FOSSIL ENERGY

DOE/BC/14957-16
(DE96001261)

IMPROVED OIL RECOVERY IN FLUVIAL DOMINATED RESERVOIRS OF KANSAS - NEAR-TERM

Annual Report

By
Don W. Green, G. Paul Willhite, A. Walton, L. Schoeling, R. Reynolds, M. Michnick, and L. Watney

November, 1996

Performed Under Contract No. DE-FC22-93BC14957

Energy Research Center
The University of Kansas
Lawrence, Kansas

Bartlesville Project Office
U. S. DEPARTMENT OF ENERGY
Bartlesville, Oklahoma

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DOE/BC/14957-16
Distribution Category UC-122

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Prepared for
U.S. Department of Energy
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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 are involved in this project. The Stewart Field is located in Finney County, Kansas and is operated by North American Resources Company. 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 is to increase recovery efficiency and economics in these type of reservoirs. The technologies being applied to increase waterflood sweep efficiency are 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 are 1) database development, 2) reservoir simulation, 3) transient testing, 4) database management, and 5) integrated geological and engineering analysis.

The Stewart Field project results are 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 of the waterflood.

Current activities and future plans for the Stewart Field project consist of the operation of a waterflood utilizing state-of-the-art technologies in an attempt to optimize secondary recovery. Production and reservoir data will be analyzed using reservoir characterization techniques and by updating the existing reservoir simulation. The analysis of results will be 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 Mid-Continent" for 1995 by Hart's Oil and Gas World.

The Savonburg Field project results are 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.

Current activities and future plans for the Savonburg Field project consist of the continual optimization of this mature waterflood in an attempt to optimize secondary and tertiary oil recovery. The waterflood optimization program is based on project results and will include continued infill drilling, wellbore cleanups, and pattern changes.

EXECUTIVE SUMMARY

This project involves 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 245,000,000 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 are 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 are 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 modeling, 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. Tasks 1-3 have been completed and water injection began in October 1995.

The Stewart Field project results to date are 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 of the waterflood.

Current activities and future plans for the Stewart Field project consist of the operation of a waterflood utilizing state-of-the-art technologies in an attempt to optimize secondary recovery. Production and reservoir data will be analyzed using reservoir characterization techniques and by updating the existing reservoir simulation. The analysis of results will be 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 Mid-Continent" for 1995 by Hart's Oil and Gas World.

In the Savonburg Project, the reservoir management portion involves 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) preliminary identification of the most efficient and economical recovery process i.e., polymer augmented waterflooding or infill drilling (vertical or horizontal wells).

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 is 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 (polymer flooding), 5) field operations, and 6) technology transfer.

The Savonburg project results to date include a complete geological and engineering analysis and field work. The geological and engineering analysis includes, 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 includes, 1) the installation of the air flotation device for improvement of water quality, 2) wellbore cleanups throughout the field, 3) completion of three in-situ permeability modification treatments, 4) two pattern changes, and 5) an in-fill well drilled and completed as an injection well.

Current activities and future plans consist of the continual optimization of this mature waterflood in an attempt to optimize secondary and tertiary oil recovery. The waterflood optimization program will be based on geological and engineering analysis conducted in Budget Period 1. The reservoir model developed in Budget Period 1 will be continually updated as additional data is collected. The air flotation unit in the waterplant will be continuously monitored to alleviate unforeseen problems and to optimize operation. The specific goals are four-fold: 1) to operate the plant effectively on an continuous basis, 2) to demonstrate that high quality water can be obtained by establishing an acceptable measure of water quality, 3) to determine the cost of treating water, and 4) to identify savings in water treatment and well cleanup costs that are directly attributed to the improvement in water quality. An additional infill well location will be identified and drilled in Budget Period 2 of this project. Possible future permeability modification treatments will be implemented. Once the water quality is stable and it is verified that water is being injected into the desired zones, a polymer augmented waterflood will be implemented if the economics are satisfactory.

Chapter 2

Stewart Field Project

OBJECTIVES

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

The reservoir management portion of this 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 modeling, 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.

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BACKGROUND

The Stewart Field is located approximately 12 miles northeast of Garden City in Finney County, Kansas (**Figure 1**). The field is about 0.25 to 0.5 mile wide, 4.5 miles long and covers approximately 2400 acres. The field was discovered in 1967 with the drilling of the Davidor and Davidor #1 Haag Estate. The well was completed in a basal Pennsylvanian Morrow sand from 4755-4767 for 99 BOPD. Three additional wells were drilled by Davidor and Davidor. In 1971, Beren Corporation acquired the Davidor and Davidor lease and attempted to extend the field to the west, drilling one marginal producer. Active development of the field by Sharon Resources, Inc. and North American Resources Company took place from 1985 to 1994. **Figure 2** is a well location plat of the field.

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. Early completion practices consisted of acid or diesel breakdown jobs. In 1990 and 1991 Sharon Resources implemented a field wide hydraulic fracture program consisting of a water base gel with 3,000 to 43,500 lbs of sand. All wells were produced with pumping units and insert rod pumps. There were 43 producing wells drilled in the field. A summary of the field data is contained in **Table 1**.

Table 1 Stewart Field Data Summary	
General	
Well Count	43 Producers, 14 Dry Holes
Operators	3
Reservoir Data	
Formation	Morrow
Depth to Top of Morrow Sand	4760 ft.
Temperature	125°F
Original Pressure	1102 psig
Average Initial Water Saturation	32.2%
Original Oil In Place (volumetric)	22,653 MSTB
Cumulative Production (as of 1-1-95)	3,479 MSTB, (15.4% OOIP)
Ultimate Primary Reserves	3,881 MSTB, (17.1% OOIP)
Incremental Secondary Reserves	3,738 MSTB, (16.5% OOIP)
Primary Plus Secondary	7,619 MSTB, (33.6% OOIP)
Rock Properties	
Lithology	Sandstone
Average Thickness	26 ft.
Average Porosity (11% cutoff)	16.5%
Arithmetic Average Permeability	138 md.
Fluid Properties	
Crude Oil -	
Gravity	28° API
Viscosity at P_i and T_{res}	12.1 cp
Initial Solution Gas-Oil Ratio	37 SCF/STB
FVF at P_{BP}	1.045 RB/STB
Produced Water -	
Resistivity at 125°F	0.04 ohm-m
Total Dissolved Solids	91,300 mg/l

Primary Production

Primary oil production for the field is shown in **Figure 3** (solid line). The increase in production rates during the period from 1985-1989 is due to rapid development of the field to the east and west by Sharon Resources and North American Resources. Peak production rates were observed following the hydraulic fracturing program carried out in 1990 and 1991. A decline curve analysis was completed using production data 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.

Water production from the Morrow formation was small. Increases in produced water were observed when production wells were fractured. Most of the produced water was attributed to fractures that were thought to extend into the underlying St. Genevieve and St. Louis formations.

The Stewart Field contains 28°API oil with a small amount of solution gas (37 SCF/bbl). The initial reservoir pressure was estimated to be 1102 psig with a bubble point of approximately 180 psi. The reservoir oil was highly undersaturated and the expected primary production behavior was a rapid decline of reservoir pressure as the reservoir energy in the form of fluid and rock expansion was depleted.

Two field wide shut in tests were conducted in 1989 and 1991 to determine reservoir pressure distribution. Pressure tests indicated continuity of the reservoir over the 4.5 mile length of the field. Material balance calculations were performed from the initial reservoir pressure to the average reservoir pressures observed in the 1989 and 1991 field wide tests. Assuming no water influx, the fluid produced should be due to fluid and rock expansion over the given pressure drop. These calculations gave an estimate 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. This uncertainty provided motivation for the extensive database development and reservoir study which was completed in Budget Period 1.

History Matching Primary Production

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 activity 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 and 2) development of a reservoir description to obtain a history match with the primary production. This reservoir description was the basis for subsequent simulation of the waterflood recovery. The independent studies resulted in different models, however, the two models provided similar results.

Data for the simulation was provided by Sharon Resources. This included porosity/permeability correlations for the three major zones within the Morrow, relative permeability data, and the history of all the wells which included location, date of completion, perforation intervals, wellbore radius, skin factor, stimulation history, production history, pressure constraints, and other information related to the wells. To identify distributions in the regions between wells, it was necessary to contour the tops, bottoms, porosity, permeability, and water saturations for each zone.

The Stewart Field model was developed in stages. Initially,the field was divided into four different segments which were assumed to be isolated from each other. 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 of the four segments:

1. Permeability of the reservoir was increased by a factor of 2 above values obtained from core analyses.
2. Reservoir volume was added to the northern portion of the Nelson and Carr leases.
3. Outside pressure support was included from the underlying Ste. Genevieve and St. Louis formations.
4. The initial skin damage on the wells were +1 and skin after fracture stimulation was -3 for all wells.
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 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.

After obtaining a history match for each section, a model of the entire field was developed. The model was built using a grid of 150x20x4. Each gridblock had average dimensions of 190x250 ft. The resulting model had about 2-3 gridblocks between each well. The model contained a total of 12,000 gridblocks. The resulting model provided a primary history match in which the simulated production was 95.74% of the actual production. Actual and simulated results are plotted in **Figure 3.** The original oil in place in the Morrow sandstone was estimated to be 26.1 MMSTB from the history match. The history match is not unique because different models produced a history match for the same field. However, estimates of original oil in place were in reasonable agreement.

Waterflood Simulation

The reservoir description developed during the history match of primary production was used to estimate waterflood performance using the VIP simulator. Six different waterflood patterns were proposed by Working Interest Owners and University personnel. The mobility ratio was favorable and high volumetric sweep efficiency was anticipated in regions contacted by the injected water. Thus, selection of injection wells was done with emphasis on getting water into wells which contacted as much of the productive sand as was possible. Since few new wells were anticipated, this meant conversion of some of the best production wells into injection wells. The injection rate was restricted by water availability of 6000 BWPD. In each case, the water was distributed equally between each injection well within the waterflood pattern. The patterns simulated were 3 line drive, 5 line drive, 7 line drive and three modified line drive patterns. All the patterns were run for a waterflood period of ten years. The production wells were set to be shut in at a watercut of 90%. **Figure 4** shows typical results for the waterflood plotted in terms of total oil recovery as a function of the volume of water injected. Incremental oil recovery due to waterflooding ranged from 15.3% to 17.5% of the original oil in place.

The Stewart Field showed favorable results for waterflood. The following conclusions were based on waterflood predictions based on simulation results:

1. Cumulative oil production and the water/oil ratios for all the patterns varied by less than 10%. Thus, pattern selection is not critical. What is critical is injecting the water into the principal reservoir zones.
2. Total oil recovery is a function of the volume of water injected, but not a strong function of the injection pattern.

Summary

Integrated analysis of the existing data and computer simulation of the reservoir provided 1) a more accurate description of the reservoir and its fluid flow characteristics, 2) identified waterflooding as the most economical enhanced oil recovery process to be implemented, and 3) facilitated unitization of the field to permit field-wide waterflooding.

A waterflood was designed and implemented for the entire field based on the geological and engineering analysis conducted in Budget Period 1. More detailed information pertaining to the work conducted during Budget Period 1 is available in the Second Yearly Technical Report submitted in June 1995[1].

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 which 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.

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.

A modified six line drive pattern (**Figure 5**) 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. These wells were the 1) Bulger 7-1, 2) Mackey #6, 3) Meyer 10-2, 4) Scott 4-2, 5) Sherman #3, and 6) 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.

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.

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 too 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) conducts the secondary field operations of the Stewart Field 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 comprise NARCO's reservoir management team who are responsible for monitoring, recommending, coordinating, and implementing the development and enhancement plans/work for the field. NARCO's reservoir management team is complemented by University of Kansas personnel, including engineers from the Tertiary Oil Recovery Project and geologists from the Kansas Geological Survey.

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 are 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 injection into all six injection wells was completed by the end of October. As stated earlier, 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. Both supply and produced water are being injected. All the injection wells have been taking water with the surface pressure being a vacuum, with the exception of the Mackey #6, which in March 1996 began having slight surface pressure of 10-30 psi. The injection rate was reduced and this well continues to take water on a surface vacuum at the reduced rate. Cumulative water injection in the field from flood startup to July 1, 1996 is 1,136,037 BW. Monthly and cumulative injection volumes for the six injection wells are shown in **Table 2.**

Table 2
Stewart Field Water Injection Summary

Date	Bulger 7-1 (BW)	Mackey #6 (BW)	Meyer 10-2 (BW)	Scott 4-2 (BW)	Sherman #3 (BW)	Sherman 3-1 (BW)	Total Injection
Oct. 1995	6561	9382	8060	9419	9510	9310	52,242
Nov. 1995	15282	14309	13781	14147	14362	13958	85,839
Dec. 1995	14958	15110	14961	14989	14845	14523	89,386
Jan. 1996	14666	13928	14299	13974	13876	13674	84,417
Feb. 1996	24401	23814	25439	24566	24825	23980	147,025
Mar. 1996	28455	23530	34855	29058	28467	28378	172,743
Apr. 1996	23751	19338	35159	34853	27483	28209	168,793
May 1996	27413	17029	34591	36308	31004	25882	172,227
Jun. 1996	29130	17134	31202	34959	28829	22111	163,365
Total Inj.	184,617	153,574	212,347	212,273	193,201	180,025	1,136,037

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. To date adjustments coincide with the maintenance of a vacuum surface injection pressure at all the injection wells.

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 began 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 6** is a plot of pressure versus shut-in time. Also shown in Figure 6 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 7**. 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 3.**

Table 3 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.

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 July 1, 1996 total waterflood response is 270-295 BOPD. **Figure 8** is a plot showing injection and production data for the field since the initiation of the waterflood. Only parts of the field have responded to water injection to date. The majority of the response is occurring in wells directly offsetting injectors. Most of the response to date has occurred in the Haag Estate #3, Mackey #4, Meyer 10-5A, and Pauls 9-3. Minor response has been observed in the Meyer 10-3 and Haag Estate #5.

Electrification of the producing wells in the field began in May 1996. Electrification of the field should provide a more reliable and lower maintenance power source that can be automated much easier. This project will continue for another 2-3 months as NARCO is working with the farmers to lay the electric lines to minimize crop damage. Approximately one third of the producing wells have been electrified to date.

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 the past year:

1. A paper titled, "Stewart Morrow Field - DOE Class 1 Project" was presented 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.

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 is in the initial stages of responding to the water injection. To date 1,136,037 BW have been injected resulting in an increase in oil production of 270-295 BOPD.

A North American Resources Company reservoir management team, working in conjunction with the University of Kansas, analyzes the production and reservoir data. The existing reservoir simulation will be updated based on waterflood response data. The analysis results will be utilized to optimize the waterflood plan and flooding techniques to maximize the secondary oil recovery.

References: [1]Second Yearly Technical Report, "Improved Oil Recovery In Fluvial Dominated Deltaic Reservoirs of Kansas - Near-Term", submitted to United States Department of Energy, Pittsburgh Energy Technology Center, Pittsburgh, PA, on June 30, 1995

Chapter 3

Savonburg Field Project

OBJECTIVES

The objective of this project is to address waterflood problems in Cherokee Group sandstone reservoirs in eastern Kansas. The general topics addressed are 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 involves 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 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. Results from Budget Period 1 are presented in the previous annual report.

Budget Period 2 objectives consist 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 is subdivided into six major tasks. The tasks are 1) waterplant development, 2) profile modification treatments, 3) pattern changes, new wells and wellbore cleanups, 4) reservoir development (polymer flooding), 5) field operations, and 6) technology transfer.

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.

The geological and engineering analysis identified two separate oil producing zones. The last annual report described that analysis in detail. **Figure 9** presents a map of all the wells and the upper B2 sand isopach maps. **Figure 10** presents a map of current active wells and the lower B3 sand isopach map.

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 May 1996 has been 362,844 barrels. Of this production, 131,530 barrels were produced by primary depletion. Water injection began in March 1981 and 231,314 barrels have been produced under waterflood operations. The most current graph of waterflood production data is presented in **Figure 11.**

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 last annual report. In that report, the high potential areas for development were defined and are presented in **Figure 11a.**

BUDGET PERIOD 2 ACTIVITIES

Waterplant Development

Background. 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 as shown in **Figure 12.** 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 and the current configuration is shown in **Figure 13.** 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, but not used, to 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.

In redesigning the Nelson Lease water plant, the following constraints and objectives guided the decision making process:

Nelson lease water plant objectives

1. Use the current mixture of produced and make-up water.
2. Reduce the oil and solids content of the raw water.
3. Produce 1000 BPD of water which can pass through a 10-micron filter.
4. Require minimal effort and time by field personnel to operate the water plant.
5. Reduce the cost of water plant operations.
6. Reduce the cost of injection well operations.

This section describes the principles of air flotation, performance of the installed unit and modifications necessary to obtain high quality water.

The principle of air flotation. The flotation process depends on the solids being made hydrophobic. Oil drops are hydrophobic. Small air bubbles in the 50 to 200-micron range will adhere to hydrophobic solids, and thereby reducing the density of the solid particle or oil drop. The stream of rising small bubbles sweep the solids and oil to the surface of the water where the solids laden froth is removed. Solid particles which are not hydrophobic, can be rendered hydrophobic by adsorption of an appropriate organic material. In addition, particles which bear a charge, negative or positive, can be flocculated by columbic attraction with a polyionic organic polymer of the opposite charge. Neutral particles, as is the case for most solids near pH of 7, can be absorbed on charged or uncharged organic polymers by van der Waal, dipole, or induced dipole interactions. Cationic, anionic,and nonionic polymers have been used to flocculate neutral particles in water. Air flotation frequently requires a flocculation, a hydrophobic or wetting, and a foaming agent to increase the efficiency of the process. Finding a formulation that will work with a specific water in the oil field requires on site testing. A major problem in eastern Kansas is finding chemical vendors who are interested in supplying or who will formulate a product that will work with the mixture of supply-produced water at the Nelson Lease.

Air Flotation Unit Operation. A schematic of the air flotation unit is shown in **Figure 14**. The flotation unit was designed to remove oil from water from off-shore operations. The design relied on the circulation of the water in the tank created by the air turbine-impeller units to move the froth to the waste weir. Dispersed oil that is floated to the surface will remain on the surface and eventually reach the froth weir for removal. No documentation was provided on how to operate the unit. Thus, the adaptation of the unit for removal of suspended solids was a process of trial and error. The floc which formed with the polymer and solids would coagulate at the water surface forming larger masses which sank back into the water. These heavier particles eventually appear at the clean water weir and exit the flotation unit rather than being removed by flotation. The coagulated solids have a tendency to build deposits on the walls of the tank at the water-air interface.

The principal operating problem in reducing solids content was traced to difficulty in froth collection at the top of the air flotation unit that caused problems with the removal of solids from the water. A number of froth weirs were fabricated and tested. Marginal improvements were observed over the original design. This problem was not fully understood until the top of the air flotation unit was cut-off in November

1995. The circulation of water at the surface was found to consist of a general counter-clockwise rotation with three addition eddies caused by the agitators as shown in **Figure 15** .

The final design of the froth weir is shown in **Figure 16.** The weir consists of a plastic "U" channel set at the surface of the water. A 4-rpm motor drives a 3-inch brush by 36-inch in length which sweeps the surface of the water. The brush just touches the surface of the water and creates a small wave which pushes the water and froth into the waste weir. This configuration reduces the time the flocculated solids are at the surface and prevents coagulation of the solids into larger masses.

Effective operation of the air flotation unit requires selection of chemicals that will float the solids to the surface. As noted earlier, the injected water contained barium sulfate and iron sulfide and/or iron oxide. Depending on the ratio of the two supply waters, the raw water is either black due to the iron sulfide or red due to the formation of insoluble iron oxide. The amount of flotation chemical necessary to float the solids varies with the iron sulfide-oxide ratio. Over and under treatment results in a variation of water quality from the flotation unit.

The flotation chemical selected for the air flotation unit was obtained from Petrolite Corporation. Petrolite FLW-162 was selected after more than 30 formulations were tested in a small unit. Petrolite FLW-162 is a water in oil emulsion consisting of a high molecular weight cationic polymer with various surfactants, wetting agents, and other components. The cationic polymer has a tendency to adhere to surfaces of the tank and the wiper brush. This required periodic cleaning of the system, which in practice was not done until the unit became inoperable. The FLW-162 must be protected from moisture while in storage and in the supply reservoir to the metering pump. Any water that gets into this chemical mixture forms viscous lumps which then clog the check values of the metering pump. This behavior is a major problem in the use of water in oil emulsion polymers. Dilution of the oil emulsion with kerosine reduced some of the problems experienced with the metering pump, but the internal phase of the emulsion tended to settle causing varying amounts of chemical to be added to the feed water. This operational problem combined with the availability of the flotation chemical in eastern Kansas caused a search for other treatment chemicals in the first quarter of 1996.

In April 1996, Rohm and Haas 7000, an anionic polymer, was tested as a substitute for the cationic polymer. This material did not cause a build-up on sticky solids on the wiper brush or the sides of the flotation tank at the water surface. However, the polymer did not form a foam which is necessary to float the particles to the surface. A liquid dish washing detergent, Joy, was found to provide sufficient foam to hold the flocculated solids at the surface of the water. For red water the anionic polymer-detergent gave the best water to date.

However, the black water-red water syndrome appeared again. The black water inhibited the formation of a foam, and therefore, the effectiveness of the anionic polymer was greatly diminished. At the present time samples of wetting agents have been ordered from Rohm and Haas which are compatible with the R&H 700 polymer. This materials will be tested in the near future. The anionic polymer is a water emulsion and can be diluted with water. The diluted polymer emulsion permitted the use of a faster pump speed which results in a better mixing of the polymer into the feed line to the flotation unit.

The major goal of the field personnel at the Nelson Lease is to keep the water injection system operational at all times. Thus, the flotation unit operation is controlled by the high-low switches on the clear water tank which feeds the triplex pump with the water sent to the individual injection wells. This causes the flotation unit to stop and start. The flotation unit has operated for as short as 12 to as long as 24 hours per day with numerous starts and stops during the day. This has resulted in a flow of water through the flotation unit beyond the 1000 bpd design capacity. Stopping and starting, and excess flow rate, contribute to the variation in the quality of the clean water.

