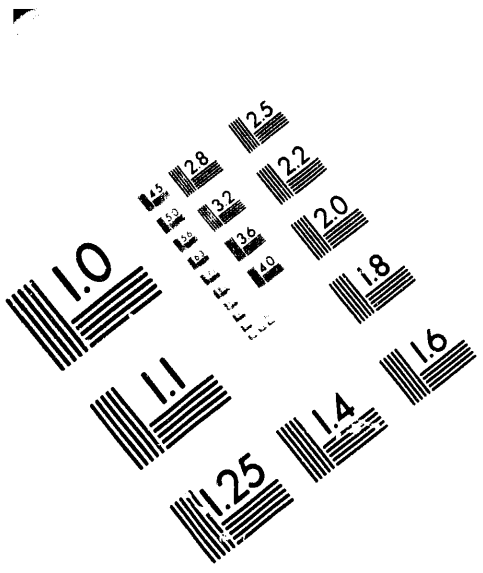
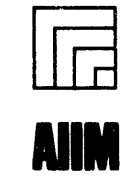
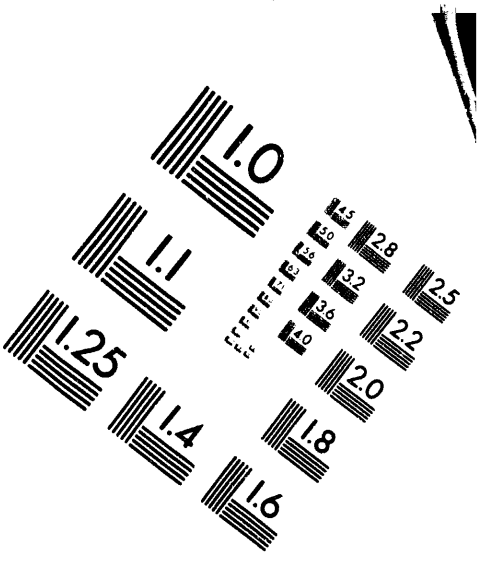
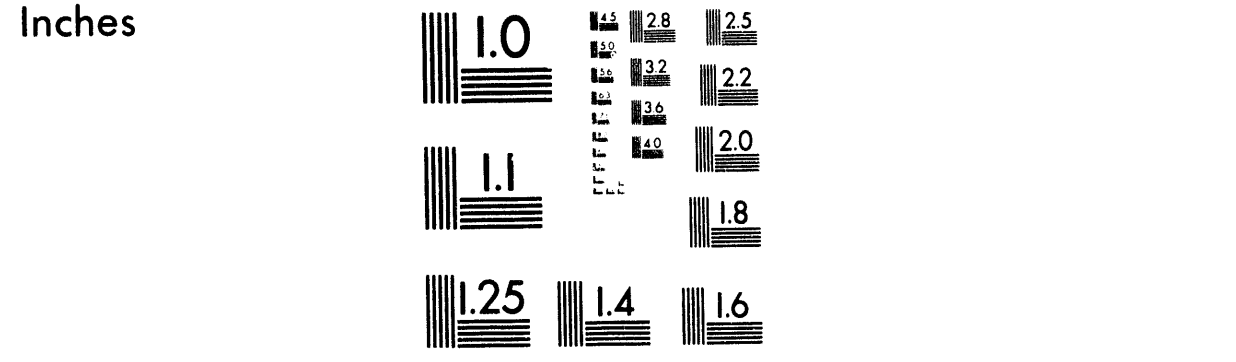
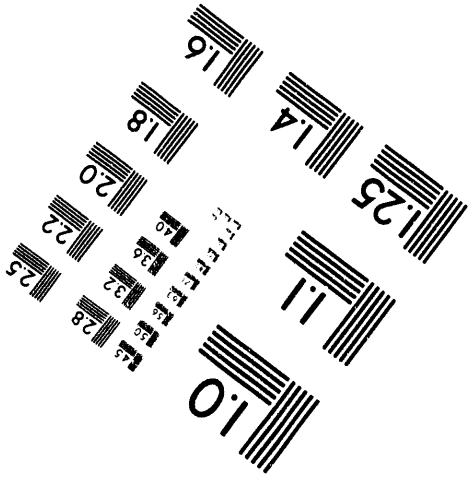




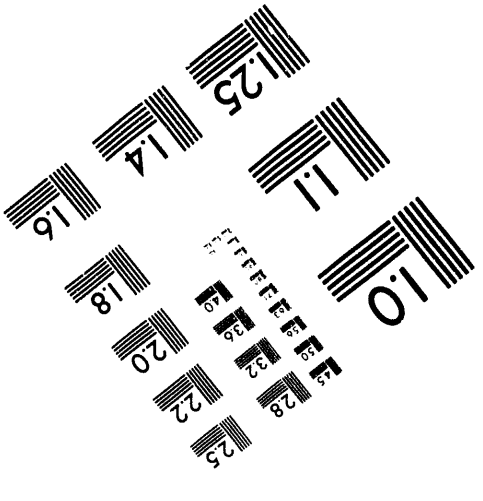
Association for Information and Image Management
1100 Wayne Avenue, Suite 1100
Silver Spring, Maryland 20910
301/587-8202







MANUFACTURED TO AIIM STANDARDS
BY APPLIED IMAGE, INC.



1 of 5

CONF-9305116--

COGA RMAG

Technical Transfer Conference

NEW TECHNOLOGY FOR THE INDEPENDENT PRODUCER

May 6 & 7, 1993 Warwick International Hotel Denver, Colorado

Sponsored by

- *Colorado Oil & Gas Association*
- *Independent Producer's Association of Mountain States*
- *National Institute for Petroleum & Energy Research/Department of Energy*
- *Rocky Mountain Association of Geologists*

General Chairman

Robert M. Cluff, The Discovery Group, Denver, Colorado

Steering Committee

Jeff Ahbe, Union Pacific Resources, Fort Worth, Texas
Edith Allison, Department of Energy, Bartlesville, OK
Suzanne Cluff, The Discovery Group, Denver, Colorado
Howard W. Dennis, Consultant, Denver, Colorado
George H. Fancher, Fancher Petroleum Company, Denver, Colorado
Susan R. Jackson, NIPER, Bartlesville, Oklahoma
S. Duff Kerr, Consultant, Denver, Colorado
William Lancaster, Elk Exploration Company, Denver, Colorado
Jim Mack, TIORCO, Denver, Colorado
R. Randy Ray, R-cubed Exploration, Denver, Colorado

MASTER

IPAMS NIPER/DOE

DISTRIBUTION OF THIS DOCUMENT IS UNLIMITED

Welcome to the Technical Transfer Conference

Many months ago the DOE assembled a panel of "oil experts" to analyze the oil reserve picture of the United States. After much study this 17-member panel concluded that the remaining recoverable crude oil in the United States could range from 99 billion barrels to 204 billion barrels at prices of $27 or less. These estimates promise potential reserves substantially greater than the 24.7-billion barrel figure for proved reserves by the DOE's own Energy Information Administration.

The difference in the panel's estimates and the probability of achieving reserves within the range focuses on the application of new technology. A summary of the panel's estimates of our oil reserves is shown in the table on the next page. All estimates included the 24.7 billion barrels currently identified as proved reserves.

The panel concluded that additional oil supplies could come from a combination of undiscovered resources and reserve growth. More than half of the yet-to-be discovered oil potential exists onshore, in the lower-48. Obviously most of the oil produced in the lower-48 comes from mature fields but the panel believes new technology will provide a greater understanding of the reservoir and allow successful infill drilling and more effective technology to push greater amounts of oil through the reservoir.

Today, abandonment of existing domestic fields alarms the experts. Even with the development of new technology, it is unlikely that wells, once abandoned, would be reopened. The private sector is downsizing its research or abandoning the domestic sector for the greener and less regulated pastures of foreign exploration. These two factors alone make the transfer of any new technology critical.

It is important that independents avail themselves of every opportunity to keep up with new technology through active membership in industry organizations and attending technical transfer conferences whenever possible. This technical transfer conference is aimed at the independent operator from whose efforts the additional oil supplies will come. Without an effective means of transferring new technology the industry will not even reach the lower figure of 99 billion barrels.

DISCLAIMER

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

Table 1.

Summary of Oil Resources Panel Estimates

	Existing Technology ($20/bbl)	Advanced Technology ($20/bbl)	Existing Technology ($27/bbl)	Advanced Technology ($27/bbl)
Lower 48 Onshore				
Reserve Growth	24	45	33	70
Undiscovered	24	34	33	48
Subtotal	48	79	66	118
Lower 48 Offshore				
Reserve Growth	2	3	3	6
Undiscovered	11	14	13	17
Subtotal	13	17	16	23
Alaska Onshore				
Reserve Growth	5	7	7	13
Undiscovered	8	12	12	17
Subtotal	13	19	19	30
Alaska Offshore				
Undiscovered	—	2	4	8
Total Reserve Growth	31	55	43	89
Total Undiscovered	43	62	62	90
Total Reserve Growth & Undiscovered	**74**	**117**	**105**	**179**
Proved Reserves (End of 1991)	25	25	25	25
Total Resources	**99**	**142**	**130**	**204**

Order of Sessions

I. Reservoir Characterization

II. Drilling, Testing, and Completion

III. Enhanced Oil Recovery

IV. 3-D Seismic and Amplitude Variation with Offset (AVO)

V. Biotechnology for Field Applications

VI. Well Logging Technology

Sponsors:

- Colorado Oil and Gas Association
- Independent Petroleum Association of the Mountain States
- National Institute for Petroleum and Energy Research/Department of Energy
- Rocky Mountain Association of Geologists

General Chairman - Robert M. Cluff, The Discovery Group

Steering Committee:

Jeff Ahbe, Union Pacific Resources
Edith Allison, Department of Energy
Suzanne G. Cluff, The Discovery Group
Howard W. Dennis, Consultant
George H. Fancher, Fancher Oil Company
Susan R. Jackson, National Institute for Petroleum and Energy Research
S. Duff Kerr, Kerr & Associates
William Lancaster, Elk Exploration Company
James Mack, TIORCO
R. Randy Ray, R^3 Exploration

We wish to express our appreciation to the speakers and their companies for generously giving their time to this important project.

RESERVOIR CHARACTERIZATION SESSION

Thursday, May 6, Morning: 8:00 AM to 11:30 AM
Session Chair: Susan R. Jackson, National Institute for Petroleum and Energy Research

Introduction ..... *ii*
Susan Jackson

DOE Advanced Oil Recovery Program, a Resource for Independents *1*
Edith C. Allison, U.S. Department of Energy, Bartlesville, OK

Effects of Reservoir Heterogeneity on Oil Recovery Efficiency *3*
Susan R. Jackson, NIPER, Bartlesville, OK

Reservoir Characterization for Enhanced Oil Recovery Potential Evaluation *11*
Ming Ming Chang, NIPER, Bartlesville, OK

Application of Standard Petrographical Analysis *19*
Richard A. Schatzinger, NIPER, Bartlesville, OK

Imaging Technology Applied to Rock and Fluid Measurements in Cores *29*
Liviu Tomutsa, NIPER, Bartlesville, OK

Thursday, May 6, Afternoon: 1:15 PM to 4:45 PM

Application of Hydrogeochemical Techniques to Reservoir Characterization *39*
Michael Szpakiewicz, NIPER, Bartlesville, OK

Reservoir Heterogeneity and Infill Drilling *51*
Riley B. Needham, Phillips Petroleum Co., Bartlesville, OK

Lithology: The Missing Ingredient in Core Fracture Analysis *61*
John C. Lorenz, Sandia National Laboratories, Albuquerque, NM

Characterization of the Arbuckle Group in Cores from the Mid-Continent in Assessing Potential for Horizontal Drilling *69*
R. D. Fritz, P. L. Medlock, M. D. Kuykendall, and M. W. Allen, MASERA Corporation, Tulsa, OK

Modeling Reservoir Heterogeneity to Determine Current Oil Saturation Distribution in a Mature Field *73*
Ron Collings, Chevron U.S.A. Production Company, Rangley,CO

Valley-Fill Sandstone Reservoir Heterogeneity, Stateline Trend, Colorado & Kansas *81*
R. W. Tillman, Consultant, Tulsa, OK; E.D. Pittman, Consultant, Sedona, AZ; Beverly Blakeney-DeJarnett, Consultant, Fort Worth, TX.

SUMMARY OF THE RESERVOIR CHARACTERIZATION SESSION

Reservoir characterization requires the integration, reconciliation, and distillation of information from (1) various sources and disciplines, and (2) information of various scales, into a physically equivalent, unified reservoir model. The constraints in reservoir characterization are due to the complexity of the rock and fluid distributions, and the typically inadequate amount of information available even in the most ambitiously sampled reservoirs. The end products of reservoir characterization are reservoir simulation models that allow the prediction of fluid flow within the reservoir and provide information for reservoir management decisions such as the spacing and location of wells, selection of optimum recovery techniques, estimation of the risk, cost, and benefit of alternative reservoir management strategies.

This session on reservoir characterization contains papers that address three areas: (1) a general overview of DOE programs and reservoir characterization; (2) various tools and methods to obtain information about reservoirs; and (3) field case histories.

A general overview of DOE funded field demonstration projects, programs, sources of data, and technology transfer efforts will be presented first. Subsequent papers will address the types and effects of reservoir heterogeneity on oil recovery efficiency, methods for EOR potential evaluation, a generalized methodology for reservoir characterization, and methods of production data analysis to obtain dynamic reservoir information.

Tools and methods useful for reservoir characterization include:

- Petrographical analysis techniques that provide a wide variety of data useful for planning strategies to improve recovery from domestic oil fields, including wireline log calibration, information about rock-fluid interactions during drilling, completion and stimulation, and designing secondary and tertiary recovery programs.

- Imaging technologies of X-ray Computerized Tomography (CT) and Nuclear Magnetic Resonance Imaging (NMRI). CT imaging is a nondestructive method that can provide measurements of fluid saturation distributions within a core. It allows monitoring of front movement, trapping and displacement of fluids within the cores and provides information for the selection of representative samples for petrophysical measurements, and the design of EOR processes to optimize displacement.

- Hydrogeochemical analysis techniques provide inexpensive information on reservoir compartmentalization and salinity values important for calculating oil saturations from resistivity logs. The methods, applications, and advantages of monitoring the chemical and isotopic composition of reservoir waters will be presented.

- Fracture analysis methods are presented that provide the information required to construct accurate models of the three-dimensional framework of fracture permeability in a reservoir. The relationships between fracture locations, fracture terminations and lithologic heterogeneity and descriptions of fractures within their lithologic context allow inferences to be made about the degree of fracture interconnectivity.

Field case histories/recovery methods include:

- An example from Hugoton field, the largest gas field in the continental U.S., provides an excellent example of how improperly integrated studies concluded that the reservoir was areally compartmentalization, when in actuality it was a layered, no crossflow type of reservoir. A discussion is also included on the types of reservoirs where infill drilling is applicable and methods to determine the types of reservoir heterogeneity.

- The role of reservoir characterization to assess the potential for horizontal drilling, and to identify those carbonate reservoirs most likely to benefit from horizontal drilling is discussed. A geological classification model for the four basic types of reservoirs where horizontal drilling is effective is presented.

- An example from the Rangley Field Weber Sand Unit under both secondary and tertiary recovery, illustrates the importance of reservoir characterization and the development of an accurate geologic model for simulation techniques to predict water break through times and oil recovery rates for secondary and tertiary recovery projects.

- A reservoir characterization study of valley-fill sandstone reservoir illustrates the types and scales of reservoir heterogeneity found in the Morrow Stateline trend in the Denver Basin.

DOE Advanced Oil Recovery Program, a Resource for Independents by Edith C. Allison, U.S. Department of Energy, P.O. Box 1398, Bartlesville OK 74005; phone 918/337-4390; FAX 918/337-4418

In 1990, the Department of Energy Oil Program initiated a new approach directed at near- and mid-term results in addition to the previous program emphasis on long-term, high-risk research. The National Energy Strategy of 1991 and the 1992 Energy Policy Act have expanded the oil program's emphasis on industry-driven applied research and demonstration. For the domestic oil exploration and production industry the new policy is providing aggressive programs to transfer known technology for improved oil recovery to smaller operators, and opportunities to participate directly in the demonstration of under-utilized oil recovery technologies.

Technology transfer efforts currently include: development and release of personal computer based software for reservoir simulation; regional workshops on the application of specific reservoir characterization and process technologies; and distribution of technical publications on oil recovery research. DOE is in the process of developing a 5-year plan for technology transfer that is expected to propose more interactive involvement with independent oil operators. One item of interest to oil operators is BOAST-VHS for the PC, a personal computer based reservoir simulator for vertical, horizontal or slant wells. This software and other publications can be obtained by contacting Herb Tiedemann (918/337-4293).

The field demonstration program targets genetic groups of reservoirs based on the idea that reservoirs that formed in the same depositional environment will have similar recovery problems. The near-term program will conduct cost shared field demonstrations with industry teams to apply conventional technologies that have the potential to be more broadly used if the economic and technical applicability is shown. Reservoir characterization is expected to be the basis for design of the drilling and improved recovery for all the projects, and technology transfer of the results and techniques will be a significant component of all the demonstrations. The first group of cost-shared demonstrations are set in fluvial-dominated deltaic reservoirs; this reservoir group was selected because of the large volume of remaining oil, the high risk of well abandonments, the potential for increased recovery and the large number of small producers that operate in the reservoirs. Figure 1 shows the locations and participating companies. The second class of reservoirs to be studied is shallow shelf carbonates. DOE will announce the selected projects in April and will request proposals for technology demonstrations in additional classes of reservoirs in the future.

The first group of demonstrations include several in the Rocky Mountains: Research and Engineering consultants, Inc. is demonstrating the economic feasibility of using 3-D seismic, advanced reservoir simulation, well testing and production monitoring to locate infill wells and improve recovery of a secondary recovery project in the Denver Basin; Lomax Exploration Company is evaluating a successful waterflood in the Uinta Basin, an area where waterfloods have rarely been attempted because of the complex geology and hydrocarbon chemistry. The project will develop new techniques to characterize reservoir heterogeneity and reservoir response to waterflooding and will apply the techniques to implement a demonstration flood of a nearby reservoir.

EFFECTS OF RESERVOIR HETEROGENEITY ON OIL RECOVERY EFFICIENCY

by
Susan R. Jackson, Min Tham and Ming Ming Chang
National Institute for Petroleum and Energy Research
P.O. BOX 2128
Bartlesville, OK 74005
phone 918-337-4465 fax 918-337-4365

This paper presents a spectrum of the types of depositionally-controlled reservoir heterogeneities that occur in clastic reservoirs and their potential effect on fluid movement within the reservoir. Production methods that mitigate the effects of heterogeneities on recovery efficiency are also briefly discussed. Examples of the most commonly reported reservoir heterogeneities were taken from NIPER studies of shoreline barrier reservoirs and the literature. The purpose of the presentation is to portray possible situations that can cause hydrocarbon trapping and bypassing so that operators may use these concepts to collect relevant information and design advanced recovery schemes for their reservoirs.

Heterogeneities that occur as a result of depositional processes may cause significant recovery problems on scales ranging from field-scale to pore-scale. Depositionally-related heterogeneities were selected because these are most likely to be common among reservoirs producing from similar depositional environments and therefore information about these heterogeneities has the greatest likelihood of being transferable from one reservoir to another.

Field-scale heterogeneities include differences in reservoir quality due to the location within the deposystem and lateral continuity and interconnectedness of sandbodies. Each location within a deposystem has a different suite of facies with different permeability, porosity, grain size and clay content, as well as sandbody geometries, vertical trends in permeability and shale lengths (Fig. 1). Potential costs of not knowing the distribution of the deposystem are selecting well locations that do not hit the pay sand, and inappropriate well spacings.

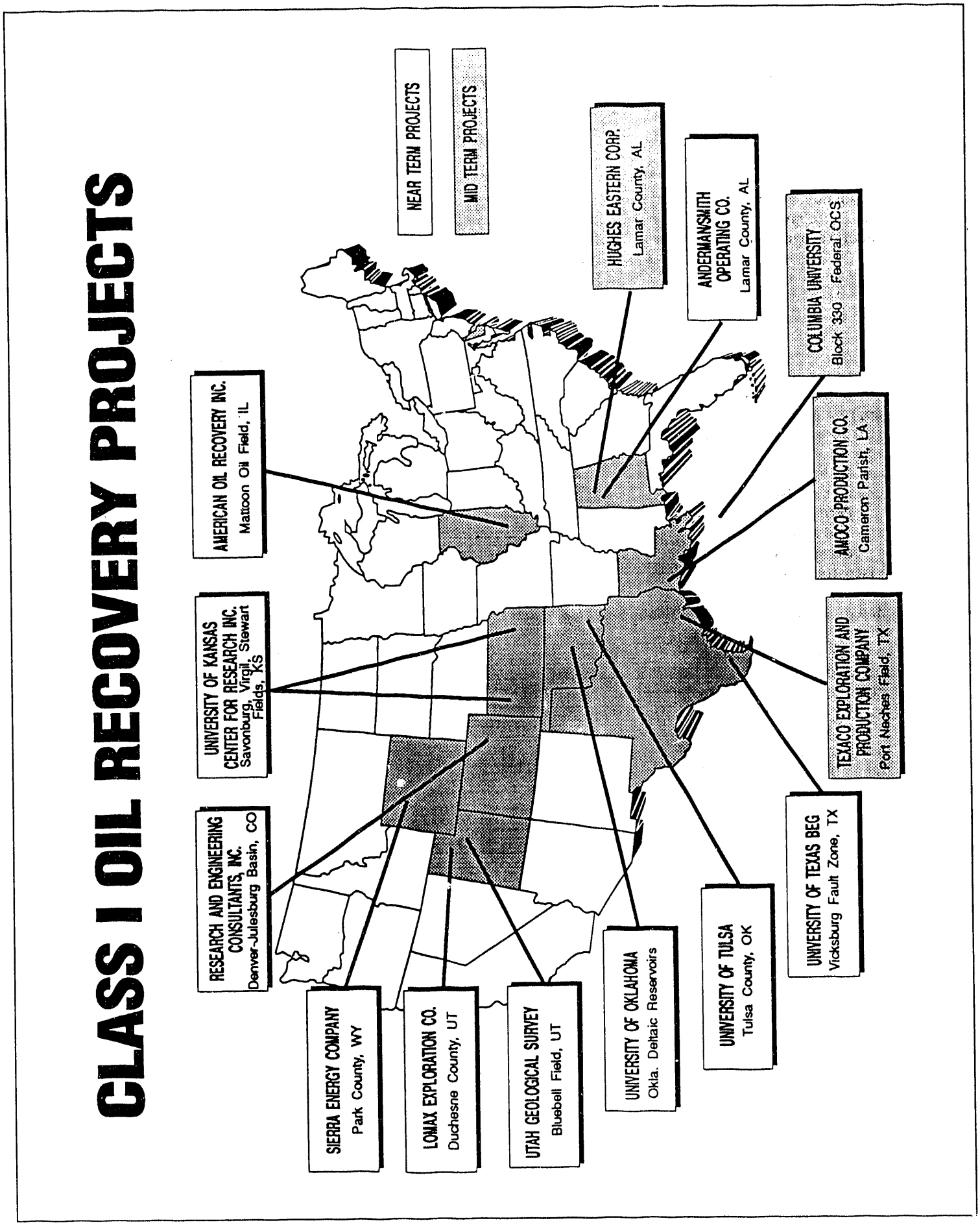
Interconnectedness of fluvial, tidal and distributary channel sandbodies is controlled by the amount of lateral migration of the channels (Fig. 2a). Lateral migration is controlled by the lithology of the underlying unit, sediment supply, and topographic gradient. If the underlying unit is shale, the channels do not tend to migrate laterally, resulting in deep, straight channels isolated by surrounding shales. If underlying unit is sand, which is more easily eroded, the channels tend to migrate laterally and produce shallower and wider channels. Figure 3 is a conceptual model of the effect of sandstone body interconnectedness on waterflood sweep efficiency. The reservoir model in figure 3a is similar to the Statfjord reservoir in the North Sea (van de Graaff and Ealey, 1989) and consists of three units separated by shales. Each unit consists of different sand/shale ratios and degree of interconnectedness of sandbodies. Figure 3b presents the fluid distribution after waterflood showing that the middle unit remains unswept and illustrates the importance of sandbody connectedness on waterflood sweep efficiency.

Interwell scale heterogeneities include: (1) boundaries between genetic units (Fig. 2b); (2) lateral facies changes (Fig. 2c); (3) permeability zonation within genetic units (Fig. 2d); (4) permeability baffles within genetic units; (Fig. 2e) and (5) permeability variations due to crossbed sets (Fig. 2f).

Boundaries between genetic units such as channel deposits often consist of clay drapes or mud-pebble conglomerates which range from low to zero permeability. These permeability barriers strongly affect horizontal and vertical sweep and contribute to compartmentalization of the reservoir. Figure 4 illustrates the combined effects of boundaries between genetic units and lateral facies changes that occurred in the M6 sandstone in the South Pass Block 27 (van de Graaf and Ealey, 1989). This reservoir consists of a distributary channel which has prograded over and cut into delta front sands. Figure 4a shows the fluid distribution within the M6 sandstone at the time of field development in 1959. Figure 4b depicts the fluid distribution after 15 years of waterflood production and illustrates the preferential sweep of the high-permeability zones.

Examples of lateral facies changes on the interwell scale are tidal or distributary channels cutting into an adjacent, thinly bedded tidal flat, sandy lagoon, bay fill or crevasse splay deposit (fig. 2c) or of a distributary channel prograding out over thinly bedded pro-delta deposits. These heterogeneities tend to cause fluid channeling, strongly affecting horizontal sweep efficiency, and moderately affecting vertical sweep efficiency.

A single channel sandstone that has cut down into thinner sandstones interbedded with shales is depicted in Figure 5a. The laterally equivalent thinner sandstones are commonly formed in tidal flat or sandy lagoonal deposits and have lower permeabilities and poorer vertical communication than the adjacent channel sandstone.


CLASS I OIL RECOVERY PROJECTS
NEAR TERM PROJECTS
MID TERM PROJECTS
AMERICAN OIL RECOVERY INC.
Mattoon Oil Field, IL
UNIVERSITY OF KANSAS CENTER FOR RESEARCH INC.
Savonburg, Virgil, Stewart Fields, KS
RESEARCH AND ENGINEERING CONSULTANTS, INC.
Denver-Julesburg Basin, CO
SIERRA ENERGY COMPANY
Park County, WY
LOMAX EXPLORATION CO.
Duchesne County, UT
UTAH GEOLOGICAL SURVEY
Bluebell Field, UT
UNIVERSITY OF OKLAHOMA
Okla. Deltaic Reservoirs
UNIVERSITY OF TULSA
Tulsa County, OK
UNIVERSITY OF TEXAS BEG
Vicksburg Fault Zone, TX
TEXACO EXPLORATION AND PRODUCTION COMPANY
Port Neches Field, TX
AMOCO PRODUCTION CO.
Cameron Parish, LA
COLUMBIA UNIVERSITY
Block 330 - Federal OCS
ANDERMAN/SMITH OPERATING CO.
Lamar County, AL
HUGHES EASTERN CORP.
Lamar County, AL

The expected fluid distribution after waterflooding that results from the permeability contrast, influence of gravity and sand continuity is shown in Figure 5b. A field example similar to this is presented by Hartman and Paynter, (1979).

Permeability zonation within genetic units can consist of decreasing permeability upward that occurs in fluvial, tidal or distributary channel deposits, or increasing permeability upwards as in shoreline barrier island and delta front distributary mouth bar deposits. Permeability zonation strongly affects vertical sweep efficiency, moderately affects horizontal sweep efficiency, moderately affects horizontal sweep efficiency, and can cause non-uniform residual oil saturation (ROS) in swept zones. The effect of this type of heterogeneity on oil recovery was investigated by simulation studies by van de Graaff and Ealey (1989). The percentage of oil cut vs. dimensionless oil recovery (equal to cumulative produced oil divided by moveable oil) resulting from simulation studies is shown in Figure 6. The two cases considered are a fining-upward (decreasing permeability) trend typical of tidal or distributary channel deposits, and a coarsening upward (increasing permeability) trend typical of shoreline barrier island, distributary mouth bar and delta front deposits. The same parameters for both scenarios were used: uniform porosity, oil viscosity of 20 mPa•sec (i.e. an unfavorable mobility ratio) and three layers of equal thickness with cross flow and with the same average permeability and absolute permeability. Only the position of the high-permeability layer is different.

Simulation results show that in the channel sandstone, a 5% oil cut (economic limit) is reached after approximately 35% of mobile oil has been produced whereas in the shoreline barrier sandstone, the oil cut is still 20% after 60% of mobile oil has been recovered. The reverse response may occur in a gas or steam injection scheme, however, because of the combined effect of gravity and presence of a high-permeability zone at the top of the sandstone. In this case, a delta front/barrier deposit will give an unfavorable sweep compared to a channel sandstone.

Permeability baffles within genetic units (fig. 2e) are typically caused by clay drapes between cross-bed sets and along scoured surfaces. Their presence moderately affects vertical and horizontal sweep efficiency.

Crossbed sets are a source of anisotropy in the reservoir. Their effect on fluid flow is dependent on the viscosity of the reservoir fluids, where the higher the viscosity of the oil, the greater the effect on waterflood recovery. Studies indicate that anisotropy from crossbedding is greater in consolidated sands than unconsolidated. Emmet et al. (1971) described the influence of cross-bedding on infill drilling and secondary recovery in the Tensleep Formation in Wyoming. They found that permeability parallel to the cross-bed laminae is about 4 times higher than that perpendicular to the laminae. The effect of the permeability contrast is dependent on the viscosity of the fluid, where the higher the viscosity of the oil, the greater the effect. Jones et al. (1987) document permeability ranges and the degree of anisotropy for the stratification types of trough cross-bedding, as well as ripples and dewatering structures in outcrop exposures of the Mesaverde Formation in Colorado.

Core plug and microscopic heterogeneities include variations caused by grain size variations within cross-bed laminae (Fig. 2g) and pore size distributions. The permeability contrasts between cross-bed laminae can range from very slight differences to great differences where impermeable shale laminae are interlayered with sandstone laminae and may impart a significant effect on residual oil saturation and log response. Kortekaas (1983) analyzed the effect of permeability variations on the displacement of oil by water within cross-beds with a permeability contrast of 5 between laminae. His work shows that when fluid flow is perpendicular to the cross-bed laminae and the rock is water-wet, oil within the higher permeability laminae may be initially bypassed due to the higher capillary pressures in the lower permeability (finer-grained) laminae (fig. 7). His simulation study also showed that low-tension (dilute surfactant) and polymer floods would improve recovery in these cross-laminated zones.

These results are consistent with those of Tomutsa et al., (1990) who used CT scanning techniques to monitor fluid distributions while flooding a cross-bedded rock sample first with oil and then with water. They found that the lower permeability laminae accepted less oil than the higher permeability layers after saturating with oil, as expected. After flooding with water, however, the water entered the lower permeability layers first. This response can be partly explained by the higher water saturations in the lower permeability layers, which result in higher initial relative permeability to water than the higher permeability, oil-saturated zones. As flooding continues, the relative permeability to water increases in the lower permeability zone with an increase in water saturation.

In general, the methods of infill drilling, horizontal/slant wells and hydraulic fracturing are stimulation/production methods that are most applicable to overcoming field-scale heterogeneities, whereas enhanced oil recovery processes are most applicable to interwell and microscopic-scale heterogeneities. The enhanced

production methods that may be applicable in overcoming the outlined heterogeneities are presented in Table 1.

In an analysis of 27 chemical EOR projects conducted in deltaic reservoirs from 17 fields (Jackson, et al., 1992), the fluid flow problems most often reported were channeling (74%), compartmentalization (48%), contacting high salinity zones (33%), formation parting (26%), and directional trends (preferential direction of fluid flow) (19%) (Table 2). Both structural features such as fractures and faults and high permeability zones within the sand matrix can cause channeling, and compartmentalization, however the presence of faults and fractures was not reported in most of the cases.

Lower than expected oil recovery was partially attributed to heterogeneity related to depositional processes in the projects listed in table 2. Quantification of the effects on recovery, are not possible at this point. However, comparison of performance to well spacing may indicate the scale of the features controlling production. Figure 8 is a plot of recovery efficiencies against well spacing for a number of micellar-polymer pilots in fields where several projects were performed with varying well spacing and similar chemical slugs. The recovery efficiency decreased from 60 to 70% to less than 30% for well spacings greater than 1 acre. Although other explanations can be advanced, the comparison of performance to well spacing may indicate the scale of the geologic features controlling production.

REFERENCES

Emmett, W. R., K. W. Beaver, and J. A. McCaleb, 1971, Little Buffalo Basin Tensleep heterogeneity - Its influence on infill drilling and secondary recovery: Jour. Petroleum Tech., p. 161-168.

Hartman, J. A., and D. D. Paynter, 1979, Drainage anomalies in Gulf Coast Tertiary sandstones: Jour. Petroleum Tech., v. 31, p. 1313-1322.

Jackson, S.R., Schatzinger, R.A., Rawn-Schatzinger, V., Tham, M.K., Chang, M.M. General geological and production characteristics of deltaic reservoirs with annotated bibliography of selected references. NIPER EPR/OP-92/14. June 1992.

Jones. J. R., A. J. Scott, and L. W. Lake, 1987, The geologic aspects of reservoir characterization numerical simulation: Mesaverde meanderbelt sandstone, northwestern Colorado: SPE Formation Evaluation, p. 97-107.

Kortekaas, T. F. M., 1983, Water/oil displacement characteristics in ... os-bedded reservoir zones: SPE 12112, p. 1-7.

Tillman, R., M. Szpakiewicz, M. Honarpour and S. Jackson, 1988, Reservoir description and production history; Bell Creek Field, Muddy Sandstone, barrier island, and valley fill deposits: (abst.) AAPG Bull., v. 72, p. 254.

Tomutsa, L., S. M. Mahmood, D. Doughty, A. Brinkmeyer and M. M. Honarpour, 1990, Applications of integrated pore-to-core level image analysis to study fluid distribution in reservoir rock: SPE 20478, 60th Annual Technical Conference and Exhibition, New Orleans, LA, p. 137-148.

van de Graaff, W. J. E., and P. J. Ealey, 1989, Geological modeling for simulation studies: AAPG Bulletin, v. 73, p. 1436-1444.

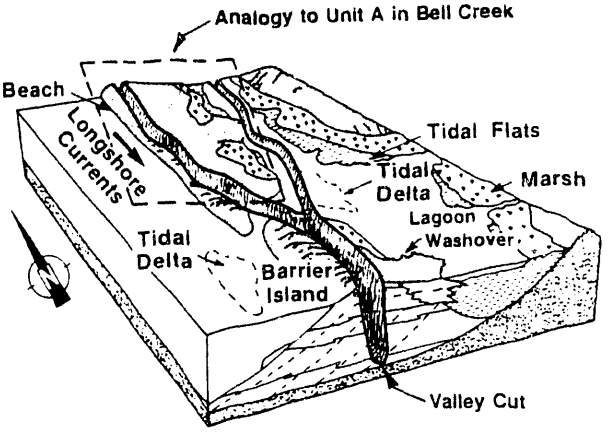


Figure 1 - Distribution of facies in a shoreline barrier island deposystem. Note that the reservoir facies of barrier island, beach and tidal delta are complexly arranged with marginal to non-reservoir facies of lagoon, marsh and tidal flat. Each facies has different petrophysical, geometric and vertical trend characteristics. After Tillman et al., 1988.

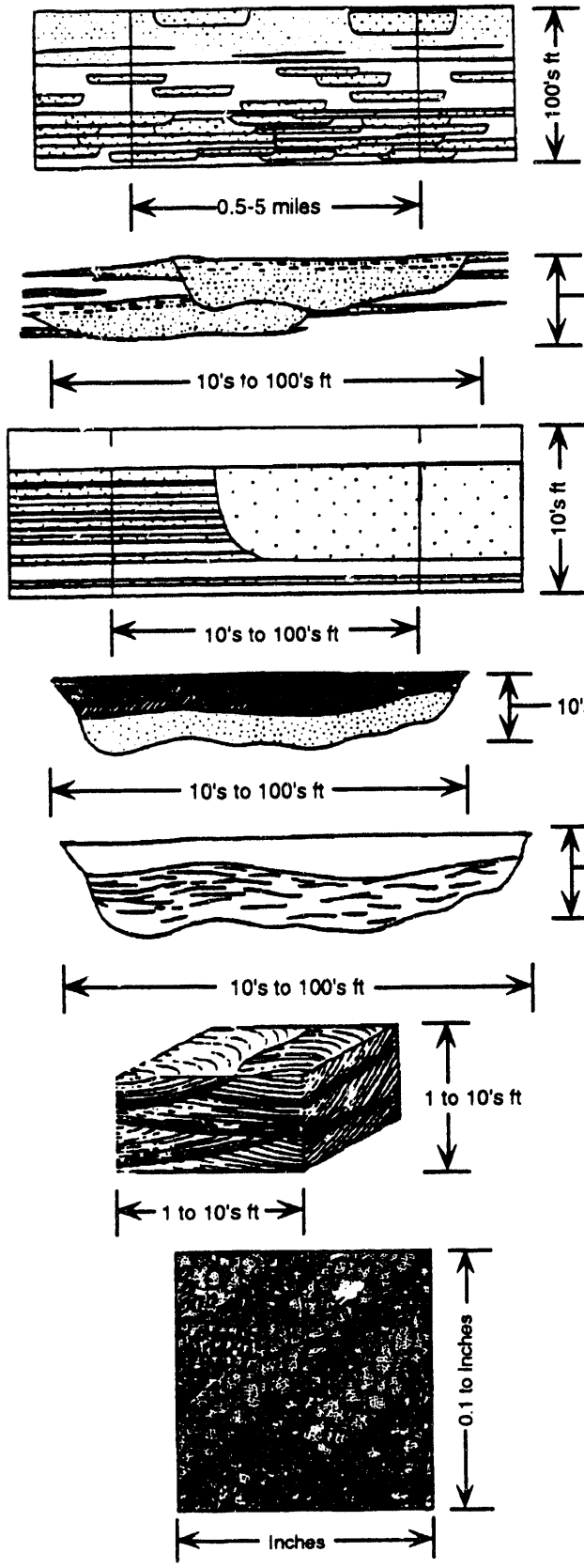


Figure 2 - Heterogeneities related to depositional processes. Modified from Weber, 1986.

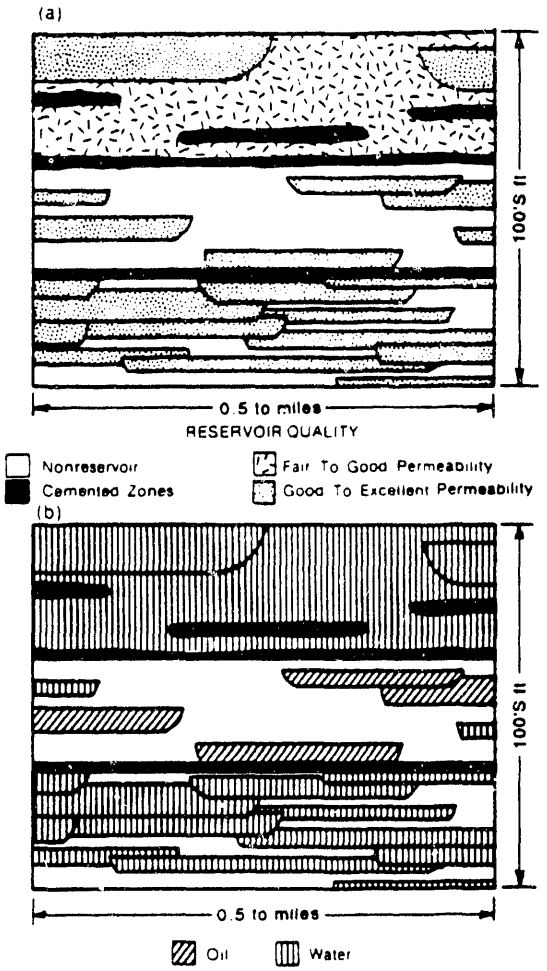


Figure 3 - (a) Various distributions and degrees of interconnectedness of channel sandbodies, (b) Conceptual fluid distribution after waterflood illustrating the effect of sandbody distribution on sweep efficiency. After van de Graaff and Ealey, 1989.

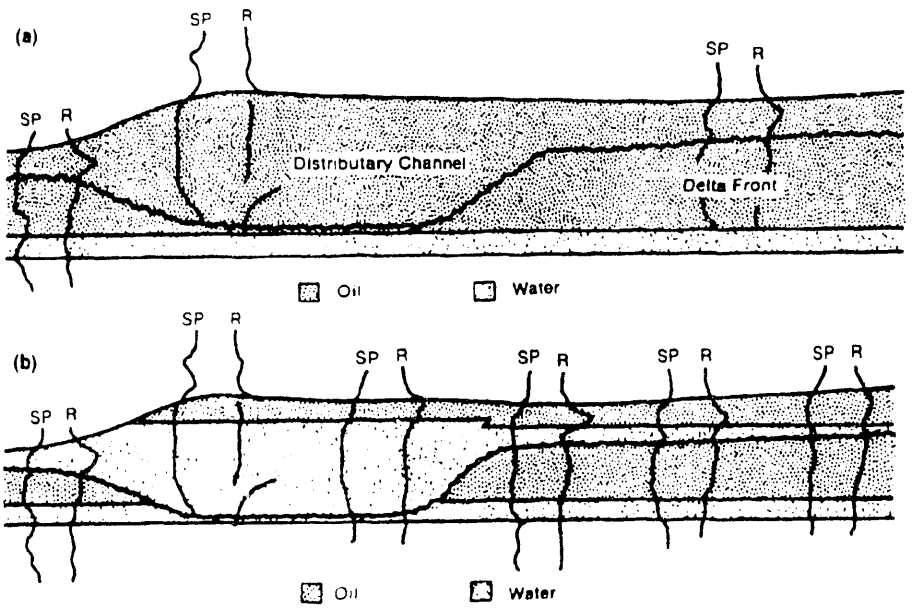


Figure 4 - (a) Fluid distribution in M_6 sandstone in 1959 at time of field development, (b) Fluid distribution in M_6 sandstone in 1974 after 15 years of production. After Hartman and Paynter, 1979.

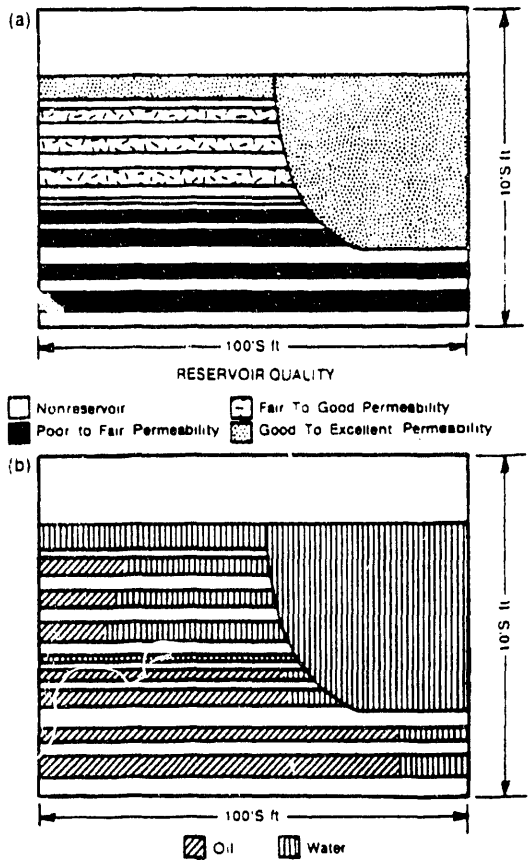


Figure 5 - (a) Channel sandstone and its lateral facies equivalents illustrating reservoir-to-genetic sand-body scale heterogeneity, (b) Conceptual fluid distribution after waterflood showing unswept layers. After van de Graaff and Ealey, 1989.

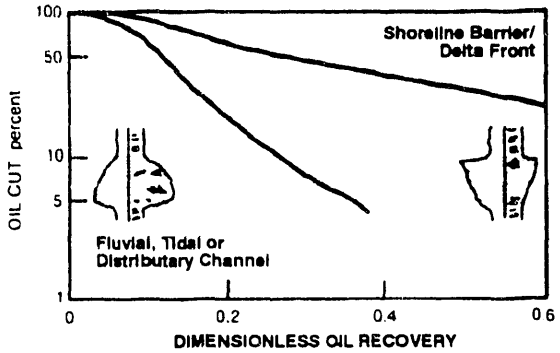


Figure 6 - Influence of vertical distribution of permeability on oil recovery. Permeability profiles typical for fluvial, tidal and distributary channel facies (decreasing permeability upward) and shoreline barrier and distributary mouth bar facies (increasing permeability upward) result in different oil cut vs. oil recovery curves even

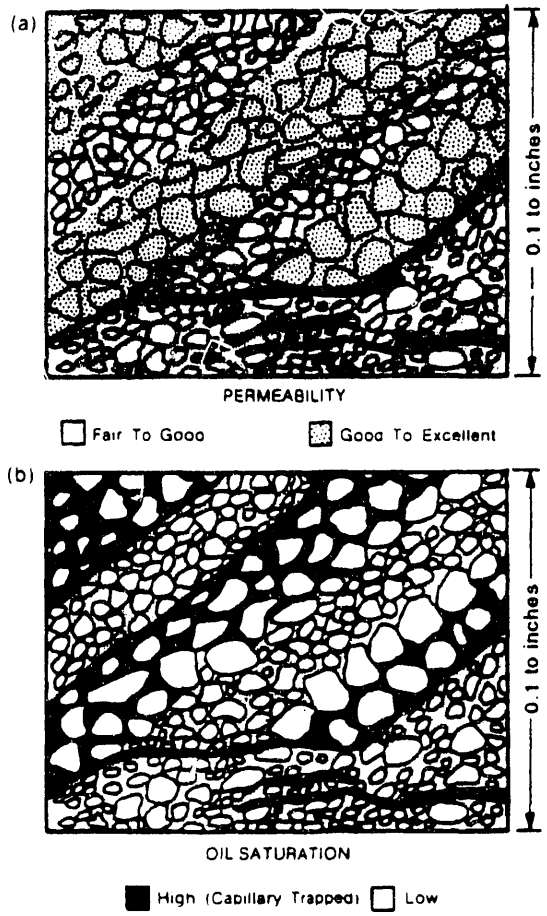


Figure 7 - (a) Conceptual model of permeability heterogeneity in crossbed laminae. After van de Graaff and Ealey, 1989, (b) Hypothetical fluid distribution after waterflood. After Kortekaas, 1983.

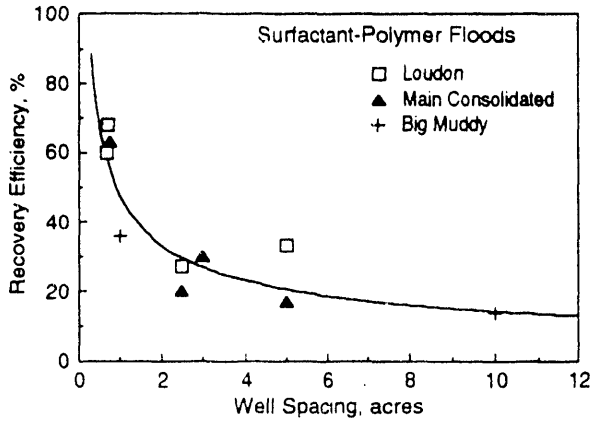


Figure 8 - Relationship between well spacing and recovery efficiency in EOR pilot projects.

Table 1. Application of enhanced production methods to heterogeneities related to deltaic depositional processes

	Infill	Horizontal/ slant	Hydraulic fracturing	Gel polymer	Polymer	Surfactant alkali-surf.	CO_2	Steam	In situ combustion
Field scale sandbody continuity									
continuous	X	X	X						
semicontinuous	X		X						
separated	X								
Boundaries between genetic unit	X	X	X						
Lateral facies changes	X	X		X					
Permeability zonation				X	X				
Permeability baffles			X						
Crossbed sets			X			X	X	X	X
Crossbed laminae					X	X	X	X	X

Table 2. Geologic factors affecting EOR recovery

Field name	EOR type	Well spacing acre	Recov. efficiency %	Chan-neling	Compart-ments	Contact high salinity	Formation parting	Direct-ional trend	Facies
Benton, IL[1]	S/P	1	27	yes	yes	yes			
Big Muddy 1, WY[2]	S/P	1	36				yes		dc,dfr
Big Muddy 2,WY[3]	S/P	10	14	yes			yes		
Delaware Childer,OK[4]	S/P	2.5	7	yes		yes		yes	
El Dorado, KS[5]	S/P	6.4	0			yes			
Glennpool, OK[6]	S/P			yes	yes		yes	yes	
Loudon 1, IL[7]	S/P	0.625	15.3			yes			
Loudon 2, IL[8]	S/P	0.68	60	yes		yes		yes	dmb,mb,df
Loudon 3, IL[9]	S/P	0.71	68	yes	yes				
Loudon 4, IL[10]	S/P	2.5/5	27/33	yes	yes				
Main Consolid.1, IL[11]	S/P	0.75	63	yes			yes		dc,pb
Main Consolid.2, IL[12]	S/P	10	39	yes					
Main Consolid.3, IL[13]	S/P	3	27 to 33						
Main Cons.4, IL[14,15]	S/P	2.5/5	20/17	yes	yes	yes	yes		
Manvel,TX[16]	S/P								
North Burbank, OK[17]	S/P	10	25	yes	yes	yes	yes	yes	fc,mmtl
North Burb., OK[18,19]	P	20		yes			yes	yes	fc,mmtl
North Stanley, OK[20]	P		1.4	yes					
Ranger, TX[21]	S/P	40	25		yes				dc
Salem 1, IL[22,23]	S/P	5	14	yes	yes	yes			df
Salem 2, IL[24,25]	S/P	5	47	yes		yes			
Sloss, NE[26]	S/P	9	yes	yes	yes				
Bay St. Elaine, LA[27]	CO_2M	-	-	-	-	-	-	-	obs
Garber, OK[28]	CO_2M	10.4	14	yes	yes				dc,df
Rock Creek 1,WV[29]	CO_2M	10	3	yes	yes				
Rock Creek 2,WV[30]	CO_2M	1.55	11	yes	yes				
Grann. Creek, WV[31]	CO_2M	0.85/6.7	37/6	yes	yes				

S/P Surfactant (including microemulsion, low tension and soluble oil)-polymer
P Polymer
CO_2M Carbon dioxide miscible
dc= distributary channel df = delta front mmtl = marginal marine tidal or lagoonal deposit
obs = overbank splay pc = point bar dfg = delta fringe
fc = fluvial channel mb= mouth bar dmb = distal mouth bar

REFERENCES

1. French, M. S., et al.,1973.
2. Ferrell, H. H., et al., 1984.
3. Cole, E. L.,1988a.
4. Thomas, R. D., et al., 1982.
5. Ferrel, H. H., et al., 1987.
6. Crawford, C. C., M.E. Crawford, 1985.
7. Pursley, S.A., et al., 1973.
8. Bragg, J. R. , et al., 1982.
9. Reppert, T. R., et al., 1990.
10. Huh, C., et al., 1990.
11. Gogarty, W.B., and H. Surkalo, 1971.
12. Earlougher, B. C., et al.,1975.
13. Howell, J. C., et al., 1979.
14. Cole, E. L., 1988b.
15. Stover, D. F., 1988
16. Hamaker, D. E. and G. D. Frazier,1978.
17. Lorenz, P. B., et al., 1986.
18. Zornes, D. R., et al., 1986.
19. Moffitt, P. D.,et al, 1990.
20. Harpole, K. J. and C. J. Hill, 1983.
21. Holley, S. M. and J. L. Cayais,1990.
22. Strange, L. K. and A. W. Talash, 1977.
23. Widmeyer, R. H., et al., 1977.
24. Ware, J. W., 1983.
25. Widmyer, R. H., et al, 1985.
26. Basan, P. B., et al., 1978.
27. Taggart, F. ZL. snf H. V. Tuddrll, 2982.
28. Kumar, R., and J. N. Eibeck, 1984.
29. Brummert, A. C., et al., 1986.
30. Watts, R. J., et al., 1982.
31. Palmer, F. S., et al., 1981.

RESERVOIR CHARACTERIZATION FOR ENHANCED OIL RECOVERY POTENTIAL EVALUATION

Ming-Ming Chang, National Institute for Petroleum and Energy Research
P. O. Box 2128, Bartlesville, Oklahoma 74005. Phone 918/337-4346, FAX 918/337-4365

An adequate reservoir characterization is found necessary for a successful implementation of EOR process. Reservoir characterization is a continued process by refining the reservoir model with upcoming production data. Several techniques are illustrated in this presentation to retrieve reservoir information from production data, and general steps for enhanced oil recovery (EOR) potential evaluation are discussed.

EOR Potential Evaluation

The EOR potential of a reservoir can be evaluated first by comparing its key reservoir properties with screening criteria (Table 1)[1] of various EOR processes. The key reservoir properties include permeability, porosity, remaining oil saturation, oil gravity, pay thickness, depth, and water salinity. These parameters dictate the chance of success for EOR operations and different EOR processes have different requirements on these parameter values. For instance, thermal methods are effective for recovering heavy oil in shallow reservoirs while CO_2 floods are efficient in recovering light oil in deep reservoirs with formation pressure greater than minimum miscibility pressure. The salinity of formation brine is critical to the success of chemical floods but not other EOR processes. Reservoirs satisfying screening criteria of certain EOR process are considered to be favored for that particular EOR operation.

The second step in EOR potential evaluation is estimating oil production rates using predict/screening models[1] and EOR reservoir simulators. Based on analytical equations, empirical correlations, and numerical simulation results, EOR screening models are used for predicting oil rates and economical return in five processes: steam flood, in-situ combustion, CO_2 miscible flood, polymer flood, and chemical flood. These PC-based screening models are easy to use but little reservoir heterogeneity except Dykstra-Parsons coefficient is considered in the model calculation. The reliability of results from EOR screening models are highly dependent on homogeneity of reservoirs to be evaluated. In addition to more rigorous calculations in EOR mechanisms, regular EOR reservoir simulators have better capabilities for incorporating reservoir heterogeneities than screening models. Regular EOR simulators are capable to provide more reliable predictions than screening models if the key reservoir characteristics is included in the model simulation.[2] Examples of comparison between EOR simulations and field production will be presented and its success and discrepancy will be discussed.

Reservoir Characterization Methodology

General steps (Table 2) in reservoir characterization are: 1) measurement and collection of rock and fluid properties from wells, 2) constructing reservoir model by incorporating interwell petrophysical distribution or heterogeneity, and 3) refining model by history match. The constructed model is then used for prediction and optimization of process and production strategy.

Rock and fluid data, such as porosity, permeability, and oil saturation, are the building blocks for constructing a reservoir model. These data should be collected to a level sufficient to design accurate reservoir models. Fluid PVT properties and rock-fluid interaction are essential to understand the fluid flow in the reservoir. Material balance calculations based on production and PVT properties provides a check of oil-in-place calculation from volumetric method.

Distribution of rock and fluid properties provides useful information of formation heterogeneity. Drastic changes in initial saturation (Fig. 1) or formation pressure might indicate discontinuity of the flow system within reservoirs. Distribution of water composition and solution gas-oil ratio (GOR) can be useful sources for determining compartments too. For implementing EOR processes distribution of remaining oil saturation (Fig. 2) is one of the critical information required. Remaining oil saturation can be determined by pressure coring, single-well tracer tests, log-inject-log, or material balance calculations.[3]

Incorporation of interwell heterogeneity into the reservoir model from data in control wells is still in the research stage. The layer cake reservoir model has been used in numerical simulations for predicting production. The stochastic and geostatistical methods were tested for interpolating interwell heterogeneities with certain success. Because we almost always face the problem of incomplete set of data, geostatistical methods such as kriging[4] and fractal[5] become alternative ways to improve the interwell modeling work.

Reservoir characterization is a continued process by refining the reservoir model with upcoming production data. Because of the nature of incomplete data the constructed reservoir model is never the "correct" model. Through the numerical simulation the reservoir model needs to be checked and updated continuously against the production data. The longer and the better the production history can be matched, the closer the model is to the real reservoir.

Characterizing Reservoirs from Production Data

Production data provide invaluable information about the reservoir structure of producing reservoirs. Distributions of reservoir pressures and producing GORs suggest the degree of interwell transmissibility. Oil declining rates reflects the drainage volume and possible compartments or fractures.

The injection water acts as a valuable tracer during waterflood. The volume and composition of produced water can be used to determine the degree of interwell communication. Water breakthrough times of waterflood are useful for detecting the existence of formation fractures (Figs. 3). Careful examinations of breakthrough times from offset wells may indicate fracture directions of formations. The fast breakthrough wells 76 and 8623 in Fig. 4, located west and east respectively to injection well 7653, showed fractures in the east-west direction .

The history of water cut and oil bank profiles provide insights of vertical profile of injected water front. A long period of high water cut in comparison to the oil bank period indicates a large contrast of formation permeability at different depths (Fig. 5). In addition to detecting wellbore condition, values of Hall plot slopes indicate possible flow barriers or deterioration of pay sand away from the water injection wellbore. Figure 6 shows numerical simulation results of Hall plot slopes from a water injection well with or without nearby flow barriers. The well near two flow barriers exhibits a higher Hall plot slope than it near only one barrier. The field data of Hall plot slopes were compared favorably to faults and pay sand distribution determined from other sources in Fig. 7. Real field examples from Patrick Draw Field[6] and Naval Petroleum Reserve No. 3[7] in Wyoming are illustrated in this presentation for determining the interwell heterogeneity.

References

1. National Petroleum Council: "Enhanced Oil Recovery," June 1984.
2. Saad N., G.A. Pope, and K. Sepehrnoori: "Simulation of Big Muddy Surfactant Pilot," SPE Reservoir Engineering, February 1989, p. 24-34.
3. Chang, M.M. et al: "Evaluation and Comparison of Residual Oil Saturation Determination Techniques," SPE Formation Evaluation, March 1988, p. 251-262.
4. Journel, A.G. and Alabert, F.G.: "New Method for Reservoir Mapping," J. Petroleum Technology, Feb. 1990, p. 212-218.
5. Hewett, T.A.: "Fractal Distributions of Reservoir Heterogeneity and Their Influence on Fluid Transport," SPE 15386, presented at 1986 SPE annual meeting, New Orleans, LA, Oct. 5-8.
6. Jackson, S.R. et al: "Integration of the Geological/Engineering Model with Production Performance for Patrick draw Field, Wyoming," Technical Report NIPER-634, Distribution Category UC-122, December 1992.
7. Jackson, S.R., M.M. Chang, and D.K. Olsen: "Synthesis of Available Structural Data and Analysis of Injection/Production Data in the Steam Generator #3 Area, Shannon Sandstone, Naval Petroleum Reserve No. 3, Teapot Dome Field, Wyoming," NIPER Technical Report, June 1992.

Table 1. Screening criteria for EOR candidates implemented technology case

Screening Parameters	Units	Miscible Flooding (Carbon Dioxide)	Thermal Recovery	
			Steam	In Situ Combustion
Oil Gravity	°API	>25	10 to 34	10 to 35
In Situ Oil Viscosity (μ)	cp	--*	<15,000	<5,000
Depth (D)	Feet	--	<3,000	<11,500
Pay Zone Thickness (h)	Feet	--	>20	>20
Reservoir Temp	°F	--	--	--
Porosity (ϕ)	Fraction	--	>0.20	>0.20
Permeability, Average (k)	md	--	>250	>35
Transmissibility (kh/μ)	md/ft/cp	--	>5	>5
Reservoir Pressure	psi	>MMP**	<1,500	<2,000
Minimum Oil Content at Start of Process (S_o x ϕ)	Fraction	--	>0.10	>0.08
Salinity of Formation Brine (TDS)	ppm	--	--	--
Rock Type		Sandstone or Carbonate	Sandstone or Carbonate	Sandstone or Carbonate
Oil Saturation		>30%	40-50%	40-50%

* Not critical
**Minimum miscibility pressure

Table 1 (Continued)

Screening Parameters	Unit	Microbial Flooding	Chemical Flooding		
			Surfactant	Polymer	Alkaline
Oil Gravity	°API	>15	--	--	<30
In Situ Oil Viscosity (μ)	cp	--	<40	<100	<90
Depth (D)	Feet	<6,800	--	--	--
Pay Zone Thickness (h)	Feet	--	--	--	--
Reservoir Temperature	°F	<170	<200	<200	<200
Porosity (ϕ)	Fraction	--	--	--	--
Permeability, Average (k)	mD	>75	>40	>20	>20
Transmissibility (kh/μ)	mD/ft/cp	--	--	--	--
Reservoir Pressure	psi	<3000	--	--	--
Minimum Oil Content at Start of Process (S_O x ϕ)	Fraction	--	--	--	--
Salinity of Formation Brine (TDS)	ppm	<100,000	<100,000	<100,000	<100,000
Rock Type		Sandstone or Carbonate	Sandstone	Sandstone or Carbonate	Sandstone
Oil Saturation		>25%	>25%	>10% mobile	>Residual

Table 2. Steps in reservoir characterization

STEPS IN RESERVOIR CHARACTERIZATION

1. **RESERVOIR AND FLUID PROPERTIES:** k, Φ, B, R_s, μ, P_c, k_r, c
   MASS OR VOLUME BALANCE: N, N_p, V, S, P_i, P
   BOUNDARY CONDITIONS: q, P_{wf}, s, W_e

2. **RESERVOIR MODEL CONSTRUCTION**
   Interwell Heterogeneity: fracture, channel, barrier, compartment

3. **HISTORY MATCH AND PREDICTION**
   Analytical Solutions of Flow Equations
   Material Balance Model
   Decline Curves
   Numerical Simulation

4. **OPTIMIZATION OF PROCESS STRATEGY**

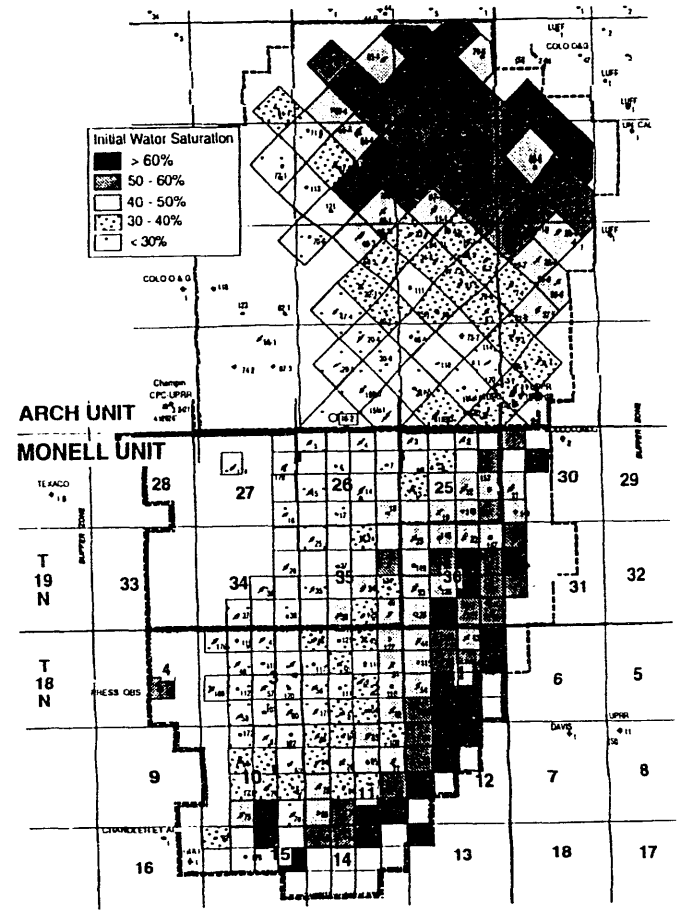


Fig.1. Initial water saturation map of Patrick Draw Field.

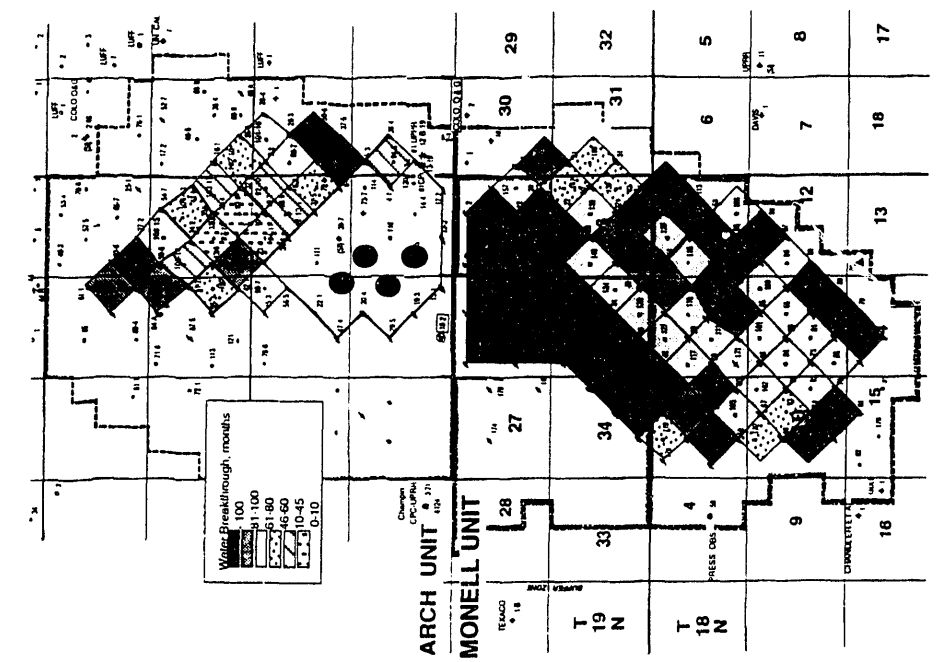


Fig.3. Map of water breakthrough time in Patrick Draw Field.

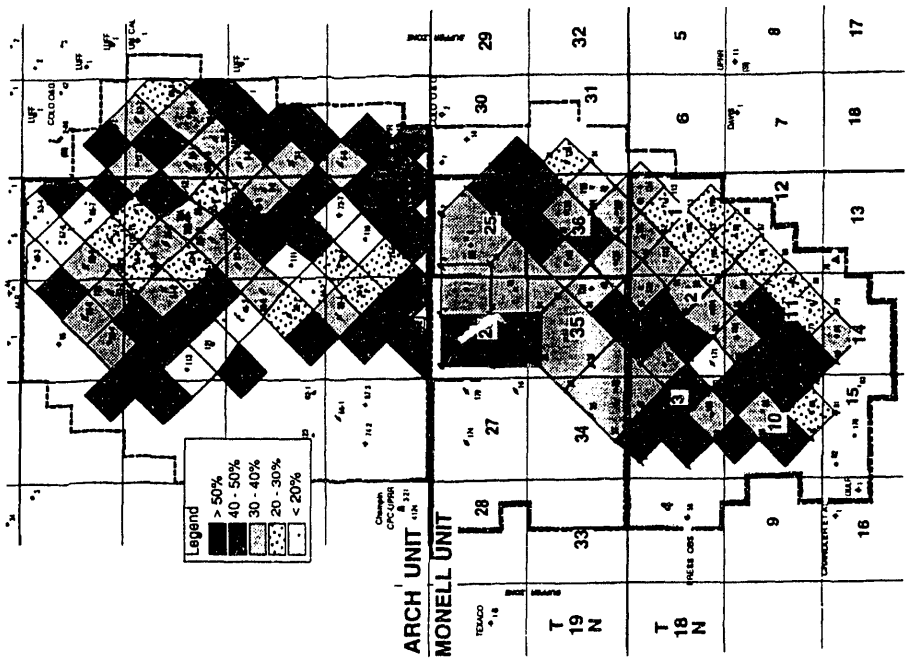


Fig.2. Remaining oil saturation map of Patrick Draw Field.

