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PLANNING PHASE FOR THE NEW MEXICO IMPROVED OIL RECOVERY PROJECT

Final Report
Contract Number: DE-FG07-89ID12872

by

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PRRC No. 91-19

June 1991

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EXECUTIVE SUMMARY

Understanding how heterogeneity affects flow through reservoirs and quantifying those effects will require further developments in reservoir characterization to improve our ability to look at well-to-well type heterogeneity. There are opportunities to combine techniques such as pressure transient testing and tracers that can be directed at improved understanding of reservoir heterogeneity. Some of these techniques are well known, but they can be expanded to provide new information, for example, a novel technique to look at wettability by the use of tracers. Other technologies are emerging in this area, especially pertaining to some of the geophysical means, such as 3-D seismic, inverse vertical seismic profiling, and crosswell tomography, as well as interdisciplinary approaches in reservoir management, and measures to quantify reservoir heterogeneity.

A project proposed at New Mexico Tech along these lines is the "New Mexico Improved Oil Recovery Project" (NMIORP). This project is a collaborative effort with Los Alamos National Laboratory, Sandia National Laboratories, and a number of universities throughout the country. Field and laboratory tests were proposed to investigate advanced technologies in reservoir characterization, reservoir simulation, and recovery enhancement. Basically, the approach was to acquire an oilfield property for experimental purposes where interdisciplinary testing could be performed. Several researchers, especially in the academic area, would like to have access to field data and have expressed interest in participating in the project. A standardized dataset from a well-characterized site could be made available to anyone who is developing and validating new simulators. The data-gathering phase should be coordinated fully with the principal users of the data, and all data should be stored in an easily accessible form. A database for the NMIORP could be established which would be designed for access by various computer networks. Early input from all participants would minimize the risk of collecting inappropriate data. Improved reservoir descriptions would permit the use of simplified simulation codes and would result in a better physical representation of reality in the simulations. This field site would be viewed not as an oil recovery project, but as a field laboratory so that some of the emerging technologies and techniques could be applied in a very well-characterized environment and extrapolated to other reservoirs.

Initially, this project provided for a planning phase for the NMIORP. A field site, the Sulimar Queen Unit, has been acquired by New Mexico Tech, and the activities specified in the planning phase have been completed. A data acquisition well was drilled, logged, and cored. Geological and reservoir studies for the Sulimar Queen Unit were conducted. Results of these studies indicate that the Sulimar Queen Unit is a suitable field site for the NMIORP. This report describes the results of the studies that were conducted and outlines possible future tests that could be performed at the field site.

BACKGROUND

In February of 1988, the Petroleum Recovery Research Center (PRRC), in conjunction with the New Mexico Institute of Mining and Technology (NMIMT), Los Alamos National Laboratory (LANL), and Sandia National Laboratories (SNL), submitted a proposal entitled "New Mexico Improved Oil Recovery Project" to the Department of Energy (DOE). The proposal was a request for funds for a five-year program designed to "develop and validate advanced methods of reservoir characterization for oil recovery processes through interdisciplinary and multi-institutional efforts focused at a field laboratory." The field laboratory would help develop the technology to bridge the gaps between reservoir characterization and oil recovery processes, actuality and simulation, and the pore-scale and reservoir-scale phenomena inherent in oil recovery processes.

In August of 1988, a Memorandum of Understanding relating to Fossil Energy Resource Characterization, Research, Technology Development, and Technology Transfer was signed by officials of the DOE and the state of New Mexico. An annex to the memorandum outlining a planning phase for the field laboratory was approved by the DOE and the State in September 1988.

In April, 1989, the planning phase began with funding of $260,000, equally divided by the DOE and the New Mexico Research and Development Institute (NMRDI). The PRRC is coordinating the project, and Dave Martin, director of the PRRC, is the Project Leader.

OBJECTIVES

The idea and impetus for this research have come from the need to maximize U.S. oil production by improved understanding of how reservoir properties govern the extraction of oil from known reservoirs. In order to do this, an understanding of reservoir structures and the development of diagnostics to characterize heterogeneities are essential. The physical phenomena involved have been relatively well understood for some time. Nevertheless, there have been disappointing gaps between laboratory, field, and computer research and the production of residual oil because of the lack of evaluations of these techniques in controlled reservoirs to develop an understanding of the manner in which heterogeneities cause oil to be trapped. The absence of detailed reservoir data contributes to this break in continuity. A research field laboratory, through an increased number of closely spaced wells, horizontal wells, comprehensive core analysis and logging programs, and the synergism resulting from research activities at a common site, would present a unique opportunity to validate the research needed for improved reservoir characterization.

The specific objectives of the planning phase of the NMIORP were to: 1) acquire an appropriate oilfield property that could serve as a field laboratory to develop techniques to improve oil recovery from known reservoirs, 2) establish a project office, 3) conduct field activities and preliminary studies, and 4) conduct planning activities.

SUMMARY OF ACCOMPLISHMENTS

A project office consisting of representatives from the PRRC, the NMIMT Petroleum Engineering Department, SNL, and LANL was established early in the project. Members of the project office are responsible for providing technical input and assistance to the Project Leader. Participants in the project's future may include individuals from other universities, other national laboratories, and industry.

Also established were a Steering Committee and a Technical Review Panel. The function of the Steering Committee is to provide input to the Project Leader and to ensure that the direction and activities of the project are consistent with the needs of the oil and gas industry, the state of New Mexico, and the Department of Energy. The Committee consists of the following: the Bartlesville Project Office, DOE; NMRDI; the Independent Petroleum Association of NM; the NM Oil & Gas Association; the NM Oil Conservation Division; PRRC, NMIMT; LANL; and SNL. The Technical Review Panel consists of New Mexico independent producers, representatives of major oil companies, and representatives from academia.

On September 1, 1989, the oil and gas lease on the Sulimar Queen Unit was transferred to NMIMT to use as a field laboratory. This 1,440-acre field (encompassing about 840 productive acres), is located about 11 miles north of Loco Hills, NM, and consists of 30 wells (18 injectors) which are cased and perforated in the pay. First production was in 1969, and the reservoir was successfully waterflooded from 1971 to 1984. Waterflood operations were curtailed, and currently one producing well is in operation. McClellan Oil Corporation was selected and contracted as site operator to maintain the day-to-day administration and supervision of the field activities.

Reservoir data obtained from the previous operator and from other available sources were compiled and evaluated in order to provide a basis upon which to perform an initial reservoir study, pressure testing, and the further development of an overall project program plan. A preliminary reservoir study was conducted; oil, gas, and water production data from the field site were analyzed; remaining oil-in-place was estimated; a baseline reservoir characterization was established; and an initial site characterization was prepared. Key properties of the Sulimar Queen Unit are shown in Table 1.

Table 1
Reservoir Properties
Sulimar Queen Unit

Chaves Co., New Mexico
840 productive acres
Permian Age
Back-reef shelf "lagoonal" sand
Fine-grained sandstone
Depth: 2,000 ft
Well spacing: ~40 ac.
Average thickness: 8 ft
Permeability: 150 md
Porosity: 20%
Stratigraphic trap
Paraffinic oil: 36° API
Connate water saturation: 34%
Original oil in place: 6.3 million STB
Primary and secondary recovery: 2.2 million STB (35.3% of OOIP)
Current average oil saturation: 39%

Requirements for initial pressure testing were established and the parameters for, and location of, a test well were determined. One of our tasks was to obtain more knowledge of the Sulimar

Queen reservoir by drilling and coring a new well. The location of the new well (Well 1-16) is shown in Fig. 1. The well location was selected for the following reasons: 1) an area with maximum reservoir thickness was needed to obtain sufficient core material, 2) the core needed to have porosity and permeability suitable for laboratory flow experiments, 3) based on cumulative water injected into Wells 1-3 and 8-1, the location of Well 1-16 is at the point of maximum injection interference; hence, there may be an accumulation of trapped oil, and 4) the location is 460 ft from Well 1-3, which will facilitate multi-well pressure transient testing, interwell tracer work, and future cross-borehole seismic research.

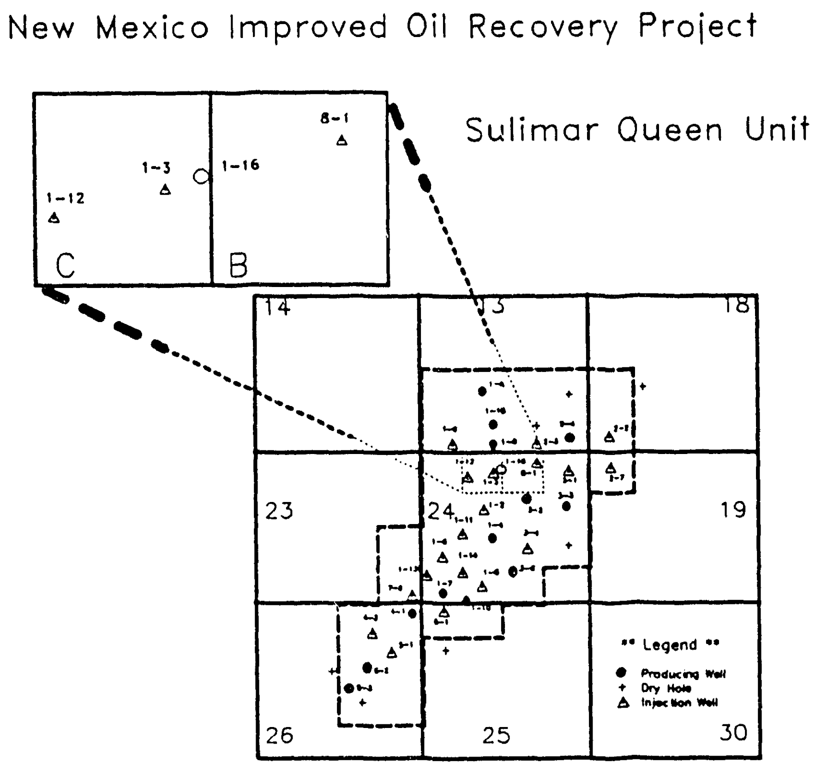

Fig. 1. Location of data well.

Well 1-16 was drilled in August 1990 to a total depth of 2,065 ft. About 30 ft of oriented core was obtained for a whole-core analysis, which is discussed later in this report. Preliminary analyses of the logs from Well 1-16 indicate that the well encountered 10 ft of sand with 23% porosity in the top zone. A lower 20 ft zone of 6% porosity sandstone was also logged. Water saturation in the upper zone averaged about 45%. Following the logging operations, casing was run in the well and cemented with 650 sacks of cement. A 5½" bell nipple was welded to the casing at the surface to cap the well. Completion of the well is pending and will depend on the nature of future tests at the site.

PRELIMINARY RESERVOIR STUDY

INTRODUCTION

One of the initial major tasks was to prepare a preliminary reservoir study of the Sulimar Queen Unit. Reservoir data obtained from the previous field operator and from other available sources were compiled and evaluated in order to provide a basis upon which to perform initial reservoir pressure testing, a new well siting and drilling, and the development of an overall project program plan. The purpose of the preliminary reservoir study was to analyze oil, gas, and water production data from the field site, estimate remaining oil-in-place, establish a baseline reservoir characterization, and prepare an initial site characterization. The results of this study are included in a report[1] entitled "Preliminary Reservoir Study, Sulimar Queen Field, Chaves County, New Mexico," which will be summarized below.

RESERVOIR GEOLOGY

Stratigraphy

Sedimentary rocks of the Queen Formation of the Artesia group include arkosic sandstone and siltstone, limestone, dolomite, gypsum, anhydrite, and halite. A sandstone-siltstone interval at the top of the Queen is considered to be equivalent to the Shattuck member of the Queen as defined at the type locality in the Guadalupe Mountains west of Carlsbad, New Mexico. In oilfield terminology, this interval is commonly referred to as the Artesia red sand. It is an excellent marker bed, easily recognized on well logs, and correlated across the shelf area of the Permian basin (Fig. 2).

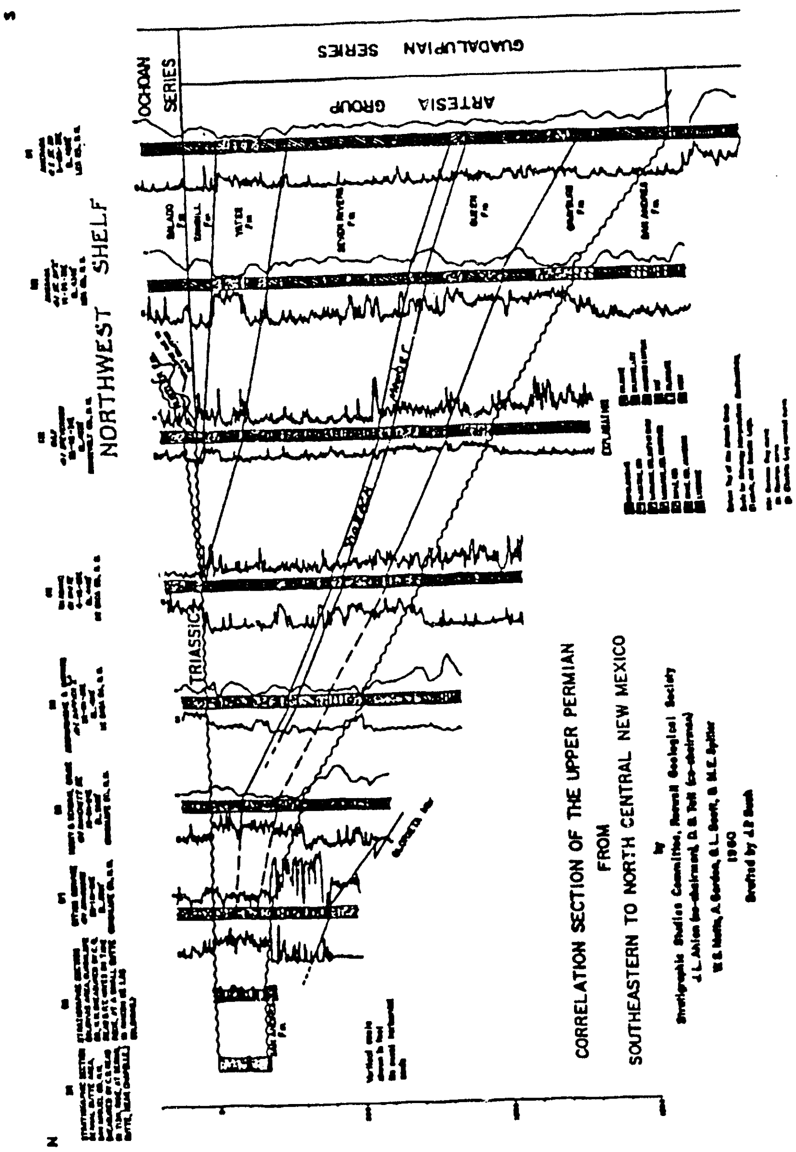

Fig. 2. Correlation section of the upper permian
from
southeastern to north central New Mexico.