Evaluation of Water Quality. Water quality in the Nelson Lease water plant was monitored by two methods. A filtration test was designed based on the ASTM D-4189-82 "Silt Density Index of Water". The test consists of passing one-liter of water through a 5-micron, 47 mm diameter nylon filter under a 10-psi air pressure supply attached to the water reservoir. A plot of the square root of seconds versus milliliters of water results in a straight line. The slope of the line was taken as a "Water Quality Index". **Figure 17** illustrates filter rate test made before and after the installation of the flotation unit. The water quality index improved from 26 to 2.6.

The filter from each filtration rate test was also dried and weighted. Each filter rate test requires one or more hours to perform in the field depending on the suspended solids in the water. Then the filter must be transported to the lab and dried for 24 hours before weighing. The weight of the suspended solids collected on the filter varied from 30 to 70 mg/L for the feed water and from 5 to 15 mg/L for the clean water from the flotation unit after November 1995. The variation in suspended solids in the clean water is due to the changing composition of the feed water and the operational time of the flotation unit. **Figure 18** illustrates the variation in solids content in the clean water. Note the change that occurred in November 1995 when the top of the flotation unit was cut off and the water circulation problem was identified. The new froth weir and wiper brush caused a substantial improvement in water quality.

A small amount of flotation polymer that carried over to the clean water was found to have a pronounced effect on the filtration rate and the life of filters in the plant. **Figure 19** illustrates what happens when excess cationic polymer chemical was used in the flotation unit. In the laboratory it was found that 500 mL of reverse osmosis water required 22 seconds to filter, whereas 500 mL of water with 10 ppm FLW-162 required 243 minutes to filter.

An alternate method to evaluate water quality in the field became apparent. Turbidity, which measures the reflected light at 90 degrees to the incident beam, was considered, but no equipment was available. As an alternate to turbidity, a photometric method was listed in the Hach Water Procedures Manual. Absorptiometry depends on the decrease in the light intensity caused by particles scattering the incident light beam. An old Hach DREL/5 colorimeter was used to measure the suspended solids at 810 nm. The results showed promise, but the correlation between weight of solids collected on the nylon filters and meter readings showed considerable scatter. A new Hach colorimeter, DR/700, was purchased in March 1996. The problem with the absorptiometric measurement of suspended solids with the DREL/5 meter was found to be due to the instability of the old meter. **Figure 20** illustrates the relationship between meter reading for the DR/700 unit and known silica solids content in water samples. **Figure 21** illustrates the relationship between solids content of the water from the flotation unit with the Hach DR/700 meter value. The data represents values measured at various points in the water plant and for various dates. These points (solids squares in **Figure 21**) were fitted to a straight line through the origin by least square method. A correlation coefficient of 0.9711 was obtained for the data. A sample of the feed water on March 7, 1996 containing 19 mg/L of suspended solids was diluted to provide samples of lesser suspended solids. The measured suspended solids (open squares in **Figure 20**) by DR/700 meter for the sample, the diluted samples prepared from the feed water, and the filtrate of the sample all fell on the correlation line. Thus, the DR/700 meter was found to be an inexpensive instrument for monitoring water quality in the field. This instrument is now used daily in the field by field personnel to evaluate water quality. A sample of water can be obtained and measured in approximately one minute.

Effectiveness of Air Flotation Unit. The water quality for the past twelve months has been better than pre-flotation unit injection water. Injection well filters have been changed from 75 to 10-micron filters. Filter changes have been no more frequently than prior to flotation unit installation. Well RW-6 uses a 5-micron filter and the new injection well RW-20 uses a 2-micron filter. Neither of these filters requires a more frequent change than the other wells equipped with the 10-micron filters.

Prior to installation of the air flotation unit, various scale inhibitors and solids suspending agents were used to treat the injection water. Scale deposits were prevalent at various points in the water system, but the scale was soft. A hard barium sulfate scale occurred at various points in the system after the flotation unit was started. In October 1995, a scale inhibitor was added to the water leaving the flotation unit. This stopped the hard barium sulfate scale that was found on the filter screens at the plant and the flow meters in the field. Since December 1995 no flow meters have been repaired due to barium sulfate scale. In addition to the use of the scale inhibitor chemical, a 300 barrel supply well water tank was installed as shown in **Figure 13**. The water from this tank flows into the 200-barrel produced water tank. A centrifugal pump was installed to circulate the produced water to the supply water tank continuously, thus providing a raw water feed to the air flotation unit that was less variable. This provided mixing of the two waters, added residence time for barium sulfate scale to form before reaching the flotation unit, and decreased the range of supply to produce water mixture. The improved mixing of the two waters increased the effectiveness of the flotation unit.

The evaluation of the effectiveness of the flotation unit requires measurement of the principal operating variables controlling the flotation process. A detailed evaluation plan is in preparation. The plan involves measurement of flow rates to and from the air flotation unit as well as water quality. During the last month, a Halliburton flow meter was installed on July 2, 1996 in the main water line to the injection wells in the field. Initial results indicate that 900 barrels per day are being injected in comparison to the 750 barrels as determined by the summation of the individual well meters. This meter has provided valuable information as to the operation of the flotation unit. An Ecosol flow meter was installed on July 18, 1996 in the feed line to the flotation unit. In the past the flow rate of the feed water has been estimated at 40+ gallons per minute from the summation of the individual injection well meters. A flow rate of 40 gallons per minute for the feed water corresponds to operating the flotation unit at 140% of design capacity. The flow rate of the feed water should be between 25 and 32 gallons per minute. At this flow rate, 750 to 1000 barrels per day of clean water can be produced with the flotation unit running 22 to 24 hours per day. Now that the flow meter is installed, the flow rate can be set to specific values and the effectiveness of the flotation can be evaluated. The effectiveness of the flotation unit will be quantitatively evaluated during fiscal year 1997.

Permeability Modification Treatments

In Budget Period 1, three permeability modification treatments were conducted and are presented in the last annual report. No permeability modification treatments were conducted in this year.

As part of this task, waterflood dynamic maps were developed to determine responses from changes in water injection. These maps were analyzed to determine the location of channels between injection and production wells. **Figure 22** presents a map indicating the location of each channel identified. It is planned to conduct permeability modification treatments throughout the field to plug the channels. Priority will be wells which effect injectivity into the B3 sandstone reservoir.

Pattern Changes and Wellbore Cleanups

Pattern Changes. Since the geological and engineering analysis 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. As of April 1996, both wells were taking the desired water injection rate at wellhead pressures (200-400 psi) less than the 700 psi line pressure. This response is considered favorable, possibly indicating fill-up has not occurred in the B3 zone.

H-14 Results to Date. One peripheral producing well H-15 (near H-14) showed increased oil production early on, however since then has produced substantially more water indicating that a fracture exists. As a result, a permeability modification treatment has been scheduled. A delta temperature survey indicates that the water is entering the B3 zone.

H-5 Results to Date. No response occurred in the peripheral wells early on. A delta temperature survey was conducted which indicated that the water was entering the formation above the B3. As a result, a permeability modification treatment has been scheduled.

Wellbore Cleanups. Injectivity improvement has been 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 coil tubing unit, and simply lubricating in the treatments. The principal functions of the acid additives are to remove wellbore emulsions, sludges 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) half a gallon of clay stabilizer (ESA-50), and 4) two gallons of micellar acidizing additive (ESA-96). **Table 4** presents the wells treated throughout the year.

Injectivity Indexes have been monitored from project startup to determine the frequency of wellbore cleanups. It is planned to compare wellbore cleanup frequency and cost before and after the water plant modifications. **Appendix A** has injectivity plots of six typical injection wells providing an example.

Reservoir Development

An infill injection well was drilled to further develop the reservoir. **Figure 23** 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 5** presents the core analysis measurements and the B2 and B3 zones. Since the injected water is of much lower chloride concentration, any watered out zones will show lower concentrations of chloride in the brine from core analysis. **Figure 24** presents this phenomena with footages (647-660) showing low concentrations of chlorides. **Figure 25** presents water saturation in the core verifying the watered out zone in the upper B2.

Figure 26 presents porosity measurements which are somewhat uniform averaging approximately 18%. **Figure 27** presents the permeability to air measurements which 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 28** showing the effective permeability to water in millidarcys. The residual oil saturation after flooding is presented in **Figure 29**.

On March 13, 1996, the well was perforated from 678 to 688 ft. These perforations were selected for two reasons, 1) injection is needed in the B3 zone, and 2) this interval showed mobile oil and no previous water invasion from the chloride tests and oil saturations. A 3 1/8" diameter hollow steel carrier casing jet gun was utilized. Waterflood injection was initiated on April 11, 1996. **Figure 30** presents pressure and rate for the first two months of injection.

As part of the reservoir development, an additional in-fill well will be drilled to better contact the oil bearing porous media in the B3 zone.

If water quality continues to improve and polymer flooding proves feasible for reservoir development, a polymer flood will be implemented.

Field Operations

Field operations consists 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. During the year, Russell Petroleum has supplied monthly reports, which consist of monthly activities and barrel tests/meter readings on active wells.

Russell Petroleum has been responsible for all field activities, 1) plant development, 2) wellbore cleanups, 3) pattern changes, 4) drilling of in-fill injection well, and 5) permeability modification treatments.

Technology Transfer

The following are the technology transfer activities conducted in conjunction with the Savonburg Field project:

1. A paper titled, "Engineering Aspects of the Savonburg Class 1 Project", was presented at the TORP Oil Recovery Conference in Wichita,KS and was published in the conference proceedings.
2. A paper titled, "Air Bubbles Clean Produced Water for Reinjection" was presented at the TORP Oil Recovery Conference in Wichita,KS and was published in the conference proceedings.
3. Methodologies used on this project were presented as a case study at a workshops titled, "Exploitation of Marginal Oil Fields-The Savonburg Field", August 9, 1995 in Iola, Kansas and "Increasing Profitability in Marginal Oil Fields" , November 29-30, 1995 in Wichita, Kansas.
4. Information was prepared and presented on the Savonburg field as part of the Traveling Workshop Series for selected Class 1 near-term projects. Presentations were made in

Bartlesville, OK, Wichita, KS, Denver, CO, Billings, MT, Oklahoma City, OK, and Grayville, IL.

5. A paper titled, "Development of an Improved Waterflood Optimization Program from the Northeast Savonburg Waterflood" 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.

CONCLUSIONS

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 has been achieved. A flocculation chemical was selected to aid in the performance of the air flotation unit. Economics look favorable.

Wellbore treatments have been conducted on many injection wells. The procedure has been documented and shows immediate benefit, however injectivity indexes on injection wells are being analyzed continually to derive the long-term benefit of the treatments.

Two production wells were converted to injection to better flood the B3 sandstone. H-14 has shown a response in H-15, however water channeling occurred. H-5 was converted to an injector, however a temperature survey has indicated that the fluid is entering the formation above the B3. Permeability modification treatments will be conducted on both these wells soon.

The engineering and geological study that was previously conducted was verified with drilling of an injection well (RW-20). The core analysis shows high oil saturations in the B3 sandstone reservoir which was picked to be of high potential.

FIGURES

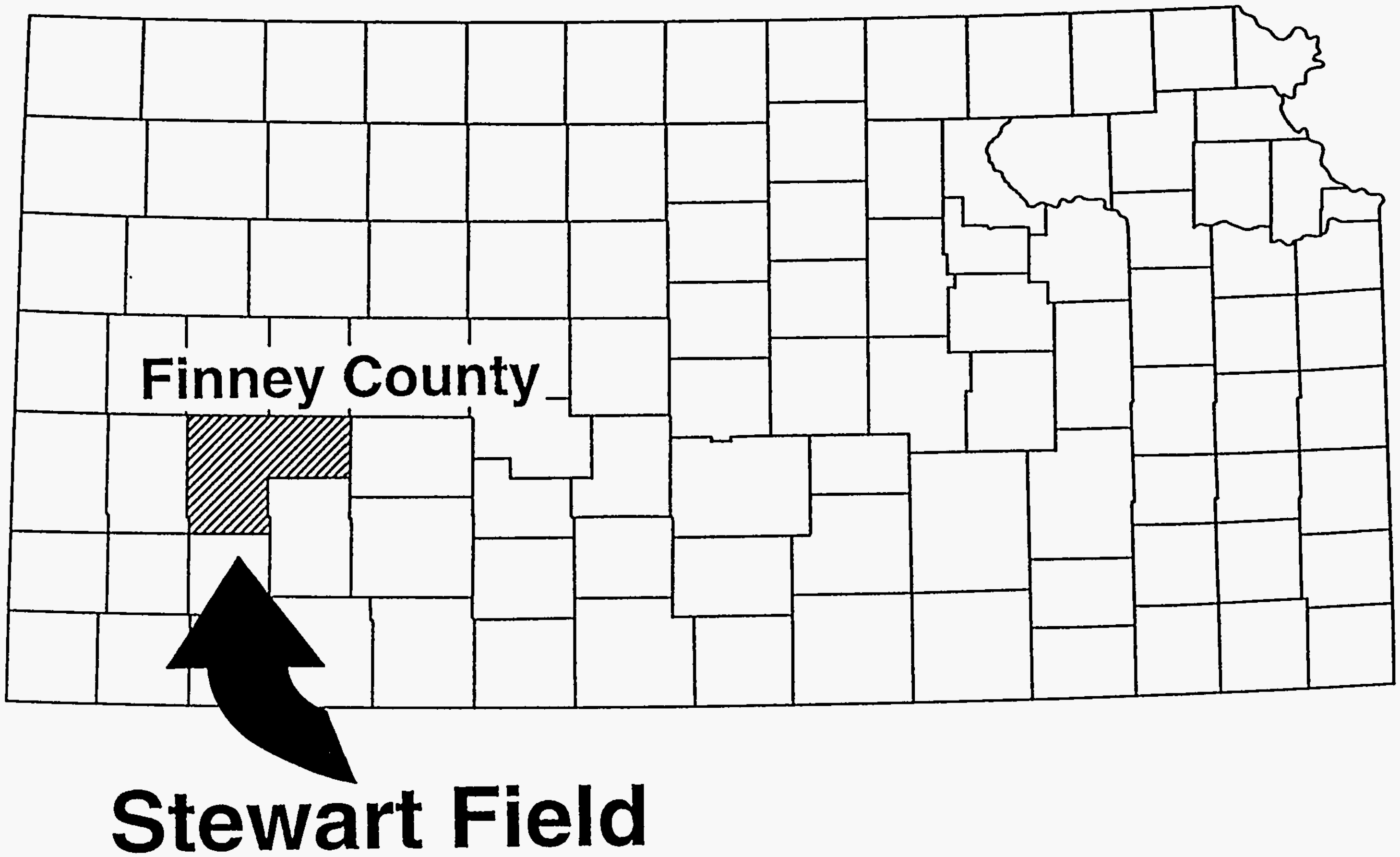

Figure 1. Stewart Field location plat, located in Southwest Kansas.

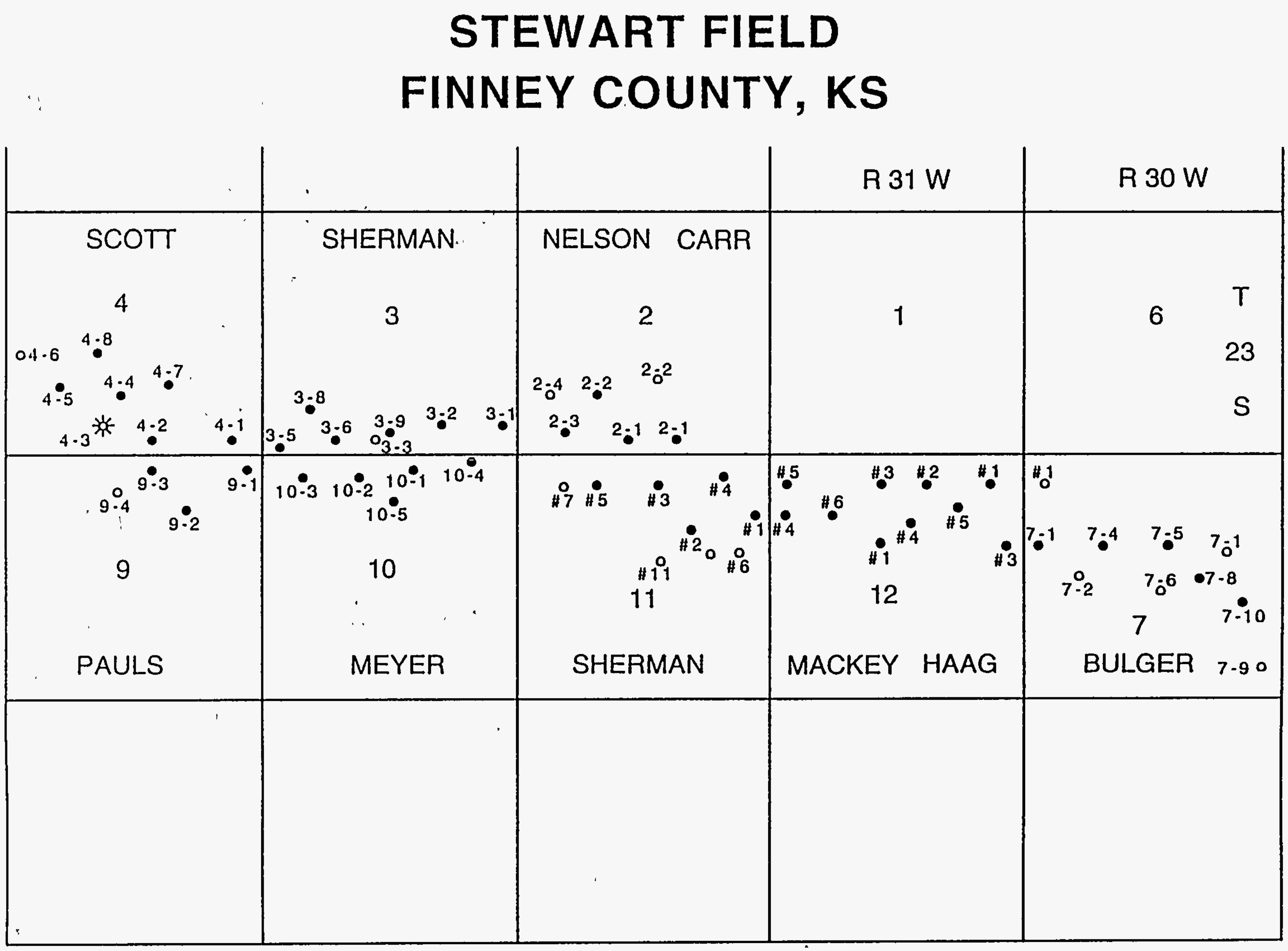

Figure 2. Stewart Field well location plat.

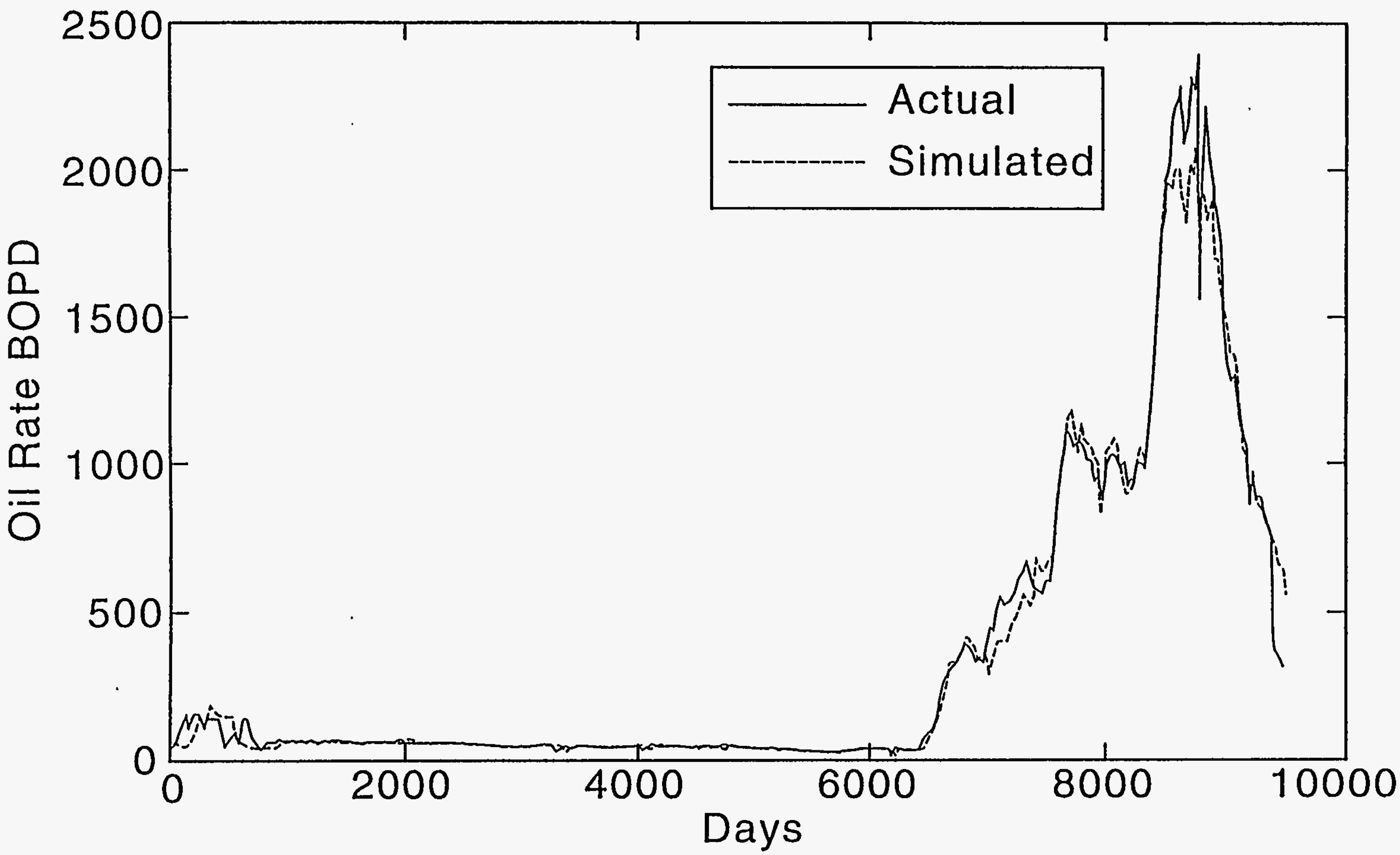

Figure 3. Stewart Field actual versus simulated primary production.