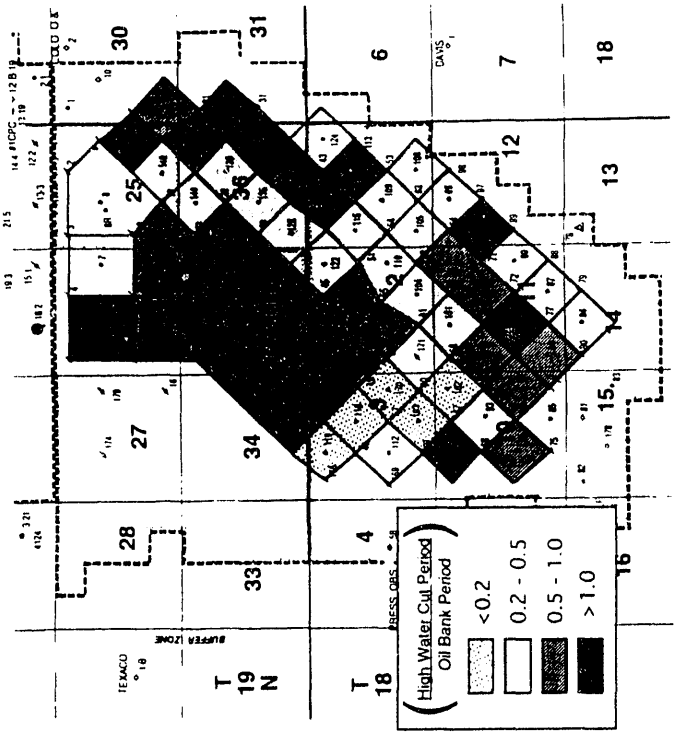


Fig. 5. Map of Ratios of high water cut period to oil bank period in Patrick Draw Field.

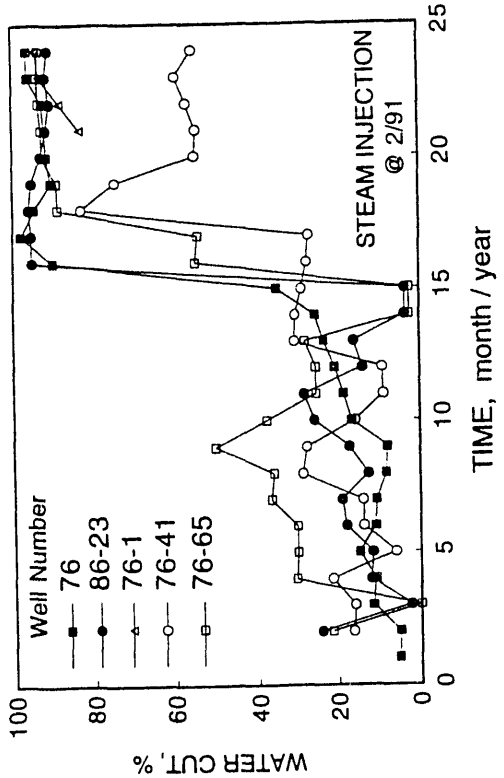


Fig. 4. Water cut history in Naval Petroleum Reserve No. 3.

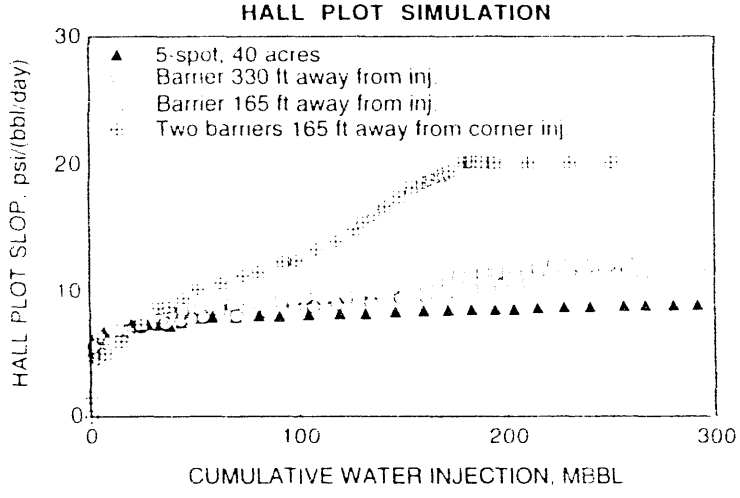


Fig. 6. Numerical simulations pf Hall plot slopes.

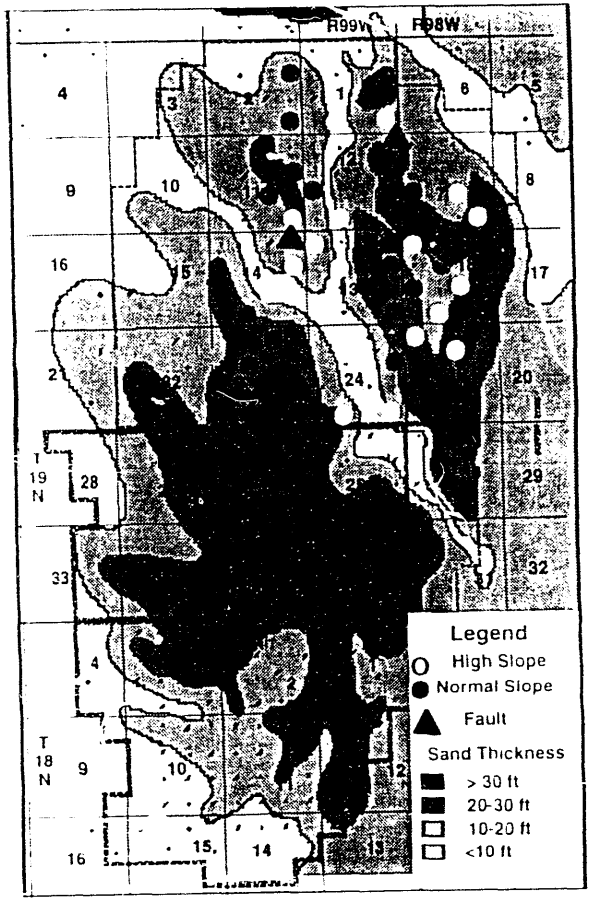


Fig. 7. Map of faults, isopach, and Hall plot slopes in Patrick Draw Field.

Notes

APPLICATION OF STANDARD PETROGRAPHICAL ANALYSIS

By R. Schatzinger
National Institute for Petroleum and Energy Research (NIPER)
P. O. Box 2128
Bartlesville, OK 74005
Phone (918)337-4470

EXTENDED ABSTRACT

Standard petrographical techniques can provide a wide variety of data useful for planning strategies to improve recovery from domestic oil fields. Petrographical analysis has application to the construction of geological models (structural, depositional, diagenetic), evaluation of fluid flow characteristics, rock-fluid interaction, well log, and routine and special core analyses. Through these areas the effect of reservoir (rock-fluid) properties on primary, waterflood, and EOR stages of production can be assessed. However, petrographical analysis is not a "stand alone" discipline. For petrographical analysis to provide the best results, input and special problems from the areas impacted must all be accounted for. In this presentation the principle costs and applications of petrographical analysis will be discussed by citing examples from field experiences.

The techniques discussed in this presentation make petrographical analysis a very useful tool to help management with development decisions, to lower risk in further developing old fields, and to provide critical information to companies in an exploration mode. Petrographical analysis can provide timely identification of sensitive minerals and help predict rock-fluid interactions during drilling, completion, and stimulation as well as during secondary and tertiary production stages. Petrographical tools are most useful to the log analyst who needs to have the mineralogy of the formation calibrated and who needs to know about the geometry of the pore system in order to adequately determine the formation factor. And finally, petrographical analysis provides invaluable information about lithology and mineralogy, pore and grain size distributions, and description of diagenetic phases within the reservoir rock and surrounding facies that must be accounted for in the various geological models as well as by inhomogeneities in these properties that are of great interest to the petrophysicist who must model rock behavior under reservoir conditions.

Standard petrographical techniques may be grouped into two categories: routinely used techniques and less routinely used techniques. Routine techniques include optical microscopy (with reflected, transmitted polarized light, UV fluorescence, and cathodoluminescence), X-ray diffraction (XRD), and scanning electron microscopy (SEM) used in conjunction with energy-dispersive X-ray analysis (EDS).

Optical microscopy may be conducted on thick, opaque samples of core or cuttings, or, more commonly, on thin sections. Visual estimates cost about $100, and point-counted results are more expensive. Reflected and transmitted polarized "white" light is the standard source for this technique that remains the base level information with which all other petrographical techniques are compared. This technique provides lithology, mineralogy, and a great deal of textural and size information such as pore system description, shape, size, and sorting of grains and

pores, and a summary of the diagenetic changes in the rock as well as the micropaleontology. Major clay groups can be identified optically; however, clay species within major groups cannot be distinguished by this method. The resolution of optical microscopy is 1 micron (μ).

Ultraviolet fluorescence of thick or thin sections instantly provides information about the distribution of fluorescent phases in the rock such as hydrocarbons. The technique is, however, most commonly employed using certain types of epoxy to impregnate the pore system of the samples. UV analysis then rapidly provides a quantifiable estimate of porosity, microporosity, and organics as well as their distribution within the rock samples. The cost of UV fluorescence is about $25-35/sample for qualitative work in addition to the normal optical microscopy fee. Sample requirements are the same as for "normal" light microscopy.

Cathodoluminescence (CL) can also be used with rock slabs or with thin sections. CL is most useful for determining the distribution and amount of luminescent phases in the rock, such as pore filling cements. The results are determined rapidly, can often be quantified, and often include information about features that are invisible in transmitted light microscopy such as compositional zoning of cements. CL is a very useful tool for helping to determine the diagenetic changes that have occurred in the rock. Analysis typically costs $25-35/ sample. Requirements are generally the same as for other optical methods except that the sample must be stable under electron beam bombardment.

X-ray diffraction (XRD) provides a quantitative analysis of the bulk and clay size fraction mineralogy. It is particularly useful for determining clay species that cannot be determined by optical methods. XRD analysis can be performed on most solids and has the advantage of requiring only a very small sample. XRD analysis, however, has limitations that are often overlooked in industrial applications: cryptocrystalline or noncrystalline phases are not well characterized (e.g. opal), mineralogically equivalent forms may not be distinguished (e.g. quartz-chert-chalcedony), it is a destructive technique, and no spatial information is generated. XRD analysis costs about $100/ sample.

Scanning electron microscopy has the advantage of very high magnification so that the smallest details of pores, pore throats, and grain surfaces can be examined. In the scanning electron image (SEI) modes, great surface topographical detail may be seen and geometrical relationships studied. In the backscattered electron image (BEI) and the X-ray scan image mode, on flat or polished samples, the images reflect changes in composition across the visible surface. SEM analysis requires only small samples. Most solids are acceptable; however, they must be stable in the vacuum of the sample chamber and remain stable under the electron beam. Plastics, such as those used in pore casts, may be studied with this technique if the beam current is reduced so as not to melt the resin cast. Resolution can be as fine as 80 Angstroms. SEM analysis will cost between about $110-150/ sample, depending on the requirements of the job.

Energy dispersive X-ray analysis (EDS) is generally used in conjunction with the SEM. The EDS provides a microscopic elemental analysis for elements generally heavier than Boron. The major advantage of EDS analysis is that minerals in SEM images can be identified based on their relative elemental content. The requirements for specimens is the same as that for SEM. Cost is about $35/ sample.

Less routinely used petrographical techniques are not necessarily less valuable than those that are more routinely used. The less routinely used techniques are simply not as popular in the oil patch for various reasons, such as cost of equipment and lack of familiarity. These techniques include computer aided petrographical image analysis, fluid inclusion studies, electron microprobe analysis, rock stable isotopes, and vitrinite reflectance.

Computer-aided petrographical image analysis (PIA) provides rapid, accurate characterization of rocks at a pore/grain scale (typically using thin sections). Grain and pore size distributions are rapidly imaged, enhanced, and quantified. Thin section porosity and permeability can be calculated and correlated with porosity and permeability from standard core analysis. The major advantages of computer-aided PIA are that the technique is rapid; once the data is in the computer it can be rapidly manipulated, and visual enhancement of grain/pore/interstitial material relationships is available. Semi-automated analysis of many features visible on standard thin sections should become a major part of all petrographical analysis in the near future. Cost is about $100-200/thin section depending on the work required.

Fluid inclusions are actual samples of diagenetic fluids trapped within and between crystals of reservoir and nonreservoir rocks. Heating (homogenization) and freezing/melting experiments on fluid inclusions yield information about the temperature of formation at the specific time that the inclusion was trapped, about the equivalent salinity of the inclusion liquid, and about the dominant chlorides within the fluid. Inclusions analysed from various diagenetic stages in reservoir rocks may therefore be used to help reconstruct the thermal history with absolute temperatures, provide information about timing of maturation of organics, and assess the chemical composition of the reservoir brines through time. The experiments are made on cut down thin sections or more often on doubly polished mineral grains plucked from the rock. Two-phase inclusions (gas and liquid) only form if the homogenization temperatures are greater than about 40°-50° C, which is common in late stage cements from petroleum reservoirs. The costs of fluid inclusion analysis will be quite variable, depending upon the types and numbers of experiments required; generally expect to spend $50-100/ hour. One half days work is often enough time to provide some minimal amount of useful information.

Electron microprobe analysis provides nondestructive quantitative or qualitative microchemical analysis at discrete locations which can be presented individually, as transects, or statistically. The resolution of spot analysis is about 2 μ. Most solids heavier than Boron can be probed provided that the sample is stable under the electron beam and can fit into the sample chamber (about 1 in. x 1 1/4 in.). The data derived from the electron microprobe is useful to many fields of interest in the oil patch, particularly fluid-rock compatability studies for secondary or tertiary production, determining composition of scales in tubing or casing, or in helping work out the chemistry of diagenesis of reservoir rocks. Element distribution "mapping" can provide valuable information about whether problematical minerals will be contacted by injected fluids and, therefore, must be chemically modelled. Costs are about $100/ hour. Quantitative microchemical spot analysis takes only minutes, however, transects across grains or cement crystals often require 2-4 hours of machine time.

The most commonly used stable isotopes are those of Carbon and Oxygen found in carbonate minerals. The isotope ratios found are a function of the depositional environment, temperature of entrapment, and equilibration

between the diagenetic fluids and the rocks. One specific example of the usage of stable isotopes of Carbon and Oxygen in carbonate reservoirs is the identification of unconformities or exposure surfaces which often have a great effect on reservoir compartmentalization. Differences in isotope ratios for the same diagenetic mineral phase may represent different compartments that were present at that time. Stable isotopes of Carbon and Oxygen from carbonates will cost about $30-40 for each isotope ratio/sample. Prices are often reduced if a large number of samples are to be run. Results may be obtained from bulk rock samples, or more useful information may be obtained from mineral separates.

The reflectance of coal macerals measured in reflected light has been a standard technique for evaluating coal ranks. It has been extended to particles of disseminated organic matter (kerogen) occurring in shales and in other rocks. Vitrinite reflectance (R_O) is a function of the thermal maturity of the type of kerogen and can be related to onset and peak generation of oil, generation of condensate and wet gas, and evolution of dry gas. R_O has great application in the exploration phase where it may be of critical interest to determine whether potential source beds have indeed been subjected to sufficient heat to generate hydrocarbons which could then migrate into potential traps. Recent studies using R_O have also begun to investigate the effects of differential organic maturity for compartments within the same reservoir. Cost for R_O analysis is about $90-120/ sample.

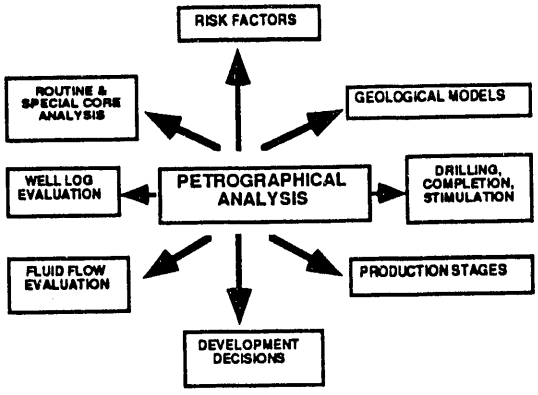


Figure 1. Areas with which petrographic analysis may be integrated.

STRUCTURAL
- COMPARTMENTALIZATION
- DIAGENETIC OVERPRINT
- DEPOSITIONAL SYSTEM

↓

STAGES OF PRODUCTION

Figure 2. Three major geological elements of the reservoir heterogeneity classification system. Note that each of these three elements has distinct effects on primary, waterflood, and EOR operations. Based on Geoscience Inst. for Oil and Gas Recovery Research, 1990.

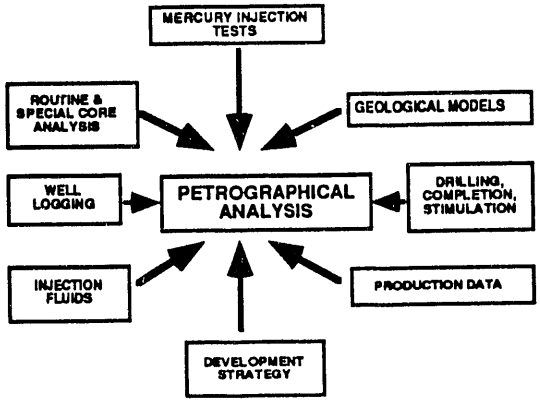


Figure 3. Petrographic analysis does not stand alone. Many areas provide data, special constraints, and insight into the job.

ROUTINE USAGE

- OPTICAL MICROSCOPY
  - POLARIZED LIGHT
  - UV FLUORESCENCE SOURCE
  - CATHODOLUMINESCENCE (CL)
- X-RAY DIFFRACTION (XRD)
- SCANNING ELECTRON MICROSCOPY (SEM)
  - ENERGY DISPERSIVE X-RAY (EDS)

Figure 4. Routinely used petrographic tools and techniques. These techniques tend to be widely known.

OPTICAL MICROSCOPY

COST:	$50 UP/ VISUAL SCAN $100 UP/ POINT COUNTED
PROVIDES:	• ROCK TYPE • MINERALOGY (major clay groups) • TEXTURAL DATA • PORE SYSTEM DESCRIPTION • SHAPE, SIZE, SORTING • DIAGENETIC HISTORY • MICROPALEONTOLOGY
REQUIREMENTS:	CORE OR CUTTINGS DESTRUCTIVE
RESOLUTION:	1 μ

Figure 5. Types of information provided, requirements, and approximate costs or commercially available optical microscopy.

ULTRAVIOLET FLUORESCENCE

COST:	$25-35/ SAMPLE- QUALITATIVE $50-60/ SAMPLE- QUANTITATIVE
PROVIDES:	• DISTRIBUTION OF FLUORESCENT PHASES • RESULTS QUANTITATIVE OR QUALITATIVE • PROVIDE ESTIMATES OF BULK POROSITY • MICROPOROSITY DISTRIBUTION • DISTINGUISH ORGANICS, FLUID INCLUSIONS
REQUIREMENTS AND RESULUTION:	SAME AS FOR OPTICAL MICROSCOPY

Figure 6. Types of information provided, requirements, and approximate costs for commercially available ultraviolet fluorescence microscopy.

CATHODOLUMINESCENCE

COST:	TYPICALLY $25-35
PROVIDES:	• LUMINESCENCE CREATED BY ELECTRON BEAM BOMBARDMENT • DETERMINATION OF PORE-FILLING FABRICS • RAPID DETERMINATION OF CL PHASES • FEATURES INVISIBLE IN TRANSMITTED LIGHT • COMPOSITIONAL ZONING
REQUIREMENTS:	SOLIDS: SLABS, POLISHED THIN SECTIONS

Figure 7. Types of information provided, requirements, and approximate costs for commercially available cathodoluminescence microscopy.

X-RAY DIFFRACTION

COST:	$100/ SAMPLE
PROVIDES:	QUANTITATIVE BULK ROCK & CLAY FRACTION MINERALOGY
REQUIREMENTS:	MOST SOLIDS SMALL SAMPLE SIZE
LIMITATIONS:	CRYPTOCRYSTALLINE OR NON-CRYSTALLINE PHASES DESTRUCTIVE (POWDERED) NO SPATIAL INFORMATION

Figure 8. Types of information provided, requirements, and approximate costs for X-ray diffraction of powdered rock samples.

SCANNING ELECTRON MICROSCOPY

COST:	$110-150/ SAMPLE
PROVIDES:	SEI: HIGH MAGNIFICATION OF PORES, GRAINS TEXTURAL, GEOMETRICAL RELATIONSHIPS BEI: IMAGES CHANGE REFLECT COMPOSITION BASED ON AVERAGE ATOMIC WEIGHT
REQUIREMENTS:	SOLIDS STABLE UNDER ELECTRON BEAM SMALL SAMPLE SIZE
RESOLUTION:	SEI 80 ANGSTROMS BEI ABOUT 2 MICRONS

Figure 9. Types of information provided, requirements, and approximate costs for scanning electron microscopy (SEM). SEI indicates secondary electron imaging, BEI indicates backscattered electron imaging.

ENERGY DISPERSIVE X-RAY ANALYSIS

COST: $35/ SAMPLE

PROVIDES: MICROSCOPIC (μ) ELEMENTAL ANALYSIS

REQUIREMENTS: SAME AS SEM (USED IN CONJUNCTION)
SOLIDS (BULK , THIN SECTION, POWDER)
ATOMIC NUMBER GREATER THAN 10

MAJOR ADVANTAGE: IDENTIFICATION OF MINERALS IN SEM IMAGES

Figure 10. Types of information provided, requirements, and approximate costs for energy dispersive X-ray analysis (EDS).

LESS ROUTINE USAGE

- COMPUTER AIDED PETROGRAPHIC IMAGE ANALYSIS
- FLUID INCLUSION STUDIES
- ELECTRON MICROPROBE
- VITRINITE REFLECTANCE
- STABLE ISOTOPES OF C, O

Figure 11. Less routinely used petrographic tools and techniques. These techniques tend to be less often used at this time mainly because of lack of widespread familiarity. They are, however, no less useful than the more routinely used techniques.

COMPUTER-AIDED PETROGRAPHIC IMAGE ANALYSIS

COST: $100-200/ THIN SECTION

PROVIDES:
RAPID, ACCURATE CHARACTERIZATION
AT PORE/GRAIN SCALE:
- GRAIN SIZE DISTRIBUTION
- PORE SIZE DISTRIBUTION
- THIN SECTION ø, K
- ø-K CORRELATION

ADVANTAGES:
RAPID
COMPUTER MANIPULATION
VISUAL ENHANCEMENT OF PORES, GRAINS

Figure 12. Types of information provided, requirements, and approximate costs for computer aided petrographic image analysis.

FLUID INCLUSIONS

COST: $50-75/ HOUR

PROVIDES:

- HOMOGENIZATION- MINIMUM TEMPERATURE OF FORMATION
- FREEZING POINT DEPRESSION- EQUIVALENT SALINITY
- FIRST MELT- DOMINANT CHLORIDE
- PRIMARY & SECONDARY INCLUSIONS WITHIN MINERAL PHASES.

REQUIREMENTS:

DOUBLY POLISHED GRAINS, THIN SECTIONS
TWO-PHASE INCLUSIONS >40°-50° C

LIMITATIONS:

DEFORMED (STRETCHED) INCLUSIONS
PRESSURE CORRECTION FOR T_H

Figure 13. Types of information provided, requirements, and approximate costs or fluid inclusion analysis.

ELECTRON MICROPROBE ANALYSIS

COST: $100/ HOUR

PROVIDES:

- NONDESTRUCTIVE, QUANTITATIVE
- MICROCHEMICAL ELEMENTAL ANALYSIS AT DISCRETE LOCATIONS
- ABOUT 1 μ SPATIAL RESOLUTION
- SPOT ANALYSES, TRAVERSES, STATISTICAL

REQUIREMENTS:

MOST SOLIDS, METALS, ROCKS, ETC.
HIGHLY POLISHED, FLAT SURFACE
FITS INTO SEM CHAMBER
WITHSTANDS ELECTRON BEAM BOMBARDMENT

Figure 14. Types of information provided, requirements, and approximate costs for electron microprobe quantitative elemental analysis.

VITRINITE REFLECTANCE

COST: $90-120/ SAMPLE

PROVIDES:

- MEAN RANDOM REFLECTANCE (R_o) OF COAL MACERALS: COALIFICATION STAGE
- THERMAL MATURITY OF ORGANIC MATTER RELATIVE TO OIL WINDOW; OIL, PEAK OIL, & GAS GENERATION
- SOURCE ROCK MATURITY

REQUIREMENTS:

ORGANICS IN SAMPLE: SHALE, COAL
DESTRUCTIVE SAMPLING: MACERATION,
R_o FROM POLISHED, DISSEMINATED ORGANICS

Figure 15. Types of information provided, requirements, and approximate costs for vitrinite reflectance.

STABLE ISOTOPES OF C, O

COST: $30-40/ SAMPLE FOR CARBONATES
$120 FOR $\delta^{18}O$ IN SILICATES

PROVIDES:
- $^{18}O/^{16}O$ RATIO (SMOW OR PDB)=$\delta^{18}O$ in ‰
- $^{13}C/^{12}C$ RATIO (PDB)= $\delta^{13}C$ in ‰
- ENVIRONMENT OF DEPO/PRECIPITATION
- TEMPERATURE OF FORMATION
- MICROSTRATIGRAPHY
- CORRELATION OF DIAGENETIC STAGES

REQUIREMENTS:
SMALL SAMPLE-DESTRUCTIVE TESTING
MICRO-SCALE DRILL PRESS WITH X,Y,Z DIRECTIONAL CONTROLS
ISOTOPES HAVE NOT RE-EQUILIBRATED

Figure 16. Types of information provided, requirements, and approximate costs for stable isotopes of carbon and oxygen from rock samples.

APPLICATIONS OF PETROGRAPHIC ANALYSIS

DRILLING, COMPLETION, & STIMULATION
- Timely Identification of Sensitive Minerals
- Predict Rock/Fluid Interaction: Water or Injected Fluids
- Identify Clay Varieties, Diagenetic Minerals
- Susceptibility to Mobilization and Fines Migration
- Anticipate Pore Geometry

LOG ANALYSIS
- Calibration of Mineralogy
- Pore Description: Formation Factor
- Clay Type & Amount, Grain Sphericity: Cementation Factor
- Geometrical Effects (eg. microporosity)
- Clay Minerals: Water Saturation Calculation

CORE ANALYSIS
- Identify Rock Framework, Matrix, & Diagenetic Mineralogy
- Describe Inhomogeneity: Volumes & Distribution; Rank & Scale Them
- Basic Information: Pore Distribution & Textural Features

STAGES OF PRODUCTION
- Primary: Characterize Textures & Petrophysical Properties
- Waterflood: Questions of Rock-Water Interaction; Maps of Mineral Distributions; Pore System Description
- EOR: Potential Reactions Between EOR Chemicals, Reservoir Rock & Formation Fluids.

GEOLOGICAL MODELS
- Lithology & Mineralogy
- Texture: Grain & Pore Size, Sorting
- Pore System: Distribution & Type
- Effects of Diagenesis: Relative Timing; Cementation, Leaching, Compaction

Figure 17. Contributions that petrographic analysis can make to five areas of reservoir description, development, and management.

IMAGING TECHNOLOGY APPLIED TO ROCK AND FLUID MEASUREMENTS IN CORES

By Liviu Tomutsa
National Institute for Petroleum and Energy Research (NIPER)
P.O. Box 2128
Bartlesville, OK 74005
Phone: (918) 337-4472

ABSTRACT

X-ray Computerized Tomography (CT) and Nuclear Magnetic Resonance Imaging (NMRI), are nondestructive imaging technologies that provide measurements of fluid saturation distributions, trapping, and temporal fluid movement within core. Also, these technologies are used to provide rapid and accurate characterization of whole core for selection of locations where representative core plugs can be extracted. CT images both the fluids and the rock matrix whereas NMRI images only the mobile fluids. The quantitative measurements of fluid saturations within cores provide the required information to understand the effect of rock heterogeneity on the movement of fluids and to design optimized processes for oil extraction. Improved oil recovery methods such as surfactant/polymer, microbial or CO_2 flooding and profile modification agents can be optimized for the reservoir fluids and the rock characteristics, by direct measurement and visualization of oil saturation distributions within cores during flooding. At NIPER, CT, NMRI, petrographic image analysis (PIA) and minipermeameter systems developed as part of multi-year research programs, are used to generate data to be used in a synergistic approach. Thus, information about rock and rock/fluid interactions at scales from microns to feet can be obtained. This information, when integrated with larger scale geological and engineering data aids in the construction of improved reservoir models. When the appropriate imaging technology is used with a clearly defined purpose, the supplemental information obtained is well worth the incremental costs incurred.

CT technology has gained increased use in the oil and gas laboratory because of its speed, accuracy, and relatively low cost. The CT scanners commonly used are the widely available medical scanners with X-ray beam energies up to 150 kV. They are adequate for most sandstone and carbonate cores with diameters of 5 in. or less. Industrial scanners with higher beam energies are recommended for highly cemented or larger diameter cores. CT scanners provide two-dimensional images that are visual maps of the X-ray attenuation (dependent on the bulk density and the effective atomic number) of small volumes (voxels) situated in cross-sections of the sample. Depending on the type of scanner, generation of a two-dimensional cross-section can take from a few minutes for early models to 5 seconds for the latest models. The voxels in an image are part of a "slice" of rock 2 to 8 mm thick. Each voxel represents a rectangular shaped volume which, depending of the scanner resolution, has a square base with sides in the range of 0.2 to 0.6 mm and an adjustable height, usually between 2 and 8 mm. Usually, a calibration scale is selected such that attenuations of air and water are -1,000 and 0 Houndsfield units (H.U.), respectively. Sandstone attenuations are usually between 1,200 and 1,600 H.U. To differentiate the water phase

from the oil phase, the X-ray attenuation of one of the phases is increased by adding a tagging agent, such as sodium iodide to water or iododecane to oil. The difference in X-ray attenuation between the scans of the rock sample fully saturated with brine and those of the dry rock is proportional to the amount of fluid present in the sample and, therefore to the sample porosity. Based on subtraction of scans of the dry sample from the saturated sample, two-dimensional porosity maps are calculated. In the next step, by combining the data from the porosity maps with the data from the scans of the sample saturated with two or three phases (brine, oil, gas), saturation maps of the fluid phases are generated. Saturation resolutions in the range ±1 to 3% can be achieved depending on the tagging agent concentration and the core rock type. Further, at NIPER, by using porosity values from CT and correlation of porosity with permeability from PIA, permeability distributions within the sample are calculated.

Three major adaptations to medical scanners are necessary for usage in the oil and gas studies:

1. providing a means of transferring two-dimensional data arrays from the CT scanner to another computer for performing the calculations necessary to generate porosities, permeabilities, and saturations;
2. providing for accurate and repeatable positioning of the core sample within the X-ray beam for generating the attenuation maps of the sample dry, brine and multiphase saturated at precisely the same locations; and
3. software to compute and display the porosities, permeabilities, and saturations.

The computer interfacing hardware and software designed and implemented at NIPER permits the transfer of data in real time, thus reducing significantly the time delay between scanning and analysis. The NIPER table permits the repositioning of the experiments within the scanner to better than 13 micron accuracy, even after the experiments have been temporarily removed from the scanner table. The data display and analysis is performed on high-end Macintosh computers using both in-house and commercial software.

By taking a series of slices of porosities, permeabilities, and saturations and joining them together, three-dimensional arrays are generated. From these, either three dimensional views or two-dimensional views in arbitrarily oriented planes can be generated. Also, monitoring tracer tests by CT provides a direct view of the presence of barriers, channels, or permeability contrasts between various layers in the samples used for bench-top flooding studies. The CT-derived porosities, permeabilities, and saturations can be used in conjunction with mathematical simulations of the flow processes in the cores to verify the validity of simulator predictions.

The CT-computed saturations are useful in designing various improved recovery processes being considered for field applications. Bench-top experiments are first performed by visually displaying the oil saturations at different flood stages thus permitting the direct computation of the effectiveness of a process. Used third-generation CT scanners can be purchased at costs of less than $50,000, and second generation scanners can be as low as $10,000. Annual maintenance costs can vary widely, depending on whether or not a maintenance contract is purchased or the maintenance is performed in-house. When in-house maintenance is performed, due to the wide availability of spare parts for certain scanners, the annual maintenance costs can be in the $10,000 to $20,000 range, while maintenance contracts often exceed $50,000. These costs do not include costs for the replacement of X-ray tubes which can be in the range of $10,000 to $30,000. Tubes usually last for 70,000 to 100,000 scans. CT costs are in the range of $10 to $20/slice for the raw CT attenuation data, depending of the equipment cost, image quality, number of slices,

experimental set-up requirements, and presentation and display requirements. When the project involves porosity, permeability, and saturation calculations, incremental costs in the range of $5 to $10/slice are to be expected.

Using the topogram mode of a CT scanner, rapid two-dimensional projections along the longitudinal axis of a core are generated. This permits the imaging of sedimentary structures, diagenetic alterations, and fractures visible at sub-millimeter resolutions in a fraction of the time required to perform cross-section CT scans, merge them, and reconstruct the longitudinal cross-sections. While more qualitative than CT scans, the topogram permits rapid evaluation of whole cores and selection of representative core plug locations. Topogram costs are in the range of $40 to $100/ft, depending on the total length of the core to be scanned, the detail of interpretation required, and the presentation and display requirements.

NMRI permits the nondestructive imaging of fluids within a core by monitoring the response to an external radio frequency signal of atomic nuclei placed in a homogeneous, strong magnetic field. The nucleus most frequently imaged is the hydrogen nucleus (^{1}H) present in both water and oil. Nuclei of the other elements such as fluorine (^{19}F), sodium (^{23}Na), and carbon (^{13}C) can also be detected. The NMR signal, since it is proportional to the nuclei concentration in the volume investigated, can be used to measure porosity or saturation. By using a variable gradient field superimposed over the initial magnetic field, the response signal frequencies can be related to the position of the respective nuclei, and an image of the spatial distribution of the porosity or saturation can be constructed. Medical NMRI scanners, which are designed for imaging patients, often are not well suited for imaging fluids in rock. Also, they are seldom available as low-cost used equipment. On the other hand, the cost of a new unit designed for core studies and having a 31-cm diameter bore superconducting magnet is over $500,000. Maintenance costs, mainly due to the periodic need for liquid helium replacement for the superconducting magnet, are higher than those for CT equipment. The spatial resolutions of CT and NMRI porosity and fluid saturation maps as well as the time required to acquire the data are comparable. Although, higher costs are involved, the NMRI techniques are necessary in cases where tagging of fluids is neither possible nor acceptable, as in the case of imaging reservoir fluids in preserved cores or when performing floods with reservoir fluids.

A highly promising application developed at NIPER is NMRI microscopy of porous rock, which allows the imaging of fluids within the pore space with spatial resolutions approaching 20 micrometers. By using specially designed, high magnetic field gradient coils and computer hardware and software, a commercial, multinuclear, high-resolution Fourier transform spectrometer has been transformed into a dual use instrument that can perform both high resolution NMR spectroscopy and NMRI microscopy. Visualization of either single phase or multiphase fluids within pores can be used to improve the understanding of rock pore structure or the distribution of fluids within pores due to the effect of improved recovery mechanisms, such as chemical or microbial flooding. Because of the novelty of this method of imaging and the highly variable time requirements and depending on the information required by a specific project, costs are variable and can be determined only after the scope of work is defined.

The attached figures, based on work performed at NIPER, illustrate briefly the imaging applications described above. More detailed information is available in NIPER publications and will be sent by the author upon request.

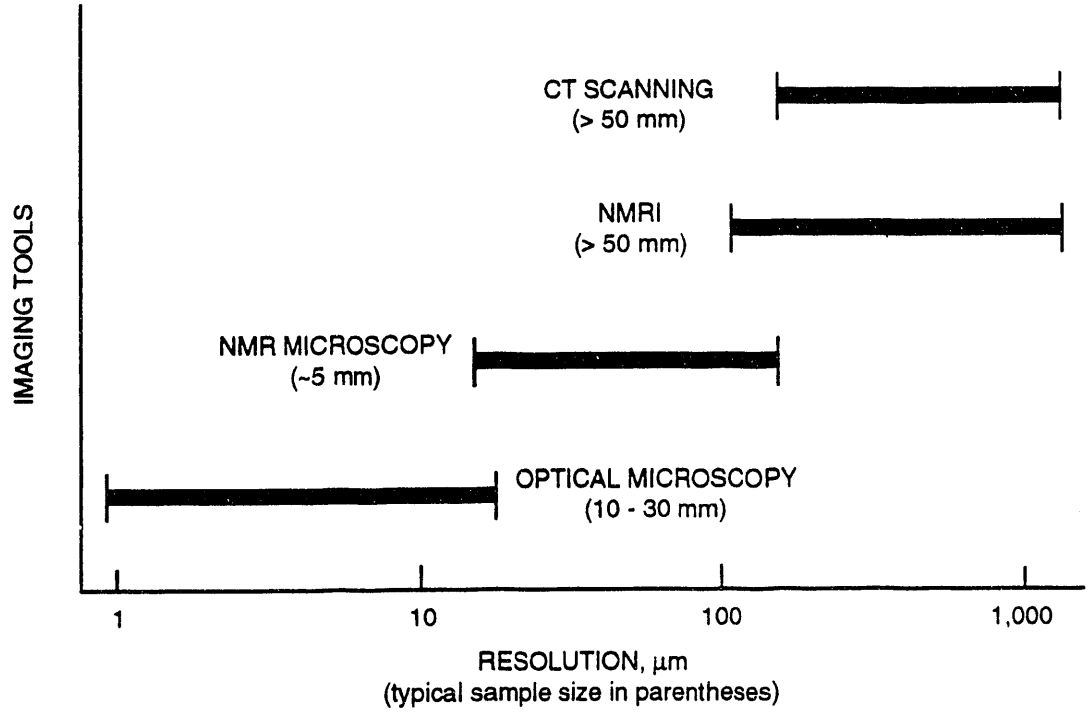


FIGURE 1 - Comparison of resolutions of various imaging techniques.

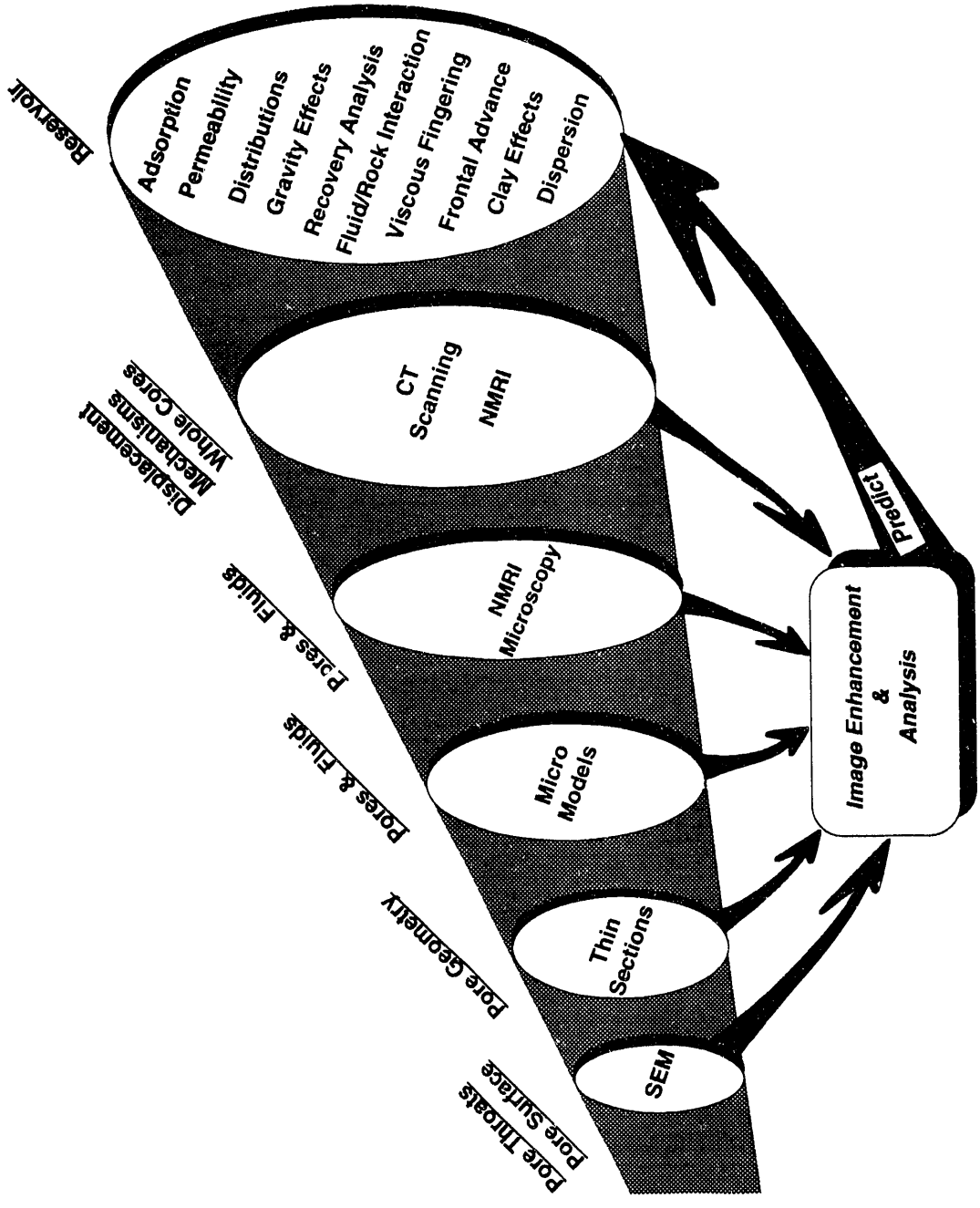


Figure 2. - Concept of integrating imaging technologies spanning several magnitudes of resolution.

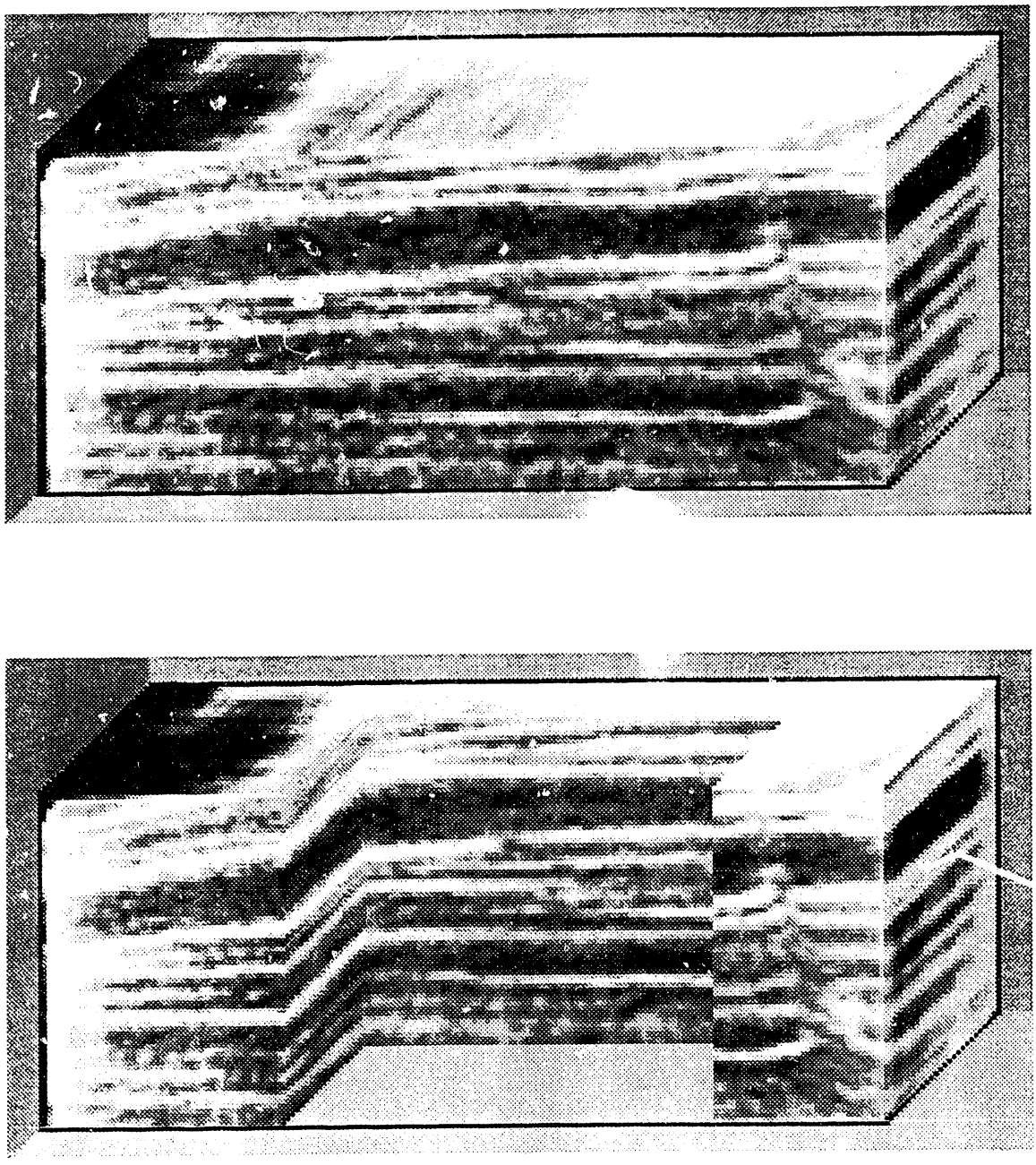


FIGURE 3. - Three - dimensional CT image of layered Shannon formation sandstone slab. Darker gray represents higher porosity rock.

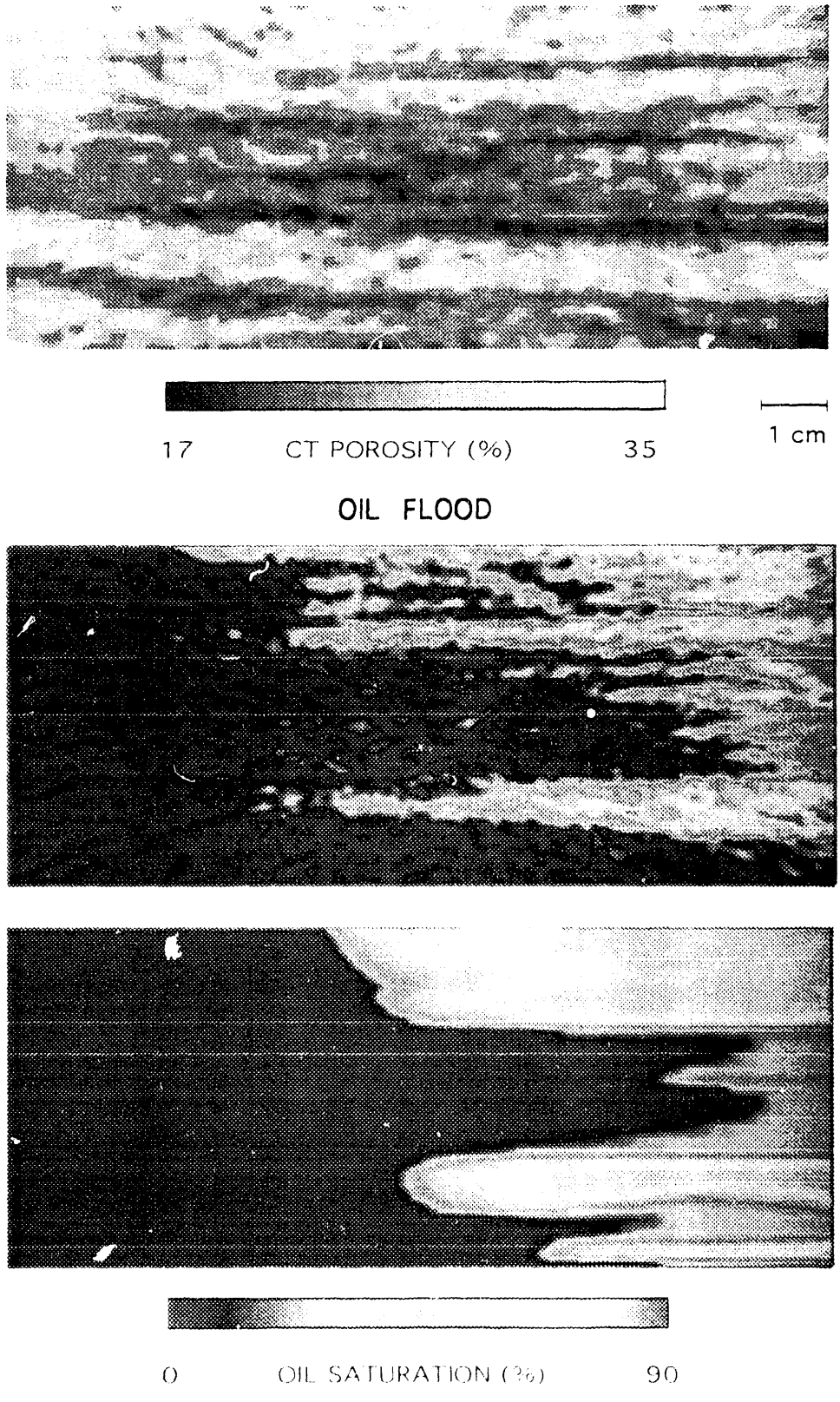
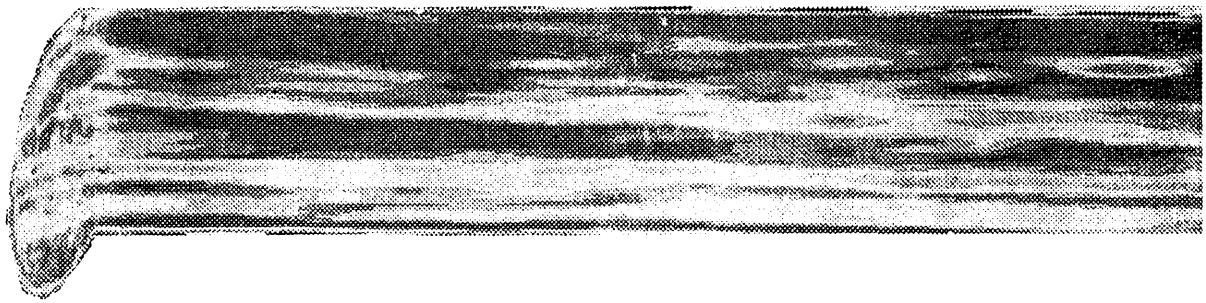
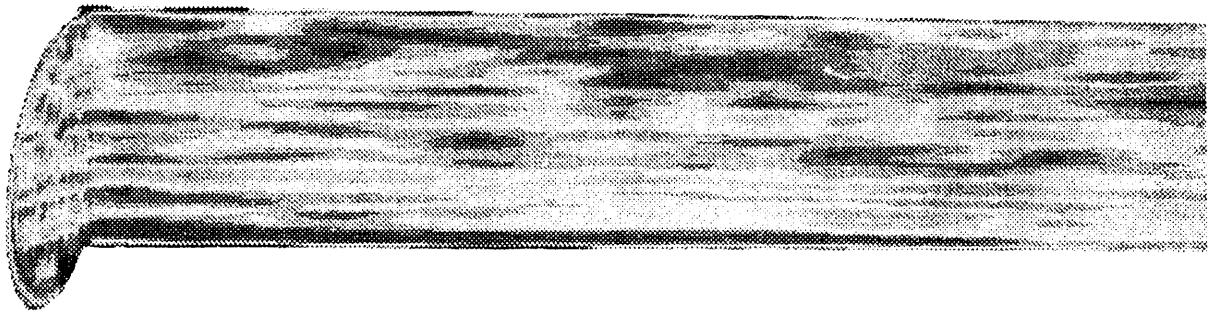


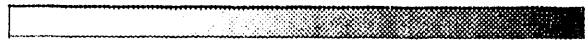
FIGURE 4. - Shannon formation sandstone porosity and oil saturation.



(a)



(b)



0 OIL SATURATION (%) 35

FIGURE 5 - CT measured core saturation (a) after waterflood (b) after microbial flood

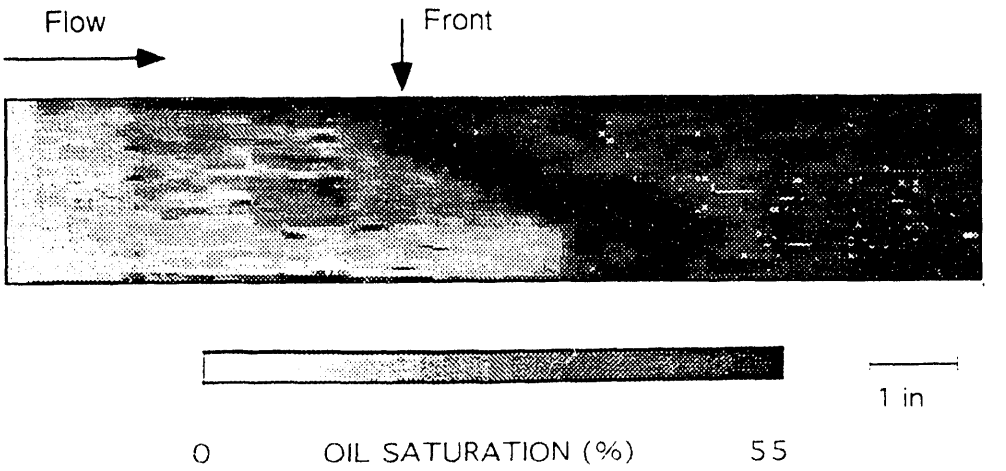


FIGURE 6. - CT measured oil saturation during surfactant flooding .

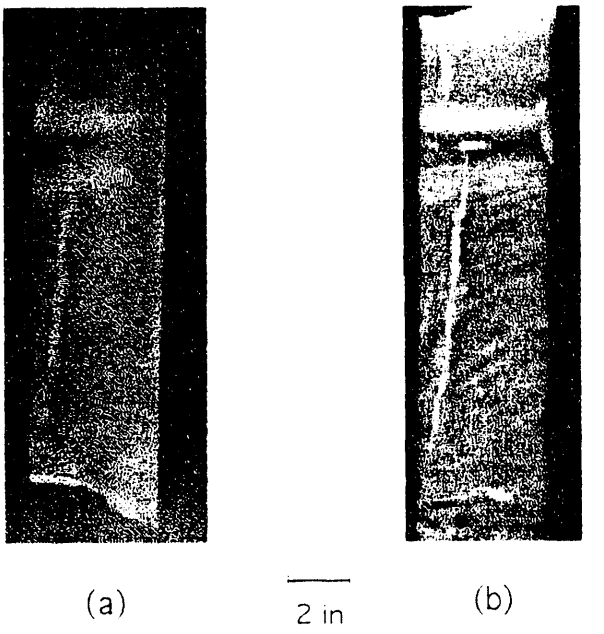


FIGURE 7. - Comparison between: (a) photograph of slabbed core and (b) X-ray topogram of whole core.

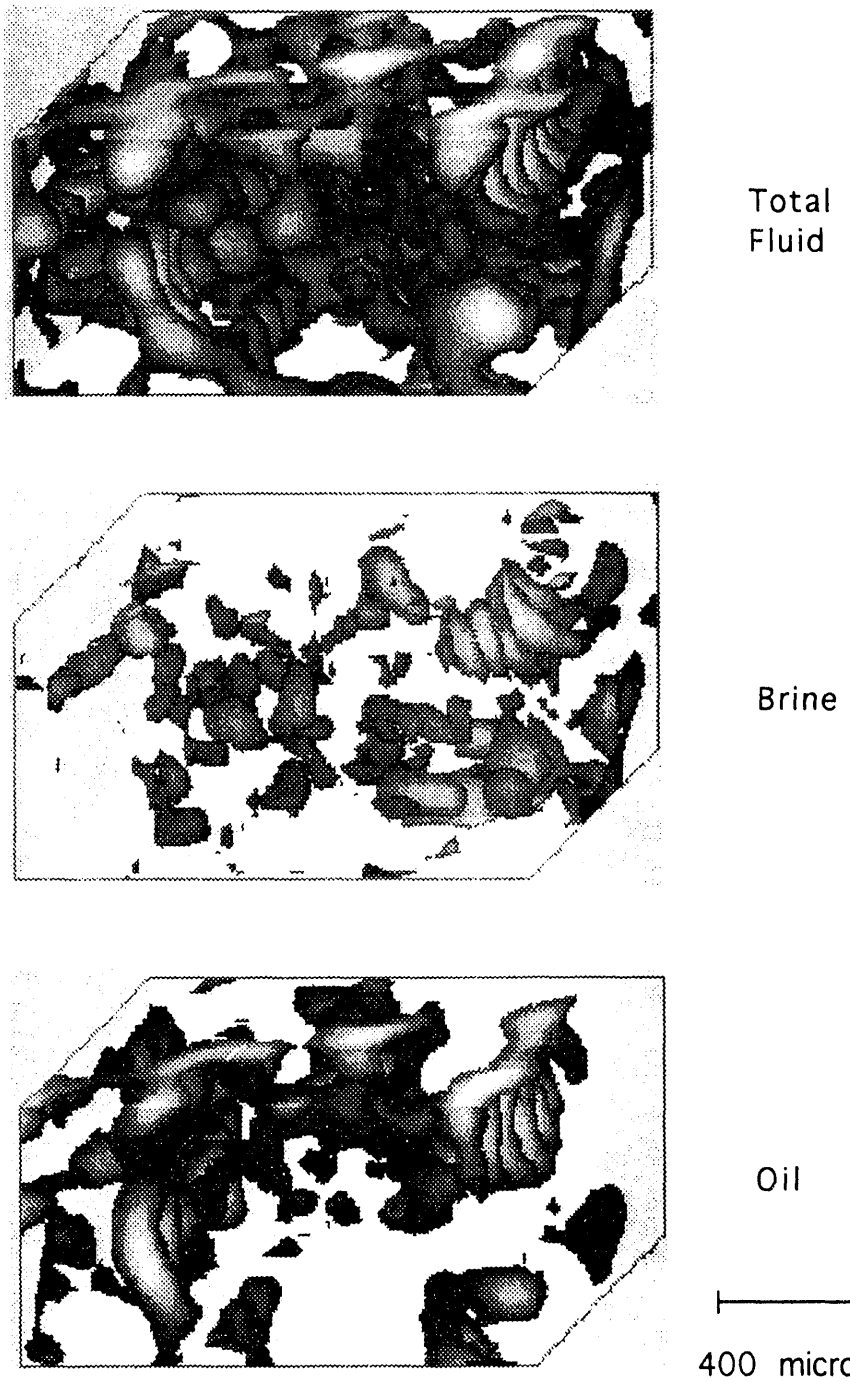


Figure 8. NMRI microscopy image of fluids in Bentheim sandstone at residual brine saturation.

APPLICATION OF HYDROGEOCHEMICAL TECHNIQUES TO RESERVOIR CHARACTERIZATION

by Michael Szpakiewicz
National Institute for Petroleum and Energy Research
P.O. Box 2128
Bartlesville, OK 74005
phone 918-337-4456 fax 918-337-4365

ABSTRACT

Advantages of monitoring the chemical and isotopic composition of reservoir waters in large- and small-scale field operations are conveyed in practical terms. Hydrogeochemical techniques are effective and affordable but not yet commonly used by field operators. Interpretation of log signatures and calculation of realistic values of oil saturation are particularly dependent on distribution of salinity, composition, and resistivity of oil-associated formation waters.

In many cases, however, these inexpensive methods cannot be used to the fullest for characterization of oil reservoirs because formation water data are scarce, incomplete, or constrained to only one stage of reservoir development. Recommendations for collecting better quality hydrogeochemical data are provided.

A flow chart of this hydrogeochemical presentation is shown in Fig. 1. It consists of two parts. In part 1, a general review of hydrochemical and isotopic methods and their practical applications will be provided (Figs. 2 and 3). In part 2, a few selected field examples will be discussed.

The following additional subjects will be addressed in part 1:

- relationship between hydrodynamics and hydrochemistry of a reservoir system;
- source of data for minimum and optimum geochemical interpretation;
- hydrogeochemical techniques, including chemical and isotopic analyses;
- sources of the most common errors in sampling and misinterpretations of results;
- costs of chemical and isotopic analyses of fluid samples (Figs. 4 and 5); and
- methods of data interpretation; selected graphic presentations of acquired data.

Part 2 of the presentation will include a brief review of three published field cases where hydrogeochemical and isotopic data proved to be useful for identification of a large-scale reservoir hydrodynamics (flow pattern), degree of fluid confinement or leakage, and for designation of flow units. In addition, the compartmentalization of fluids and reinterpretation of oil reserves will be illustrated more specifically by the case study of Patrick Draw Field in Wyoming. The hydrodynamic and interrelated hydrogeochemical pattern in Patrick Draw Field will be briefly

compared with that in Bell Creek Field in Montana.

Results obtained in Patrick Draw clearly indicate that geochemical analysis based on relatively simple and affordable hydrochemical data can significantly improve the interpretation of reservoir hydrodynamic conditions and calculation of oil reserves. Salinities range in that field from less than 20,000 to more than 72,000 mg/L total dissolved solids (TDS). The original (pre-wateflood) salinity contrasts were mapped (Fig. 6). Significantly different calculated water saturations (and oil in place) using four characteristic R_W values encountered in Patrick Draw are illustrated in Fig. 7. The isosalinity map provided the basis for recalculation of the original oil-in-place (Fig. 8). Approximate calculations of oil saturation based on the mapped distribution of water salinities and corresponding resistivities indicate up to 12% more original oil-in-place in the area of highly saline formation waters generally updip, and up to 5% less oil in the much lower salinity sections near the oil-water contact (Sharma et al. 1992). In addition, the identified contrasts in water composition and salinity (Fig. 9) indicate that some EOR processes may be negatively affected in the areas of high water salinity and enhanced quantity of divalent cations or major anions such as bicarbonates.

Approximate boundaries of several square miles of mega-compartments have been identified in Patrick Draw on the basis of mapped salinity contrasts, documented heterogeneity of hydrochemical facies, and monitored changes of bottomhole pressures (Fig. 10). The reservoir partitioning may impose severe restrictions on reservoir drainage.

Hydrogeochemical heterogeneity of the original oil associated formation waters in Patrick Draw is in a strong contrast with a perplexing homogeneity of pre-waterflood formation waters in Bell Creek (Szpakiewicz, 1992). In Bell Creek, a geological separation of productive units within the Muddy formation is evident based on earlier geological studies conducted by NIPER. Deep valley incisions into the oil productive shoreline barrier deposits apparently divide the reservoir in Bell Creek into units with separate oil-water contacts. In spite of the erosional/depositional barriers, the salinity and composition of formation waters within individual compartments (production units A, B, C, D) is surprisingly uniform (Figs. 11 and 12). Salinities of formation water in Bell Creek are anomalously low (4,000 to 7,000 mg/L TDS) at reservoir depth of 4,600 ft. A regional potentiometric map (Berg et al., 1985) clearly indicates that Bell Creek reservoir must be under hydrodynamic drive causing downdip tilt of the oil-water contacts. The hydrodynamic drive adds 429 ft (86 %) of oil column to the 68 ft of calculated hydrostatic oil column (Ibid.). there is little doubt that the hydrodynamic drive is responsible for significant increase of oil reserves and for the observed homogenization of oil associated formation waters. Downdip flow of water through the selectively leaking "barriers" also explains lack of extensive gas caps in the reservoir. Most of the reservoir gas probably escaped updip using the same low-permeability routes as water did flowing in the opposite direction.

The anomalously low salinity was recognized in Bell Creek at the very early stage of reservoir development, but the origin of the anomaly remained unclear. The areal and vertical

compositional similarity of hydrochemical facies had not been identified in the 1960s. The homogenization offers, however, clear indication of a massive water invasion which could have been easily tested by the isotopic analyses if an attempt of identification of meteoric component in water molecules had been undertaken. The potentiometric map documented the hydrodynamic flow in the 1980s. It's construction, however, required collecting pressure data from numerous wells drilled in the whole region. Underutilization of the geochemical and isotopic techniques in the 1960s probably delayed for two decades the understanding of field hydrodynamics and related distribution of hydrocarbons.

Conclusions of the presentation are given in Fig. 13. A comparison of contrasting geochemical information from Patrick Draw and Bell Creek fields provides an instructive example that hydrogeochemistry and hydrodynamics are strongly interrelated and provide most reliable information when considered together. The depositionally similar reservoirs (shoreline barrier sediments) were probably subjected to different hydrodynamic regimes and resulted in different characteristics of formation fluids, petrophysical properties of rocks, distribution of oil reserves, and hydrocarbon productivity. Hydrochemical analysis casts new light on hydrodynamic milieu of hydrocarbons in the two studied reservoirs but still more can be learned by utilizing stable isotope techniques.

References

Berg, R.R., G.M. Larberg, and L.D. Recker, 1985. Dynamic Flow in the Lower Cretaceous Muddy Formation, Northeast Powder River Basin, Wyoming and Montana. Thirty-Sixth Annual Field Conference, Wyoming Geological Association Guidebook, p. 149-156.

Sharma, B., M. Chang, and M. Szpakiewicz, 1992. The Effect of Salinity Variations on Oil Saturation Calculations from Wireline Logs at Patrick Draw Field. In: Integration of the Geological/Engineering Model with Production Performance for Patrick Draw Field. DOE Report NIPER-634, p. 41-52.

Szpakiewicz, M., 1992. The Importance and Application of Hydrogeochemical Techniques to Reservoir Characterization. In: Integration of the Geological/Engineering Model with Production Performance for Patrick Draw Field, Wyoming, DOE Report NIPER-634, p. 13-40.