In the Sulimar area, the Shattuck consists of 10 to 20 feet (Fig. 3) of generally red-colored arkosic siltstone and red, brownish-tan, and gray very fine-grained arkosic sandstone. The sandstones commonly contain scattered medium-grained, well rounded, frosted grains of quartz.

Overlying the Shattuck, at the base of the Seven Rivers Formation, is a thin (approximately one foot) bed of dolomite and 4 to 6 feet of anhydrite. The anhydrite forms the cap rock for the Sulimar reservoir.

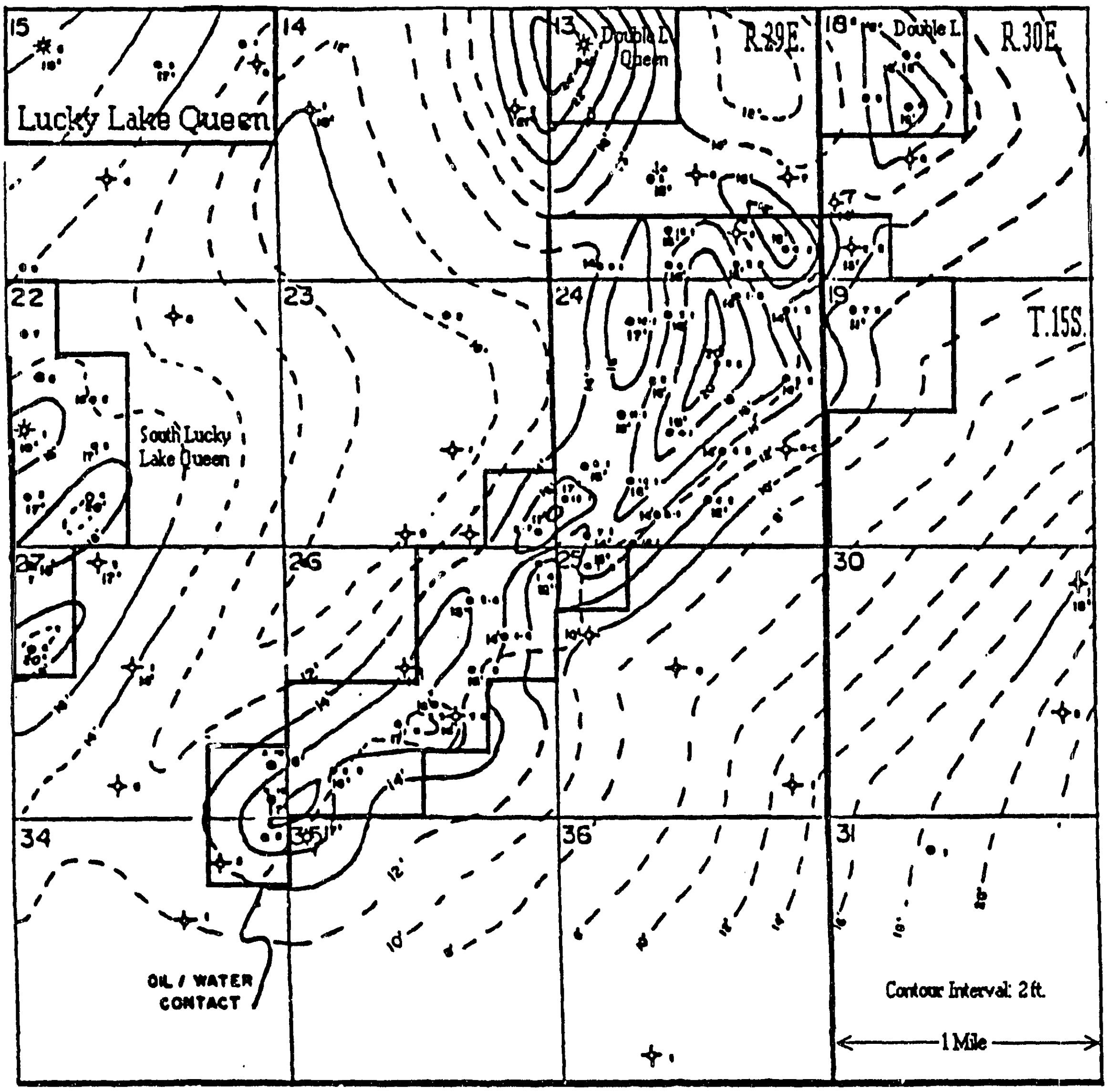

Fig. 3. Isopach map-Shattuck member.

Structure

The Sulimar Queen pool is a lenticular-shaped sand body elongated in a northeast direction (Fig. 3). It occurs at an average depth of 2,000 feet. The structural contour map (Fig. 4) shows an eastern and southeastern regional dip of 50 feet to the mile in the north and west, and 70 to 100 feet in the east. No structural closure is evident, but there are four distinct structural noses within the boundaries of the field.

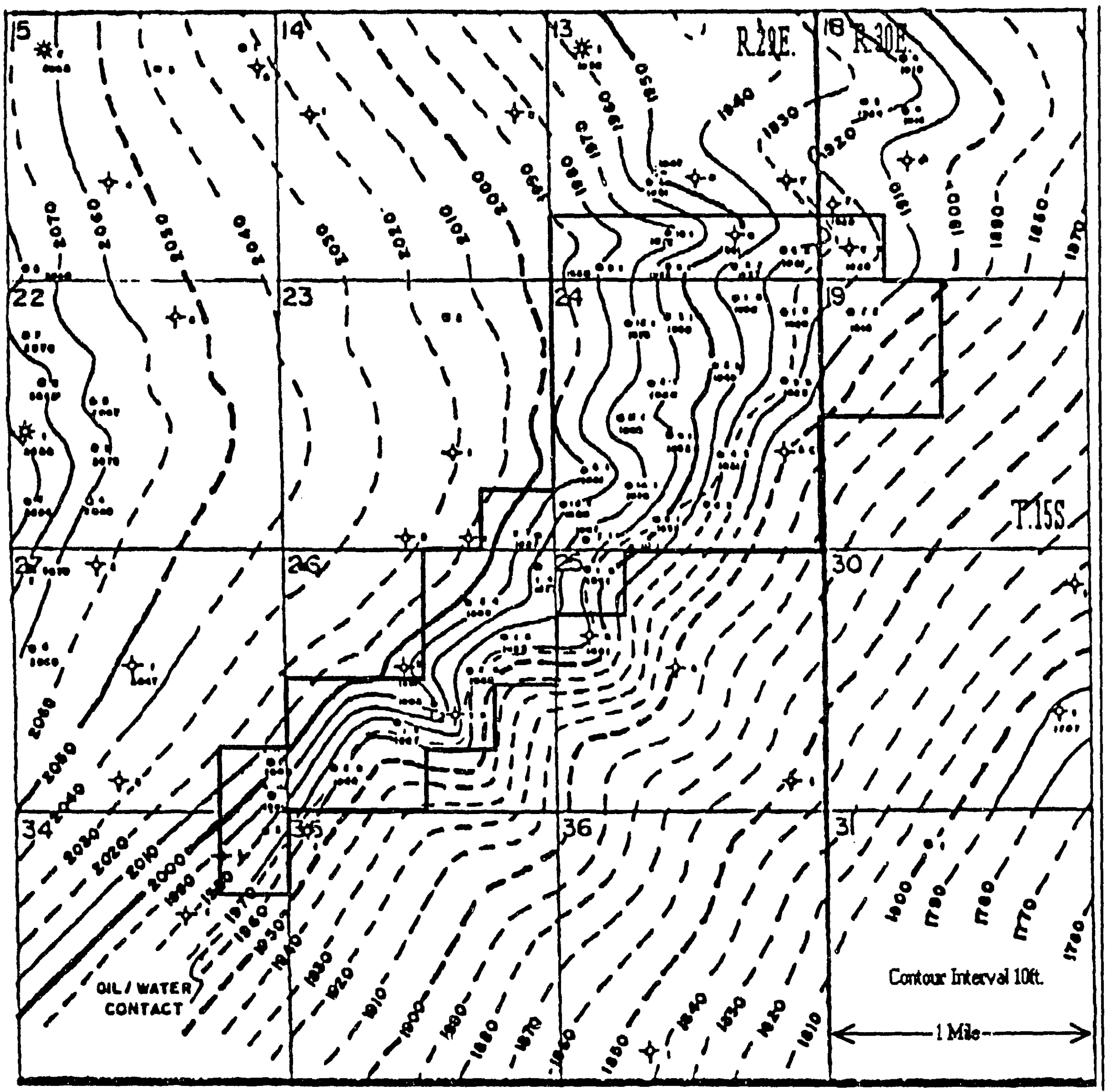

Fig. 4. Structural contour map.

Depositional Environment

The upper Queen sand (Shattuck Member) was deposited during middle Permian Guadalupian time on the Northwest shelf area of the adjacent Delaware basin. During this time, the Permian basin region was dominated by arid climatic conditions.[2]

The Shattuck Member is a back-reef shelf "lagoonal" sand that was deposited as a time-stratigraphic equivalent to part of the Goat Seep reef. This reef grew at the margin of the Delaware basin during mid-Guadalupian time. The reef formed in a barrier-like fashion, rimming the basin margin as the lagoonal waters of the shelf area progressively increased in salinity. In time, carbonate deposition on the shelf was restricted to a small area adjacent to the barrier reef, while evaporites and red beds were accumulating on the remainder of the shelf.

The various hydrocarbon-bearing reservoirs that produce from the upper Queen sand in this vicinity (Lucky Lake, Vest Ranch, Double L, Sulimar, Caprock, and Round Tank) occur as subparallel, lenticular sand bodies along a north-northeastern, south-southwestern trend (Fig. 5). The trend of these lenticular sand bodies is coincident with the boundary between the evaporites of the Northwest shelf area and the back-reef lagoonal sediments, roughly parallel to the strand line of the Goat Seep lagoon.

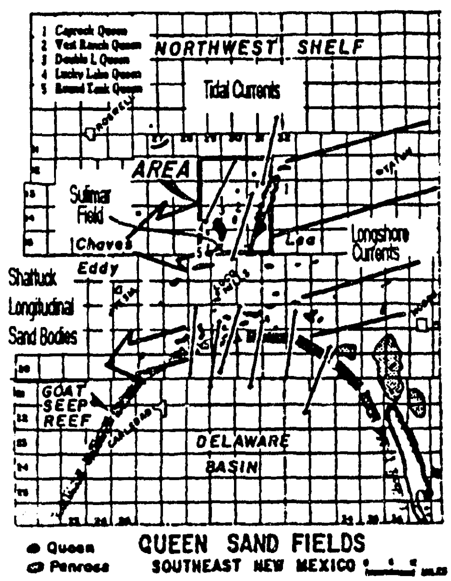

Fig. 5. Regional Queen Sand fields.

Studies done by Williams,[3] Boyd,[4] and Newell[5] suggest that sands of the Shattuck Member were affected by both eolian and longshore current processes. Through paleocurrent analysis, Williams[3] showed that large-scale crossbed sets (with thicknesses up to 5 ft in outcrop) were oriented parallel to the basin margin, indicating longshore current deposition. He also noted that superimposed upon these crossbeds were bimodal current ripples, indicating the ebb and flow of tidal currents. Williams stated (p. 39) that: "Queen tidal channel, tidal bore, and tidal flat deposits contain paleocurrent structures oriented perpendicular to the basin margin." This suggests that tidal currents dissected barrier bars that formed parallel to the strand line to create longitudinal bars oblique to the shelf margin.

Boyd[4] interpreted that the water depth in the shelf/lagoonal area during much of Queen time was less than 5 ft. This conclusion was based primarily on information from sedimentary structures such as crossbedding, current ripple marks, and stromatolite morphologies.

Following deposition of the Shattuck sand in the Sulimar/Double L area, sedimentation processes shifted briefly toward carbonate production, and then subsequently to evaporite deposition. This sequence of depositional processes resulted in a thin bed of dolomite overlain by anhydrite. The vertical succession of lithologies from sand to carbonate to evaporites is interpreted to represent a shoaling upward sequence into an evaporative tidal flat environment.

