waste water weir. The original waste water weir was a pie-shaped collector that extended from the wall of the center of the tank at the water surface. A 6-inch wide opening for froth was 4-inches from the wall of the tank. The waste weir had an adjustable weir plate to allow the froth to pass into the weir with a selected amount of water. Observation of the froth at the water surface was difficult due to the enclosed tank construction. From the port hole one could observe the froth collecting at the wall and at the apex of the waste weir. A piece of paper dropped on the surface of the water would take an erratic path as it moved through various eddy areas at the water surface. The problem of the solids accumulating on the surface of the water became evident when the top of the enclosed flotation tank was cut open in September 1995. Figure 7 illustrated the eddy areas observed at the water surface   A new waste weir was constructed from a "U" shaped a PVC floor drain and extended across the tank at the water surface. This improved the removal of solids, but did not eliminate the accumulation of solids on the air pipes for the air turbines. A 4-rpm wiper arm was constructed to skim the surface of the water and force the froth into the "U"shaped, waste water weir. This wiper could not gather all the froth due to the air tubes near the wall for the air turbines. The first wiper arm used rubber to skim the surface of the water. After a few weeks the rubber became stiff and the wiper would catch on the waste weir. Next the rubber was replaced with fiber bristles, but suffered the same problem when it became coated with dried froth.

The final solution to the waste weir problem coincided with the optimum location of the venturi tubes. When the two venturi tubes were 12-inches from the bottom of the flotation tank, 180° apart, and at a 45° angle with respect to the diameter line of the tank, then the water would circulate at 3 to 5 rpm with the bubbles rising around the perimeter of the tank. This top-to-bottom and wall-to-center circulation of the water with the bottom-to-top and wall-to-center movement of the air moved the froth to the center of the

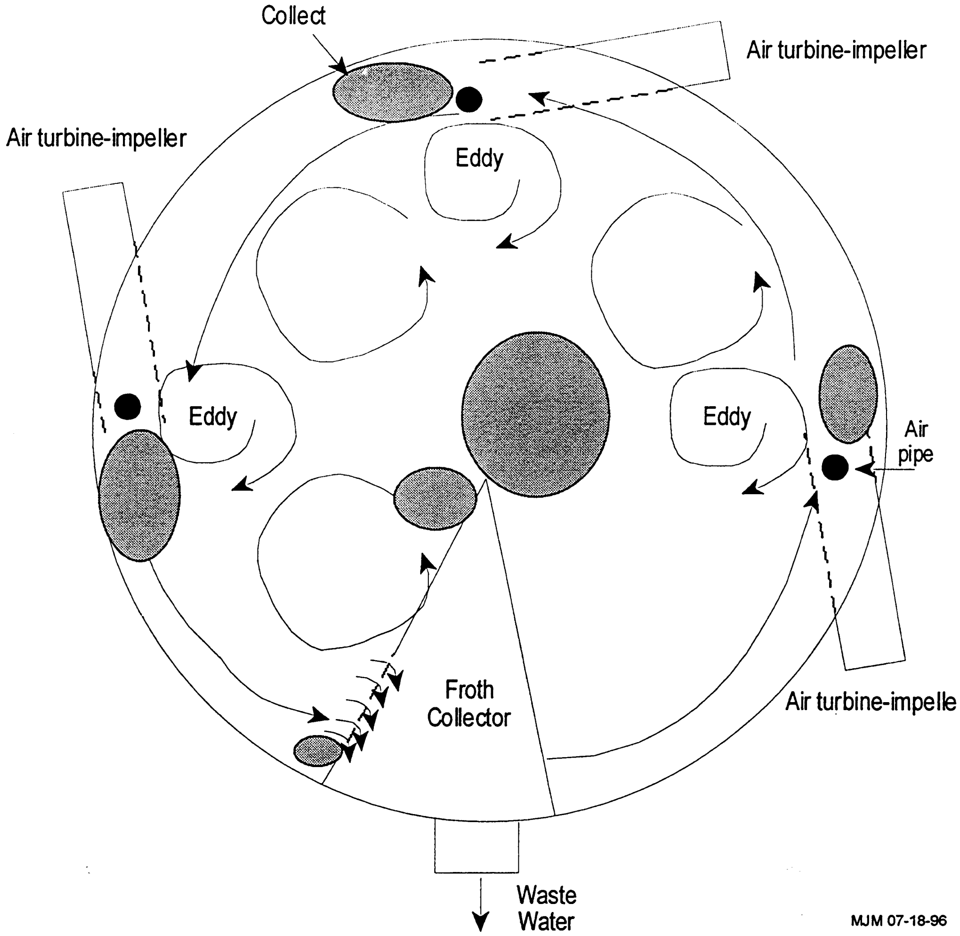


Figure 7. Location of eddy areas on the water surface of the air flotation tank which allowed solids to accumulate on the surface of the water at the tank wall.

tank at the water surface. The impingement of the water jets from the venturi tubes on the wall of the tank forced the air bubbles to sweep the wall of the tank. The air bubbles rising along the wall of the tank prevent solids from accumulating on the wall of the tank, especially at the water surface. A 6-inch pipe at the center of the tank was adequate to catch and remove the froth. Figure 8 is a schematic of the air flotation tank with the modified waste water weir and the two venturi tubes used to generate the air bubbles. The location of the venturi tubes at the bottom of the tank, and the waste weir in the center of the tank, along with sufficient volume of air, resulted in quality water from the air flotation unit of less than 10 mg/L by turbidity (2.2 mg/L solids by weight).

Problem Nine. Analytical Measurements.

Relationships and conclusions in engineering and science can only be made from quantitative data. All else is speculation. From startup of the flotation unit in July 1994 until February 1996 no quantitative measuring equipment was available at the Nelson Lease for routine measurement of flow rates or suspended solids in the feed and clean water.