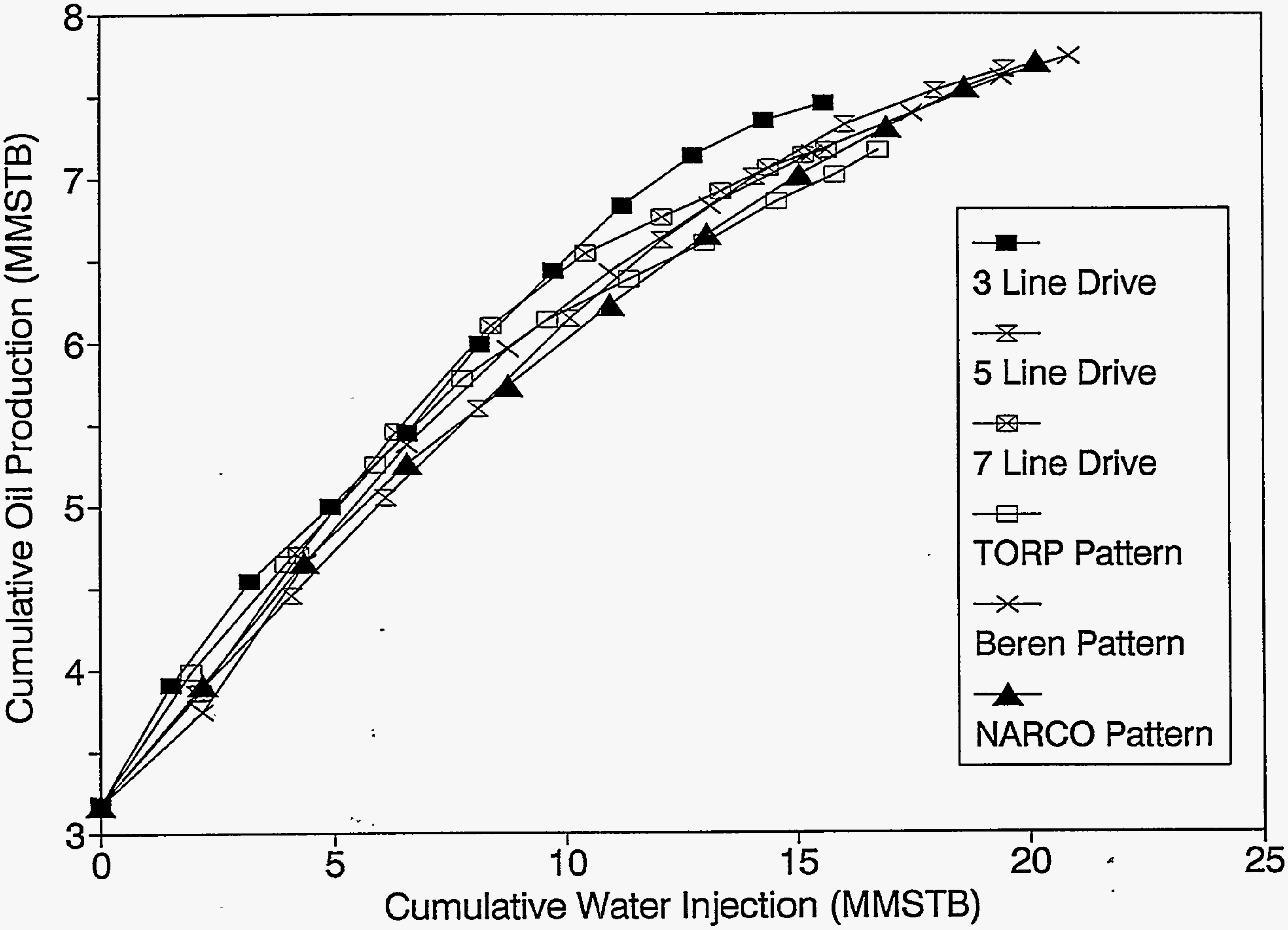

Figure 4. Stewart Field simulated waterflood patterns, cumulative oil prod. vs water injection.

STEWART FIELD
FINNEY COUNTY, KS

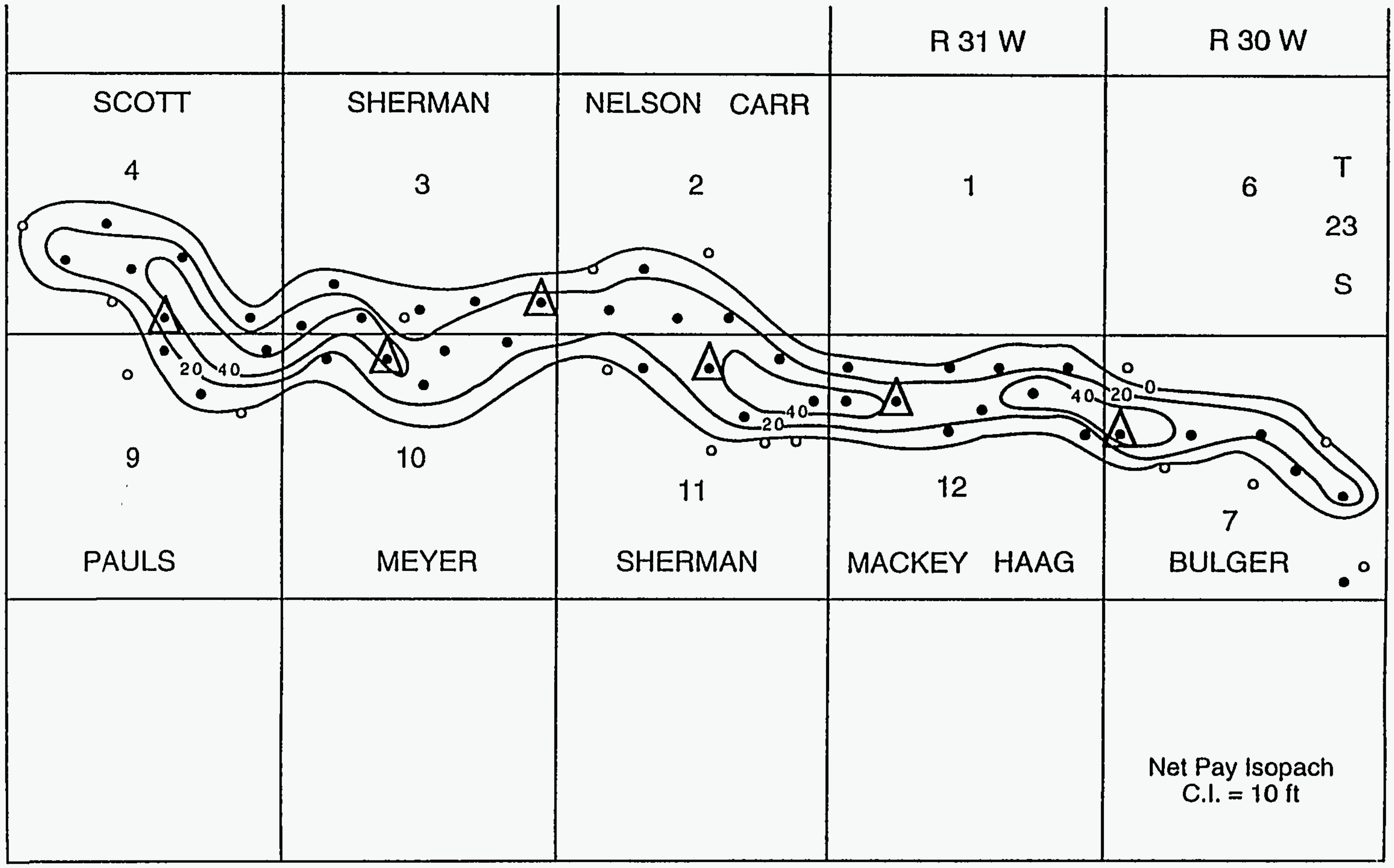

Figure 5. Stewart Field net pay map and waterflood pattern selected for implementation.

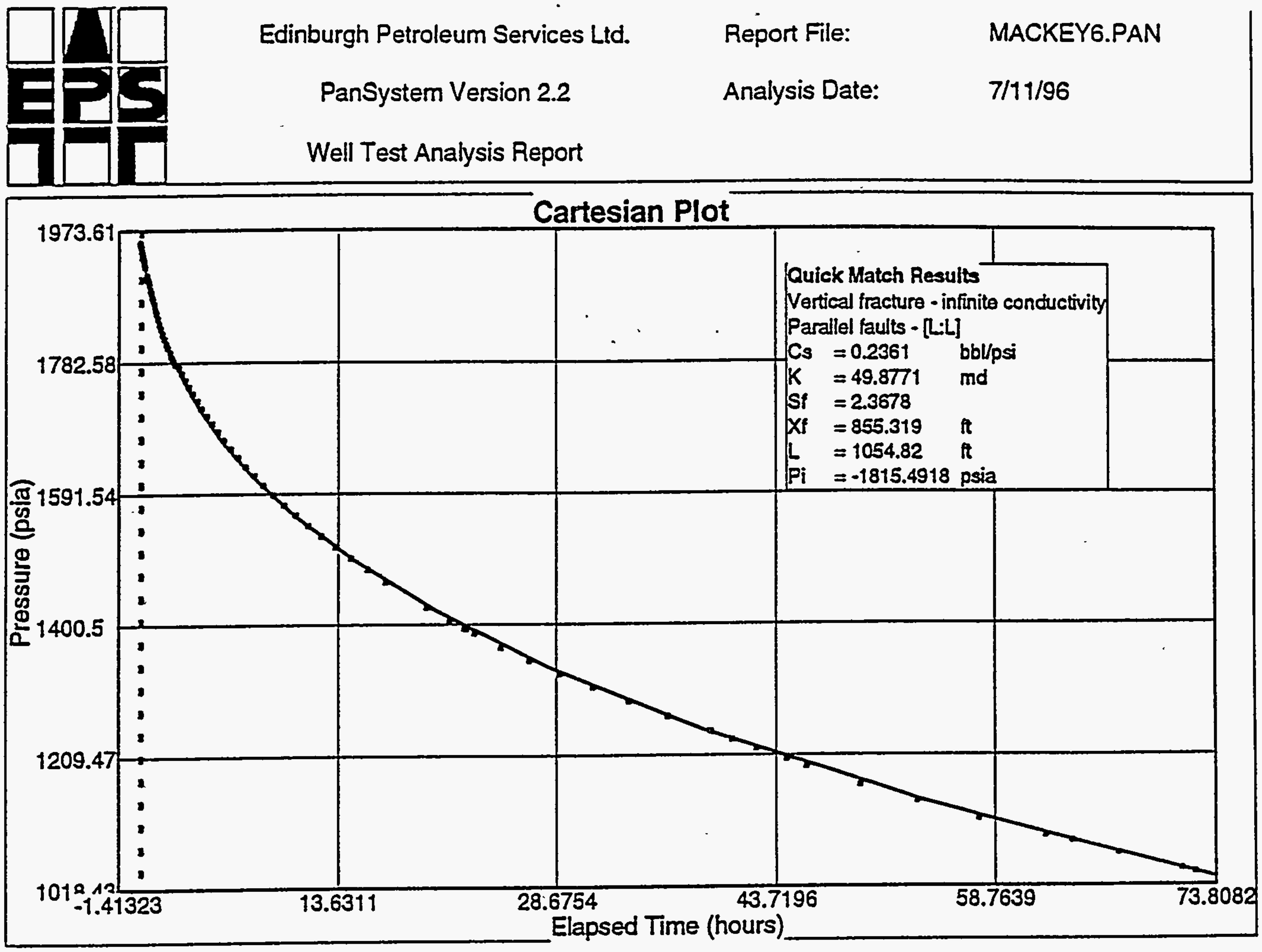

Figure 6. Bottomhole pressure versus shut-in time for Mackey #6 falloff test.

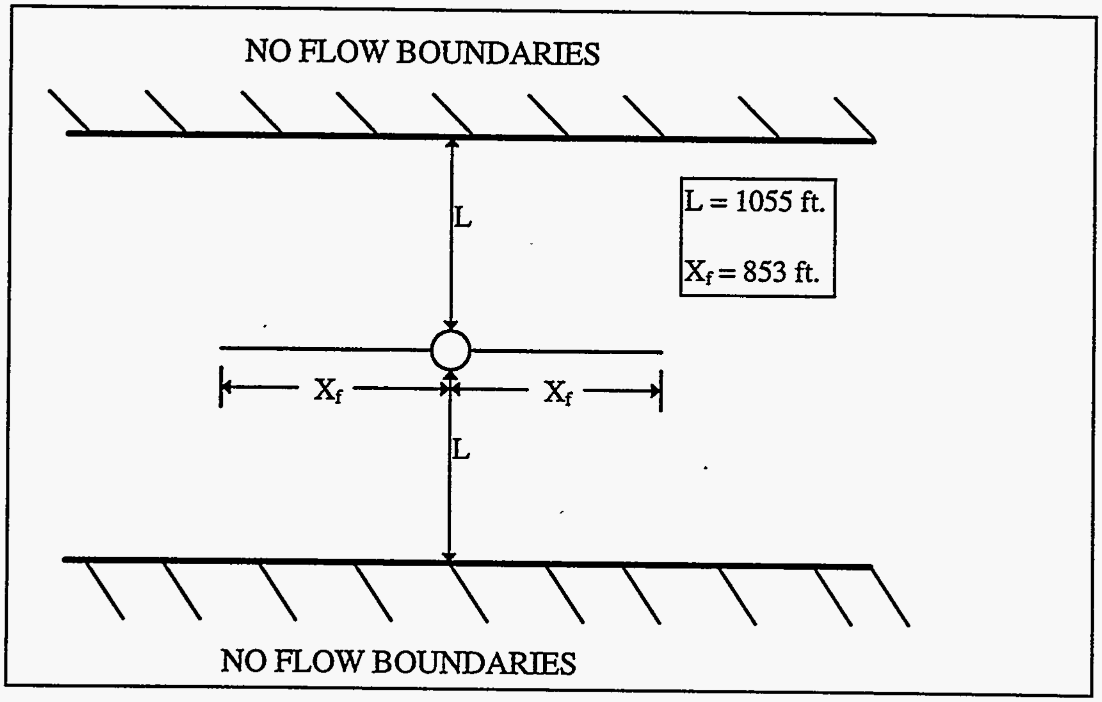

Figure 7. Schematic of reservoir parameters computed from match of Mackey #6 falloff data.

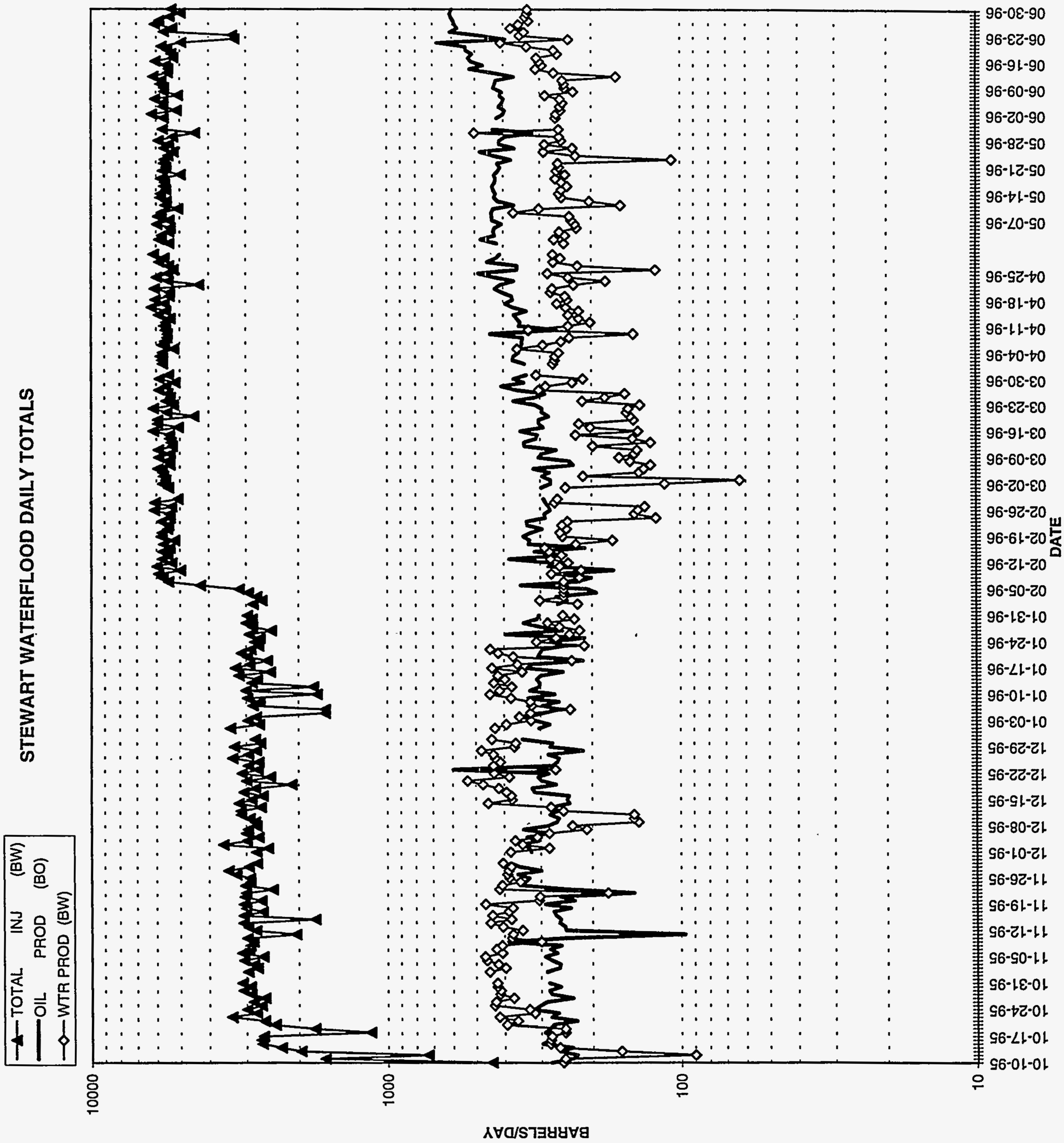

Figure 8. Stewart Field injection and production data since initiation of waterflood.

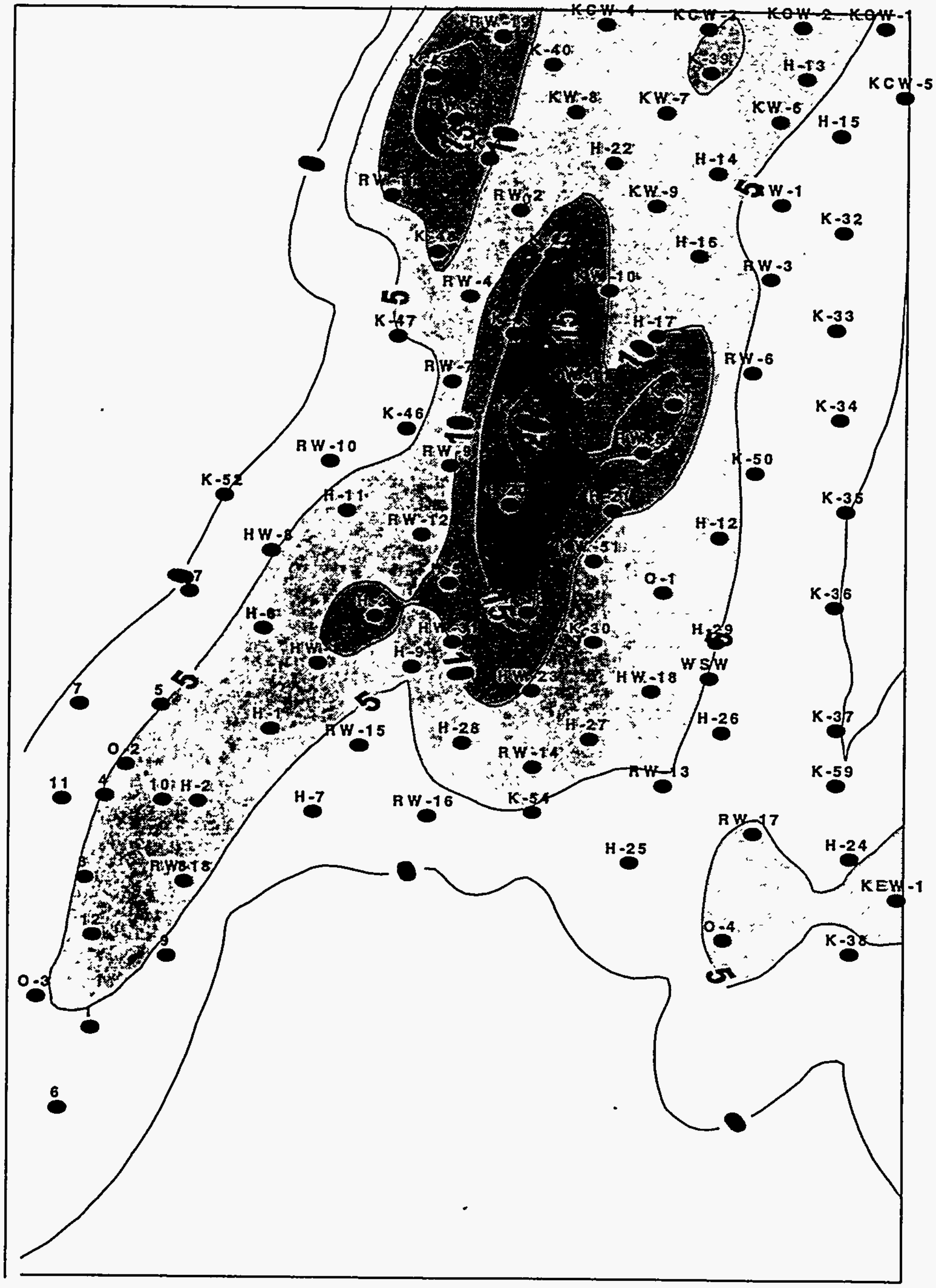

Figure 9. Savonburg Field isopach map of B2 sand.