The types of sedimentation processes presently at work in the Persian Gulf area may provide a modern analog to the paleoenvironment of the Sulimar area during Permian time. The succession of a thin dolomite bed overlain by an anhydrite facies occurs commonly on evaporative tidal flats (sabkhas) in the Persian Gulf area.[6]

The position of sea level is believed to have been fluctuating during sand deposition. The red oxidized sands in the lower zone of the Shattuck Member would suggest that after a brief period of detrital clastic influx, the sand body was subaerially exposed allowing oxidation of the iron in the sand. Eolian transportation and sedimentation processes may have been quite significant during periods when the sand was subaerially exposed.

Carbonate production was probably inhibited because of the high influx of detrital clastics composing the Shattuck Member. Carbonate production most likely proceeded after influx of detrital clastics was reduced, before any significant drop in the relative position of sea level. As carbonate production proceeded, salinities increased, relative sea level presumably dropped, and carbonates were succeeded by evaporites. At this time, the depositional surface was probably frequently subaerially exposed, and formation of evaporative sulfates (gypsum and anhydrite) occurred with repeated imbibition and evaporation of saline waters in the sands.

Reservoir Boundaries

The reservoir is a stratigraphic trap caused by updip termination of porosity and permeability in the oil-bearing sandstone intervals, and, in part, by a facies change to siltstone. The distribution of porosity and permeability are the result of both primary and secondary processes. Primary processes of current winnowing and wave agitation in a shallow beach/shoal environment resulted in the deposition of well-sorted medium to very fine-grained sand. This hydraulic energy promoted reworking of the sediments in the surf zone (probably above wave base), removing fine-grained argillaceous material from the interstices of the sand grains.

Other processes, such as the early formation of evaporite minerals in the interstices of the sand grains, may have controlled the spatial distribution of porosity. Because the Shattuck sands accumulated in a saline environment, it is plausible that evaporite minerals such as halite and gypsum were deposited on the flanks of the sandbars in areas where stagnant, dense saline brines were not diluted or affected by wave agitation. Dolomite, gypsum or anhydrite, and halite are all present as interstitial cements (possibly from both early and late diagenetic origins). The relative proportions of porous, permeable dolomite cements to nonporous anhydrite and halite cements may have been critical in controlling the economic potential of the sands. The distribution of pore-bridging blocky anhydrite strongly influences the amount and continuity, or connectivity, of the reservoir porosity.

A secondary (diagenetic) process is believed to be responsible for the majority of the reservoir porosity present in the gray and brown reduced pay zones.[7] The dark gray-brown color of the producing sands was caused by the reduction of ferric oxide (Fe_3O_2) to soluble ferrous oxide (FeO). The reduction of the ferric oxide may have been caused by anaerobic bacteria or by the migration and emplacement of hydrocarbons into the reservoir.

Based on initial production data and log studies, the original oil-water contact appears to occur between +1,930 feet at the north end of the reservoir and +1,960 feet at the south end (Fig. 4). It is indicated that the oil-water contact forms the boundary of the pool in the northeast. Wells near this northeast boundary yielded small amounts of water during initial production tests while a majority of the wells in the remainder of the field yielded only oil and gas. The southeastern and western limits are considered to be controlled primarily by the morphological and lithological constraints discussed above.

The net pay thickness of the reservoir cannot be adequately determined from the driller's logs or from gamma ray and neutron wireline logs available for this field. Based on the isopach map and cumulative production maps, reservoir volume is estimated to be 30,320 acre-feet.

This preliminary reservoir study of the Sulimar Queen Unit was conducted based on information that was available before the property was donated to NMIMT. This study provided the background information on the suitability of the Sulimar Queen Unit for the field testing proposed in the NMIORP. An analysis of the NMIORP is provided in the next section of this report.

ANALYSIS OF THE NEW MEXICO IMPROVED OIL RECOVERY PROJECT

INTRODUCTION

The goal of the project is to develop and validate advanced methods of reservoir characterization for oil recovery projects. For example, the product of the research could be used to fill in the grid blocks in Fig. 6, which depicts the 2,000 ft sandstone oil reservoir acquired by the PRRC for experimental purposes. The scale of the illustrated grid blocks varies from 8 ac/block (properties of which might come from a well test) to $6x10^{-6}$ ac/block (which is core plug scale).

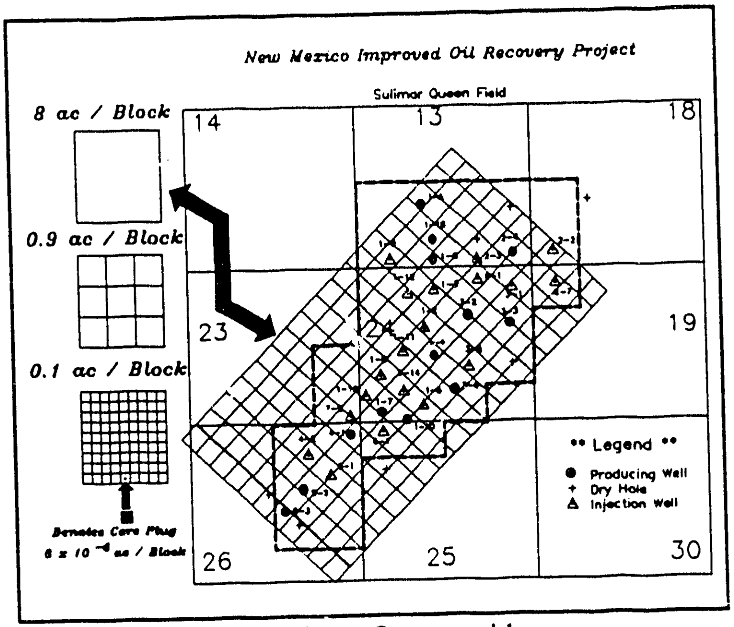

Fig. 6. Sulimar Queen grid.

DISCUSSION

This report summarizes the current understanding of the Sulimar Queen Sand reservoir and provides a starting point for future characterization efforts. The description is organized into four scales of measurement: gigascopic, megascopic, macroscopic, and microscopic, as illustrated in Fig. 7 after Halderson.[8] Information gained from a data acquisition well drilled during August 1990 is included in this analysis.

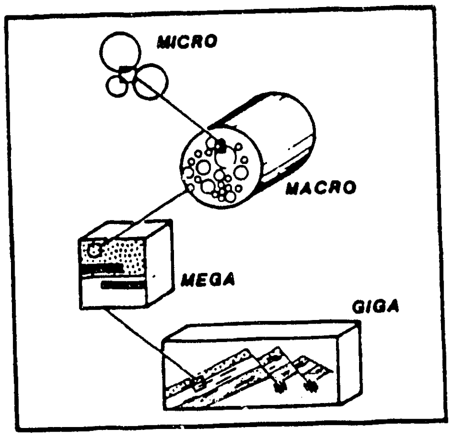

Fig 7. Four conceptual scales.

Gigascopic Scale (Regional and Fieldwide)

Regional

The regional setting is the Northwestern Shelf and the Central Basin Platform (rim) of the Delaware Basin. The location of Queen oil fields in a back-reef lagoonal trend[1] is illustrated in Fig. 8 by Holtz.[9] It is evident from Fig. 8 that there are ample opportunities to apply reservoir characterization techniques developed at the Sulimar Queen to other fields in the trend. The location of the Sulimar Queen is highlighted.

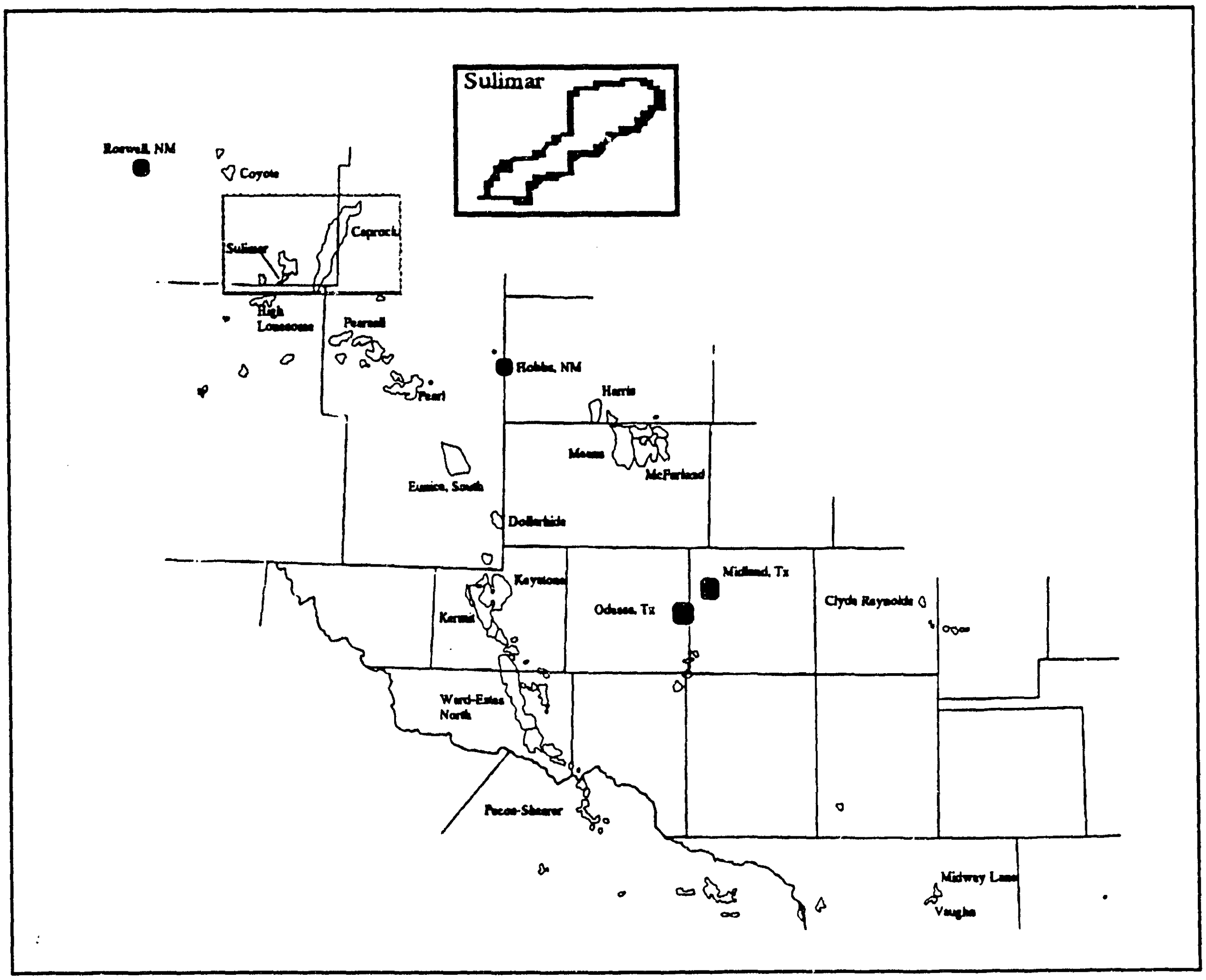

Fig. 8. Queen oil fields.

Currently, Sulimar Queen field wells are the primary source of descriptive information. However, outcrop analogies could provide a source of additional data. The Queen formation is extensively exposed in the vicinity of the old Queen Post Office, Sec. 30, T.24S., R.22E. in the Guadalupe Mountains. Williams[3] states that the best Queen exposures are located in Dark and North Mckittrick Canyons. The Queen also outcrops in the Brokeoff Mountains' West Dog Canyon along Cutoff Ridge. Geostatistical studies in the areal and vertical paths could be readily conducted at these exposures.

Fieldwide

The Sulimar Queen base map depicted in Fig. 9 includes log cross-section reference lines. Individual well data generally fall into the Megascopic scale. However, in this case since the data are assembled into a fieldwide package it is included in the gigascopic scale.

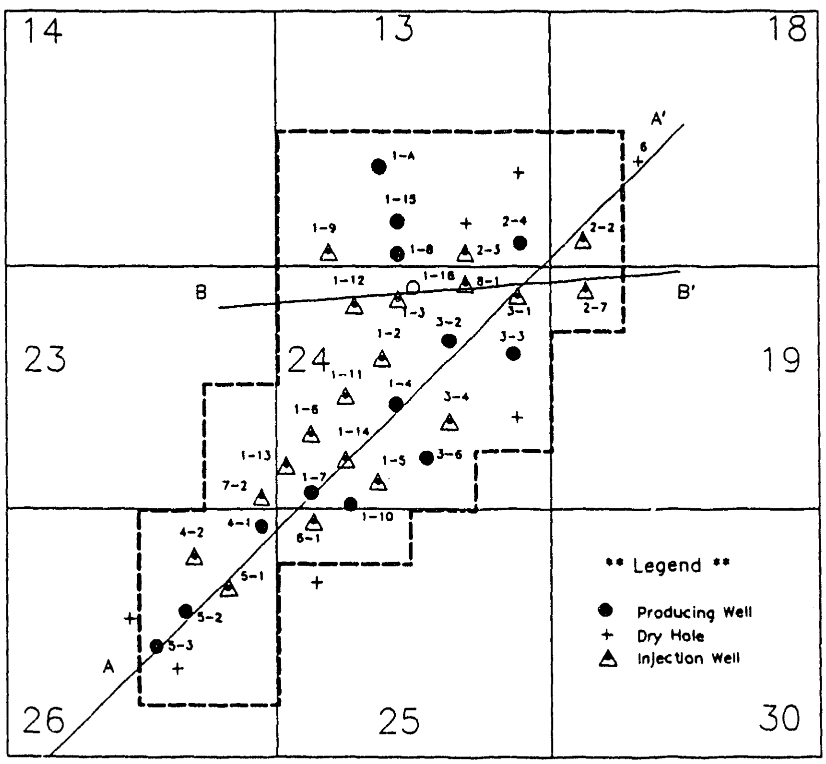

Fig. 9. Base map with cross section reference lines.