A. Water flow measurements.

The schematic of the water plant in Figure 3 shows five flow lines for which flow rates were needed to understand and quantify the functionality of the air flotation unit. From July 1994 to July 1996 the flow rate through the flotation unit was estimated from the sum of the individual injection well flow meters. In July 1996 a turbine flow meter was installed in the clean water line leaving the plant and provided a daily

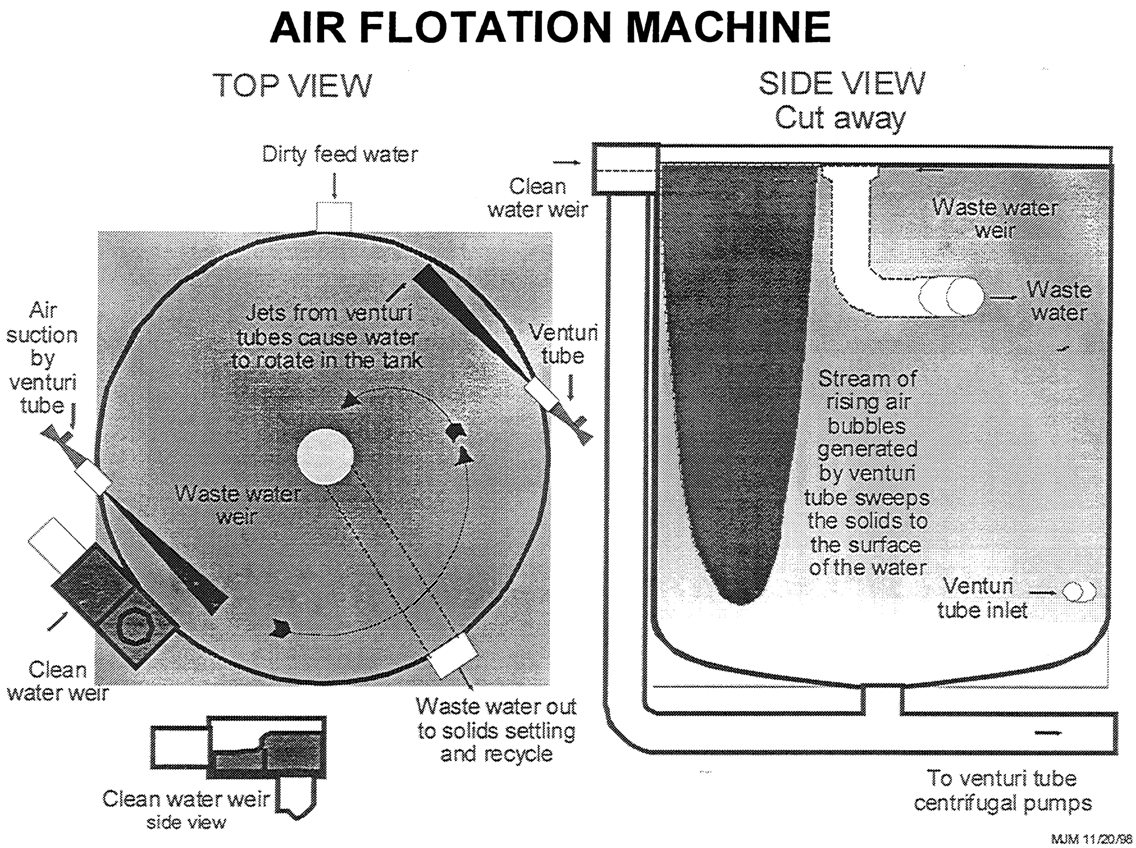


Figure 8. Modified air flotation unit with two 1.5-inch venturi tubes mounted 12-inches from the bottom of the tank and at a 45° angle with respect to the diameter of the tank. The water jets from the venturi tubes cause the water in the tank to rotate at 3 to 5 rpm. The water jets also carry the entrained air to the tank wall where the rising bubbles sweep the dirt to the water surface and also keep the wall free of solids. The waste weir is 6-inches in diameter and located in the center of the tank. The water enters near the surface of the tank and descends in a spiral counter to the spiral of rising bubbles.

volume for water leaving the plant. A paddle type meter was installed also on the transfer line to the air flotation unit, but due to location gave high daily water volumes. This meter is in the harsh, scaling water and requires frequent removal for cleaning. A turbine flow meter was installed on the supply well in January 1997, damaged in April 1997, and replaced in February 1998. Flow of waste water was determined by periodic sampling of flow with a 5-gallon bucket starting in July 1998. The waste water bucket test was done on most days, except weekends.

An attempt was made to meter the produced water in February 1997. A paddle meter was installed in the flow line from the gun barrel to the produced water tank. However, no useful data was collected for the short time the meter was in use. A good estimate of the daily water volume to the flotation unit was made by using the daily water volume sent to the field, the waste water volume, and the supply well volume. Table 2 summarizes the results from July 4 through November 22, 1998. This information was vital in that it supplied the basis for evaluation of the functionality of the air flotation unit. From the flow rate data accumulated, the deficiency in the quality of the water exiting the flotation unit was not due to the suspected variation in the feed water rate, but was due to lack of sufficient air volume in the unit to sweep all the dirt to the surface of the water. This was verified in the bench air flotation unit.

B. Quantitative measurement of suspended solids in water.

The second important measurement needed was an instrument to measure water quality. Water quality requires a knowledge of the constituents in the water and, for a waterflood operation, how well the water flows through the porous media, a filter. The flood water problem at the Nelson lease was due to

Table 2. Summary of water flow from July 4 through November 23, 1998 in barrels per day.

Water	Low	High	Average
Supply well	5	1035	260
Produced	115	1120	780
Transfer to AFU[1]	522	1930	1420
Transfer to AFU by difference[2]	1030	1420	1230
Triplex to the field	835	1240	1050
Recycle from waste	90	380	220
Ratio of produced to supply water	0.1	11	3

1. Results are unreliable due to location and fouling of the paddle meter.
2. Transfer is based on sum of the water sent to the field and returned from air flotation as waste water.

suspended and dissolved solids in the water. Table 1 (Nelson Lease Water Problem) lists the ion analysis or the produced, supply waters, and combined waters for October 23, 1993. Analysis of the produced, supply, and mixed waters on other dates before and after October 1993 gave similar values as determined by Oil Field Research Laboratory of Chanute, Kansas. Analysis by other laboratories also gave comparable values. However, the analysis of the water is incomplete and does not represent the water at the time the water sample(s) was obtained. Carbonate, bicarbonate, sulfide, pH, and iron values can change between sample and analysis time, and frequently some essential analyses are not routinely done.