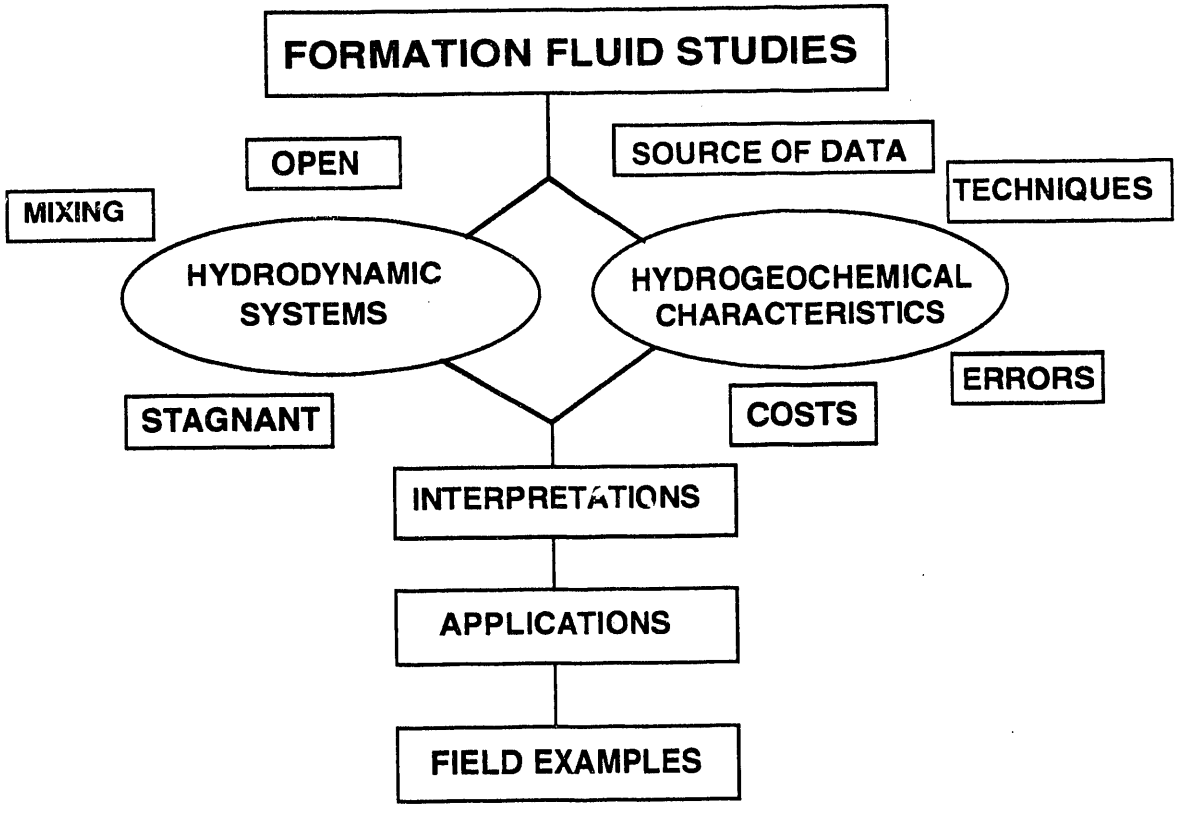

FORMATION FLUID STUDIES
OPEN
SOURCE OF DATA
MIXING
TECHNIQUES
HYDRODYNAMIC SYSTEMS
HYDROGEOCHEMICAL CHARACTERISTICS
ERRORS
STAGNANT
COSTS
INTERPRETATIONS
APPLICATIONS
FIELD EXAMPLES

FIGURE 1

APPLICATIONS OF HYDROGEOCHEMICAL ANALYSIS

- **DEFINES FLOW/NO-FLOW ZONES:**
  - FLUID COMPARTMENTS
  - FLOW BOUNDARIES
  - FLOW UNITS (HYDROSTRATIGRAPHY)
  - CROSS-FLOW, LEAKAGE, MIXING OF FLUIDS
- **INDICATES POTENTIAL FOR:**
  - DIAGENETIC ALTERATIONS
  - SCALING
- **IMPROVES:**
  - LOG INTERPRETATION
  - CALCULATION OF OIL RESERVES (OOIP)
  - DESIGN OF EFFECTIVE EOR PROCESSES

FIGURE 2

ISOTOPE RATIO ANALYSES

$^{3,2,1}H_2$ $^{18,17,16}O$ $^{13,12}C^{2,1}H_4$

$\delta\ ^{18}O/^{16}O\ H_2O$ (‰)

$\delta\ D/H\ H_2O$ (‰)

$\delta\ ^{13}C/^{12}C\ CH_4, C_2 - C_4, HCO_3^-$ (‰)

$\delta\ ^{34}S/^{32}S\ SO_4^{-2}$ (‰)

$^{87}Sr/^{86}Sr$; $^{36}CL/^{35}CL$; $^{37}CL/^{35}CL$

FIGURE 3

COSTS OF STABLE ISOTOPE RATIO ANALYSIS

(SIRA PER FLUID SAMPLE)

HYDROGEN	
WATER	$40.00
ORGANICS	$75.00

OXYGEN	
GAS	$20.00
WATER	$30.00
CARBONATES	$30.00

CARBON	
CO_2	$20.00
CARBONATES	$35.00
ORGANICS	$45.00

SULFUR	
SULFATES	$60.00
ORGANICS	$100.00

STANDARD ADDITIONAL COSTS
SAMPLING
INTERPRETATION

COSTS EXAMPLES
SIRA OF WATER MOLECULES ($^{2/1}H_2\,^{18/16}O$) - $70.00 PER SAMPLE
SIRA OF HYDROCARBONS ($^{2/1}H^{13/12}C$) - $120.00 PER SAMPLE

FIGURE 4

APPROXIMATE COSTS OF CHEMICAL WATER ANALYSES (PER SAMPLE)

• STANDARD SHORT ANALYSES	COSTS
$Na^+ + K^+$, Ca^{2+}, Mg^{2+}	
Cl^-, HCO_3^-, SO_4^{2-}	
T, pH, Rw, TDS, density (ρ)	$100.00
• EXPANDED ANALYSES	
Major ions and physical properties plus:	
Sr^{2+}, Ba^{2+}, $Fe^{2+,3+}$, Mn^{2+}	
CO_3^-, I^-, Br^-, B^-	
Eh	$200.00
• STANDARD ADDITIONAL COSTS	
Sampling and sample handling	
Field measurements of unstable constituents	
Geochemical interpretation	

FIGURE 5

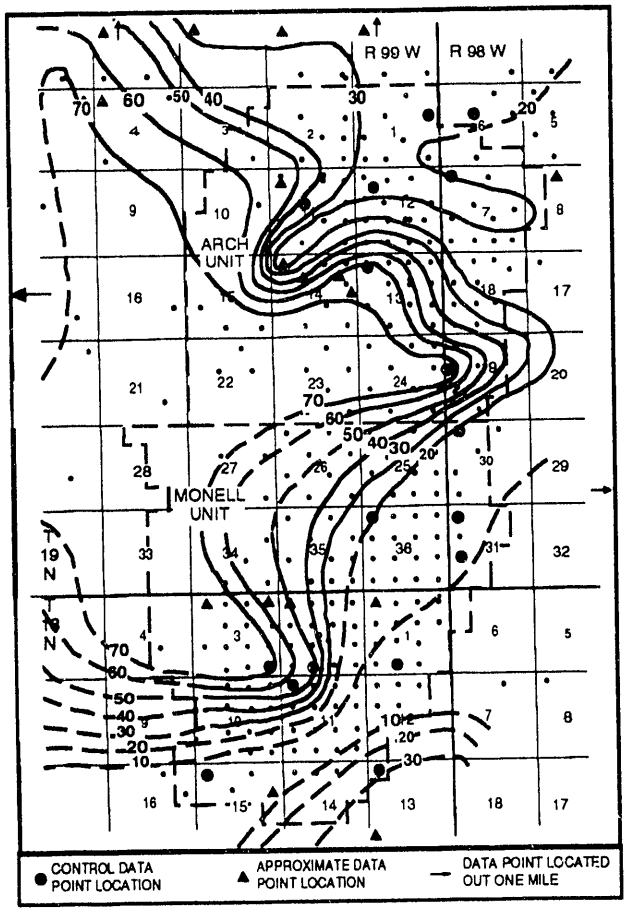


FIGURE 6. Isosalinity map of formation waters in the Almond Formation of Patrick Draw Field (in g/l).

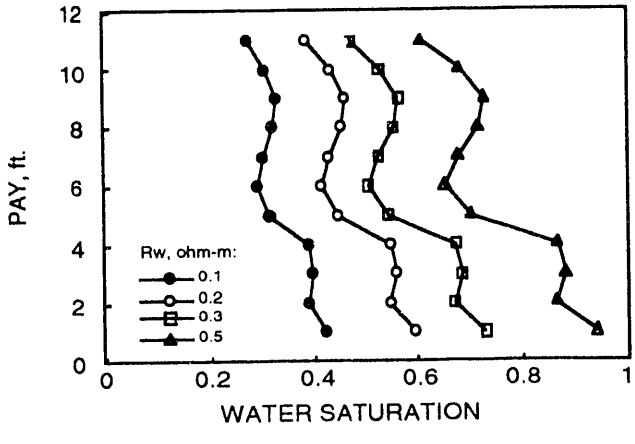


FIGURE 7. Water saturation profiles of well Arch 46, calculation based on four different water resistivity values.

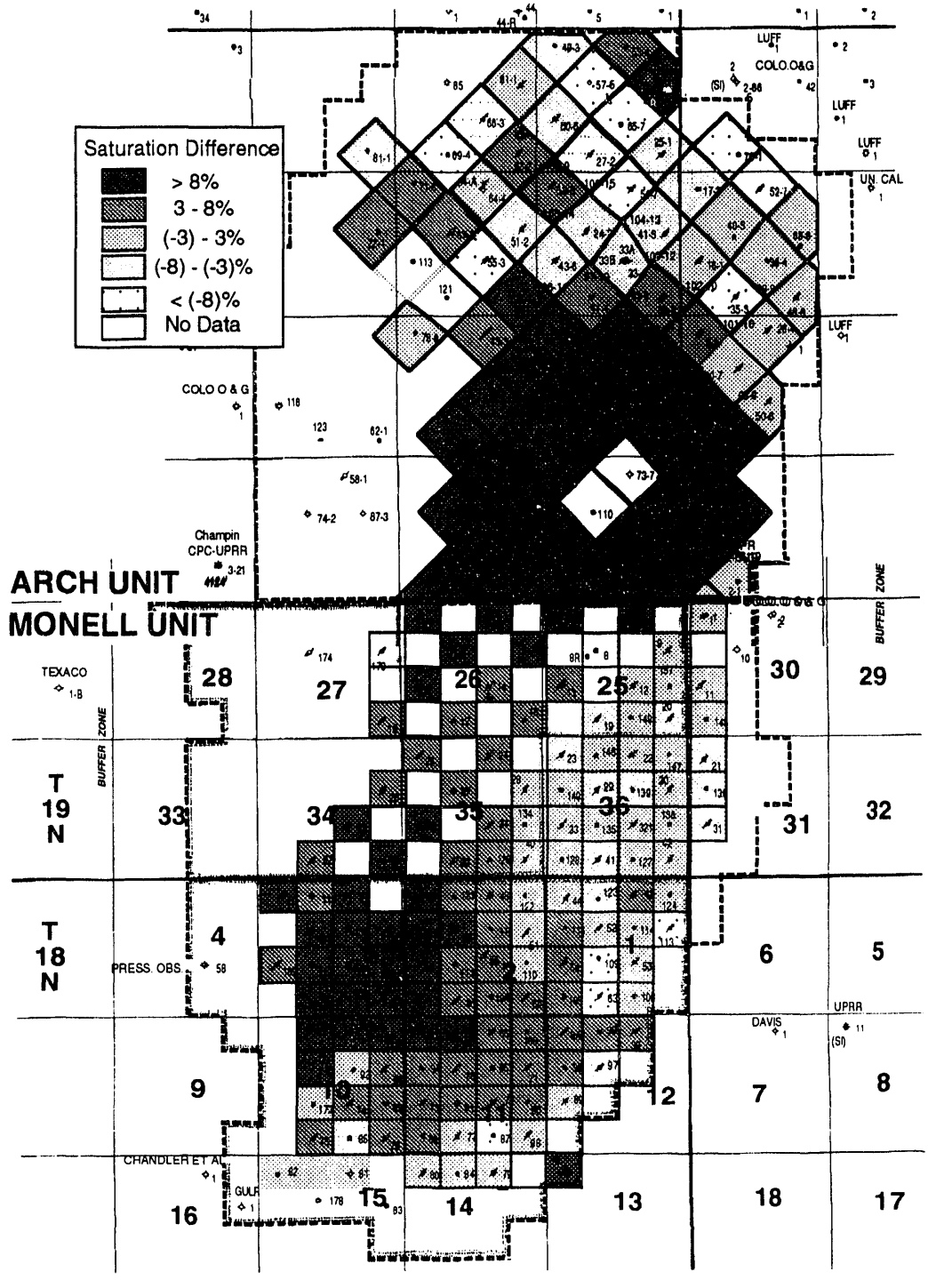


FIGURE 8. Difference of oil saturation interpretation in Patrick Draw Field by subtracting Sw values based on constructed salinity map from those based on constant water resistivity.

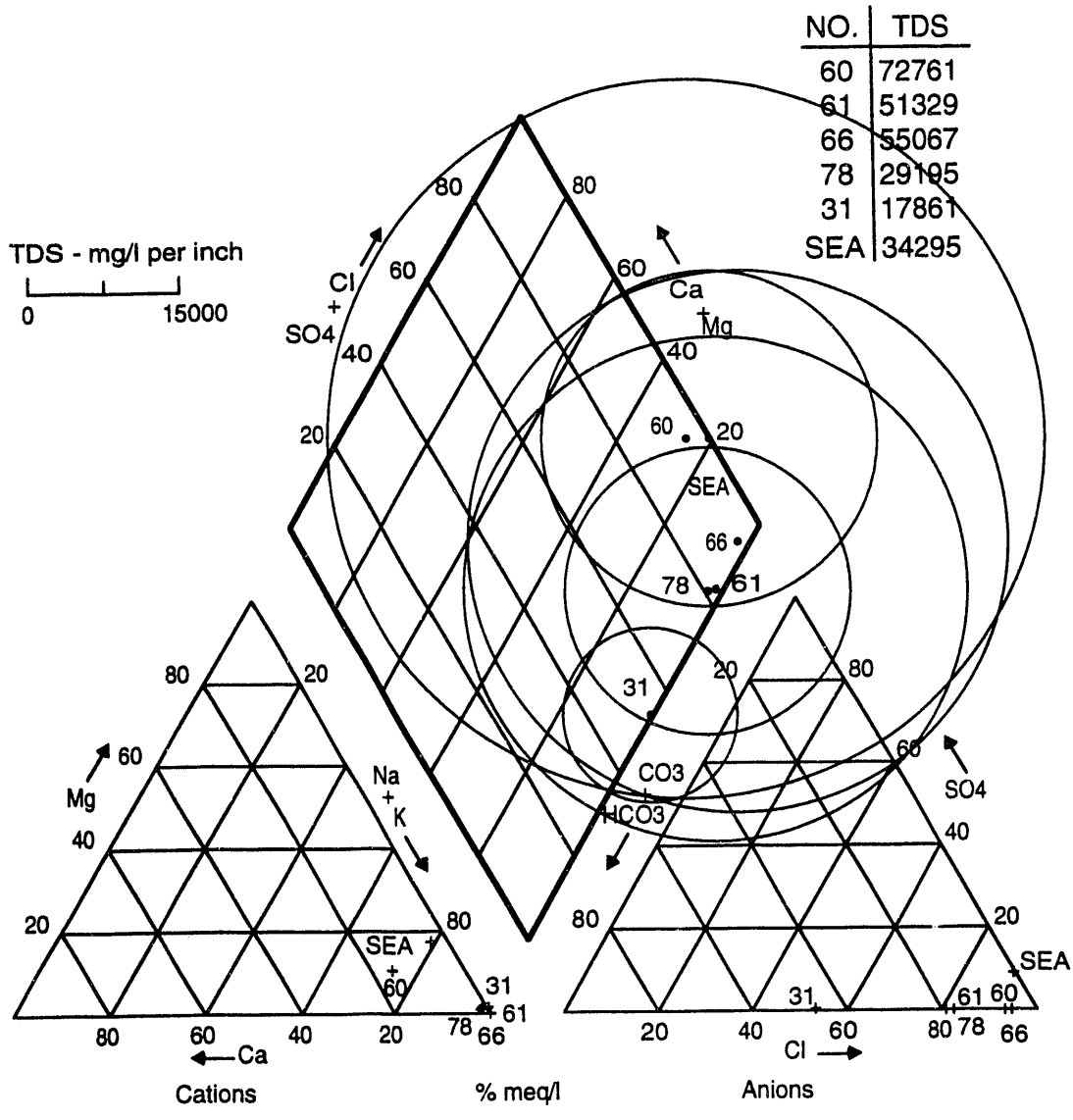

NO. | TDS
60 | 72761
61 | 51329
66 | 55067
78 | 29105
31 | 17861
SEA | 34295
TDS - mg/l per inch
0
15000
Cl + SO4
Ca + Mg
Na + K
CO3 + HCO3
SO4
Cl
Mg
Ca
SEA
Cations
% meq/l
Anions

FIGURE 9

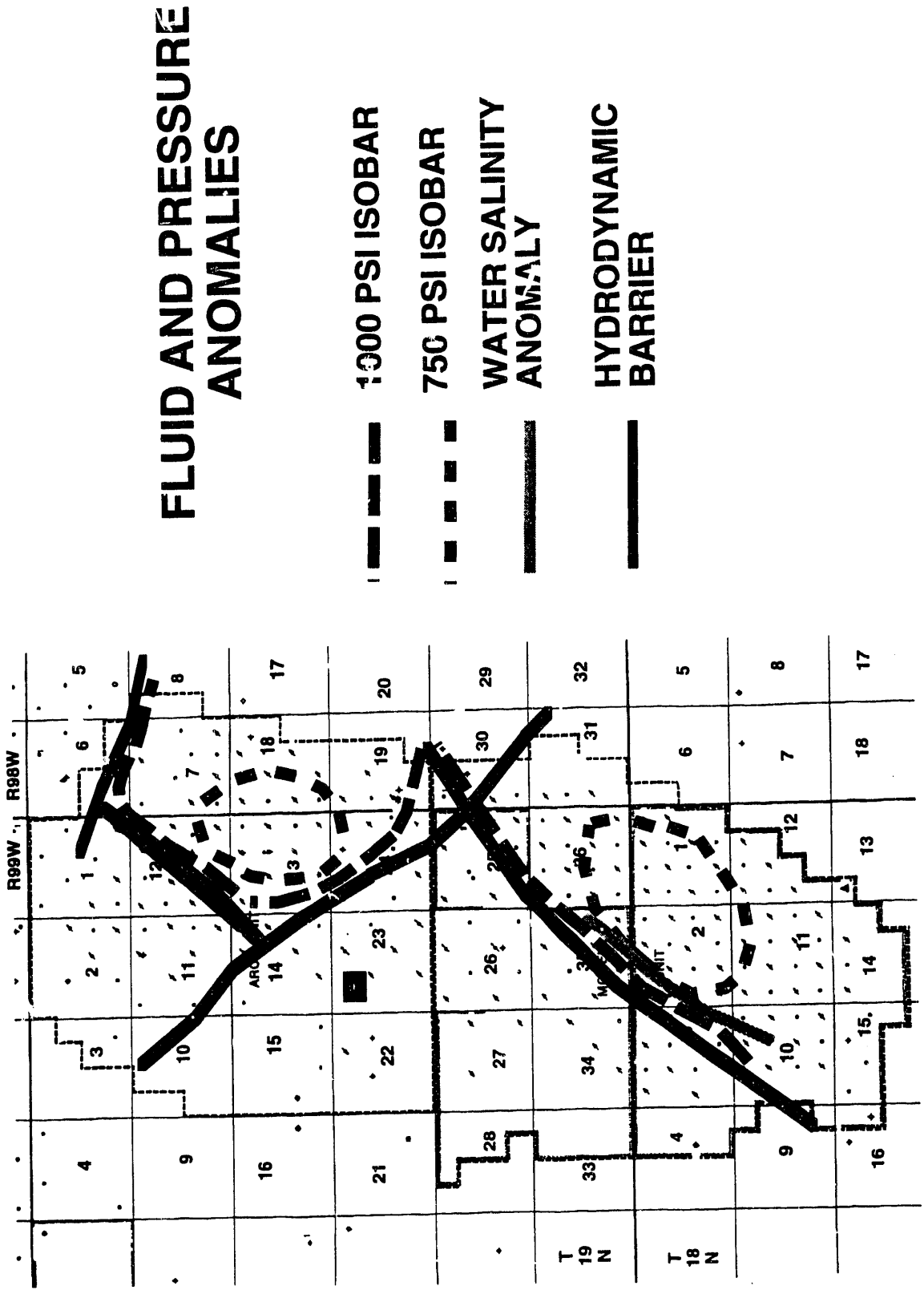

FLUID AND PRESSURE ANOMALIES
1300 PSI ISOBAR
750 PSI ISOBAR
WATER SALINITY ANOMALY
HYDRODYNAMIC BARRIER
R99W
R98W
T 19 N
T 18 N

FIGURE 10

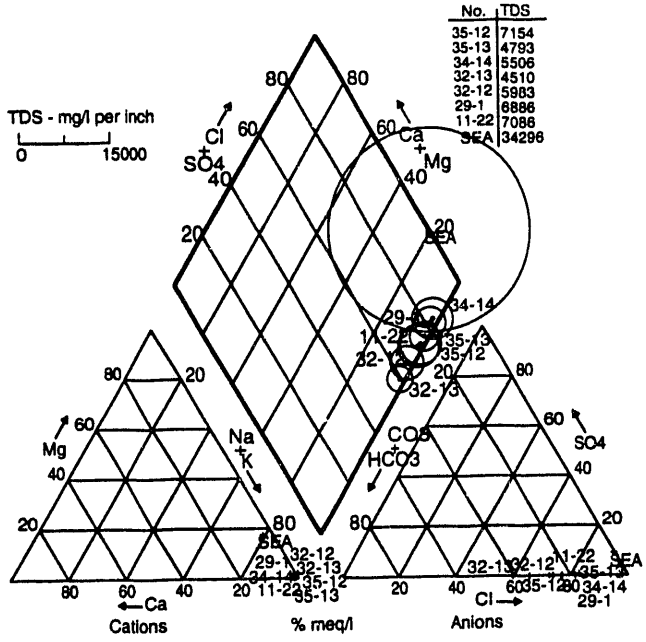


FIGURE 11

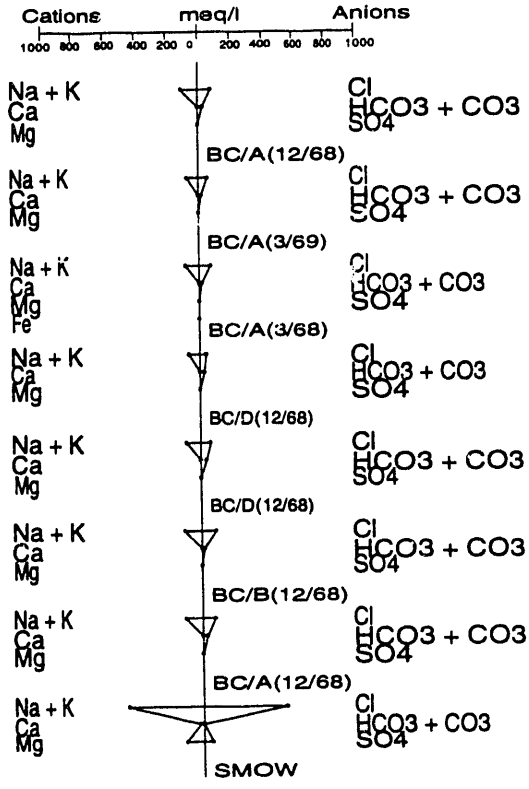


FIGURE 12

SUMMARY

- STUDYING FORMATION FLUIDS IS INFORMATIVE & AFFORDABLE
- HYDROGEOCHEMISTRY REFLECTS RESERVOIR HYDRODYNAMICS
- CONTRASTING WATER COMPOSITION INDICATES COMPARTMENTS
- LATERAL & VERTICAL HYDRAULIC COMMUNICATION IS INDICATED BY HOMOGENIZATION OF CHEMICAL AND ISOTOPIC COMPOSITION
- ROCK PETROPHYSICS IS STRONGLY AFFECTED BY PRODUCTS OF WATER-ROCK INTERACTION (DIAGENESIS)
- SALINITY VARIATION AFFECTS RESISTIVITY DISTRIBUTION, LOG INTERPRETATION, AND CALCULATION OF OIL RESERVES
- WATER COMPOSITION AFFECTS EFFECTIVENESS OF EOR PROCESSES

FIGURE 13

RESERVOIR HETEROGENEITY AND INFILL DRILLING

by

Riley B. Needham
Phillips Fellow Emeritus
Phillips Petroleum Co.
Bartlesville, Ok 74003
(918-661-9681)
fax: (918-662-2047)

Michael J. Fetkovich
Phillips Fellow Emeritus
Phillips Petroleum Co.
Bartlesville, Ok 74003
(918-661-6742)
fax: (918-662-2047)

W. Terry Siemers
Sr. Geol. Research Specialist
Phillips Petroleum Co.
Bartlesville, Ok 74003
(918-661-9514)
fax: (918-662-2047)

INTRODUCTION

It is well recognized that infill drilling has application in specific types of reservoirs. Two types are generally recognized as suitable for infill drilling: (1) reservoirs that exhibit areal differences in performance because of the presence of sealing faults, and (2) reservoirs of very low permeability, where closer well spacing is required to deplete the resource in an appropriate time. For all other types of reservoirs, it is critical that the type of heterogeneity be correctly identified before an infill drilling program is undertaken. When the reservoir heterogeneity is predominately vertical, resulting in layered, no crossflow behavior, then infill drilling is not applicable. The apparent potential for infill drilling typically stems from the concept of areal compartmentalization (development of sealed lenses or pods) as a result of lateral heterogeneity. To correctly determine the type of reservoir heterogeneity, it is absolutely essential to conduct and properly integrate a multidisciplinary engineering and geological evaluation of a reservoir. We are explicitly concerned with present integration methods and the non-rigorous synthesis and interpretation of reservoir engineering and geological data.

DISCUSSION

The Hugoton Field, the largest gas field in the continental United States, provides an excellent example of how improperly integrated studies can "go astray" and interpret the reservoir heterogeneity incorrectly as areal compartmentalization. Using all of the available performance information, it is clear that the reservoir, the Chase Group, is actually a layered, no crossflow type of reservoir. (Figures 1, 2, 3, and 4) (1, 2, 3, 4, 5, and 6)

In the engineering analysis of the Hugoton Field, higher measured pressures in newly drilled wells is repeatedly used as "evidence" that the reservoir is areally compartmentalized. Pressure

measurements obtained on the shutting-in of newly drilled wells can not support such a conclusion. By contrast, a limited number of pressures have been taken on individual layers which clearly establish that the heterogeneity type is layered, no crossflow (note the pressures and flow meter values in Figure 4).(8) In other fields, the exponential decline is used as a basis for the evaluation of the improved performance obtained by infill drilling. (9) Also, computer models are frequently used as the basis to justify infill drilling. (10) Caution must be used with these models because the "matched" solution obtained is not unique. Use of non-unique models and performance analysis based on the exponential decline often incorrectly indicated that infill drilling was successful. (7,8) An illustration of how exponential decline is incorrectly used to project expected future performance is shown in Figure 5. The actual well performance is shown for two wells to emphasize that the future performance is not represented by an exponential curve of rate versus time. For example, if an infill well had been drilled in 1966 and the actual curve shown was experienced (i.e., no production rate whatsoever from the infill), then the "improved performance" would be attributed to the act of drilling the infill well. Such an obviously erroneous method of analysis has been used to conclude that infill drilling was justified. A similar analysis can be done, with the same erroneous outcome, using the material balance with p/z versus cumulative production extrapolated as a straight line.

In the geological analysis arena, one often used technique to justify the need for infill drilling is the "potential for pods". In the visualization of the hypothetical pods, maps are constructed based on changes in the reservoir quality such as changes in porosity or water saturation. A cross-section drawn to illustrate this visualization of pods using porosity as a measure of reservoir quality is shown in Figure 6. In the visualization of pods, the changes in the reservoir quality are assumed to show that the formation of isolated, gas filled pods or lenses are highly probable. For pods to have been formed in the Chase Group, to have obtained a seal on all sides and be retained full of gas requires a very complex set of events. To date no scientific mechanism for such a set of events has been forthcoming. Indeed, if the formation of isolated pods is correctly viewed as a hypothesis, then there is overwhelming evidence, both geologic and engineering, which shows the hypothesis to be false. The hypothetical pods do not exist. Since the method of visualization of pods has been shown to be invalid in the Chase Group, why would the technique continue to be used in other reservoirs? We would suggest that infill drilling is being promoted rather than viewed on a rigorous basis using the best available analysis methods to integrate all of the geological and engineering data.

In the example case of the Chase Group of the Hugoton Field, there is a wide range of types of information which shows that additional gas from infill drilling will not be obtained. These include: 1) geologic evaluation of the productive layers and the interbedded barriers to vertical flow, 2) evaluation of the p/z versus cumulative production performance of original and replacement wells drilled over many years in 72 sections in the Guymon-Hugoton, 3) properly constructed and validated reservoir models used to forecast infill drilling performance, 4) the performance of the wells in the Kansas Hugoton during the mid 1960's when hydraulic fracturing was being conducted, and 5) the performance of all of the infill wells drilled since 1986 in the Kansas Hugoton.

Although the best chance for adding reserves by infill drilling would exist on the edges of the field, Figure 7 shows the results of drilling 3 wells on the edge of the field over a time period of from 1955 to 1983. All three wells were uneconomic; however, during the 27 years of no production the pressure encountered with the last well, drilled in 1983, had declined 241 psi. This decline shows that the section was being drained by other wells in the field although the reservoir quality at this location is not sufficient to result in economic production. This is good evidence that even the low quality reservoir rock is being depleted and is in effective communication with the rest of the field. Many other examples can be sited from the reference on the analysis of the 72 replacement wells.(5) When it is considered that the distribution of the replacement wells covered the entire Guymon-Hugoton, then the chance that new reserves would be found by infill drilling is very unlikely, even on the field edges.

In summary, it should be emphasized that when a layered, no crossflow type of reservoir (i.e., the Chase Group of the Hugoton Field) is improperly identified as being areally compartmentalized and infill drilling is invoked, the result is large capital expenditures with essentially no additional reserves being added. By focusing on infill drilling, critical capital is being wasted. Better performance could be achieved by reviewing individual well performance to assure that each well had been properly completed and stimulated. In layered, no crossflow reservoirs it is essential that completions and stimulations properly influence the entire productive interval, which frequently requires special stimulation techniques to assure that lower permeability layers are properly treated.

Examples are available from the performance of wells in the Kansas Hugoton that new completions in both old wells and in infill wells can result in higher production rates. These increased rates make individual wells more competative, but have not been seen to increase the gas reserves of the field.

CONCLUSIONS

1-- The proper identification of infill drilling applications requires the determination of the type of heterogeneity being exhibited through the proper integration of both geological and engineering investigations.

2-- Individual well performance must be evaluated to obtain a unique determination of the type of heterogeneity being exhibited.

3-- Properly designed and validated computer models can contribute to a better determination of the influence of the heterogeneity on the reservoir performance.

REFERENCES

1. McCoy, T. F., Fetkovich, M. J., Needham, R. B., and Reese, D. E.: "Analysis of the Kansas Hugoton Infill-Drilling Program," Journal of Petroleum Technology (June, 1992) 714-723.
2. McCoy, T. F., Fetkovich, M. J., Needham, R. B., and Reese, D. E.: "Analysis of Kansas Hugoton Infill Drilling-Part I: Total Field Results," paper SPE 20756 presented at the 1990 SPE Annual Technical Conference and Exhibition, New Orleans, Sept. 23-26.
3. Fetkovich, M. J., Needham, R. B., and McCoy, T. F.: "Analysis of Kansas Hugoton Infill Drilling, Part II: Twelve Year Performance History of Five Replacement Wells," paper SPE 20779 presented at the 1990 SPE Annual Technical Conference and Exhibition, New Orleans, Sept. 23-26.
4. Fetkovich, M. J., Ebbs, D. J., and Voelker, J. J.: "Development of a Multiwell, Multilayer Model to Evaluate Infill Drilling Potential in the Guymon-Hugoton Field," paper SPE 20778 presented at the 1990 SPE Annual Technical Conference and Exhibition, New Orleans, Sept. 23-26.
5. Ebbs, D. J., Works, A. M., and Fetkovich, M. J.: "A Field Case Study of Replacement Well Analysis Guymon-Hugoton Field, Oklahoma," paper SPE 20755 presented at the 1990 SPE Annual Technical Conference and Exhibition, New Orleans, Sept. 23-26.
6. Siemers, W. T. and Ahr, W. H.: "Reservoir Facies, Pore Characteristics, and Flow Units-Lower Permian, Chase Group, Guymon-Hugoton Field, Oklahoma," paper SPE 20757 presented at the 1990 SPE Annual Technical Conference and Exhibition, New Orleans, Sept. 23-26.
7. Clausing, R. G.: "Prefilled testimony," Docket No. C-164 Kansas Corporation Commission,

Topeka (1985) 1-26.

8. Carnes, L. M. Jr.: "Replacement Well Drilling Results--Hugoton Gas Field," Paper presented at the 1979 Kansas U. Heart of America Drilling & Prod. Inst. Mtg., Liberal, KS, Feb 6-7.
9. Sippel, M. A. and Levey, R. A.: "Gas Reserve Growth Analysis of Fluvial-Deltaic Reservoirs in the Frio and Vicksburg Formations Located in the Stratton Field, Onshore Texas Gulf Coast", paper SPE 22919 presented at the 1991 SPE Annual Technical Conference and Exhibition, Dallas, Tx, October 6-9.
10. Hower, T. L. and Collins, R. E.: "Detecting Compartmentialzation in Gas Reservoirs Through Production Performance", paper SPE 19790 presented at the 1989 SPE Annual Technical Conference and Exhibition, San Antonio, Tx, October 8-11.

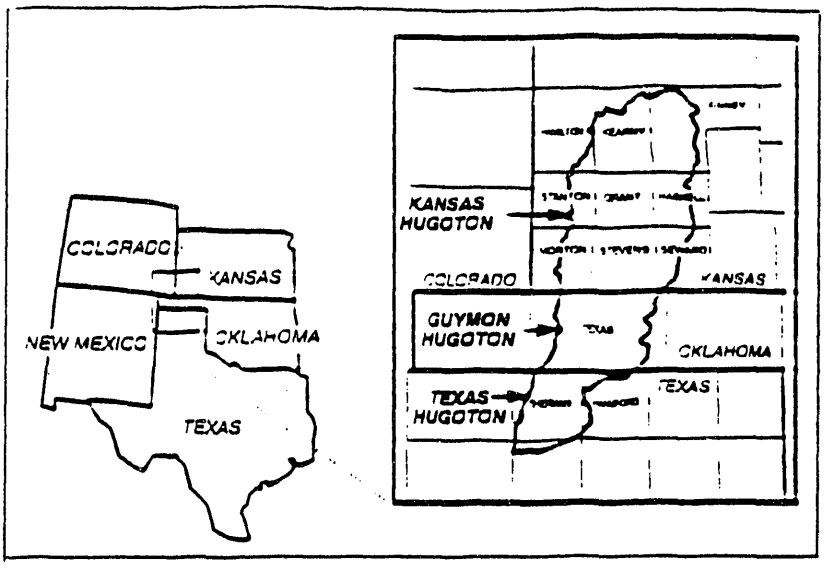


Fig. 1—Kansas Hugoton field location map.

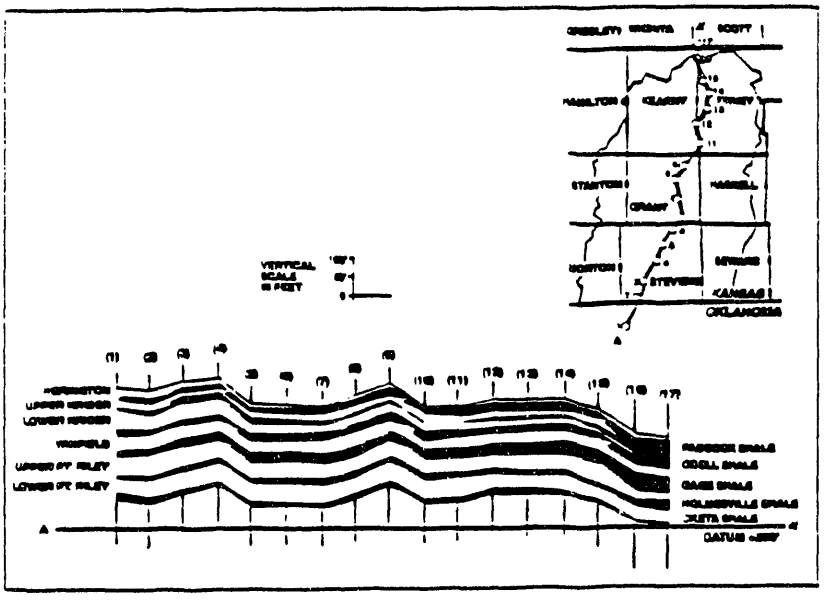


Fig. 2--North-south cross section through the Kansas Hugoton (after Clausing).

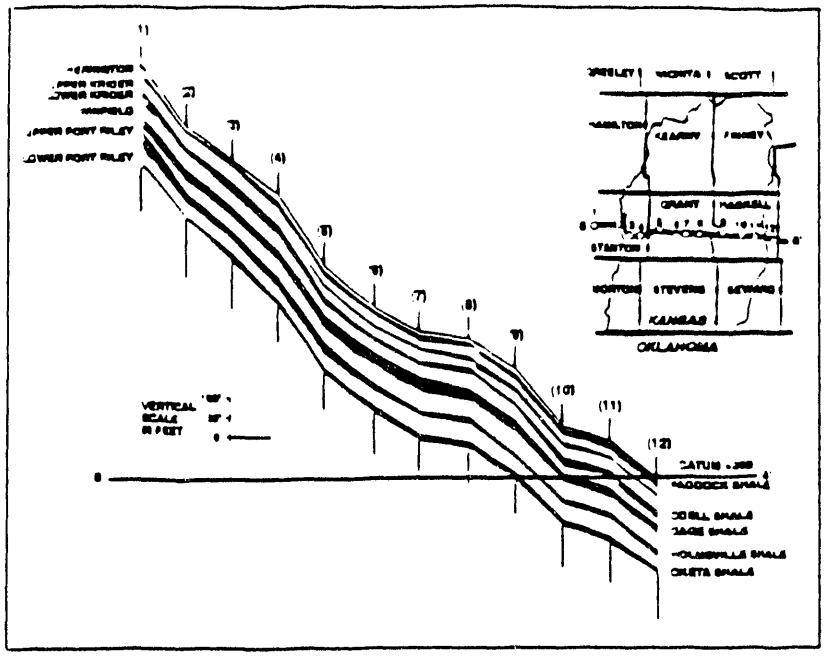


Fig. 3--East-west cross section through the Kansas Hugoton (after Clausing).

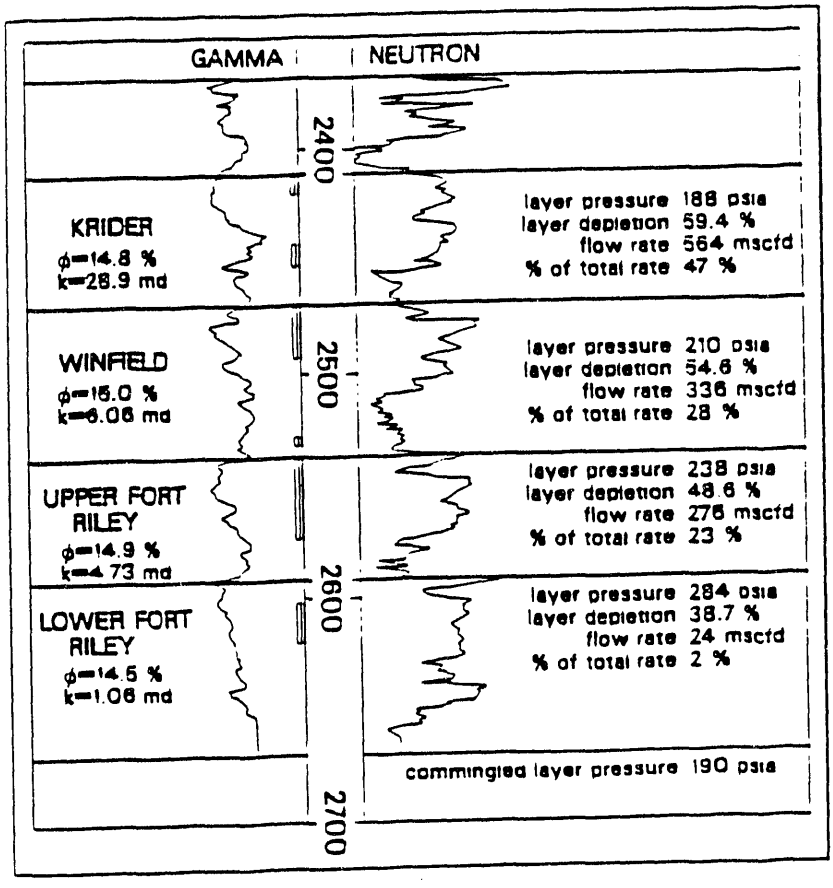


Fig. 4—Type log for the Gano No. A1 with individual-layer pressures and flow rates (after Carnes).

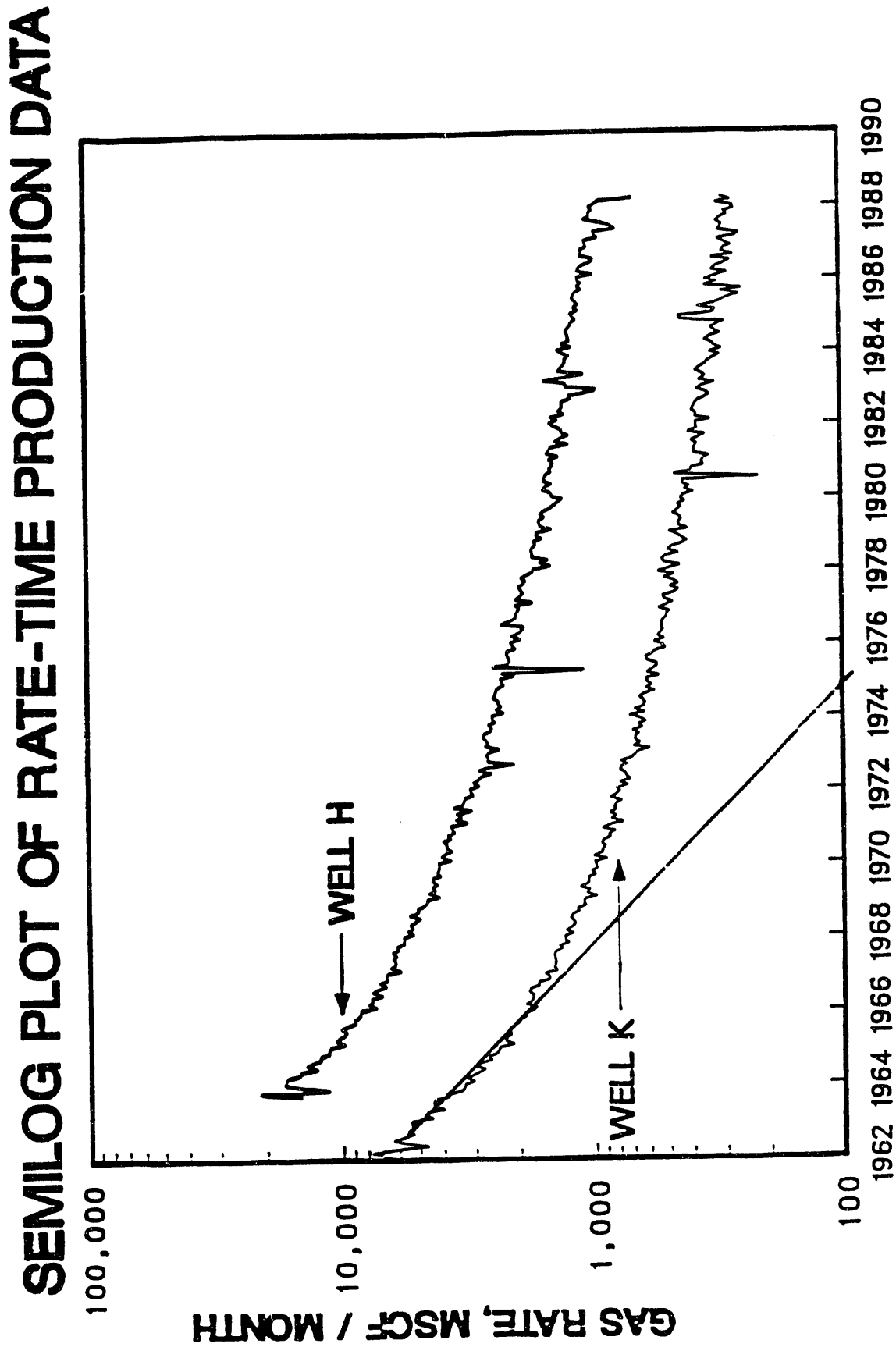

SEMILOG PLOT OF RATE-TIME PRODUCTION DATA
GAS RATE, MSCF / MONTH
100,000
10,000
1,000
100
WELL H
WELL K
1962 1964 1966 1968 1970 1972 1974 1976 1978 1980 1982 1984 1986 1988 1990
TIME, YEARS

FIGURE 5

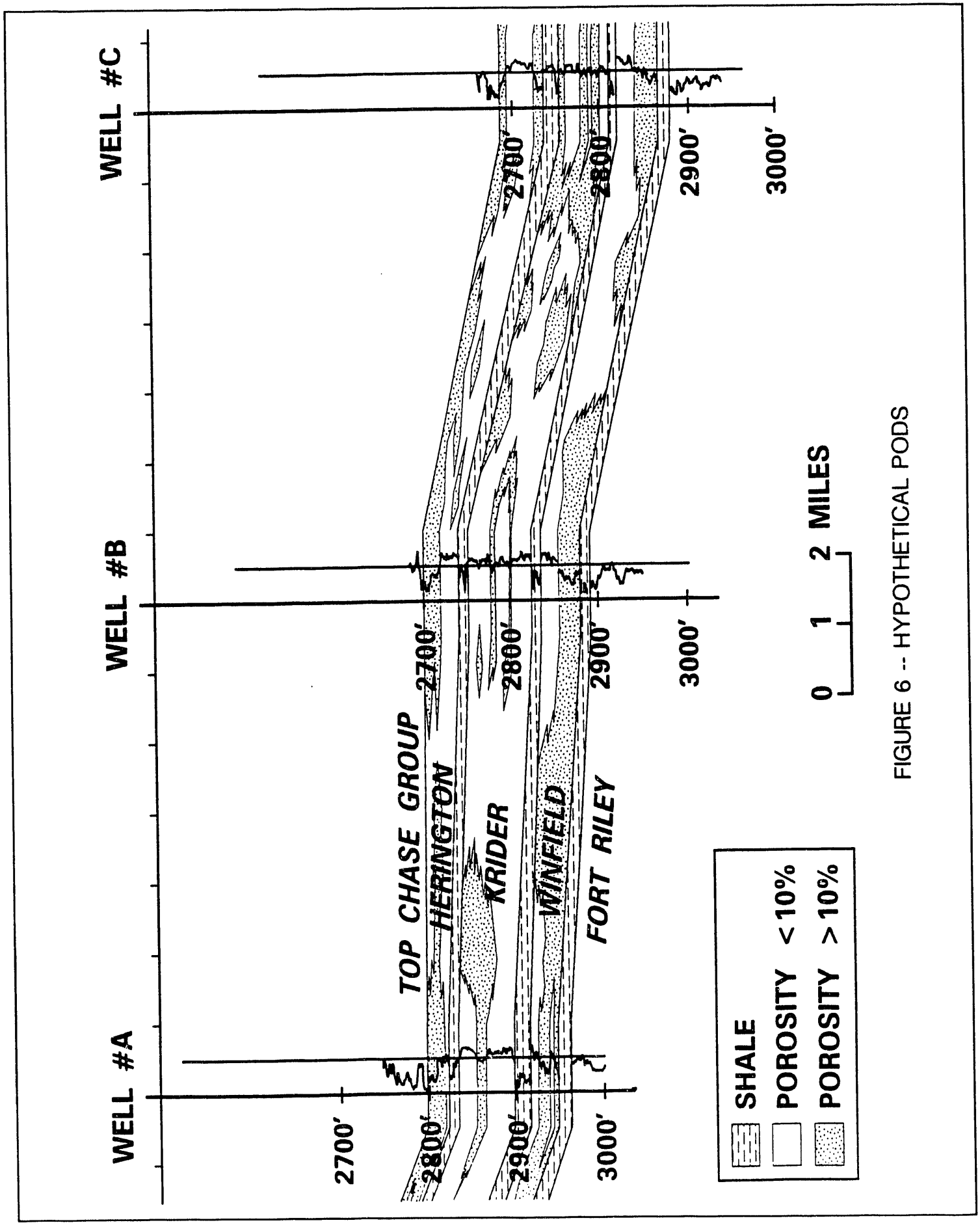
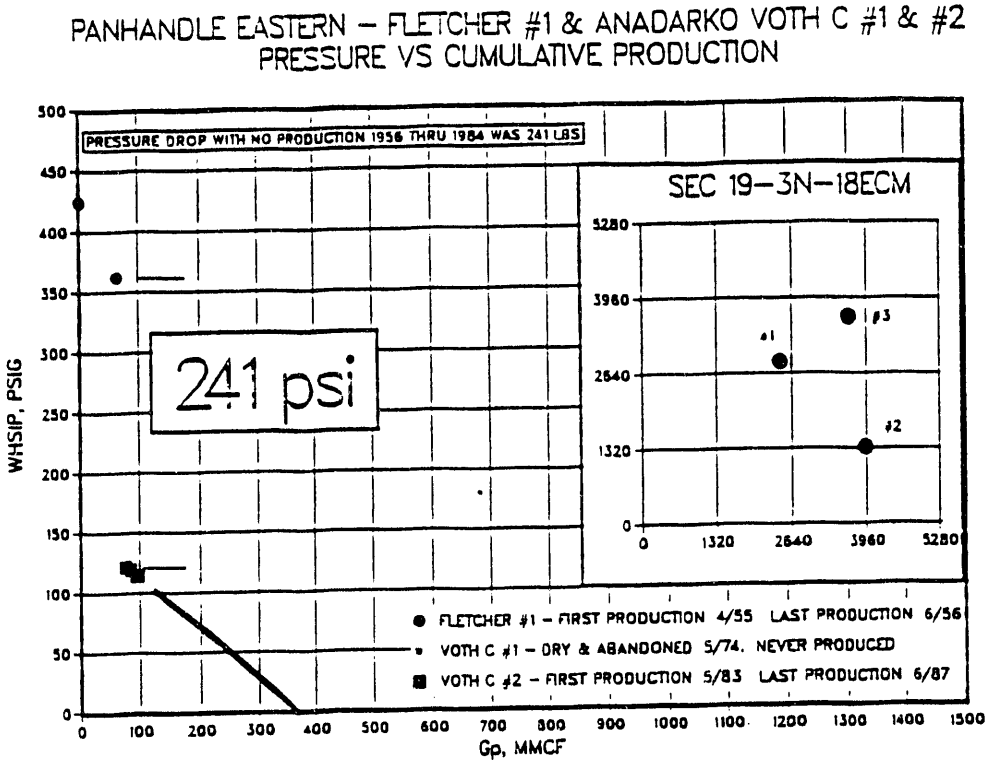


FIGURE 6 -- HYPOTHETICAL PODS


PANHANDLE EASTERN – FLETCHER #1 & ANADARKO VOTH C #1 & #2
PRESSURE VS CUMULATIVE PRODUCTION
PRESSURE DROP WITH NO PRODUCTION 1956 THRU 1984 WAS 241 LBS
241 psi
SEC 19–3N–18ECM
5280
3960
2640
1320
0
#1
#2
#3
WHSIP, PSIG
500
450
400
350
300
250
200
150
100
50
0
0 100 200 300 400 500 600 700 800 900 1000 1100 1200 1300 1400 1500
Gp, MMCF
FLETCHER #1 – FIRST PRODUCTION 4/55 LAST PRODUCTION 6/56
VOTH C #1 – DRY & ABANDONED 5/74. NEVER PRODUCED
VOTH C #2 – FIRST PRODUCTION 5/83 LAST PRODUCTION 6/87

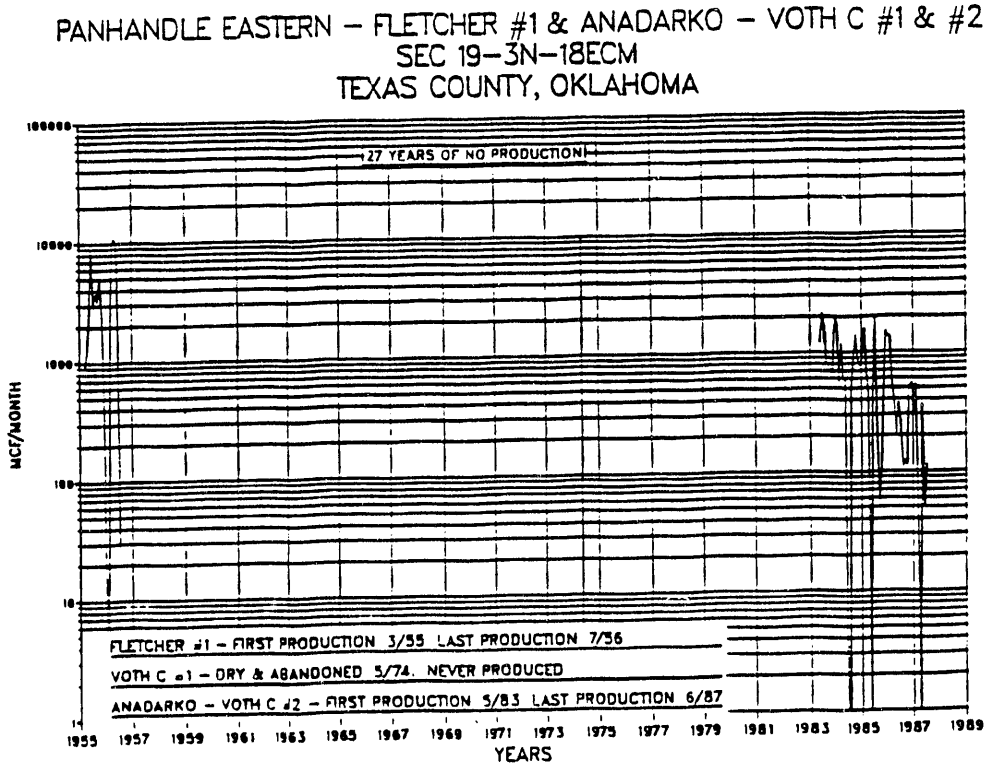

PANHANDLE EASTERN – FLETCHER #1 & ANADARKO – VOTH C #1 & #2
SEC 19–3N–18ECM
TEXAS COUNTY, OKLAHOMA
27 YEARS OF NO PRODUCTION!
MCF/MONTH
1955 1957 1959 1961 1963 1965 1967 1969 1971 1973 1975 1977 1979 1981 1983 1985 1987 1989
YEARS
FLETCHER #1 – FIRST PRODUCTION 3/55 LAST PRODUCTION 7/56
VOTH C #1 – DRY & ABANDONED 5/74. NEVER PRODUCED
ANADARKO – VOTH C #2 – FIRST PRODUCTION 5/83 LAST PRODUCTION 6/87

FIGURE 7

LITHOLOGY: THE MISSING INGREDIENT IN CORE FRACTURE ANALYSIS

John C. Lorenz
Dept. 6117, Sandia National Laboratories
Albuquerque, NM 87185
Phone: (505) 844-3695
Fax No.: (505) 844-3296

Most analyses of fractures in core provide, as an end product, concise tables of fracture data such as width, length, orientation, and mineralization. However, the relationships between fracture locations, fracture terminations, and lithologic heterogeneity are usually not reported in these tables. This information is critical to constructing an accurate model of the three-dimensional framework of fracture permeability in a reservoir. Descriptions of fractures within their lithologic context allow inferences to be made about the degree of fracture interconnectivity, whereas sterile tables of fracture data may obscure important information.

For example, the following limited number of conclusions about the fracture system can be drawn from the fracture data listed in Table I.

1. There are four coring-induced fractures.
2. There are five natural fractures, of which:
   - -four are near-vertical, and filled to partially filled with calcite
   - -one diagonal fracture is present that is partially filled with quartz, indicating the probable presence of a separate fracture system
   - -a cumulative natural fracture height (calcite-filled set only) of 2.4 ft, or about a fourth of the total core length, is present within the ten ft of core
   - -three of the five natural fractures may have very low

permeabilities, based on the fracture widths listed

If the fractures are studied in slabbed surfaces of the same core (Fig. 1), additional observations include:

3. Most of the fracture heights listed in the table are minimum heights, since one or more of their vertical terminations are unknown.

4. Fracture no. 3 consists of two en echelon segments, whereas fractures nos. 2 and 3 may in fact be segments of the same fracture. Fractures nos. 5 and 6 may also be pieces of a single fracture.

5. Fractures nos. 7, 8, and 9 are parts of the same coring-induced system, and may not be worth lisiing separately.

If, however, whole core is available for study, the interactions between fracture location and lithology become apparent, and more significant insights can be gained into the fracture permeability system of the reservoir. If the original core (Fig. 2) had been studied when compiling the data set presented in Table 1 and on figure 1, the following important points could have been noted:

1. There is a fracture at 0.0-0.4 ft, and the fracture between 7.2-8.3 ft is paralleled by a secondary fracture, both of which are present in the butt of the core but not in the slabs. The total natural fracture height in this core may be up to 4.4 ft (44% of the hypothetical ten-ft core interval).

2. If the non-reservoir, non-fractured, shale intervals are not considered, the fracture height represents as much as 50% of the net reservoir rock, suggesting that the fracture frequency within this reservoir is nearly twice that listed under point no. 2 above.

3. Five of the eight known fracture terminations are caused by interbedded shales (Fig. 3). This implies a significantly restricted vertical permeability within the reservoir despite numerous fractures. A horizontal well in such a reservoir may not provide significant increases in productive capability even if fractures are intersected at the optimum 90-degree angle, because of the limited vertical communication (Lorenz, 1992).

4. Fractures nos. 2 and 3 are very probably the same fracture, and fractures 5 and 6 are definitely a single fracture, implying a larger average fracture height for fewer fractures.

5. The data suggest but do not prove (since the core continuity is broken at 2.8, 5.1, and 6.9 ft) that the vertical, calcite-mineralized natural fractures form a single parallel set, providing highly anisotropic horizpntal permeability.

6. Fracture no. 1 is a petal fracture, and strikes parallel to fracture "a". This suggests that the in situ stress is parallel to the natural fractures (Lorenz et al., 1990). However, petal fractures nos. 7-9 strike oblique to fractures 5,5a. If a reason for oblique petal fracture strikes can be documented (such as core barrel jamming at the end of a coring run), the relationship between stress orientation and fracture strike may be inferred to be a parallel one throughout the reservoir. Thus, a hydraulic stimulation fracture may not be effective in intersecting the natural-fracture permeability.

Notations such as these also address the rarely considered factor of whether fractures that are present in core are limited to the reservoir facies (Fig. 4) or extend through the nonreservoir strata to connect into adjacent potential pay zones. Because the sedimentology of a reservoir commonly influences its fracture characteristics (e.g., Lorenz and Hill, 1992), the data shown on Table II should be recorded as part of any core or outcrop fracture study.

References

Lorenz, J.C., 1992, Well-bore geometries for optimum fracture characterization and drainage: West Texas Geological Society Bulletin, v. 32, p. 5-8.

Lorenz, J.C., and Hill, R.E., 1992, Measurement and analysis of fractures in core; in, Schmoker, J.W., Coalson, E.B., and Brown, C.A. (eds), Geological studies relevant to horizontal drilling: Examples from western North America: Rocky Mountain Association of Geologists, p. 47-59.

Lorenz, J.C., Finley, S.J., and Warpinski, N.R., 1990, The significance of coring-induced fractures in Mesaverde core, northwestern Colorado: American Association of Petroleum Geologists Bulletin, v. 74, p. 1017-1029.

FIG. 1: FRACTURES IN SLABBED CORE; (SAMPLES AND SOUVENIRS REMOVED)

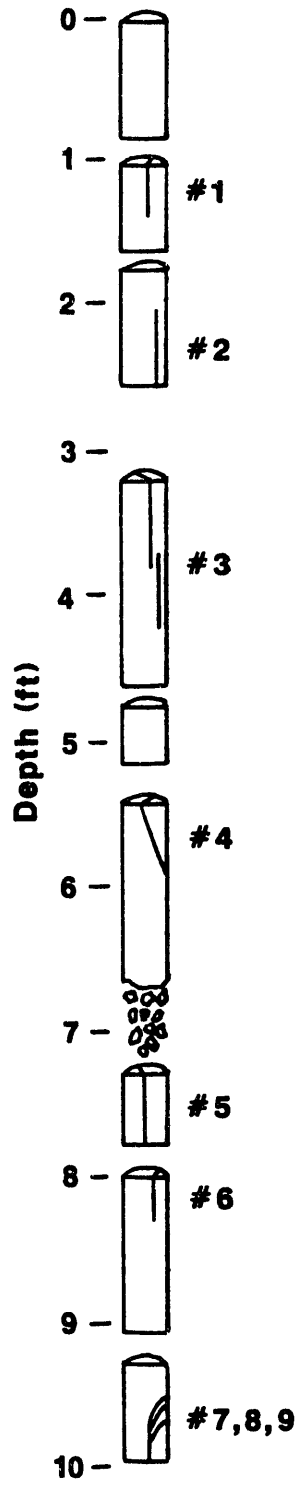


FIG. 2: FRACTURES IN WHOLE CORE, WITH LITHOLOGIES NOTED

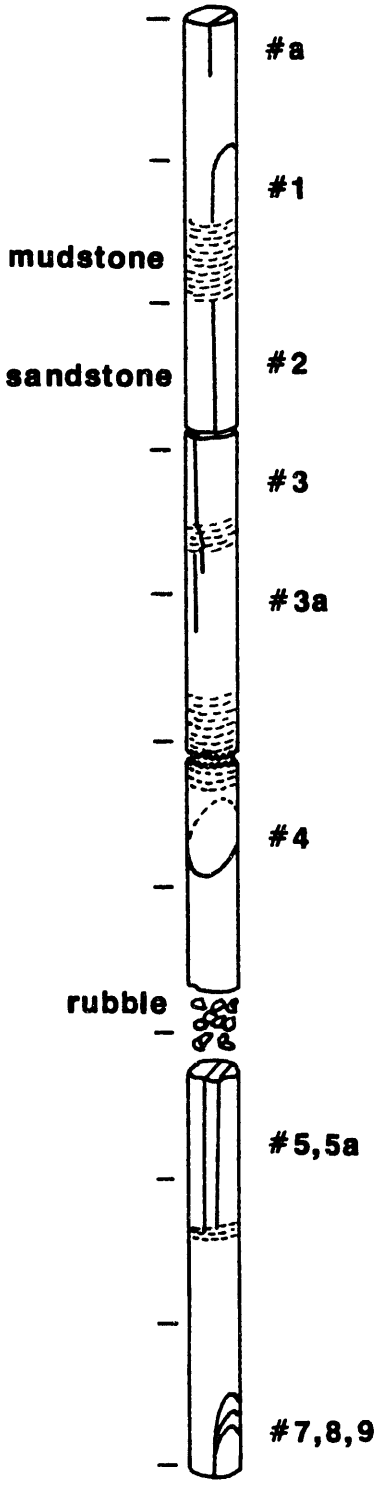
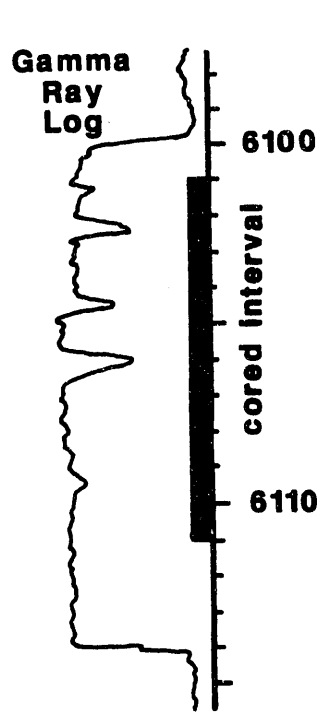
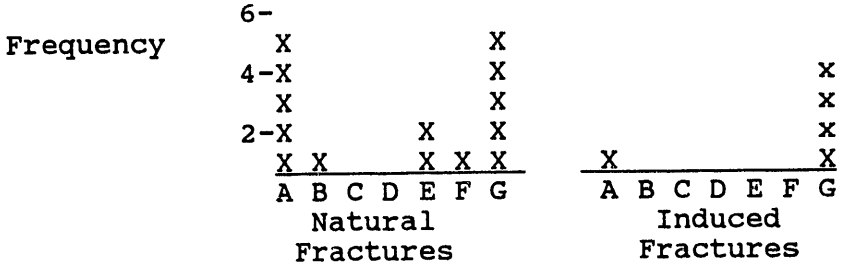


FIG. 3: FRACTURE TERMINATIONS AND CONTINUITY





A. at internal lithologic contact
B. crosses internal heterogeneity
C. at reservoir boundary
D. extends into adjacent, nonreservoir lithology
E. within homogeneous reservoir lithology
F. en echelon transition to next fracture
G. unknown (out of core, rubble, sample missing, etc)

1. Cumulative Fracture Height: min. 5.0' (w/o diagonal fracture)
2. Average Fracture Height: min. 1.0'
3. Cum Height/Reservoir Thickness: 0.36' of frac h / 1' res. h
4. Cum Frac height/Total Core Length: 0.5' of frac h/1' core h
5. Average Fracture Height/Average Internal Bed Thickness: 0.7
6. One-ft average frac h << reservoir thickness,
-but-
7. One-ft average frac h is nearly 3/4 average bed h

FIG. 4: HOST LITHOLOGY PREFERENCE (NATURAL FRACTURES)

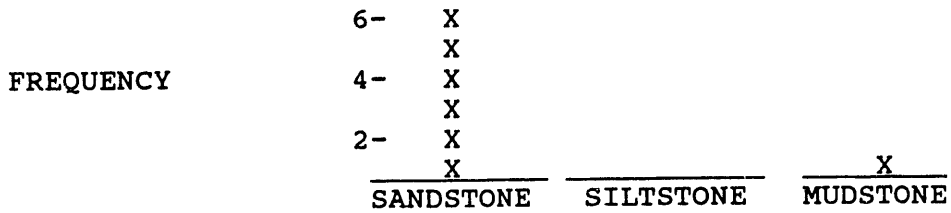


TABLE I

Typical Fracture Report

Fracture Number	Depth (ft)	Height	Dip (Deg)	Width	Class	Mineralization
1	1.0-1.4	0.4	90	0.5mm	CI*	---
2	2.0-2.6	0.6	90	0	N*	calcite
3	3.2-4.2	1.0	85	0	N	calcite
4	5.4-5.9	0.5	65	0.5mm	N	quartz
5	7.3-7.8	0.5	90	0	N	calcite
6	8.0-8.3	0.3	80	0.5mm	N	calcite
7	9.5-9.7	0.2	60	0.5mm	CI	---
8	9.6-9.8	0.2	60	0.5mm	CI	---
9	9.7-10.0	0.3	60-90	0.5mm	CI	---

*CI = coring induced
N = natural

TABLE II

Lithologic Characteristics to Include During Fracture Measurements

1. Host lithology: type and thickness: number and type of sedimentary heterogeneities
2. Vertical terminations: location and character, relationship to sedimentary heterogeneity,
3. Fracture height: note if this is a minimum height due to fracture exiting core, or due to missing core pieces, and termination(s) were therefore not observed

NOTES

CHARACTERIZATION OF THE ARBUCKLE GROUP IN CORE FROM THE MID-CONTINENT IN ASSESSING POTENTIAL FOR HORIZONTAL DRILLING

by: Richard D. Fritz, Patrick L. Medlock, Michael D. Kuykendall, and Mark W. Allen
MASERA Corporation
P.O. Box 702708
Tulsa, OK 74170

Geological applications for horizontal drilling have proven most effective in tight fractured reservoirs, heterogeneous paleokarst reservoirs and porous and permeable reservoirs with coning problems. A modified version of standard fracture classification can be used to define most potential horizontal drilling targets in the Mid-Continent into four types (Fig. 1). Carbonate reservoirs with horizontal drilling potential (HD-reservoirs) such as the Cambro-Ordovician Arbuckle Group can be further categorizaed by facies related reservoir characteristics.

Tight fractured carbonate reservoirs, with similar features to the Bakken Shale, are often developed in low energy basinal settings. These reservoirs are characterized by little or no effective matrix porosity with the only porosity and permeability provided by fractures. The Mississippian Sycamore Limestone and Devono-Mississippian Woodford Shale currently produce from vertical wells in southern Oklahoma and are indicative of this first type of this first type of potential HD-reservoir (Type A); they are currently key horizontal drilling targets in the Mid-Continent (Fig. 1).

The Austin Chalk is a basinal pelagic carbonate and typifies the second type of HD-reservoir (Type B) which has fair to good matrix porosity with very low permeability (Fig. 1). The only producing chalk reservoirs near the Mid-Continent region are in the northern and northwestern parts of the Denver Basin, as exemplified by the Upper Cretaceous Niobrara Formation.

Although in the northern part of the Mid-Continent area Ordovician Viola carbonates and the "Mississippi lime" contain high-energy deposits, in Oklahoma they were deposited in relatively low-energy subtidal conditions on shallow marine ramps and can have porosity and permeability profiles similar to chalks. Both reservoirs require fracturing for good production and are actively being pursued as horizontal drilling candidates.