The perforated interval is highlighted with the gamma ray and neutron logs NE-SW and E-W cross sections as seen in Figs. 10 and 11. Notice the peculiar gamma ray response to the Queen formation. The increased gamma ray count is the result of radioactive material that is normally associated with shale.

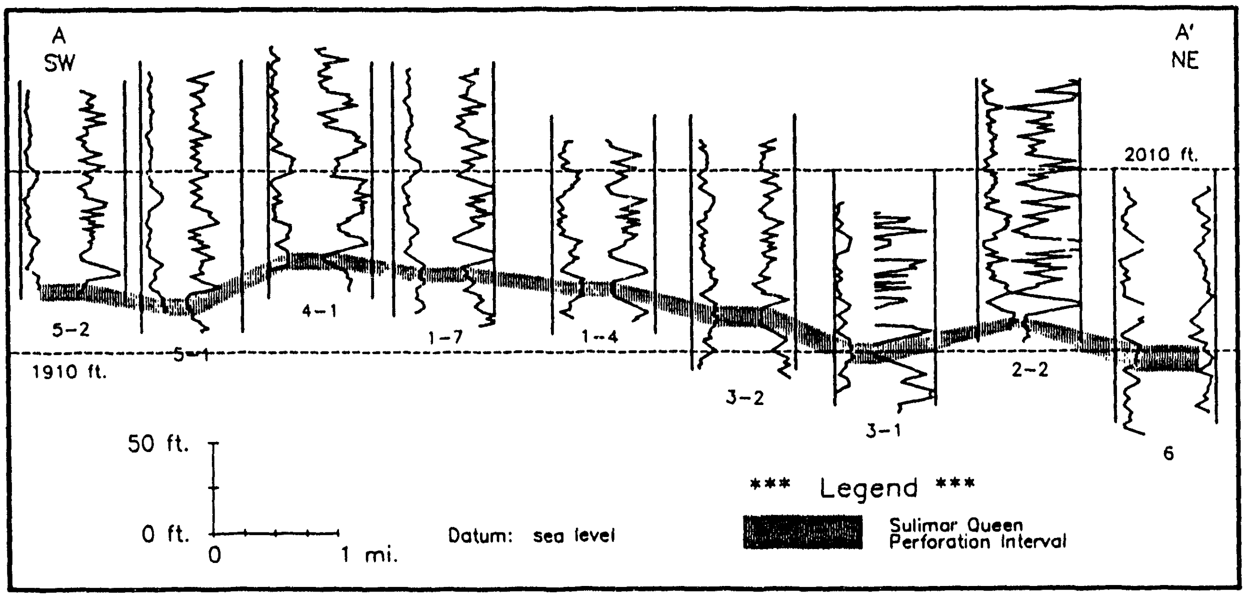

Fig. 10. A-A', SW-NE log cross-section.

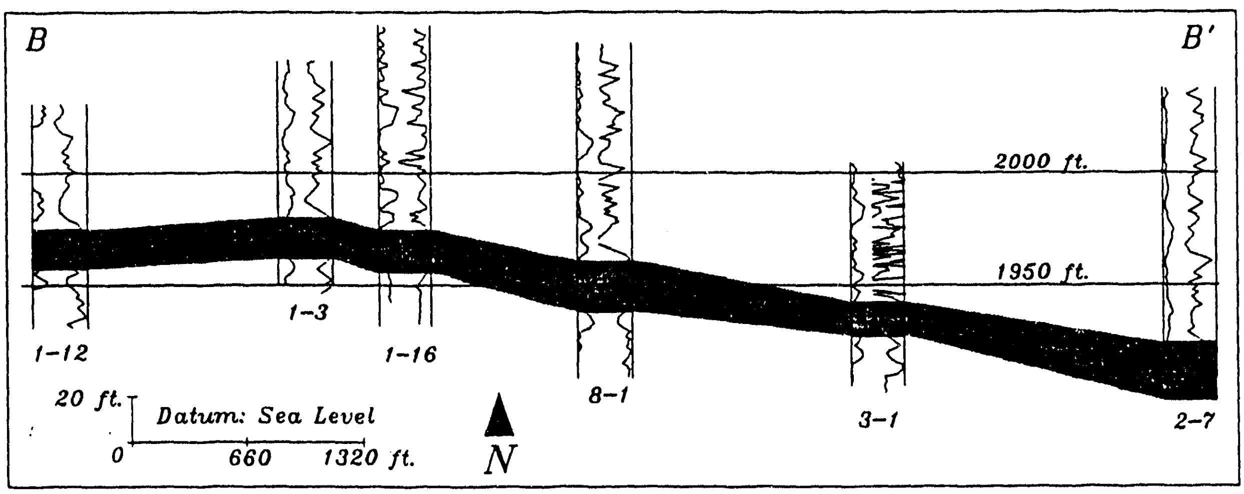

Fig. 11. B-B', W-E log cross-section.

The structure in Fig. 12 is seen with the aid of a 3-D view from the southeast direction along the NE-SW A-A' log cross-section.

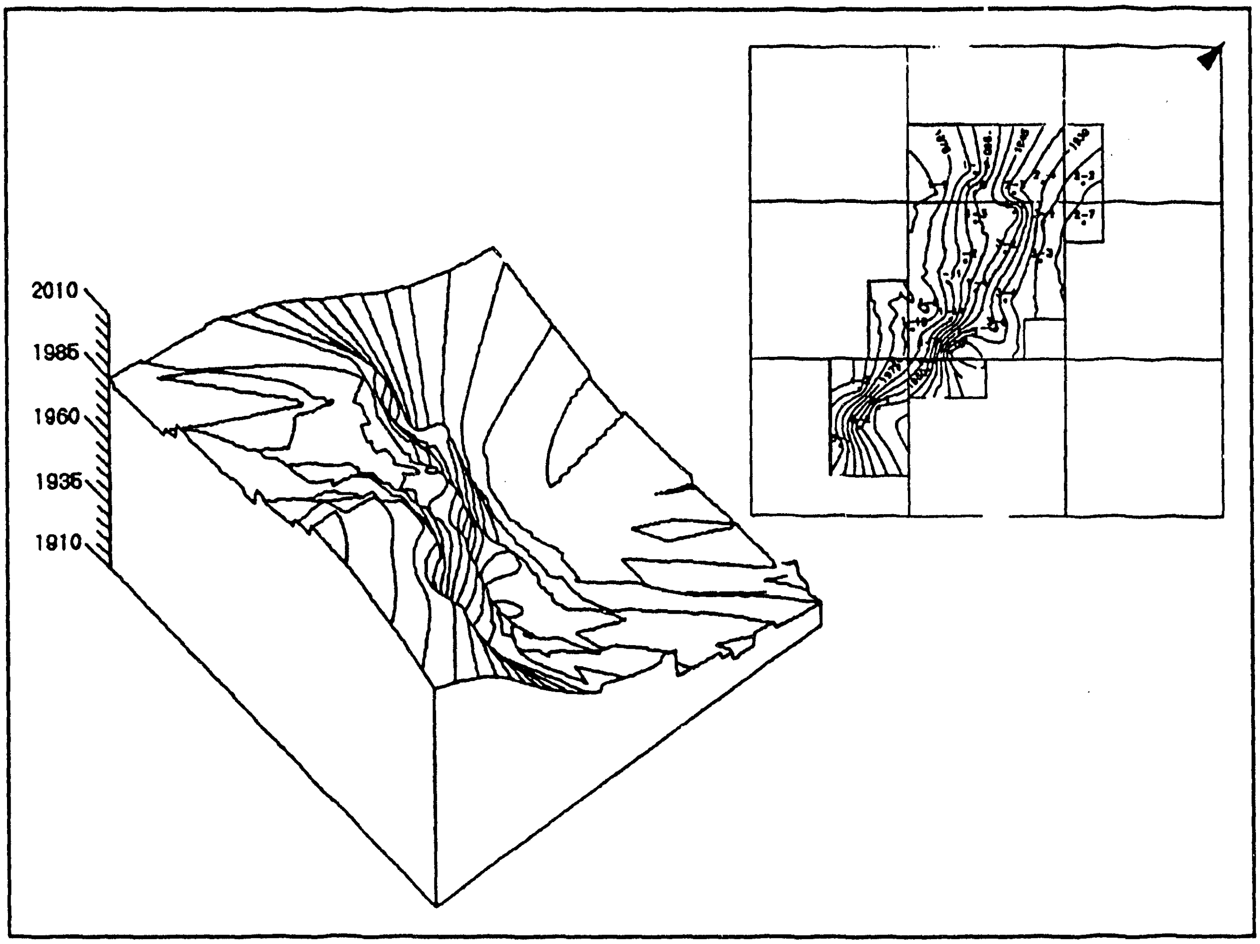

Fig. 12. Sulimar structure map.

Three seismic surveys were recorded and processed by Teledyne during 1982 and 1983. The survey lines, illustrated in Fig. 13, cross the Sulimar Queen and could be acquired from Permian Exploration Corporation to enhance the structural picture.

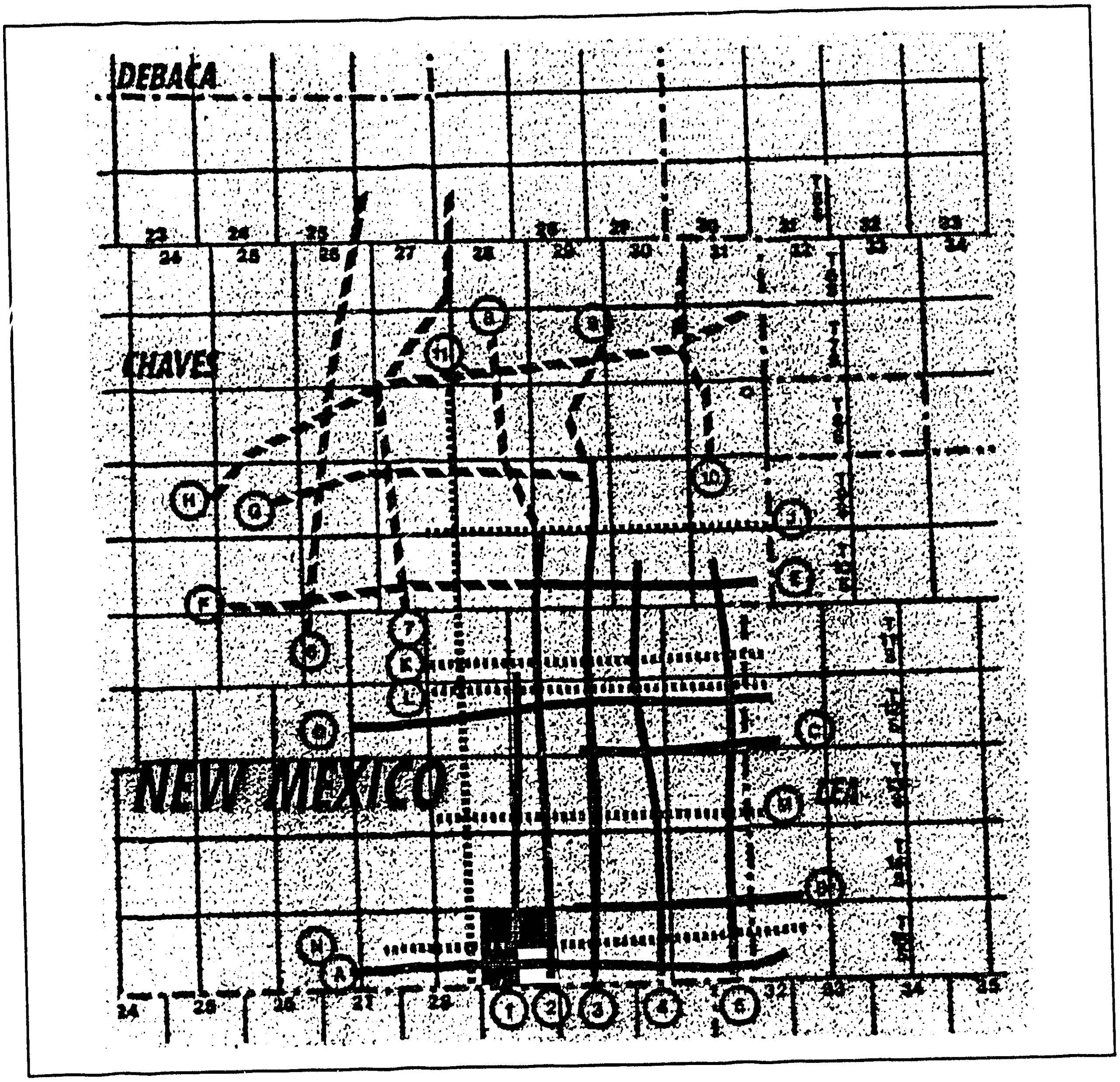

Fig. 13. Seismic survey lines. Note Sulimar in 15S-29E.

Fieldwide performance history is seen in Fig. 14. Waterflooding commenced during December 1971.