As mentioned in the "Nelson Lease Water Problem" section, the quality of the water is compromised when the supply and produced water are mixed. The sulfate and sulfide in the supply water and the barium and iron in the produced water causes barium-sulfate and iron sulfides to form. Both waters also contain bacteria, clay, sand, and organic matter. The solids in the water along with oil caused plugging problems at the injection wells. In this study no attempt was made to improve or expand the scope of the water analysis. Instead the filtration characteristics became the important measurement for the mixed supply–produced water.

The quantification of the mixed water as to filtration was accomplished by using a modified ASTM procedure D-4189-82, "Silt Density Index of Water". A 10 psi air pressure differential was used since this permitted a polyethylene water reservoir to be used. Initially, 0.45-micron polycarbonate filters were used, but later 0.5-micron fiberglass, 47 mm diameter filters were found more practical for the filtration of one liter of water. Fiberglass filters are classified as a depth filter whereas the polycarbonate filters are classified as a sieve filter. The depth filter removed the same quantity of solids from the water in a shorter filtration time. In appendix A, a description of the filtration procedure is given. The parts list and sources are also given for the construction of the filtration apparatus.

A plot of the square root of time versus cumulative water volume results in a straight line for non compressible solids collecting on the filter. The slope of the line can be used as index of water quality. Excessive amounts of oil in the water, and especially cationic polymer, will cause an excessively long filtration time, which results in a large "Water Quality Index" value. Addition of 0.1 mL of 5% sodium hypochlorite to the liter of water would deactivate the cationic polymer and results in a realistic filtration time and "Water Quality Index". The actual solid content in the liter of water was measured by weighing the filter before and after the filtration. Solid content required the filter to be washed with distilled water in the field, which was not convenient, or in the laboratory to remove dissolved salts in the water on the filter.

Fiberglass filters were superior in that the solids could be treated with acid to separate the soluble from the insoluble solids collected. The polycarbonate or nylon filters disintegrated in acid.

The filtration of a liter (quart) of water was time consuming and too complicated for field personnel to do daily, and thus, was done by a professional from either the Tertiary Oil Recovery Project or Russell Petroleum. Filtration procedure took from 15 minutes to several hours depending on the amount of solids and the presence of the cationic polymer in the water. A second filtration with hypochlorite in the water would distinguish between polymer interference and other cause. The results required returning the filter to the laboratory for drying and weighing on the analytical balance. Thus, the results were not available to the field personnel or the engineers in time to make reasonable changes in the air flotation operational parameters. From the startup of the flotation unit in July 1994 until February 1996, the performance of the unit in response to changes made was subjective and depended on whether field personnel, the engineer from Russell Petroleum, or the engineer from the Tertiary Oil Recovery Project was operating the unit.

The filtration measurement was done one to five times per week by professional personnel from Tertiary Oil Recovery Project or Russell Petroleum. The data obtained from the filtration test was useful in verifying the practicality of a portable, inexpensive colorimeter used to measure turbidity (suspended solids) at the various water sample points.

The purchase of a simple, easy-to-use, HACH DR/700 colorimeter for $500 by Russell Petroleum in February 1996 provided the means to make an essential measurement of suspended solids on a daily basis. A HACH colorimeter was then purchased by the Tertiary Oil Recovery project in April 1996. Field personnel were trained in the use of the colorimeter in fifteen minutes. It takes only 30 seconds to turn on the instrument and set the zero, and then each water sample takes 15 seconds for a suspended solid measurement. The effect of a change in a flow rate through the flotation unit or amount of flotation chemical could be detected by the turbidity measurement. The quantitative numbers eliminated the subjective judgement as to water quality and eliminated the long periods of operating the flotation unit with excess flotation chemical. The daily measurements of suspended solids in the feed, the air flotation, the filtered, and the triplex water provided a basis in the evaluation of the air flotation unit. The HACH meter along with a bench air flotation cell was the key in determining cause and effect as the operational parameters of the air flotation unit were varied.

In addition, the HACH DR/700 colorimeter has interchangeable modules that permit many analyses to be done in the field, such as oxygen, oil, barium, ferrous, ferric and other constituents in water. This instrument provided the quantification necessary in relating cause and affect. The calibration incorporated in the 81.01 Module (810 nm) for suspended solids is for sewage containing solids with a density close to one (Method 8006). Actual solid content by weight is possible is possible by a calibration with test solids. Figure 9 is an example of the relationship between the HACH value with the weight for a fine silica sand. Figure 10 is for the solids in the mixed water that was serial diluted with the same water in which the solids had been removed by filtration. During the two years the HACH colorimeter was used in testing the air flotation water, the HACH meter values were used without correction as to actual solids content since a reading of 10 mg/L or less was within the goal of less than 10 mg of solids per liter of water by weight. Figure 11 shows the relationship between the HACH meter readings for suspended solids and the actual weight of solids as determined by the filtration procedure.

C. The bench air flotation cell.

A change of an operational parameter for the air flotation unit, such as change in flotation chemical feed rate or type, or water flow rate, or residence time, would take 3 to 72 hours before a noticeable change observed in the effluent at the flotation unit or at the clean water exiting the plant. A quicker method was needed to evaluate change in water quality, due to change in an operational parameter for the air flotation unit. Thus, a bench model air flotation unit was designed by Michnick and constructed in the machine shop of the Tertiary Oil Recovery Project in March 1997. This bench air flotation cell consisted of a one gallon (4 liters) clear plastic tank. Water is withdrawn at the bottom center to feed a small centrifugal pump that powers a 0.5-inch venturi tube mounted at the side, near the bottom of the tank. The venturi tube is mounted at an angle of 45°with respect to the diameter of the tank. This configuration causes the water in the bench air flotation unit to rotate as in the water plant flotation unit. The solids move to the water surface and accumulate at the center within seconds after the addition of the flotation chemical into the inlet of the centrifugal pump. The clear plastic tank allows visual observation in the improvement in water quality as the flotation chemical coagulates and flocculates the solids. A water sample port near the bottom of the tank allows the withdrawal of water for turbidity measurement in the HACH colorimeter every minute during the test.