The limestones and dolomites of the Siluro-Devonian Hunton Group are similar to those of the Viola and "Mississippi lime" in that they were deposited on a carbonate ramp. Except for the Frisco and Sallisaw formations, reservoirs in the Hunton Group are often composed on interfingering upper subtidal, intertidal and supratidal facies. Although these carbonates represent different facies, their reservoir characteristics are somewhat similar to those found in the Permian age Abo "Reef" trend reservoirs in southwestern New Mexico which defined the third type of HD-reservoir (Type C). These reservoirs are characterized by their heterogeneity and good porosity with fair permeability which is often complemented by fractures (Fig. 1). Reservoir heterogeneity is further complicated by a long and varied diagenetic overprint.

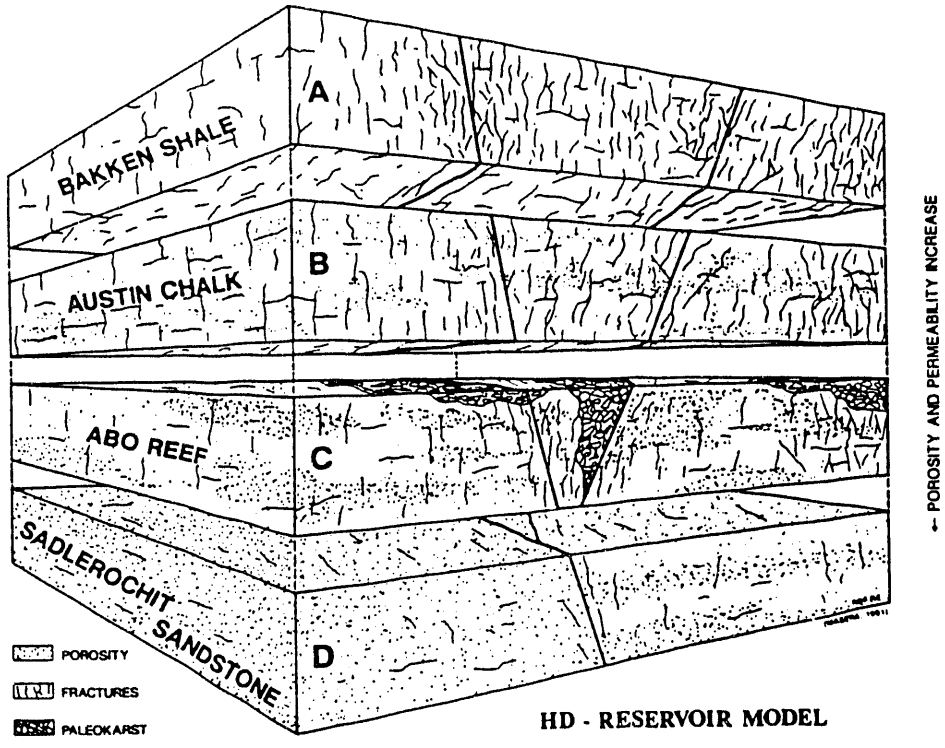


Figure 1--Geological classification model for the four basic types of HD-reservoirs (MASERA, 1991).

Platform margin carbonates, in particular reefs, may also represent good horizontal drilling targets, however, there are few significant reefal build-ups in the southern Mid-Continent region. Mud mounds, such as those found in the Devonian Frisco Formation, are a type of reef and can be quite heterogeneous.

Although the fourth type of HD-reservoir (Type D) may be found in carbonates, the analogue is the Permo-Triassic Sadlerochit Sandstone in Prudhoe Bay Field (Fig. 1). This fourth type of HD-reservoir may or may not be fractured and is represented by zones with good porosity and permeability with either gas or water coning problems. These zones are usually homogeneous and in this case an abundance of fractures may actually be detrimental to the reservoir and increase coning problems.

Some carbonates, such as the platform carbonates of the Arbuckle Group, may contain examples of more than one or even all four types of HD-reservoirs (Fig. 2). Type A reservoirs may be exploited from fractured tidal flat deposits such as those found in core from the Pure Pruitt No. 1 well in Sec. 26, T3S, R1E in Carter County, Oklahoma. This core is mostly limestone with minor amounts of dolomite. It is extensively fractured with very little matrix porosity.

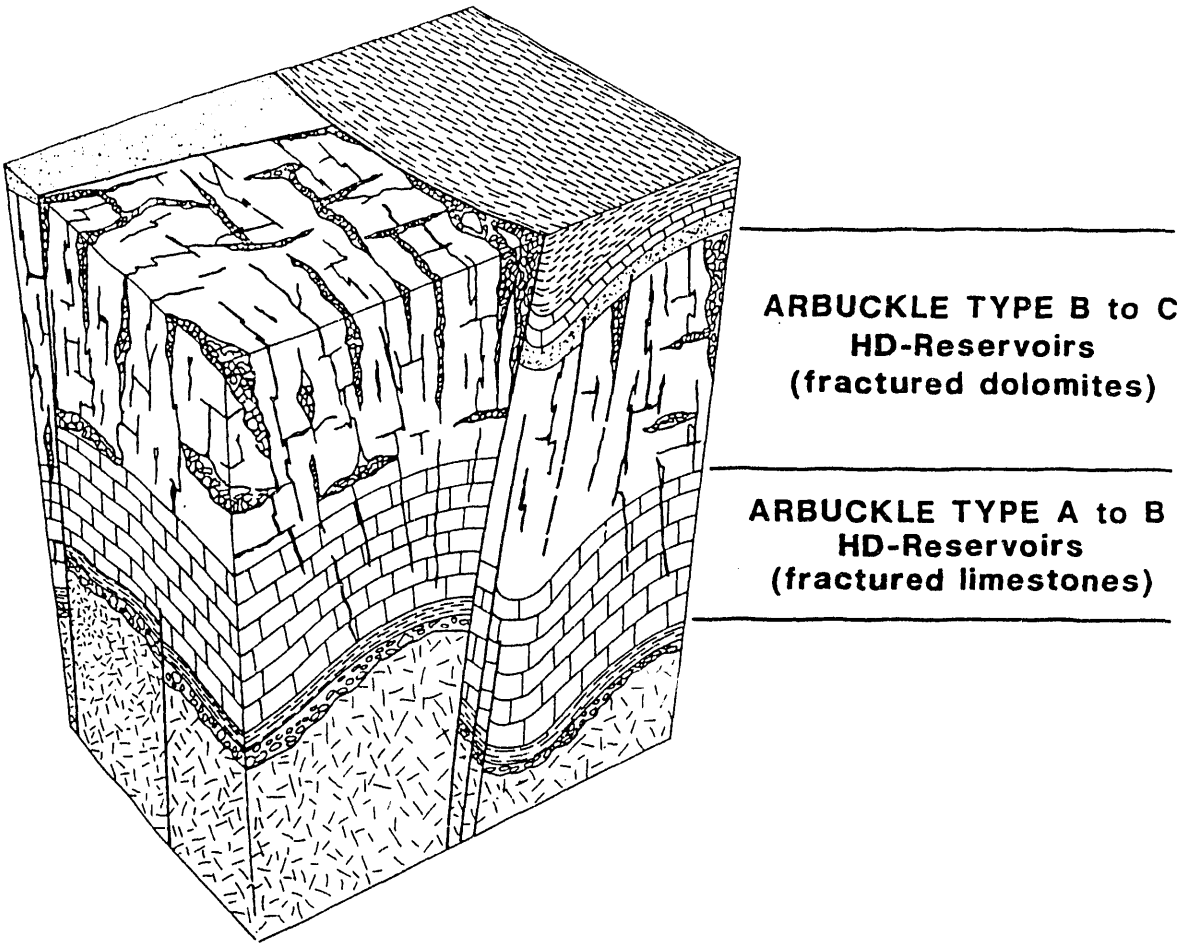


Figure 2--Arbuckle HD-reservoir model (MASERA, 1990).

Most Arbuckle production is from rather heterogeneous fractured and karstic dolomites which represent both Type B and Type C HD-reservoirs. Core from the Shell Wesley Unit No. 1A-3 in Sec. 3, T4S, R3W in Carter County, Oklahoma has the qualities of Type B HD-reservoirs in that it has fair porosity defined by intercrystalline pores with fractures providing much of the permeability. The rock is composed mostly of thermal dolomite.

The E.L. Cox Wesley No. A-1 in Sec. 3, T4S, R3W also in Carter County, Oklahoma contains core which represents a Type C HD-reservoir even though it is from the same stratigraphic interval as in the Shell Wesley Unit No. 1 A-3. Much of the rock has been altered by karstification and thermal dolomitization. The rock is very heterogeneous with fair to good matrix porosity and permeability.

Although most Type D reservoirs in the Mid-Continent are sandstones, extremely porous reservoirs within the Arbuckle, such as shown in core from the Texaco Osage No. C-1 well in Sec. 24,

T20N, R11E in Osage County, Oklahoma, are also considered as Type D reservoirs especially those zones with coning problems.

The Mid-Continent has an abundance of potential HD-reservoirs due in part to its complex structural history. Fractures and heterogeneity are the most important factors in developing good HD-reservoirs. Heterogeneity is often caused by secondary processes such as karstification which is pervasive in Mid-Continent carbonates due to the presence of numerous disconformities and several unconformities. Fractured and karstic carbonates such as these of the Arbuckle Group provide excellent targets for future horizontal drilling.

728
Ronald C. Collings
Chevron U.S.A. Production Company
100 Chevron Road
Rangely, Colorado 81648

(303) 675-3850 Work
(303) 675-3800 Fax

MODELING RESERVOIR HETEROGENEITY TO DETERMINE CURRENT OIL SATURATION DISTRIBUTION IN A MATURE FIELD

by

Ron Collings

Hybrid Simulation is a new reservoir simulation technique that combines finite difference and streamtube simulation technologies. This technique provides accurate water breakthrough and oil recovery schedules for secondary and tertiary recovery projects when combined with a sound geologic model. The primary benefits of this technique are rapid turn around time for flood analysis and minimal computer time. An example of this technique is presented here using the Rangely oil field with an emphasis on the geologic model, which is always the basis for accurate water flood evaluation.

The Rangely Weber Sand Unit is located in northwestern Colorado. It is on the hanging wall of the Uinta Basin boundary thrust fault just west of the Douglas Creek Arch which separates the Uinta and Piceance basins. The Rangely field is defined by a doubly plunging asymmetric anticline with 1500 feet of closure, and 950 feet of hydrocarbon column.

The Rangely Weber Sand Unit is a mature field under both secondary and tertiary recovery projects. Reservoir characterization and simulation is being used to help maximize recovery efficiency by identifying areas of the field that are not being adequately swept by injected fluids.

The first step in modeling the current oil saturation, and therefore determining our areas of opportunity, was to characterize the reservoir's porosity, permeability and initial water saturation. This was done by using modern core data to transform density and sonic traces to porosity and permeability traces. The permeability transform was found to vary by stratigraphic zone, as is shown in **Figure 1**. This finding was particularly important for Zone 5. This eolian zone was found to have a significantly higher permeability for a given porosity than the other eolian zones, as is illustrated by **Figure 2**.

Ron Collings

Modeling Reservoir Heterogeneity to Detemine Current Oil Saturation Distribution in a Mature Field

The Rangely Weber Sandstone is composed of two primary rock types; eolian and fluvial. Core description has indicated that the fluvial rock type was non-effective because there was no apparent oil staining. It was known, however, that the fluvial rock, while tight, is still permeable. The proper characterization of the fluvial rock type was important because approximately 40% of the reservoir by volume is occupied by this argillaceous rock type. It was suspected that the absence of oil in the rock was related to the capillary characteristics of the rock. This was confirmed through mercury porosimetry experiments conducted on both eolian and fluvial rock types. **Figure 3** shows the differences between eolian and fluvial pore throat distributions. These two samples have similar porosity and permeability. The two distributions have similar modes, explaining why they have similar permeability. The fluvial rock, however, exhibits more pore volume with smaller pore throats suggesting that the capillary characteristics of the fluvial rock will be significantly different from the eolian rock. This difference is illustrated by the J-Function correlation for the two different rock types shown in **Figure 4.**

The initial water saturation trace was generated with the J-Function by using the porosity and permeability traces with the gamma ray for control. From the initial water saturation trace and porosity trace we generated the hydrocarbon porosity trace. This is the information needed to build reservoir models for flow simulation. Porosity thickness and permeability thickness maps were generated using a range ellipse from variogram analysis in a kriging algorithm. The kriging algorithm provides an estimation variance at unsampled locations based on data density and location. These maps are used with injection and production data in an interactive streamtube model. This model predicts well to well interactions on an areal basis.

The porosity and permeability traces were also used for generating finely gridded cross-section models for use in a conventional finite difference simulator. The result of the water flood displacement through the cross-section is a fractional flow table or a set of production characteristic curves illustrated in **Figure 5.**

The streamtube displacement simulation uses the production characteristic curves to determine the produced fluid composition from each streamtube, sums the production at each well, and provides a production forecast. Historical performance is matched by trying a variety of production characteristic curves from several cross-sections. After matching historical performance (**Figure 6**), the remaining oil saturation distribution is known and future operating scenarios can be investigated.

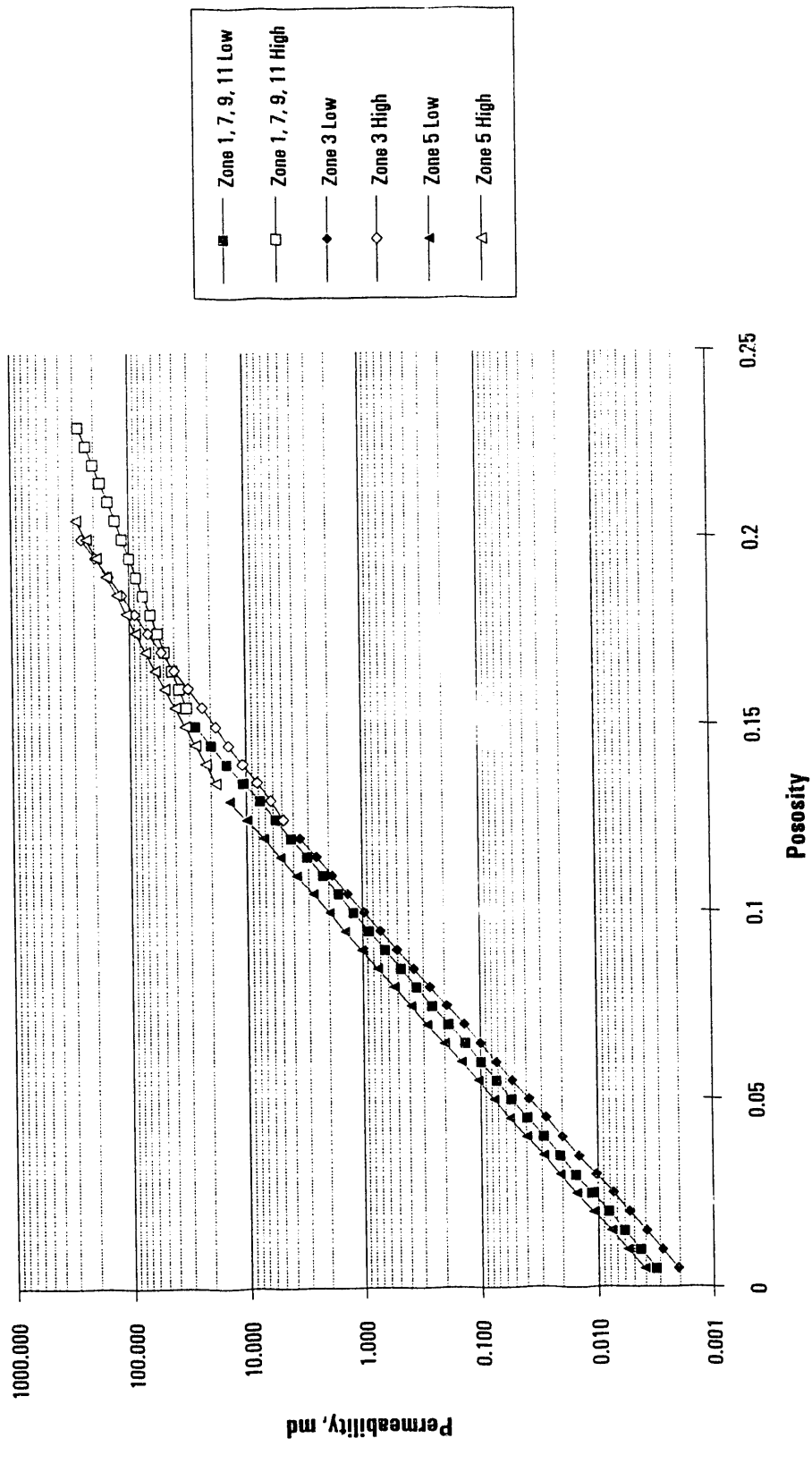

ZONAL POROSITY TO PERMEABILITY TRANSFORMS
Zone 1, 7, 9, 11 Low
Zone 1, 7, 9, 11 High
Zone 3 Low
Zone 3 High
Zone 5 Low
Zone 5 High
Permeability, md
1000.000
100.000
10.000
1.000
0.100
0.010
0.001
Pososity
0
0.05
0.1
0.15
0.2
0.25
TRANSPIC.XLS Chart 2

Figure 1

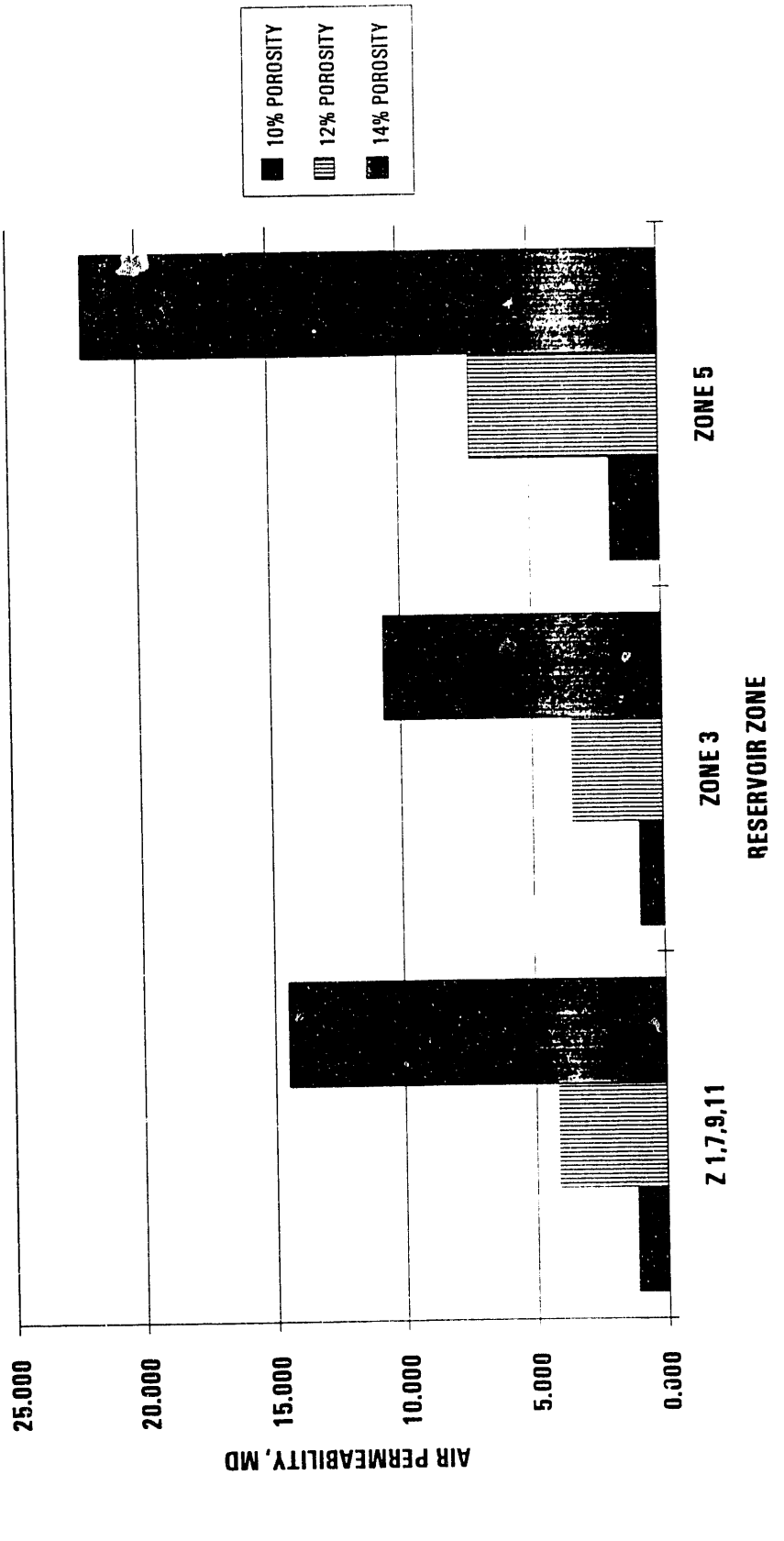

EFFECT OF ZONAL TRANSFORMS
PERMEABILITIES AT VARIOUS POROSITIES
10% POROSITY
12% POROSITY
14% POROSITY
25.000
20.000
15.000
10.000
5.000
0.000
AIR PERMEABILITY, MD
Z 1,7,9,11
ZONE 3
ZONE 5
RESERVOIR ZONE
PERMEFF.XLC

Figure 2

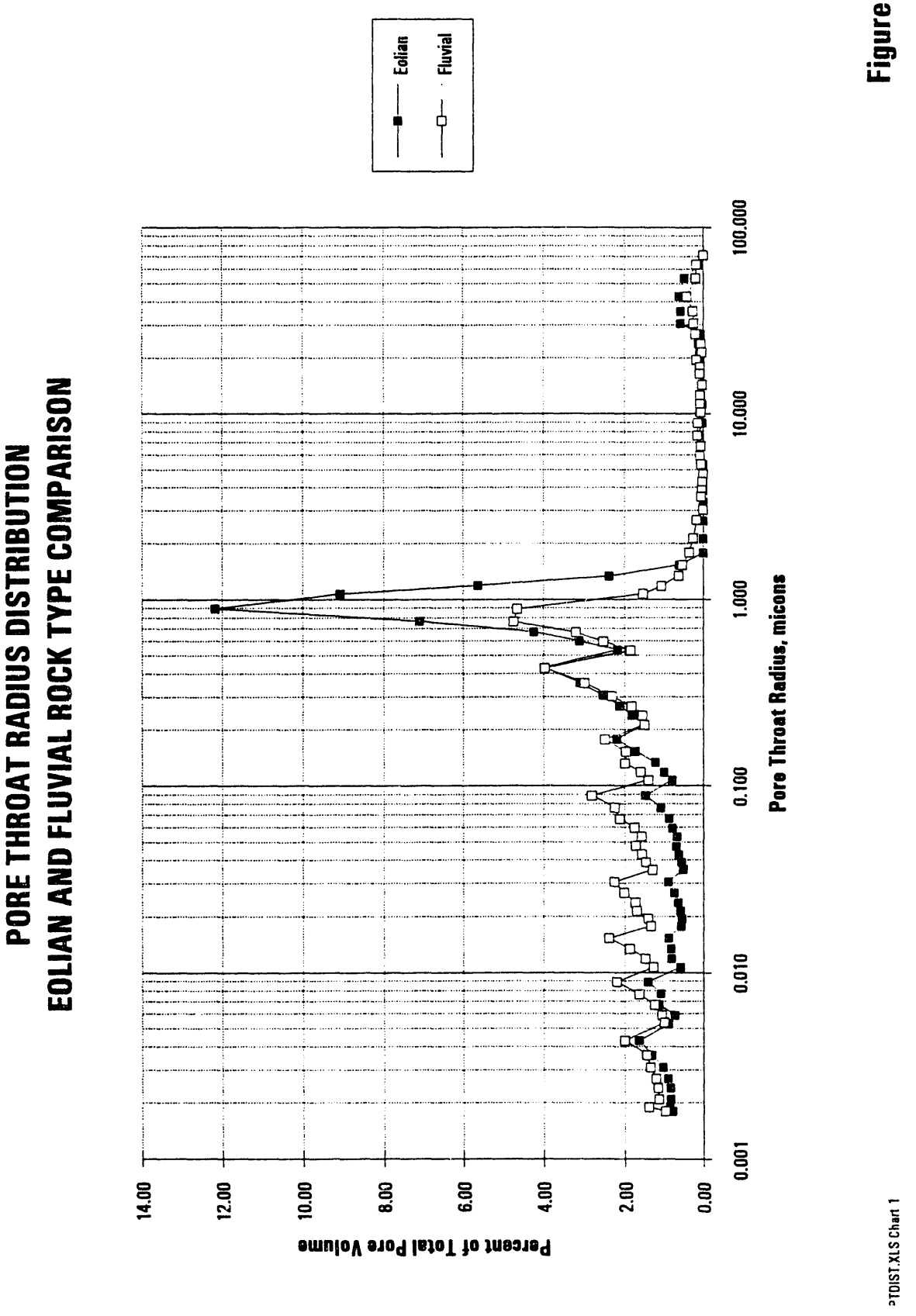

PORE THROAT RADIUS DISTRIBUTION
EOLIAN AND FLUVIAL ROCK TYPE COMPARISON
Eolian
Fluvial
Percent of Total Pore Volume
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
0.001
0.010
0.100
1.000
10.000
100.000
Pore Throat Radius, microns
PTDIST.XLS Chart 1

Figure 3

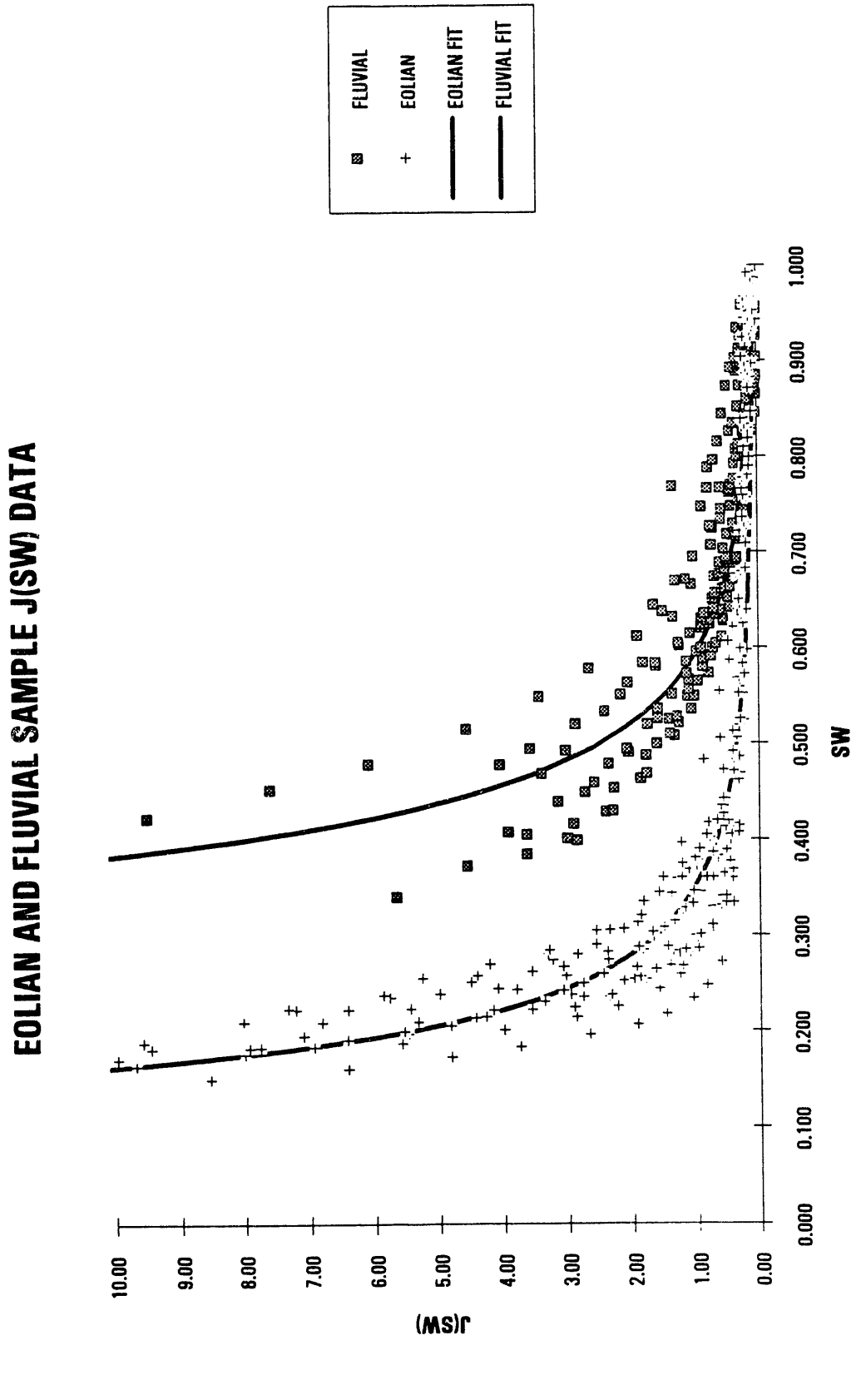

EOLIAN AND FLUVIAL SAMPLE J(SW) DATA
FLUVIAL
EOLIAN
EOLIAN FIT
FLUVIAL FIT
J(SW)
SW
10.00
9.00
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
0.000
0.100
0.200
0.300
0.400
0.500
0.600
0.700
0.800
0.900
1.000
ALLDATA.XLC

Figure 4

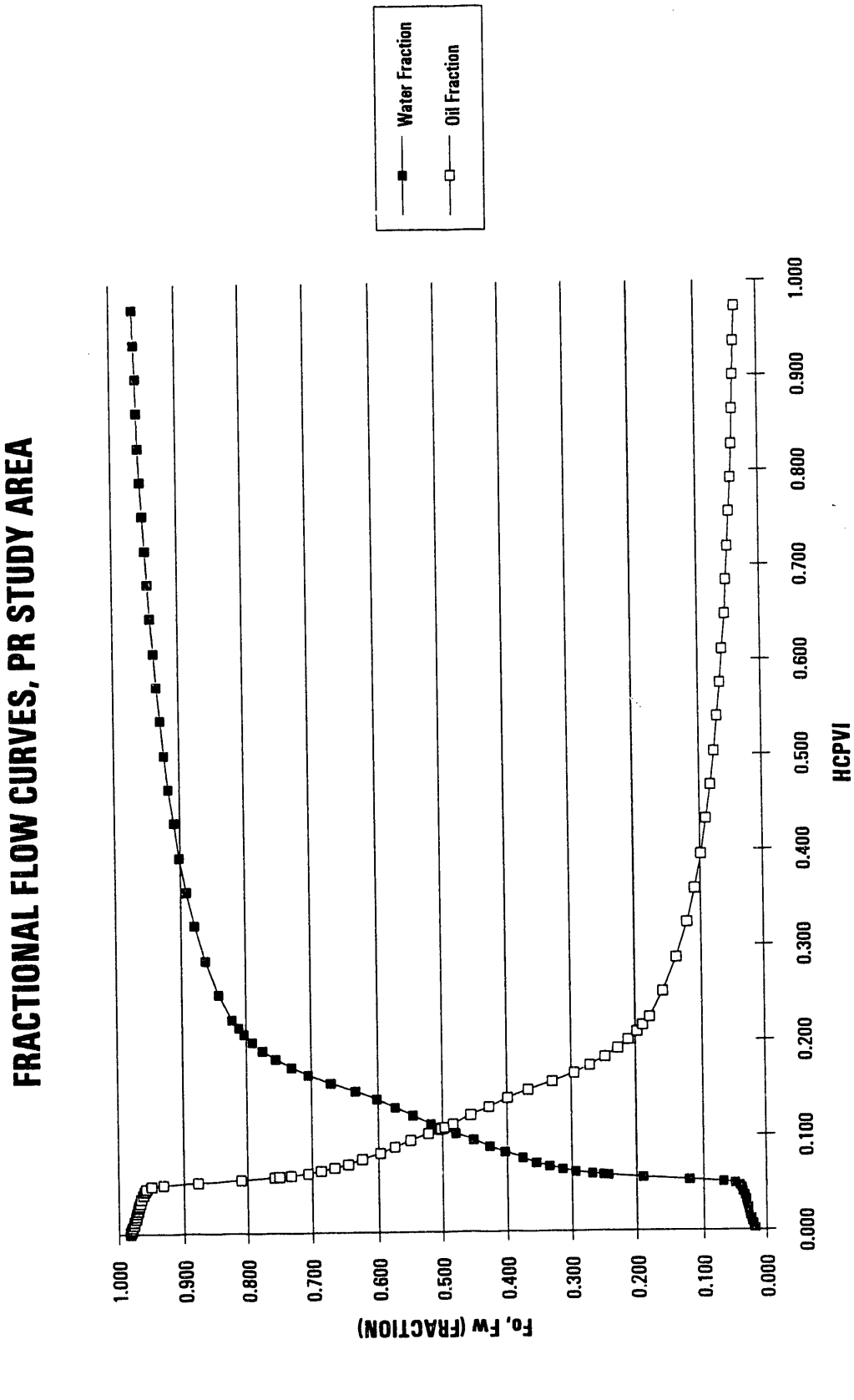

FRACTIONAL FLOW CURVES, PR STUDY AREA
Water Fraction
Oil Fraction
Fo, Fw (FRACTION)
1.000
0.900
0.800
0.700
0.600
0.500
0.400
0.300
0.200
0.100
0.000
HCPVI
0.000
0.100
0.200
0.300
0.400
0.500
0.600
0.700
0.800
0.900
1.000
PR1W.XLS Chart 1

Figure 5

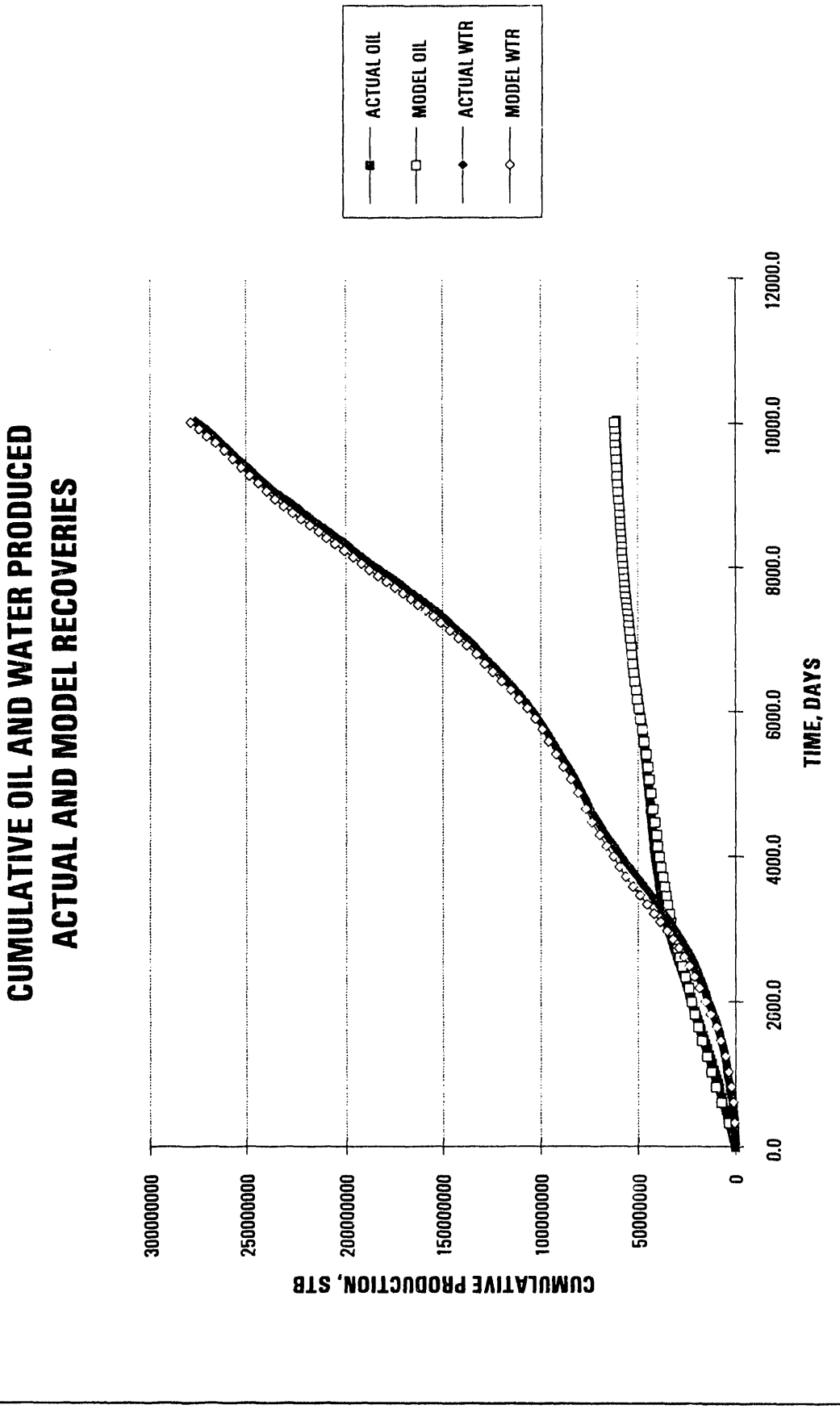

CUMULATIVE OIL AND WATER PRODUCED
ACTUAL AND MODEL RECOVERIES
ACTUAL OIL
MODEL OIL
ACTUAL WTR
MODEL WTR
CUMULATIVE PRODUCTION, STB
300000000
250000000
200000000
150000000
100000000
50000000
0
0.0
2600.0
4000.0
6000.0
8000.0
10000.0
12000.0
TIME, DAYS
CUMAREA.XLC

Figure 6

VALLEY-FILL SANDSTONE RESERVOIR HETEROGENEITY, STATELINE TREND, COLORADO AND KANSAS

Roderick W. Tillman
Consulting Sedimentologist/Stratigrapher
2121 E. 51st, Ste. 112
Tulsa, Oklahoma, 74105-5862
(Phone 918-749-3184)

Edward D. Pittman
Consulting Petrologist
222 Bowstring Drive
Sedona, Arizona, 86336

Beverly Blakeney-DeJarnett
Consulting Geologist
5040 Byers Avenue
Ft. Worth, TX 76107

One of the most important kinds of relatively small sandstone reservoirs being explored for and developed today is the valley-fill sandstone. Because of their relatively small size (0.5 to 4 miles wide), poorly understood origins and difficult to predict occurrences, valley-fill reservoirs have not always been attractive targets for drilling. However, in the last few years valley-fill reservoirs have become very important and some are currently undergoing secondary recovery. Because of the absence of adequate geologic descriptions, valley-fill reservoirs have, in the past, commonly not been differentiated from deltaic and river-channel sandstones. Because there are significant differences in the distribution of reservoir seals and internal heterogeneity characteristics in valley-fill reservoirs, compared to deltaic and river-channel reservoirs, different patterns of production will occur within individual fields and pools which produce from these distinctly different geologic environments.

Valley-fill heterogeneous reservoirs in the Morrowan (Pennsylvanian) age Stateline Trend along the Kansas-Colorado border produce from valley-fill reservoirs and are internally complex, contain geographically and vertically limited reservoirs and can only be effectively drained if the detailed internal architecture of the reservoirs is understood. Development of detailed geologic models utilizing core interpretations for fluvially and tidally deposited valley-fill sandstone reservoirs enhance results of reservoir simulation and improve planning for secondary recovery and possible tertiary production. Only by including the location and degree of impermeability of barriers to flow at the margins of and within the valley-fill reservoirs can historical simulation modeling and secondary recovery methods yield satisfactory economic results.

The valleys in which the reservoirs occur at Southwest Stockholm Field were cut by rivers during drops in sea level and remained as conduits (narrow open valleys trending perpendicular to the regional shoreline). At a later time, as sea level rose, the valleys were filled from the landward side by rivers or from the seaward side by shoreline processes or alternately from both the landward and seaward sides at the same time.

Detailed geologic analysis of cores from the field combined with cross sections and isopach and structure maps yielded details of reservoir heterogeneity. Reservoir production properties vary greatly between the two major valley-fill producing facies, fluvial and tidal (estuarine) sandstones. Within the approximately 150-ft thick valley-fill vertical sequence at Southwest Stockholm field, just one of the three sandstones yields significant production. Topographic highs on the valley bottom, covering an area as large as 1/2 section reduce the depositional thickness of the reservoir sandstones. Impermeable limestones and shales commonly form lateral barriers to flow at valley margins and locally within the valleys. Erosion of portions of potentially productive sandstones within the valleys was found to be important in isolating reservoirs (flow units).

Tidally deposited (estuarine) sandstones are finer grained and more clay prone than the fluvial sandstones and as a result have poorer reservoir properties. In Southwest Stockholm field fluvial deposits have average porosities of 15.4% (range from 2.8 to 21.6%) and average permeabilities of 784 md (range from 0.03 to 5500 md). Tidal-channel sandstones have average porosities of 10% (range from 3.1 to 18.4% and permeabilities of 129 md (range 0.12 to 470 md). Note the significant differences in the mean values for the two types of deposits. Where tidal sandstones interfinger with fluvial sandstones, vertical permeability is diminished and flow units are fragmented.

Valley-fill deposits in Southwest Stockholm field differ from deltaic deposits geologically, geometrically and in the characteristics and distribution of flow units. Overbank and fine-grained levee deposits, typical of deltas, are most commonly absent at the margins of valley-fill deposits and valley-fill deposits occur below the regional TSE (transgression surface of erosion) rather than above it as do many deltas.

Secondary (post burial) events affected the production characteristics of the reservoirs. The post-depositional events that affected the reservoirs were

significantly different in several of the seven recognized depositional lithofacies. Up to half of the porosity in Southwest Stockholm field may be leached (secondary) porosity. Where millimeter thick shale lenses were deposited within tidally deposited sands, pressure solution of quartz in contact with the clay reduced porosity.

Reservoir characteristics are relatively similar within sandstone units interpreted to have been deposited by the same depositional processes. However, reservoir characteristics are significantly different among different depositional lithofacies. All sandstones deposited by the same processes are assigned to the same lithofacies. Although other types of sandstones were vertically or laterally "connected" to the better reservoir lithofacies, perforated intervals were commonly limited to valley-filling fluvial sandstones in Southwest Stockholm field. Understanding the differences in heterogeneity characteristics between fluvial and tidal (estuarine) valley-fills, such as those studied herein, allows proper economic evaluation and more efficient reservoir management of these kinds of reservoirs.

References

Blakeney, B. A., L. F. Krystinik, A. A. Downey, 1990, Reservoir Heterogeneity in Morrow Valley Fills, Stateline Trend: Implications for Reservoir Management and Field Expansion, in Morrow Sandstones of Southeast Colorado and Adjacent Areas, S. A. Sonnenberg, L. T. Shannon, K. Rader, W. F. von Drehle, G. W. Martin (eds.), Rocky Mountain Association of Geologists, p. 131-142.

Hartman, D. J. and E. B. Coalson, 1990, Evaluation of the Morrow Sandstone in Sorrento Field, Cheyenne County, Colorado: in S. A. Sonnenberg and others (eds.), Morrow Sandstones of S. E. Colorado and Adjacent Areas; The Rocky Mountain Association of Geologists, Denver, Colorado, p. 91-100.

Brown, L. G., W. A. Miller, E. M. Handley-Goff and S. L. Veal, 1990, Stockholm Southwest Field, in Morrow Sandstones of Southeast Colorado and Adjacent Areas, S. A. Sonnenberg, L. T. Shannon, K. Rader, W. F. von Drehle, G. W. Martin (eds.) Rocky Mountain Association of Geologists, p. 117-130.

Shumard, C. B. and L. E. Avis, 1990, Key Morrow predictive exploration model: Southwest Stockholm field, Oil and Gas Journal, v. 88, p. 87-94.

Tillman, R. W. and E. D. Pittman, 1993, Reservoir Heterogeneity in Valley-Fill Sandstone Reservoirs Southwest Stockholm Field, Kansas, in Linville, B. (ed.) Reservoir Character III, PennWell Books, Tulsa, Oklahoma, p. 51-106.

Wheeler, D. M., A. J. Scott, V. J. Coringrato, and P. E. Devine, 1990, Stratigraphy and Depositional History of the Morrow Formation, Southeast Colorado and Southeast Kansas, in Morrow Sandstones of Southeast Colorado and Adjacent Areas, S. A. Sonnenberg, L. T. Shannon, K. Rader, W. F. von Drehle, G. W. Martin (eds.), Rocky Mountain Association of Geologists, p. 9-35.

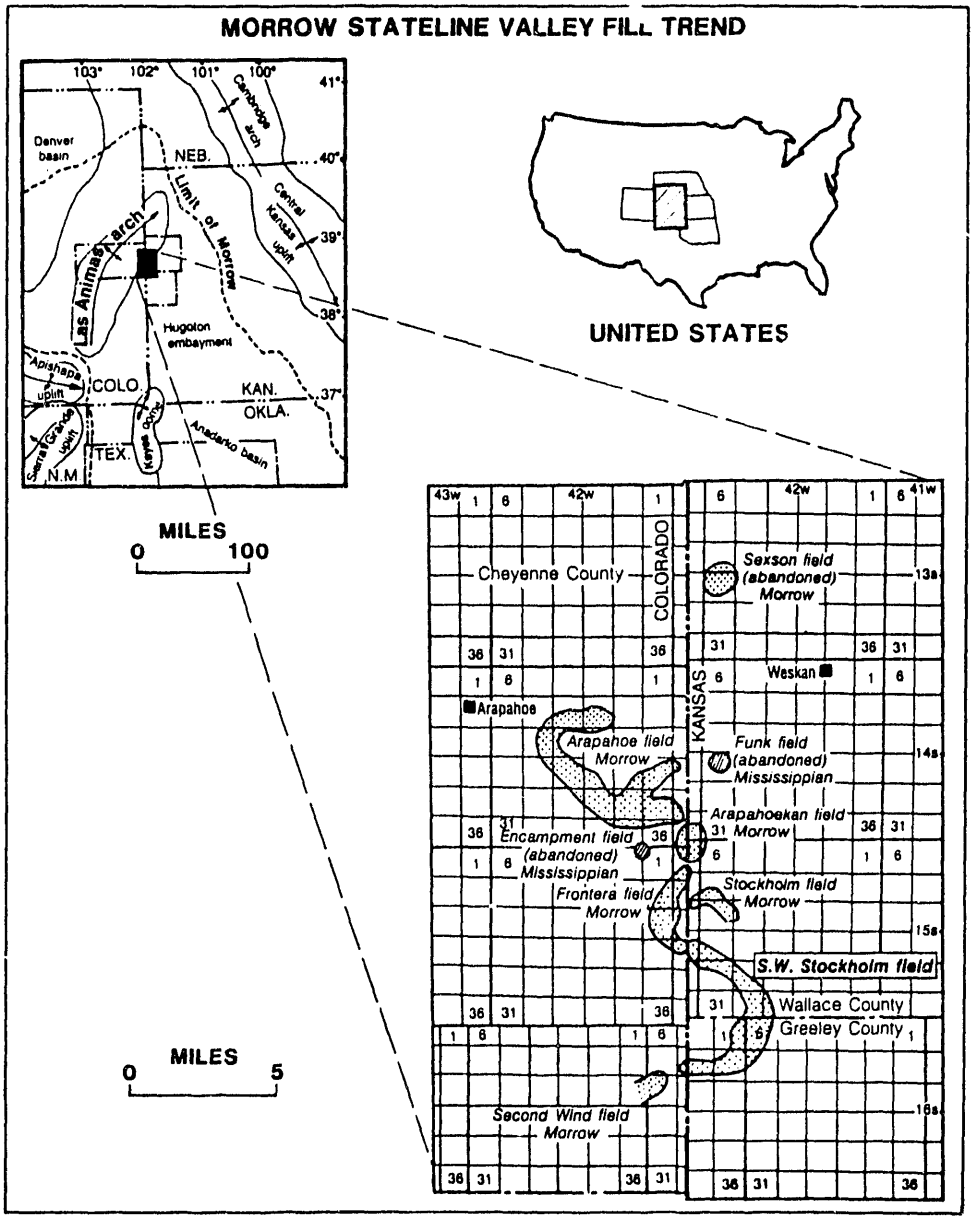


Fig. 1 - Location of 20-mile-long "Stateline Trend" Morrow Sandstone fields, which produce from valley-fill sandstone reservoirs. Southwest Stockholm field, Kansas, is located in Greeley and Wallace counties, Kansas. (Modified from Shumard and Avis, 1990).

TYPE LOG

Texas Oil and Gas 4 Evans E, NW NE SE 11-16s-43w

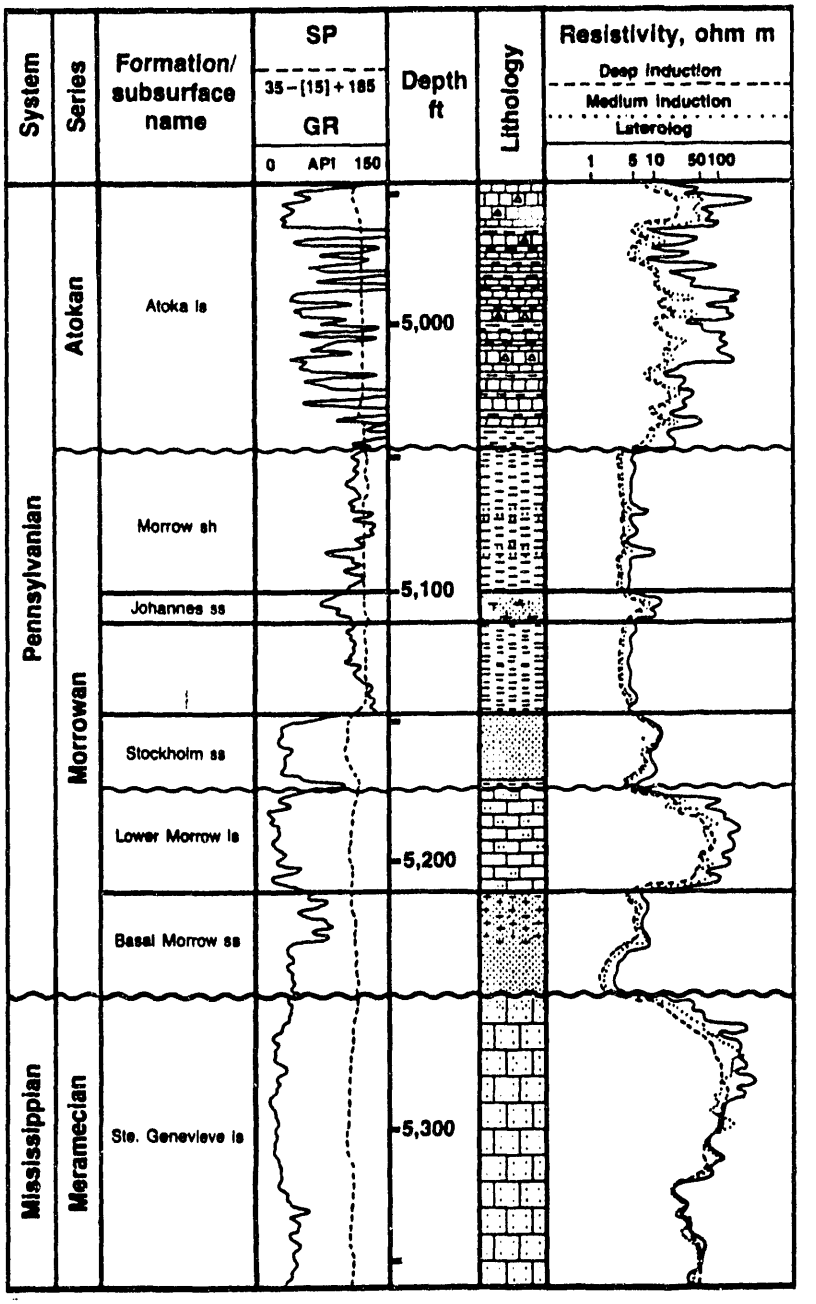


Fig. 2 - Type log for Southwest Stockholm field. Geographic location shown on Figure 4 (Well No. 124). Note that three potentially productive sandstones are present in the Morrow interval. At Southwest Stockholm field the basal Morrow Sandstone is non-productive as is the lower Morrow Limestone. The basal Morrow Sandstone is limited in distribution by limestone valley walls. The Stockholm and Johannes valley-fill sandstones are both productive in Southwest Stockholm field. The contact between the Morrow and the Mississippian limestones is a regional unconformity which in most areas forms the bottom of the valley that is filled with numerous lithologies including sandstone, limestone and shale.

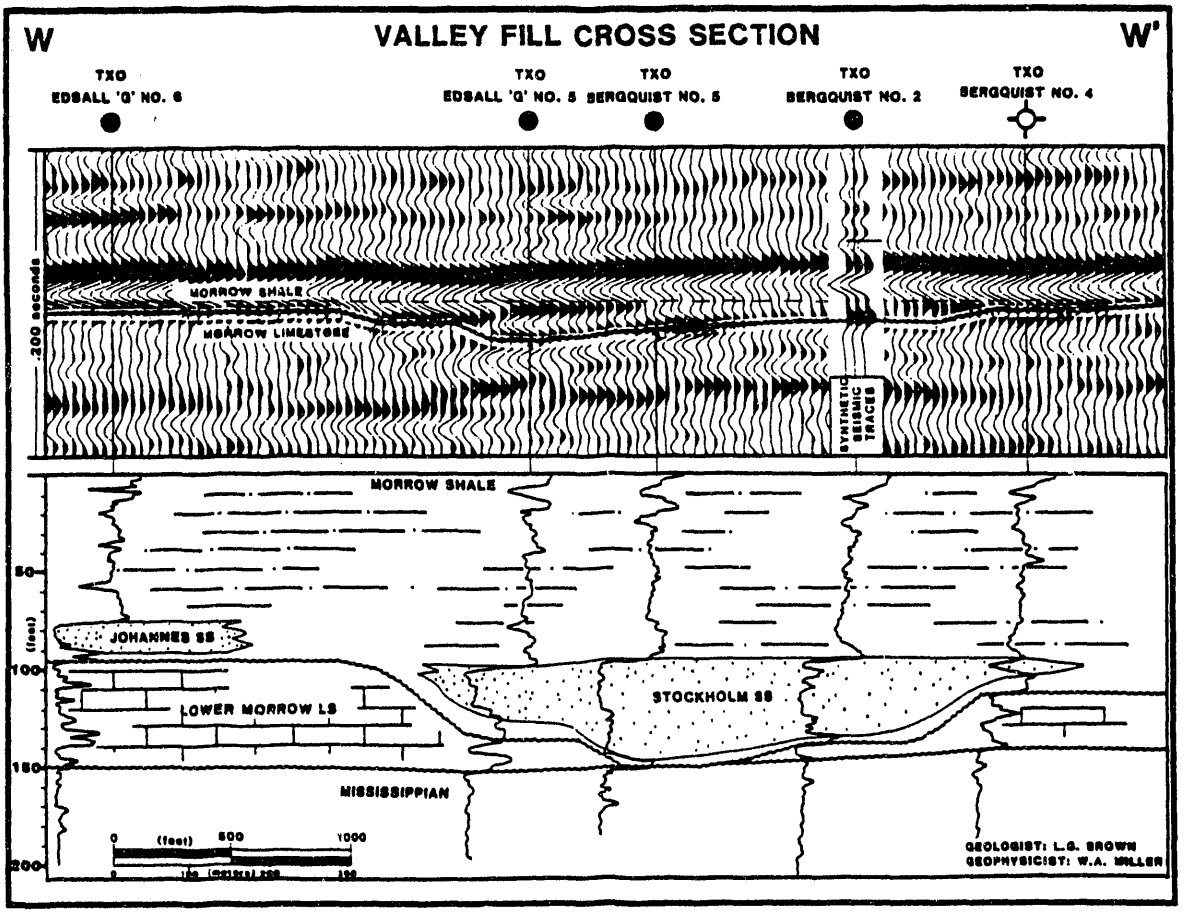


Figure 3 - Stratigraphic and seismic cross sections through two laterally separated Morrow Sandstone valley-fill reservoirs at Southwest Stockholm field, Kansas. TXO Bergquist No. 2 is a cored well in which a synthetic seismic profile was calculated. Note that the Stockholm Sandstone fills an erosional "channel." Flow in the "channel" was out of the diagram. The Johannes Sandstone is also limited areally by valley walls but is more lenticular and is present in discontinuous lenses.

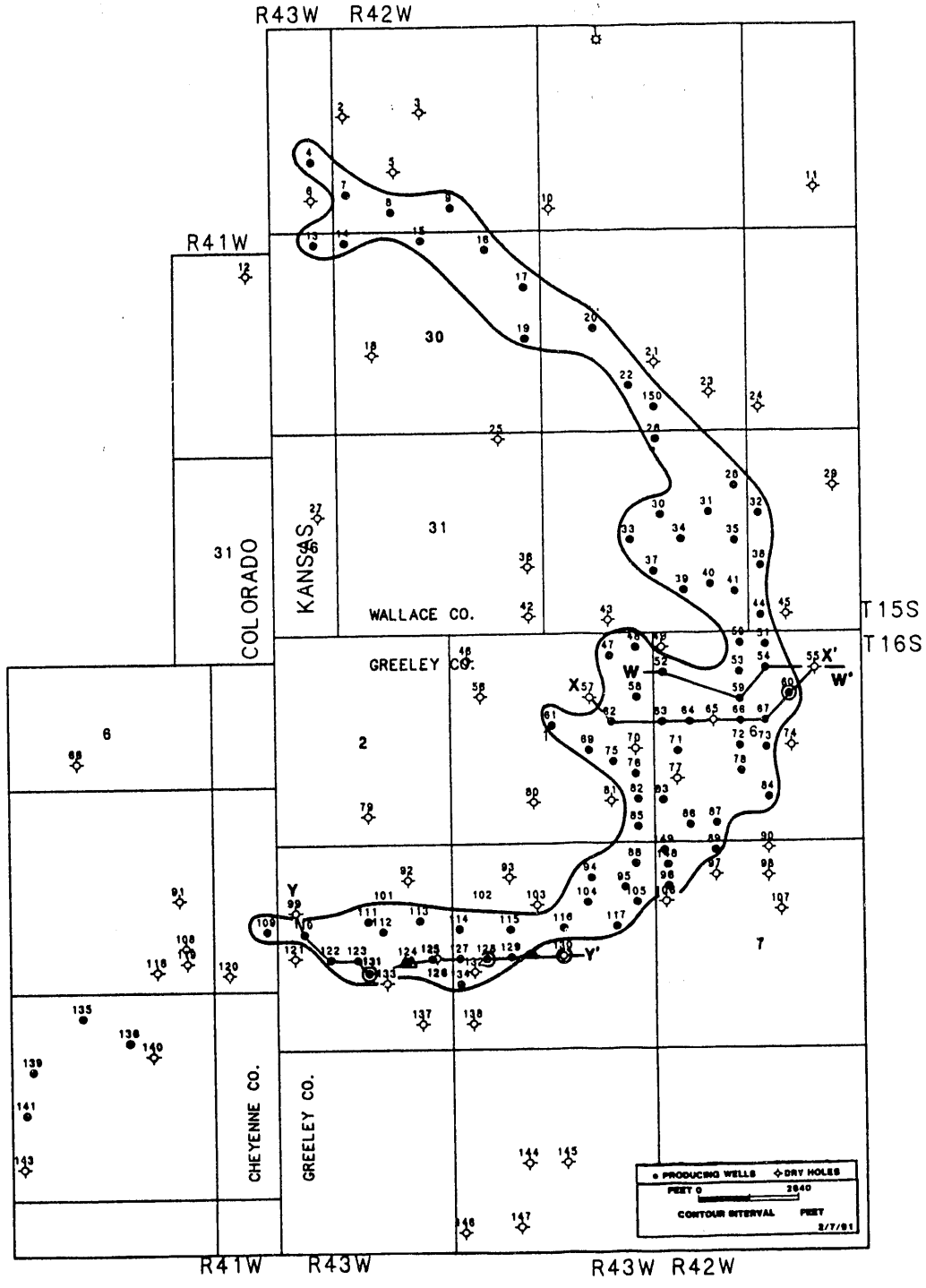


Fig. 4 - Base map, outlining borders of Southwest Stockholm field, Kansas. Cored wells described for this study are circled. Location of the type-log well (#124, Fig. 2) is indicated by a triangle. A list of all numbered wells on this map is available from the senior author.

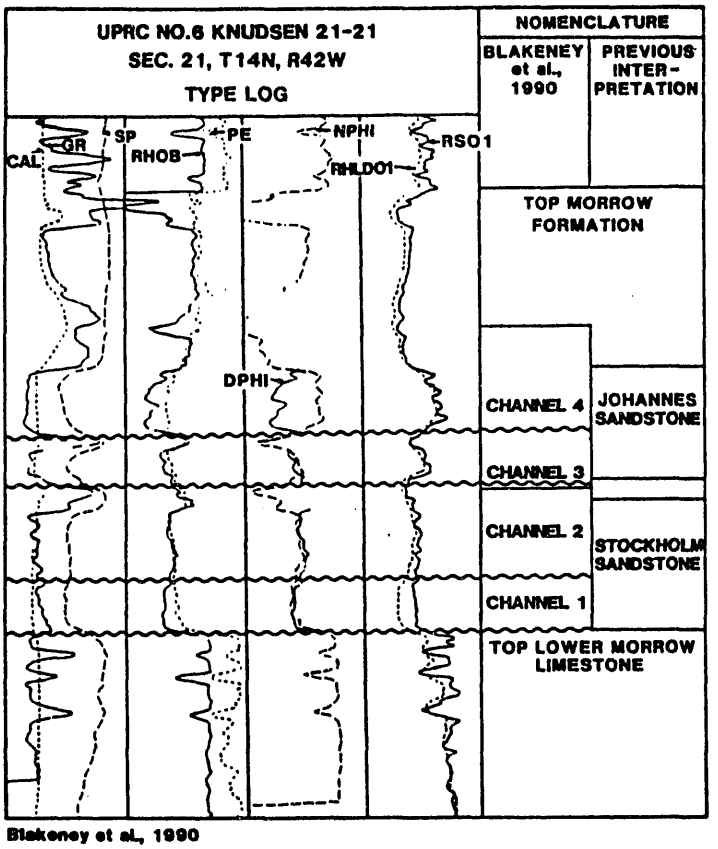


Fig. 5 - Morrowan stratigraphic section in S. W. Stockholm field of "Stateline Trend". Includes four valley-fill units; three are valley-fill sandstones (Basal Morrow, Stockholm and Hohannes) and a valley-fill carbonate (Lower Morrow Limestone). Unconformity at base of Morrowan is a regional unconformity with significant relief.

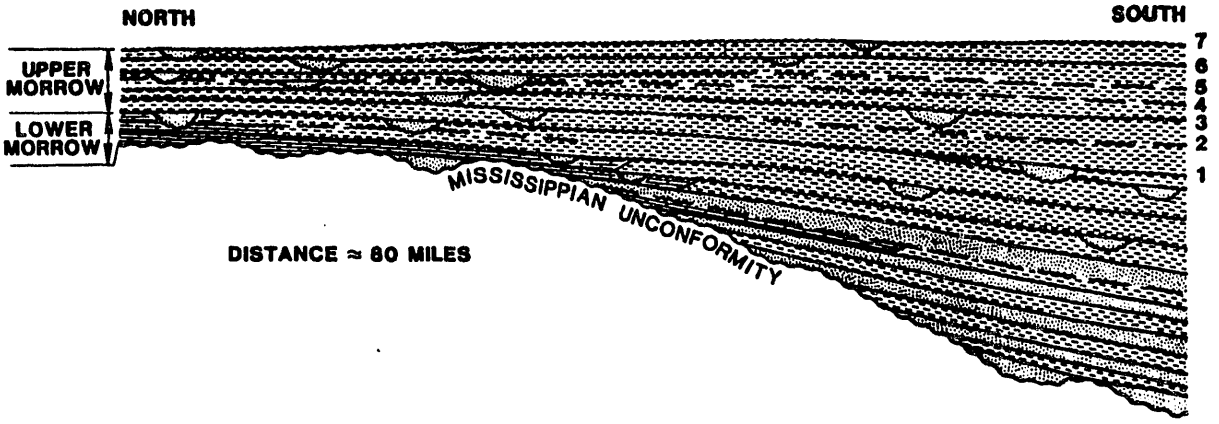


Fig. 6 - Schematic regional cross section of the Morrow Formation along the "Stateline Trend" of the Kansas-Colorado border. A subaerial unconformity separates each of the valley-fills from the underlying marine shales and/or carbonates. The unconformities are numbered (1 to 7) from the base to the top. A map of the valley for the unconformity labeled number 1 is shown in Figure 7. (Wheeler, et. al. 1990).

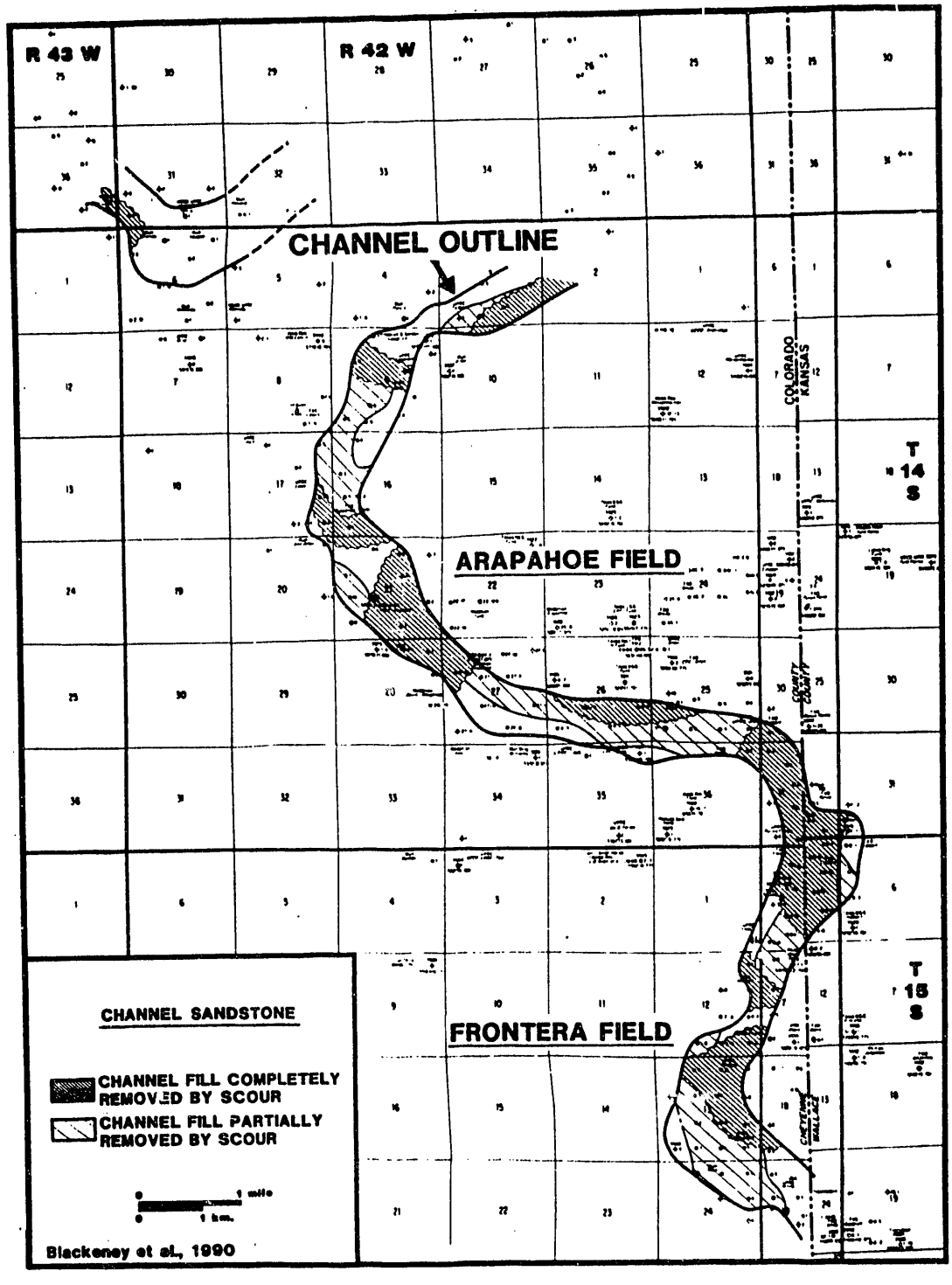
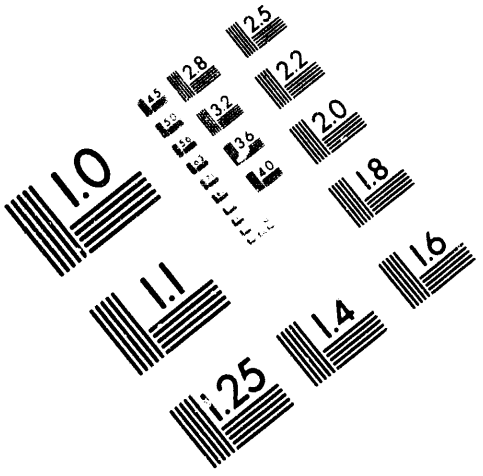
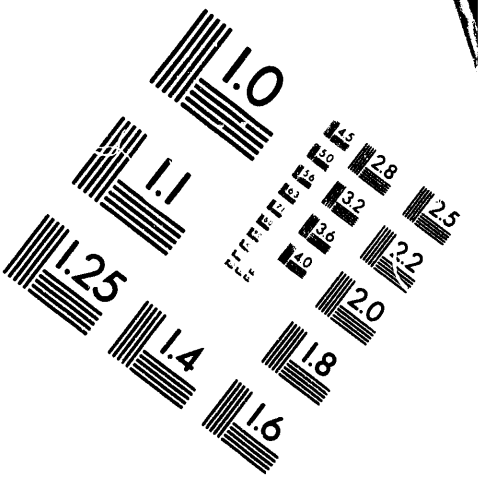


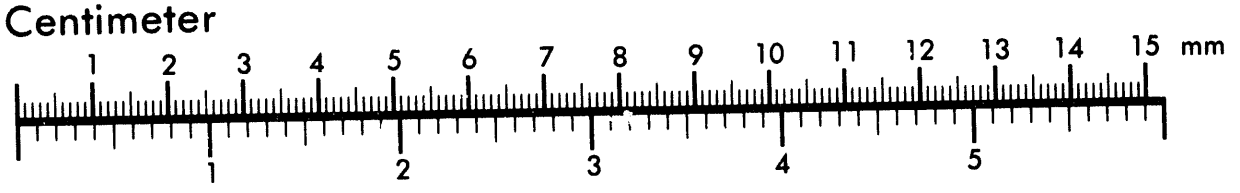
Fig. 7 - Valley in Morrow Sandstone, "Stateline Trend", Colorado and Kansas.