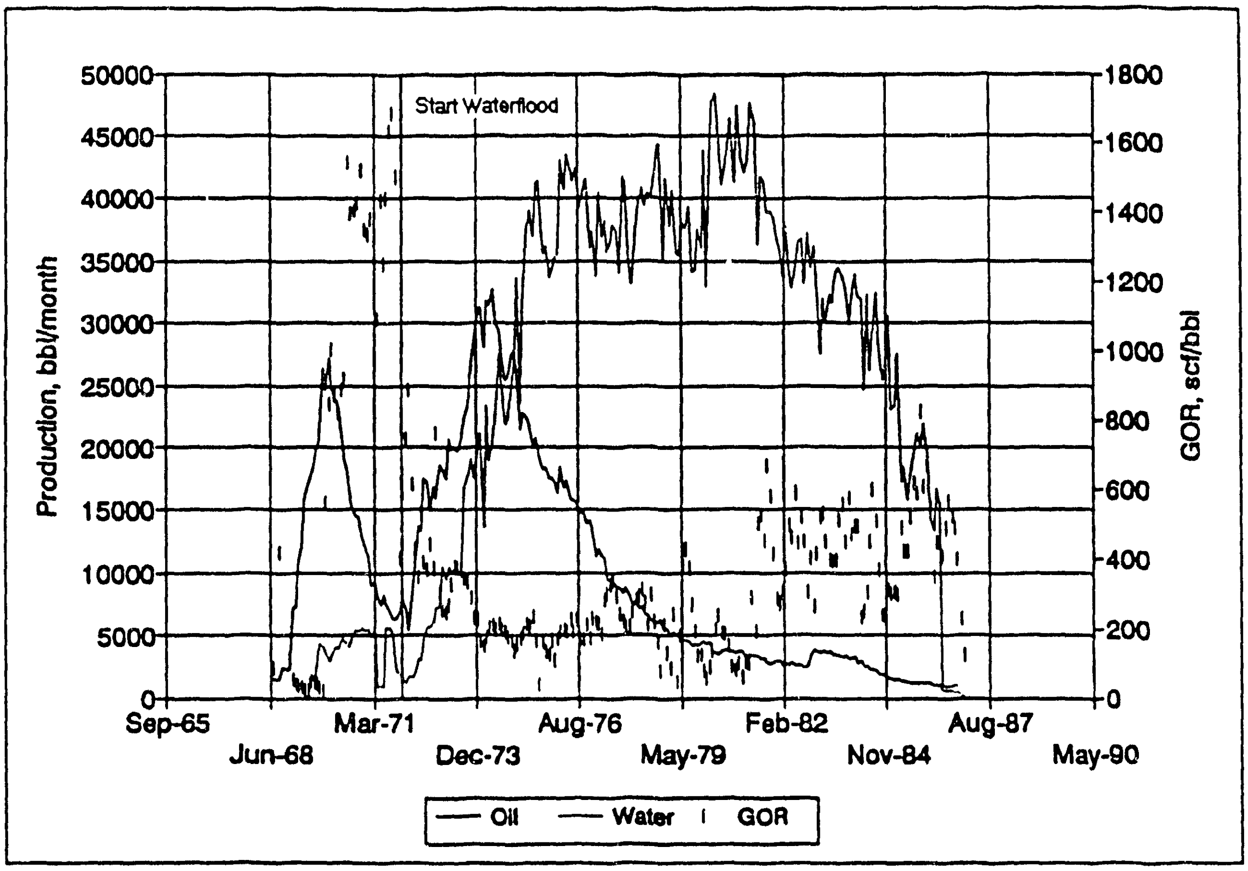

Fig. 14. Sulimar Queen performance history.

Through December 1971, the field produced 532,019 STB oil, 389,615 mscf gas, and 114,095 bbl water, primarily by gas expansion. Since then, an additional 1,481,877 STB oil, 329,966 mscf gas, and 5,180,009 bbl water have been produced with the injection of 10,424,524 bbl of water through 1989. The current average oil saturation is estimated to be 39% PV.[1]

The production response, presented as percent oilcut versus cumulative barrels of oil by well, is mapped in Fig. 15.

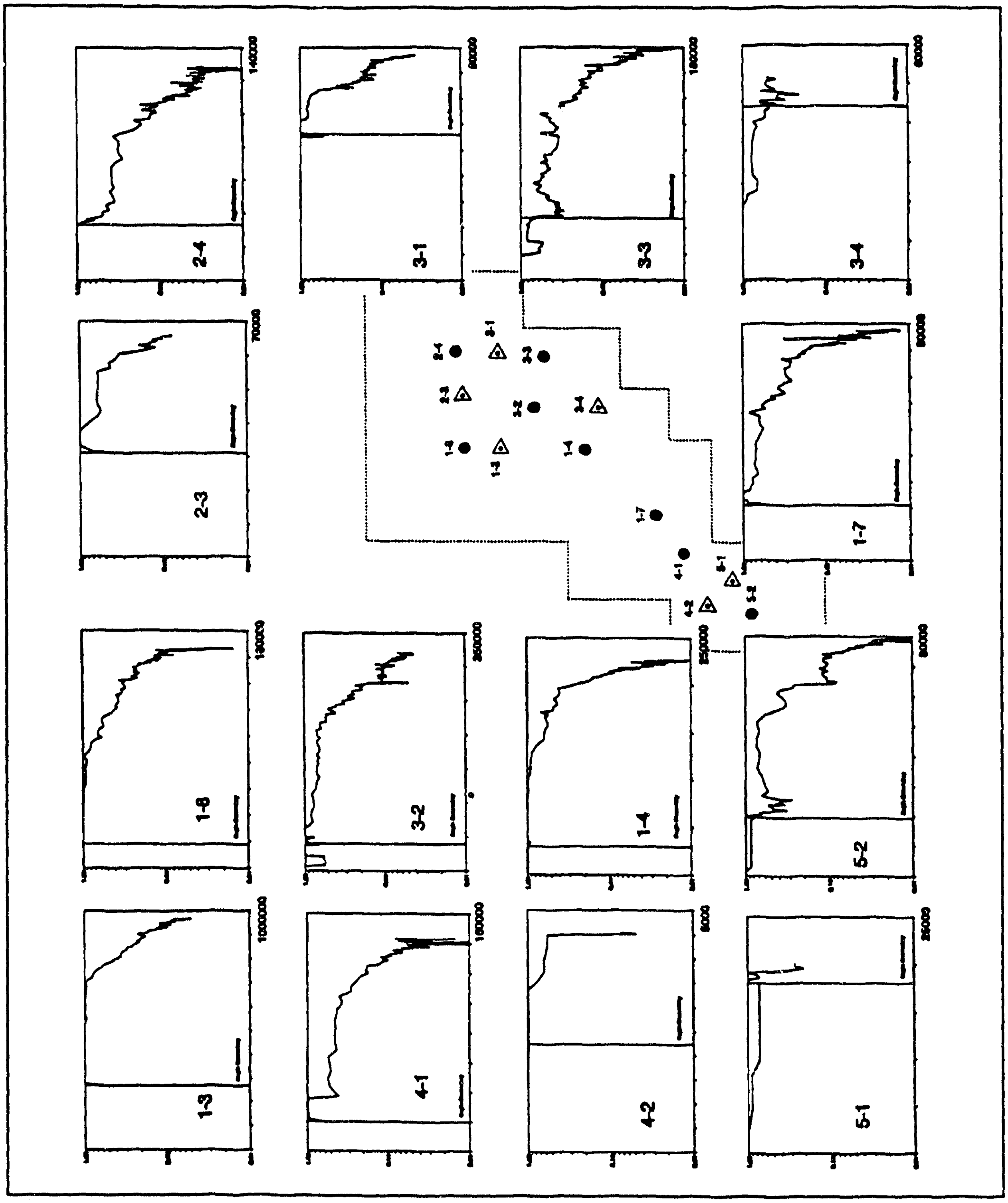

Fig. 15. % oilcut map.

Wells on the east side of the field at the water-oil contact were producing at less than a 100% oilcut prior to water injection because of a weak, edgewater drive. Note the increase in the oilcut from the wells as they responded to the waterflood, confirming that the natural water influx was weak.

The injection versus production graph, illustrated on Fig. 16, suggests that free gas was produced during the course of the waterflood, or that injection water was lost out of the producing interval.

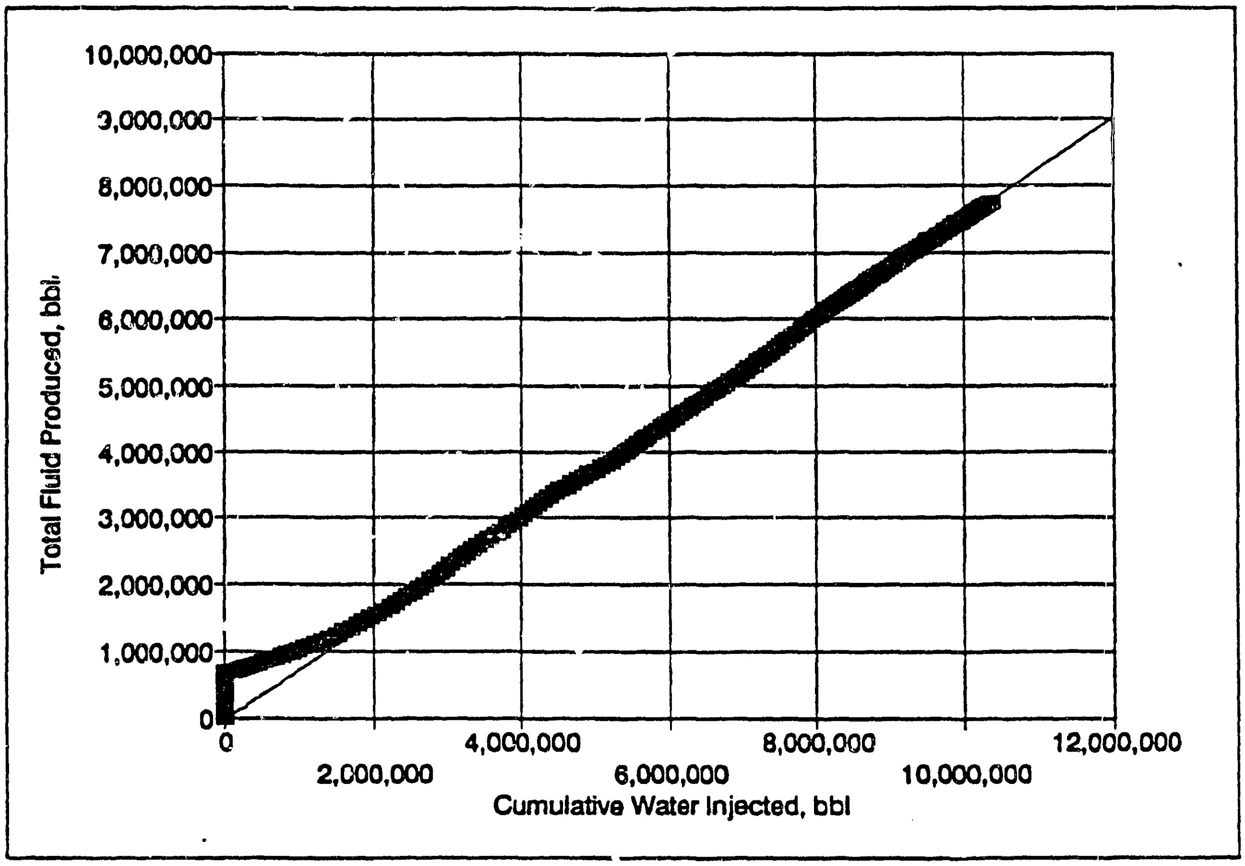

Fig. 16. Injection vs. production.

Static pressures were measured with a bottomhole pressure bomb during July 1990 and corrected to +2,027 ft, which was the minimum fluid level. The equal pressure contours are presented in Fig. 17. The lateral pressure gradient is about 0.2 psi/ft towards the south.