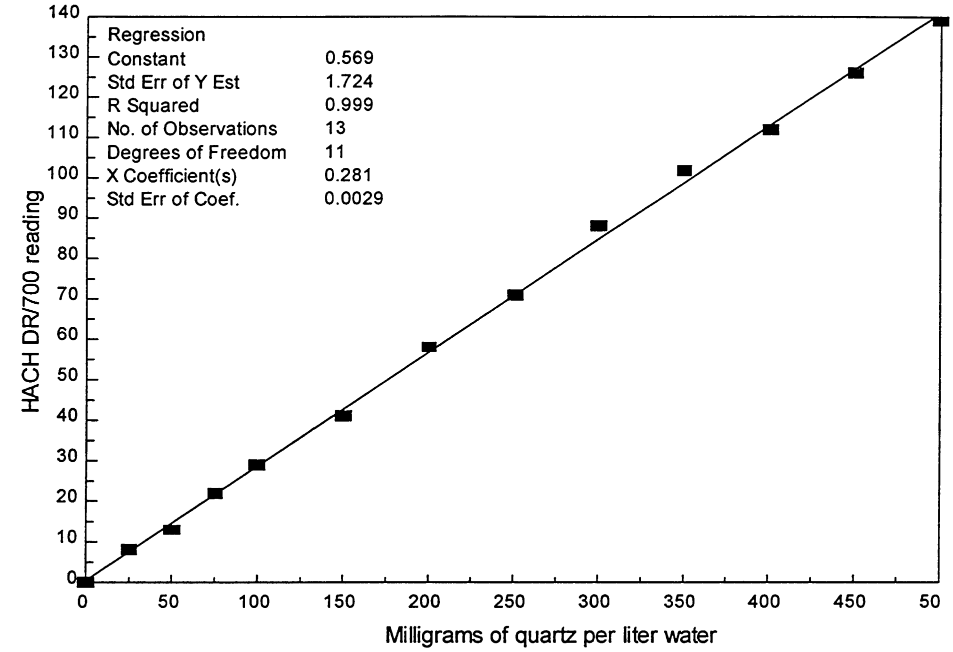


Figure 9. Comparison of suspended solids reading by HACH DR/700 colorimeter with known weight of quartz powder in water. Solid boxes are experimental data and the line is best fit by least squares regression of the data.

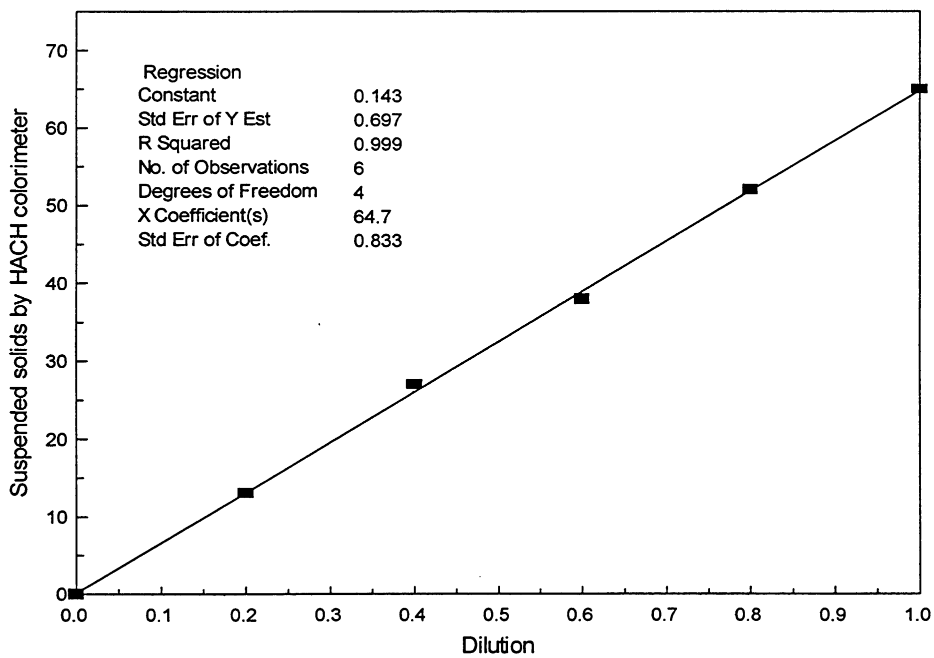


Figure 10. Comparison of suspended solids in the feed water as measured by the HACH DR/700 colorimeter as the water sample was diluted with the filtrate from the same water sample. The solid boxes are the experimental data and the line is the best fit of the data by least square regression of the data.

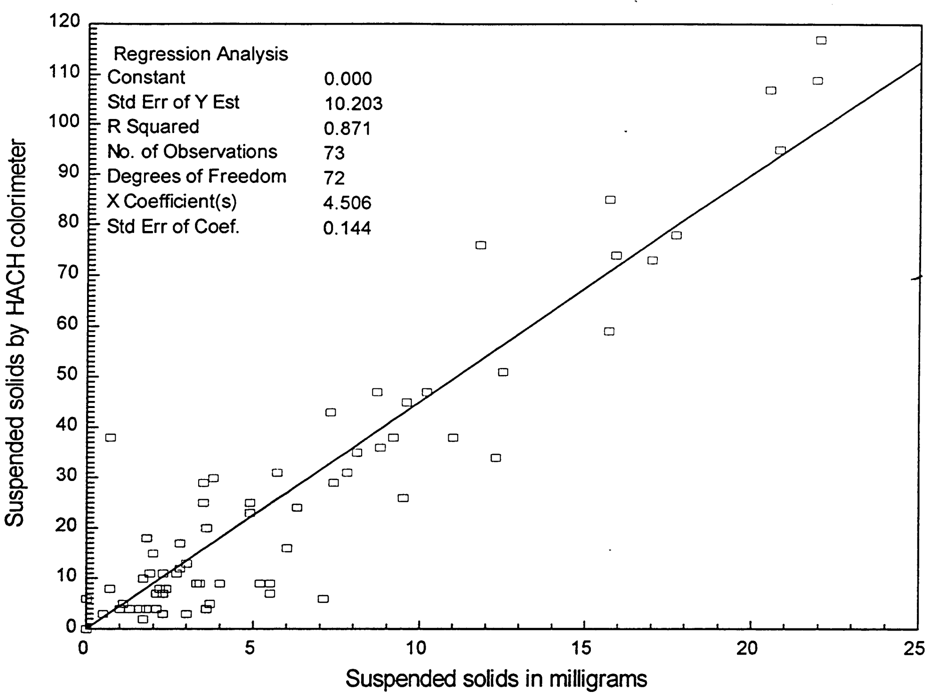


Figure 11. Correlation between weight of suspended solids collected on a filter and HACH colorimeter reading. Filtration consists of passing one liter of water through a 0.5-micron fiberglass filter using a 10 psi pressure differential. Each filter weight was corrected for the 6.6 mg of dissolved solids in the water which adheres to the filter. Data set is for the clean water at the exit of the triplex pump for the year 1998.