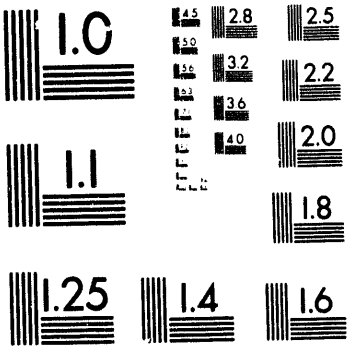


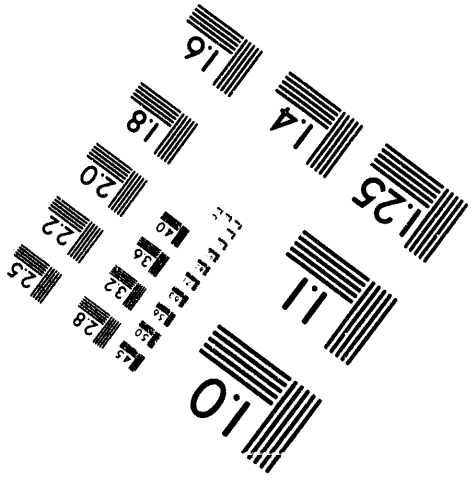


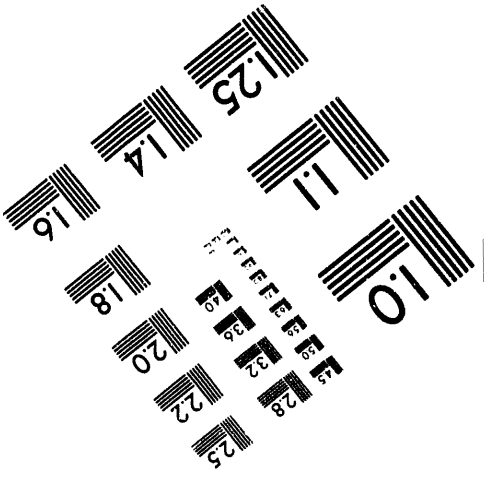
Association for Information and Image Management
1100 Wayne Avenue, Suite 1100
Silver Spring, Maryland 20910
301/587-8202











MANUFACTURED TO AIIM STANDARDS
BY APPLIED IMAGE, INC.

2 of 5

DIAGENETIC SEQUENCE OF EVENTS FOR STOCKHOLM SANDSTONE

EVENT	RELATIVE TIME SEQUENCE*
Compaction	Physical — Chemical
Pyrite	
Chlorite	
Qtz. Overgrowth	
Calcite	
Barite	
Ferroan Dolomite (Baroque)	
Siderite	
Kaolinite	Replacement — Void-fill
Dissolution	

*Feldspar overgrowths are too sparse to be fit into diagenetic sequence.

Fig. 8 - Diagenetic sequence of events for the Stockholm Sandstone, Southwest Stockholm field. One oaf the most important events in some facies after burial of sediments is dissolution of carbonate cement giving significant "secondary porosity". All events listed on figure, other than dissolution, tend to decrease porosity in Morrow valley-fill sandstones.

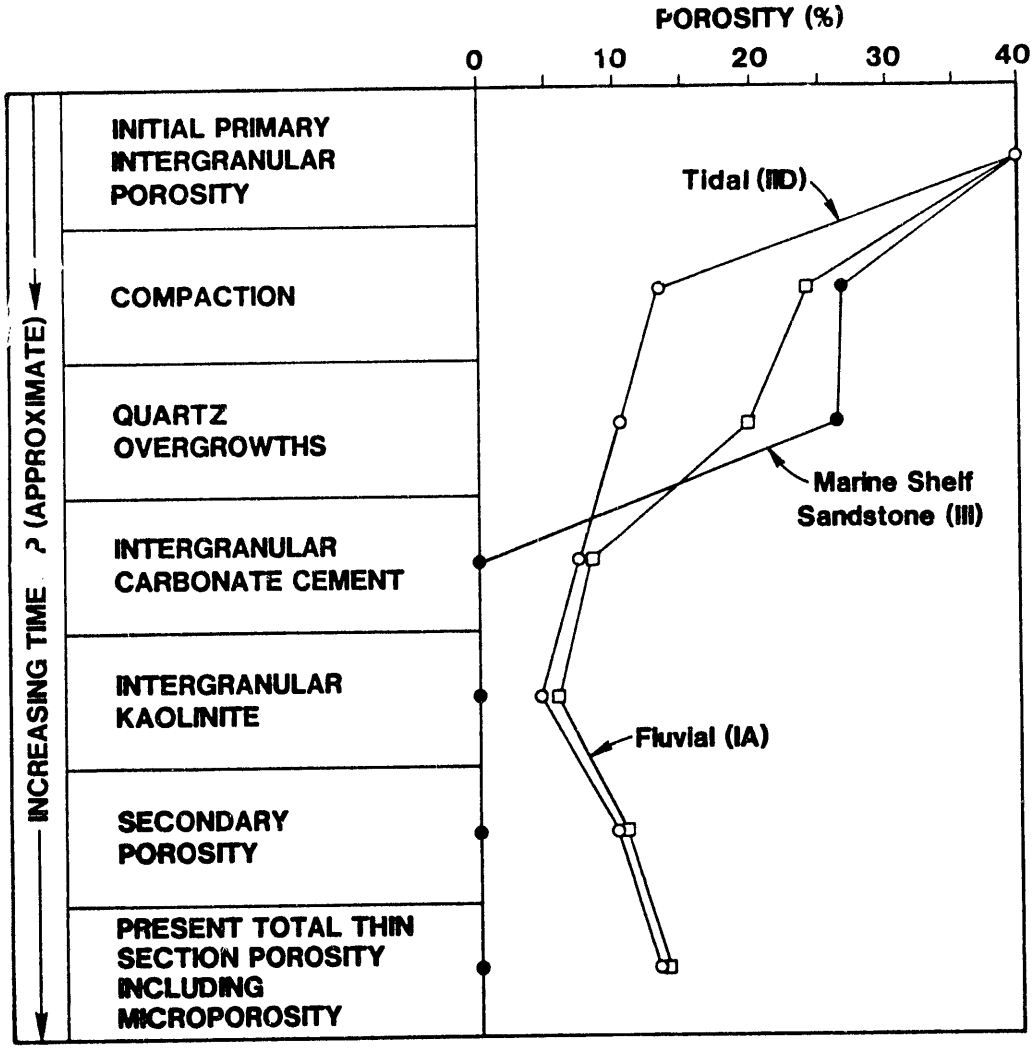


Fig. 9 - Diagram expressing the effect of the major diagenetic events on porosity for selected facies in SW Stockholm field. Interpreted sequence of porosity destroying events resulting from secondary processes in three Morrow reservoir sandstone facies: fluvial, tidal and marine shelf. Note that because rock propeties differ among lithofacies, the method and amount of porosity diminution vary among the facies. Note especially the increase in porosity for fluvial and tidal sandstones due to formation of secondary porosity. Because diagenetic events commonly overlap through time with increasing depth of burial, this is not a time or depth diagram. For this diagram, however, except for compaction, depth and time generally increase downward. Comparison of the history of the Stockholm Tidal Facies (based on only two samples) and Stockholm Fluvial Facies indicates that compaction is more important in the Tidal Facies and that quartz overgrowths and carbonate cement are more important in the Fluvial Facies. However, the two facies, despite the differences in their history, have about the same total thin-section porosity. The Stockholm Marine Shelf Sandstone, Facies, developed pervasive carbonate cement that destroyed porosity. The later dissolution event did not dissolve the carbonate, probably because the low permeability did not permit entry of the leaching solutions.

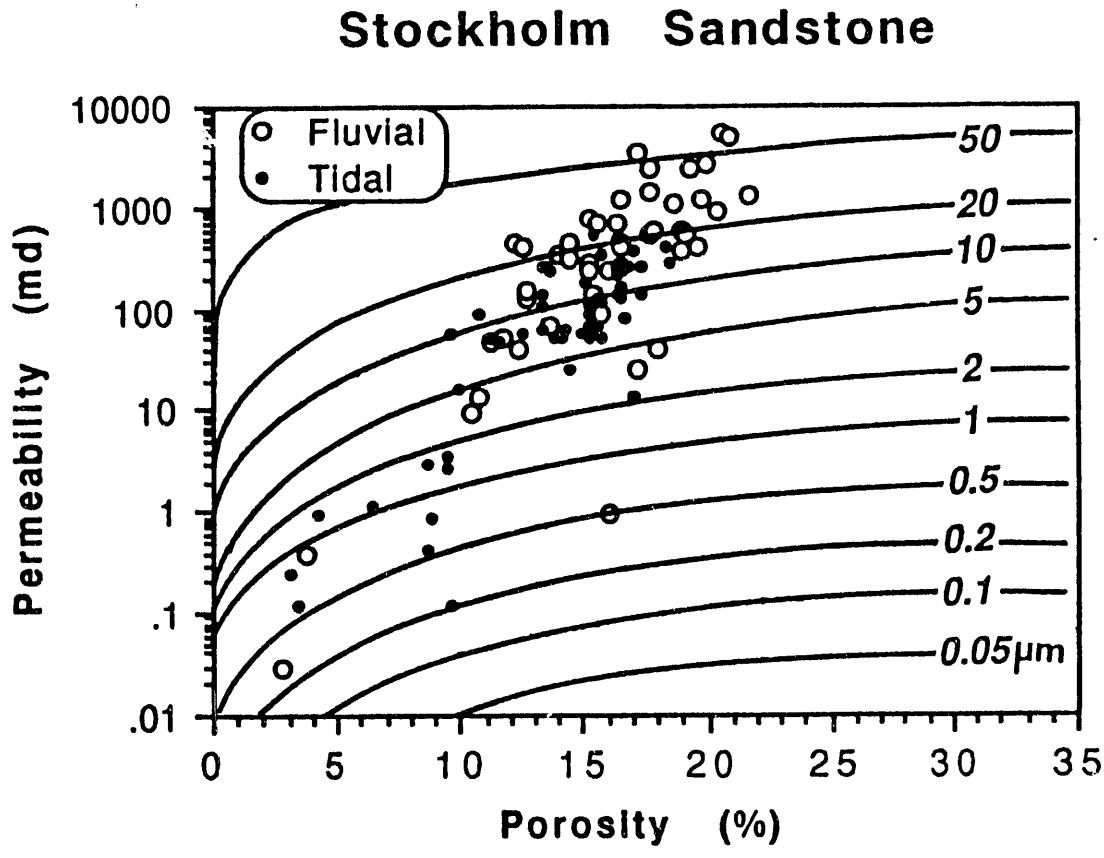


Fig. 10 - Plot of K vs Ø graphical solution to Wyland's equation (from Hartmann and Coalson, 1990) showing Stockholm Sandstone samples from Southwest Stockholm Field. The Morrow Sandstones that produce from Southwest Stockholm field are primarily fluvial valley-fill sandstones.

DRILLING, TESTING, AND COMPLETION SESSION

Thursday, May 6, Morning: 8:00 AM to 11:30 AM
Session Co-Chairmen: Jeff Ahbe, Union Pacific Resources; Bill Lancaster, Elk Exploration Company; Howard W. Dennis, Consultant.

Introduction ..... *ii*
Howard Dennis, Denver, CO

New Bit Technology Can Save the Operator Money *1*
Tim Burton, Smith International, Denver, CO

Reservoir Engineering Aspects of Horizontal Wells *5*
Jerry Jargon, Marathon Oil Company, Lakewood, CO

Economics of Slimhole Drilling *17*
Marshall Adkins, Maurer Engineering, Houston, TX

Short-Radius Horizontal Drilling and Its Application *35*
Joel W. Werner, Slimdril International, Houston, TX

A Slim-Hole Horizontal Re-Entry Program *49*
Chip Abrant, BecField Drilling Services, Houston, TX

Radial Coring and Drilling Technology *51*
Robert B. Tabb, Gardes Directional Drilling Co., Cyprus, TX

Thursday, May 6, Afternoon: 1:15 PM to 4:45 PM

Slimhole Testing Procedures *71*
Cliff McKaughan, Baker Tools, Houston, TX

The Economics of Gelled-Water Stimulation vs Foam *91*
Craig Cippola, Union Pacific Resources, Fort Worth, TX

Development of an Economic Restimulation Program in a Near-Shore Carbonate Reservoir *103*
Gene L. Gaz, Bass Enterprises Production Co., Denver, CO

Stimulating the Niobrara, Silo Field *115*
Ted Brown, Union Pacific Resources, Fort Worth, TX

Coiled Tubing Applications *125*
Marshall Adkins, Maurer Engineering, Houston, TX

Multi-String Tubing Completions in East Texas *127*
Alex Sackeyfio, Union Pacific Resources, Fort Worth, TX

Introduction

Howard W. Dennis, Consultant, Denver, CO

New bit technology allows faster drilling; new drilling technology allows greater exposure to the reservoir; new completion techiques lower costs and increase production. But it isn't always the "new" technology that helps the operator reduce exploration and production costs. It can be updating older methods and factoring in the time-use of money that allows the operator to successfully use less expensive methods to increase his rate of return.

Today an operator must investigate all the opportunities that are available and choose that which best suits his particular project. A new drill might best use slim-hole techniques when proving the prospect. For a recomplete project the operator can choose between various new re-entry techniques. Many operators and geologists have a prospect in the back of the filing cabinet that was once drilled only to be found to be "off-structure" or "just missed the sand." Financing a second well under these conditions would have been difficult. Now with this new technology, a re-entry could cost less and perhaps find new fields.

These are exciting times. We just need to convince management that new or up-dated technology can solve old problems.

New Bit Technology Can Save the Operator Money

by Tim Burton, Smith International, Denver, CO

Operators not aware of the new technology in bits may be leaving money in the hole. With recent advances in bit technology, which require fewer trips and make more hole faster, the operator can save dollars, reduce payout time, and make more projects economical.

POLYCRYSTALLINE DIAMOND COMPACT (PDC) BITS

Over the past decade, Smith International has developed its line of polycrystalline diamond compact (PDC) bits in a variety of styles, with features that deliver the lowest cost-per-foot under a broad range of downhole conditions.

More than any other Smith product or tool, PDC bits have revolutionized drilling in just the last several years.

A PDC bit is simply a matrix or steel body bit with forced-fitted PDC (man-made diamond) cutters. Unlike our three-cone tungsten carbide or steel bits, there are no moving parts on a PDC bit. A PDC bit is designed to cut only shale rock and weak sand stringers, but not compressed sands.

Ideal Rocky Mountain PDC applications include the DJ Basin (to the D Sand), Southwestern Wyoming (Hilliard Shale) and Powder River Basin (to the Mowry and Frontier Formations).

PDC bits have cut drilling costs at a dramatic rate the last ten years.

For instance, in the DJ Basin, 7,200-foot wells that took 130 rotating hours and four-five bits to drill ten years ago are now being drilled in 55 hours with one PDC bit, surface to total depth.

Because of different applications due to formation, only 20 percent of the wells drilled in the Rockies utilize PDC bits.

BEARINGS AND SEALS

No matter what the application, Smith has developed a bearing system to deliver maximum bit performance while lowering drilling costs.

The most significant bearing development in recent years in the spinodal bearing system. Spinodal, a patented copper/nickel/tin alloy produced through a process of casting, annealing, quenching and age-hardening, provides a high degree of strength and ductility.

Our engineers have incorporated a free-floating, split-ring sleeve of spinodal alloy in the space between the bearing surface formed in the cone and the main bearing surface around the journal. This results in the reduction of the outside and inside surface speeds up to 50 percent, minimizing heat and wear. Its greater tensile strength increases bit weight and rpm capacity, and its high ductility provides increased impact resistance as well.

NATURAL DIAMOND BITS

Most diamond bits belong to a family of fixed head drill bits called "shear" bits. These bits drill formation in a shearing mode, rather than a compressing or crushing mode, as three-cone bits do. Therefore, the shear strength if of greater importance to the rock failure that the formation's combressive strength. This is a very important point to consider when selecting a bit to drill plastic formations, usually in the soft to medium-hard range. In plastic oilfield formations, the shear strength is usually a third of the value of the compressive strength. Shearing the formation can then be done with a third of the energy as would be used to crush the rock. This phenomenon results in the ability to drill with less weight and fewer drill collars than three-cone bits. The shearing mechanism is accomplished by placing diamond materials onto a "fixed head" bit body, one with no moving parts. Because the energy is supplied to the bit through both weight and rotary speed, shear bits run very well on mud motors.

Diamonds used in drill bits can be either natural (mined from nature) or synthetic (PDC). Industrial grade natural diamonds are found in varying sizes and qualities. Typical diamond size oilfield usage ranges from one stone per carat to 15 stones per carat. Larger diamonds are used to drill softer formations. Their setting is referred to as "surface set." Two thirds of the diamond is buried into the matrix bit body material and one third is exposed on the surface. Small diamonds, eight to 10 stones per carat or smaller, can be completely buried into ridges of tungsten carbide matrix powder to protect the diamond from fracture when drilling extremely hard or abrasive formations.

The cost of a diamond bit can be up to twenty times the cost of a mill tooth bit and up to four times the cost of a tungsten carbide insert bit. For this reason, the use of a diamond bit must be economically justified by its performance.

Occasionally, this performance justification is accomplished by simply staying in the hole longer. In such cases, the benefits of using a diamond bit are intangible.

The main reason for using a diamond bit, however, is to save money on a cost-per-foot basis. A diamond bit, to be economical, must make up for the additional cost by either drilling faster or staying in the hole longer. Since the bottom line on drilling costs is dollars and cents, a bit's performance is based upon the cost of drilling each foot of hole. The following formula is used for determining cost-per-foot:

$$C = \frac{R\,(T+D) + B}{F}$$

C = Drilling cost-per-foot ($/ft.)
R = Rig operating cost ($/hr.)
T = Trip time (hours)
D = Drilling time (hours)
B = Bit cost ($)
F = Footage drilled

STEERABLE-MOTOR BITS

Smith is running strong in steerable-drilling technology with a new line of three-cone tungsten carbide insert (TCI) and milled (steel) tooth bits, engineered for this demanding application. Enhancements to the bearing design, seal system and cutting structure maximize the bits' overall performance for high-speed drilling needs.

Smith steerable-motor bits incorporate the features required to provide optimum performance, offering drillers a line of more efficient bits for straight-hole, as well as tnagent-section drilling. However, the bits are specifically designed for steerable-drilling applications where speed and directional responsiveness are essential requirements.

To withstand the high rotary speeds generated by mud motors, Smith has developed two new bearings for both TCIf and milled tooth steerable-motor bits: a special-design spinodal sleeve bearing for small-to-medium-size bits and a crowned roller bearing for medium-to-large-size bits.

The side-loading and higher rpm generated by steerable systems can cause bits to go under-gage prematurely. Smith has developed tungsten carbide side-cutting elements that keep the bit in-gage longer and use the side-loading forces to maximize the steerability of the bit. This feature is an integral part of both TCI and milled tooth bits.

A standard feature on all Smith steerable-motor bits is the full leg-back hardmetal overlay. It protects the shirttail from excessive wear in highly deviated holes or long intervals.

The optional leg-back lug helps stabilize and protect the bit in horizontal holes, highly deviated holes or in straight holes in abrasive formations.

Because gage wear becomes a significant problem, causing a loss of directional control, slower rates of penetration, shorter bit runs and subsequent reaming, Smith has developed diamond enhanced, steerable-motor insert bits. In these applications, the cutting structure design in the gage area incorporates the use of PDC inserts on the gage row of the bit.

PREMIUM CUTTING STRUCTURES (3-CONE TCI AND MILLED TOOTH BITS)

Today, the company that once sharpened fishtail bits for California oilfields is designing, manufacturing and marketing tungsten carbide insert and milled tooth for the worldwide oil and gas industry, using the most advanced technology available. In keeping with its tradition to develop ever better products, Smith International continues to enhance its bits for optimum drilling performance--from the bearing designs, to the seal systems and cutting structures.

Some of the recent Smith introductions to its bits are as follows:

Gage Inserts - Severe drilling environments require bits capable of performing in hard rock and/or abrasive sand formations--situations where extreme wear protection is needed. For these applications, diamond enhanced insert bits has been developed for TCI bits. Diamond wear resistance is 1,000 times greater than carbide, virtually eliminating insert. Diamond inserts are applied to the gage cutting area to maintain full gage longer and drill higher ROP for longer intervals than ordinary TCI bits.

Heel Inserts - For the same extreme conditions, a diamond enhanced heel insert--the special "OD" feature, has been applied to the heel area (back side of cone, along gage area). Diamond enhanced heel inserts act the same as the gage inserts to provide a full-gage hole.

Insert Retrofit - It is not always possible to plan for highly abrasive drilling conditions where undergage hole problems can necessitate different bit requirements. This situation is especially true for exploratory wells or where casing programs have to be redesigned. For these unexpected, severe situations, most TCI bits have been designed so they could be quickly retrofitted with diamond enhanced inserts. The wear-resistant properties of polycrystalline diamond combined with the impact resistance of tungsten carbide enables these inserts to significantly increase bit life and footage drilled.

Hardmetal/Milled Tooth Bits - Smith had applied Grade 70C and 70+C hardmetal to both sides of the steel teeth of the cutting structure of our softest milled-tooth bit, the FDS+. This allows for prolonged life of the teeth and significantly higher penetration rates.

Reservoir Engineering Aspects of Horizontal Wells

by Jerry Jargon, Marathon Oil Company, Lakewood, CO

The following pages are presented courtesy of *World Oil*, Gulf Publishing Company

Jerry Jargon is currently manager of Reservoir Management Department at Marathon Oil Company's Petroleum Technology Center in Littleton, CO. Mr. Jargon has worked in the areas of reservoir simulation, well testing and multi-phase flow in pipes. He has a B.S. Ch.E. from the University of Illinois and an M.S. Ch.E. from the University of Denver.

Evaluating horizontal vs. vertical well performance

Numerical simulation, used to estimate productivity and recovery from horizontal wells, aids the decision making process

J. R. Gilman, Senior Reservoir Engineer,
and **J. R. Jargon,** Manager, Reservoir Management,
Marathon Oil Co., Littleton, Colo.

Numerous analytical solutions for estimating horizontal well productivity have been provided in the literature. But these solutions are valid only for single-phase flow in homogeneous closed systems. This article compares some of the most commonly used analytical solutions and discusses estimates of horizontal well productivity and performance through numerical simulation, which is a powerful tool for comparing the productivity of vertical and horizontal wells since it can account for natural fractures, heterogeneities in three dimensions, multi-phase flow and a variety of boundary conditions.

Simulation results will be presented in a subsequent article for homogeneous and anisotropic reservoirs for production and ultimate recovery due to primary production, waterflooding, and gas and water coning.

INTRODUCTION

Recent interest in horizontal wells has been accelerating because of improved drilling and completion technology. This has led to increased efficiency and economics in oil recovery. Increases in oil production rate and improvement in ultimate recovery has given horizontal wells the edge over vertical wells in many marginal reservoirs.

The advantages of horizontal wells can be classified under the following topics:

- Increased productivity or injectivity
- Improved sweep efficiency
- Reduced coning or viscous fingering
- Increased drainage area.

The reduction in gas or water coning may actually be considered an improvement in vertical sweep efficiency or a result of increased productivity. The advantage of horizontal wells when intersecting undrained areas is obvious, but difficult to predict.

Some of the disadvantages of horizontal wells compared to vertical wells are:

- Higher cost
- More difficult to log, stimulate and selectively perforate
- Limited recompletion alternatives for high gas or water rates
- Vertical permeability barriers limit vertical sweep efficiency.

Productivity (or injectivity) of a horizontal well can be greater than that of vertical wells for several reasons. First, horizontal wells can be open to a much greater portion of the reservoir than vertical wells. Horizontal wells can be drilled perpendicular to oriented natural fractures and therefore, intersect more fractures. Also, it may be possible to induce multiple hydraulic fractures in a horizontal well. The main benefit of improved productivity obviously is higher oil production rate, which must be sufficient to justify the cost of drilling a horizontal well. If the main purpose for a horizontal well is to increase oil rate, and well rate will not be limited by tubing or surface facilities, then equations that follow can be used to estimate the well length needed to obtain the desired oil rate. The new well decline curve can be estimated from material balance calculations or reservoir simulation.

Another benefit of increased productivity is reduced drawdown for the same withdrawal rates, possibly resulting in reduced water and/or gas production. If surface facilities are limited by gas or water handling capacity, this may mean that overall field oil production rate can be increased. In condensate systems, increased productivity can result in reduced liquid dropout near the well. There are several potential problems that may limit the productivity increase. Skin damage may be difficult to remove from horizontal wells. Also, an effective low vertical permeability due to shales, etc., may mean that horizontal well length must be very long to obtain sufficient productivity improvement.

Areal sweep efficiency can be better in horizontal wells compared to vertical wells for favorable well orientations in pattern floods. As horizontal well length approaches a value equal to the distance between injectors and producers, areal sweep efficiency theoretically will approach 100%. The vertical sweep efficiency will depend on where the horizontal well is completed in the vertical section. The efficiency could be greater or less than that of vertical wells. For example, if vertical barriers are present, vertical sweep efficiency could be very poor. Sweep efficiency is best evaluated by numerical simulation.

For oil production from a reservoir with a gas cap and/or aquifer, horizontal well sweep efficiency can be better than that of vertical wells because the gas or water crest due to horizontal wells is larger than the cone due to vertical wells. Very long horizontal wells may even allow the reservoir to be produced below the critical coning rate. Horizontal wells can also be completed farther away from the gas-oil or water-oil contact, delaying breakthrough of gas and water. However, it may be dif-

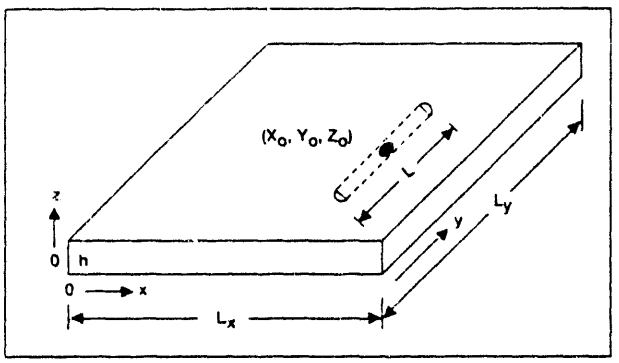


Fig. 1. Babu and Odeh's physical model.

Rules-of-thumb for horizontal wells

- Horizontal wells have a large potential to improve oil production rates and ultimate recovery in many reservoirs. The relative improvement of horizontal wells compared to vertical wells depends on many factors that must often be studied through numerical simulation.
- In single-phase homogeneous reservoirs, horizontal well length must be greater than $h\sqrt{k_h / k_v}$ to exceed the productivity of a fully penetrating, unfractured vertical well.
- Analytical equations for vertical and horizontal well productivity in single-phase closed systems can be used to estimate the ratio of horizontal to vertical well productivity in multi-phase systems.
- Primary recovery can be improved greatly in low permeability homogeneous reservoirs or in anisotropic reservoirs with large k_x/k_y variation by drilling horizontal wells.
- Waterflooding with horizontal producers and injectors primarily accelerates production. This acceleration may make horizontal drilling economically attractive.
- Horizontal wells can increase ultimate recovery by a factor of two-to-three in thin oil columns overlain by gas or underlain by water.
- Reservoir simulators are the best tools to compare the performance of horizontal, slant and vertical wells. Reservoir description is the limiting factor in accurately predicting the actual future performance.

ficult to produce oil located above the horizontal well for water-oil systems and similarly for oil below the well in gas-oil systems. For systems with both gas-oil and water-oil contacts, optimum horizontal well placement between the contacts is important. Optimum placement depends on the strength of the aquifer or gas cap, phase densities, viscosity, relative permeability and the ability to handle gas or water. Reservoir simulation is the best way to study optimum placement of the horizontal well in such systems.

Possibilities to minimize some of the problems listed above include: 1) hydraulically fracturing vertical or horizontal wells, 2) drilling highly deviated wells, 3) drilling multi-spoke horizontal wells and 4) producing from both the vertical and horizontal sections of a well. When comparing vertical and horizontal wells, it is important to realize that a horizontal well may cost twice as much as a vertical well, and therefore, comparisons should be done on an equivalent cost basis.

ANALYTICAL METHODS FOR ESTIMATING HORIZONTAL WELL PRODUCTIVITY

Several authors have provided equations to predict the productivity of horizontal wells in **single-phase** systems. Some of the most widely used include Giger,[1] Joshi,[2,3] Babu and Odeh,[4] and Goode and Kuchuk.[5] These all considered a horizontal well in a closed drainage area, and each has several simplifying assumptions. Joshi's equation is an extension of Giger's, and therefore, Giger's formulation is not included here. Babu and Odeh's formulation is the most general case and is more applicable to most situations encountered. Joshi's equation is the most simple form and is therefore suitable for hand calculations. Joshi's PI equation is given as

$$PI_h = \frac{0.00708 k_h h}{B\mu\left(\left(\frac{a+\sqrt{a^2-0.25L_w^2}}{0.5L_w}\right)+\frac{\beta h}{L_w}\left(ln\left(\frac{0.5(\beta h)^2+2(\beta\delta)^2}{\beta h r_w}\right)+s_d\right)\right)}$$

where

$$\beta = \sqrt{k_h / k_v}$$

$$a = 0.5L_w\left[0.5+\sqrt{0.25+\left(2r_e/L_w\right)^4}\right]^{0.5}$$

Other terms are defined in the nomenclature. The main limitations are that the equation is valid only for $L_w > \beta h$ and $L_w < 1.8\ r_e$. Joshi's equation applies for steady-state flow conditions.

Odeh's and Babu's equation for a horizontal well in the y-direction is given by

$$PI_h = \frac{0.00708 L_y \sqrt{k_x k_z}}{\mu B\left[ln\left(\sqrt{L_x h}/r_w\right)+ln\left(C_h\right)-0.75+s_R+s_d L/L_y\right]}$$

Where s_R and C_h are partial penetration skin factor and geometric factor, which depend on drainage area and permeabilities. This equation assumes pseudosteady state conditions with no-flow boundaries.

These equations are more difficult to evaluate, but can be programmed easily on a computer. The advantage of Babu and Odeh's formulation is that k_x and k_y need not be the same. The equation as given above is for a well in the y-direction (Fig. 1). This equation will show the advantage of drilling wells perpendicular to the high permeability direction. In Babu and Odeh's formulation, the horizontal well can fully penetrate the drainage area and therefore the formulation does not have the the limits of Joshi's equation. There are certain restrictions on the use of Babu and

Odeh's equation and these are discussed by the authors.

In addition to an equation for noflow boundary conditions, Goode and Kuchuk provided an estimate for horizontal well productivity for an infinite areal system with a constant pressure at the top or bottom of the reservoir to approximate a gas cap or large aquifer. The equation is:

$$PI_h = 0.5\frac{L_w\sqrt{k_h k_v}}{162.6B\mu C}$$

where

$$C = \log\left[\frac{8h}{\pi r_w(1+1/\beta)}\cot\left(\frac{\pi z_o}{2h}\right)\right] + 0.4343\left[s_d - \frac{h-z_o}{L_w}2\beta\right]$$

Table 1 compares productivity for horizontal wells in a rectangular drainage area with noflow boundaries and a constant pressure upper boundary using the analytical equations and a numerical reservoir simulator. A one-quarter symmetry element was simulated. Productivity index in the simulator was evaluated after pseudo-steady state flow conditions were established.

In these comparisons, the horizontal and vertical wells are centered in the drainage area. Note that there are some differences between the various analytical equations and simulations, however, both Babu and Odeh's and Goode and Kuchuk's equations give results comparable to the simulation in most cases. Joshi's equation always appears to give low productivities, but remember that his equation is for steady state flow conditions and for areally isotropic conditions. Goode and Kuchuk's equation for a constant pressure upper boundary gave good results for the one case shown.

In Table 1, the analytical equation for productivity of a vertical well for the case of noflow boundaries is given as:

$$PI_v = \frac{0.00708k_h h}{B\mu\left(\ln\left(3.1725\frac{\sqrt{L_x L_y/C_A}}{r_w}\right)+s_p+s_d-0.75\right)}$$

Table 1. Comparison of simulator and analytical productivities in single-phase systems

						Horizontal Productivity			
L_w	Dir†	k_x	k_y	Boundary	PI_v	Simulator	Babu	Goode*	Joshi*
400		100	100	noflow	2.22	5.30	4.82	5.18	3.92
400		100	100	cpb	2.83	8.10		7.13	
400	x	10	100	noflow	0.70	2.43	2.21	2.49	1.60
400	y	10	100	noflow	0.70	1.65	1.22	1.30	1.60
400	x	1	100	noflow	0.22	0.47	0.42	0.47	0.60
400	y	1	100	noflow	0.22	0.24	0.22	0.23	0.60

* $k_h = \sqrt{k_x k_y}$ was used to calculate PI
†Orientation of horizontal well.

Table 2. Comparison of simulator and analytical productivities in multiphase systems

			Simulator PIs									
p_w	k_z	cumo MSTB	horiz	vert	ratio	Babu*	Goode* noflow	Goode* cpb	Joshi*	Vertical* noflow	Vertical* cpb	ratio†
450	10	75	0.51	0.051	10.1	0.143	0.158	0.461	0.118	0.036	0.045	19.99
		150	0.49	0.046	10.7							
		250	0.47	0.044	10.6							
400	10	200	0.42	0.030	14.0	0.143	0.158	0.461	0.118	0.036	0.045	19.99
		400	0.38	0.024	15.8							
		600	0.34	0.021	16.2							
100	10	500	0.32	0.015	21.3	0.143	0.158	0.461	0.118	0.036	0.045	19.99
		1000	0.22	0.012	18.3							
		2000	0.13	0.010	13.0							
100	1	500	0.11	0.025	4.4	0.0971	0.106	0.143	0.075	0.033	0.036	3.86
		1500	0.091	0.018	5.1							
		3000	0.07	0.013	5.4							
100	0.05	1200	0.027	0.023	1.2	0.0336	0.042	0.039	0.023	0.030	0.029	1.34
		2400	0.026	0.022	1.2							
		3600	0.025	0.021	1.2							

* oil zone properties were used in the analytical equations
†PI ratio for analytical equations uses constant pressure PI's.

where the skin effect due to partial penetration, s_p, is given by[6]

$$s_p = \left(\frac{h}{h_p}-1\right)\left[\ln\left(\frac{h}{r_w}\beta\right)-2\right]$$

The shape factor, C_A is 30.883 for a vertical well in the center of a square drainage area. Vertical fractures can be incorporated in the above equation by inputting negative skin factors[7] or replacing r_w by fracture half-length and using the appropriate shape factor.[8] The solution for a vertical well with a constant upper pressure boundary is given in reference 9.

The analytic .l equations can easily be used to show the effect of various parameters on the well productivity.

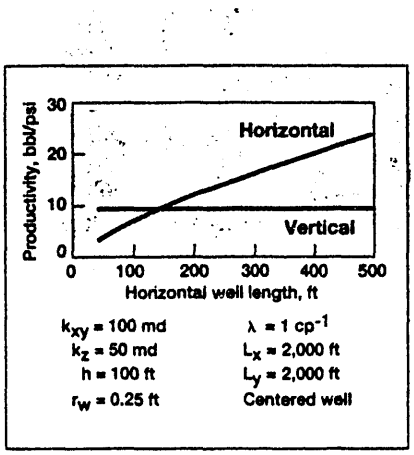


Fig. 2. Horizontal well productivity as a function of well length.

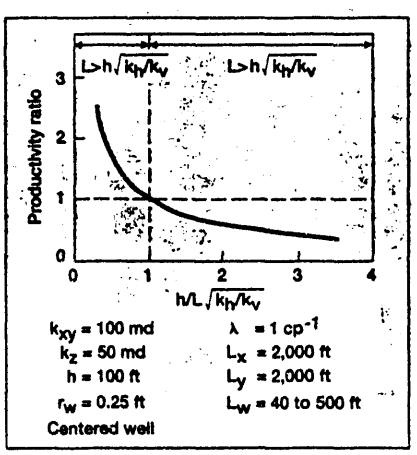


Fig. 3. Horizontal well/vertical well productivity ratio as a function of scaled length.

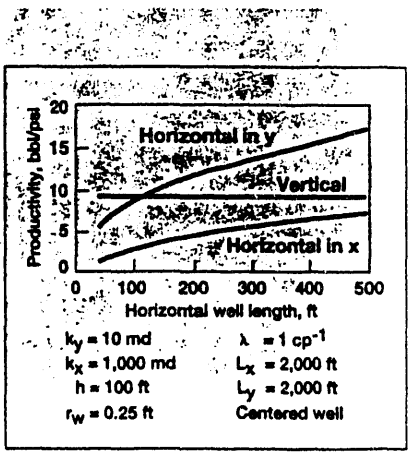


Fig. 4. Horizontal well productivity as a function of well length in an anisotropic system.

For example, Fig. 2 shows the productivity for a horizontal well as a function of well length. Other parameters are listed in the figure. This figure and other calculations show that, over a wide range of well lengths, well productivity is approximately linear with length. Using Babu and Odeh's formulation with k_x equal to k_y, it appears that in many cases, horizontal productivity will be greater than vertical productivity, provided the following relation holds:

$$L_w > h\sqrt{k_h/k_v}$$

Thus for large k_h/k_v ratios, L_w must be much larger than reservoir thickness in order to obtain improved productivity. This is depicted in Fig. 3 where the ratio PI_h/PI_v is plotted versus $h\sqrt{k_h/k_v}/L_w$. Assuming $k_h/k_v = 10$, and $h = 100$ ft, L_w would need to be over 600 ft to obtain twice the productivity of a fully penetrating vertical well. For areally anisotropic systems, ($k_x \neq k_y$) the horizontal well could be oriented perpendicular to the high permeability direction to obtain the best productivity for a given well length. Fig. 4 shows the importance of drilling the horizontal well perpendicular to the high permeability direction. For the data given, the productivity of a 500-ft horizontal well drilled parallel with the direction of the high permeability never exceeds vertical well productivity.

In general, the single-phase productivities as estimated by the analytical equations cannot be used in multi-phase systems. However, the estimated productivity ratio (PI_h/PI_v) may apply, and therefore, the above equations can be used to estimate whether horizontal wells can improve productivity in multi-phase systems. This is illustrated in Table 2, which compares productivities in a three-phase system as predicted by reservoir simulation versus the productivities estimated by the above equations for a single-phase system. The simulation was for a 50-ft oil zone connected to a large gas cap and aquifer, which approximate constant pressure boundaries. The model again used one-quarter symmetry to reduce running time. The simulator calculated oil productivities decline with time because of increasing water-cut and/or gas-oil ratio. The first three cases also show that the productivities decline with increasing drawdown because of increased coning. The ratio of horizontal to vertical productivities is given in the table. The analytical PI ratio uses the constant pressure boundary (cpb) PIs. Note that at early times (low cumulative oil) the productivity ratios from the simulator and the analytical equations are similar. This example illustrates the difficulty in estimating the productivity of horizontal wells from the analytical formulations. The analytical equations are developed for single-phase, homogeneous systems, which are seldom candidates for horizontal wells.



PARMELEE... World's only Girth Wrench

Encircles pipe, rod or cylinder. Holds and turns like a hand of steel. Gives you a new grip with each pull on handle. Gets into tight places where ordinary wrenches don't fit. Won't burr or scratch.

Available in 72 O.D. girths. Don't accept substitutes. There aren't any. Send for brochure.

PARMELEE WRENCH CO.
127 JERSEY STREET • HARRISON, NJ 07029 USA
Phone: 201-483-3232 • FAX: 201-484-3621

LITERATURE CITED

1. Giger, F. M., "The Reservoir Engineering Aspects of Horizontal Wells", SPE 13024 presented at the 59th Annual Technical Conference, Dallas TX. (Sept. 16–19, 1984).
2. Joshi, S. D., "A Review of Horizontal Well and Drainhole Technology" SPE 16868 presented at the 62nd Annual Technical Conference, Dallas, TX. (Sept. 27–30, 1987).
3. Joshi, S. D., "Production Forecasting Methods for Horizontal Wells", SPE 17580 presented at the SPE International Meeting on Petroleum Engineering, Tianjin, China (Nov. 1–4, 1988).
4. Babu, D. K. and Odeh, A. S., "Productivity of a Horizontal Well", *SPE Res. Eng.*, pp. 417–421 (Nov. 1989).
5. Goode, P. A. and Kuchuk, F. J., "Inflow Performance for Horizontal Wells," SPE *Reservoir Engineering*, pp. 319–323, Aug. 1991.
6. Saidikowski, R. M., "Numerical Simulation of the Combined Effects of Wellbore Damage and Partial Penetration", SPE 8204 presented at SPE Annual Technical Conference Las Vegas, NV, (Sept. 23–26, 1979).
7. Cinco-Ley, H., Samaniego-V, F., Dominguez-A, N., "Transient Pressure Behavior for a Well With a Finite-Conductivity Vertical Fracture", *Soc. Pet. Eng. J.*, pp. 253–264 (Aug. 1978).
8. Earlougher, R. C. Jr., "Advances in Well Test Analysis", *SPE Monograph 5*, Society of Petroleum Engineers, Dallas (1977).
9. Streltsova-Adams, T. D., "Pressure Transient Analysis for Afterflow-Dominated Wells Producing From a Reservoir With a Gas Cap", *J. Pet. Tech.*, pp. 743–754 (April 1981).

NOMENCLATURE

- a = Half the major axis of drainage ellipse, ft
- B = Formation volume factor, RB/STB
- C_h = Odeh-Babu geometric factor, dimensionless
- C_A = Shape factor for well drainage shape, dimensionless
- h = Thickness, ft
- h_p = Perforated height, ft
- k = Permeability, md
- L = Reservoir drainage length, ft
- L_w = Horizontal well length, ft
- PI = Productivity index, STB/psi-day
- q = Flow rate, bpd
- r = Radius, ft
- s = Skin factor
- s_p = Skin factor from partial penetration of the vertical well
- s_R = Skin factor from partial penetration of a horizontal well
- x_o = x coordinate of horizontal well center, ft
- y_o = y coordinate of horizontal well center, ft
- z_o = z coordinate of horizontal well center, ft
- β = $\sqrt{k_h/k_v}$
- δ = Vertical distance of horizontal well from reservoir mid-height, ft
- μ = Viscosity, cp

Subscripts

- d = Damage
- e = Exterior
- h = Horizontal
- v = Vertical
- w = Wellbore
- x = x-direction
- y = y-direction
- z = z-direction

Evaluating horizontal vs. vertical well performance

Part 2—Reservoir simulation results are used to predict production and ultimate recovery due to primary production and waterflooding, and to evaluate effects of gas and water coning

J. R. Gilman, Senior Reservoir Engineer, and **J. R. Jargon,** Manager, Reservoir Management, Marathon Oil Co., Littleton, Colo.

An earlier article (see *World Oil,* April 1992, page 67) compared some commonly used analytical solutions for estimating horizontal well productivity and performance. This installment demonstrates some of the capabilities of reservoir simulation for evaluating horizontal well behavior.

Numerical simulation is a powerful tool for comparing the productivity of vertical and horizontal wells since it can account for heterogeneities, multi-phase flow and a variety of boundary conditions. The accuracy of numerical simulation often depends on numerous factors such as grid size, time-step size, solution methods and the accuracy of the input data (in fact, reservoir description can be considered a limiting factor in accurately predicting future performance).

DEPLETION—HOMOGENEOUS RESERVOIRS

Single porosity, homogeneous reservoirs were depleted with a vertical production well and a horizontal production well. A 320-acre drainage area was assumed with the wells located in the center of the drainage area. A three-layer model with 60 ft total thickness and 30 md permeability was constructed for a ¼ segment of the drainage area. A flowing BHP of 50 psi is set to control production. The fully penetrating vertical well initially produces at a rate of 100 STB/D while the 933-ft horizontal well initially produces at 1,500 STB/D. Both of these rates decline rapidly with production dropping to 23 and 100 STB/D, respectively, during the first 100 days (Fig. 5).

This points out the fallacy of putting too much emphasis on initial short term production reports. High rates reported during short term tests (2-3 hours) are completely misleading as far as longer term producing rates are concerned.

For this homogeneous reservoir with moderate permeability, the horizontal well produces more than three times the cumulative oil of the vertical well during the first five years (93,500 STB vs. 29,800 STB) and 2.6 times the vertical well at 15 years (173,000 STB vs. 66,900 STB).

The same cases were repeated for a dual porosity reservoir (naturally fractured). For these cases, the fracture permeability is 300 md and the matrix permeability is 30 md. The decline in rate is less drastic (Fig. 6). At 100 days, the vertical well is producing 218 B/D and the horizontal well is producing 630 STB/D. At five years, the vertical well has produced 227,900

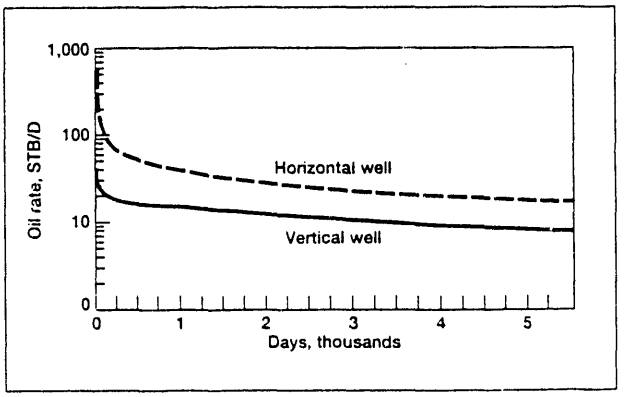


Fig. 5. Simulated depletion rates for a homogeneous reservoir.

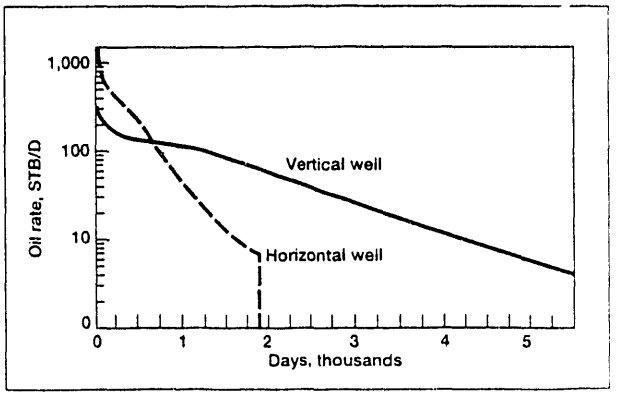


Fig. 6. Simulated depletion rates for a dual porosity reservoir.

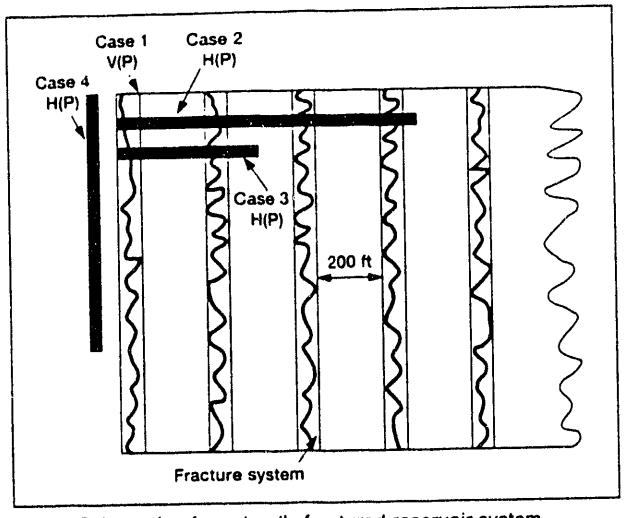


Fig. 7. Schematic of a naturally fractured reservoir system.

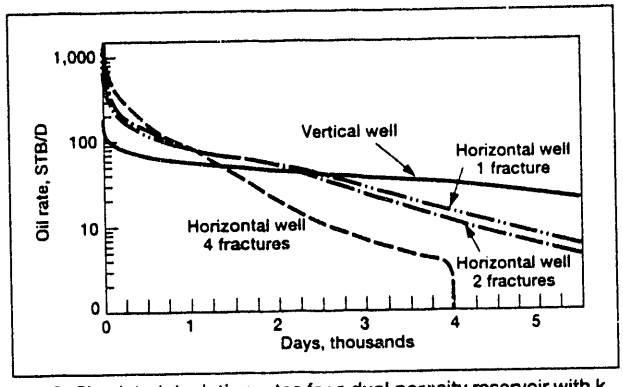


Fig. 8. Simulated depletion rates for a dual porosity reservoir with k_m equal to 30 md.

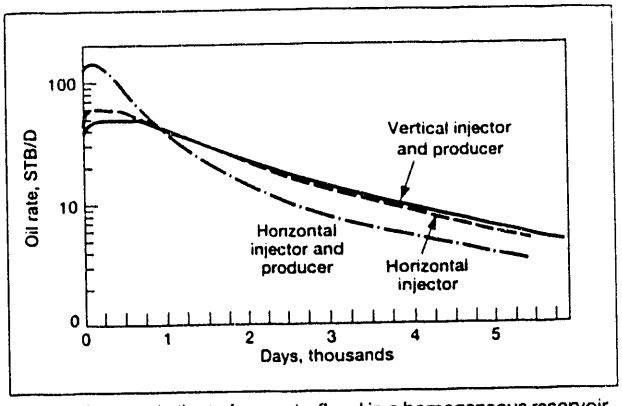


Fig. 9. Simulated oil rate for a waterflood in a homogeneous reservoir.

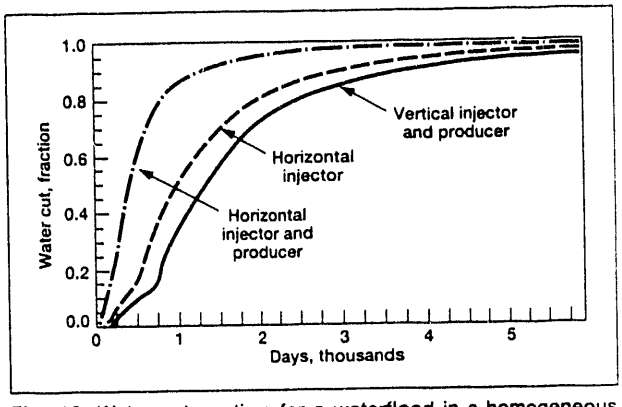


Fig. 10. Water cut vs. time for a waterflood in a homogeneous reservoir.

STB and the horizontal well has produced 310,600 STB. Ultimate recovery is 305,700 STB at 15 years for the vertical well and 311,000 STB at 5.1 years (reservoir depleted) for the horizontal well. A horizontal well accelerates production as reservoir permeability increases, while ultimate recovery is only slightly larger.

Horizontal wells can be expected to provide higher rates and significant incremental recovery in lower permeability reservoirs and essentially accelerate recovery in high permeability reservoirs with marginal increases in ultimate recovery.

DEPLETION—ANISOTROPIC RESERVOIRS

Fig. 7 shows a diagram of a naturally fractured reservoir with fractures aligned every 200 ft and perpendicular to the *X* coordinate. The fracture permeability is 300 md and the matrix permeability is 30 md. Primary fluid storage is in the matrix. Cases were simulated with a vertical well intersecting a fracture at the origin; a horizontal well 933 ft long and intersecting four sets of fractures; a horizontal well 442 ft long and intersecting two sets of fractures; and a horizontal well drilled 933 ft along the first set of fractures. Table 3 shows results at 15 years of depletion or at time of depletion if depletion occurs sooner. Production profiles are given in Fig. 8.

Table 3. Anisotropic fractured reservoir

k_f = 300 md, k_m = 30 md

Case	Time (yr)	Cum. oil (STB)
Vertical well	15	240,900
Horz. well (4 fractures)	10	312,800
Horz. well (2 fractures)	15	305,700
Horz. well (1 fracture)	15	301,800

Table 4. Anisotropic naturally fractured reservoir

k_f = 300 md, k_m = 3 md

Case	Time (yr)	Cum. oil (STB)
Horz. well (4 fractures)	15	271,100
Horz. well (2 fractures)	15	186,100
Horz. well (1 fracture)	15	137,100

As expected, the longest horizontal well, drilled perpendicular to the fracture system, recovers the most oil and does so in a shorter time period.

For comparison, the matrix permeability was decreased to 3 md. These results are given in Table 4.

A more dramatic decrease in oil recovery is observed if the horizontal well is shorter or is drilled parallel to the fracture system when the matrix permeability is lower (3 vs. 30 md). Thus, knowledge of fracture orientation is necessary to obtain optimum results from horizontal wells. Many reservoirs are thought to be compartmentalized as depicted here (Austin Chalk, Bakken, etc.) and better results are obtained with longer horizontal wellbores intersecting multiple sets of fractures.

WATERFLOODING

Waterflooding is the most common method of improving oil recovery beyond primary production. However, very few horizontal wells have been used in waterflood application.

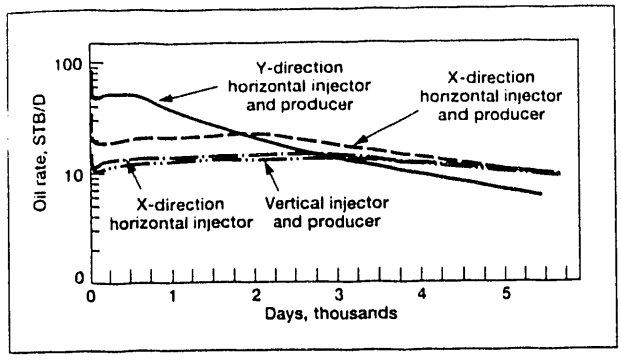


Fig. 11. Oil rate for various producer/injector combinations for the case of a waterflood in an anistropic reservoir (k_x = 300, k_y = 30 md).

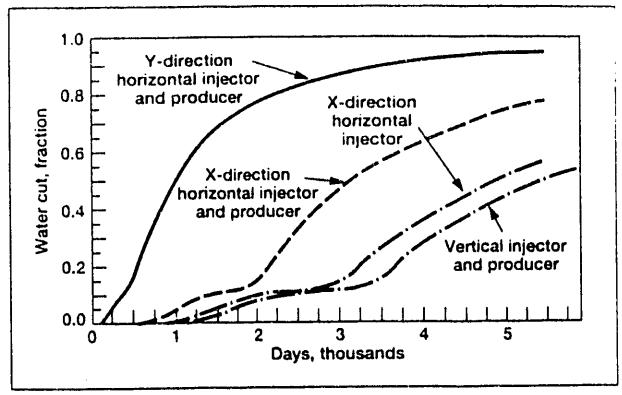


Fig. 12. Water cut for various producer/injector combinations for the case of a waterflood in an anistropic reservoir (k_x = 300, k_y = 30 md).

Several cases were run to compare results of waterflooding with horizontal wells to that obtained using vertical wells or a mixture of both. A three layer model with 60-ft thickness was constructed for a ¼ segment of a 40-acre, 5-spot waterflood. Three cases with homogeneous reservoir properties were run:

- Vertical fully penetrating injector and producer
- Horizontal injector completed in the middle layer with well length equal to ½ the side of a quarter 5-spot and a vertical producer
- Horizontal injector and producer each ½ length of a side.

The case with a horizontal injector and vertical producer was chosen because many fields are originally drilled with vertical wells for primary production, and waterflood development takes place at a later time with the option later to drill horizontal injectors. In all cases the wells were operated at constant flowing bottomhole pressure. Thus injection and production rates varied depending on the well PI, which is a function of well length.

The following table lists recovery after 15 years of waterflooding. Fig. 9 and 10 show plots of oil rate and water cut vs. time.

Table 5. Waterflood—Homogeneous reservoir

Injector	Producer	Cum. oil production (STB)	Water cut, %
V	V	116,719	94.8
H	V	120,437	96.8
H	H	135,633	99.1

Initial rate for the horizontal well is over 200 STB/D while the vertical producer is only 77 STB/D. Rates decline initially due to transient effects, then increase and stabilize due to pressure support from injection, and finally, begin a steady decline after water breakthrough. In this waterflooding situation, cases with the horizontal wells perform better vs. time because of higher productivity and injectivity indexes.

Incremental cumulative production is evident throughout the 15 years, but the horizontal well cases are producing at a higher water cut. At equivalent water cuts of 95%, the vertical well case has produced 116,700 bbl, the horizontal injector case has produced 113,400 bbl, and the case with both wells being horizontal has produced 110,000 bbl. The main effect of horizontal wells in waterflooding a homogeneous reservoir is acceleration of production.

Waterflooding simulations were also performed for anisotropic reservoirs with permeability varying by a factor of 10 in the *X* and *Y* direction. Table 6 summarizes cumulative recovery at 15 years for various well combinations.

Figs. 11 and 12 show oil rate and water cut vs. time for the above cases, respectively.

At 50% water cut, the two-horizontal-well case shows cumulative oil production of 48,600 STB compared to 65,600 STB for the two-vertical-well case. Time to reach this level of water cut is only 2.8 years for two horizontal wells compared to 15 years for two vertical wells. The two horizontal wells markedly accelerate oil production.

An increase in oil production at 15 years of 173% is seen for the horizontal wells vs. vertical wells and may make drilling of horizontal wells economic depending on incremental drilling costs.

Table 6. Waterflooding—Anisotropic reservoirs

k_x = 300 md, k_y = 30 md

Injector	Producer	Horizontal well direction	Cum. oil production (STB)	Water cut, %
H	H	Y	113,650	94.9
H	H	X	93,950	77.6
H	V	Y	71,870	74.7
H	V	X	71,125	56.6
V	V		65,565	50.0

Table 7. Waterflood—Naturally fractured reservoirs

Injector	Producer	Cum. oil production (STB)	Water cut, %
V	V	22,228	99.9
H	V	22,265	99.9
H	H	23,181	99.9

Waterflooding in naturally fractured reservoirs can be successful if the reservoir rock is water wet and the fracture system is fairly uniform. Highly conductive fractures will lead to early water breakthrough and a long period of producing at high water cut (80–90%) while imbibition occurs in the matrix to displace the oil. If the reservoir rock is oil wet, very little oil will be recovered from the matrix and oil production will be mainly from the fracture system. This could lead to very poor recovery efficiency since fracture pore volume is usually small when compared to the matrix.

A homogeneous naturally fractured waterflood model was used to see if horizontal wells would improve recovery. Table 7 shows recovery at 15 years for two vertical wells; a hori-

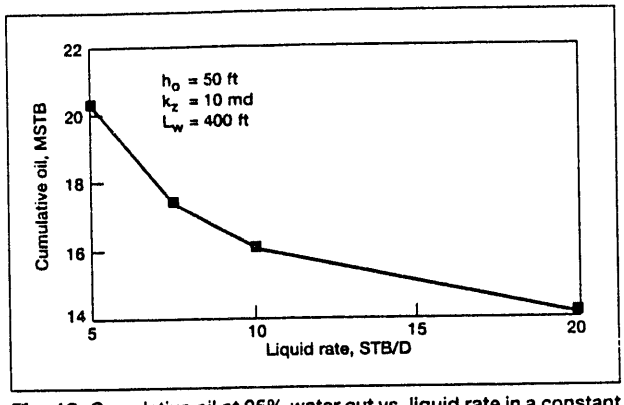


Fig. 13. Cumulative oil at 95% water cut vs. liquid rate in a constant pressure, bottom water system.

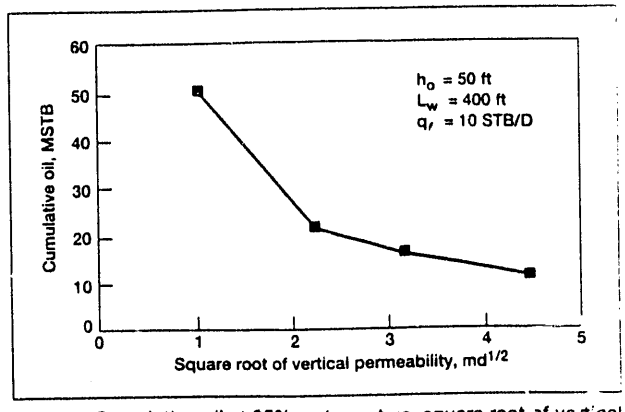


Fig. 15. Cumulative oil at 95% water cut vs. square root of vertical permeability in a constant pressure, bottom water system.

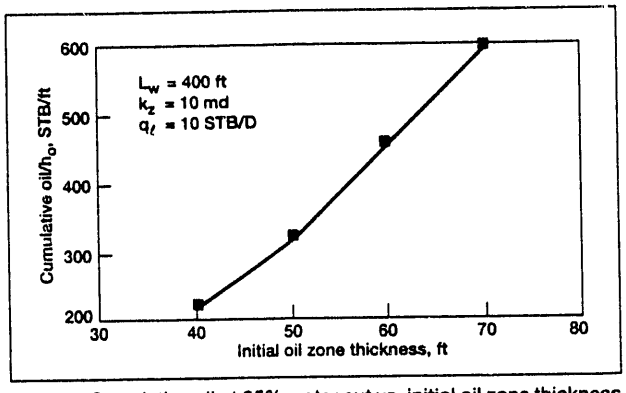


Fig. 14. Cumulative oil at 95% water cut vs. initial oil zone thickness in a constant pressure, bottom water system.

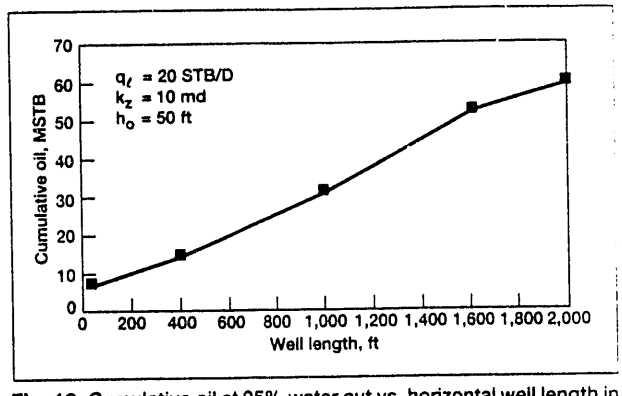


Fig. 16. Cumulative oil at 95% water cut vs. horizontal well length in a constant pressure, bottom water system.

zontal injector and vertical producer; and two horizontal wells. Matrix permeability is 30 md and fracture permeability is 300 md.

Recovery is low in all cases due to limited spontaneous imbibition from the fracture system to the rock matrix.

Horizontal wells in a homogeneous naturally fractured reservoir where fracture conductivity is fairly high do not show incremental recovery or even acceleration of production since vertical well productivity will be large if the vertical well intercepts a well connected fracture network.

Waterflooding results presented herein are for limited reservoir types. Results have shown acceleration of recovery due to improved productivity and injectivity of horizontal wells. Areas where horizontal wells might show definite increases in ultimate recovery are line drive pattern floods and peripheral floods. These cases are not investigated here, but recovery efficiency would be improved.

Many situations occur in which normal waterflooding with vertical wells gives very poor results due to reservoir heterogeneities. The best way to evaluate these cases is to prepare an extensive reservoir description and then run simulations to compare recovery with vertical and horizontal wells.

The key to successful waterflooding in many instances will be detailed reservoir evaluation prior to initiating the flood.

SIMULATION OF CONING EFFECTS

This section deals with horizontal wells in systems with a large gas cap and/or aquifer, and therefore, displacement is primarily vertical. Horizontal wells can work well in this system because they can be completed away from the gas-oil or water-oil contacts while meeting or exceeding the productivity of vertical wells.

In systems where coning is important, vertical sweep efficiency is better for horizontal wells as compared to vertical wells because the sweep efficiency depends on the area under the cone. The crest under a horizontal well will be larger than the cone under a vertical well. According to Ozkan and Ragahavan,[2] in their analysis of the steady-state pressure distribution of a constant pressure bottom water system, the maximum drainage radius of a vertical well is:

$$r = 2.3\, h_0 \sqrt{k_h / k_v}$$

Therefore, for small h (i.e., as the oil column becomes thin) or for small k_h/k_v, drainage radius becomes small. To drain a greater area than given above, horizontal well lengths must be more than twice this value, in which case the drainage area is approximately L_w^2. Their evaluation has numerous assumptions including negligible gravity effects, however, it does indicate that horizontal wells or closer vertical well spacing could be required to effectively produce a thin oil column in a reservoir with constant pressure bottom water or constant pressure gas cap.

Numerous authors have given equations to estimate the critical oil production rate and/or cone breakthrough

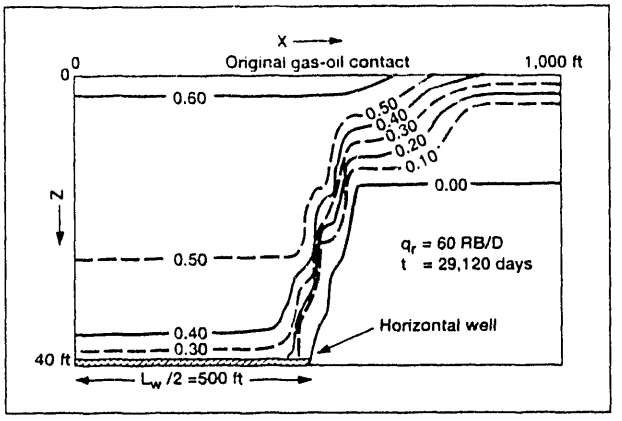


Fig. 17. Gas saturation contours at economic gas-oil ratio (10 Mcf/bbl) for a 1,000-ft horizontal well.