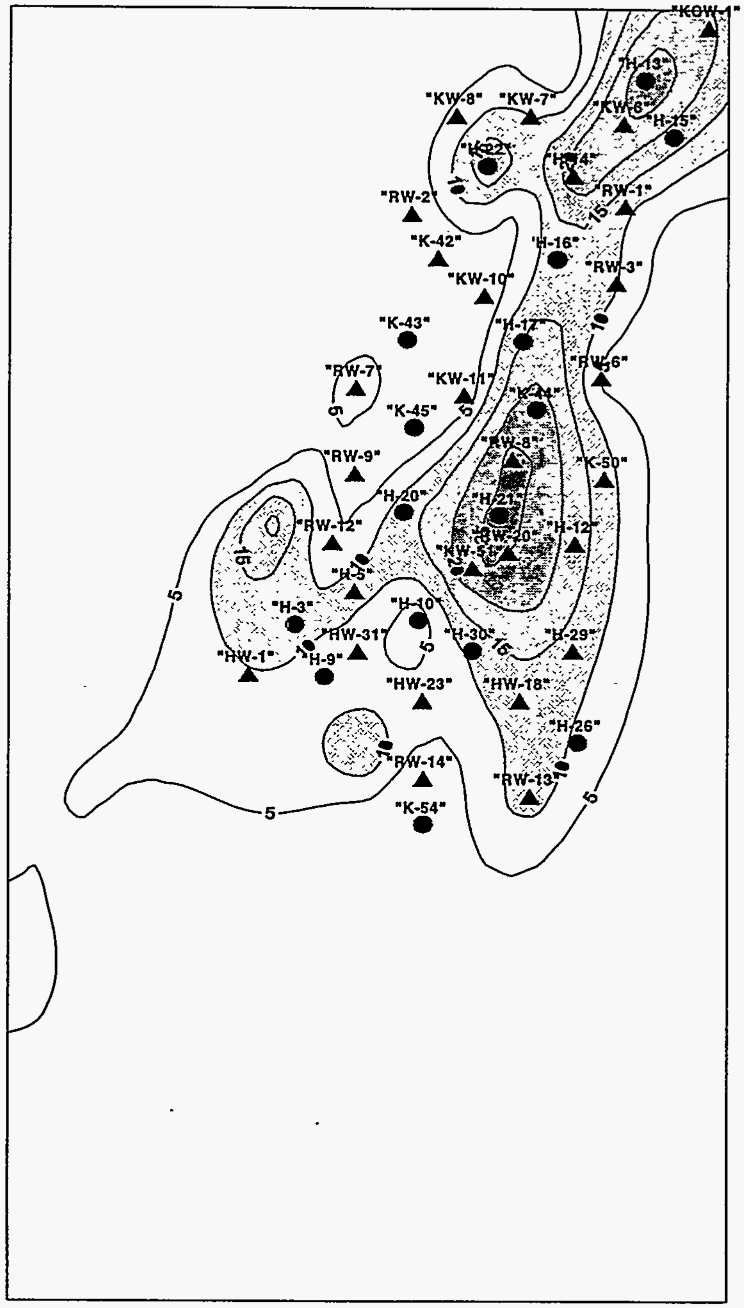

Figure 10. Savonburg Field isopach map of B3 sand.

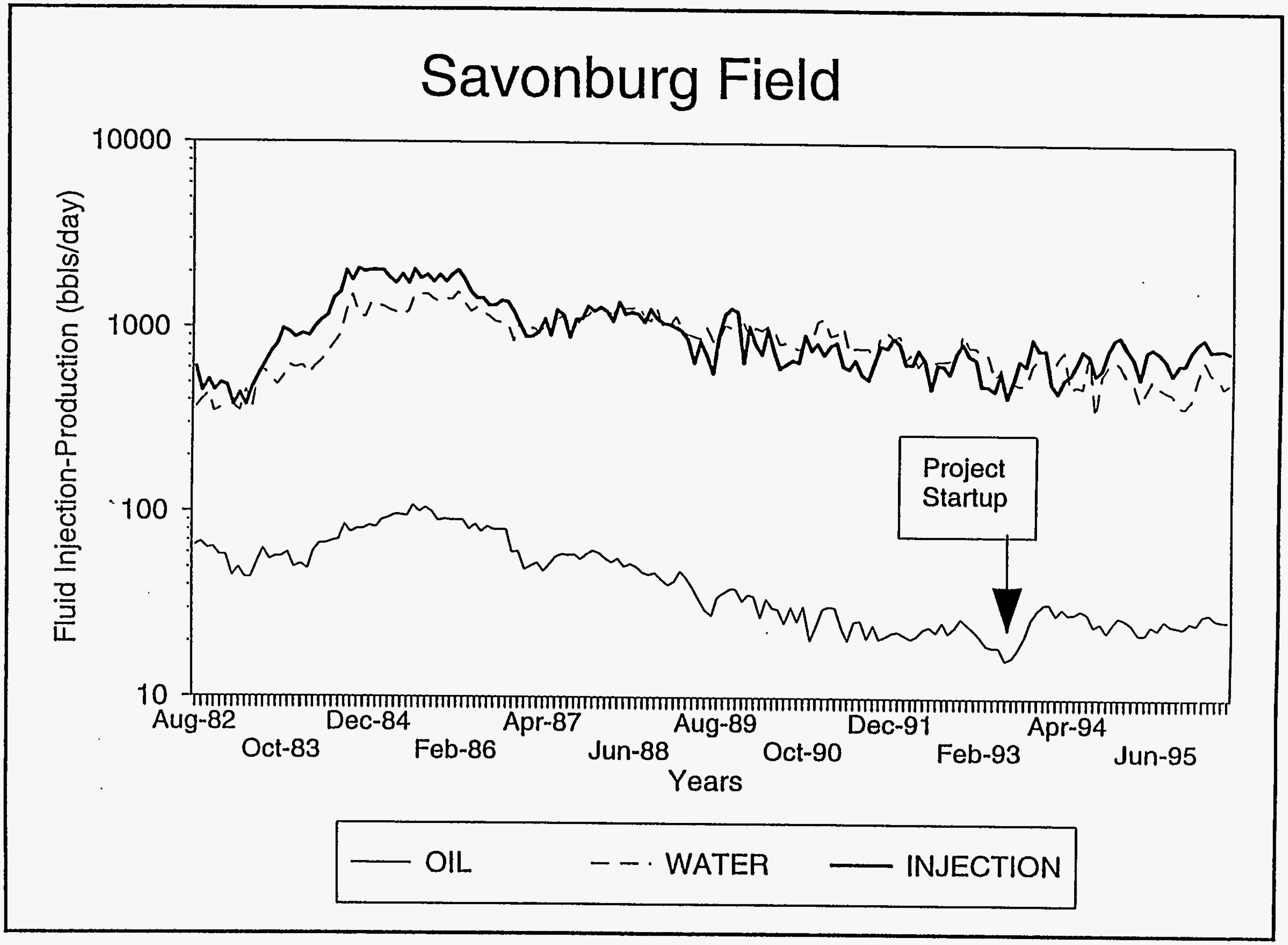

Figure 11. Savonburg Field injection and production data.

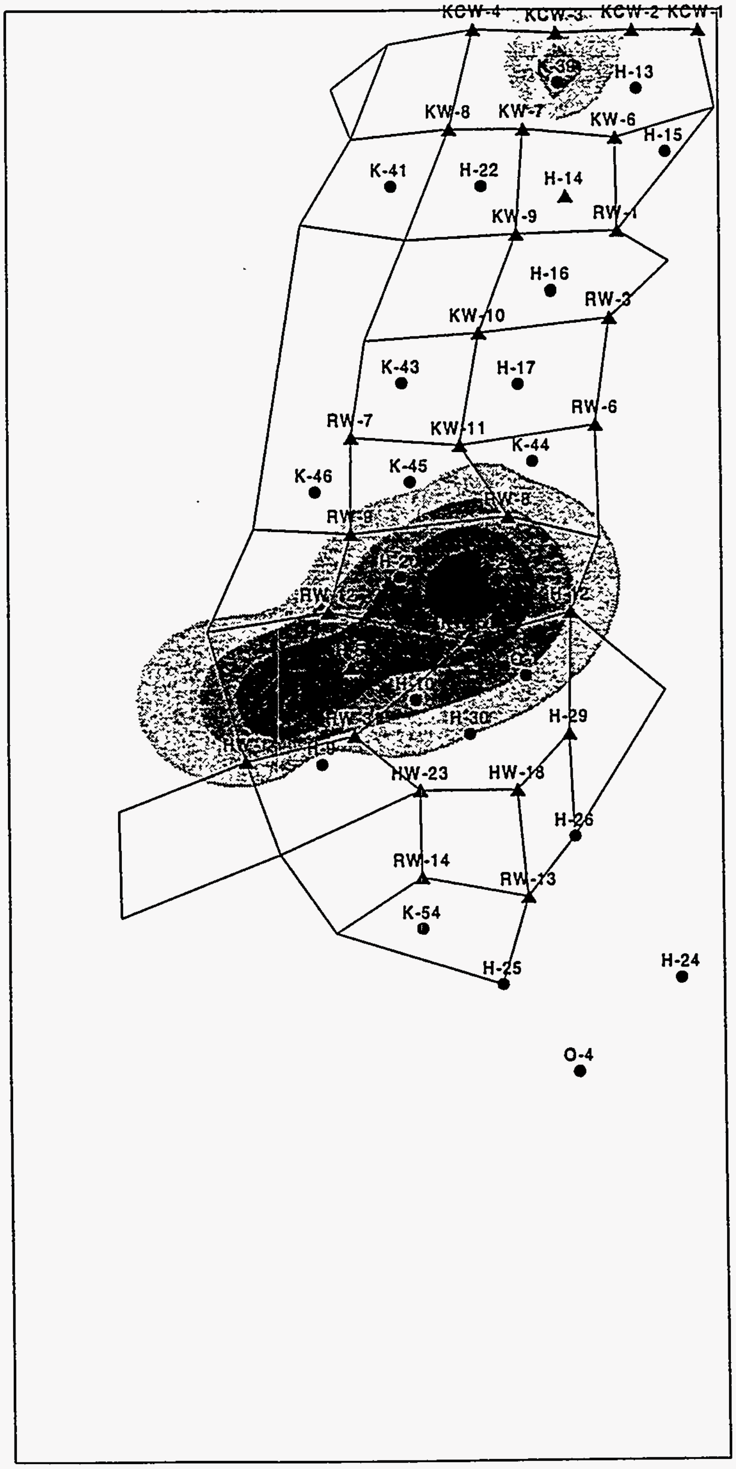

Figure 11a. Savonburg Field areas of high potential.

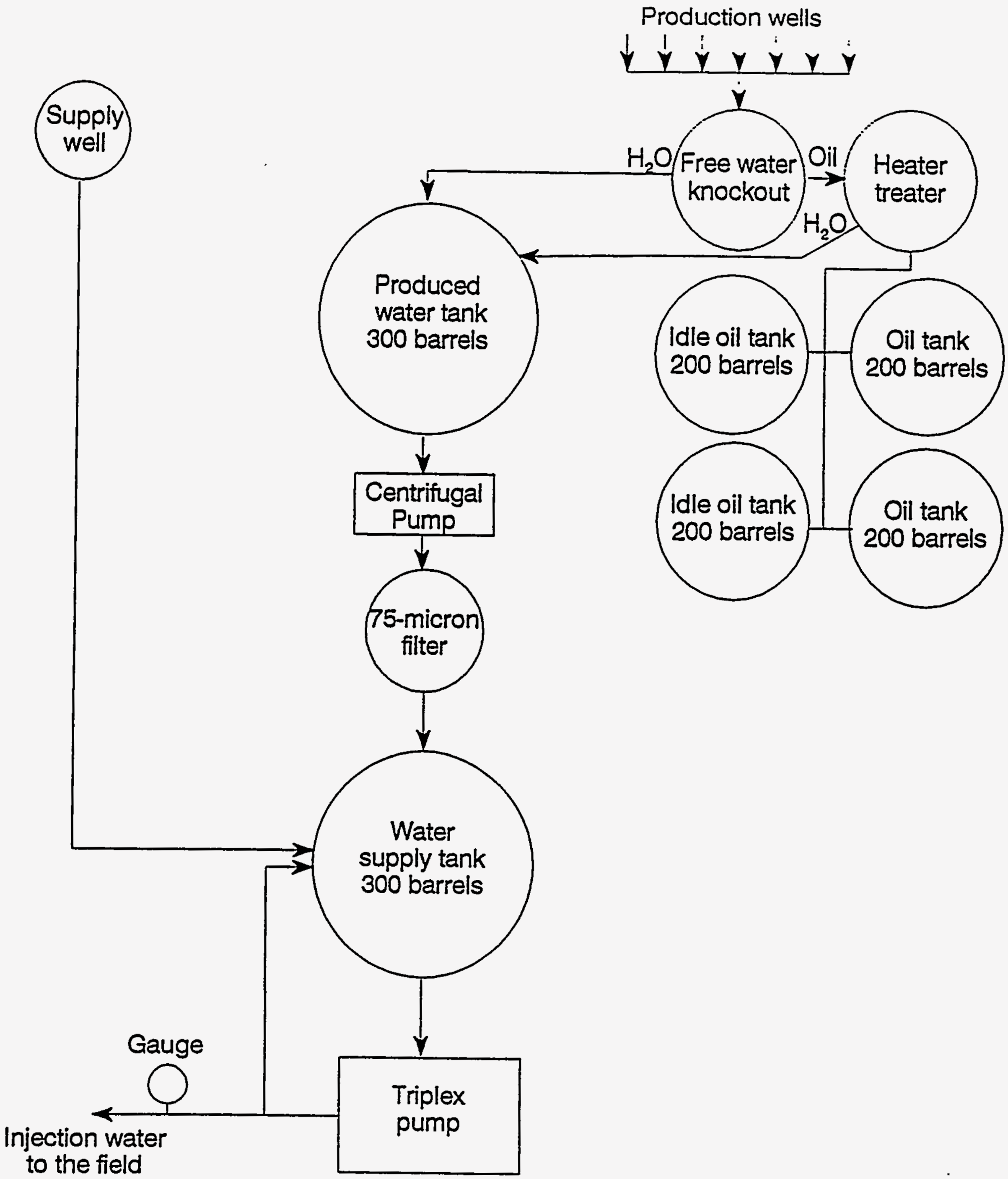

Figure 12. Savonburg Field original water plant design.

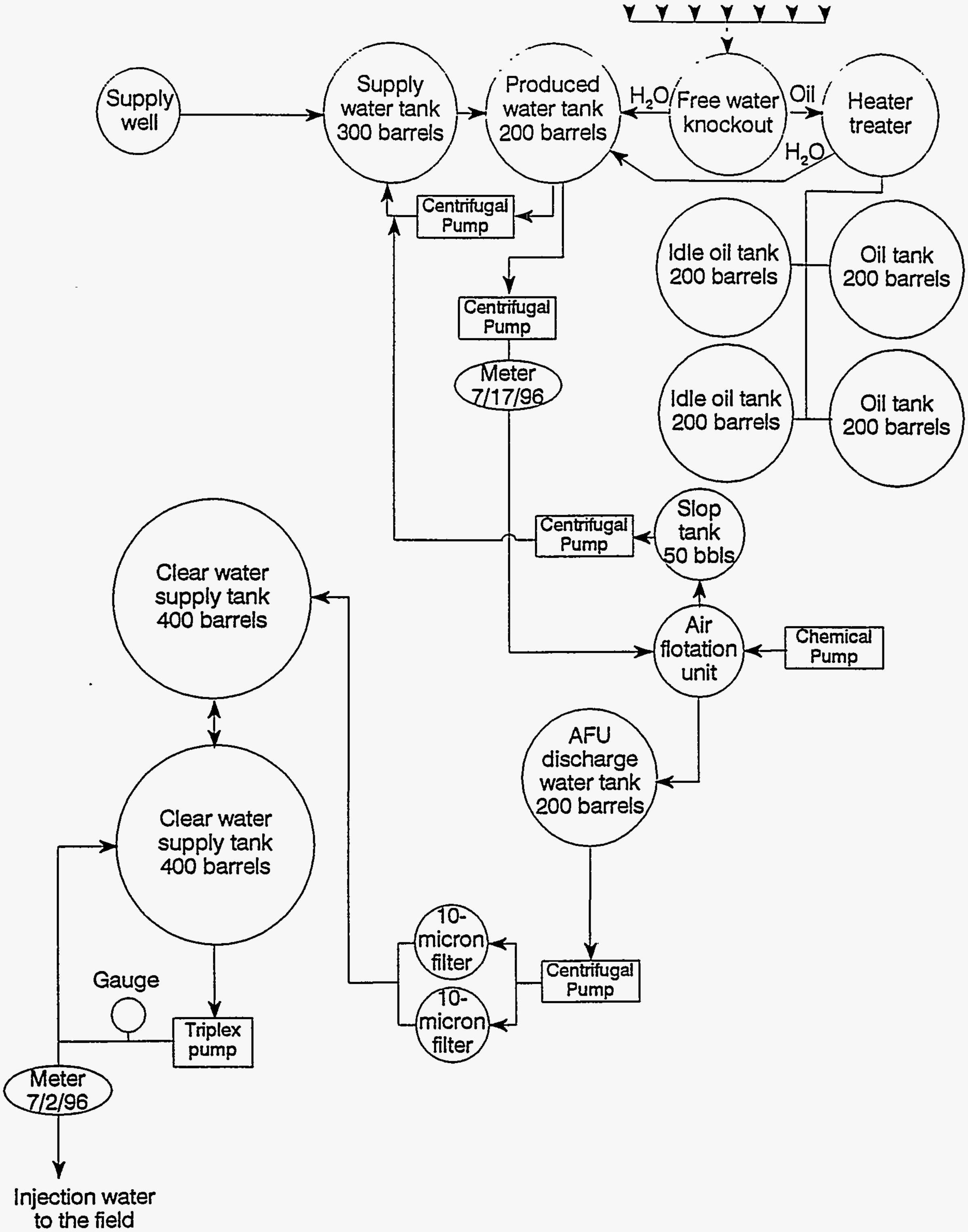

Figure 13. Savonburg Field current water plant design.

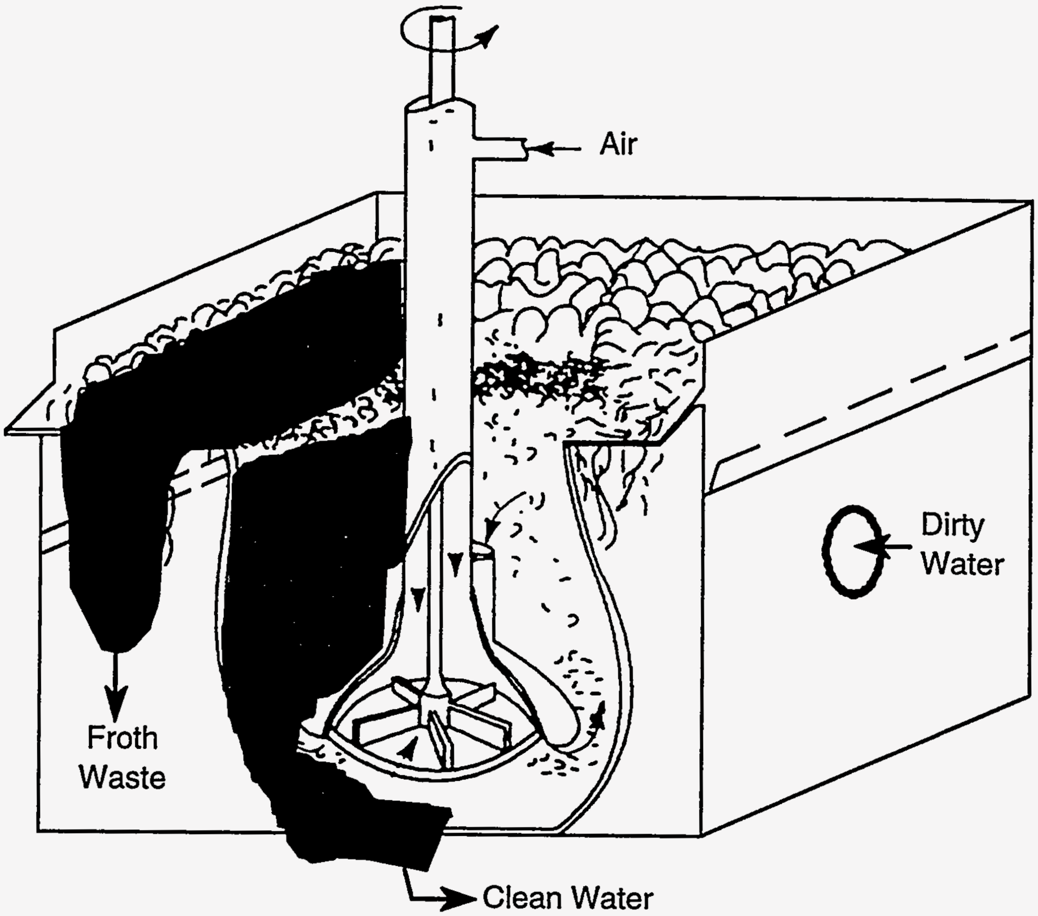

Figure 14. Schematic of the air flotation unit.