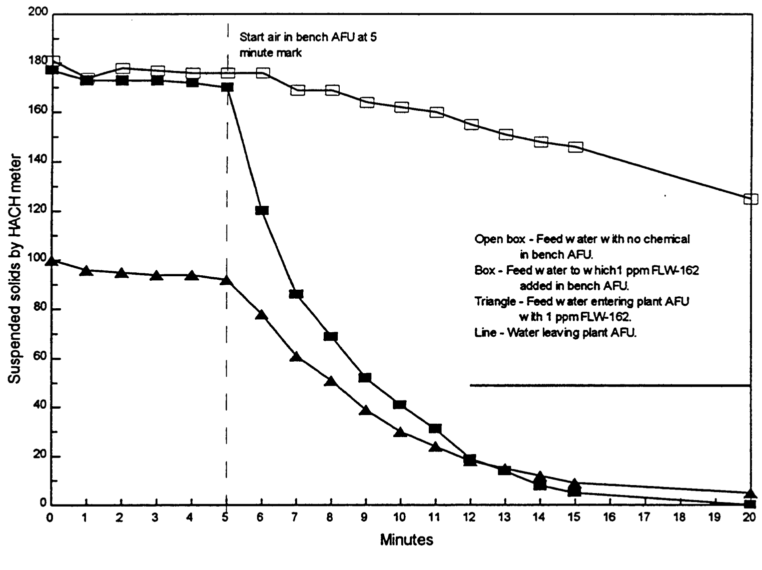


Figure 12. Comparison of water quality between bench and plant air flotation units. The feed water contained 177 mg/L suspended solids as measured by HACH meter. Treating 1-gallon of feed water in bench flotation cell with 1 ppm FLW-162 resulted in water with 0 mg/L solids. The water entering flotation unit measures 100 mg/L solids due to coagulation and flocculation that takes place in the transfer line and exits the unit with 49 mg/L solids. The same water when placed in bench flotation cell and exposed to air for 15 minutes had only 9 mg/L solids showing that more air is needed in the plant flotation unit.

Figure 12 is an example of the results obtained from the bench air flotation unit. The feed water to the flotation unit contained 177 mg/L of suspended solids. A sample of the feed water was placed in the bench flotation cell and treated with 1 ppm FLW-162 and air for 15 minutes. The resulting clean water had no solids by HACH meter. A sample of the water entering the plant flotation unit, which had 1 ppm FLW-162, was then paced in the bench unit and exposed just to air for 15 minutes. The resulting water tested at 9 mg/L solids compared with 49 mg/L solids in the water from the plant flotation unit. This clearly showed that the plant flotation unit did not have sufficient air to remove the solids in the water. Appendix B describes the bench air flotation unit along with the materials for construction of the unit. The bench air flotation unit was used extensively by the engineer-chemist from the Tertiary Oil Recovery Project to test and compare the results from the 1-gallon bench unit and the 1000-barrel a day air flotation unit from April 1997 through July 1998. A typical test would require 30 to 60 minutes to perform. This included the filtration test of the feed water being tested plus the clean water from the bench unit. The filtration tests provided the information to verify the mass of solids in the feed and clean waters, respectively. Various proposed flotation chemicals were tested such as the anionic polymer with and without various additives. The bench unit clearly showed that an air flotation formulation was superior to any combination of chemicals tried, although the anionic polymer with a cationic wetting agent showed promise. Since the proposal was for "Off the Shelf Technology", little time was spent in developing a simpler to use formulation than the FLW-162 formulation, which is a high molecular weigh, cationic polymer prepared as the internal phase in an oil emulsion.

The bench air flotation unit demonstrated that the remaining deficiency in the air flotation unit was in air volume necessary to float all the solids to the surface. It was not as suspected in the variation in the flow rate of water through the flotation unit, or in the change in the ratio of produced to supply water, or the amount of cationic flotation chemical.

Problem Ten. The need to keep water flowing to the field at all times.

The major constraint in the study was that injection water had to be kept flowing to the field always, especially in the winter. Once the air flotation unit had been purchased and installed the only option left was to bypass the unit and send the untreated mixture of supply–produced water to the field. This was done only in the early days when the air turbines were being repaired. This was necessary since insufficient tankage was available to store the incoming produced water for the eight or more hours during the repairs to the unit. Although the flotation unit did not produce the best quality water for the first four years, Russell Petroleum saw the advantage that the improvement in water quality had on the cost in maintaining the injection wells. Therefore, all changes in the operational parameters were constrained by water needed for the waterflood of the lease. For 1998 the demand for injection water ranged from 725 to 1050 BPD. The produced water tank could only take about three hours of production before an overflow condition would be reached, thus, water had to be withdrawn from the produced water tank continuously. Operation the flotation unit at desired test rates of 500 or 1500 barrels per day was not possible because of lack of tanks to store produced or clean water.

Oxygen in water

In many typical produced water handling systems the water is exposed to oxygen from the air. A water stream falling through the air from a separator or heater-treater into the produced water tank will be oxygenated between 6 and 10 ppm oxygen, depending of salt content. The use of an oil pad on the tank does not prevent oxygen from entering the water even if the incoming water is introduced below the oil pad. Surprisingly, the solubility of oxygen in oil is greater than in water. Bacteria in the water are the main reason many produced water tanks have almost no oxygen in the water, especially tanks with stagnant water at the bottom of the tank.

The air flotation unit will produce water that is fully oxygenated. In the past, corrosion was no problem at the injection wells at the Nelson Lease. A check for oxygen at individual wells was negative until recently. Table 3 shows some values at selected points in the water plant and at individual wells. The presence of oxygen was detected at 3 mg/L at test well RW-20 and at the extreme end of the lease at H-7 when bacteria and algae were controlled in the clean water storage tanks. Whether corrosion will become a problem at the Nelson Lease, will depend on control of the growth of algae in the unpainted fiberglass clean water storage tanks, especially in warm weather. The technology and chemicals are readily available to remove the oxygen from the water as it leaves the plant, when it becomes necessary, due to corrosion at the injection wells.