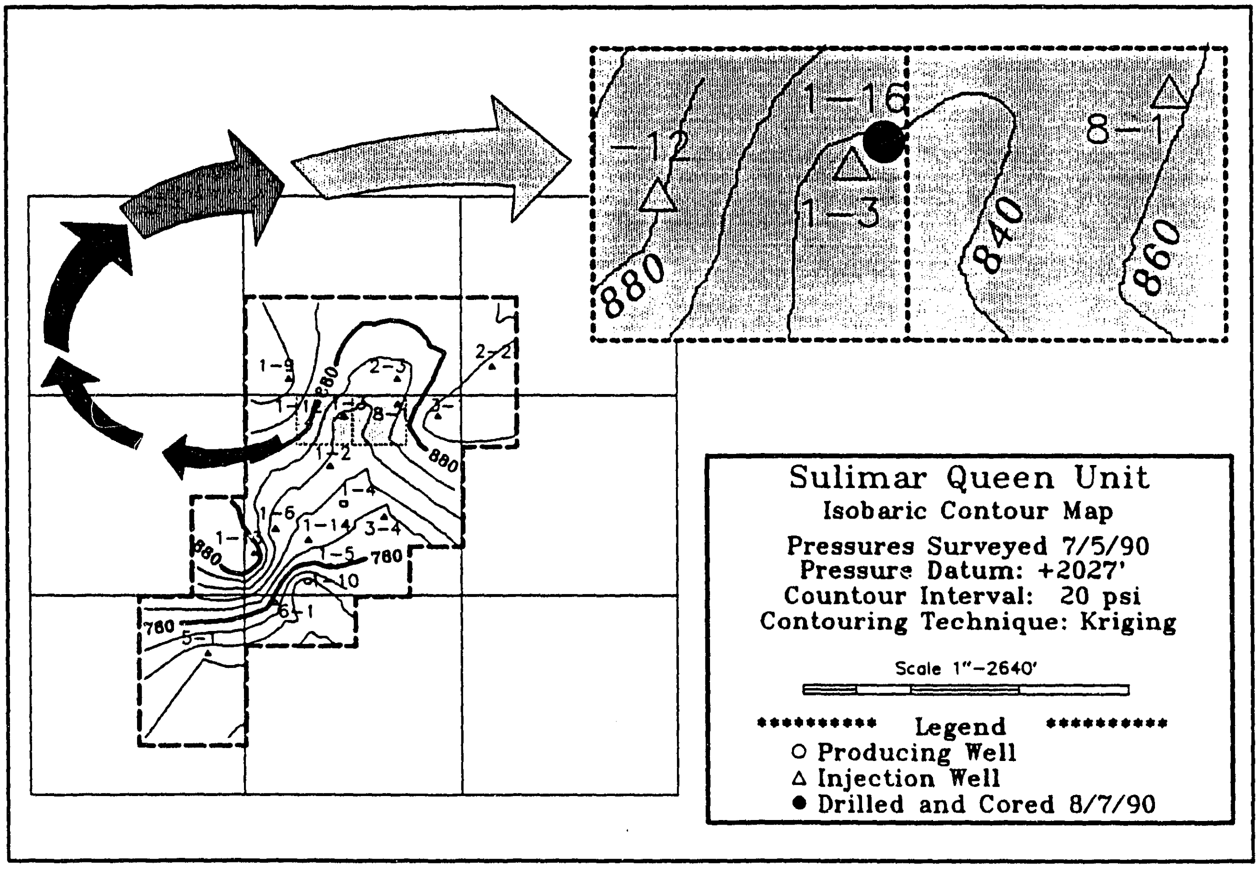

Fig. 17. Isopressure map.

Megascopic Scale

A pressure buildup test was conducted in Well 1-15 during March 1991. The diagnostic plot is shown in Fig. 18 and a MDH plot of the test data is presented in Fig. 19.

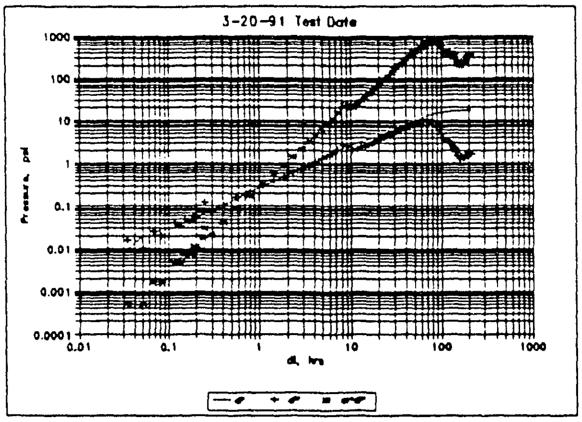

Fig. 18. Well 1-15 diagnostic plot.

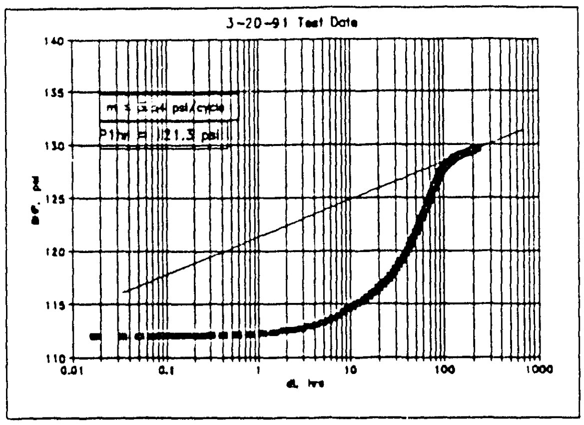

Fig. 19. Well 1-15 pressure buildup plot.

Automatic fluid level measurement equipment was used to collect the Well 1-15 pressure-time history. It was thought that the well was damaged since production was 3.25 bbl/day yet bottomhole pressure was believed to be 840 psi as seen in Fig. 17. The diagnostic plot suggests that the radial flow period begins at 150 hr where the (dt)(dp') plot has a unit slope.[10] The straight line through the 150-hr-to-the-end-of-the-test data points is seen in the MDH plot. Since the well produced 3 bbl of water and 0.25 bbl of oil, the analysis is based on a 3.25 bbl/day water flow rate. The appropriate calculations suggest that the permeability is 24.6 md, which agrees with the porosity-permeability correlation seen in Fig. 23, assuming the average porosity is 20%. Surprisingly, skin is -2.8 and static pressure at +2,027 ft is 150 psi. It is apparent that there is a barrier between Well 1-15 and the portion of the field that was waterflooded.

Sulimar Queen wells were generally drilled with cable tool rigs, and openhole logs were not run. Gamma ray and neutron well logs were run through casing to select perforating intervals. The logs can be used to correlate the zone from well to well as was done in Fig. 10 and 11. Generally, the neutron logs were not calibrated, which limits their usefulness as a porosity tool.

Macroscopic Scale

Three wells, including the newly drilled (August 1990) data acquisition Well (1-16 in Fig. 17), have been cored. Modern openhole logs were run in Well 1-16 and an oriented core was cut. The log response, core analyses, and core description are summarized in Fig. 20.

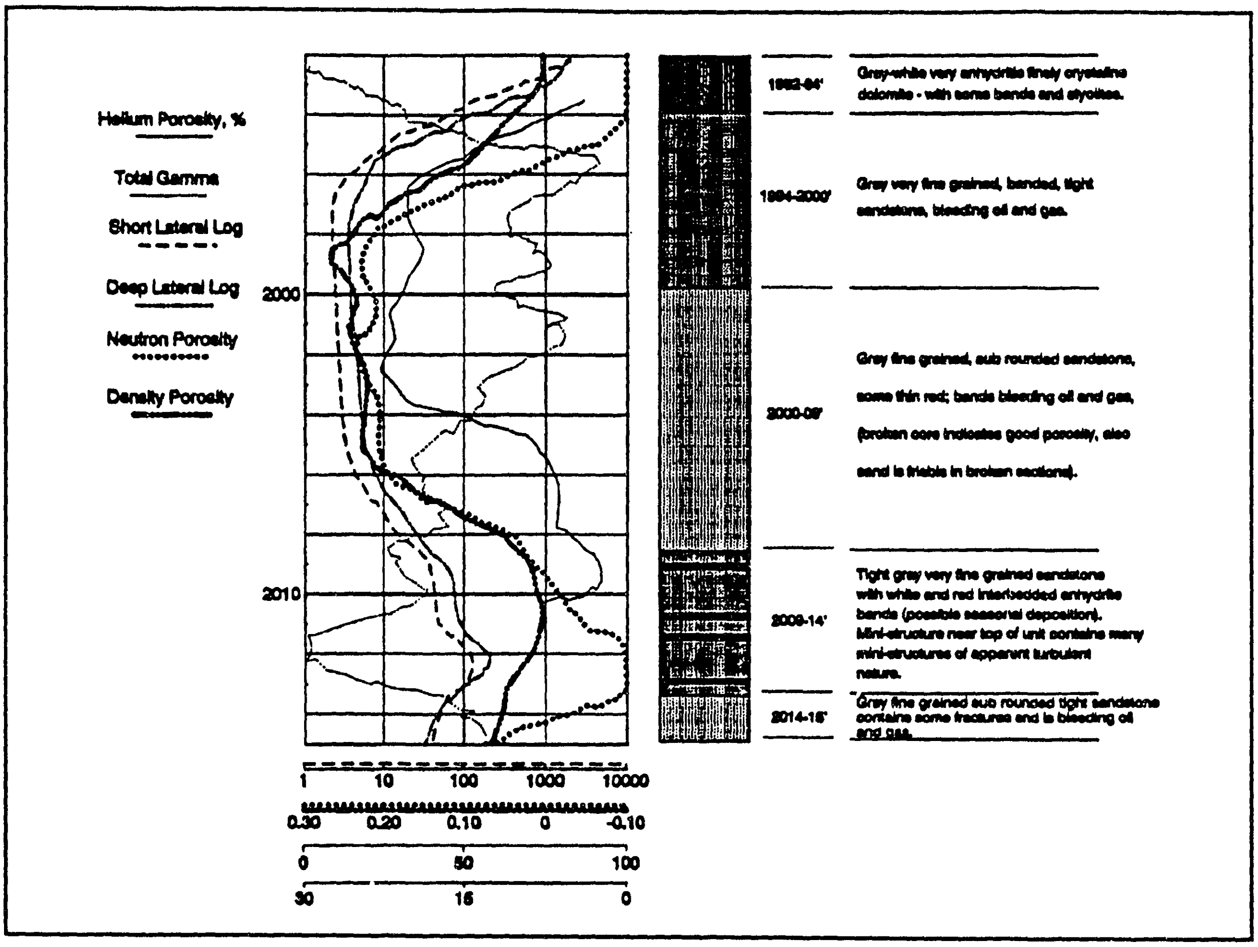

Fig. 20. Summary of log response, core analyses, and core lithology.

From the resistivity logs, the average water saturation of the Queen formation in the vicinity of Well 1-16 is calculated to be 45%. The well location, 460 ft from a west-offset injection well and 2,300 ft from an east-offset injection well, was selected based on the need for maximum reservoir core material, and the need for a closely spaced well pair for interwell tracer, pressure, and seismic field experiments. Trapped oil was anticipated and the low water saturation suggests that the data well will produce oil. The zone has not been perforated and the volume of the trapped oil remains to be determined.

In an attempt to develop a method to analyze the old well logs, Well 1-16 core porosity was correlated with the gamma ray log in Fig. 21. Evidence of top and bottom zones can be seen in the correlation. However, when the same technique is applied to core data from Wells 5-1 and

1-14 the correlation is less apparent. It does seem that if the API gravity exceeds 50° in the top zone, porosity could be 15% or greater, which may be useful information when working with other Queen fields.

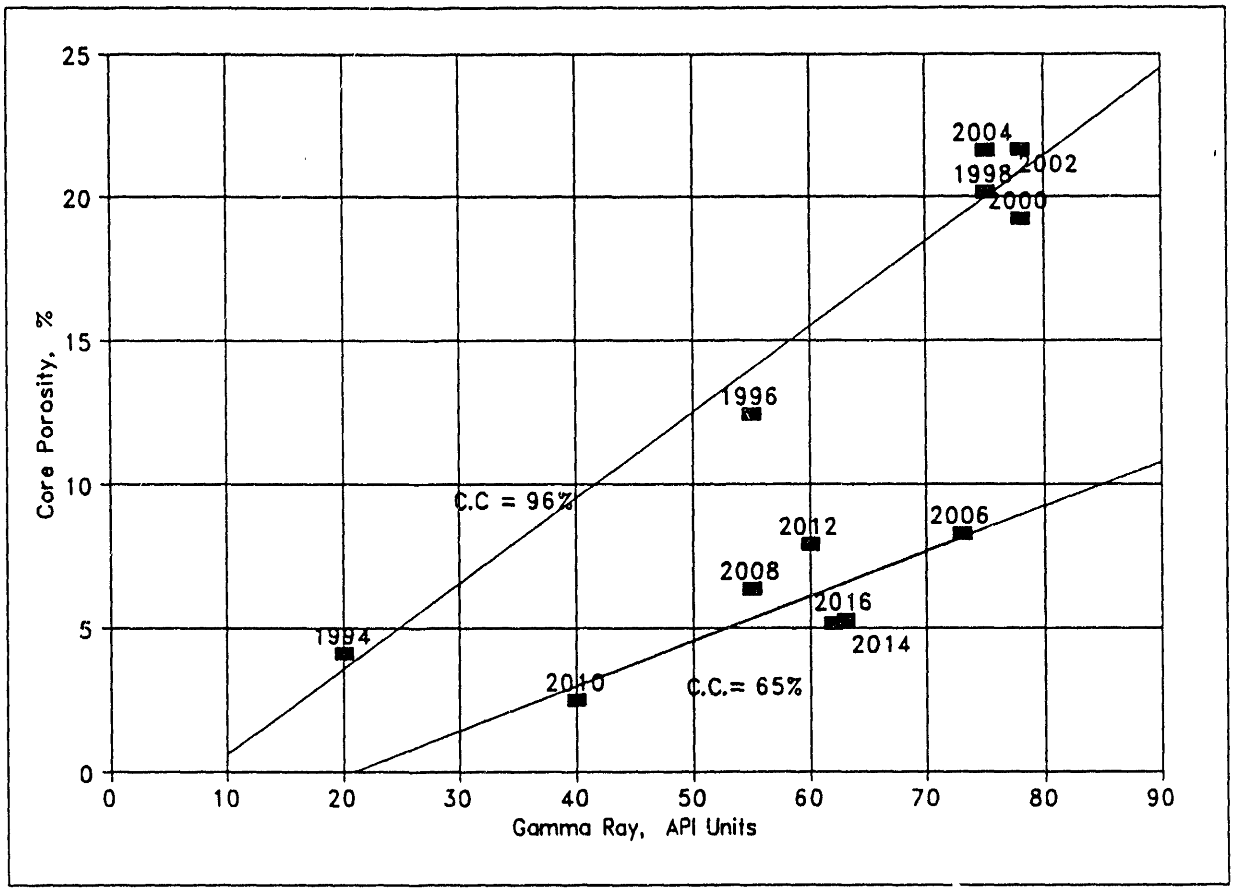

Fig. 21. Porosity vs. gamma ray response.