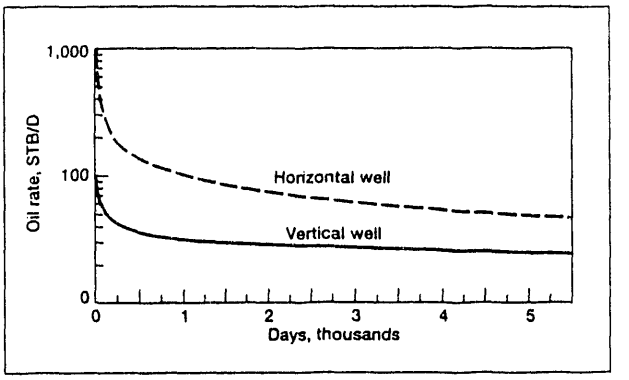


Fig. 18. Simulated oil rate for the case with gas coning in vertical and horizontal wells.

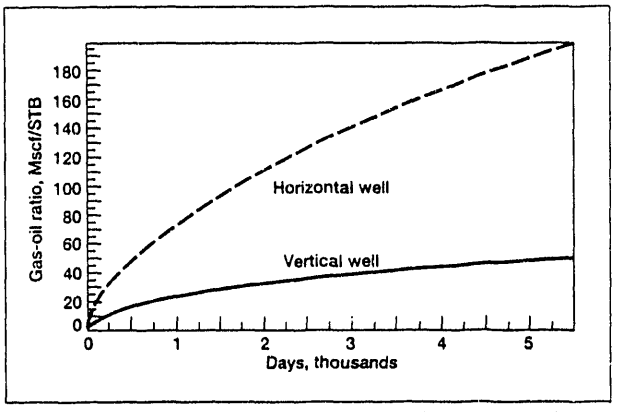


Fig. 19. Simulated gas-oil ratio for the case with gas coning in vertical and horizontal wells.

time for vertical and horizontal wells.[3-7] The critical rate is defined as the maximum rate that will allow water (or gas) free oil production. The equations have many assumptions, such as infinite drainage area and homogeneous properties, which are often not realistic in actual field situations. The equations can give some insight into the properties that are important in coning and relative comparisons between coning in horizontal and vertical wells; however, reservoir simulators can easily be set-up to study coning under more realistic assumptions.

A reservoir simulator was used to study the effect of various parameters on ultimate recovery for a single well in a limited drainage area with water or gas coning.

The horizontal well is located in the top layer for bottom water systems and in the bottom layer for gas cap systems. Systems with both water and gas coning were not studied. In such systems, less pressure drop is required to cone water to the well, but depending on the mobility ratio, it may still be more economical to complete the well near the water-oil contact. This aspect should be studied with actual field data if such an application is planned. Important parameters would include distance to contacts, drainage radius, drawdown, relative permeability, capillary pressure, viscosity, wellbore damage, boundary conditions and natural or vertical fractures.

Simulations were performed to study the effect of various parameters on the cumulative oil recovery at assumed economic limits of 10 Mscf/STB gas-oil ratio or 95% water cut. The simulations used constant liquid rate (oil plus water) for the bottom water cases and constant reservoir voidage rate (oil plus gas) for the gas cap cases. Because the rate of the higher mobility phase is increasing with time, the drawdown will be actually decreasing with time in these systems. Calculations from the equations[3-7] show that the critical coning rate is very low for thin oil columns. No attempt was made to operate below this critical rate.

Fig. 13 shows the cumulative oil recovery at the assumed economic limit as a function of production rate for the gas and water systems. The figure shows the significant sensitivity of economic oil recovery to rate. This indicates that production rates in such a system would need to be reduced significantly as the oil column thins or that large amounts of gas and water would need to be produced to maintain oil rates. This is also shown in Fig. 14 where cumulative oil per foot of initial oil zone thickness is plotted versus initial oil zone thickness for constant liquid rate production. The liquid rate would need to be reduced as the oil column thins, to obtain the same recovery at all elevations.

Vertical permeability is also a very important parameter. As vertical permeability increases for a given horizontal permeability, the cumulative oil recovery decreases because of increased coning (Fig. 15).

Increased horizontal well length is a very effective means of increasing oil recovery while maintaining production rate. This is shown in Fig. 16 where cumulative oil recovery at the economic limit is plotted vs. well length for the gas and water systems. Recovery is nearly linear with length. The vertical sweep efficiency is depicted in Fig. 17 for a 1,000-ft well in a gas-oil system. Gas saturation contours for a vertical *xz* slice through the wells at the economic GOR limit is shown. The zero gas saturation contour qualitatively confirms Ozkan and Ragahavan's calculations[2] in that there is very little sweep beyond the end of the horizontal wells. For vertical wells in such a system, the cones are very narrow.

GAS CONING—HORIZONTAL VS. VERTICAL WELL

A comparison was made for gas coning of horizontal and vertical wells where the oil column thickness is orig-

inally 60 ft and pressure is essentially maintained in the gas cap by re-injecting the produced gas. The oil column is divided into three layers with the vertical well being completed in the bottom two layers and the horizontal well completed in the middle oil layer. Better incremental recovery would be obtained with the horizontal well completed only in the bottom layer. Horizontal well length was 933 ft. Plots of oil production rate and GOR are shown in Figs. 18 and 19. (No restriction was placed on producing GOR.)

The horizontal well produces at substantially higher rates than the vertical well throughout the 15-year simulation. Oil recovery at five years for the horizontal well is four times that for a vertical well (237,000 vs. 64,000 STB). The GOR is substantially higher for the horizontal well; and at equal GORs (20 Mcf/STB), the horizontal well cumulative production is 55,600 STB vs. 32,800 for the vertical well. Horizontal wells clearly produce substantial incremental oil over vertical wells for gas coning situations. Oil saturation plots (not shown) at five years around the vertical and horizontal wells clearly show a larger areal decrease in oil saturation for the horizontal well.

WATER CONING—HORIZONTAL VS. VERTICAL WELL

This same model was used to compare recovery from horizontal wells vs. vertical wells for a water coning situation. Again, production occurs at a constant flowing BHP and water is injected into the aquifer to maintain pressure. Oil production rate and water cut behavior are similar to oil rate and GOR for gas coning simulations (Figs. 18 and 19).

Water breakthrough from coning occurs within days after production begins. Cumulative oil production at 50% water cut for the vertical well is about 7,000 STB and about 21,000 for the horizontal well. Oil rate declines rapidly for both cases, but the oil rate at any point in time is substantially higher for the horizontal well. At five years, the horizontal well has produced 229,000 STB, and the vertical well has produced 70,000 STB.

NOMENCLATURE

B = Formation volume factor, RB/STB
h = Thickness, ft
k = Permeability, md
L_w = Horizontal well length, ft
PI = Productivity index, STB/psi-day
q = Flow rate, B/D
r = Radius, ft

$$\beta = \sqrt{k_h / k_v}$$

Subscripts
f = Fracture
h = Horizontal
l = Liquid
m = Matrix
o = Oil zone
r = Reservoir voidage
v = Vertical
w = Water
x = X-direction
y = Y-direction
z = Z-direction

LITERATURE CITED

1. Bargas, C. L., and Yanosik, J. L., "The Effects of Vertical Fractures on Areal Sweep Efficiency in Adverse Mobility Ratio Floods," Paper 17609, SPE International Meeting on Petroleum Engineering, Tianjin, China, 1988.
2. Ozkan, E., and Raghavan, R., "Performance of Horizontal Wells Subject to Bottomwater Drive," *SPE Reservoir Engineering*, pp. 375–383 (Aug. 1990).
3. Chaperon, I., "Theoretical Study of Coning Toward Horizontal and Vertical Wells in Anisotropic Formations: Subcritical and Critical Rates," Paper 15377, 61st Annual SPE Technical Conference, New Orleans, La., 1986.
4. Giger, F. M., "Analytic 2-D Models of Water Cresting Before Breakthrough for Horizontal Wells," *SPE Reservoir Engineering*, pp. 409–416 (Nov. 1989).
5. Hoyland, L. A., Papatzacos, P., and Skjaeveland, S. M., "Critical Rate for Water Coning: Correlation and Analytical Solution," *SPE Reservoir Engineering*, pp. 495–502, (Nov. 1989).
6. Karcher, B. J., Giger, F. M., and Combe, J., "Some Practical Formulas to Predict Horizontal Well Behavior," Paper 15430, 61st Annual SPE Technical Conference, New Orleans, La., 1986.
7. Papatzacos, P., Herring, T. R., Martinsen, R., and Skjaeveland, S. M., "Cone Breakthrough Time for Horizontal Wells," *SPE Reservoir Engineering*, pp. 311–318 (Aug. 1991).

Notes

Slim-Hole Technology

When looking at ways to cut costs, one must first understand which costs have the greatest impact upon the exploration and production business. Undoubtedly, the largest costs that any successful E&P company must manage are the costs associated with drilling a hole in the ground. Regardless of whether or not an operator can improve his accuracy through 3D seismic or his productivity through integrated information technology, when the day is over he must still drill a hole in the ground.

Recent advances in *slim-hole drilling technology* have enabled operators to cut initial drilling and completion costs by as much 75%. Because these drilling and completion costs account for over 70% of the costs incurred by domestic oil and gas operators (Figure 1), slim-hole technology has the potential to significantly impact the overall economics of domestic oil and gas production. This talk will review the history of slim-hole drilling technology, identify its cost-saving potential, and describe several real-life experiences where operators have utilized slim-hole drilling technology to substantially reduce their costs.

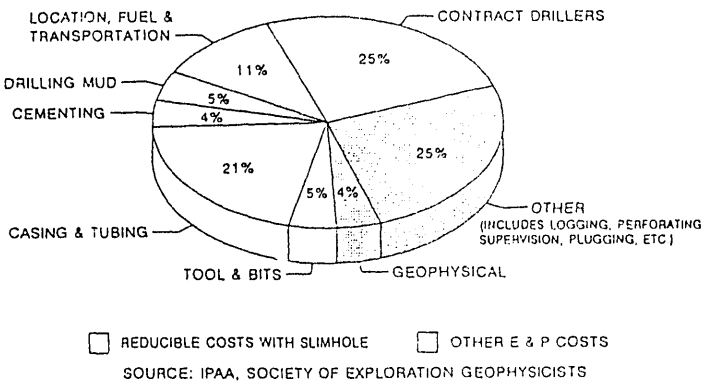


Figure 1. 1990 E&P Expenditures ($11 Billion Total)

Hydraulic fracturing was the technology of the 60s, PDC bits were the technology of the 70s, horizontal drilling was the technology of the 80s and *slim hole and coiled tubing will be the technology of the 90s.* Significant cost savings through reduced materials and improved drilling rates have prompted many oil companies to re-examine the use of slim-hole technology that was popular in the late 50s and 60s. Applications being considered include not only exploratory wells but also domestic development wells, deepenings, and horizontal entries.

Maurer Engineering Inc. with the Drilling Engineering Association and sponsors Texaco (USA) and BP (Europe) has initiated a three-year project to study slim-hole and coiled-tubing technology developments. The objective of this project is to keep members abreast of the latest technical developments in slim-hole and coiled-tubing technology and to assist in expanding the use of this technology as quickly as possible.

J. Marshall Adkins is a Senior Petroleum Engineer with Maurer Engineering and holds a BS Petroleum Engineering and Masters Business Administration, both from The University of Texas. He spent six years in engineering, sales, and finance with B.J. Services before joining Maurer Engineering in 1991. Mr. Adkins helps coordinate the DEA-67 project and is involved in the engineering, schools, and forums related to the slim-hole, coiled-tubing, and horizontal projects.

SLIM-HOLE TECHNOLOGY

PRESENTED BY
MARSHALL ADKINS

DENVER COLORADO
MAY 3, 1993

MAURER ENGINEERING INC.

2916 WEST T.C. JESTER
HOUSTON, TX. 77018
Ph. (713)683-8227

"SLIM-HOLE TALK IS STRONGER TODAY THAN EVER. DRILLING CONTRACTORS ARE WONDERING IF THIS IS MERELY ANOTHER OF THE PERIODIC UPSURGES THAT WILL GRADUALLY DIE DOWN AS IN THE PAST, OR IF THIS REALLY INDICATES A COMING WIDESPREAD TREND."

OIL & GAS JOURNAL

2668001A

DEA-67

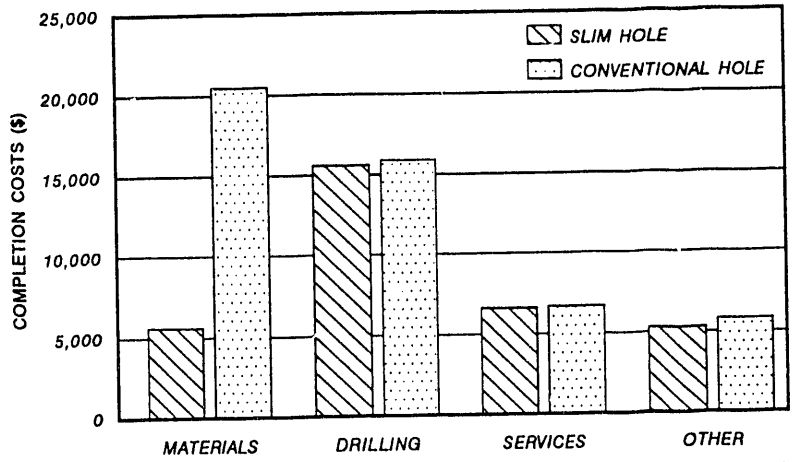
WHAT HAPPENED ?

- FISHING PROBLEMS
- CROOKED HOLES
- SLOW DRILLING RATES
- ARTIFICIAL LIFT PROBLEMS
- UNDERREAMING COSTS
- "CASED OUT OF THE HOLE"
- WORKOVER PROBLEMS
- WELL CONTROL
- TWIST OFFS
- LOGGING TOOL AVAILABILITY

DEA-67

SLIM-HOLE COMPLETION COSTS

WORLD OIL (MAY, 1960)



2630232A

* 6 1/4" HOLE WITH 2 7/8" TUBING CEMENTS

DEA-67

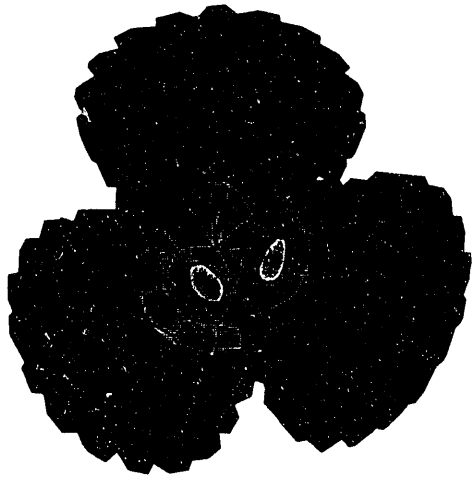
WHAT HAPPENED ?

- FISHING PROBLEMS
- CROOKED HOLES
- SLOW DRILLING RATES
- ARTIFICIAL LIFT PROBLEMS
- UNDERREAMING COSTS
- "CASED OUT OF THE HOLE"
- WORKOVER PROBLEMS
- WELL CONTROL
- TWIST OFFS
- LOGGING TOOL AVAILABILITY

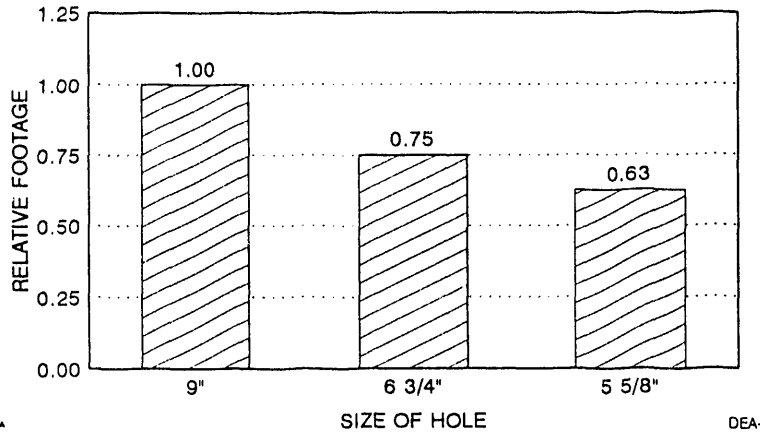
2660307A

DEA-67

ROLLER BIT

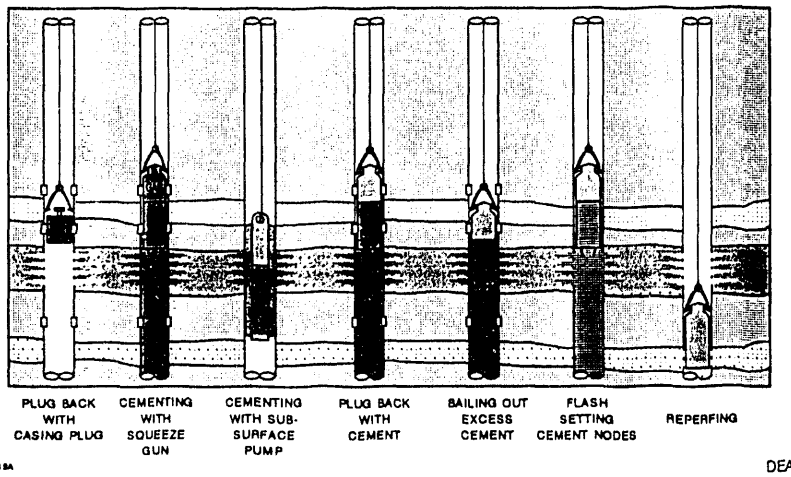


FOOTAGE PER ROLLER BIT
(OCTOBER 1959)



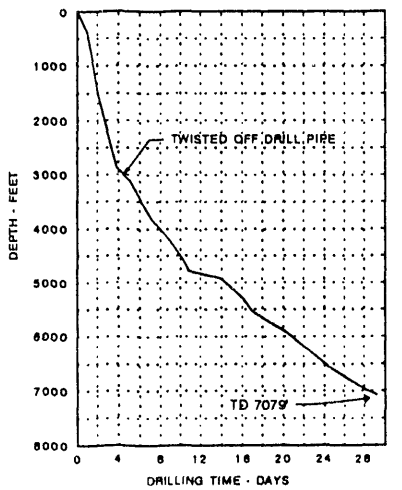
DEA-67

METHODS FOR REWORKING SLIM-HOLE WELLS
(AIME APRIL, 1956)



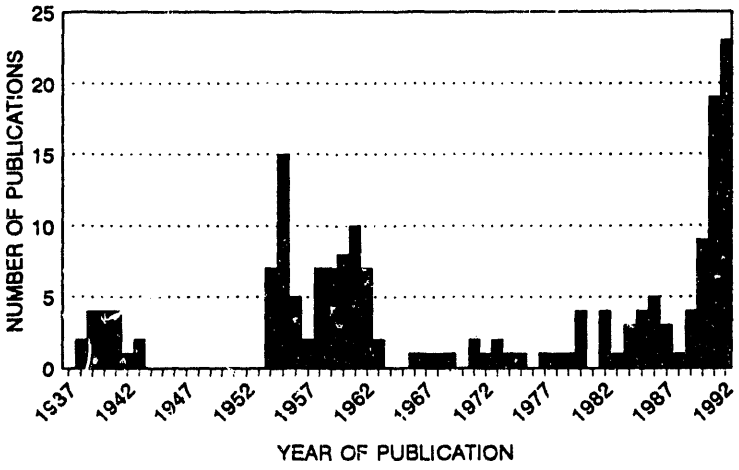
DEA-67

SLIM-HOLE DRILLING RATE CHART
(PETROLEUM ENGINEER, 1958)



DEA-67

SLIM-HOLE PUBLICATIONS



DEA-67

WHAT IS DRIVING SLIM-HOLE REVIVAL ?

- FIXED-CUTTER BITS
- COILED-TUBING WORKOVERS
- NEW DRILLING SYSTEMS
- COST SAVINGS
- COST SAVINGS
- COST SAVINGS

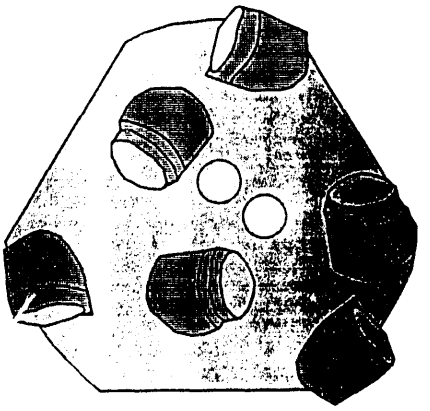
DEA-67

WHAT IS DRIVING SLIM-HOLE REVIVAL ?

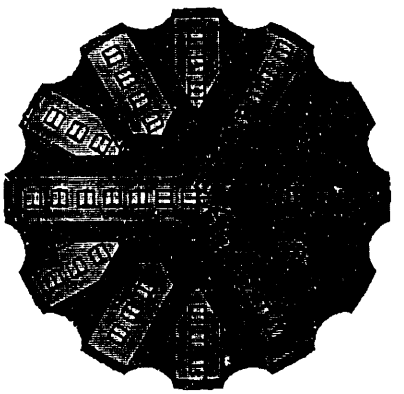
- FIXED-CUTTER BITS
- COILED-TUBING WORKOVERS
- NEW DRILLING SYSTEMS
- COST SAVINGS
- COST SAVINGS
- COST SAVINGS

DEA-67

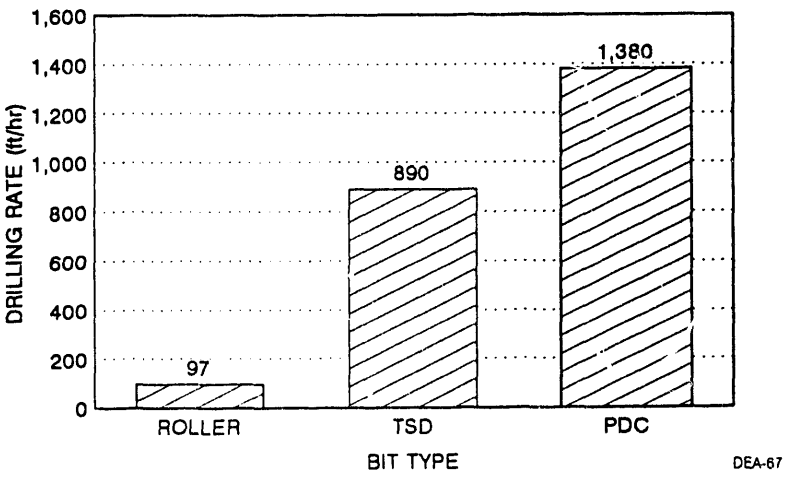
PDC BIT



TSD BIT



LEUDERS LIMESTONE

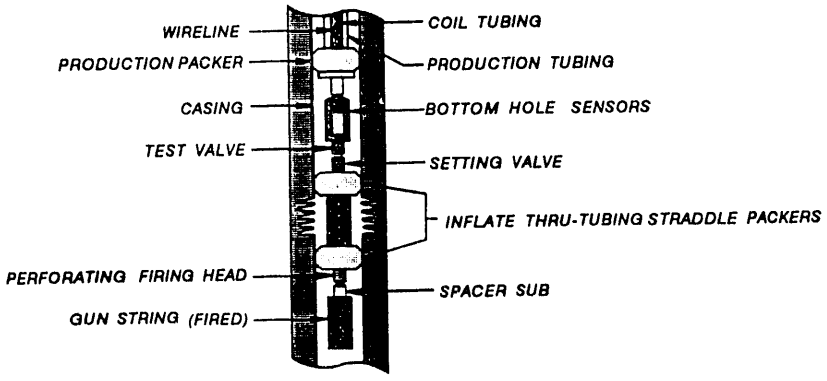


WHAT IS DRIVING SLIM-HOLE REVIVAL ?

- FIXED-CUTTER BITS
- COILED-TUBING WORKOVERS
- NEW DRILLING SYSTEMS
- COST SAVINGS
- COST SAVINGS
- COST SAVINGS

DEA-67

COILED TUBING COMPLETION OPERATION
(COOPER et al., 1988)



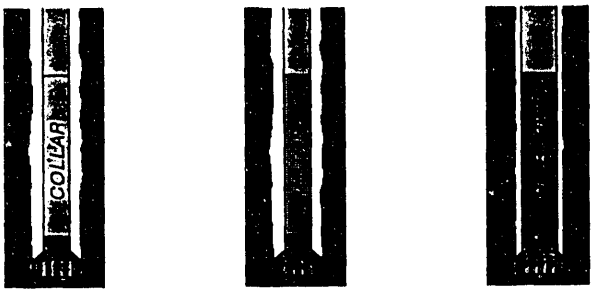
DEA-67

WHAT IS DRIVING SLIM-HOLE REVIVAL ?

- FIXED-CUTTER BITS
- COILED-TUBING WORKOVERS
- NEW DRILLING SYSTEMS
- COST SAVINGS
- COST SAVINGS
- COST SAVINGS

DEA-67

SLIMHOLE SYSTEMS



ROTARY | DOWNHOLE MOTOR | CONTINUOUS CORING

DEA-67

WHAT IS DRIVING SLIM-HOLE REVIVAL ?

- FIXED-CUTTER BITS
- COILED-TUBING WORKOVERS
- NEW DRILLING SYSTEMS
- COST SAVINGS
- COST SAVINGS
- COST SAVINGS

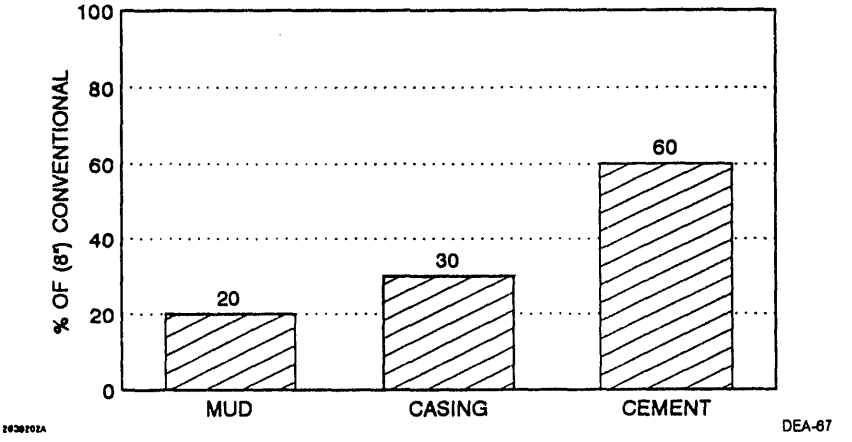
DEA-67

HOW CAN TODAY'S SLIM HOLE SAVE MONEY ?

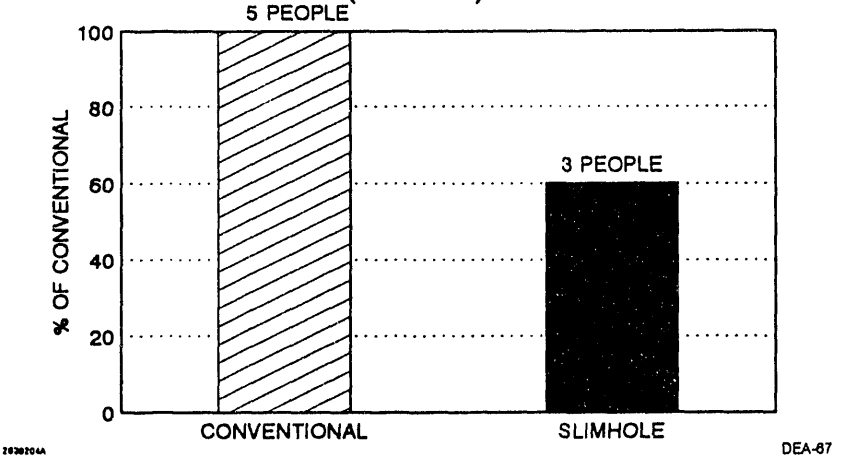
- MATERIALS
- LABOR
- TRANSPORTATION
- LOCATION SIZE
- ENVIRONMENTAL IMPACT
- DRILLING RATE

DEA-67

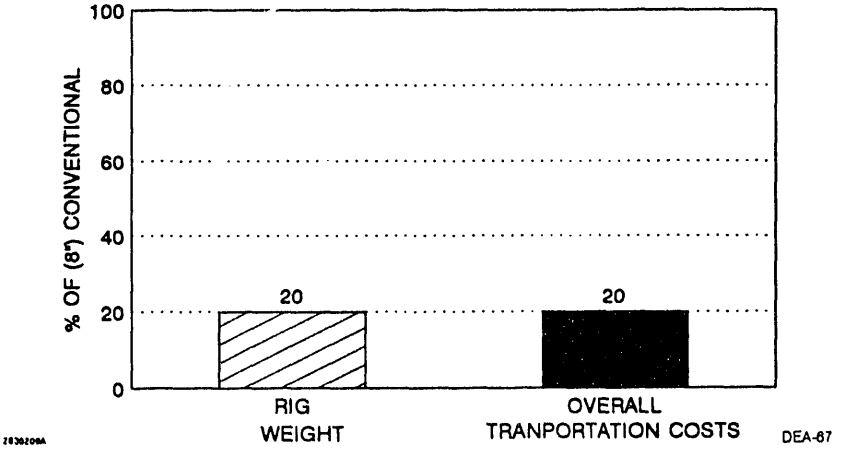
MATERIAL COST
(3" vs 8")



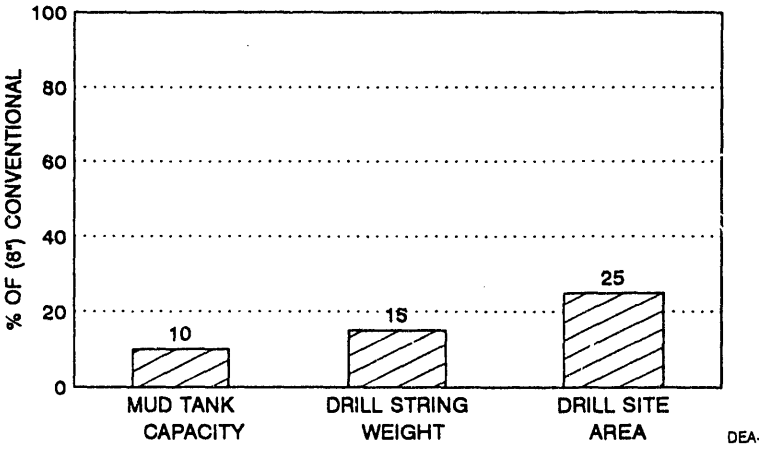
LABOR COST
(3" vs 8")



TRANSPORTATION
(3" vs 8")

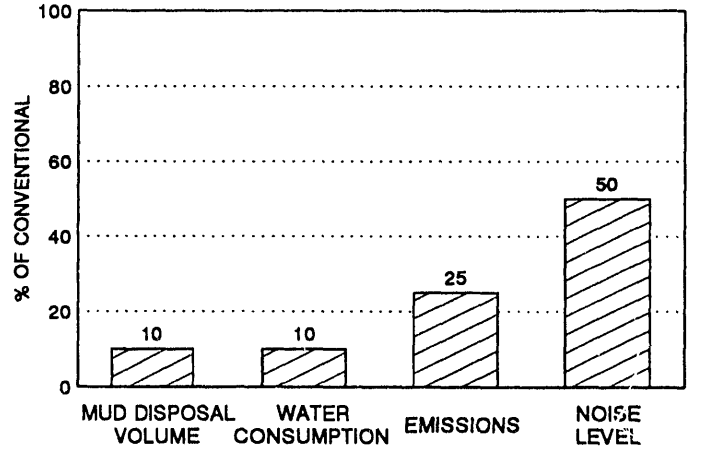


LOCATION SIZE
(3" vs 8")



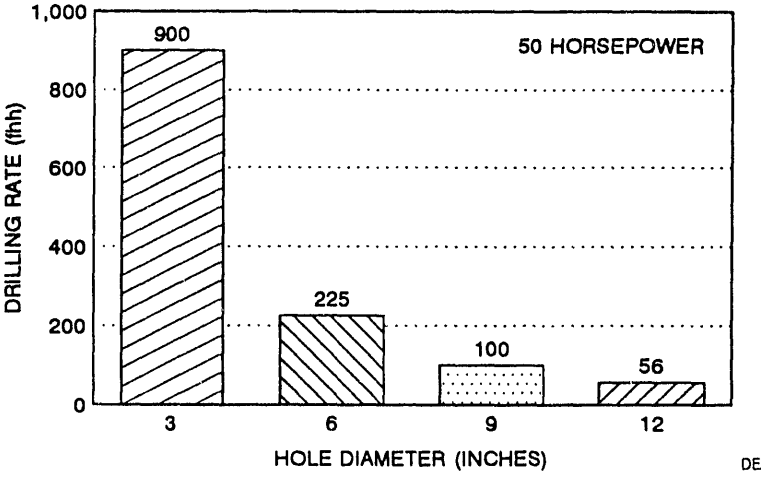
2638207A DEA-67

ENVIRONMENTAL COST
(3" vs 8")



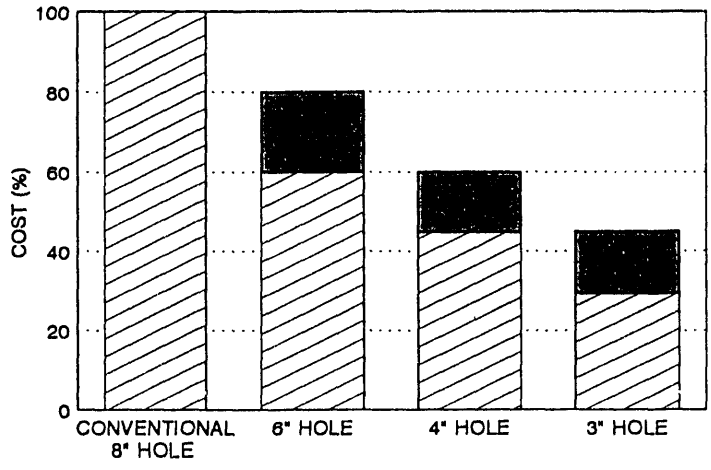
2638206A DEA-67

DRILLING RATE vs. HOLE SIZE



2638210A DEA-67

HOLE SIZE COST COMPARISON

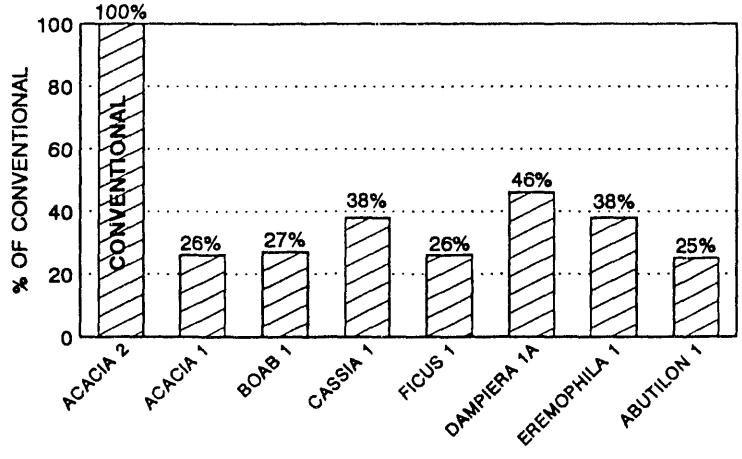


DEA-67

CASE HISTORIES

WESTERN MINING DRILLING COST COMPARISONS

(PORTER et al., 1982)



DEA-67

OPAB DRILLING COST COMPARISON

(DAHL, 1982)

CONVENTIONAL RIG			
HOLE	RESULT	DEPTH	COST (000's KRONER)
BONSARVE 1	PRODUCER	493 m	817
HAMRA 8A	PRODUCER	640 m	875
GRUNNET 3	DRY	536 m	329

MICRO-DRILL RIG			
HOLE	RESULT	DEPTH	COST
FARDUME 1	PRODUCER	243 m	235
STRUGRINDE 1	PRODUCER	249 m	156
AUSTRE 1	DRY	495 m	115
NORS 1	DRY	359 m	105
OJNAREMYR 1	DRY	267 m	86

2630220A

DEA-67

OPAB DRILLING COST COMPARISON

(DAHL, 1982)

AVERAGE DRYHOLE COST
31% OF CONVENTIONAL

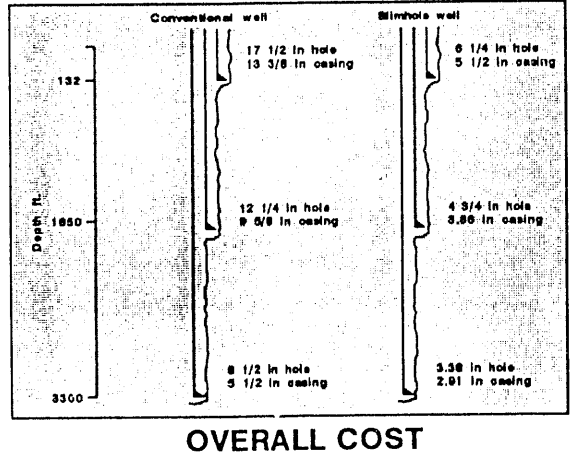
AVERAGE PRODUCER COST
23% OF CONVENTIONAL

2630228A

DEA-67

BP SLIM-HOLE COST SAVINGS

(FLOYD, 1987)



OVERALL COST
30% - 50% OF CONVENTIONAL

2630223A

DEA-67

AMOCO SLIM-HOLE SAVINGS
(WALKER, 1989)

	CONVENTIONAL ($/FT)	SLIM HOLE ($/FT)	CONVENTIONAL (%)
ALASKA	1224	655	53
PAKISTAN	193	132	68
KENYA	338	211	62

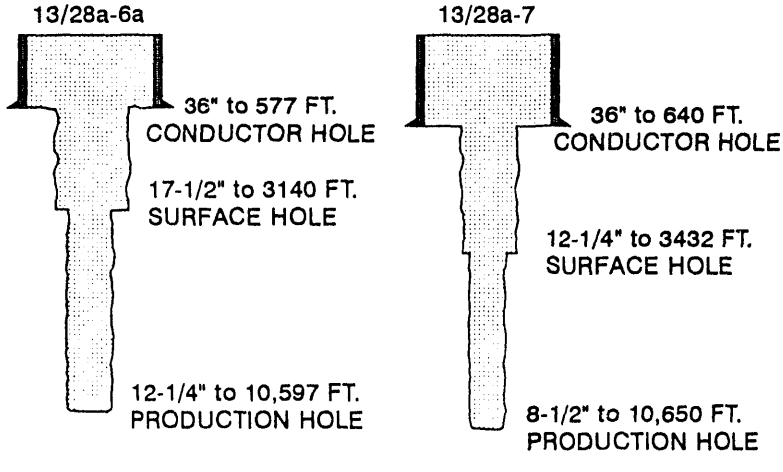
DEA-67

WHAT IS "SLIM HOLE"

- "A HOLE TOO SMALL TO RECEIVE 5 1/2 in CASING"
  - WORLD OIL, 1956
- "90% OF LENGTH IS DRILLED SMALLER THAN 7 in"
  - AMOCO, 1989
- "ANYTHING SMALLER THAN WHAT YOU ARE CURRENTLY DRILLING"
  - ELF, 1990
- "FINAL HOLE SIZE 4 3/4 in OR SMALLER"
  - RESOURCE MARKETING, 1992

DEA-67

BP SLIMHOLE COST SAVINGS



DEA-67

BP SLIMHOLE COST REDUCTIONS
NOVEMBER, 1992

WELLHEAD	- 32,200
CASING	11,443
CEMENT	11,425
MUD	115,142
DRILLING TOOL RENTAL	64,000
BITS	167,707
DRILLING TIME (54 Hr.)	432,000
TOTAL	769,517

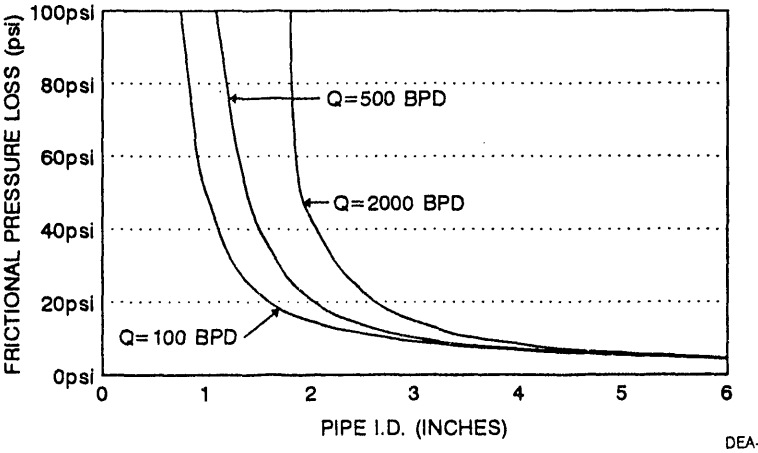
DEA-44

WHY NOT SLIM HOLE?

- PRODUCTION RATES
- HIGH-RATE FRACTURING
- TOOL AVAILABILITY
- WELL CONTROL
- "CASING OUT" RISK

DEA-67

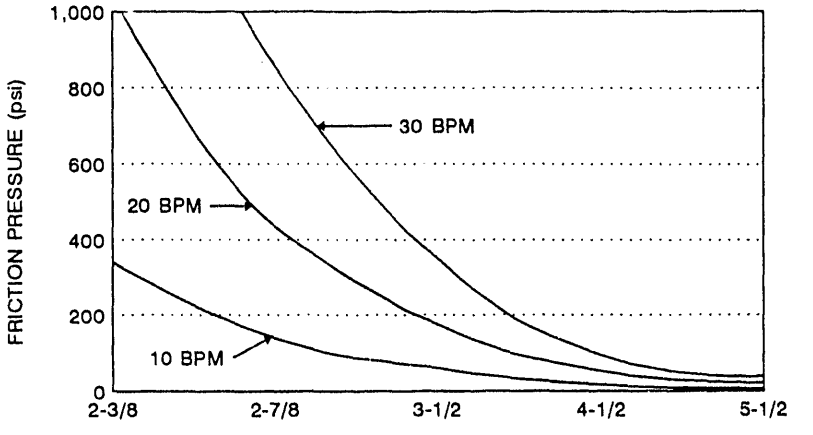
PRESSURE DROP DUE TO CASING SIZE
DEPTH = 1000 ft.



DEA-67

HYDRAULIC FRACTURING PRESSURE DROP

(DEPTH = 1000 ft, GEL WT = 20#/1000)



DEA-67

SLIM-HOLE LOGGING CAPABILITIES

(AFTER WORRALL, 1992)

TOOL TYPE	WESTERN ATLAS	SCHLUMBERGER	BPB	HLS
CLASS	COMBINABLE 350°F (20K psi)	COMBINABLE 350°F (20K psi)	NON-COMB 212°F (7.5K psi)	COMBINABLE 500°F (25K psi)
INDUCTION	2.75"	2.75"	2.25"	2.75"
LATEROLOG	3.4"	2"	1.88"	---
MICROLOG	3.63"	2.75"	1.88"	2.75"
DENSITY	3"	2.75"	1.88"	2.75"
NEUTRON	1.7"	1.7"	1.5"	2.75"
SONIC	1.7"	1.7"	2"	---
SPEC. GAMMA	---	---	3"	---
DIPMETER	4"	3.63"	2"	---
MICRO-SCA	---	3.63"	---	---
SONIC-SCAN	---	2.75"	3"	3.64"
FLUID SAMPLE PRESSURES	4.3"	3.63"	3.5"	---
ROCK SAMPLE	3"	3.34"	2.25"	1.7"
PULSED NEUT	1.7"	1.7"	1.7"	---
GEOPHYSICAL TOOLS	1.7"	2"	2"	---

DEA-67

SLIM-HOLE WELL CONTROL

- WELL CONTROL COMMITTEE
- BETTER MEASUREMENT SYSTEMS
- DOWNHOLE KICK DETECTION
- COMPUTER MODELS
- DYNAMIC KILL
- LESS OF AN ISSUE IN NON-CORING

DEA-67

WHAT ABOUT UNPLANNED CASING STRINGS?

ASSUMPTIONS:

1. CONVENTIONAL WELL COST = $250,000
2. SLIM-HOLE WELL COST = $175,000 (30% REDUCTION)
3. 5% OF WELLS (1 OUT OF 20) REQUIRE UNPLANNED CASING
4. 20 WELL DRILLING PROGRAM

DEA-67

WHAT ABOUT UNPLANNED CASING STRINGS?

CONVENTIONAL COSTS:
$250,000 x 20 WELLS = $5,000,000

SLIM-HOLE COSTS: (1 EXPENDABLE WELL)
$175,000 x 21 WELLS = $3,675,000

SLIM-HOLE COST SAVINGS = $1,325,000 OR
7 EXTRA WELLS WITH $100,000 LEFT OVER FOR YOUR BONUS

DEA-67

WHAT IS NEEDED IN THE FUTURE ?

- EDUCATION
- COMMERCIAL DRILLING SYSTEMS
- SLIM-HOLE TOOLS
- COMPLETION TECHNOLOGY
- CHANGE OF MINDSET

DEA-67

WHERE CAN I GET MORE INFORMATION?

- NABORS/LOFFLAND
- MICRODRILL
- PARKER
- POOL
- RESOURCE MARKETING
- MAURER ENGINEERING

2660312A DEA-67

DEA-67 SLIM-HOLE & COILED-TUBING TECHNOLOGY

START DATE: JANUARY 1, 1992

COST: $35,000

PARTICIPANTS: 44

DURATION: 36 MONTHS

BUDGET: $1.54 MILLION

SPONSORS: DEA-67 - TEXACO
DEA(E) 35 BRITISH PETROLEUM

2638247A DEA-67

DEA-67 SLIM-HOLE & COILED-TUBING
PARTICIPANTS

ABU DHABI NATIONAL OIL
AGIP
AMOCO CANADA
ARAMCO
BAKER HUGHES
BHP PETROLEUM
BOWEN OIL TOOLS
BP EXPLORATION
BRITISH GAS
CANADIAN OCCIDENTAL
CHEVRON
CUDD PRESSURE CONTROL
DEUTAG
DOWELL SCHLUMBERGER
ELAN ENERGY
EXXON
FLETCHER CHALLENCE
GULF CANADA
HYDRIL
INTEVEP
JAPAN DRILLING CO.
KOOLAJKUTATO VALLALAT
MARATHON
MOBIL
NABORS LOFFLAND
NORANDA
NORSK HYDRO
OCEAN DRILLING PROGRAM
OMV AKTIENGEELLSCHAFT
ORYX
OTIS ENGINEERING
OXY USA
PETROBRAS
PETRO-CANADA
PHILLIPS
QUALITY TUBING
SASKATCHEWAN OIL & GAS
SHELL DEVELOPMENT
S.I.A.T.
SLIMDRIL INTERNATIONAL
STATOIL
SUNCOR
TEXACO, U.S.A.
U.S. DEPARTMENT OF ENERGY

2638248A as of February 1993 DEA-67

Notes

"SHORT RADIUS HORIZONTAL DRILLING AND ITS APPLICATIONS"

Joel W. Werner
SlimDril International, Inc.

Abstract

A brief overview of short radius horizontal drilling will be discussed as well as its specific, proven applications. The following material will be presented: short radius horizontal objectives, the short radius horizontal BHA and related drilling equipment, geographic regions and target formations drilled, drilling parameters associated with specific applications, and typical completion techniques of these applications. In closing a Kern County, CA short radius horizontal case history will be discussed and concluding comments made.

Mr. Werner holds B.S. degrees in Petroleum Engineering and Operations Management from Louisiana Tech University. After graduating in 1990, he joined SlimDril International, Inc., working in drilling operations. He is currently involved in the technical sales group of that company. Mr. Werner is a member of SPE, ADDA, and AADE.

FIGURE 1

WELL CONFIGURATIONS

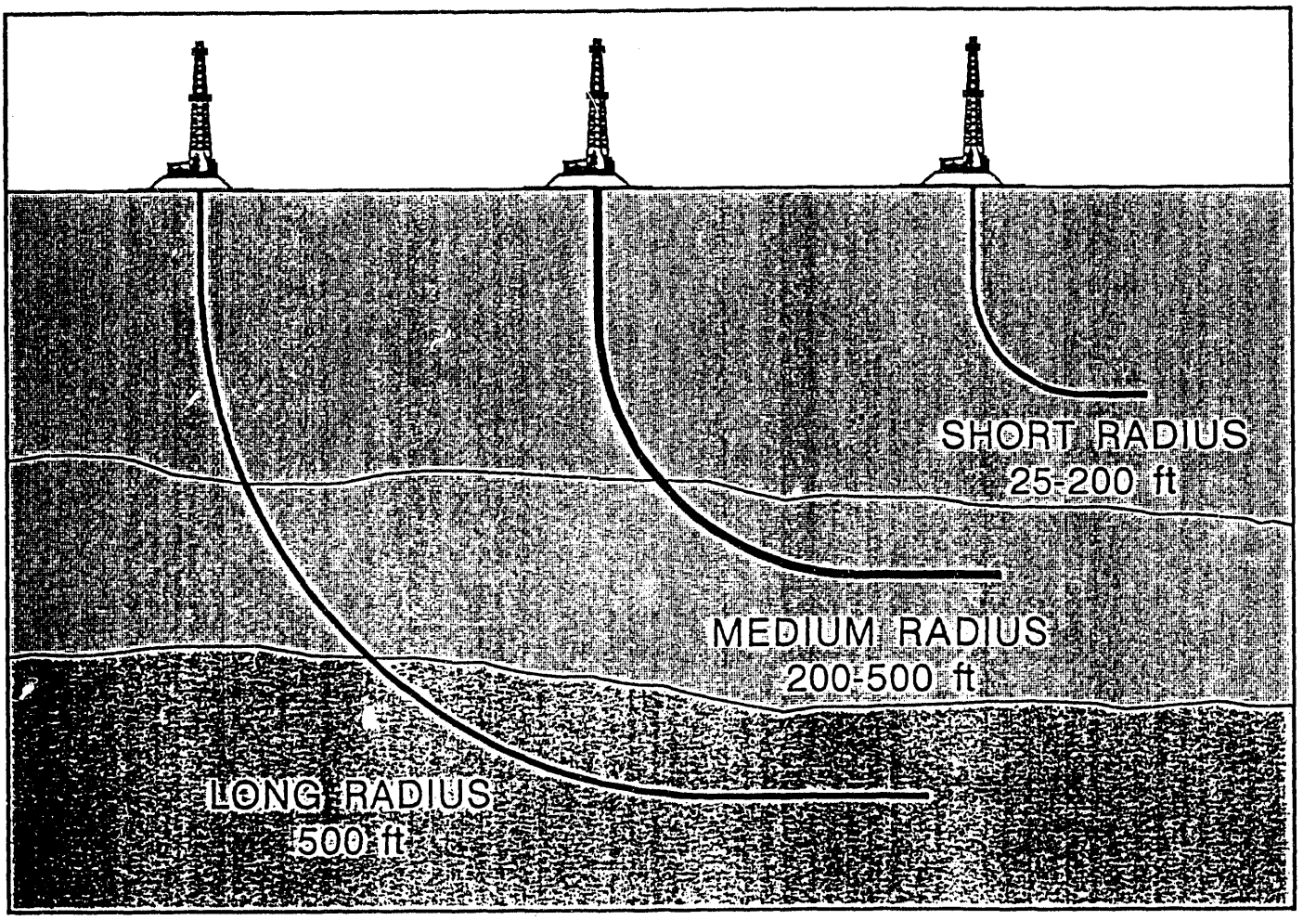


FIGURE 2

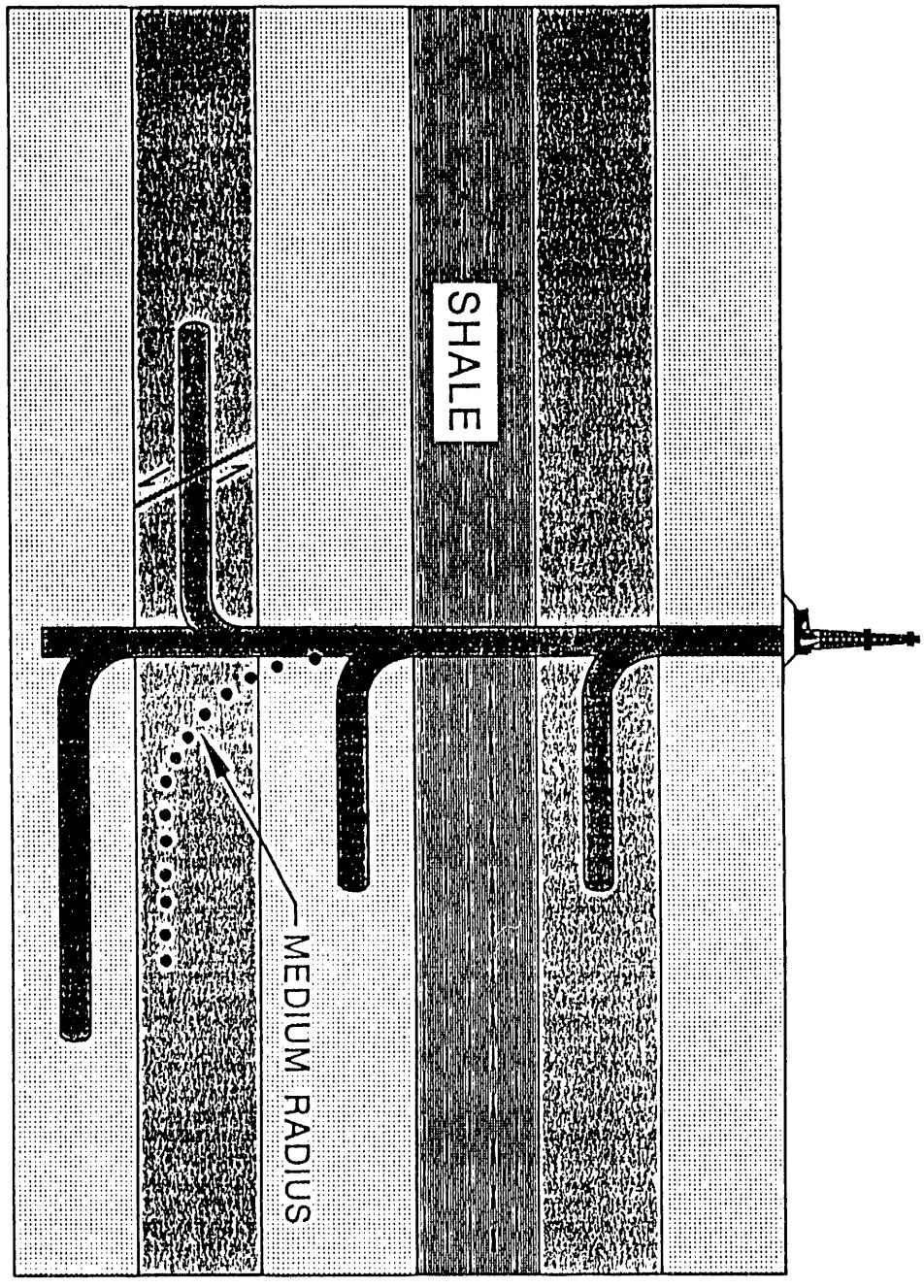
SHORT-RADIUS HORIZONTAL OBJECTIVES

- AVOID DIFFICULT DRILLING ZONE
- SHALLOW TARGET
- REDUCE DRILLING FOOTAGE/TIME
- NEAR WELLBORE TARGET
- PUMP CLOSER TO FLUID LEVEL

4509266P

FIGURE 3

4509267P



SHORT RADIUS

FIGURE 4

TYPICAL MEDIUM RADIUS HORIZONTAL DRILLING PARAMETERS

RADIUS SIZE	200'- 475'
BUILD RATE	12°/100' - 28°/100'
CASING SIZE EXITED	4-1/2" - 8-5/8"
DISPLACEMENT	1000' - 3000'+
SCENARIO	RE-ENTRY OR NEW WELL

FIGURE 5

TYPICAL SHORT RADIUS HORIZONTAL DRILLING PARAMETERS

RADIUS SIZE	65'- 100'
BUILD RATE	57°/100' - 88°/100'
CASING SIZE EXITED	4-1/2" - 8-5/8"
DISPLACEMENT	750' - 1000'+
SCENARIO	RE-ENTRY OR NEW WELL

FIGURE 6

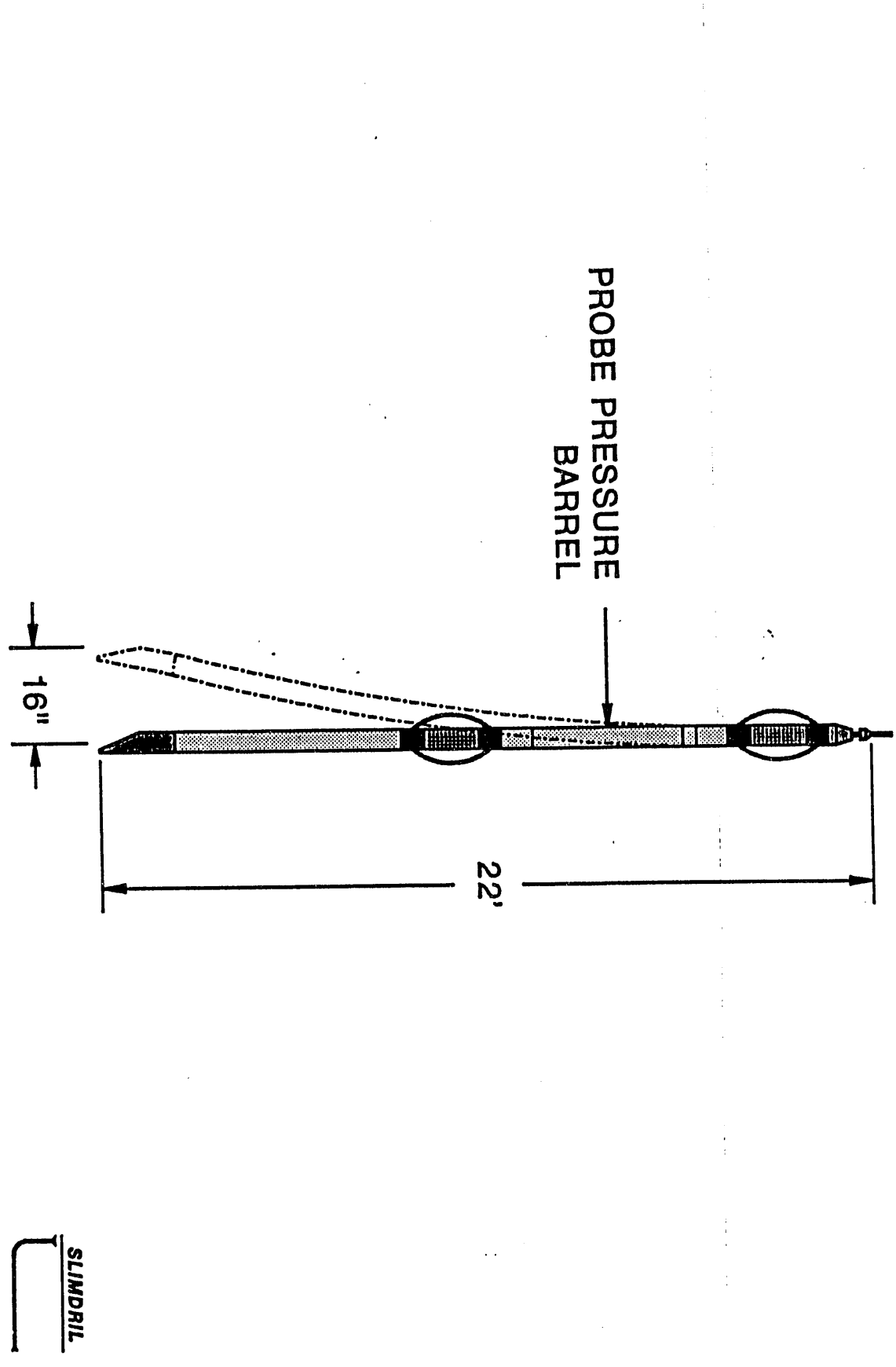

SHORT RADIUS HORIZONTAL SURVEY SYSTEM
PROBE PRESSURE BARREL
16"
22'
SLIMDRIL

FIGURE 7

GEOGRAPHIC REGIONS DRILLED WITH SHORT RADIUS HORIZONTAL SYSTEM

LOCATION	TARGET FORMATION
KERN CO., CALIFORNIA	BELRIDGE DIATOMITE
FRESNO CO., CALIFORNIA	TEMBLOR SANDSTONE
CARSON CO., TEXAS	PRECAMBRIAN FRACTURED GRANITE
CROCKETT CO., TEXAS	YATES SAND
PECOS CO., TEXAS	YATES SAND
STUEBEN CO., NEW YORK	LIMESTONE REEF

FIGURE 8

TYPICAL DRILLING PARAMETERS OF SHORT RADIUS HORIZONTAL SYSTEM

CASING EXITED	HOLE SIZE	SIZE OF RADIUS
8-5/8"	5-1/2"	84' or 68°/100'
7"	4-3/4"	80' or 72°/100'
5-1/2"	3-3/4"	101' or 57°/100'
4-1/2"	3-3/8"	74' or 77°/100'

NOTE: HORIZONTAL DISPLACEMENT OF 1000 FEET HAS BEEN ACHIEVED AS 1000 FEET "PLUS" DISPLACEMENTS ARE ACHIEVABLE

FIGURE 9

TYPICAL HORIZONTAL COMPLETION METHODS

- SLOTTED LINER
- PRE-DRILLED/PRE-PERFORATED LINER
- WIRE WRAPPED SCREEN OR LINER
- PREPACKED SCREEN (SAND)
- GRAVEL PACKED SCREEN (U.S. MESH GRAVEL)
- SOLID LINER (WITH/WITHOUT ECP)
- OPEN HOLE OR "BAREFOOT"

FIGURE 10

MOST COMMON HORIZONTAL COMPLETION METHODS

- SLOTTED LINER
- BLANK LINER

FIGURE 11

WELL INFORMATION

- FORMATION: BELRIDGE DIATOMITE-HEAVY OIL
- OBJECTIVE: INCREASE DRAINAGE AREA
- CASING: 8 5/8", 24#/FT, J-55
- WELL TYPE: NEW DRILL
- KICK-OFF: 808 FEET TVD

FIGURE 12

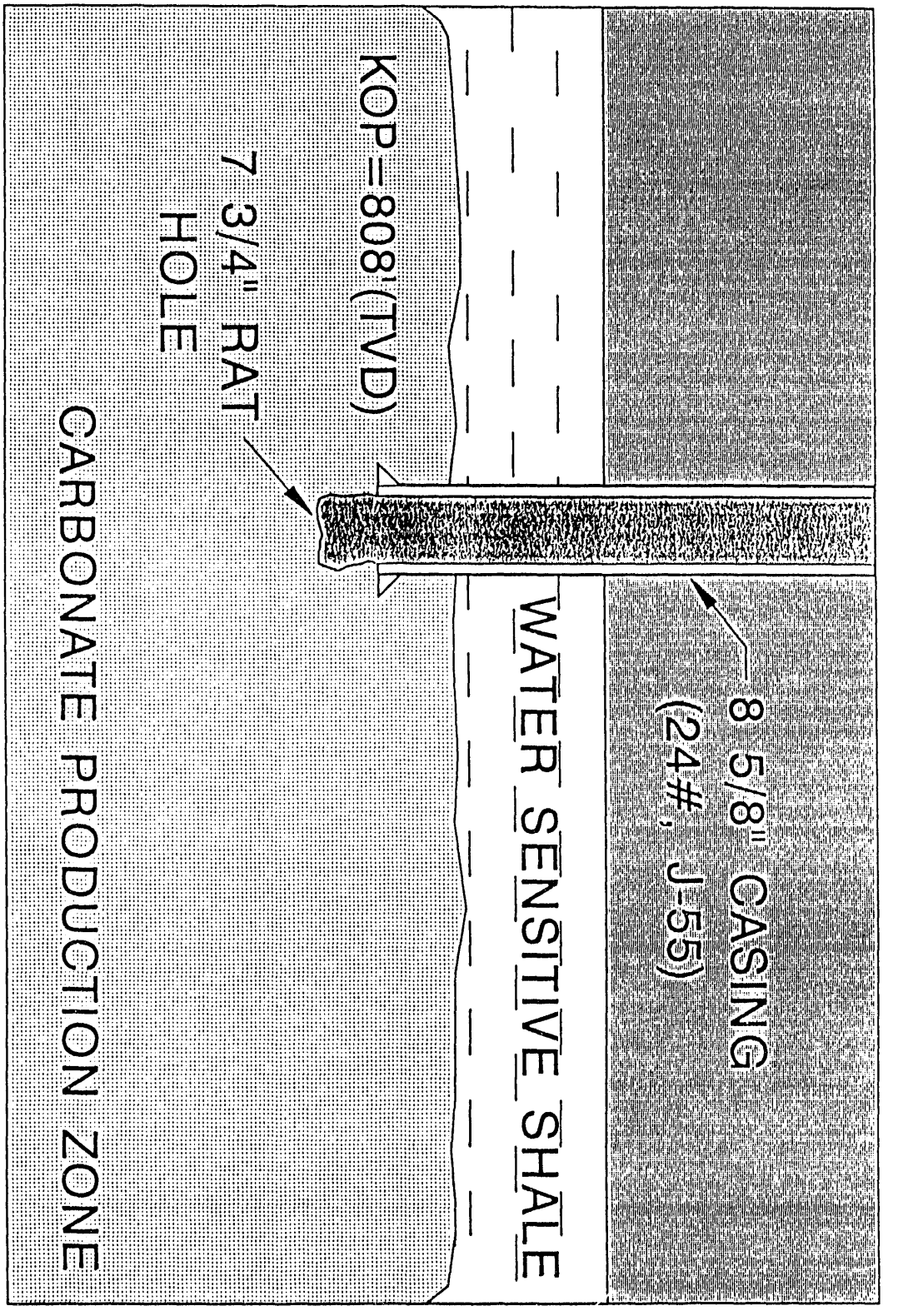

SHORT-RADIUS DRILLING CONDITIONS
8 5/8" CASING
(24#, J-55)
WATER SENSITIVE SHALE
KOP=808'(TVD)
7 3/4" RAT
HOLE
CARBONATE PRODUCTION ZONE

FIGURE 13

DRILLING EQUIPMENT

- MOTOR: 3 3/8" MODIFIED PDM
- STEERING MECHANISM: DOUBLE BEND HOUSING,
  BENT SUB
- SURVEY EQUIPMENT:
  "HIGH DEVIATION" STEERING TOOLS
  SIDE-ENTRY SUB/WIRELINE
- DRILL PIPE: 2 7/8" (10.4#/FT, S-135)
  AMERICAN OPEN HOLE

FIGURE 14

DRILLING RESULTS

- HOLE SIZE: 5 1/2"
- BUILD RATE: 68°/100 FEET
- RADIUS: 84 FEET
- HORIZONTAL DISPLACEMENT: 1000 FEET

FIGURE 15

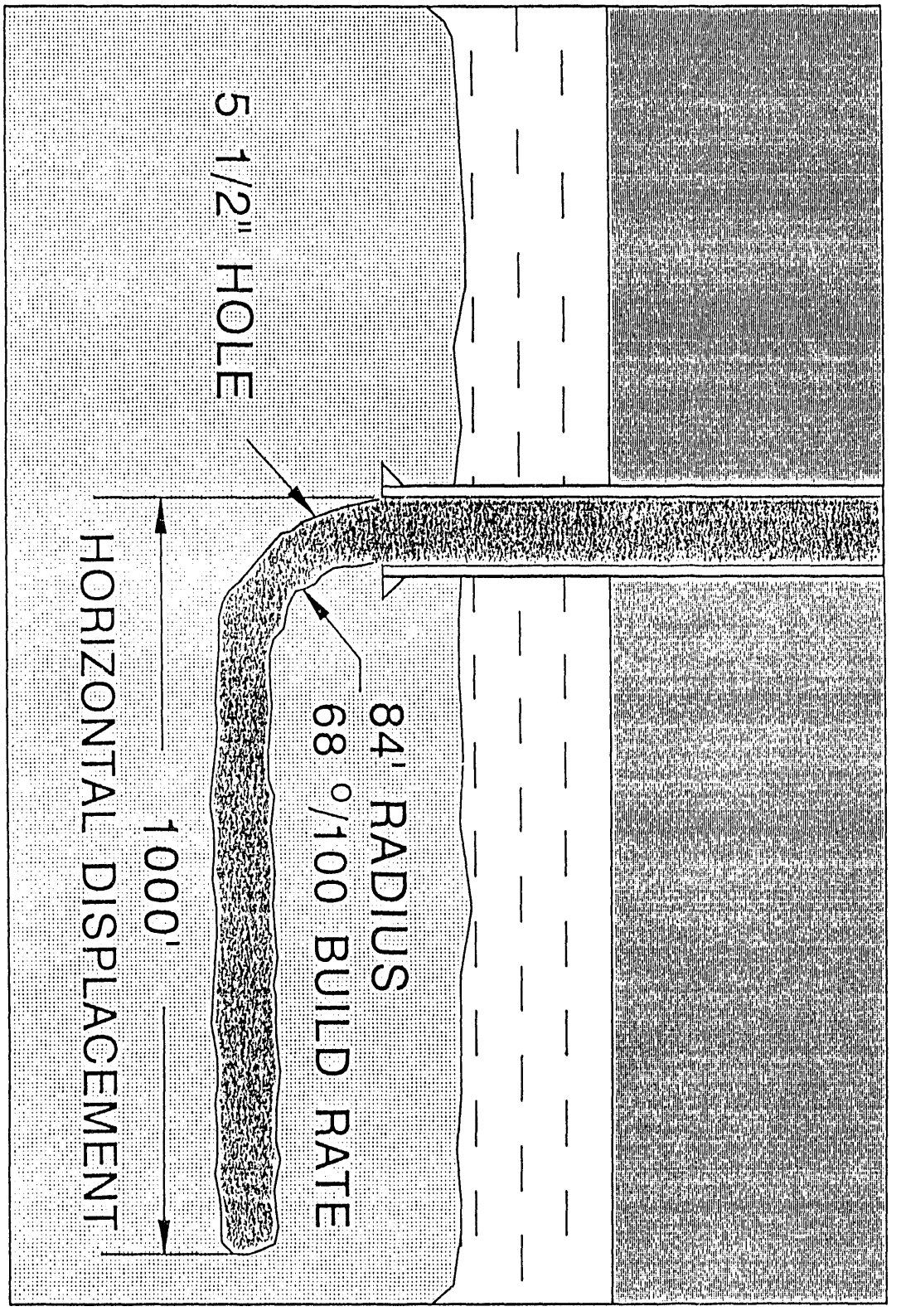
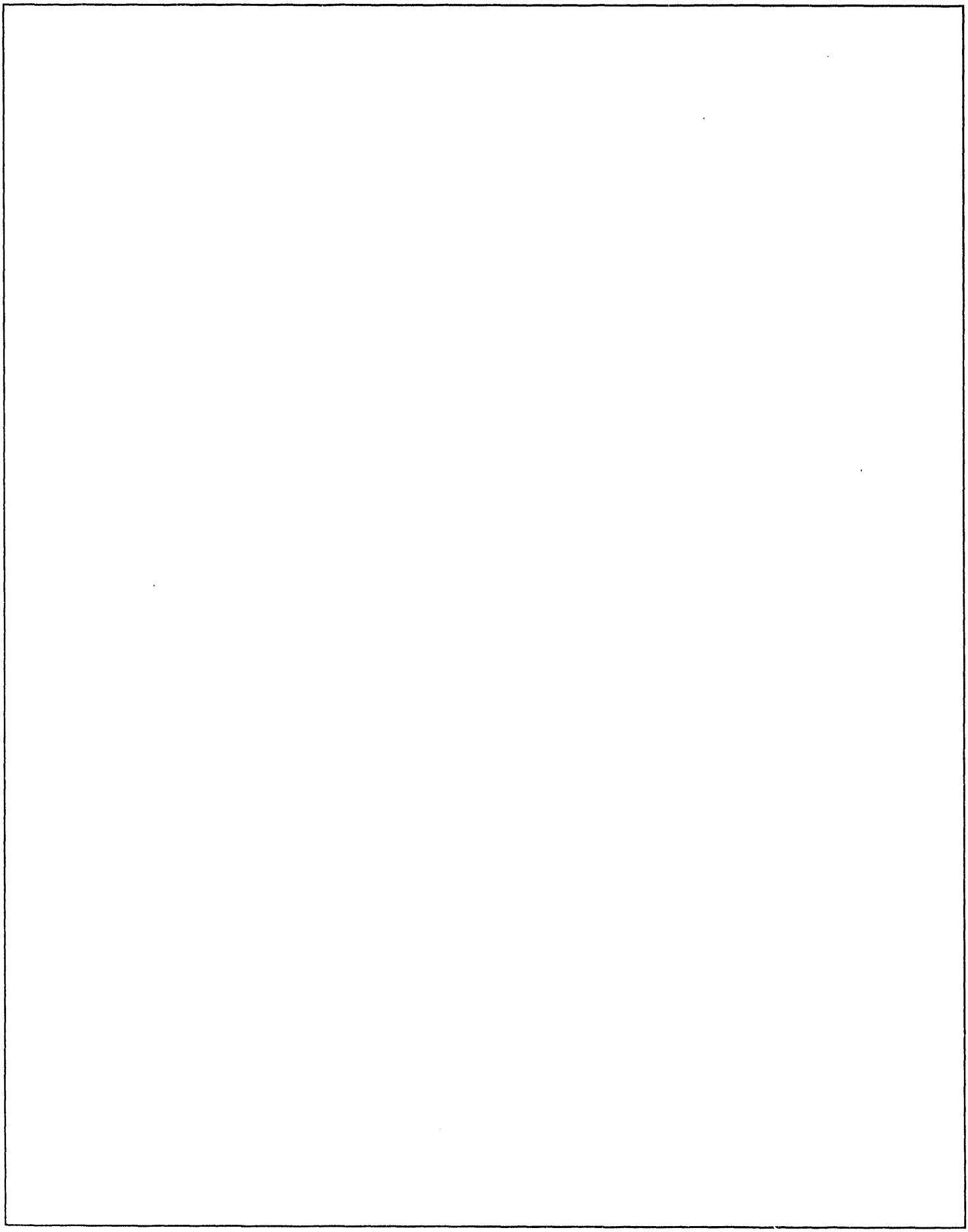

SHORT-RADIUS HORIZONTAL RESULTS
5 1/2" HOLE
84' RADIUS
68 °/100 BUILD RATE
1000'
HORIZONTAL DISPLACEMENT
4509264P

FIGURE 16

CONCLUSIONS

- SHORT RADIUS IS EFFECTIVE ALTERNATE TO ULTRA-SHORT AND MEDIUM RADIUS TECHNOLOGY
- SHORT RADIUS BHA ALLOWS 100% CONTROL OF INCLINATION, AZIMUTH, AND TOOL FACE
- BASED ON PROVEN MEDIUM RADIUS EQUIPMENT AND TECHNOLOGY
- ECONOMICS ARE EXTREMELY COMPETITIVE TO PRESENTLY AVAILABLE METHODS



A Slim-Hole Horizontal Re-Entry Program

by Chip Abrant, Technical Manager, BecField Drilling Services, Houston Texas

There are hundreds of thousands of existing wellbores in the United States and Canada that were completed using 5-1/2 or 4-1/2-inch casing. Many of these wells have experienced a standard decline in production; some may have missed the more prolific producing zone of the targeted horizon.