Table 3. Typical oxygen values in mg/L for the feed water, air flotation unit water, clean water, and injection water at test well RW-20 and H-7.

Date	Feed water	Flotation	Clean water	RW-20	H-7
11/06/96	—	7.2	4.0	0.0	—
11/13/96	—	7.2	6.9	—	—
11/21/96	4.1	6.4	6.1	—	—
10/06/98	5.4	7.9	5.7	1.3	—
10/20/98	3.9	7.6	6.3	1.8	6.0[1]
11/04/98	7.4	8.4	7.4	5.1	—
11/17/98	6.4	8.6	7.3	3.2	3.2

1. Fiberglass flow line from plant to north end of field was flushed for 15 minutes before sampling.

Results

The air flotation unit was modified to provide an economical alternative to cleaning produced water for re-injection into the reservoir. The original cost of the flotation unit from Separation Specialists of Bakersfield, California was $30,000. Figure 3 is a photograph of the unit as received in June 1994 and Figure 8 is a schematic of the unit with the venturi tubes and center waste weir. This is the arrangement of the flotation now in operation. A similar size flotation can be built for an estimated $10,000. Figure 13 is a schematic for the same size flotation unit constructed from a 4-foot diameter by 4-foot tall steel tank. 4-foot diameter by 4-foot tall tank. A bare steel, flat bottom tank is the least expensive and easiest in which to install the necessary fittings. A dish-bottom, fiberglass tank is desirable, but more expensive. However, note that this is a schematic for a planned flotation unit that has not been tested and actual costs can vary.

The clean water sent to the injected wells allowed the replacement of the 75-micron cartridge filters with 5-micron filters. Filter change at each injection well was no more frequent with the 5-micron cartridges than was the case with the 75-micron cartridges; field personnel stated that the 5-micron filters appeared to have fewer solids with the air flotation water than the 75-micron filters before the start of the air flotation unit. A test injection well used a 2-micron cartridge filter. Filter changes for the 2-micron filter were no more frequent than the other injection wells with the 5-micron filters.

Important findings of the investigation are; (1) An air to water ratio of at least 4 SCFM of air to each 40 gpm water is needed to sweep the solids to the surface of the water; (2) A stream of small air bubbles rising at the sides of the tank is needed to keep solids from accumulating at the tank wall, especially at the water surface; (3) By angling the venturi tubes at 45° to the center line of the tank, the water jets from the venturi tubes with the air bubbles can be directed to the wall of the tank and cause the water to rotate in the tank at 3 to 5 rpm; (4) Removal of waste solids and water at the center of the tank at the water surface instead at the tank wall improved the efficiency of the flotation unit; (5) Introduction of air near the bottom of the tank further reduced the solid content of the clean water exiting the flotation unit; (6) A preventive maintenance schedule for pumps and meters is necessary to insure the continuous operation of the flotation unit, particularly on the raw water side of the flotation system; (7) Good records on the daily operation of the water plant are essential; and (8) The injection well filters were changed from 75 to 5-micron with no more frequent change of filters.

From July 4 through November 22, 1998 the air flotation unit reduced the suspended solids from an average daily value of 80 to 7 mg/L as measured by the HACH meter, 19 to 2 mg/L by weight. Solids in feed water ranged from 40 to 367 mg/L by HACH, 9 to 90 mg/L by weight. This corresponds to an average of 90% in the removal of solids from the water by the flotation unit, which reduced the solids entering the injection wells in the flood water from 2400 to 240 pounds per year. The cost of chemicals for the water plant has been reduced from $35 to $15 per day. Table 4 contains a list and cost of chemicals used from July 4 through November 22, 1998 in the operation of the flotation unit at the Nelson Lease. Future chemical costs are expected to be less because the averages calculated contains days when one or more chemicals were used at a greater rate than necessary due to a malfunction of a metering pump or a planned test.

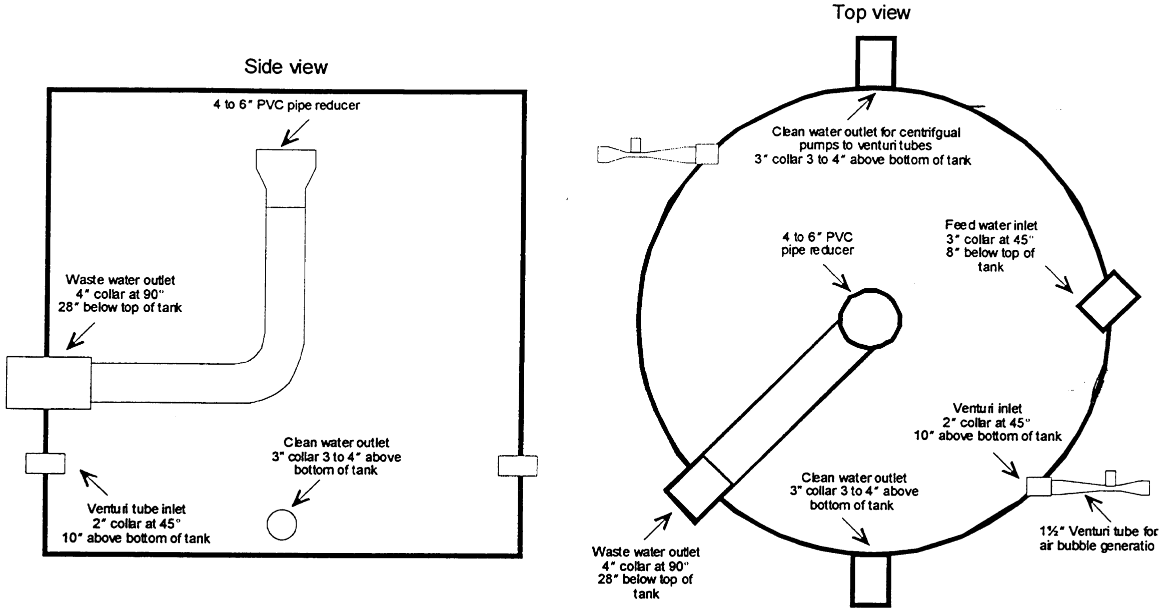


Figure 13. Schematic of proposed air flotation unit constructed from a 4-foot tall by 4-foot diameter steel tank. Note this flotation unit has not been built and tested.