Whole-core analyses from Well 1-16 are provided in Table 2. The presence of directional permeability is not clear from the oriented core permeability analyses. The 1,997 ft interval seen in Table 2 suggests that the reservoir may not be isotopic, but the reported directional permeabilities in the other intervals are rather uniform. Interwell tracer and pressure tests may prove to be a better means of determining anisotropy than the oriented core.

Table 2
Well #1-16 Core Analysis

SAMPLE NUMBER		DEPTH ft	PERMEABILITY 90 DEG md	K/S md	E/W md	NE/SW md	NW/SE md	POROSITY (HELIUM) %	SATURATION (PORE VOLUME) OIL %	WATER %	GRAIN DENSITY gm/cc	DESCRIPTION
		CORE NO. 1 1984-2015 CUT 31' REC 31'										
		1984.0- 88.0										NA Sh salty v/dol
		1988.0- 92.2										NA Dol slt/anhy
		1992.2- 93.0										NA Dol
	1	1993.0- 94.0		<.01	0.06	<.01	1.00	4.1	0.0	85.3	2.83	Dol slt/shy sh lam
S	2	1994.0- 95.0		0.40	0.13	0.04	0.04	9.6	7.0	80.8	2.70	Sd shy sh lam
S	3	1995.0- 96.0		76.0	77.0	71.0	72.0	15.4	13.2	75.4	2.83	Sd slt/lam
S**	4	1996.0- 97.0						20.2	25.5	44.4	2.66	Sd
S	5	1997.0- 98.0		34.0	54.0	45.0	72.0	20.2	19.4	70.3	2.62	Sd
S**	6	1998.0- 99.0						18.8	19.4	71.9	2.67	Sd sh lam
S*	7	1999.0- 00.0	4.30					20.1	30.4	52.8	2.67	Sd sh lam
**	8	2000.0- 01.0						22.0	20.2	64.7	2.67	Sd
S**	9	2001.0- 02.0						21.4	26.9	50.6	2.67	Sd v/shy sh lam
S**	10	2002.0- 03.0						23.2	32.0	41.7	2.67	Sd shy sh lam F
S*	11	2003.0- 04.0	85.0					20.1	20.8	64.3	2.67	Sd shy sh lam
*	12	2004.0- 05.0	4.10					9.4	20.0	44.1	2.71	Sd sh lam
S	13	2005.0- 06.0		0.32	0.32	0.32	0.21	7.2	14.8	78.2	2.71	Sd slt/shy sh lam
*	14	2006.0- 07.0	0.00					6.3	6.2	82.4	2.74	Sd
S	15	2007.0- 08.0		0.49	0.35	0.42	0.35	6.4	6.9	87.1	2.76	Sd slt/shy sh lam
S	16	2008.0- 09.0		<.01	<.01	<.01	<.01	3.0	23.7	52.3	2.74	Sd clay
S	17	2009.0- 10.0		<.01	<.01	<.01	<.01	2.0	22.2	49.6	2.78	Sd v/clay
*	18	2010.0- 10.2	0.11					7.9	4.8	78.8	2.80	Sd dol anhy shy
		2010.2- 12.7										NA Anhy
	19	2012.7- 13.0		0.09	0.00	0.09	0.00	4.1	33.5	57.7	2.77	Sd slt/dol slt/shy slt/clay
S	20	2013.0- 14.0		0.14	0.17	0.17	0.17	6.2	19.4	54.5	2.67	Sd clay slt/shy
	21	2014.0- 15.0		0.05	0.05	0.02	0.05	5.3	12.0	62.1	2.71	Sd slt/shy sh lam

Correlations between porosity and permeability, and permeability and oil saturation are illustrated in Figs. 22 and 23.

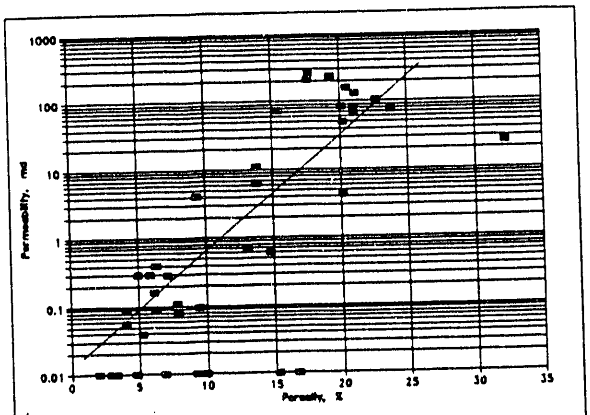

Fig. 22. Porosity vs. permeability.

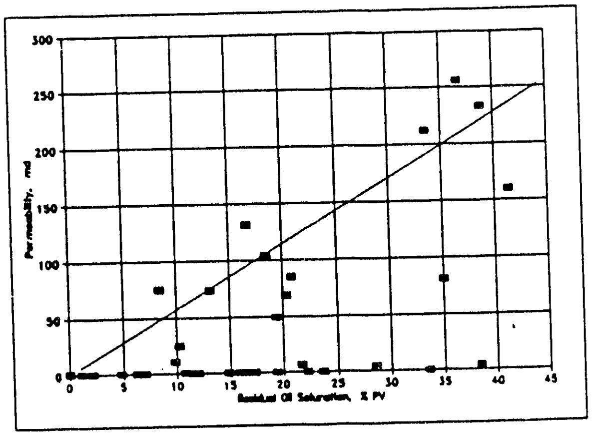

Fig. 23. Permeability vs. S_{or}.

There is a general increase in permeability with porosity as seen with the trend line. Well testing is probably the best method of estimating average permeability and directional trends in a field. Slug testing could be an especially effective transient testing technique prior to activating the field.

The residual oil saturation-permeability correlation (from core analyses) seen in Fig. 23 is weak, probably because of clay present in the reservoir. The proper residual oil saturation is of major importance in reservoir characterization, especially when selecting relative permeability data for simulation work.

It can be seen in Fig. 24 that the variation in the vertical permeability distribution is more or less log normal. A Lorenz type permeability plot is presented in Fig. 25.

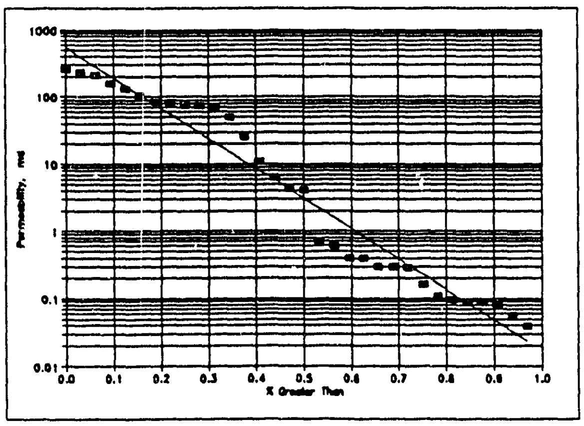

Fig. 24. Vertical permeability distribution.

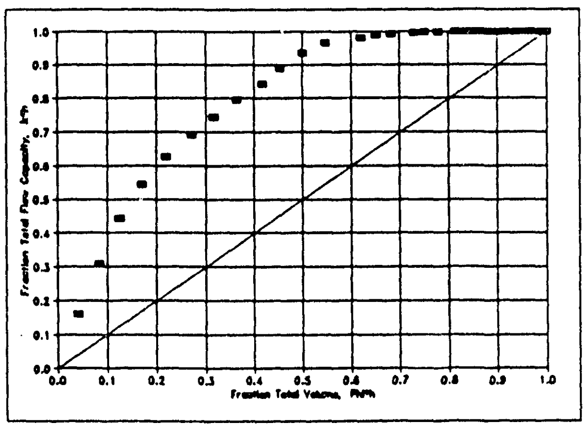

Fig. 25. Lorenz coefficient = 0.64.

The Lorenz coefficient is 0.64 which suggest a heterogeneous reservoir. Since waterflood production was almost three times that of primary, it is apparent that factors other than the heterogeneous nature of the permeability distribution affect recovery. Hence, there is a need to determine the in-situ wettability along with suitable capillary pressure and relative permeability relationships.

Microscopic Scale

Neasham[11] described three categories of dispersed clay using a scanning electron microscope. The categories are discrete particles, linings on pore walls, and bridges across pores. The three types of dispersed clay are illustrated in the left side of Fig. 26 with drawings from Ref. 11. The example photomicrographs in the center of Fig. 26 are from Ref. 12. The photomicrograph on the right of Fig. 26 is from the Sulimar data acquisition Well 1-16 core. The presence of chlorite was confirmed by the dominance of chlorite in the energy dispersive spectroscopy analysis. It is possible that illite is also present, but masked by the chlorite.

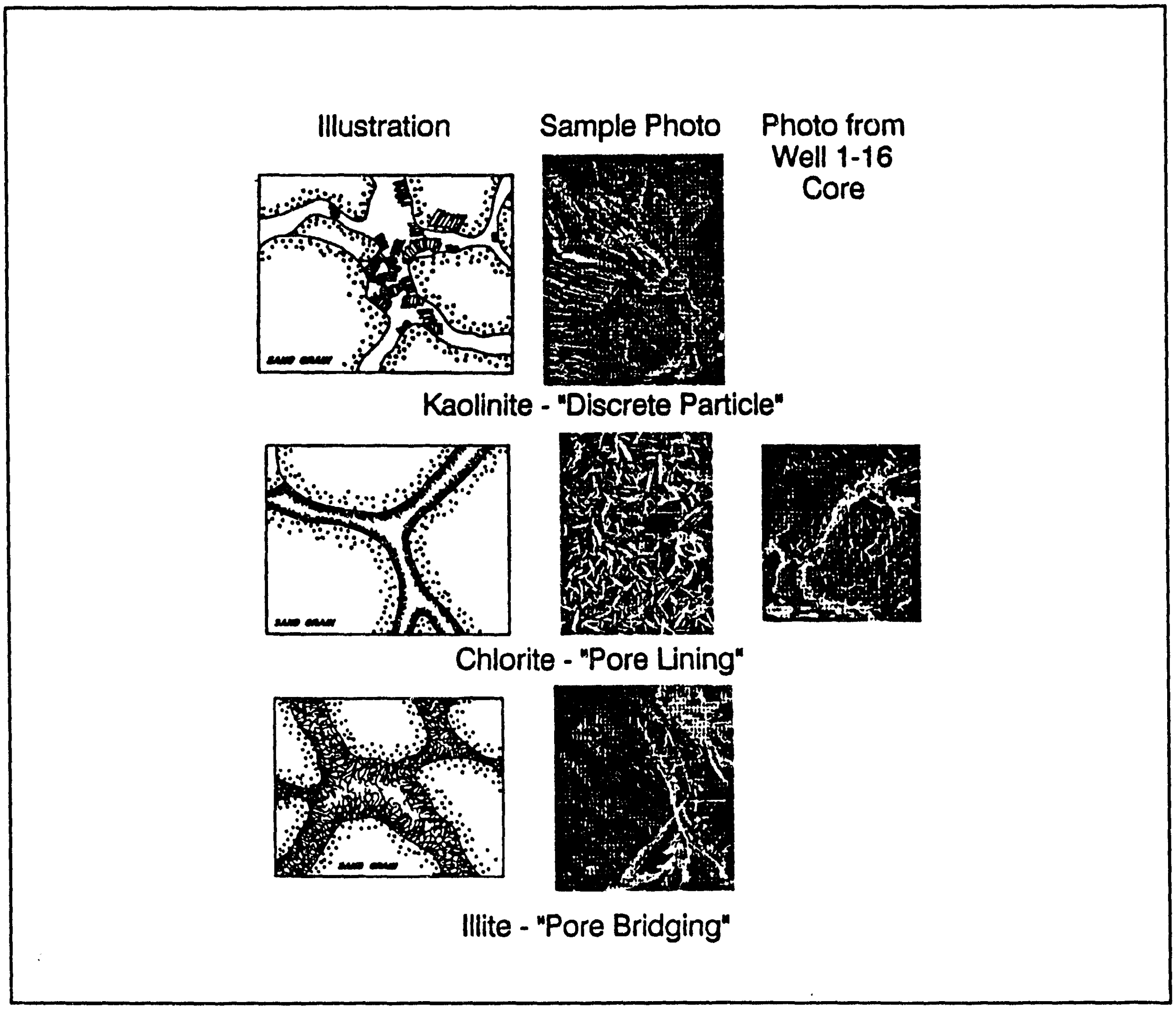

Fig. 26. Dispersed clay examples.

The Well 1-16 photomicrograph above is from the pay interval (1,994-2,000 ft in Fig. 21). Inspection of the lower interval (2,009-2,014 ft) photomicrographs suggests that the pore space is filled with diagenetic anhydrite.

Well 1-15, located two locations north of the data acquisition well as seen in Fig. 9, is currently the only producing well in the field. A sample of crude oil was collected from Well 1-15 on April 26, 1991. The oil analysis (plus a repeat run) is illustrated in Fig. 27 as a mole fraction and in Fig. 28 as a weight fraction. From the cumulative mole fraction, 57.5% of the sample is C_{10} or less while 33.9% of the sample by weight fraction is C_{10} or less. The equivalent molecular weight is 179, based on a normal alkane series.