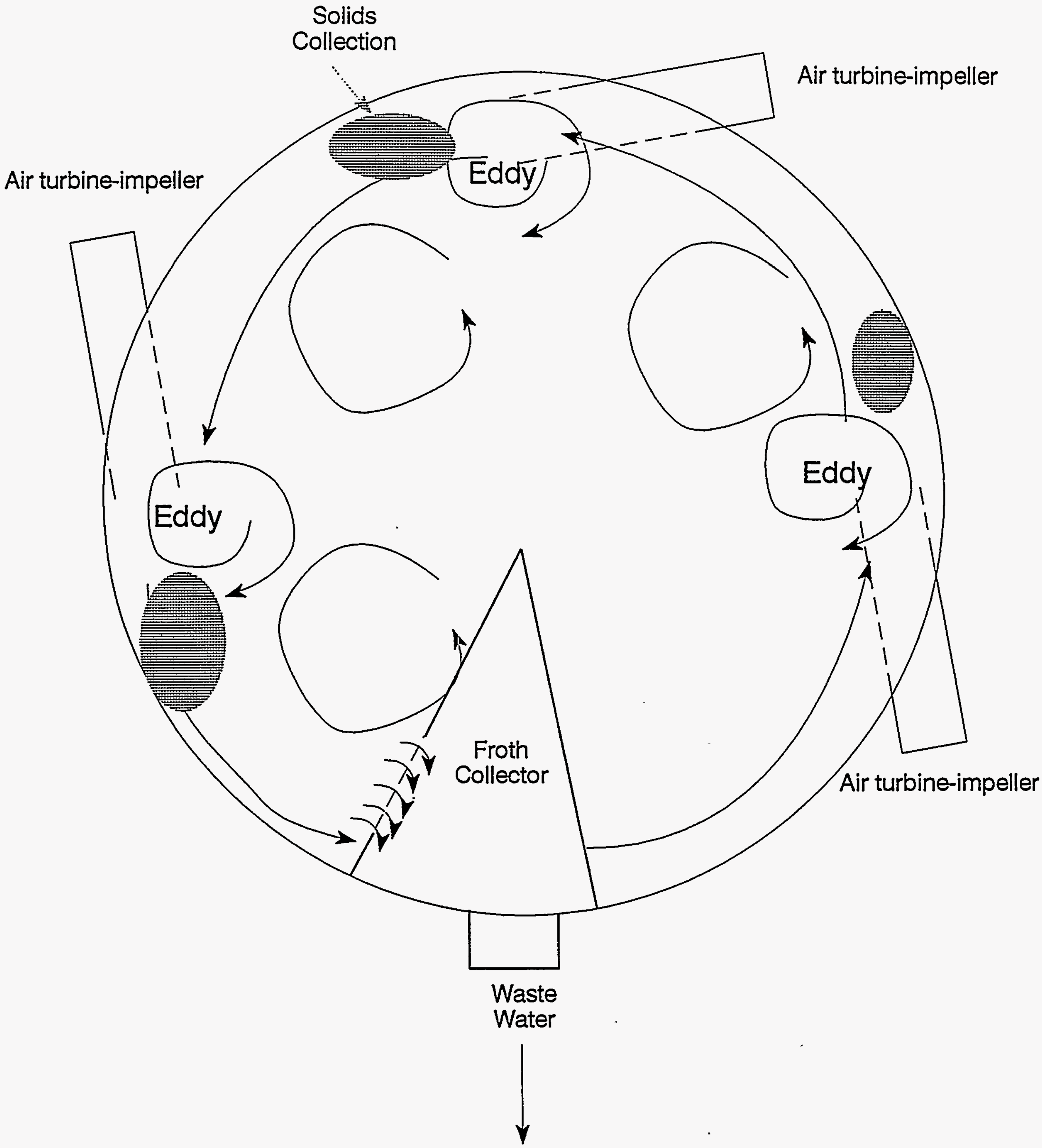

Figure 15. Schematic of water circulation in the air flotation unit.

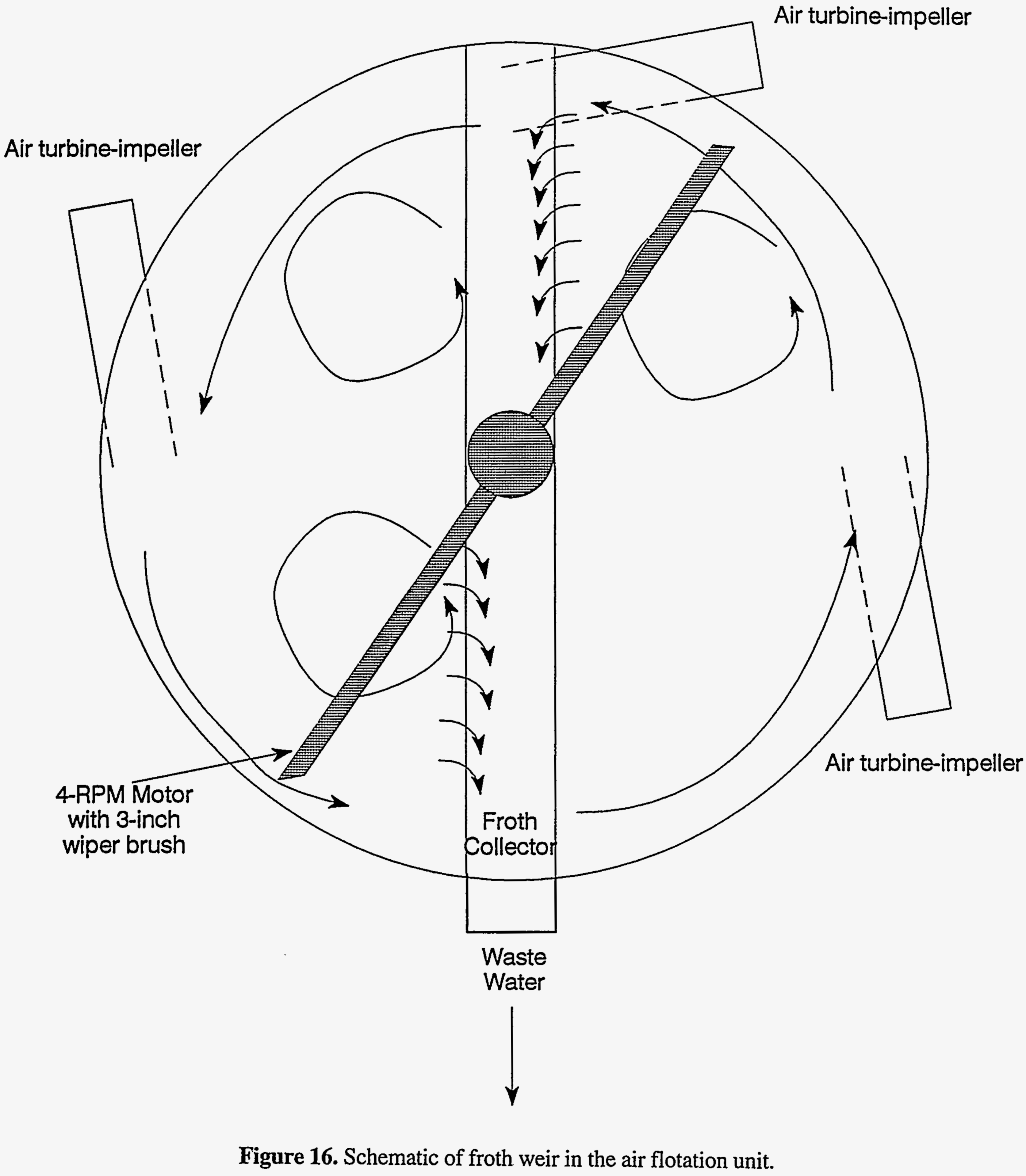

Figure 16. Schematic of froth weir in the air flotation unit.

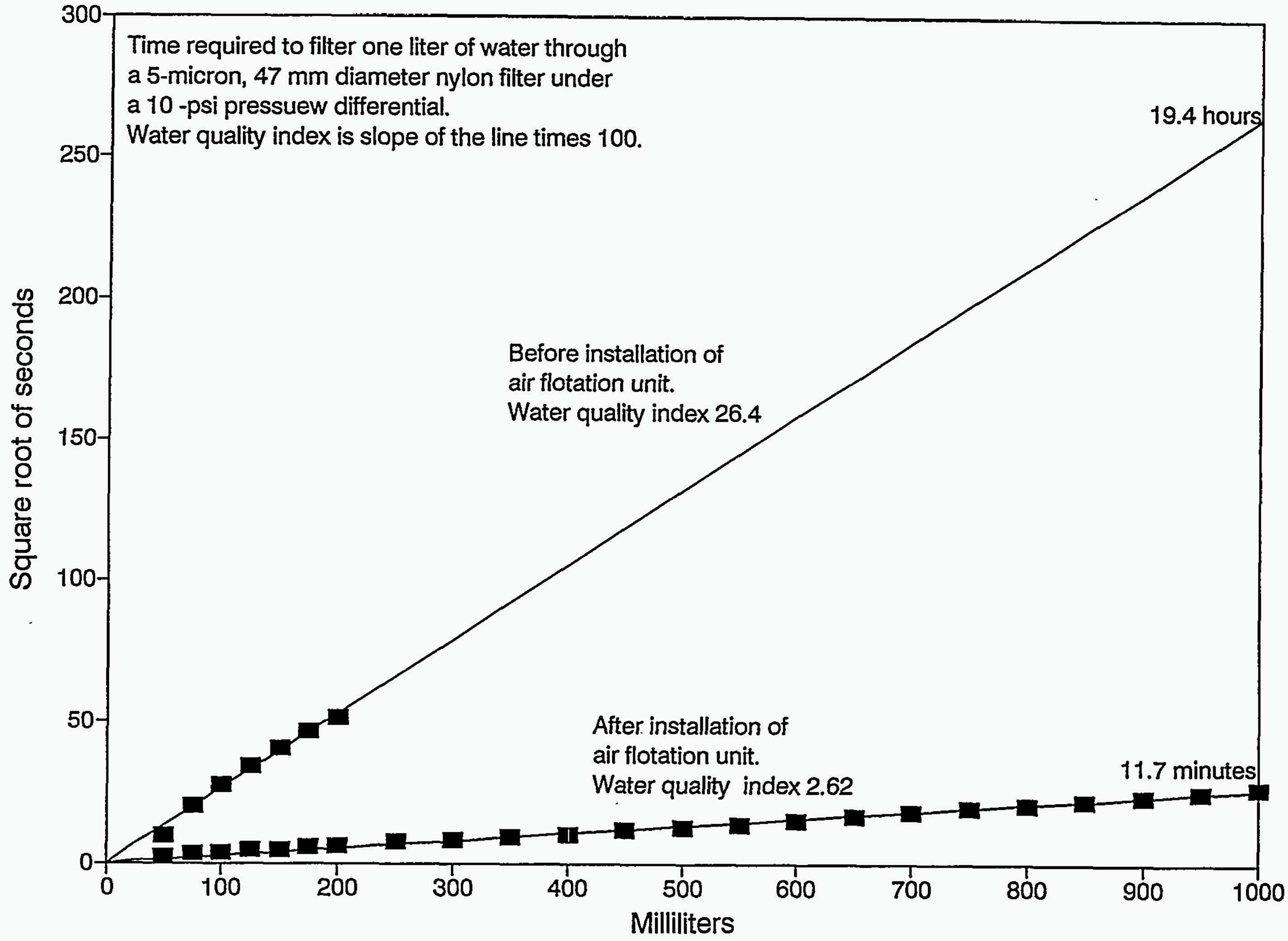

Figure 17. Savonburg Field plot of water quality index.

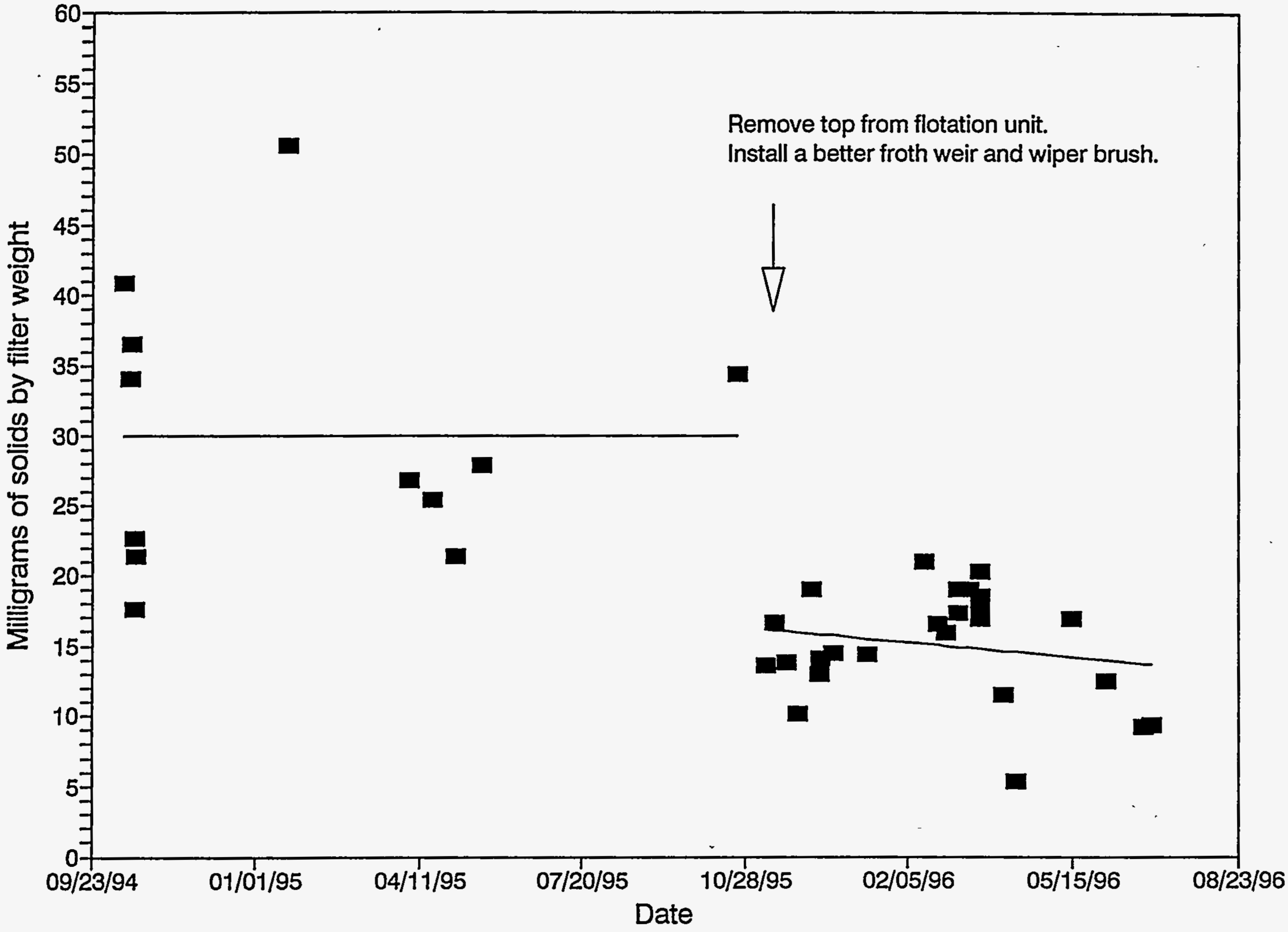

Figure 18. Savonburg Field plot of variation in solids content in the clean water.

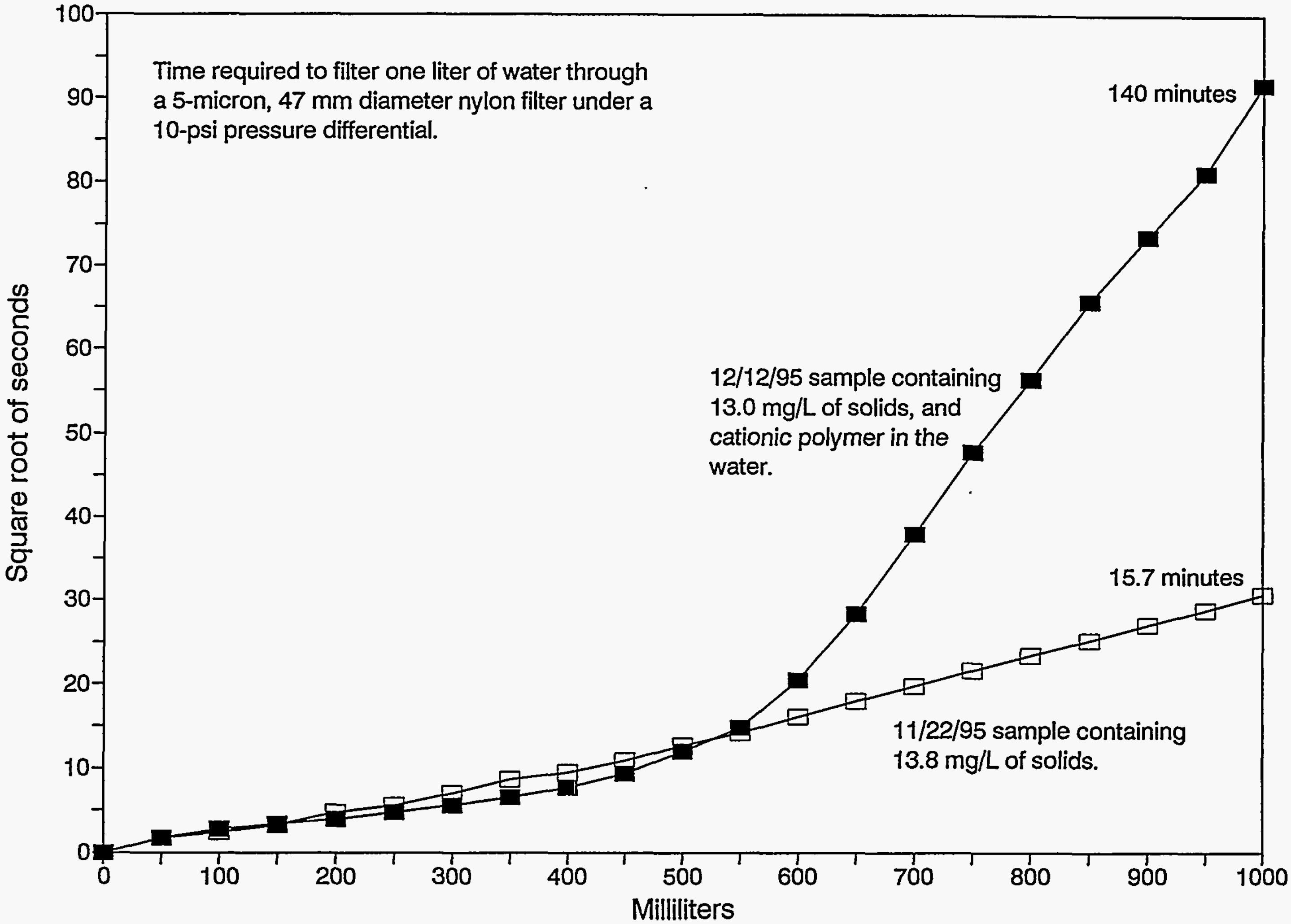

Figure 19. Savonburg Field results of cationic polymer used in the air flotation unit.

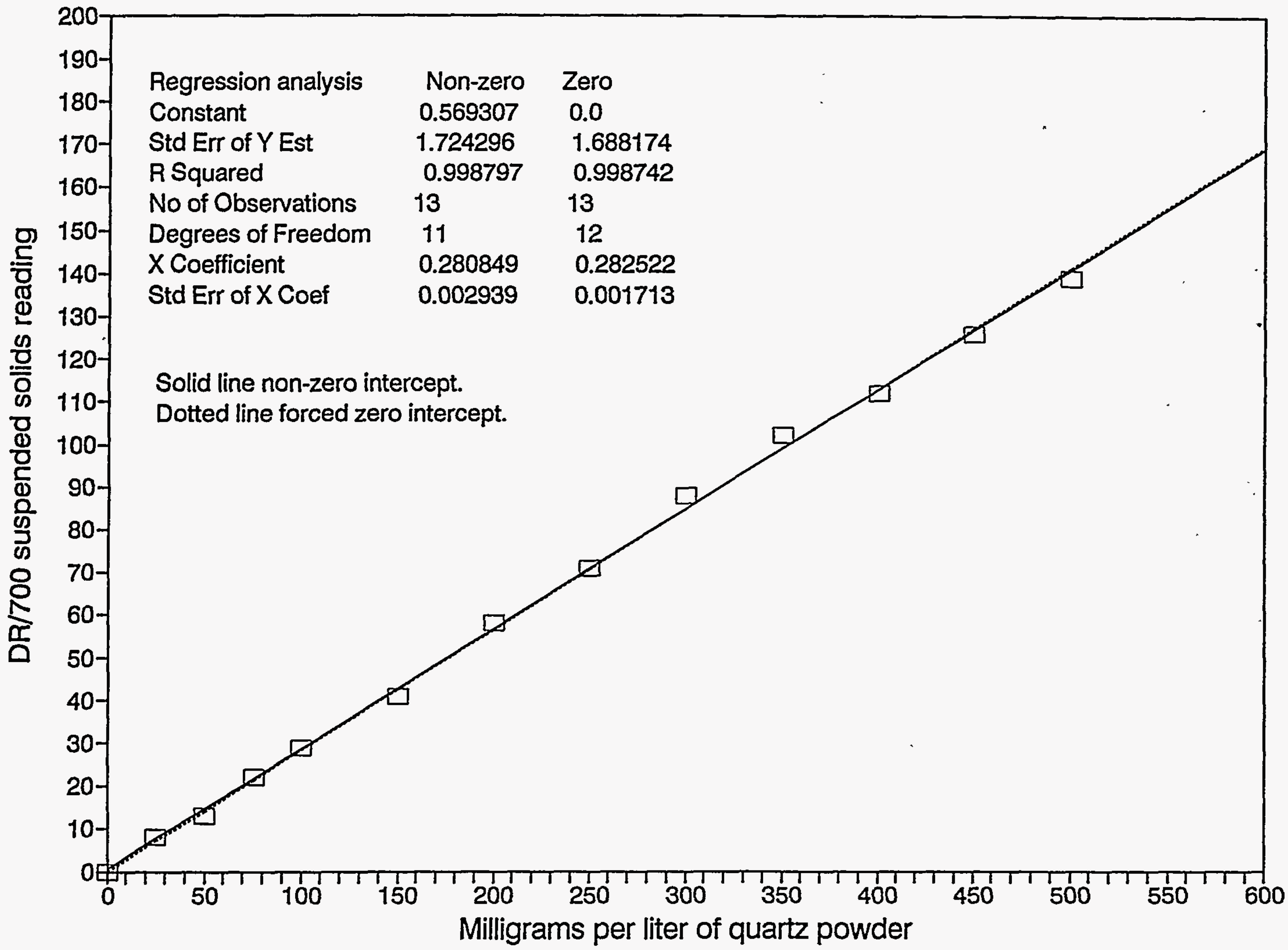

Figure 20. Relationship between DR/700 reading and silica solids content in water samples.