Table 4. Chemical used in operation of flotation unit from July 4 through November 23, 1998 with costs.

Chemicals	Low	High	Average	$/gal	$/day
Hypochlorite, gal	1.5	5.0	2.7	2.10	5.70
Scale inhibitor, qts	0.0	5.5	3.0	10.00	7.50
Flotation chemical, lbs	0.30	1.17	0.51	20.00	1.20
Total					14.40

Conclusions

1. The "Off the Shelf Technology" approach has limitations. One must have some knowledge of the technology and should have some experience. Otherwise, time and money will be spent in learning the technology and operation of the equipment.
2. Air flotation is an economic alternative to cartridge, bag, or sand filtration of produced water that is re-injection into the reservoir.
3. A 1,000 barrel per day air flotation unit can be constructed from a 4-foot diameter by 4-foot tall tank for about $10,000. This estimate includes centrifugal pumps to power the venturi tubes and to recycle the waste water, venturi tubes, a HACH DR/700 colorimeter, and chemical metering pumps. Installation costs depend on the current or anticipated plant configuration. The estimate does not include tanks for storage of produced, supply, and clean waters.
4. Time required to monitor and maintain the flotation unit should be about one hour per day, mainly in keeping operation records, and in preventive maintenance of pumps.
5. Chemical costs were reduced from $35 per day in 1993 to less than $15 per day for 1998.
6. Clean injection water will reduce the frequency, and thus the cost, of maintaining the injection system.
7. The mixed feed water will always contain oxygen whenever the tanks are open to the atmosphere. Air flotation added only 2 to 3 mg/L more oxygen to the water. The oxygen in the clean water decreased rapidly due to algae growth in the clean water tank. Aerobic bacteria in the water also consume oxygen.
8. Oxygen was detected at the injection wells only when the algae and bacteria in the clean water storage tanks were vigorously treated with appropriate chemicals.
9. A preventive maintenance schedule for pumps and meters, and a set of daily water plant operation data will permit management to spot problems before they become serious.

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Appendix A. Water quality index by filtration (as modified by Michnick).

A modified procedure, along with the equipment used, is described here for the measuring the quality of a water by filtration. The procedure is a modification of the ASTM D-4189-95 "Silt Density Index for Water". The ASTM procedure calls for recording the times for passage of the water volumes through a 0.45-micron, 47 mm diameter membrane filter using a 30 psi gas pressure. A lower pressure permits simpler and lighter weight equipment to be used in the field. Figure A1 is a schematic of the simplified apparatus and contains a list of parts with prices as of 1999. The only additional item is a tape recorder to record times at selected volumes of water collected for those samples which filter rapidly.

Assembly of the apparatus and operation is simple. A filter is placed in the filter holder connected to the polyethylene water reservoir through a ball valve and flexible plastic tubing. The bottle is filled with more than one liter of water. The air pump is started and pressure adjusted to 10 psi. The air hose is connected to the polyethylene bottle cap using the quick connectors to pressurize the system. The valve is opened and the time recorded for uniform volume increments in the collecting cylinder. A plot of the square root of time versus cumulative volume generally results in a straight line. The slope of the line times 100 can be used as a water quality index. The smaller the slope the better the quality of the water. Filtration time, using a 0.5-micron fiberglass filter, ranges from one minute for clean water to hours depending on solids and other organic contaminants in the water. The pressure is released from the apparatus, the filter removed, blotted on paper toweling and stored until it can be dried and weighed in the laboratory.

Ideally, the air in the filter line and filter should be displaced with water and the filter wetted with clean water. However, from experience I found this only increased the time to perform the test and provided little or no improvement in the precision or quantitative values in the index number as calculated from the slope of the line. This plot can be made in the field on graph paper and the slope estimated without the aid of a calculator. The actual weight of solids in one liter of water can be determined by pre-weighing the filter before the test. The filter should be washed in the field with 50 to 100 mL of water, but I have found this again to be inconvenient. A filter can be mounted in a simple filter holder in the laboratory and washed, either before or after they have become dry during storage. For the Nelson Lease water the solid contribution from the soluble salts in the water sticking to the filter was essentially constant over a twelve-month period at 6.6 mg per filter. Duplicate filtrations made in the field in which one was washed in the field and the other washed in the laboratory gave the same results to within 0.1 mg. The same 6.6 mg weight average for soluble salts was obtained for nine filters soaked in filtered Nelson Lease water, blotted, and dried A balance weighing to the 0.1 mg is necessary to obtain the weight of the dried solids.

The limitation of the method is the time to filter samples. The presence of a few milligrams per liter of the cationic flotation polymer caused very long filtration times. Addition of 0.1 mL of 5% sodium hypochlorite to the liter of test water reduced the filtration time to within the expected time for the solid load in the water. Excessive amounts of dispersed oil or bacteria can also lead to long filtration times, but this is a true indication of the quality of the water. Hypochlorite does not change the water quality index by oxidation of the oil or bacteria. The method is to time consuming for field personnel to do and results are not as useful as a turbidity measurement in the operation of the flotation unit.

Appendix B. The design and fabrication of a bench air flotation test unit. A chemical change made as an operational parameter of the air flotation unit would take 3 to 72 hours before a noticeable change observed in the effluent at the flotation unit or at the clean water exiting the plant. A quicker method was needed to evaluate change in water quality due to changes in how much flotation chemical needed. Thus, a bench model air flotation unit was constructed in the machine shop of the Tertiary Oil Recovery Project. Figure B1 is a schematic of the bench flotation unit and with a list of parts and prices as of 1999. The unit consists of a one gallon (4 liters) clear plastic tank. Water is drawn from the bottom center to feed a small centrifugal pump that powers a 0.5-inch venturi tube mounted at the side, near the bottom of the tank. The water action in the bench unit is very similar to the field flotation unit. A tee with a septum port allows for injection of micro liter amounts of test chemical to the circulating water. A ball value is used to control the water to the venturi tube. This valve is adjusted so that a vortex is not created in the tank. A valve on the air inlet to the venturi tube controls the air to the flotation cell. A sample port near the bottom of the tank allows for periodic withdrawal of water for suspended solid measurements in the HACH colorimeter. At the end of the test a liter of water is withdrawn for water quality index measurement and solid content by weight using the filtration apparatus. Testing time for a water sample is usually 15 minutes in the flotation unit, and then another 2 to 30 minutes for the filtration test. The solids in the water from the bench and the plant air flotation unit agreed within 1 to 5 mg/L, by turbidity, for the same amounts of flotation chemical(s) in the two flotation units.