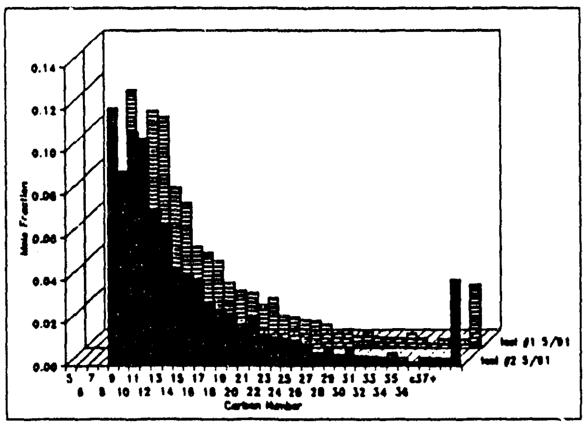

Fig. 27. Mole Fraction

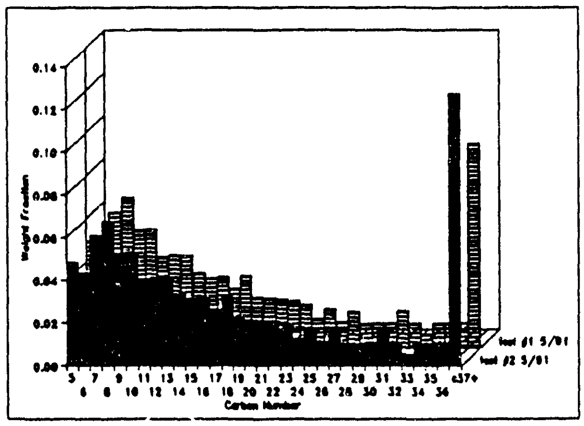

Fig. 28. Weight Fraction

The viscosity of the oil sample is 9.8 cp at 60°F, 6.7 cp at 77°F, and 4.0 cp at 113°F (reservoir temperature). The crude oil density at 60°F is 0.841 gm/cc which yields a gravity of 36.8°API. Overlying the oil zone is a gas zone that contains relatively high quantities of nitrogen (see Table 3).

Table 3
Analysis of Queen Gas
Sulimar Queen Unit

Sample: Produced Gas from Field Discovery Well (Lisa Federal #1-C)

Date: 9-6-68

BTU: 702	SP. GR.: 0.902	MOL. WT.: 27.6	BOPD: 51	GOR: 277

ANALYSIS	
	MOL. %
hydrogen sulfide	0.00
carbon dioxide	0.10
nitrogen	50.81
methane	34.32
ethane	8.17
propane	3.01
isobutane	0.44
n-butane	1.22
isopentane	0.48
n-pentane	0.58
hexanes	0.57
heptanes	0.40

History of the Equipment and Facilities at the Sulimar Queen Unit

McClellan Oil Corporation discovered the Sulimar field in 1968 when they drilled the Lisa Federal #1-C in the NE 1/4 of the NE 1/4 of section 24, T15S, R29E. Developmental drilling of the Sulimar field proceeded from 1969 to 1979. The Sulimar field development was based on a 40-acre well spacing pattern. All wells (excluding those that were cored) in the field were drilled with cable tool drilling rigs. Driller's logs describing the types of rock cuttings and fluids swabbed from the hole were recorded. If hydrocarbons were recovered during swabbing (in viable amounts), the well would usually be completed.

Producing wells were generally completed by setting 5-1/2" production casing, and logging the hole with a gamma-ray/neutron logging suite for correlation and perforation control. The pay zone was usually perforated at a density of two shots per foot. Most wells were then treated with a small acid stimulation (200 gallons) to clean up the perforations, and then fractured with 20,000 gallons of treated water and 30,000 pounds of sand proppant. Wells were then produced through production tubing (2" or 2-3/8"). Production packers were not employed in most producing wells.

In 1972 a unitized waterflood project was initiated, and fresh water was used for injection. An analysis of the fresh injection water is given in Table 4.

Table 4
Water Analyses Results
Sulimar Queen Unit

SAMPLE #	SOURCE	DATE
1	Produced Water from Well 1-15	7-31-90
2	Fresh Water from Waterflood Plant	8-22-79

SAMPLE #	TEMP	pH	H_2S	SPECIFIC GRAVITY	RESISTIVITY
1	90°F	6.2	0	1.2073	0.052 ohms/m
2	80°F	7.9	0	1.0003	-

CONSTITUENT	SAMPLE #1	SAMPLE #2
Alkalinity as HCO^{-3}	205.0	195.0
Chlorides as Cl^-	188,900.0	52.0
Sulfates as SO_4^{-2}	2,910.0	44.0
Hardness as $CaCO_3$	42,000.0	280.0
Calcium as Ca^{+2}	2,120.0	80.0
Magnesium as Mg^{+2}	8,920.0	19.0
Iron as Fe^{+2} or Fe^{+3}	16.9	0.5
Total Dissolved Solids (calc)	307,700.0	390.0

With the exception of Temperature, pH, Specific Gravity, and Resistivity, results are expressed as milligrams per liter.

Injection wells were completed in a similar fashion to the producing wells in the field. Similar perforating and completion schemes were employed in the injection wells. Packers were set in some, but not all, of the injection wells.

A well-by-well summary of data including well completion schemes, inventory of tubulars, and a basic schedule of drilling and production has been compiled.[1]

After the waterflood was terminated in 1986, all of the wells, with the exception of Well 1-15, were shut in and temporarily abandoned. All of the temporarily abandoned wells could be reactivated for subsequent tests. The waterflood plant remains intact and is used to dispose of accumulated produced water. The plant consists of water and oil storage tanks and a high pressure injection pump. Oil/water separators and oil and water storage tanks are located near the oil sales facility. An analysis of brine produced from Well 1-15 is provided in Table 4. Since this well was not affected by the waterflood, this analysis should closely represent connate water in the Queen Sand. A recent analysis of the hydrocarbons present in the produced water is shown in Table 5. As the analysis shows, the BTX (benzene, toluene, and xylene) levels are quite low.

Table 5
Hydrocarbon Present in Produced Water
Sulimar Queen Unit

Sample: Produced Water from Well 1-15
Date: 7-31-91

METHOD: EPA 418.1	
COMPOUND	mg/L
Total Petroleum Hydrocarbons	983

METHOD: EPA 524.2	
COMPOUND	mg/L
Benzene	1.64
Toluene	2.74
Ethyl Benzene	0.19
Total Xylenes	0.44

All of the facilities are operational or can be made operational with minimal effort. The facilities are sufficient and appropriate for the types of studies envisioned for NMIORP. On the basis of the work done to date and discussed in this report, the Sulimar Queen Unit is judged to be suitable for the purposes and needs of the NMIORP.

POSSIBLE FUTURE TESTS AT THE NEW MEXICO IMPROVED OIL RECOVERY PROJECT

EVALUATION OF RESERVOIR WETTABILITY

A laboratory study could provide baseline wettability data using reservoir rock and fluid samples. Recommendations could be made on methods of obtaining appropriate samples for wettability studies in the laboratory. Wettability assessment could be made on the basis of the following procedures: 1) Amott imbibition and displacement core tests; 2) adhesion mapping to determine regions of adhesional behavior as a function of aqueous phase pH, ionic strength and composition; and 3) micromodel displacements. These baseline data can be used to predict the effects of enhanced recovery techniques on reservoir wetting and thus on oil recovery.

A field wettability test could then be conducted using single-well tracers. A recommended procedure is:[13] 1) inject tracers in water, shut in, produce tracers, and measure concentrations and flowing pressure; 2) inject tracers in oil, shut in, produce tracers, and measure concentrations and flowing pressure; and 3) history match tracer production and reservoir pressure using a suitable simulator by adjusting relative permeability, capillary pressure, and capacitance-dispersion parameters. The ratio of the end point relative permeabilities can be used to infer wettability or the relative permeabilities; capillary pressure and capacitance parameters can be compared with data from core floods. Nonwetting phases will show more capacitance. Formation properties such as permeability and permeability variations will tend to cancel out since both water and oil are injected and produced.

MIXING EXPERIMENTS IN RESERVOIR CORES

Attempts at scaling mixing parameters obtained from laboratory scale displacements to field scales have been largely unsuccessful. Most likely, the problems with scaling arise from variations in the mixing behavior throughout the reservoir. Studies at NMIORP could examine both the areal and vertical mixing behavior and attempt to predict larger scale mixing behavior.

The mixing of fluids while flowing through a porous media depends on the surface and body forces on the fluids, the transport properties of the fluids, and the geometry of the pore spaces through which the fluids are flowing. Even the simplest porous media (i.e., a uniform bead pack) has an incredibly complicated pore space geometry, and the geometry of the pore space of reservoir rocks has a whole progression of increasing complexity. Likewise, the complexity of fluid combinations progresses from the simplest (i.e., single-phase, matched density, matched viscosity) to extremely complex (i.e., multiple phases, unmatched density and viscosity). In laboratory measurements of the fluid mixing in reservoir rocks, the complication of the pore space cannot be controlled. However, the complexity of the fluids may be controlled so that useful measurements of mixing may be obtained. As the complexity of fluids increases, the time required for obtaining measurements also increases.

Samples of rock from the producing formation could be used for the study. Two types of mixing experiments could be performed on laboratory cores prepared from these samples: miscible displacements, and two-phase displacements in which the fluids are matched in density and viscosity. Mixing behavior can be correlated with measurements made on thin sections of the same rock samples. The results of the mixing measurements can then be used to predict the mixing that occurs in field scale tracer tests and displacements during production operations.

NEW SINGLE-WELL TEST METHODS OF RESERVOIR CHARACTERIZATION WITH TRACERS AND PRESSURE TESTS

Pressure transient testing is traditionally used to characterize average flow properties such as kh and skin around a well (single well test). A single-well test could be used to gather and analyze pressure transient data in combination with tracers in a single-well test.

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Analysis of the travel time and waveform of acoustic signals transmitted through the reservoir can provide information on the continuity of lithology between the closely-spaced wells. Results of these tests can be compared to the tracer tests and core analysis.

INTEGRATION OF GEOLOGICAL, GEOPHYSICAL, AND ENGINEERING PARAMETERS FOR RESERVOIR SIMULATION

A key issue for numerical simulation is posed by the difficulty in adequately simulating the physical phenomena, which range in scale from the microscopic to reservoir-scale, in a model that is efficient and cost-effective to use.

Field measurements could be used to estimate the variability and statistical correlation scale associated with reservoir properties. Roughly speaking, these scales give an indication of the average distance over which features are interrelated. They are generally important in flow predictions and in calculating the uncertainty associated with such predictions. These measurements, along with "soft" geologic measurements, acoustic data, and other information can further be used to create geological maps and also maps of features that control flow and transport. The geostatistical approach not only offers alternatives to contouring, but can also be used to incorporate the subsurface maps with other data, to incorporate seismic profile data, etc. Methods like kriging, co-kriging and "soft" kriging can be used to combine the data for maps of associated properties; note, though, that these maps generally represent "smoothed" versions or estimates associated with the actual field.

The stochastic approach could be used to study interrelationships between the geological or other parameters and flow predictions. This method has been used in groundwater hydrology and also in some of the current research on modeling petroleum reservoir heterogeneity and its effects. More precisely, the flow and transport equations are treated as stochastic differential equations with random inputs quantified by the correlation behavior discussed above. The solutions to these equations, in turn, then contain the random or spatial variability within them. There are some analytical methods available (e.g., spectral methods) for studying restricted cases. These could be used to select the controlling parameters and also to develop averaged or effective equations.

For a field model, a more likely model for interpretation is a Monte Carlo numerical model. To use such a method, fast procedures for generating the required input random fields are needed. These methods, like turning bands and Fast Fourier transform methods, are currently being refined and would be available for this application.

Finally, the stochastic and geostatistical approach is amenable to the important notion of "conditioning" or incorporating data and observations into the reservoir simulation models. Such conditioning should yield more accurate predictions and give more realistic results. Several groups are working on various approaches, and collaborations with a number of individuals at other organizations, are possible.

OTHER RESERVOIR CHARACTERIZATION RESEARCH AREAS FOR NMIORP

In addition to the possible future tests described above, there are a number of complementary tests that a could be performed at a well-characterized field site to provide advances in reservoir characterization. A fairly complete listing of the types of tests envisioned for NMIORP is provided in Table 6. These tests will require increased collaboration amongst researchers and a team effort to provide the interdisciplinary approach necessary for providing the knowledge to maximize oil production from known reservoirs.

Table 6
Reservoir Characterization Research Areas for NMIORP

Outcrop studies	Analysis of production history
Subsurface geology	Well tests
Sedimentology	Pressure
Well logging	Tracer
Standard core analysis	Diagnostic techniques
Advanced core analysis	3-D surface seismic
Diagenesis	Vertical seismic profiling
Pore structure	Interwell acoustic
Clay distribution	Microseismic
Wettability effects	In-situ stress
Fluid flow mixing	Fracture studies
Cores from horizontal wells	Geostatistics
Rock/fluid interactions	Physical and numerical simulation

ACKNOWLEDGEMENT

The authors wish to thank Tim Cowan, Gene Beck, and John MacMillan for conducting the preliminary reservoir study of the Sulimar Queen field. We thank Roy Foster, consulting Geologist, and Neil Whitehead, New Mexico Bureau of Mines and Mineral Resources, for providing geological input, McClellan Oil Company (in particular, Jack McClellan) for their cooperation at all times and their willingness to provide information, and K. Allbritton, Karen Bohlender, Janet Golding, and Cliff Polston for preparing the report. We gratefully acknowledge the financial support of the U.S. Department of Energy and the New Mexico Research and Development Institute.

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