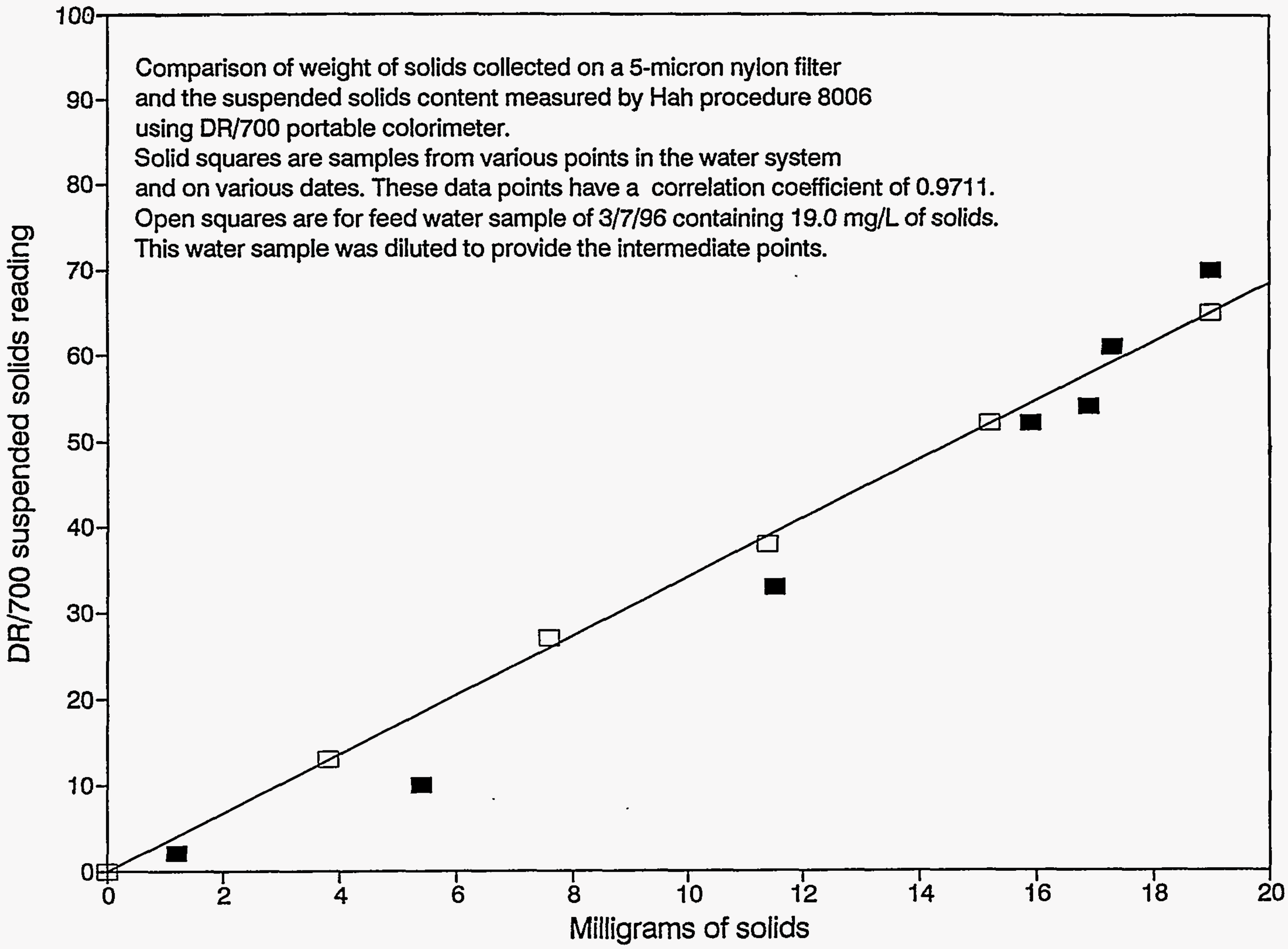

Figure 21. Relationship between solids content in the water from the air flotation unit.

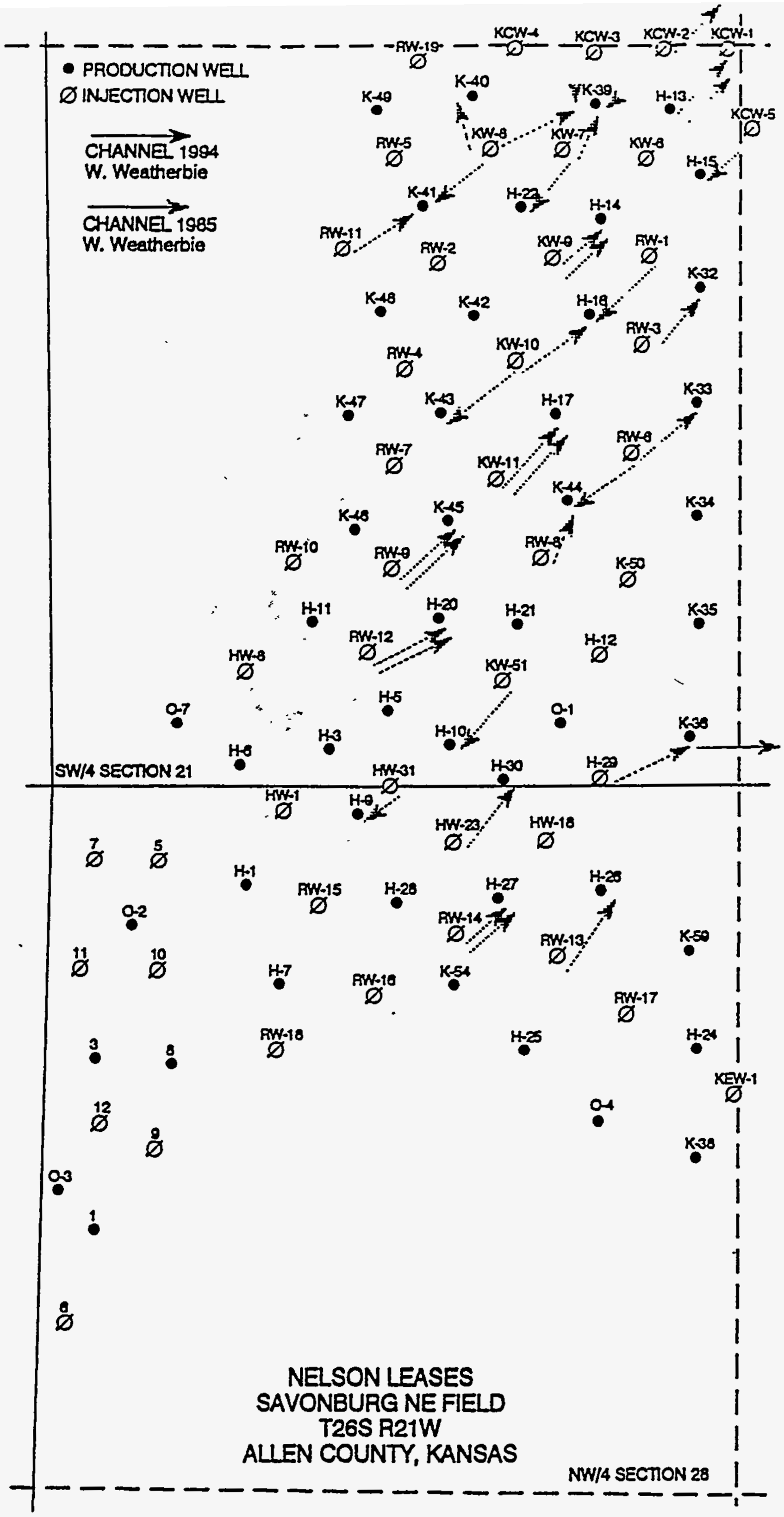

Figure 22. Savonburg Field map of channel locations.

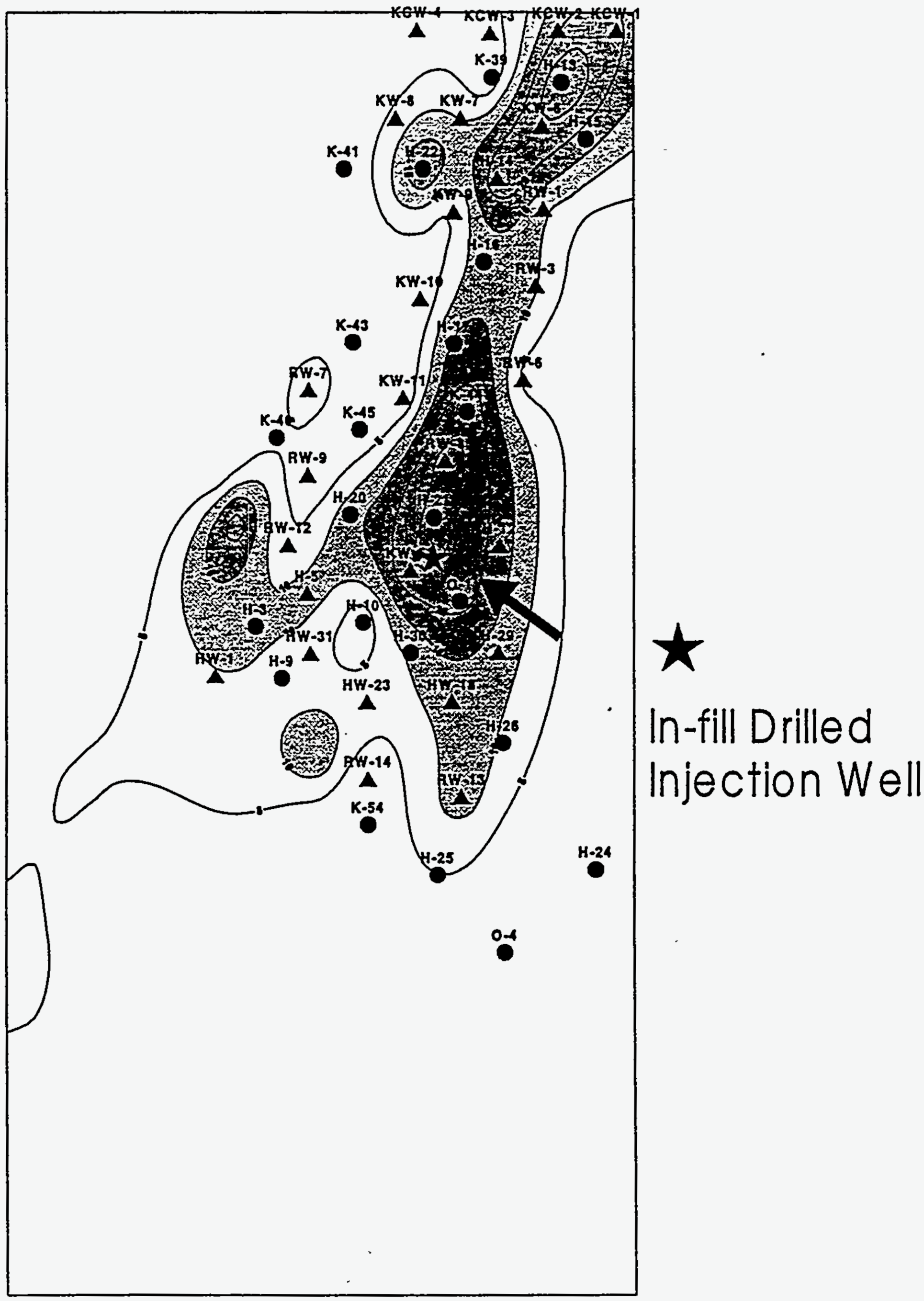

Figure 23. Savonburg Field location of infill well.

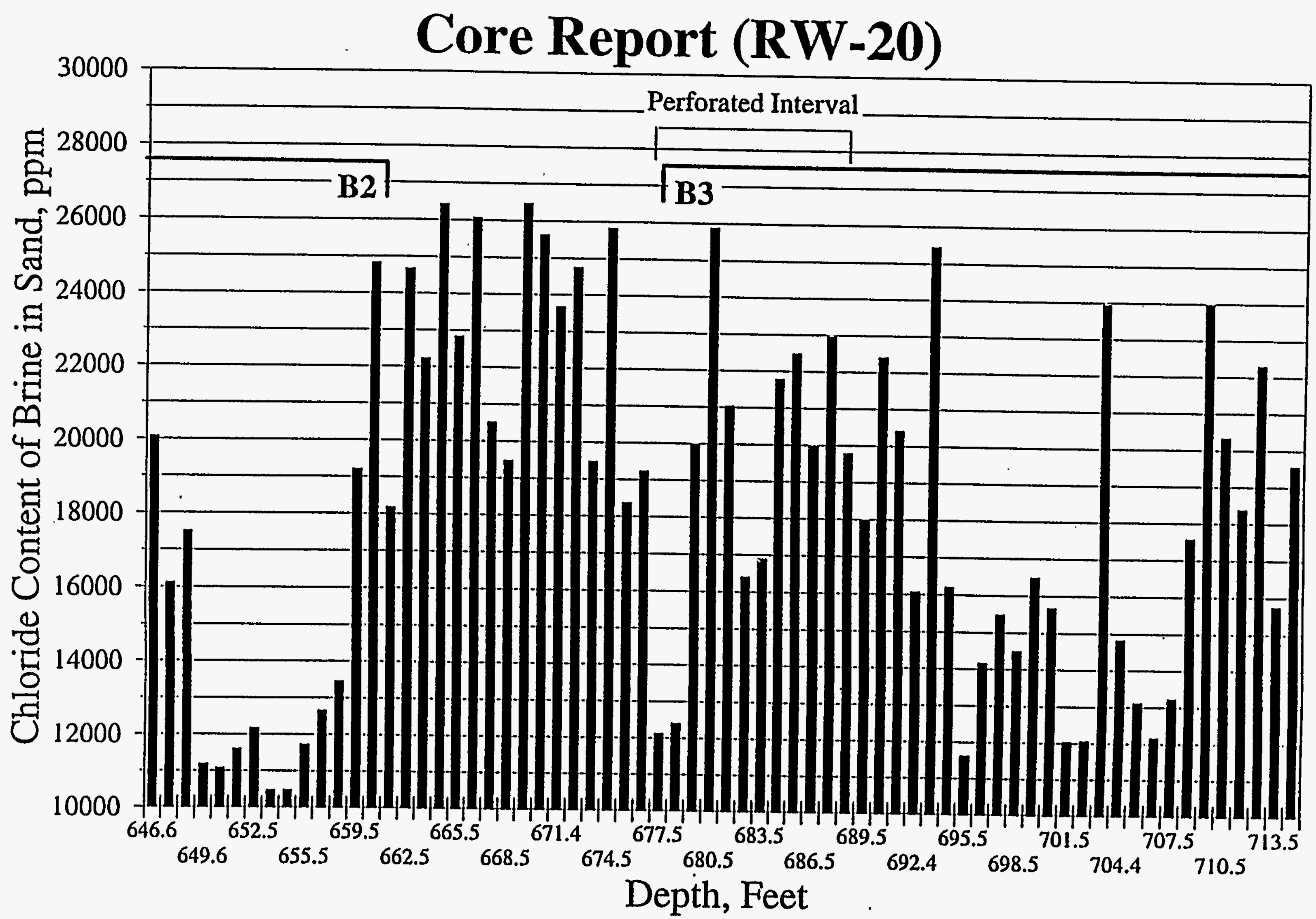

Figure 24. Chloride concentration from core analysis of infill well.

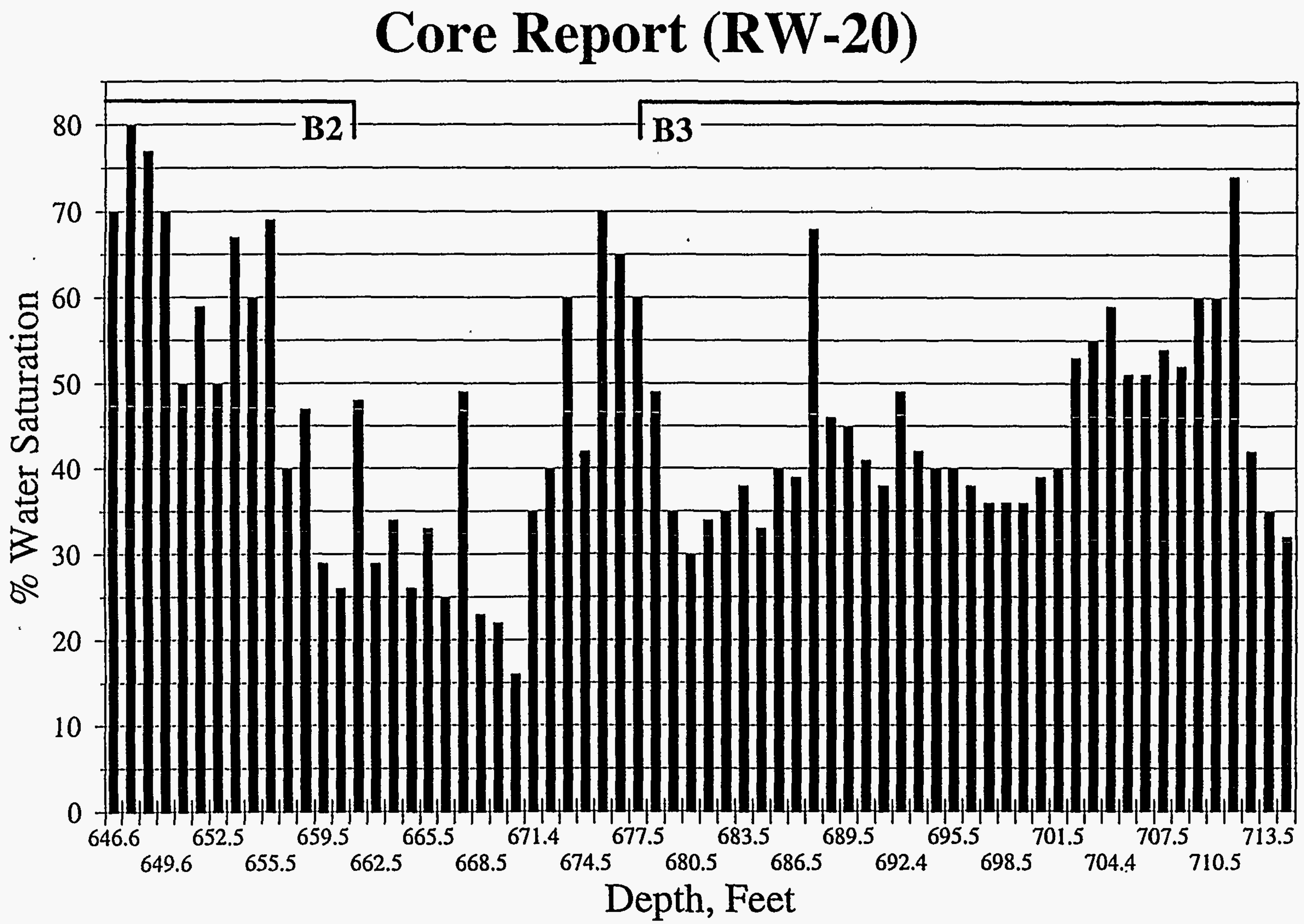

Figure 25. Water saturation from core analysis of infill well.

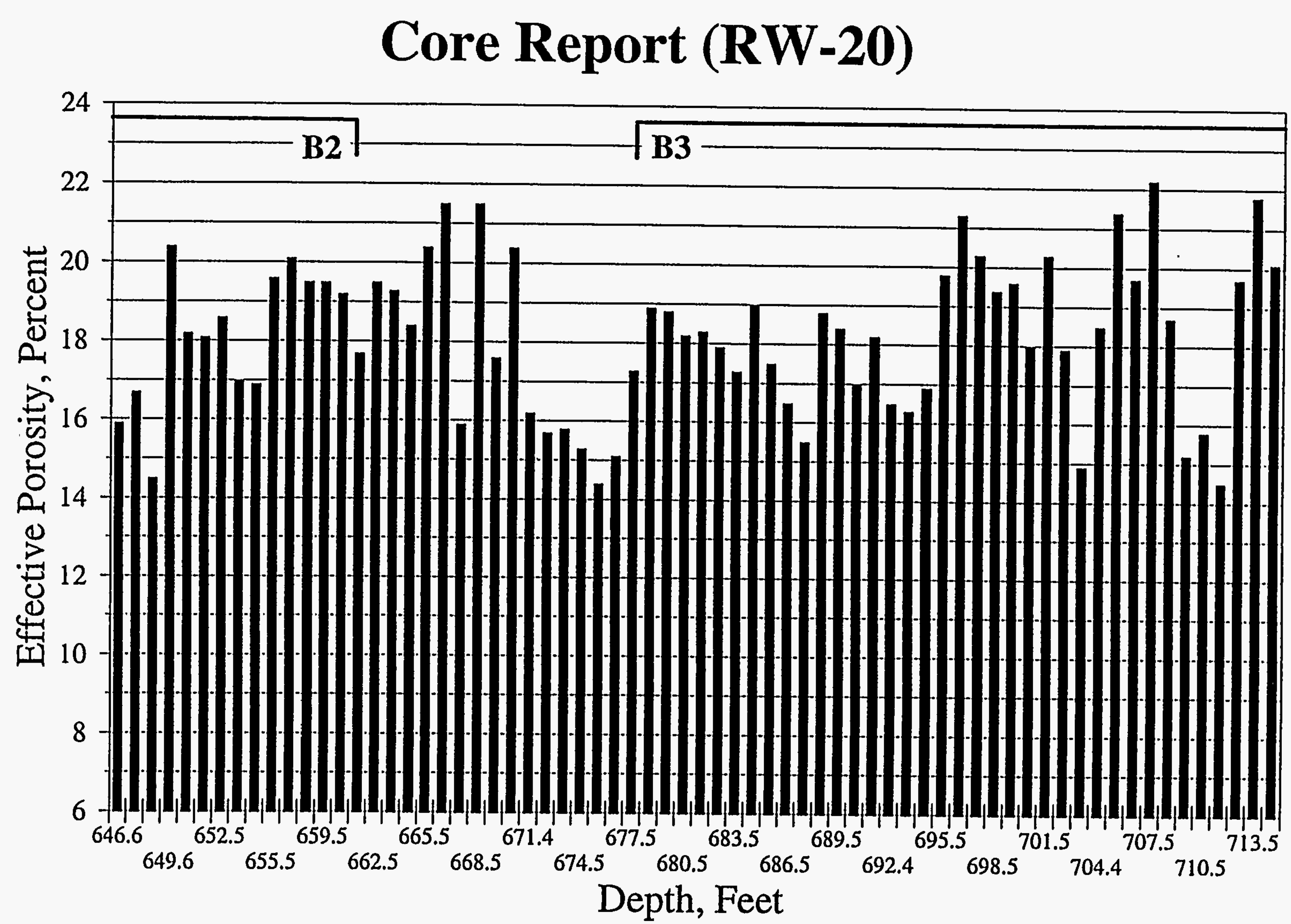

Figure 26. Effective porosity from core analysis of infill well.