WATER FILTRATION APPARATUS

Part	Number	Price
Air pump	P-07059-40	$440.00
Tubing, per 50 ft	P-06408-66	19.50
Quick dicsonnect	P-06360-50	13.25
	P-06360-75	8.75
Carboy with tubulation	P-06080-10	14.00
¼″ ball valve	P-06225-54	13.50
Filter holder	P-06623-22PP	20.50
0.5-micron glass fiber filters	09-730-61	37.00
500 mL graduate cylinder	P-06137-80	8.25
Stopwatch	P-99410-20	36.00

All part numbers refer to Cole-Parmer catalog, except filters from Fisher Scientific. Other vendors supply similar or identical items at comparable prices.

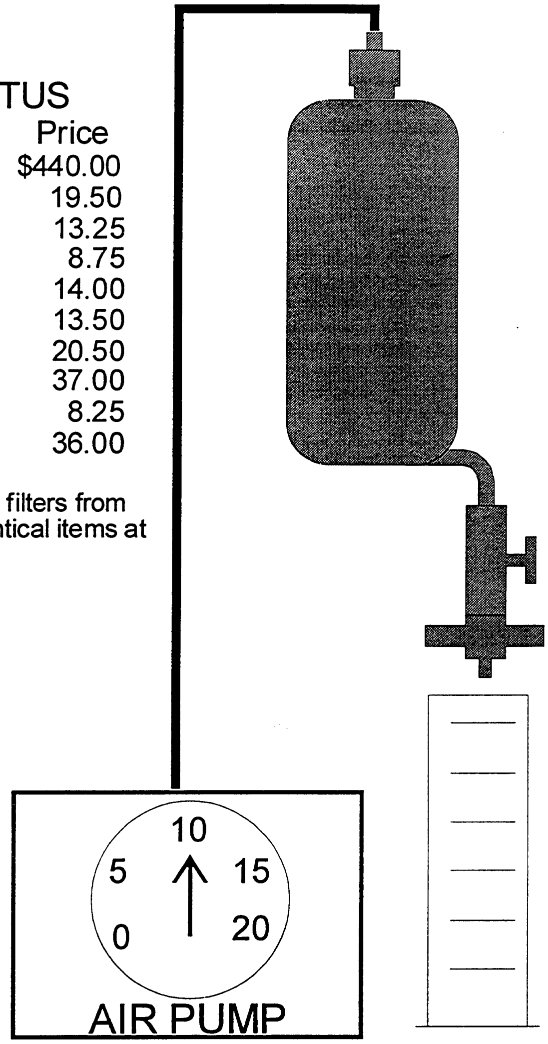

Figure A1. Apparatus to measure water quality by filtration time and to obtain solids by weight.

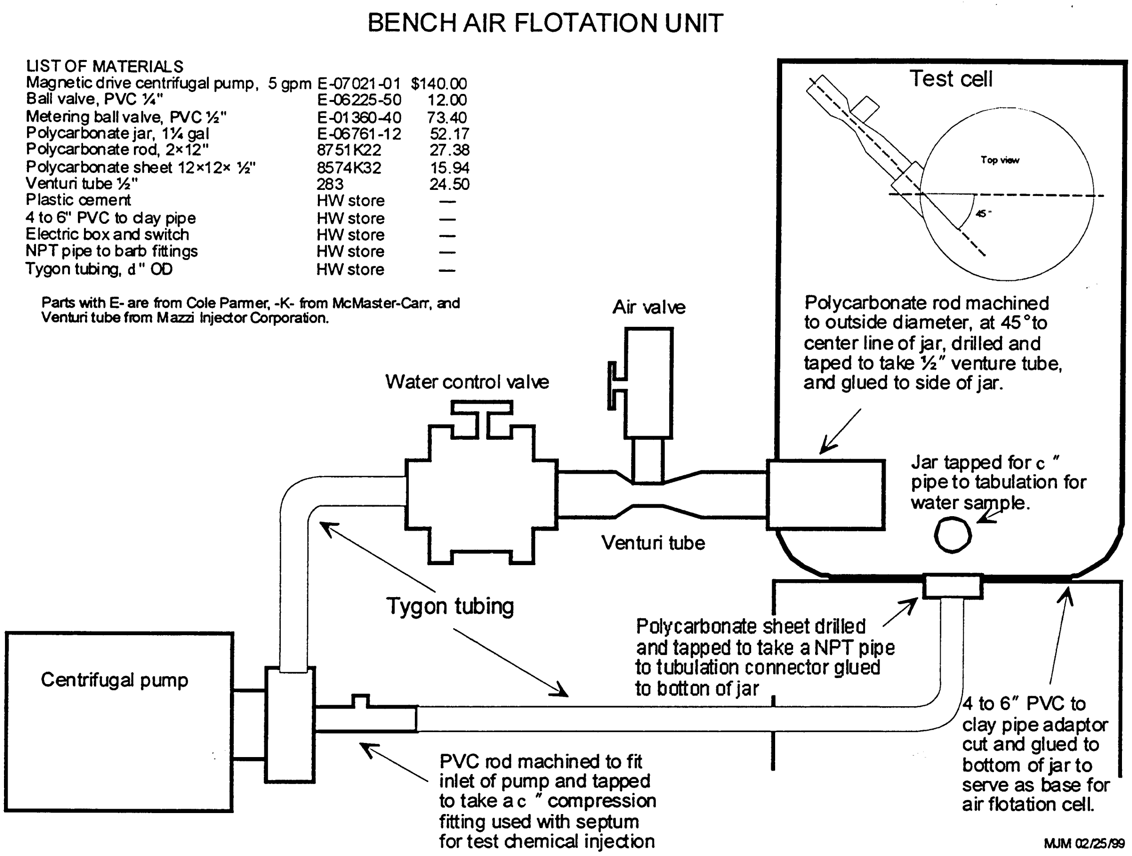

Figure B1. Bench unit for testing water for solids removal by air flotation.