On numerous occassions, wells, such as the ones just described, have been successfully re-entered and drilled as medium radius, horizontal wells.

Depending upon casing depth and the "new" zone of interest, a horizontal well can be drilled utilizing existing, casing-exiting techniques to exploit distinct zones at any depth within the existing wellbore. In the event that water coning was a factor in the productive life of the vertical well, a horizontal leg within the oil column is possible which horizontal leg will recover known in-place reserves while minimizing coning effects.

This presentation will discuss the planning and operational phases of executing a slim-hole, horizontal, re-entry program. Several case histories will be presented to illustrate the technology.

Mr. Abrant will distribute figures and additional information at the Conference.

RADIAL TECHNOLOGY
DRILLING AND PRODUCTION OF HYDROCARBONS
(REF GARDES DIRECTIONAL DRILLING)

EXECUTIVE SUMMARY

Radial drilling and production technology is state of the art directional drilling that allows a hydrocarbon reservoir to be intersected by many hundreds (or thousands) of feet of interconnected wellbore, all radiating from a single horizontal (or highly deviated) main wellbore. The radial system can be installed at depths ranging from a few hundred feet to 8,000 feet (utilizing existing equipment). This radial technology is a cost effective, environmentally superior production system. A single radial well replaces multiple vertical in-fill wells exposing increased reservoir area amenable to thermally enhanced oil recovery methods (i.e. hot inert gas injection). Hydrocarbon reservoirs that are particularly suitable for development by radial technology are:

- o Shallow, pressure depleted zones
- o Heavy oil (less than 20 degree API)
- o Fractured reservoirs
- o Laminated payzones
- o Coalseam methane gas

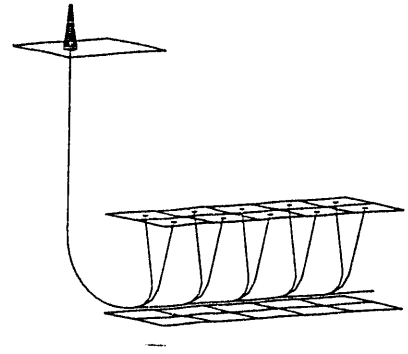
RADIAL TECHNOLOGY - ADVANTAGES

The radial technology is based on proven drilling/production *techniques developed in three specialized, diverse industries (directionally drilled pipelines, horizontal drilling for oil and gas, and oil mining)* and fused into a single composite technology. Pursuant to the recovery of oil and gas, the unique benefits of the radial technology include:

- o A single radial well can replace multiple vertical wells, eliminating wellsites, reserve pits, infield pipelines, etc. and thus providing an environmentally superior alternative.

- o A single pump is sufficient to produce and entire radial installation, resulting in a significant reduction of long term operational and maintenance expense as compared to multiple vertical wells.

- o The large amount of wellbore to reservoir contact, in conjunction with gravity assisted drainage, make the system particularly suitable to EOR and heavy oil operations.



- o Non magnetic drill motors, in combination with accurate guidance equipment, allow for exacting placement of the radial wellbores within the hydrocarbon reservoir.

- o The radial wellbores are cost effective, with the cost/foot of payzone exposed substantially reduced (generally by 100% of more) as compared to conventional infill wells.

- o Radial wellbores are suitable for use with all present EOR methods (i.e. steam injection, chemical/surfactant flooding, microbial, etc.) and particularly hot inert gas injection.

RADIAL TECHNOLOGY - DESCRIPTION

A brief description of the installation of the radial well system is as follows:

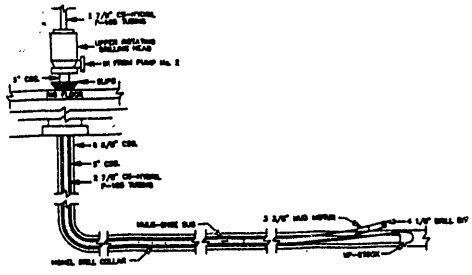
(1) A wellbore is spudded and drilled vertically (using conventional rotary methods) to a kick-off point 1,000 - 2,000 feet above the hydrocarbon reservoir. An angular rate of build using medium radius technology is effected utilizing downhole mud

motors and directional guidance systems (such as MWD). The angle of the wellbore is increased at the prescribed build rate until the wellbore reaches a horizontal attitude within the reservoir.

(2) The wellbore diameter is enlarged and a casing pipe is inserted and cemented in place. The casing size is generally in the range of 8-5/8 to 10-3/4 inches.

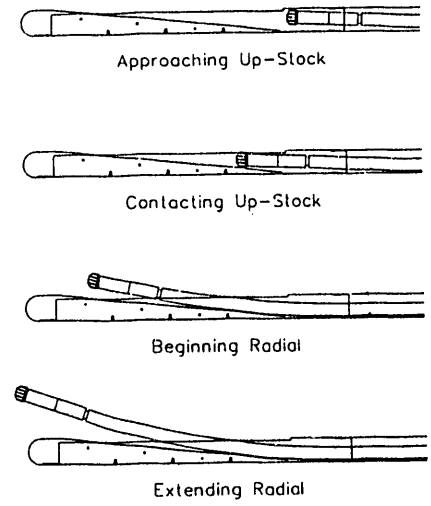
(3) The casing float equipment is drilled out, and a steerable system (consisting of a drill bit, mud motor, MWD guidance package and nonmagnetic collars/stabilizers) is used to drill a horizontal borehole through the payzone. Typical horizontal lengths achievable range from 1,000 - 3,000 feet, with wellbore diameters ranging form 7 to 9 inches. The steerable equipment is then withdrawn from the wellbore.

(4) The specialty portion of the radial installation now begins. A deflection tool, (called an upstock)



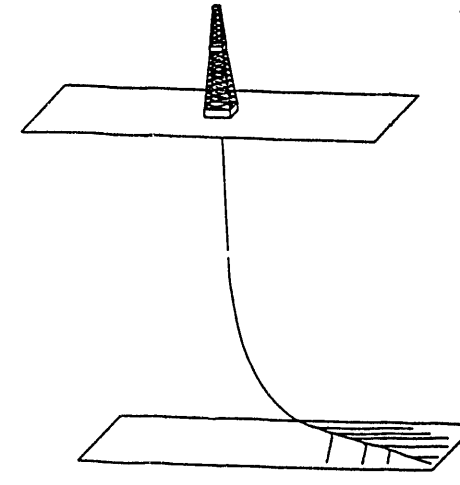
developed by Gardes Directional Drilling is lowered into the wellbore on the leading end of a string of carrier drillpipe. Upon reaching the intended location of the first radial wellbore, the deflection ramp portion of the tool is oriented and activated. The carrier drill string is secured in the slips on the rig floor.

(5) A smaller radial drill string, with a mud motor/drill bit on the leading end is lowered into the borehole (through the carrier drillstring) until it reaches the ramp section of the upstock. The mud motor, powered by the pumped drilling fluid, is started. The motor/bit moves across the ramp, causing it to be deflected out into the formation.



Simulation of Radial Process

(6) The radial wellbore is drilled in an accurate path outwardly from the main horizontal wellbore. A small bend in the motor housing located behind the drill bit allows the radial wellbore to be steered in a very precise manner. The borehole can be directed upwardly, downwardly, horizontally or any combination thereof. Continuous readings of inclination, azimuth and bend orientation allow exacting placement of the radial wellbores. The radial wellbore may be extended for a considerable length, allowing increased aerial sweep of the reservoir.



(7) After the radial wellbore is terminated, the motor/bit is withdrawn to a point inside the carrier drill string, and the 2 drill strings are coupled together. The deflection ramp on the upstock tool is deactivated.

(8) The carrier drill string is lowered to the next radial wellbore location, carrying along the radial drill string. The Upstock tool is reoriented, activated and secured on the rig floor. The radial drilling process can now be repeated as many times as required. Up to 10, 20, 50, or 100 radial wellbores from a single horizontal well are possible. There is no need to withdraw either drill string between the drilling of subsequent radials, contributing to the cost effectiveness of the technology.

(9) After installing the desired quantity of radial wellbores, both drill strings are withdrawn. The horizontal section can be completed by 1) slotted liner, 2) prepacked screen or 3) gravel pack. The individual radial wellbores can likewise be completed by any of the above methods, or can be left "open hole". The radial wellbores may thus be acidized hydraulically fractured, or stimulated by other means, if desired.

(10) The radial wellbore system is now ready to begin production. A single pump located near the bottom of the casing can be utilized to produce the entire system.

(11) Production can be enhanced by intermittent or continuous injection of inert hot gases into the horizontal bore network by the Therminert process.

RADIAL TECHNOLOGY - CAPABILITIES

- The radial drilling technology is applicable in both consolidated and unconsolidated formations, ranging from tar sands to chalk and limestone.

- The depth limitation for installation of the radial network is 8,000 feet, utilizing present equipment. Radial installations as shallow as a few hundred feet are practical. To date, individual radial lengths exceeding 400 feet have been realized (although reservoir boundaries, and not technical considerations, dictated the termination). Radial wellbore lengths of 1,000 feet are deemed possible with existing equipment.

- Angle build rates of up to 35^{o}/100 feet have been achieved with the radial wellbores. Ultimate build angles of 150^{o} and turn angles of 71^{o} (with respect to the horizontal section) have been realized to date.

- Multiple radial wellbores can be drilled from a single horizontal section. Up to 10, 25, 50 or even 100 radial wellbores can be drilled from a main wellbore.

- The diameter of the horizontal wellbore can vary between 7 and 8-1/2 inches. The diameter of the radial wellbore is variable from 3-1/2 to 4-1/2 inches using present equipment.

- The reservoir sweep possible utilizing radial technology allows a single radial system to cover 50 - 100 acres. This can easily replace up to 10 - 50 conventional wellbores, thus greatly minimizing the environmental impact.

- Accuracy of the radial wellbores are +/-2 -3 feet vertically and $+/-1^{o}$ in azimuth (magnetic heading).

- The cost of the radial/horizontal network of wellbores is almost always *significantly less per foot of payzone* exposed to the wellbores, as compared to conventional infill wells. In addition, the entire radial system can be produced by a single production pump/facility, lowering associated long term operational and maintenance expenses of the field.

- The radial wellbores can be completed by several methods, including 1) slotted liner, 2) prepacked wellscreen or 3) gravel packed screen, or may be left "open hole". The horizontal wellbore may also be completed in any of the above manners. This allows stimulation techniques, such as acidization or hydraulic fracturing , to be performed in the radial wellbores.

- The horizontal portion of the wellbore may be cased prior to the drilling of the radial wellbores. Proprietary techniques allow for sealing of the interface between the horizontal and radial wellbores.

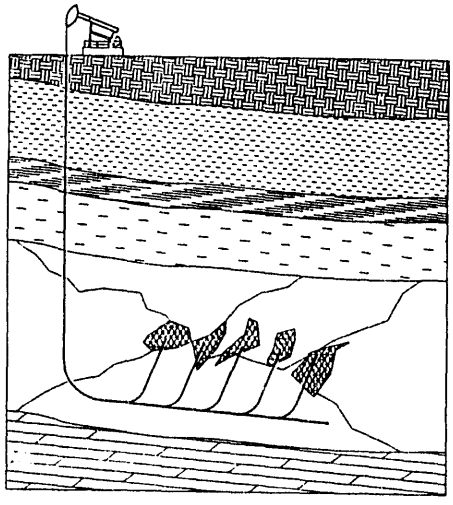
RADIAL TECHNOLOGY - APPLICATIONS

The present radial drilling and production technology is a suitable means to develop a variety of reservoir types. Specific reservoir types. Specific reservoirs that are particularly suitable, along with the pertinent advantages afforded by radial development, include:

(1) Heavy Oil - Significantly increased wellbore to payzone exposure and aerial sweep (as compared to conventional infill wells) at a fraction of the cost of oil mining or conventional individual horizontal wells; gravity drainage is enhanced by interconnected radial wellbore network.

(2) Shallow, Pressure Depleted Formations - Significantly increased wellbore to payzone exposure; gravity drainage compensates (to some degree) for low formation pressure.

(3) Fractured Formations - Ability to contact numerous vertical fractures.

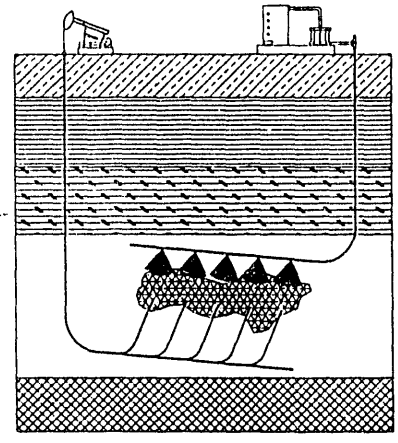


(4) Laminated Payzones - Capability to contact multiple zones in "stacked reservoirs, where impermeable layers (stringers) between hydrocarbonstrata limit production of vertical wells, often resulting in premature abandonment.

(5) Coalseam Gas - The radial network allows for faster production of formation water and thus higher yields of methane gas in a shorter time period; several thin seams can be accessed from a single horizontal wellbore.

RADIAL TECHNOLOGY- SUPPLEMENTAL ENHANCEMENTS

The Therminert Oil Recovery Process generates heated nitrogen and carbon dioxide. These two hot inert gases in turn are introduced to the formation through an injection well, driving oil to surrounding production wells or into recovery radials.



The benefits of nitrogen and carbon dioxide injection are well documented within the petroleum industry. Therminert gaseous injection products will have multiple effects on the formation - all combining to enhance recovery.

Nitrogen pressure provides mechanical drive energy, while carbon dioxide helps lower the oil viscosity. The Therminert BTU converter requires no heat exchanger or water treatment as with conventional steam generation equipment. Injection volume, pressure and temperature are pre-determined before actual injection begins. Large volumes of inert gases are produced thru the combustion process utilizing any gaseous hydrocarbon as the fuel source. The use of insulated thermal injection string insures much less

heat loss as the heated inert gases are introduced to the formation pay zone. Untreated water is introduced with the inert gases to modulate the injected product temperature thus less water is produced with recovered oil minimizing separation and disposal. Produced water can be re-cycled through the thermal converter minimizing water usage.

Advantage of the Therminert Oil Recovery process include:

* Delivery of more heat to the pay zone via directional/radial drilling techniques.

* Advantage of non-condensing nitrogen's mechanical drive energy to increase recovery rates.

* Heat and carbon dioxide lower oil viscosity.

* No treated water is required for operation.

* Much less water is injected than with steam, minimizing separation and disposal.

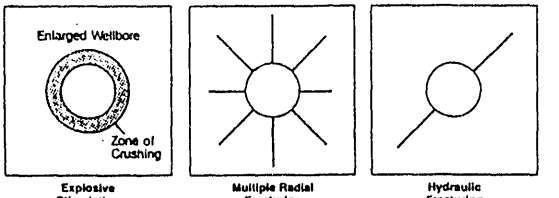
* EOR chemicals can be injected along with the inert gases if needed.

* Capital and operation costs are less than for conventional practices.

* No stack gases are generated by the thermal converter, reducing environmental impact.

DYNAMIC GAS PULSE LOADING

Dynamic Gas Pulse Loading (DGPL), is an advanced well stimulation process which, in many instances, is found to be superior to hydraulic fracturing or acidizing. DGPL was designed to ensure generation of a complete stimulation system, including vital cross-cutting fractures. This is accomplished by adjusting the loading rate to neutralize and exceed all the composite formation stresses, without regard to their orientation, in milliseconds. As many as six fractures (perforation geometry) can be produced and extended by this method. Large or multiple zones may be treated without need to isolate previously treated intervals. Moreover, DGPL allows precise control superior to any comparable system.



Extensive observation show that DGPL creates multi-directional fractures radiating from the wellbore in a pattern influenced by the casing perforation geometry. Vertical growth of the created fractures is limited, ensuring in-zone stimulation. Since the in-site stress level of the formation is exceeded by a significant amount, created fractures do not take the path of least resistance, as invariably occurs with hydraulic applications.

==END==

RADIAL CORING

Radial coring is a patented technology of Gardes Directional Drilling, Inc. Radial coring's innovation in concept was to create a method which allows standard sized (2-3") core samples to be recovered from a pre-drilled well and after logging analysis is completed. The core is recovered at a suitable distance from the well bore, thus not tainted by drilling fluid contaminates.

In the radial coring process, the upstock, Gardes' proprietary assembly, is run on a carrier string and is lowered into the well bore to the desired interval to be cored. A coring assembly of either the conventional rotary type or mud motor driven variety is lowered into the well bore through the larger diameter carrier string until it reaches the face of the upstock. The coring assembly is rotated and the assembly is thrust into the formation. If additional cores are needed, the process is repeated.

Radial coring has numerous advantages. Cores can be taken from greater lateral distances from the well bore (up to 500 ft.). Cores recovered using this technique are beyond the skin damaged area of the well bore. Numerous cores can be taken from a single well bore. Coring can be effected in a pre-drilled and logged well bore so that the interval to be cored can be judiciously selected, thus less samples are needed. This results in less trips in and out of the hole, saving time and money. Moreover, as opposed to conventional coring, the drilling process need not be interrupted to retrieve a core.

Notwithstanding the advancements in coring technology, there are still several inherent problems that exist in extracting pure, untainted samples. The area in close proximity to the well bore is often infiltrated by drilling fluids. Consequently, samples obtained from areas immediately adjacent to the well bore are contaminated by materials such as bentonite, polymers, etc.

Another problem is that oftentimes the points of interest to be cored are not known until a complete sweep of electric logs are run and analyzed. However, after the well bore is drilled and logged, coring cannot be done in a conventional manner and a sidewall core is the only alternative. Sidewall coring can only recover cores of small diameter (1/2"-1") and only several inches into the strata. Up until now, sidewall coring was the only technique to obtain core samples in a pre-drilled well bore.

The unique technology of radial coring can be applied in evaluating older fields. As America's dependence on foreign oil increases, more older domestic fields are being re-evaluated for secondary recovery projects. Using radial coring, an operator has the ability to re-enter old or abandoned wells, retrieve full sized cores and have same examined for purposes of water-flood efficiency.

NEW RADIAL TECHNOLOGY

ENHANCES CORING RECOVERY

Originating from the concept that drilling multiple radials from a horizontal or vertical wellbore has numerous advantages, the technology used in drilling radials can also be applied in recovering cores. This technique allows operators to obtain conventional sized cores from targeted zones after a well has been drilled to total depth and logged. Moreover, cores can be recovered from areas of the reservoir not affected by mud invasion.

RADIAL DRILLING

In addition to enhancing productivity by exposing more of the reservoir to a single production conduit, radial drilling has other advantages:

- Each radial can theoretically produce the equivalent of a vertical well, thus eliminating the need of surface disturbances such as wellsites and reserve pits, therefore providing environmentally attractive options;
- A single pumping unit can be used to produce an entire radial system, thereby reducing long term operational and maintenance costs;
- A radial system is compatible for EOR techniques such as steam injection, or chemical/surfactant floodings.

A new technological device called an "upstock" is used to bore each radial and can be utilized in radial coring.

CONVENTIONAL CORING

As used in conventional coring oilfield context, the terms "coring", or "taking cores" refers to the act of removing from the wellbore, actual samples of the subterranean strata. These "cores" or samples are subsequently analyzed at the surface, yielding a multitude of data as to the physical composition and properties of the strata. Reservoir parameters that can be obtained from cores include porosity, permeability and grain structure. As such, successful core recovery represents an invaluable tool for geologists, reservoir engineers and other earth scientists.

Traditionally, core samples are taken by inserting a specialized assembly, consisting of an open center drill bit, outer housing and inner sleeve (or core barrel) into a wellbore and advancement of this assembly using rotary drilling methods. As the assembly advances, the core is "captured" in the inner barrel. After the desired interval is cored, the assembly is brought to the surface and the core sample removed from the barrel. Numerous advancements in coring equipment and techniques have been made in the last decade. These advancements include 1) oriented coring, 2) coring with PDM's mud motors, and 3) stackable core barrels, making it possible to core 50 feet or more in a single run.

In spite of advancements made in coring technology, several problems still exist using conventional methods of extracting pure, untainted cores. The area in close proximity to the wellbore is generally infiltrated by drilling fluid additives such as barite and polymers. When retrieving conventional cores, the drilling process

is interrupted. Moreover, coring depths selected may not be accurate, resulting in additional trips with the coring assembly. The possibility exists that the zone of interest may be encountered further up hole than anticipated, leaving sidewall coring as the only option.

The problem of mud invasion is exasperated when using sidewall cores in low pressured, high permeability reservoirs, especially in zones penetrated several days prior to reaching TD whereby the reservoir may be subjected to excessive mud damage due to infiltration. A sidewall core is a device whereby a gun, run on electric wireline and made up to a string shot, shoots hollow, cylindrical bullets, into the formation that is exposed in the wellbore. Once energized, the bullets are fired into the formation and are retrieved by springs attached to the cylindrical carriers. This tool can recover small diameter cores (1/2" - 2") and penetrates several inches into the desired strata. Consequently, core samples recovered by side-wall coring may be contaminated. Another problem that arises is that reservoir analysis cannot be completed until the well is drilled, logged and evaluated. However, after the wellbore is drilled and logged, coring cannot be done in a conventional manner, and a sidewall core becomes the only alternative.

In cases of washed out wellbores, often the spring energizing the hollow, cylindrical carrier, will not extend into the formation. It is not uncommon for the carriers to remain either lodged in the wall-cake or fall and leave debris at the bottom of the well. Moreover, when attempting to retrieve side-wall cores in coal seams, the coal may shatter upon impact of the individual bullet.

However, up until recently, side wall coring was the only practical technique for obtaining core samples in a predrilled borehole. A Calgary, Alberta based firm has introduced a tool/technique to get cores that are both larger in diameter (2-1/2"), longer in length (up to 10') and taken further from the wellbore. Unfortunately, an integral step in this process involves the enlarging of a section of the wellbore in order to initiate the kickoff point of the coring. This enlarged section can (potentially) be a problem for future well operations.

Radial coring does not affect the integrity of the wellbore. The existing wellbore does not have to be modified, thus risking the possibility of formation damage. Most importantly, the coring can be done after the well has been drilled and logged wherein the intervals cored can be judiciously selected. Standard cores up to fifty (50) feet in length and four (4) inches in diameter can be recovered. See Figure 1.

THE UPSTOCK

The apparatus used to deflect the core bit into the sidewall of the well, the upstock, was developed by Gardes Directional Drilling, Inc. The upstock allows for the drilling of offset wellbores with respect to a main central wellbore wherein the central wellbore can be either vertical, horizontal or slanted. The apparatus consists of a deflection tool body containing an angled ramp. The upstock is run on a carrier or work string. A drilling assembly is then run on a smaller, inner string, inside the carrier pipe. The drilling assembly is deflected off the face of the ramp and into the formation, commencing the radial borehole. See figure 2. The tool's body can be oriented (by use of a steering tool or survey tool) several times before tripping to a new depth, so that multiple cores, each of known radial orientation, can be recovered from the main wellbore.

RADIAL CORING

The subject of this disclosure is a novel coring methodology which allows a standard size (2-3") core sample to be obtained in a predrilled (and logged) well. The core target can be located at a suitable distance from the wellbore. In addition, this methodology does not require a modification (enlargement) of the original wellbore.

In the coring process, the deflection tool is lowered on the end of the carrier string into the well to the desired interval to be cored on the end of the carrier string. The deflection ramp can be oriented using a conventional steering tool. The carrier string is secured (hung off) using rig floor slips. A coring assembly of

either the conventional rotary type or the mud motor driven variety is lowered into the wellbore through the carrier string until it reaches the deflection tool ramp. See figure 3. The coring on the section is now started. The coring assembly is rotated (via either rig rotary/top head drive or the mud motor is started with pumped fluid) and the assembly is thrust into the sidewall of the wellbore. The coring assembly is advanced as far as desired. Upon completion of the coring, the coring assembly is withdrawn. The process can be repeated at that depth by simply re-orienting the tool's face. If cores are to be taken at different depths, the upstock can be positioned at a different depth simply by tripping the carrier string, either in or out of the hole.

The advantages of this system are numerous. Coring can be affected in a predrilled (and logged) wellbore so that the interval can be chosen after well log interpretation. Cores can be taken away from wellbore (1'-500' for example). Numerous cores can be taken from either a cased/uncased wellbore. The existing wellbore does not have to be modified (and potentially damaged). Standard diameter cores can be obtained up to fifty feet (50') in length.

PLANNING

Prior to coring, detailed planning of the operator's goals should be reviewed. All hole diameters must be taken into consideration. This includes the cased hole inner diameter and the outer diameter of the open hole. A review of an open hole log is critical especially where washouts may occur. These parameters have direct affect on the carrier string design, its bottom hole assembly and mud hydraulics.

Selection of the inner string (drilling medium) is important. The drilling assembly can be coiled tubing, drill pipe or tubing. Proper pre-planning will provide an opportunity to make-up all cross-overs and to ensure clearance of the drilling BHA through the upstock. Other factors that need to be addressed are surface location limitations, hydraulic flow capacities of the coring assembly and core bit selections.

CASE STUDY

The upstock has been used successfully to recover cores from coalbed methane wells in the Black Warrior Basin, Alabama. The upstock was run on 4-1/2" X-H drill pipe, spaced out, then the drill pipe was hung-off. A 1-1/2" coiled tubing unit was used as the drilling medium. A 2-3/8" mud motor rotated the 3" core bit.

Several factors were taken into consideration when spacing out the upstock. The upstock was positioned several feet above the coal seam, depending on the gauge of the open hole. The upstock was to be positioned so that when the core

assembly deflected off the ramp, a full diameter core of the target formation could be obtained.

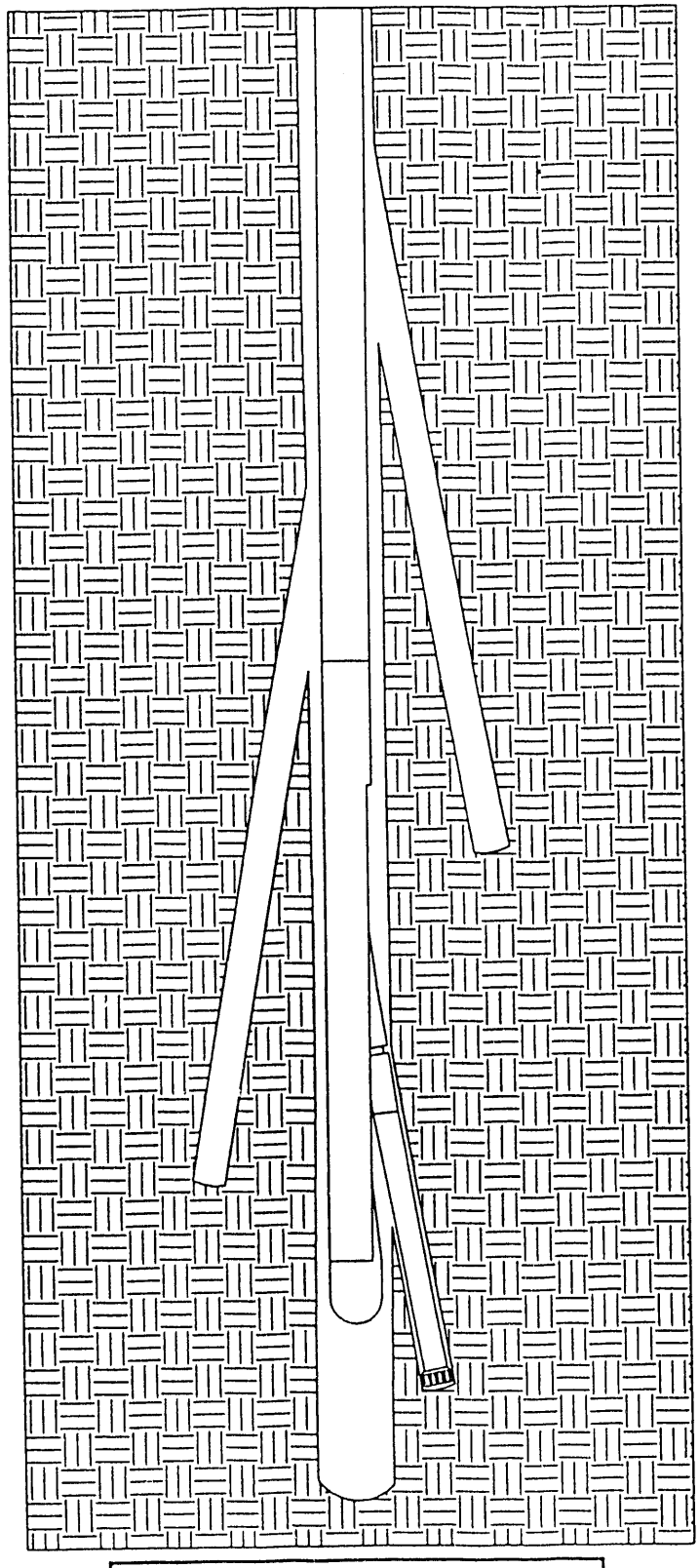
After positioning the upstock, a full gauged TIW was made up to the drill pipe. The coiled tubing equipment was made up to the drill pipe, above the TIW. A pump-in valve was installed above the TIW. This allowed the rig pump to pump down the drill pipe, through the 1-1/2" x 4-1/2" annulus while coring. This additional fluid circulation down the annulus was designed to reduce the severity of torque and drag problems. The CTU injector head and BOP's were connected to the drill pipe above the pump in sub. This configuration insured maximum safety in the event well control problems were encountered during coring operations. See figure 4. All returns were taken from the 4-1/2" x 8-5/8" casing annulus.

The coring assembly was made up to a 2-3/8" mud motor. The mud motor was crossed over to the 1-1/2" coiled tubing and run in the hole, inside the drill pipe to the face of upstock. The coiled tubing was flagged and the coring process commenced.

After coring, the coring assembly was retrieved. The injector head and coiled tubing BOP's were disconnected. The core was recovered and placed into desorption canisters for lab analysis. The drill pipe was then pulled out of the hole to the next interval to be cored and the entire process was repeated.

CONCLUSIONS

- Radial coring provides method to recover conventional sized cores after the well has been drilled and logged.
- Cores can be recovered from areas of the formation untainted by mud invasion.
- Cores can now be recovered from several feet up to several hundred feet from the wellbore.
- Numerous cores can be taken from a single wellbore and from the same zone of interest.
- Techniques used in this type of coring recovery be applied to other areas of radial endeavors such as radial drilling from horizontal and vertical wells.



Radial Coring Application

Fig. No. 1

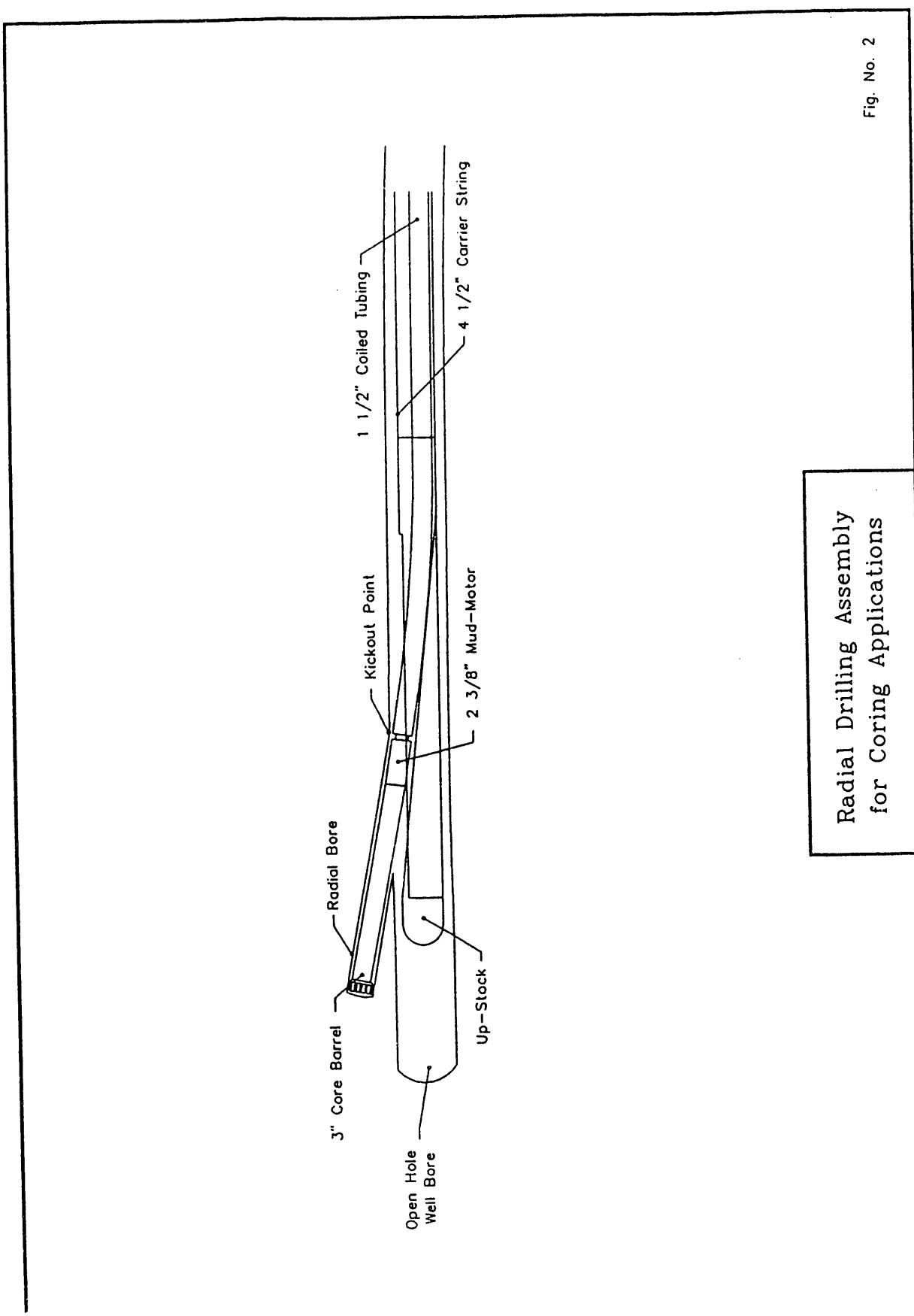
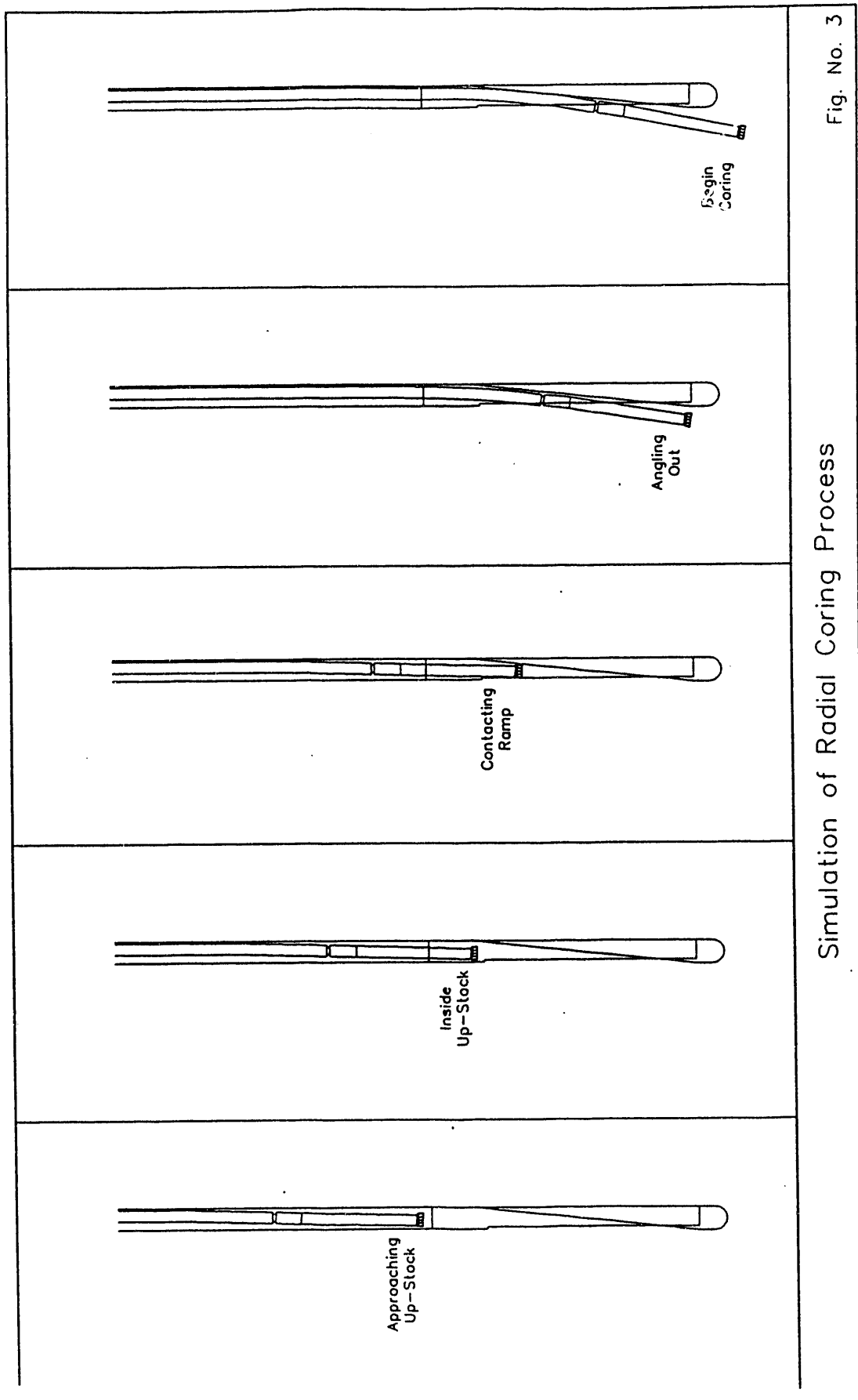


Fig. No. 2

Radial Drilling Assembly
for Coring Applications


Begin Coring
Angling Out
Contacting Ramp
Inside Up-Stock
Approaching Up-Stock
Simulation of Radial Coring Process
Fig. No. 3

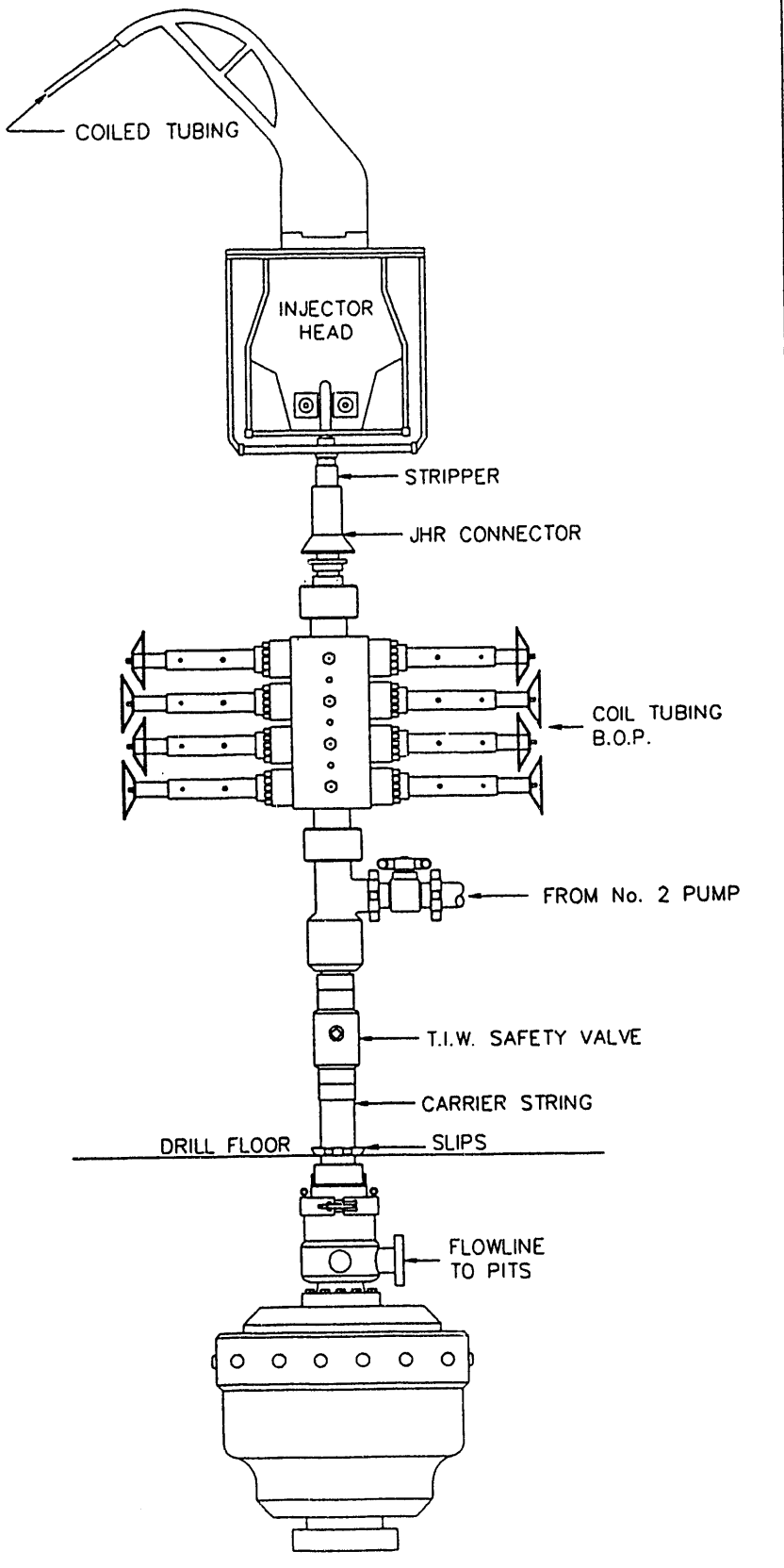

COILED TUBING
INJECTOR HEAD
STRIPPER
JHR CONNECTOR
COIL TUBING B.O.P.
FROM No. 2 PUMP
T.I.W. SAFETY VALVE
CARRIER STRING
DRILL FLOOR
SLIPS
FLOWLINE TO PITS

Fig. No. 4

Notes

SLIMHOLE FORMATION TESTING

INTRODUCTION:

Present a brief history of the Inflatable products and Baker Oil Tools drill stem test equipment. To introduce the different types of formation test that can be performed and in what type of applications each of these are used. To understand the capabilities of the equipment that can be used in slim hole formation testing. The information is recorded by the use of electronic and mechanical gauges.

MAIN BODY:

There are two types of equipment that can be used for slim hole formation testing. One type is a on-bottom test with compression type packers. This type of tool is limited to 4 3/4" open hole and larger. These tools must be set on bottom of the wellbore to be able to compress the packers to isolate a formation. Another type is a inflatable straddle drill test tool that does not require weight to set the packers.. This type of tool is used to isolate and straddle a formation for testing. The straddle tool is inflated with fluid in the tubing and applying pressure at the surface to inflate the elements. Due to the smaller O.D. of these tools they can be set in 2 3/4" to 4 3/4" open hole. Also the inflatable straddle can be reset as many times as the element will allow. Formation pressure can be recorded by a electronic memory gauge that has pressure and temperature capabilities, mechanical gauges are also available.

CONCLUSION:

By using either of the DST tools mentioned above we can record formation pressures during flows and shut-in periods. Also a sample of formation fluids or gases can be recovered with this equipment.

Cliff McKaughan joined Lynes Inc. in 1984 in Oklahoma City, Ok. where his responsibilities were running drill stem test , inflatable products and field sales. In 1986 Lynes Inc. and Baker Service Tools merged, he was transferred to Kalkaska MI. . There he trained the district employees to perform drill stem test and was also responsible for sales of Baker Service Tools products. In 1990 he was transferred to Houston Tx. as a Application Specialist for the domestic and international markets, which is his current position. He has co-authored a paper on inflatable kill packers used in Kuwait to kill the burning wells. Currently he is responsible for applications of all Inflatable products including Thru-Tubing Inflatables.

SLIMHOLE FORMATION TESTING

In recent years an increase in slimhole exploration and production has proven to be a cost effective solution to todays low energy prices. Recovery of formation fluids and pressures have continued to be an ongoing challenge in slimhole wells. The following information is designed to provide a better understanding of the types of equipment available for slimhole formation testing. Due to the different types of applications needed for testing, presently there are two types of equipment available, conventional and inflatable. The use of electronic and mechanical gauges are available to record formation pressures and temperature. Both types of gauges can be utilized with either type of test equipment.

SLIDE #1

Presently two types of equipment are currently available for slimhole formation testing. One is the conventional on bottom tools which have compression type packing elements, single set applications and limited to 4 3/4" to 7" open. The second type is the inflatable straddle drill stem test tools. Some of the features of this tool include the inflatable element, resetting capabilities, set at any given depth and limited to 2 3/4" to 4 3/4" open hole.

SLIDE #2

Here is the standard conventional on bottom formation test tools used to test a zone near or at T.D. of the well. Starting from the bottom, a bull plug anchor shoe is used to set on the bottom of the wellbore. Perforated anchors are placed in the string to space out the packers, and also used as test ports.

(1)

The perforated anchor has approximately ten holes per foot which are 1/8" in diameter.

Next is the outside recorder carrier which has the capability of carrying up to two recorders if needed. These recorders can be either mechanical or electronic to record pressure and temperature.

Two compression packers are installed right above the recorder carrier. The elements are 4" to 5 3/4" O.D. and 24" long, with a differential of 5500 PSI. When the elements are compressed they have a 18" seal, with variations depending on the size of the hole.

A safety joint is installed directly above the top packer section. It's only use is if the string becomes stuck in the hole and the need to back off the upper section of the tools to continue a fishing procedure.

Hydraulic jars are ran above the safety joint, these jars are sometimes used to assist in unseating the packers.

A inside recorder carrier is installed below the jars to record the internal flow and shut-in pressures, with a two recorder capacity.

A sample chamber with 1500 CC of capacity can be ran in the string between the recorder carrier and hydraulic tool, this is an optional tool.

One of the purposes of the hydraulic shut-in valve is to keep fluid from entering the drill pipe while running in the hole. Also at any time during the test straight pick up will close the valve and serve as a safety valve.

A rotating shut-in tool is used to open and close the tools by means of right-hand rotation. Two flows and two shut-in

periods is normally all that can be performed with the test.
Reverse circulating subs are spaced above the test tool string. These subs can be manipulated by internal pressure or by dropping a bar from surface to shear knock-off rods installed in subs. Drill collars and drill pipe is ran to surface to complete the string.

SLIDE #3

This slide illustrates the tool while going in the hole, at this point the packers are not set. THe drill pipe is dry while running in the hole, if necessary, a water cushion can be ran inside the drill pipe. A cushion is used when the differential pressure overcomes the rating of the element, also if the zone pressure requires it for safety purposes. Before the packers are set the surface equipment is installed to the appropriate manifold or sstorage tanks.

SLIDE #4

The packers are now set above the test zone, isolating the zone, the test is ready to begin. To accomplish this the drill pipe weight must set down on the test tool string to set the packers and open the tool. To successfully compress the packers and achieve a pack-off, 20,000 to 25,000 pounds must be set on the packers. At this time the hydraulic shut-in valve will open in 2 to 3 minutes, which will allow flow to enter the test tools. Right hand rotation at the surface will open and close the tool for the remainder of the test- (11 rds.-close 11rds.-open 11 rds.-close.) A normal test is 5 to 10 minute preflow, 30 minute to 1 hour shut-in, 1 to 4 hour flow, and 4 to 8 hour final shut-in, this may vary depending on the zone being tested. When the test is completed the packers are unseated, at this time the drillpipe or tubing can be reverse circulated. When this

operation is completed the tool can be retrieved to the surface and the information analyzed.

SLIDE #5

This schematic drawing illustrates the Inflatable Straddle drill stem test tool. Mechanically, this tool has more moving parts, and depends on O-ring seals for it's pressure integrity. WIth this in mind, the following description of the tools and the general running procedure goes into lore detail than the conventional equipment. Starting at the bottom of the test tool string is the tail pipe located below the bottom packer section and is merely a protective cover for the bottom packer section mandrel which moves a maximum 17 inches up or down during the test.

The bottom packer section acts as the lower pack-off during a straddle test. The inner mandrel is ported, and in the inflate position the port is located just near the end of the packer element, sealed by O-rings. When the mandrel is moved down toward the swab or tool closed position, the inflation port moves between a distal two sets of O-rings while retaining the inflation pressure. When the mandrel is picked up to deflate the packers, the port returns to it's original run-in position and because the pressure in the element is hydrostatic pressure plus 1,500 PSI inflation pressure, this pressure is released to the I.D. of the string. This is possible as the shut-in tool is open at the end of the test. In the top sub of the bottom packer section is the external/lower flow ports, through which the test fluid/gases flow.

Each spacing section has an outer body and an inner mandrel. The spacers are made up between the top and bottom packers to provide the required interval length. The inner mandrels are

connected to the mandrels of the top and bottom packers and is the inflation channel to the bottom packer. The annular space between the I.D. of the outer body and the O.D. of the inner mandrel is the flow channel for formation fluid/gases. The formation flow enters this channel through the ports in the top sub of the bottom packer.

The top packer section acts as the upper pack-off during a straddle test. It has an inner mandrel with two seperate ports and a Jay slot assembly on top. The Jay slot assembly section controls the testing sequence and assists in the opening and closing of the shut-in tool. The Jay slot is 17" long. When the Jay lugs are in the uppermost position the upper ports are sealed near the end of the packer element. The string is pressured up in this position. With 4" of down movement the lower ports move past the element seals and retains the inflation pressure. The upper ports move out of their O-ring seals and at this point there is communication between the annulus and the tubing. The remaining pressure is bled off at surface and the string is lowered again 13" to the bottom of the j-slot.

At this point the upper ports are now sealed again by a farther set of O-rings and the lower ports have passed through the bottom of the packer and have now become the upper flow ports. With right-hand torque the lugs are moved to the small lower section of j-slot, and the shut-in tool can be opened by pulling the tension on the string. To deflate both packers at the end of the test, the Jay lugs are moved back to the original run-in postion, and because there is hydrostatic pressure and 1,500 PSI inflation pressure on the elements, they will bleed to the string I.D.

The safety joint is run above the top packer section. It is comprised of two sections. It is made up to less torque than

the other connections in the string. Should it be required, the upper half of the safety joint can be disconnected by applying left-hand torque at surface. On retrieval, the upper half of the safety joint can be connected to a fishing assembly in order that the 'fish' be recovered.

The inside recorder carriers are 10' spacer sections with the inner mandrels removed and special top subs remain. The flow area is the annular space between the I.D. of the carrier body and the O.D. of the gauges. One electronic memory recorder and one mechanical recorder are normally run.

The downhole shut-in tool is open when it is in tension and closes when weight is slacked off. It is a multiple flow and shut-in valve. The tool does not meter open hydraulically, and is run in the hole in the open position. The string does not fill because the ports in mandrels are in the packer sections. Tension and weight down operates the tool when the Jay lugs are locked in the bottom postion. The opening or closing of the tool can be observed by a 4" free point movement at surface. A sample chamber can be ran with the shut-in tool, it has a 2 liter total capacity.

The bar/ball circulating valve is run above the shut-in tool. Prior to pulling out of the hole the formation fluid recovered is often reversed out. With this sub it can be performed two ways.

1. Sinker bar is dropped which drives the sleeve down, exposing the circulating ports, or-
2. The setting ball is dropped to the inner sleeve, then the string is pressured up to pump the sleeve down, the sleeve is normally opened by a tubing pressure of 700-1,100 PSI.

The inner sleeve is hydraulically balanced and shear pinned in place by a small piece of light shear pin, ran to ensure the sleeve does not move during the test.

SLIDE #6

The D.S.T. assembly should be made up as the tool schematic.

1. Once the pressure recorders have been loaded and the shut-in tool and reverse sub installed, the string is ready to be run in the hole.
2. The test string should be 'drifted' prior to run-in. This can be done either with a swabbing assembly, or a special 'pig'. Each section of pipe should be drifted as it is picked up.
3. During run-in, the string must be filled with fluid to avoid a large pressure differential being created across the packer elements.
4. At setting depth, surface equipment is installed and pressure tested.

SLIDE #7

The string is then pressured up to 1,500 above hydrostatic PSI which inflated both packers simultaneously. This pressure should be held for 10 to 15 minutes to allow the packers to conform to the well bore.

1. Right hand torque to achieve 1/4 turn at the tool is then placed on the drill pipe. The amount of torque will vary depending on deviation, depth, etc. The string is then lowered to the equalize position(6") at which a pressure loss in the drill pipe will be noted. Any pressure still maintained should be bled off at the choke manifold. This movement moves the inflation holes from the packer elements to equalize

pressure in the drill string with the annulas above, before the tool is opened to the tested formation. Inflation pressure in the packers trapped as the tool mandrel is lowered through the j-slot.

2. The string is then lowered the full 21" which will be the bottom of the Jay slot and the shut-in tool closed. At this point, the lubricator and swabbing gear can be installed.
3. During swabbing, the amount recovered should be monitored in a seperate gauge tank.
4. Once swabbing is complete, the flow line is installed and right hand torque applied to the drill pipe. The string is moved 4" up to the open shut-in tool. Right hand torque prevents the Jay lugs traveling up the length of the Jay slot and into the deflate positon. The pre-flow is normally 5 to 10 minutes.
5. To close the tool for the initial build up, the string is moved down 4" and weight is set on the tool. The shut-in is usually 1 hour.
6. To open the valve for the main flow period the string is worked as in the above procedure. The duration of the main flow is dependant on surface indications and the hole conditions.
7. The tool is shut for the main build-up.
8. When the build up is complete, the test recovery can be identified by one of three methods:
   (a) The swabbing assembly can be ran in to tag the fluid level and the varying amounts of fluid can be removed.
   (b) A ball or drop bar can be used to open the reverse circulating sub and the string contents reversed out. The amount of fluid required to fill the annulus should be carefully monitored.

(c) Run wireline sample chambers to retrieve the test fluid.

9. Prior to deflating the packers, the drill string must be full to avoid a large pressure differential across the packer elements. How the string is filled depends on the method of test recovery/identification selected.
10. To deflate the packers, a simple upward movement of the string is necessary while holding a slight amount of left hand torque, andthe string picked up 21" to the original mark. This will place the test ports back into the packer elements and, due to the greater pressure in the elements, the inflation pressure will be lost to the string I.D. The shut-in tool will be open at this point.
11. 5 to 10 minutes is given for the packers to deflate, and the surfaced equipment rigged down. The tools can be repositioned up hole for additional testing, or if the testing is complete the circulating valve can be opened to allow the string to be pulled dry.
12. On retrieval of the tools, the pressure recorders are checked and the tools prepared for the next test or laid down as required.

By using either types of these tools, formation test can be performed in most all slim hole applications. With the use of conventional equipment, formation test are possible in many on-bottom situations. The Inflatable straddle tools can be set at any given depth in the well. This type of equipment is continually used worldwide with great success.