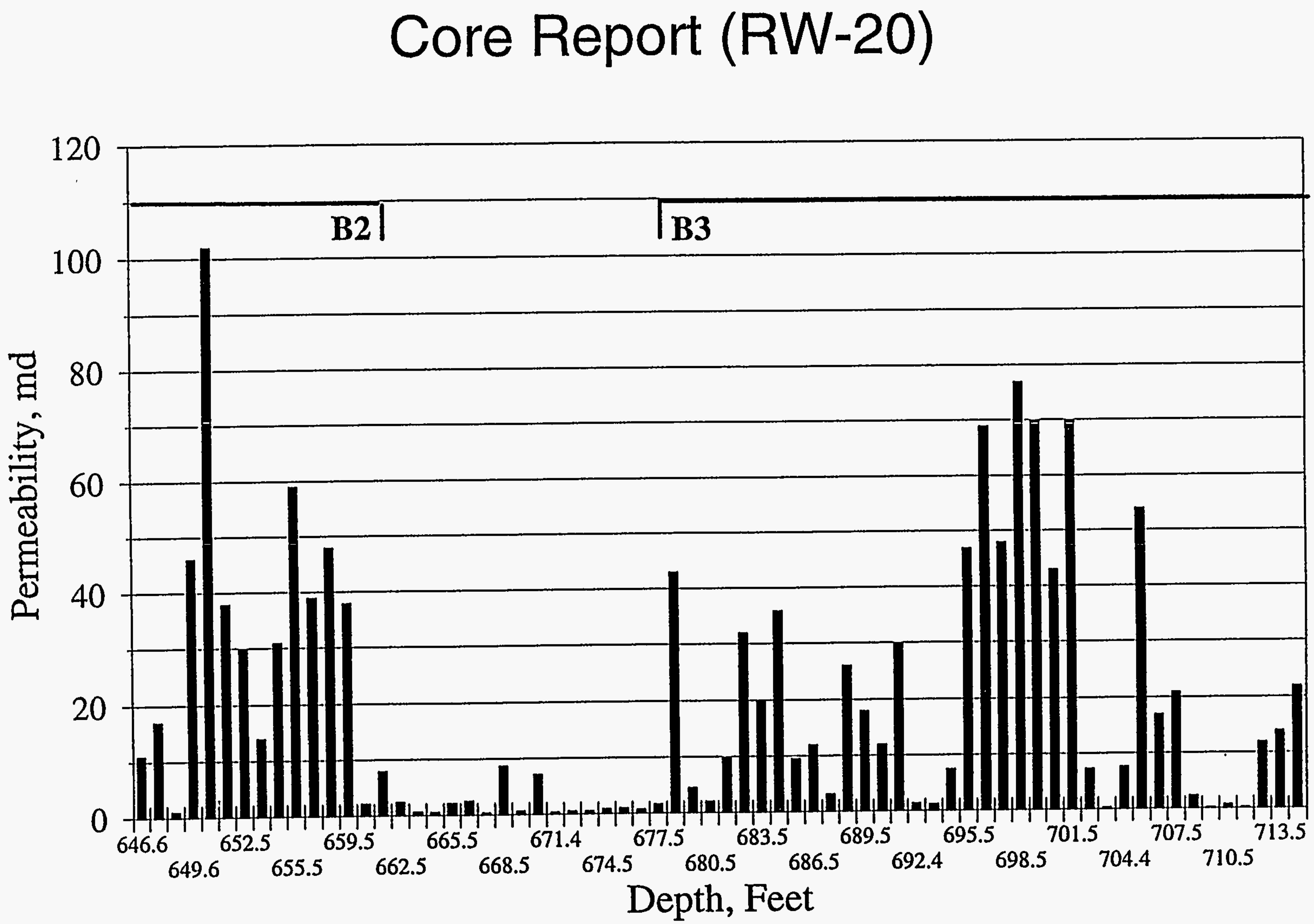

Figure 27. Permeability to air from core analysis of infill well.

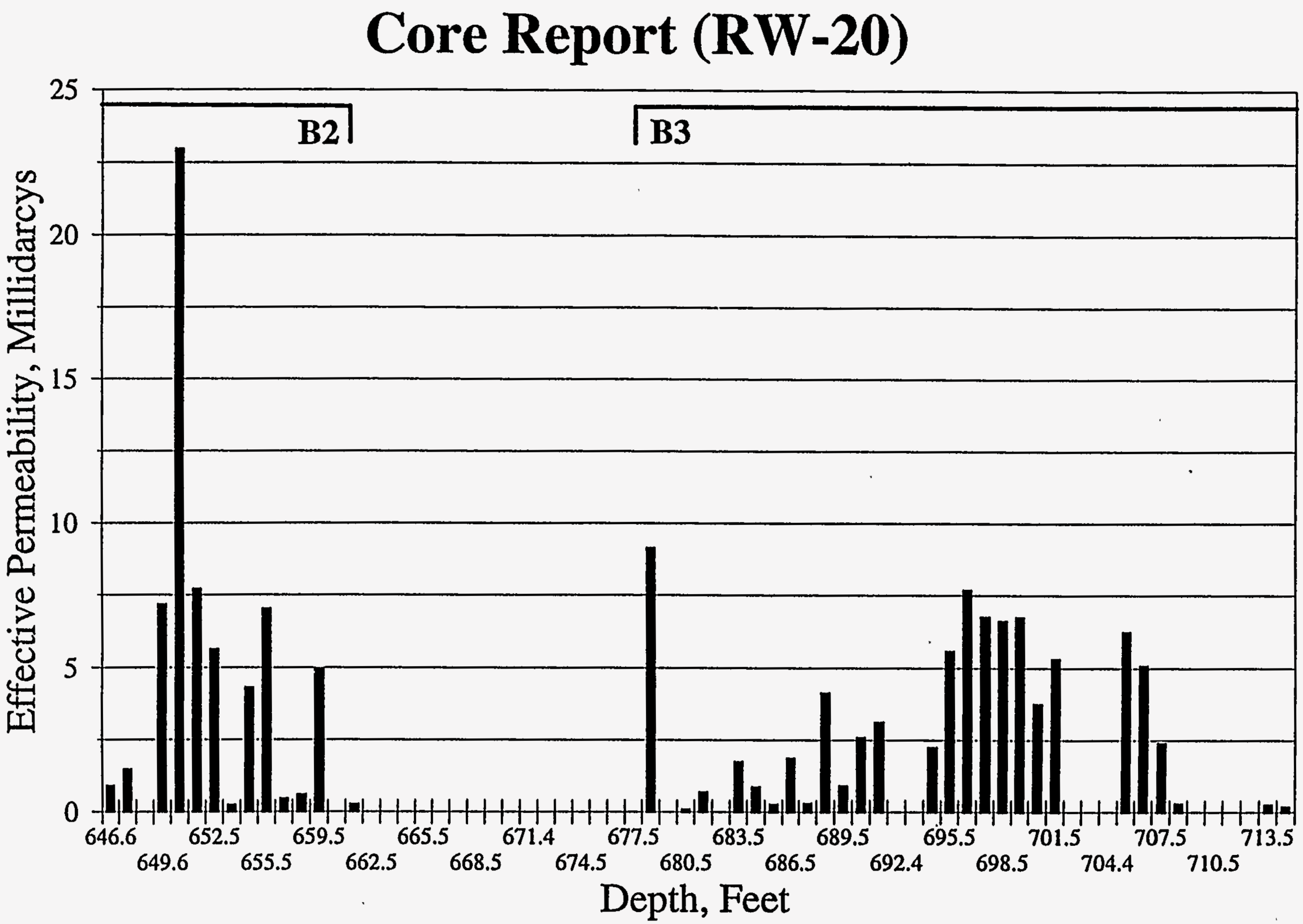

Figure 28. Effective permeability to water from core analysis of infill well.

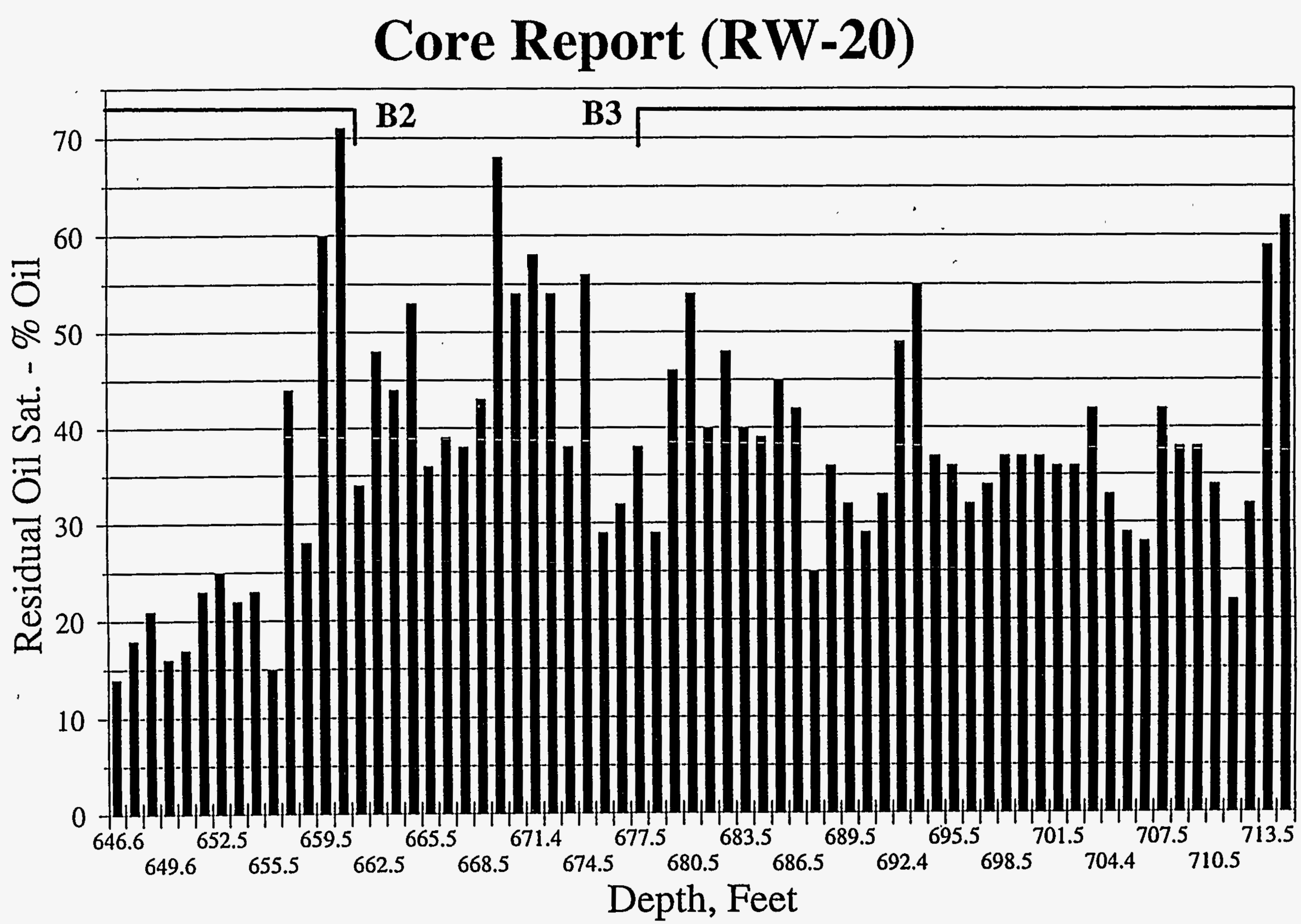

Figure 29. Residual oil saturation after waterflooding from core analysis of infill well.

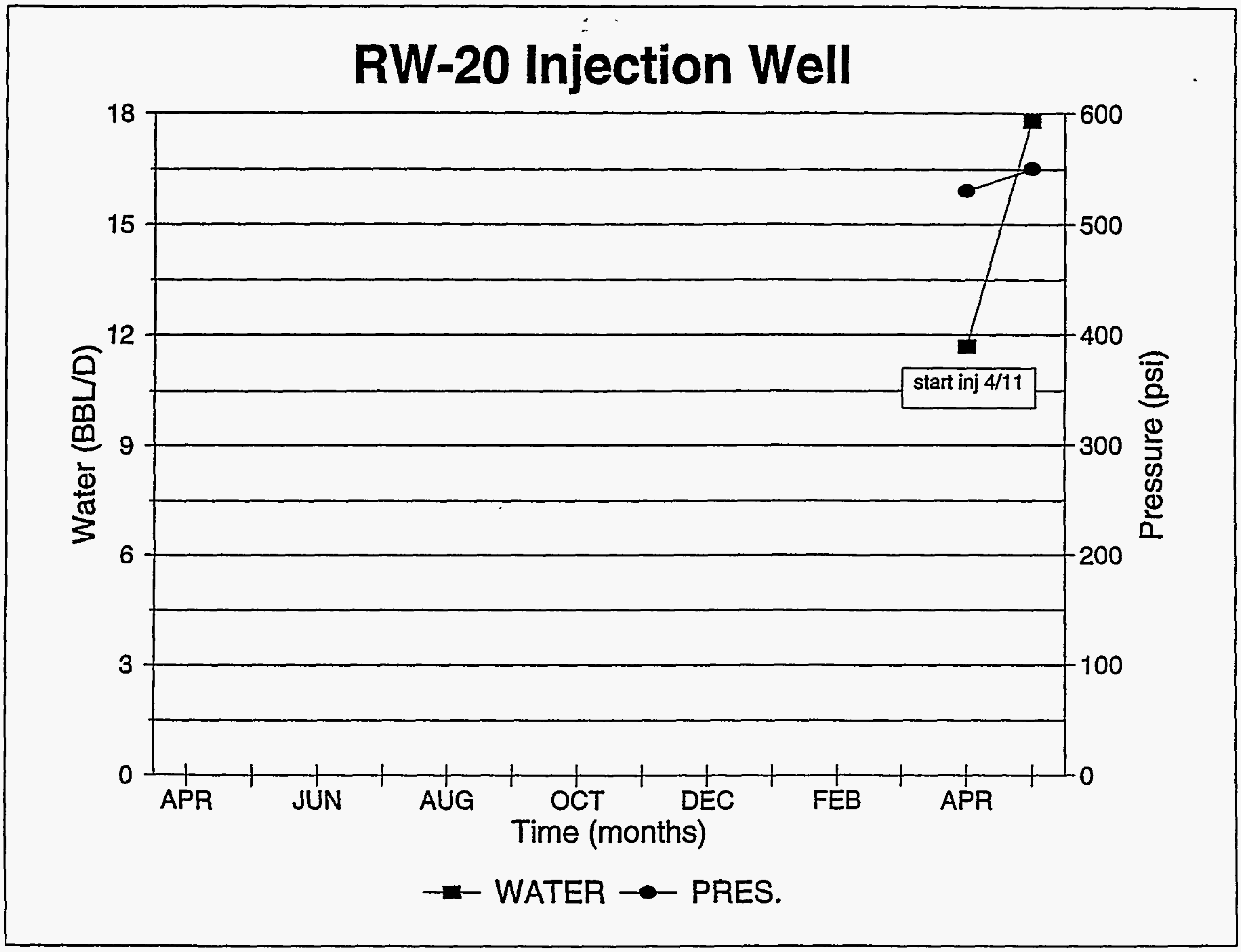

Figure 30. Injection pressure and rate for infill well.

TABLES

	Wellbore Cleanups											
	Apr-95	May-95	Jun-95	Jul-95	Aug-95	Sep-95	Oct-95	Nov-95	Dec-95	Jan-96	Feb-96	Mar-96
H-5												
H-12	x			x								
H-14				x								x
H-15		x	x	x								
HW-1									x	x		
HW-18								x				
HW-23								x				
HW-29								x				
HW-31								x				
K-32								x				
K-42									x	x		
K-44									x	x	x	
K-50									x			
KW-6		x	x	x								
KW-7						x		x				
KW-8	x					x	x	x				
KW-9						x		x				
KW-10	x							x				x
KW-11												
KW-51	x							x				
RW-2	x											
RW-3	x						x	x				
RW-6	x							x				
RW-7	x					x						
RW-8								x				
RW-9	x											
RW-10		x		x						x		
RW-12						x						
RW-13			x	x		x						
RW-14	x					x	x	x				
RW-1							x					
HW-23				x				x				
KCW-1												x
						x		x				

Table 4. Savonburg Field Frequency of Wellbore Cleanups.

RW-20								
Sample #	Depth	Eff. Porosity	Percent Oil Saturation			Perm.	Effective Perm.	Chloride Content of
	Feet	Percent	Oil	Water	Total	Mill	Millidarcys	Brine in Sand, ppm
1	646.6	15.9	14	70	84	11	0.94	20,094
2	647.5	16.7	17	80	97	17	1.5	16,131
3	648.4	14.5	21	77	98	1.1	imp	17,526
4	649.6	20.4	16	70	86	46	7.2	11,196
5	650.4	18.2	17	50	67	102	22.99	11,093
6	651.5	18.1	23	59	82	38	7.73	11,616
7	652.5	18.6	25	50	75	30	5.66	12,181
8	653.5	17.0	22	67	89	14	0.27	10,487
9	654.5	16.9	22	60	82	31	4.33	10,492
10	655.5	19.6	15	69	84	59	7.06	11,742
11	656.5	20.1	44	40	84	39	0.48	12,674
12	657.5	19.5	28	47	75	48	0.63	13,466
13	659.5	19.5	60	29	89	38	5	19,204
14	660.5	19.2	71	26	97	2.2	imp	24,838
15	661.5	17.7	34	48	82	8	0.28	18,180
16	662.5	19.5	48	29	77	2.5	imp	24,695
17	663.5	19.3	45	34	79	0.72	imp	22,248
18	664.5	18.4	53	26	79	0.66	imp	26,433
19	665.5	20.4	36	33	69	2.2	imp	22,862
20	666.5	21.5	40	25	65	2.6	imp	26,079
21	667.5	15.9	38	49	87	0.47	imp	20,525
22	668.5	21.5	43	23	66	8.8	imp	19,484
23	669.4	17.6	69	22	91	0.71	imp	26,477
24	670.4	20.4	54	16	70	7.2	imp	25,643
25	671.4	16.2	58	35	93	0.43	imp	23,696
26	672.5	15.7	54	40	94	0.63	imp	24,774
27	673.5	15.8	37	60	97	0.6	imp	19,477
28	674.5	15.3	56	42	98	1	imp	25,835
29	675.5	14.4	28	70	98	1.1	imp	18,371
30	676.5	15.1	32	65	97	0.79	imp	19,235
31	677.5	17.3	38	60	98	1.7	imp	12,137
32	678.5	18.9	39	49	88	43	9.16	12,418
33	679.6	18.8	46	35	81	4.6	imp	19,997
34	680.5	18.2	54	30	84	2.1	0.11	25,883
35	681.5	18.3	44	34	78	10	0.72	21,045
36	682.5	17.9	48	35	83	32	imp	16,414
37	683.5	17.3	44	38	82	20	1.78	16,906
38	684.5	19.0	39	33	72	36	0.89	21,799
39	685.5	17.5	45	40	85	9.5	0.28	22,501
40	686.5	16.5	51	39	90	12	1.89	19,984
41	687.5	15.5	25	68	93	3.2	0.33	22,961
42	688.5	18.8	38	46	84	26	4.16	19,792
43	689.5	18.4	34	45	79	18	0.94	17,997
44	690.5	17.0	33	41	74	12	2.61	22,429
45	691.5	18.2	39	38	77	30	3.16	20,432
46	692.4	16.5	49	49	98	1.5	imp	16,083
47	693.5	16.3	55	42	97	1.3	imp	25,464
48	694.5	16.9	50	40	90	7.5	2.28	16,214
49	695.5	19.8	38	40	78	47	5.61	11,632
50	696.5	21.3	43	38	81	69	7.7	14,169
51	697.5	20.3	37	36	73	48	6.79	15,497
52	698.5	19.4	42	36	78	77	6.65	14,510
53	699.5	19.6	40	36	76	70	6.77	16,493
54	700.5	18.0	39	39	78	43	3.78	15,692
55	701.5	20.3	38	40	78	70	5.33	12,057
56	702.4	17.9	36	53	89	7.3	imp	12,084
57	703.4	14.9	42	55	97	0.35	imp	23,967
58	704.4	18.5	33	59	92	7.7	imp	14,838
59	705.5	21.4	29	51	80	54	6.26	13,136
60	706.5	19.7	28	51	79	17	5.11	12,176
61	707.5	22.2	42	54	96	21	2.44	13,247
62	708.5	18.7	38	52	90	2.4	0.33	17,570
63	709.5	15.2	38	60	98	0.28	imp	23,996
64	710.5	15.8	34	60	94	0.81	imp	20,342
65	711.4	14.5	23	74	97	0.23	imp	18,381
66	712.6	19.7	32	42	74	12	imp	22,336
67	713.5	21.8	59	35	94	14	0.28	15,760
68	714.5	20.1	62	32	94	22	0.22	19,581

Table 5. Savonburg Field Core Analysis from Infill Injection Well.

APPENDIX A

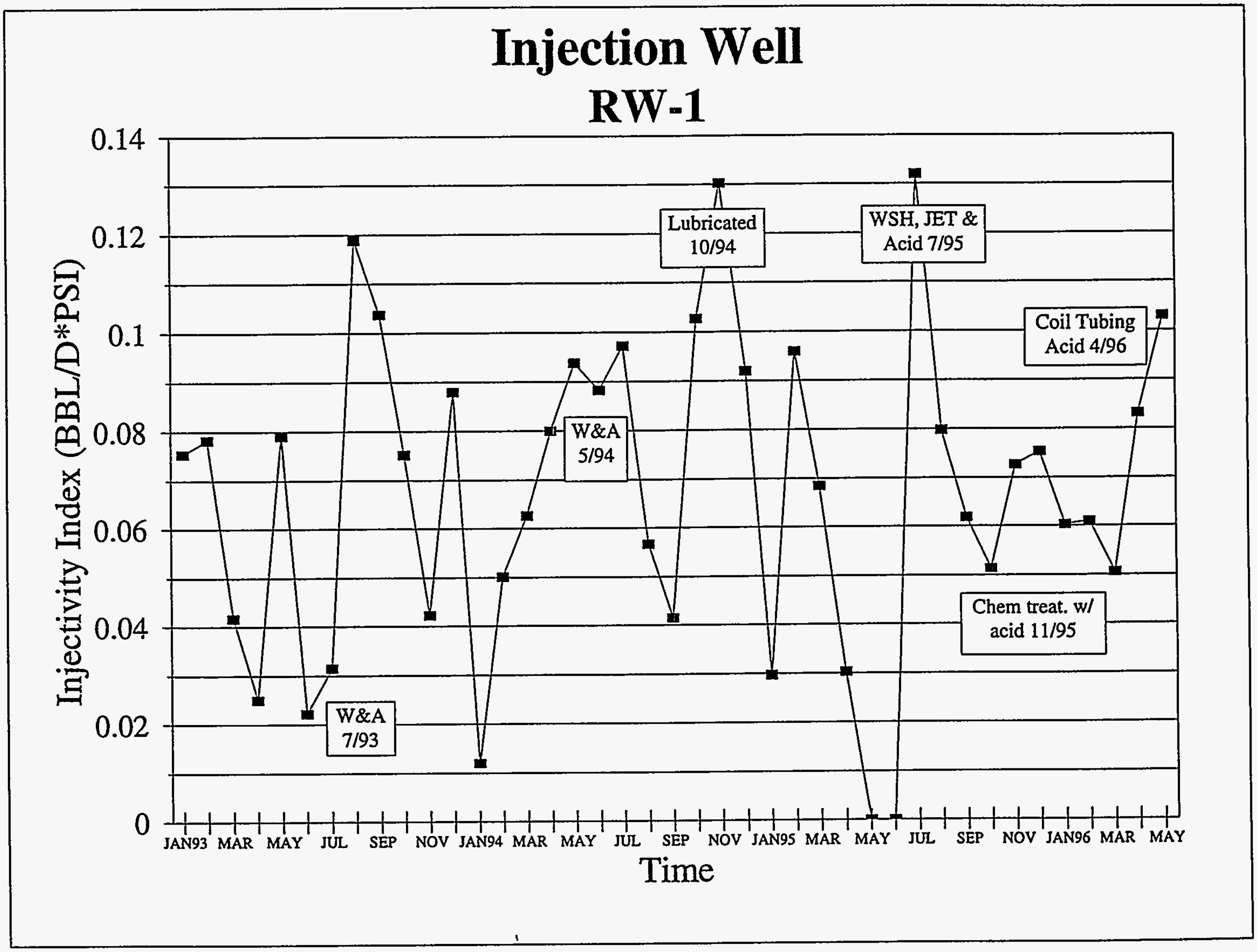

Figure A-1. Injectivity Index Plot for RW-1.

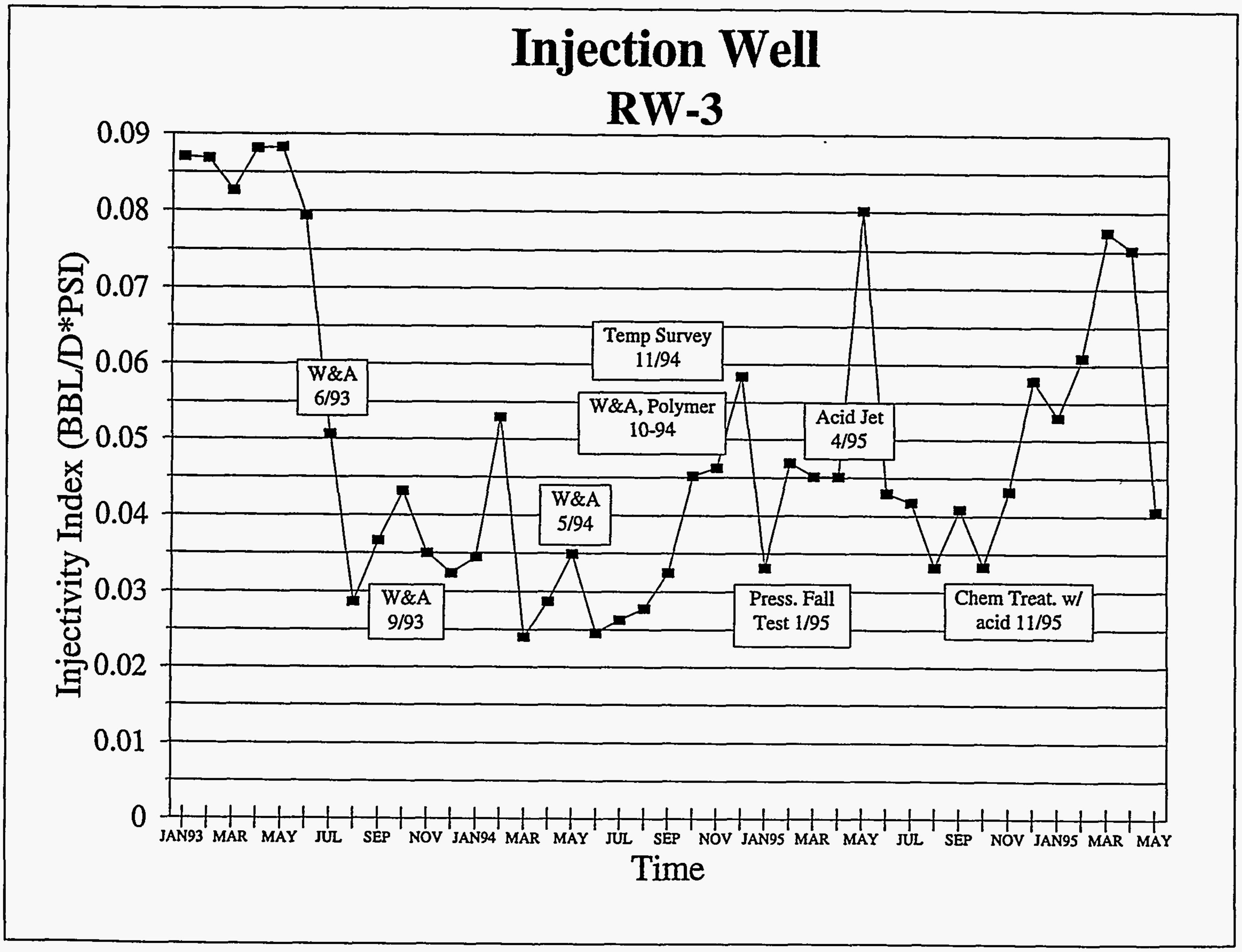

Figure A-2. Injectivity Index Plot for RW-3.

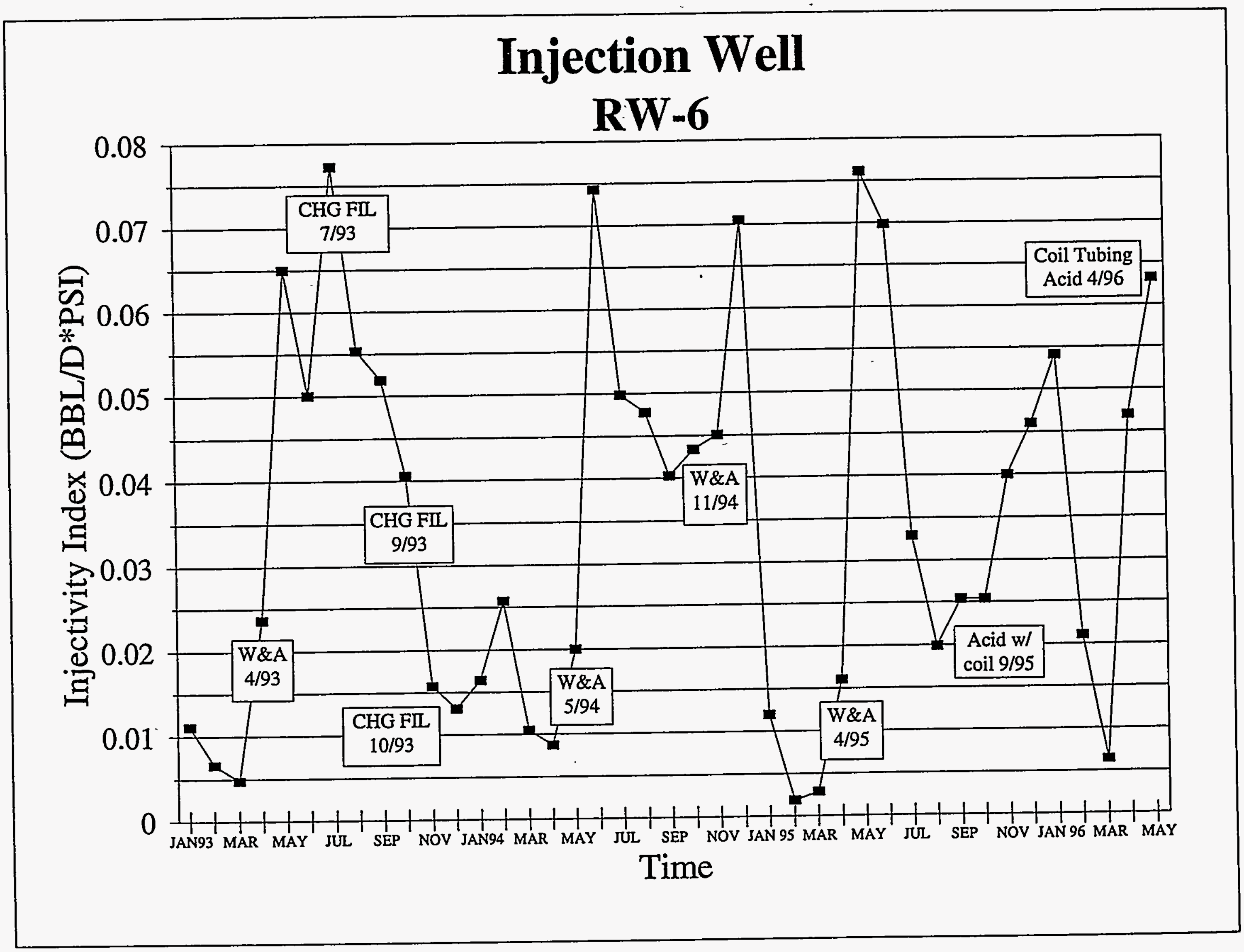

Figure A-3. Injectivity Index Plot for RW-6.

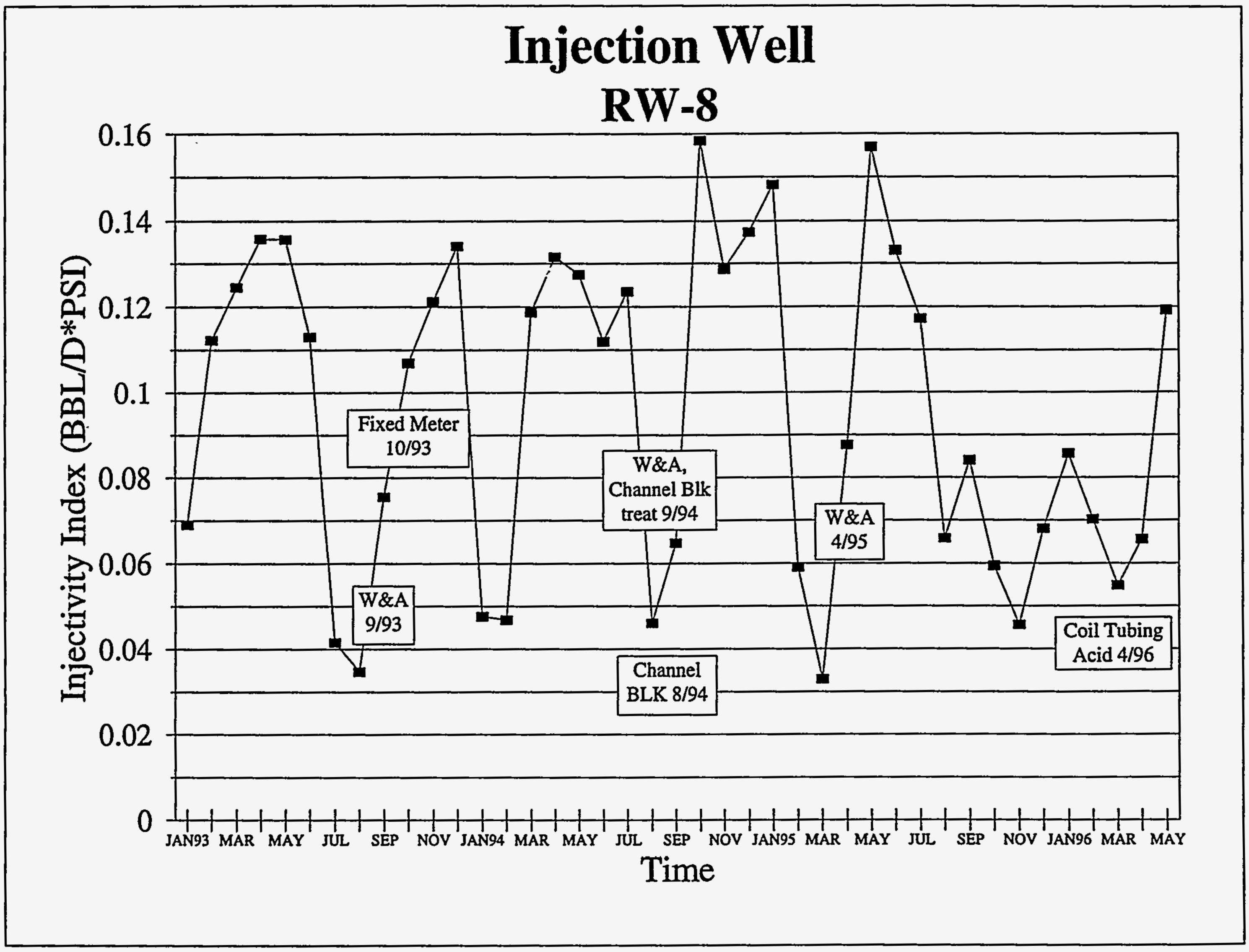

Figure A-4. Injectivity Index Plot for RW-8.

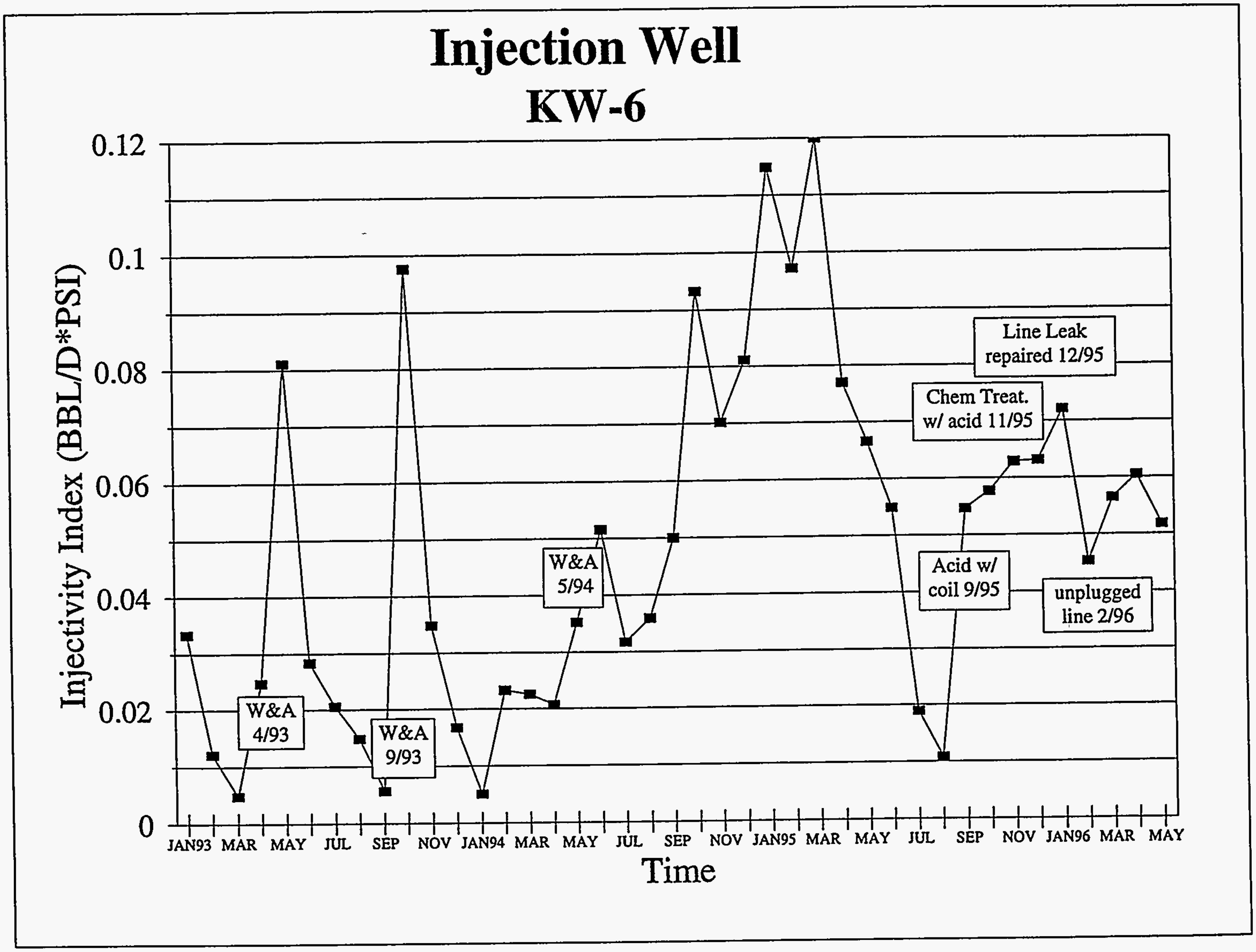

Figure A-5. Injectivity Index Plot for KW-6.

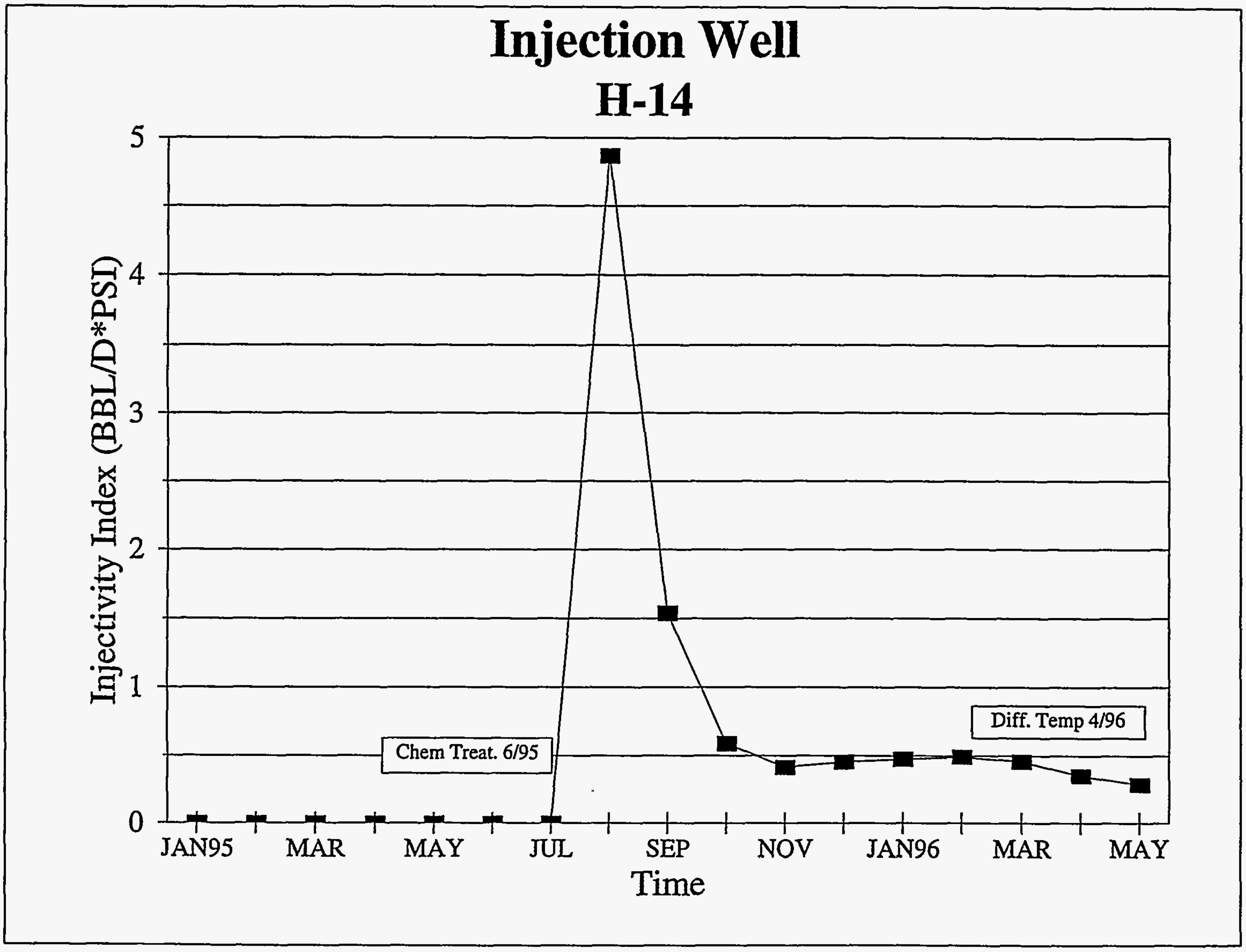

Figure A-6. Injectivity Index Plot for H-14.

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