Types of Slimhole DST Equipment

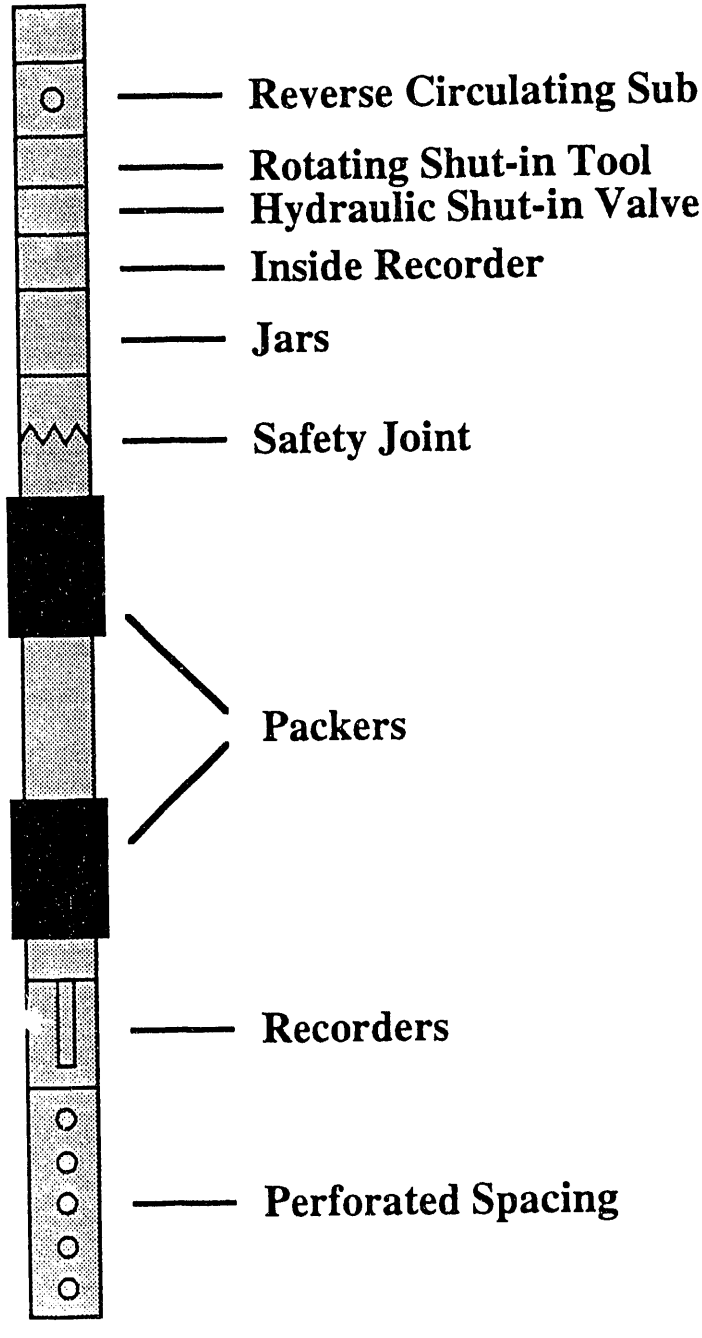
Conventional On-Bottom DST Equipment

- Compression type packing elements
- Single set applications
- Limited to 4-3/4" - 7" open hole

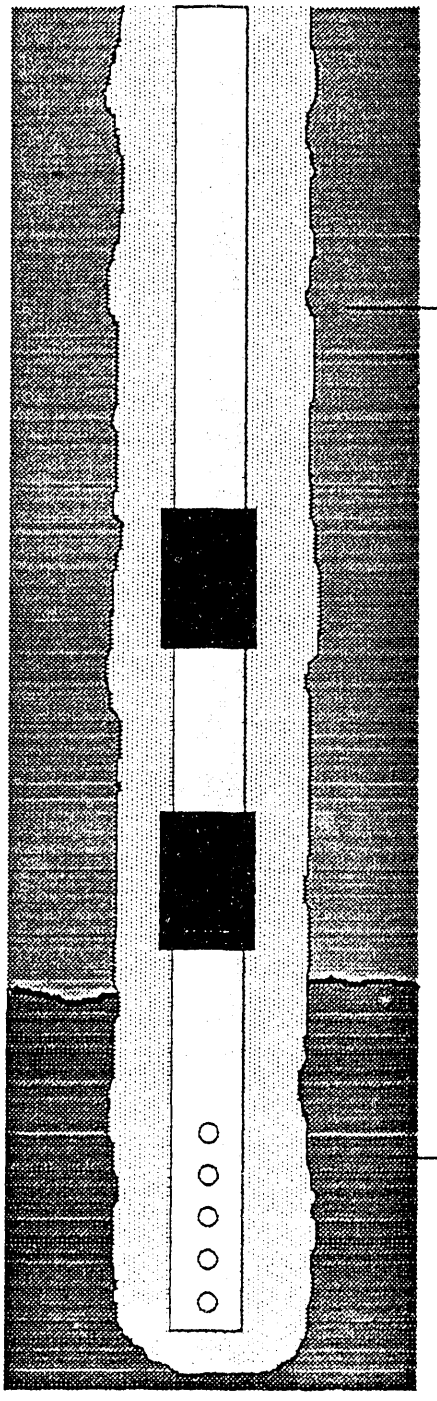
Inflatable Straddle DST

- Inflatable element
- Resetting capability
- Can be set at any depth
- Set in 2-3/4" - 4-3/4" open hole

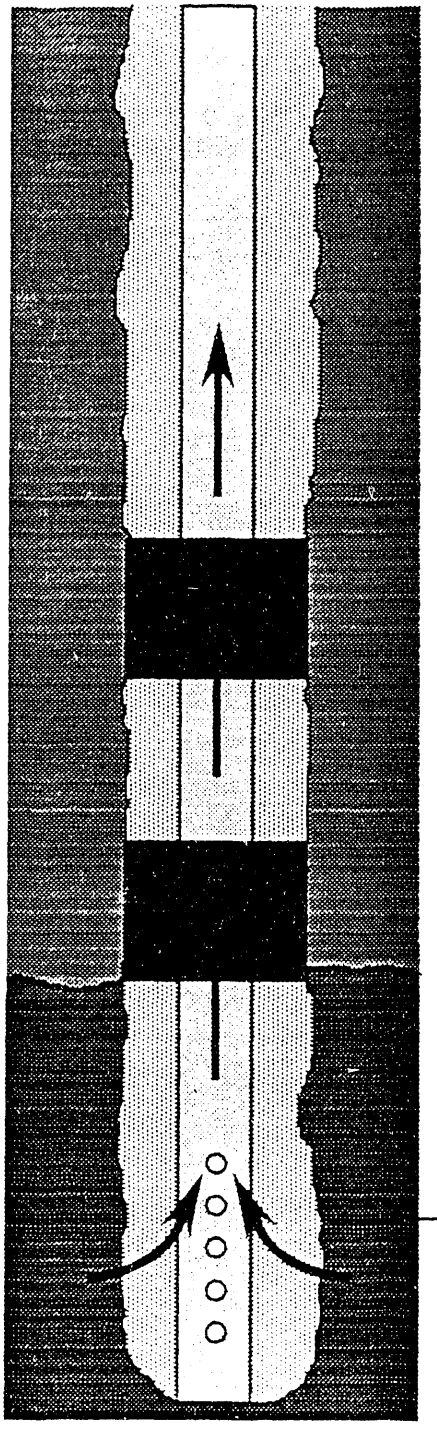
Conventional On-Bottom DST Tool



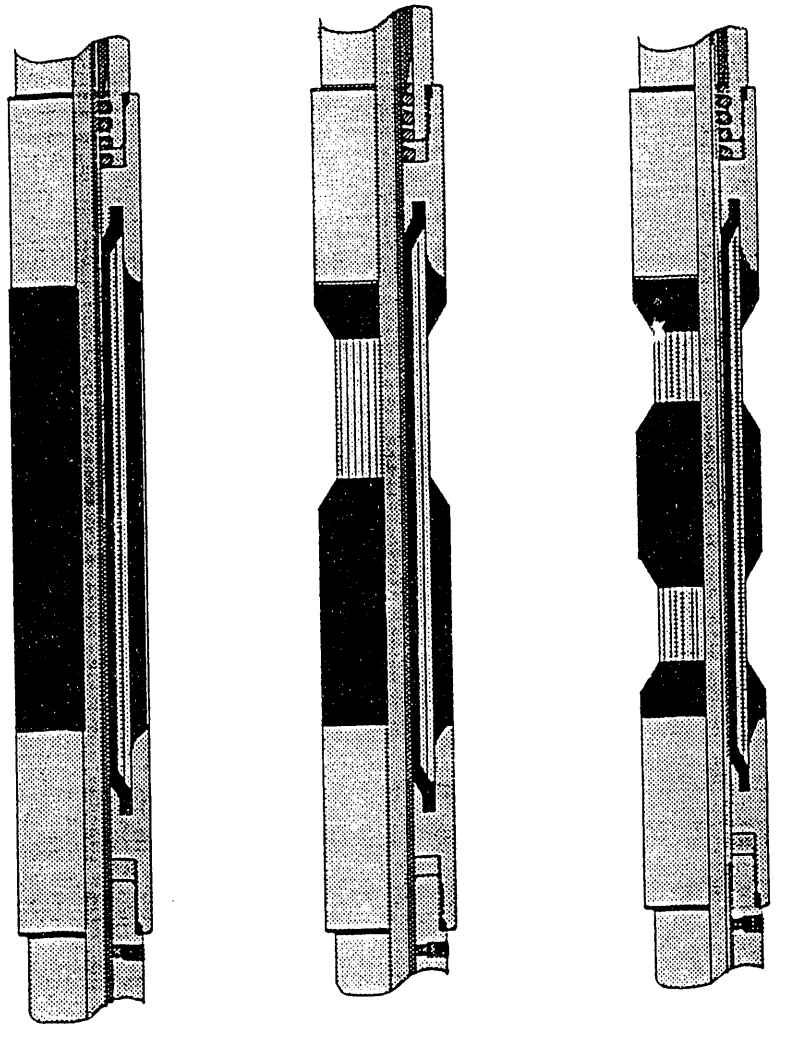
Conventional On-Bottom DST
Running in the hole



Element is set and the tool is open for testing



Inflatable Elements

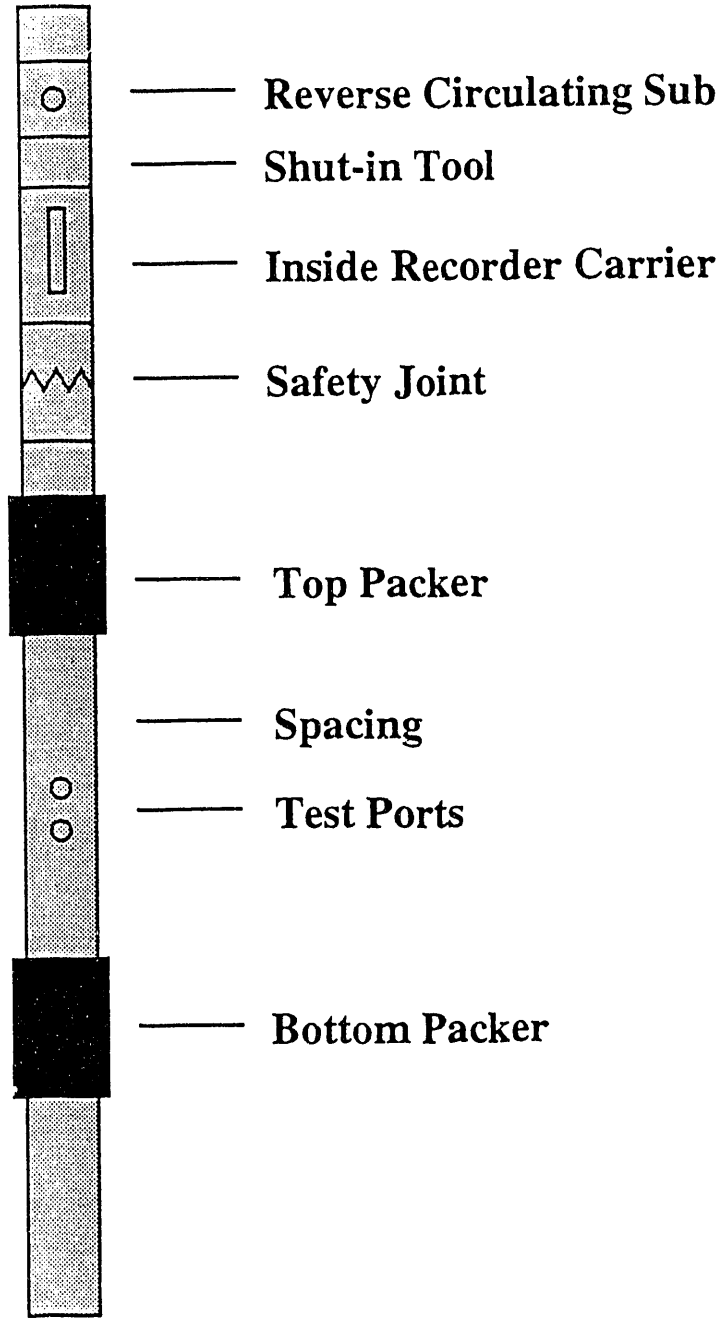


Open Hole Element

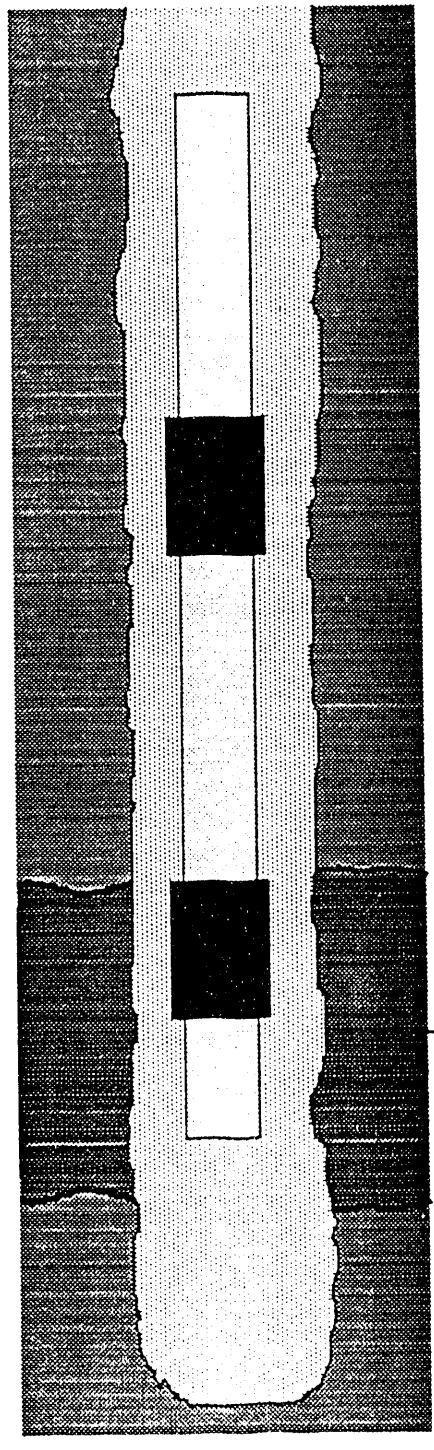
Single Anchor Element

Double Anchor Element

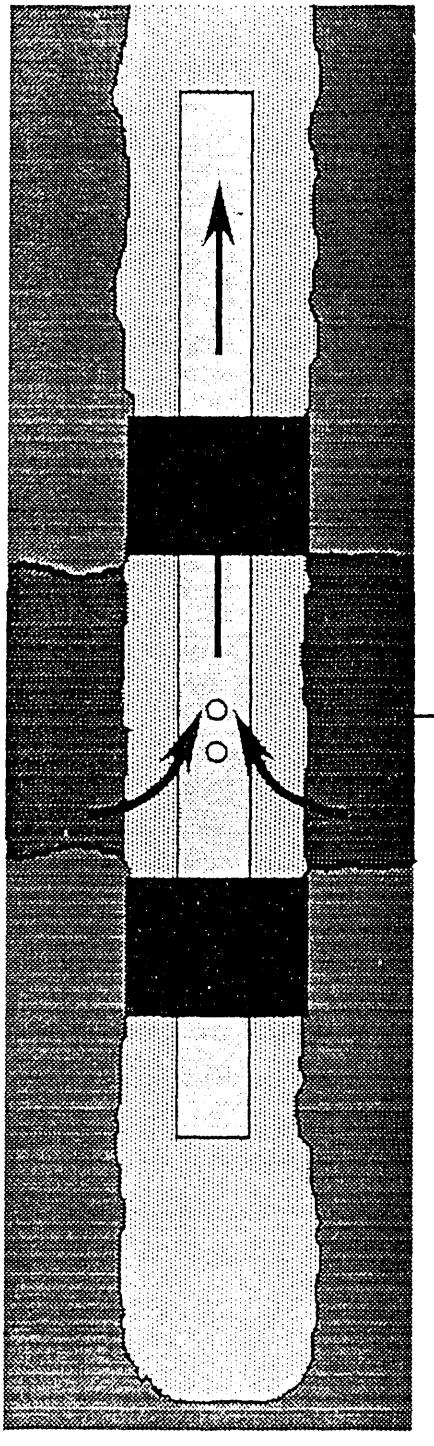
Inflatable Straddle DST Tools



Inflatable Straddle DST
Running in the hole



Elements set and the tool is open for testing



PRODUCT REPORT

BAKER SERVICE TOOLS
A Baker Hughes company

MARCH 1992

INFLATABLE PACKER

SHORT RADIUS PRODUCTION INJECTION PACKER (PIP) (Product No. 300-29)



DESCRIPTION/APPLICATION:

The Short Radius PIP is designed for horizontal well applications. Due to its unique design it is capable of running thru reduced I.D.S. or short radius wells and set in tubing, casing or open hole. The tool can be set up to run as a Treating and Testing Packer, Permanent or Retrievable Bridge Plug, Squeeze Packer or a Production Packer.

OPERATION:

The Short Radius PIP is run on threaded or coiled tubing with a solid or ball shear seat. Pressure is applied to expand and set the inflatable element. Run as a Packer, the seat is sheared out with additional pressure leaving a flow path through the tool so the desired operation can be performed. Run as a bridge plug the seat will remain intact. The tool is released by pulling tension and shearing the release mechanism. The element will then deflate and the packer can be retrieved.

FEATURES/BENEFITS:

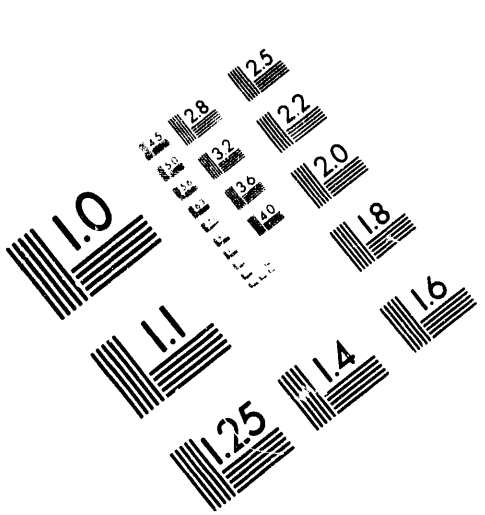
- Short Overall Length
- Compatible with threaded or coiled tubing
- Set in tubing, casing, or open hole
- Pull-release
- Element is sheared pinned to the bottom sub
- Greater expansion than standard tool
- 23" long element
- Run through reduced I.D.

DIMENSIONAL DATA:

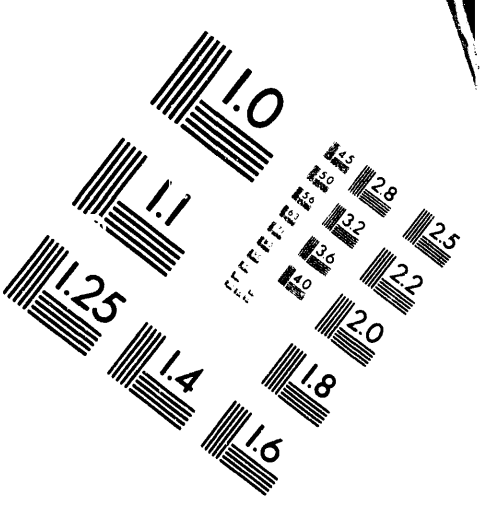
Size	Max.O.D.	Min. I.D.	Length	Expansion Range *
2 1/8"	2.125"	.62"	54.31"	2 1/2" to 7"

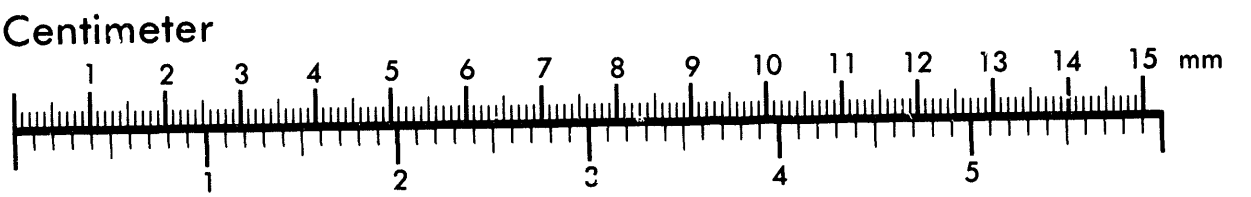
*Limited by temperature and differental pressure

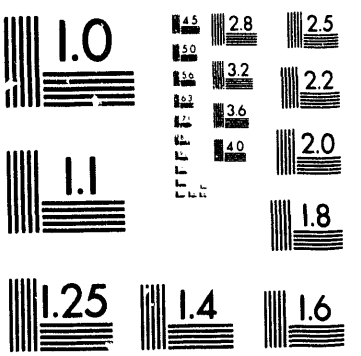
© 1992, Baker Service Tools. BHPT. All rights reserved 9202-1000

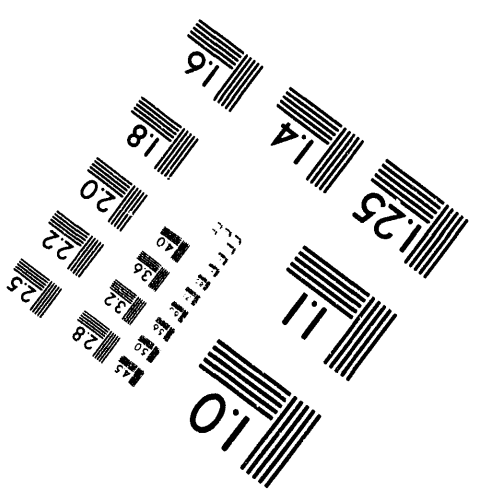


Association for Information and Image Management
1100 Wayne Avenue, Suite 1100
Silver Spring, Maryland 20910
301/587-8202

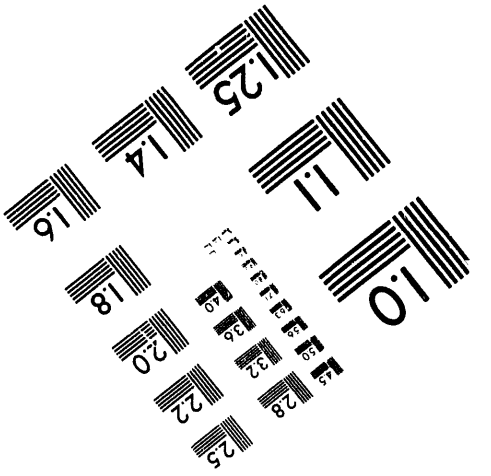








MANUFACTURED TO AIIM STANDARDS
BY APPLIED IMAGE, INC.



3 of 5

The Economics of Gelled-Water Stimulation vs Foam

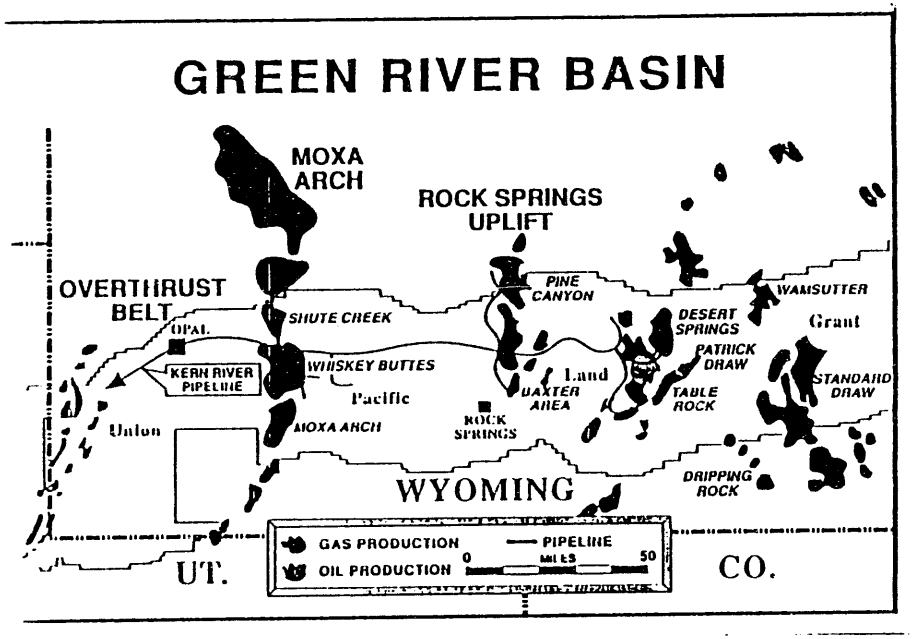
by Craig Cippola, Union Pacific Resources, Fort Worth, TX

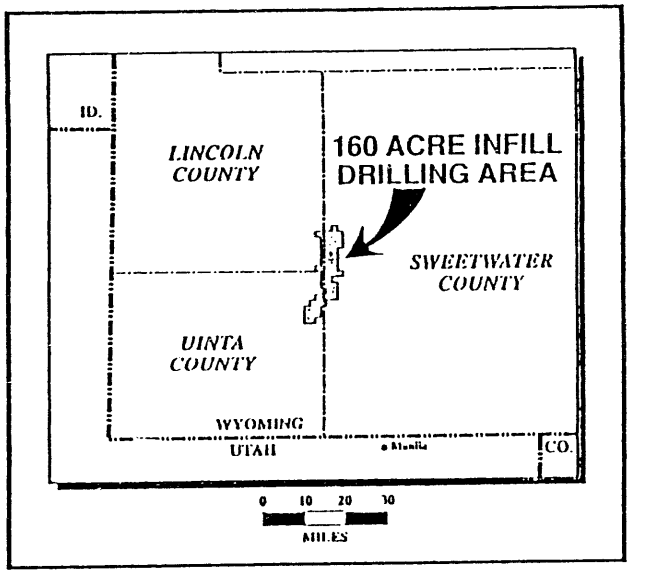
Mr. Cipolla holds undergraduate degrees in Engineering and Chemistry from the University of Nevada, Las Vegas, a d a M.S. Degree in Petroleum Engineer - ing from the University of Houston. In the past 12 years Mr. Cipolla has been involved in numerous research projects and large-scale, field studies directed at optimiz - ing production and stimulation practices. Mr. Cipolla is currently assigned to the Moxa Arch area in Southwestern Wyoming and is responsible for reservoir engineering and hydraulic fracturing technology.

HYDRAULIC FRACTURE PERFORMANCE IN THE MOXA ARCH FRONTIER FORMATION

UNION PACIFIC RESOURCES COMPANY

MAY 1993





Moxa Arch

Reservoir Study

- Geology, Petrography & Diagensis
- Log & Core Analysis
- Reservoir Modeling
- 3D Fracture Modeling

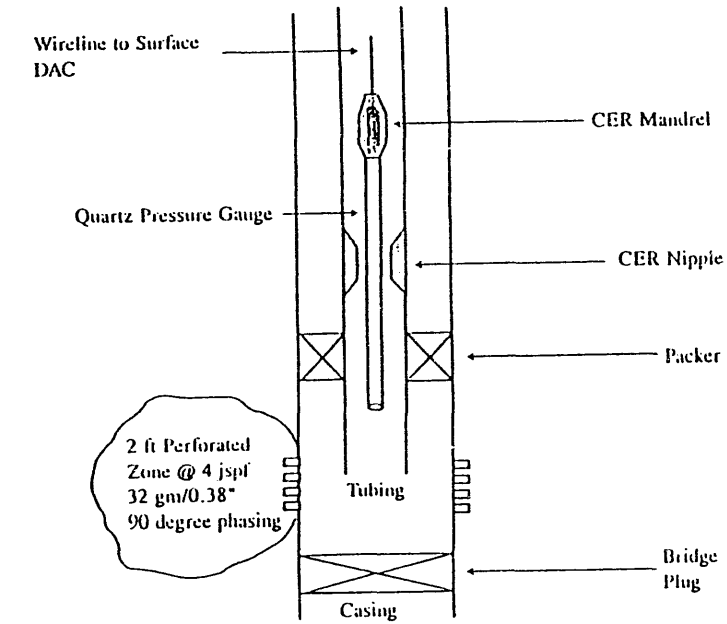
Moxa Arch

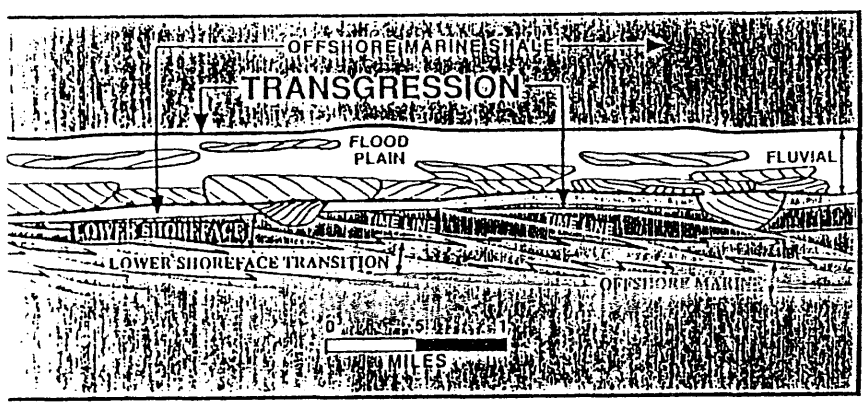
Reservoir Study

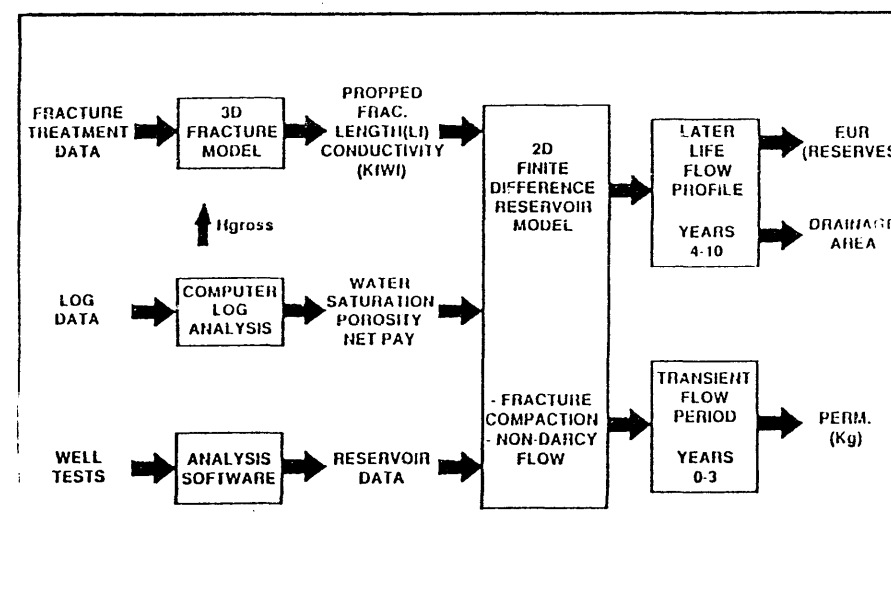
- 200 Well Data Base (Geology & Logs), 10 yrs of Production on 100+ Wells
- 150 Wells Evaluated Using Reservoir & Fracture Modeling
- 36 "Dead Sring" Hydraulic Fracture Treatmens Modeled - 1992
- 33 Mini-Fracs Modeled - 1992

SOURCES OF RESERVOIR HETEROGENEITY IN THE FRONTIER FORMATION

- EROSION OF MARINE FACIES BY THE OVERLYING FLUVIAL FACIES
- CAPPING OF MARINE SEQUENCE BY OFFSHORE SHALE
- CHANNEL SANDS OF LIMITED AREAL EXTENT
- SHALE DRAPES WITHIN THE CHANNELS
- DIAGENETIC OVERPRINT ON THE DEPOSITIONAL FABRICS







MOXA ARCH STRESS MEASUREMENTS

DEPTH	FD 4-34	FD 3-2	ZONE
11463		0.85	Shale
11563		0.77	Fluvial Sand
11603	0.82		Fluvial Siltstone
11623	0.74	0.7	Marine Sand
11661		0.84	Shale
11693	0.84		Shale
11757		0.82	Shale
11780	0.82		Shale
11887	0.79		Shale

CPC 285 AMOCO E-1
RESERVOIR AND ROCK DATA

SOURCE	PARAMETER	VALUE
DST	PERMEABILITY	0.005mD
DST	PRESSURE	6,827 psi
LOGS	NET PAY	43 ft
LOGS	POROSITY	11%
LOGS	Sw	53%
	MODELING RESULTS	
FRACTURE	Lf	725 ft
FRACTURE	KIWf	75 mD-ft
RESERVOIR	Kg	0.004 mD
RESERVOIR	DRAINAGE AREA	77 acres
RESERVOIR	EUR	1.5 BCF

LOG CALCULATED STRESS

$$Sh = u/(1-u)*(Sv - P) + P + C$$

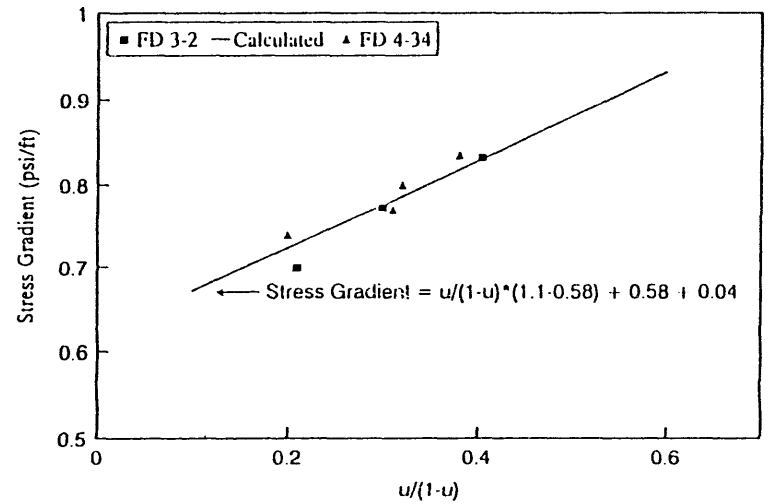
Sh = minimum horizontal stress, psi/ft

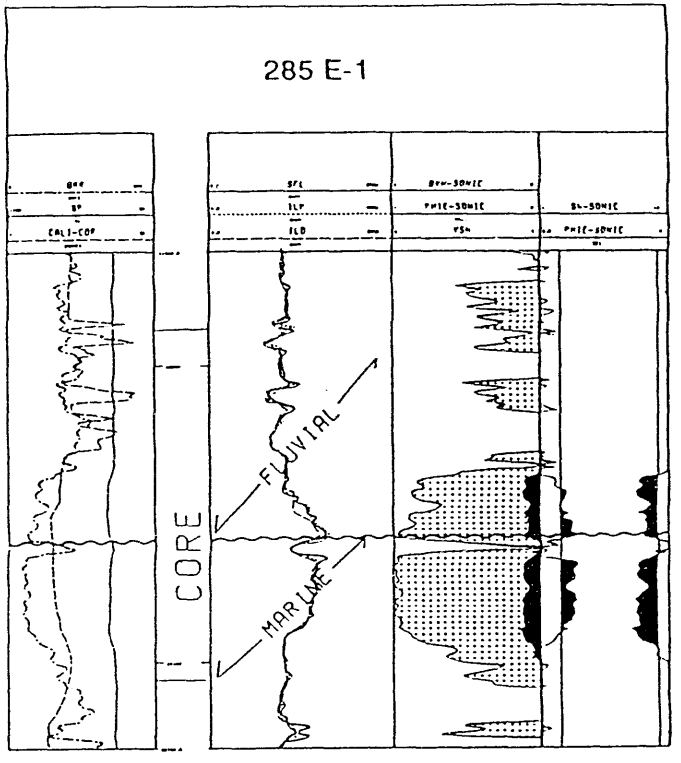
u = poison's ratio

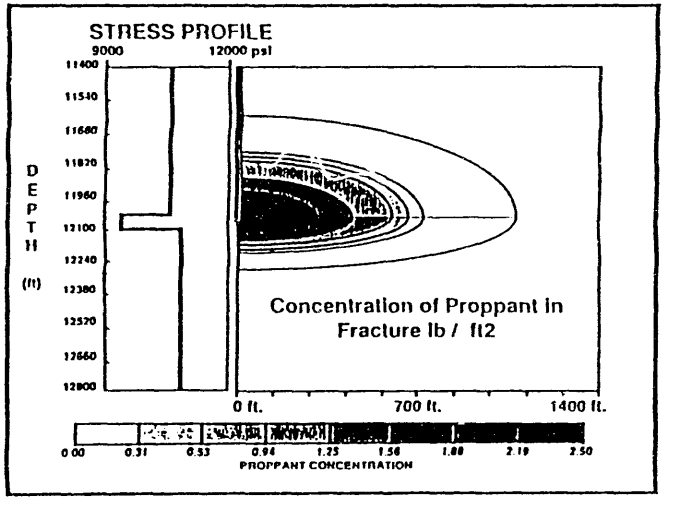
Sv = vertical stress = 1.1 psi/ft

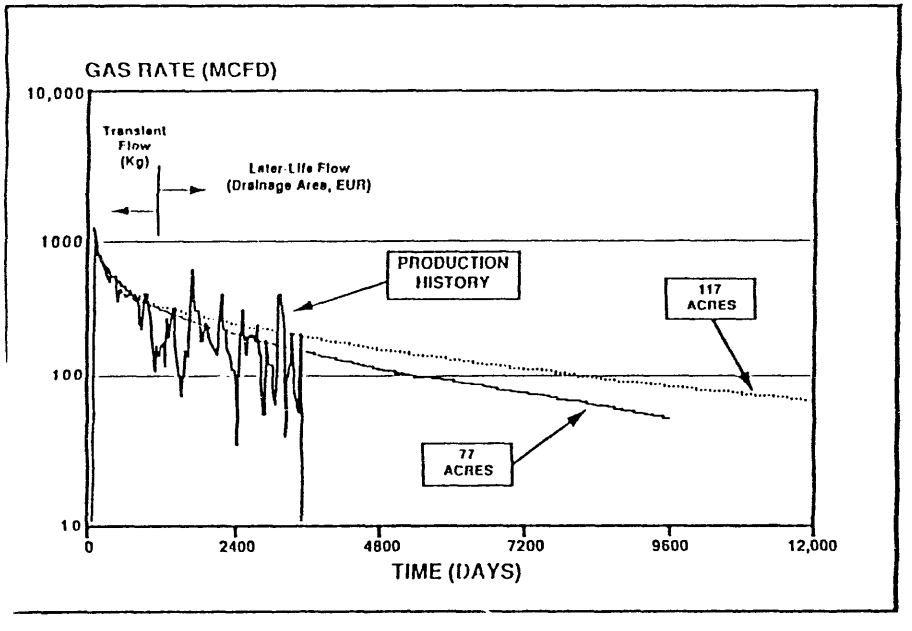
P = pore pressure = 0.58 psi/ft

C = constant = 0.04 psi/ft





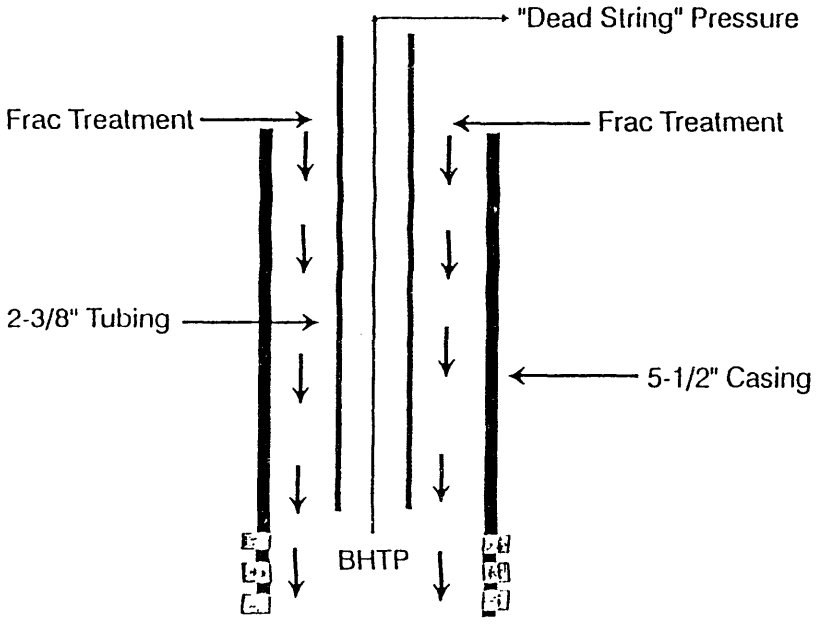




Frontier Fracture Treatments

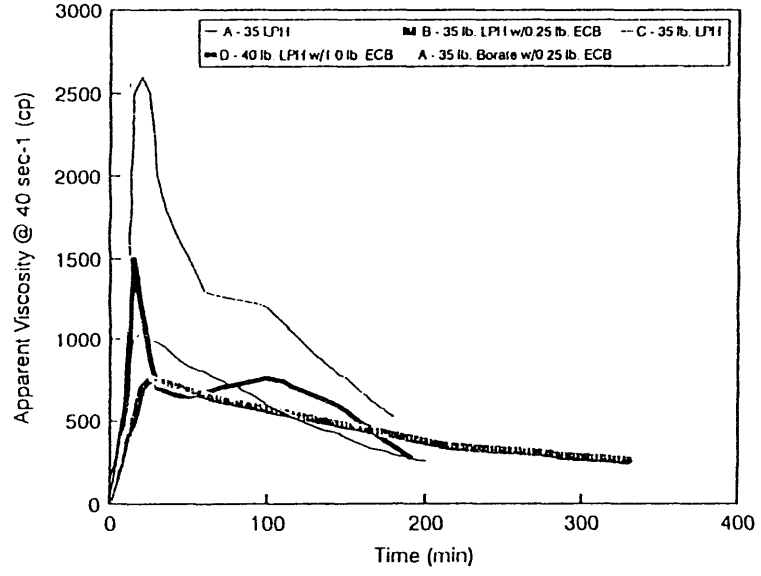
Moxa Arch 1992

- 36 "Dead Strings"
- 33 Mini-Fracs (20,000 gal)
- Water Mini-Fracs (8,000 gal)
- Borate Fluids
- Zr-CMHPG Low pH Fluids (LPH)



Fracture & Reservoir Modeling

- Direct Input of Treatment Data
- Field Confirmed Rheology
- Lithology Based/Measured Stress Profile
- Estimate Ct from Mini-fracs
- Match Complete Net Pressure History
- Model Post-Frac Production
- Identify Anomalous Behavior

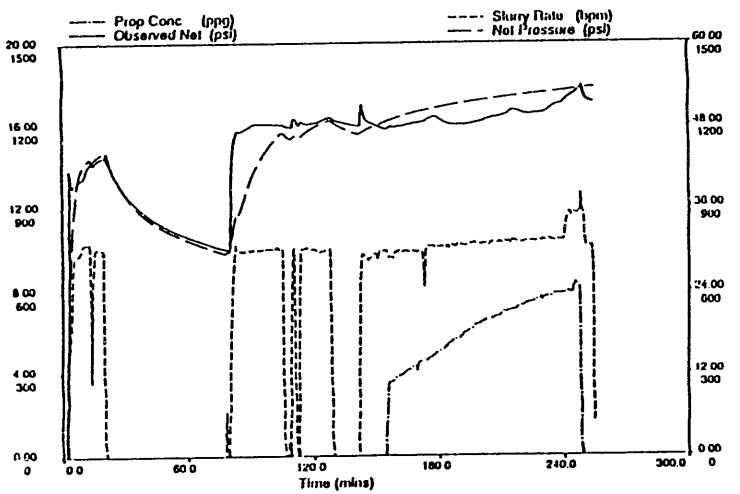


Temperature approx. 210 F

Bruff 285 I-3

- Well Test Permeability - 0.008 mD
- 190 Kgal Borate Fluid
- 590 Klbs Proppant
- 870 ft Hydraulic Length
- 700 ft Propped Length
- 1.4 ppsf Avg. Prop Concentration
- Ct = 0.00035 ft/min**1/2
- History Match Permeability - 0.0085 mD

BRUFF 285 I-3
NET PRESSURE MATCH

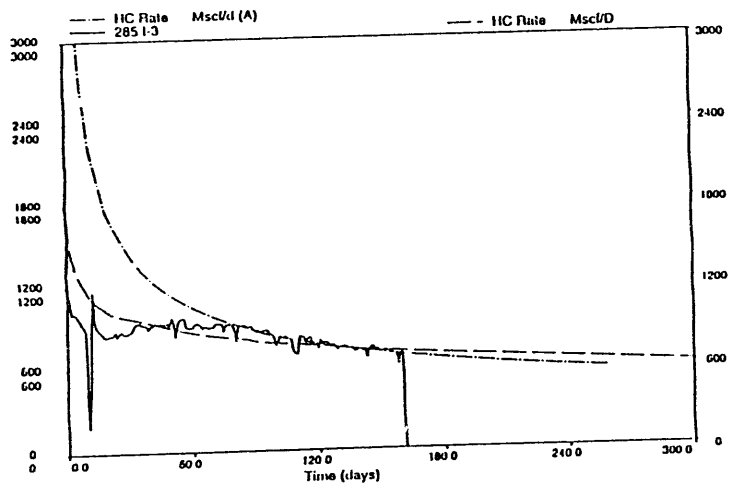


Bruff 285 I-3

Production Modeling

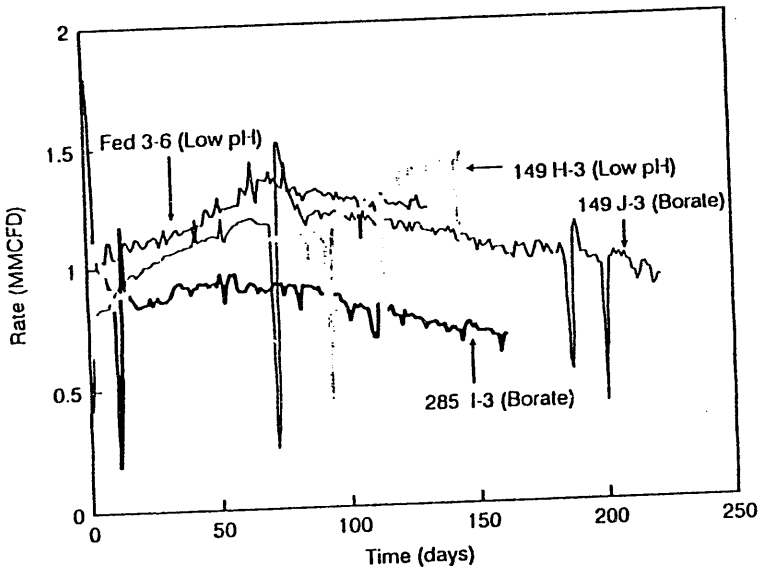
- Cleanup Effects Suppress Initial Rate
- Cleanup can be Modeled
- Well Test & Model Perm within 6%
- Cleanup Effects Insignficant After 90 Days

BRUFF 285 I-3
PRODUCTION HISTORY MATCH



Cleanup Effects

- Similar in Borate & LPH Treatments
- 30 to 90 Days Typical
- Probably Present in ALL Wells
- Can Result in Erroneous Conclusions based on Analysis of Initial Production



FRONTIER RESERVOIR PROPERTIES

MOXA ARCH AREA

	Average	Low	High
Pressure (psi)	6600	6150	7100
Depth (ft)	11800	11200	12100
Net Pay (ft)	30	10	70
Porosity (%)	10.7	8	14
Permeability (mD)	0.009	0.001	0.2
Drainage Area (ac)	160	70	640
EUR (BCF)	2.3	0.5	10

Fracture Modeling Summary

	Average	Min.	Max.
Lf (ft)	533	330	870
Lp (ft)	465	280	700
Prop. Con. (ppsf)	1.88	0.07	2.8
Ct (ft/min**1/2)	0.001	0.0002	0.0025

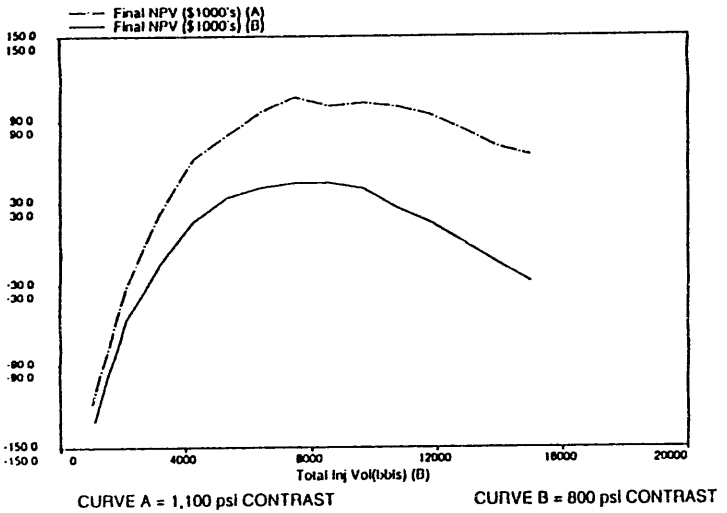
FRACTURE OPTIMIZATION

MOXA ARCH FRONTIER FORMATION

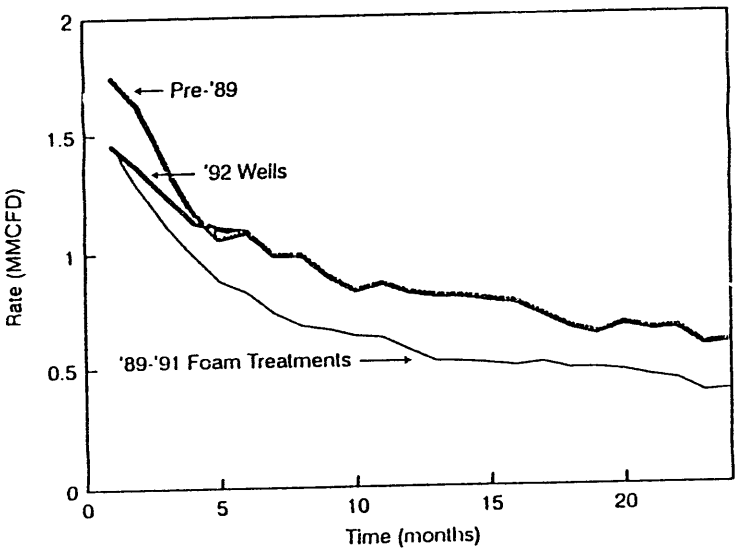
- Net Pay = 30 ft
- Porosity = 10%
- Sw=50%
- 160 acre Drainage
- Ct=0.001 ft/min**1/2
- 35% Pad, 3-8 ppg
- $750 K base Well Cost
- $30 K + $0.75/gal
- 15% Discount, 5% escalation

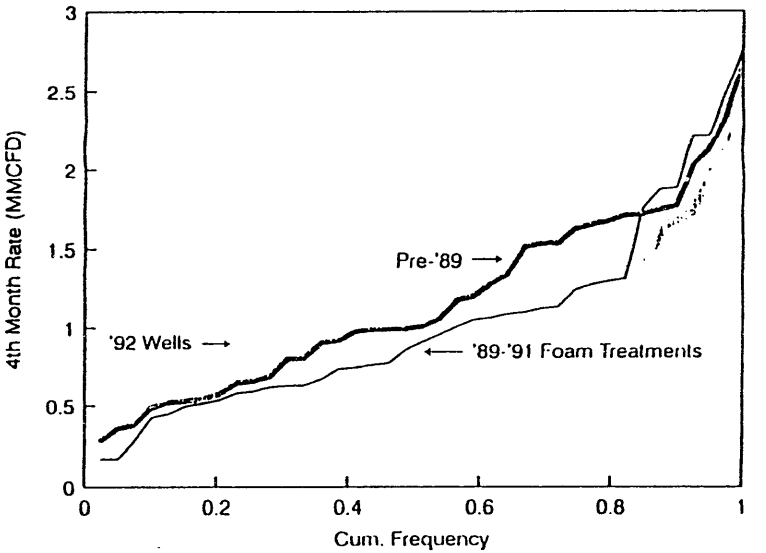
BASE DATA

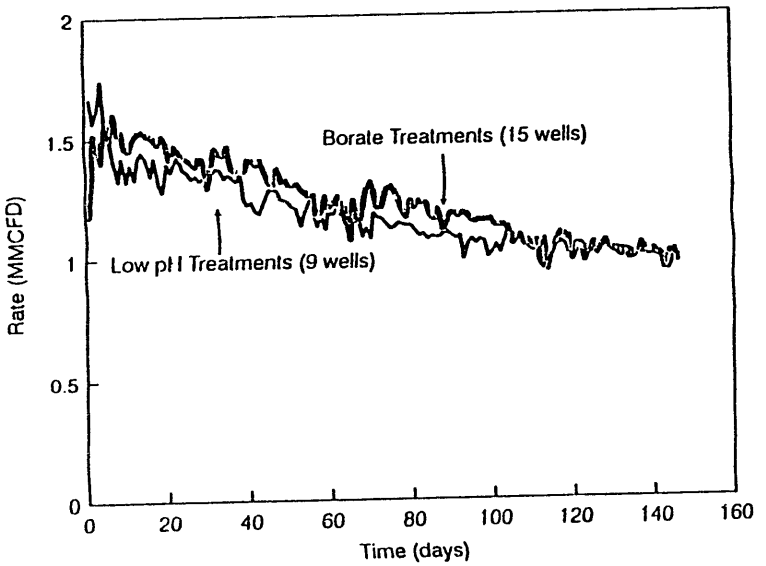
MOXA ARCH FRONTIER
FRACTURE OPTIMIZATION



	1975-85	1989-91	1992
Fluid Type	X-Link Gels	CO2 Foams	Borate/LPH
Proppant Type	Sand	ISP	Sand
Volume (Kgal)	210	180	170
Prop (Klbs)	450	440	560
Spacing (ac)	640	320	160







CONCLUSIONS

- Net Pressures Can Be Matched/Predicted Using 3D Modeling and Measured Stress Profiles
- Predicted Fracture Geometry & Conductivity from over 200 Wells is Consistent With Production Performance
- Water Based Fluids & Sand Proppants Provide Optimum Performance

CONCLUSIONS (cont)

- CO2 Foam Treatments were Inferior to X-Link Gels
- Borate & LPH Fluids Provide Similar Performance
- "Cleanup Effects" Suppress Initial Production and Last 30 to 90 Days
- Stress Profiles Are Not Constant & May be Influenced by Structural Location, Local Tectonics , and Deposition.

Notes

Development of an Economic Restimulation Program in a Near-Shore CarbonateReservoir

by Gene L. Gaz, Division Engineer, Bass Enterprises Production Co., Denver, CO

Mr. Gas is a 1973 graduate of the Colorado School of Mines with a B.S. in Petroleum Engineering. Prior to joining Bass Enterprises in 1978, Mr. Gas worked for Amoco Production Company.

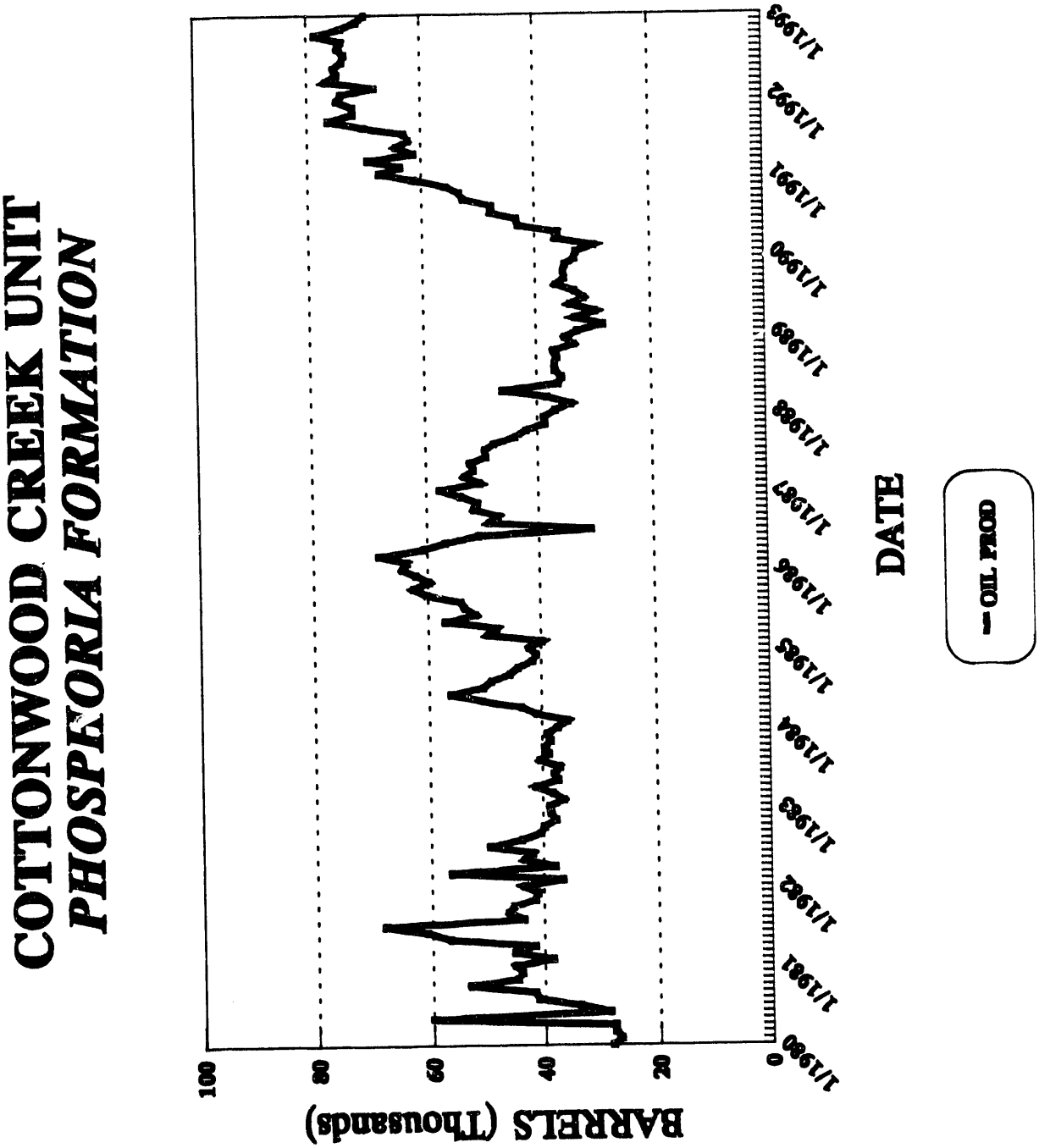
DEVELOPMENT OF AN ECONOMIC RESTIMULATION PROGRAM IN A NEAR-SHORE CARBONATE RESERVOIR

Just because a field was discovered in the 50's and has produced 36 million barrels of oil doesn't mean it's dead. The Cottonwood Creek Unit Phosphoria isn't dead, by any means. After being purchased by Bass Enterprises from Amoco Production in 1989, the oil production has increased from 34,000 BOPM to over 75,000 BOPM by applying a detailed technical approach to analyze past and present stimulation techniques. Restimulation using gelled water and emulsified acid as a fracturing fluid has proved to be very successful and the production responses have been predictable. The incremental recovery is 115,000 BO per well. Fifty-one wells have been restimulated to date.

The current stimulation technique consists of using 100,000 gals of gelled KCl water, 60,000 gals of emulsified acid and 10,000 gals of gelled acid in alternating stages, costing approximately $175,000. The emulsified acid is a mixture of 70%-28% HCl and 30%-#2 diesel. The purpose of the emulsified acid is to "retard" the acid reaction rate by a factor of 5, as compared to regular 28% HCL, which allows the acid to reach further down the created hydraulic fracture. The increased "etched" fracture half-length improves the productivity over the original treatments. The initial treatments range from 0'-300' of etched length, as compared to 500'-800' for the refracs. The fracture conductivity is usually increased from finite, which acts like a choke, to infinite in the refracs.

The Phosphoria dolomite is 95% soluble in acid. The formation porosity is 8-12%, the formation is oil wet and contains 27° API sour crude. The bottomhole temperature is 100-130°F at depths from 5,500' to 11,000'. The formation has high permeability streaks (2-20 md) surrounded by low permeability (.2 md) rather than a natural fracture system as previously published. The oil viscosity is 6 cp, which relates to a low fluid transmissibility. The average reservoir pressure is near the bubble point of 1,100 psi. However, the near wellbore producing pressure is 50 psi. This very low near-wellbore pressure requires the use of viscous gelled water to control increased leak-off due to increased fluid compressibility. The viscosity of the fracturing fluid is the mechanism that controls leak-off in acid fracturing rather than the wall building coefficient used in sand fracturing. Excessive leak-off in an acid fracture tratment creates short conductive fracs that may not achieve the needed economics.

Iterative production history matching, using a black oil reservoir simulator and an acid reaction model, allows for the comparison of prior stimulations to proposed restimulations. The purpose of the modeling is to iterate on formation permeability and fracture length. Reservior modeling has proven to be a good predictive tool in estimating the anticipated production response and in determining stimulation candidates.


COTTONWOOD CREEK UNIT
PHOSPHORIA FORMATION
BARRELS (Thousands)
100
80
60
40
20
0
1/1/80
1/1/81
1/1/82
1/1/83
1/1/84
1/1/85
1/1/86
1/1/87
1/1/88
1/1/89
1/1/90
1/1/91
1/1/92
1/1/93
DATE
OIL PROD

PERTINENT DATA SHEET
COTTONWOOD CREEK PHOSPHORIA

Formation Data

Producing Formation	Phosphoria
Geologic Age	Permian
Depth, ft	9750
Subsea Datum, ft	-5264
Net Pay, ft	55
Porosity, %	8
Connate Water Saturation, %	10
Reservoir Temperature, ^{o}F	104

Reservoir Fluid Data

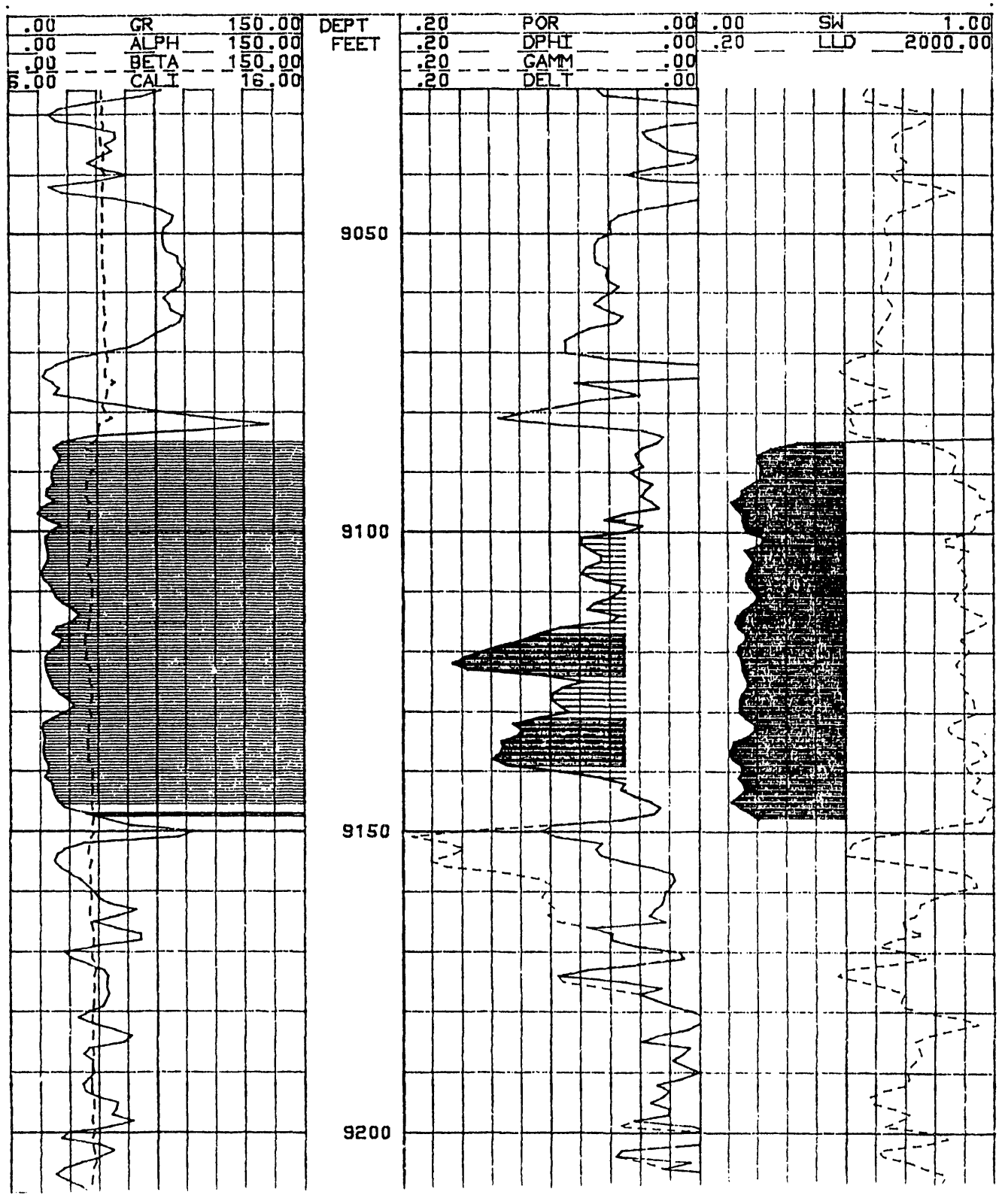
Original Reservoir Pressure, psi	3608
Original Bubble Point Pressure, psi	1126
Formation Volume Factor, rb/stb	
at 2225 psi	1.14
at Bubble Point	1.15
Solution GOR, scf/stb	313
Oil Gravity, ^{o}API	26.6
Viscosity at Bubble Point, cp	4.75

Typical Restimulation

Stage 1: 20,000 gal YF235
Stage 2: 10,000 gal DGA 328
Stage 3: 20,000 gal YF235
Stage 4: 20,000 gal SXE
Stage 5: 20,000 gal YF235
Stage 6: 20,000 gal SXE
Stage 7: 20,000 gal YF235
Stage 8: 20,000 gal SXE
Stage 9: 20,000 gal Yf235
Displace with Kcl flush

COTTONWOOD CREEK
HISTORY MATCH SUMMARY

Well	h_{Net}	$h_{high\ k}$	$k_{high\ k}$	h_{Phos}	Depth	Initial Frac		Refracture	
Name	(ft)	(ft)	(md)	(ft)	(ft)	X_f (ft)	k_fw (md ft)	X_f (ft)	k_fw (md ft)
CCU 161	38	10	5	80	9100	300	500	900	1000
CCU 165	50	7	1	96	10210	260	500	950	3000
CCU 180	33	8	2	102	8810	260	500	700	3000
CCU 182	45	10	20	114	8760	240	1000	800	4000
CCU 183	50	20	7	100	10275	260	50	800	6000
CCU 54	27	10	2	82	8908	320	300	850	1500
CCU 167	32	20	2	90	8613	250	200	1320	600
CCU 185	55	6	7	90	9070	-----	----	680	50
CCU 190	50	5	2	102	9835	250	40	550	50


WELL NAME: 161 CCU (47910913)
.00 GR 150.00
.00 ALPH 150.00
.00 BETA 150.00
6.00 CALI 16.00
DEPT
FEET
.20 POR .00
.20 DPHI .00
.20 GAMM .00
.20 DELT .00
.00 SW 1.00
.20 LLD 2000.00
9050
9100
9150
9200

TREATMENT SUMMARY
CCU #161

INITIAL TREATMENT: (12/28/84)

FLUID	VOL(gal)	RATE(BPM)
40# XLink Gel	5000	14.00
28% Gelled HCl	9000	14.00
40# XLink Gel	5000	18.00
28% Gelled HCl	9000	24.00
40# XLink Gel	5000	25.00
28% Gelled HCl	8000	15.00
40# Linear Gel	2000	25.00

REFRACTURE TREATMENT: (10/5/90)

FLUID	VOL(gal)	RATE(BPM)
WF225	50,000	20.00
SXE	25,000	20.00
WF225	25,000	20.00
SXE	25,000	20.00
WF225	20,000	20.00
SXE	29,400	20.00
WF225	25,000	20.00

Note: Rheology of WF225 measured on location: n'=0.55, k'=0.006.
Fluid temperatures: 60°F.

Fundamental of Acidization Process

* **Mass Transfer Limited:**

  Assume acid-reaction rate at the surface is much faster than the mass transfer rate

$$Cs = 0.0$$

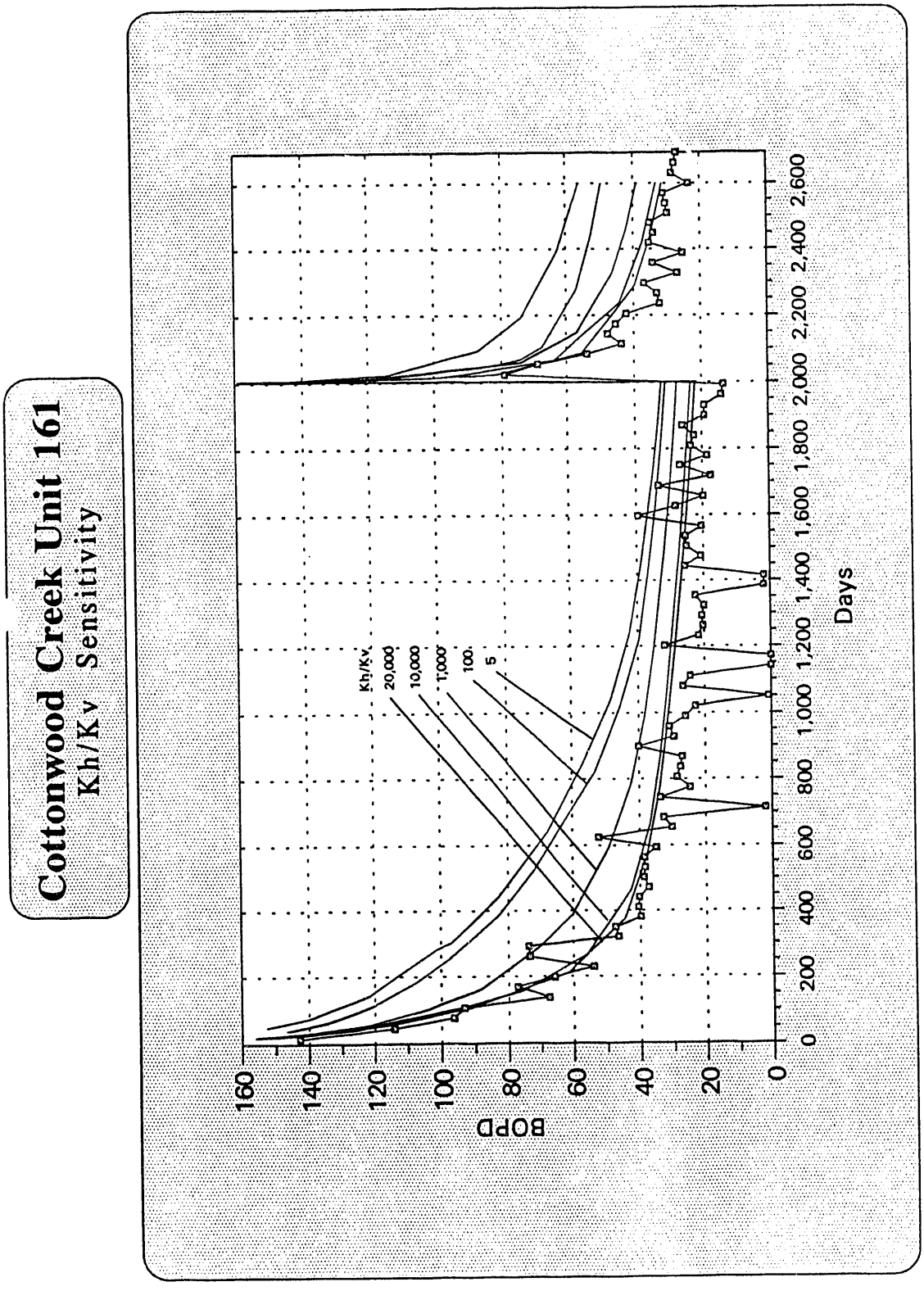
* **Reaction Rate Limited**

  Assume the mass transfer is much faster than the acid-reaction

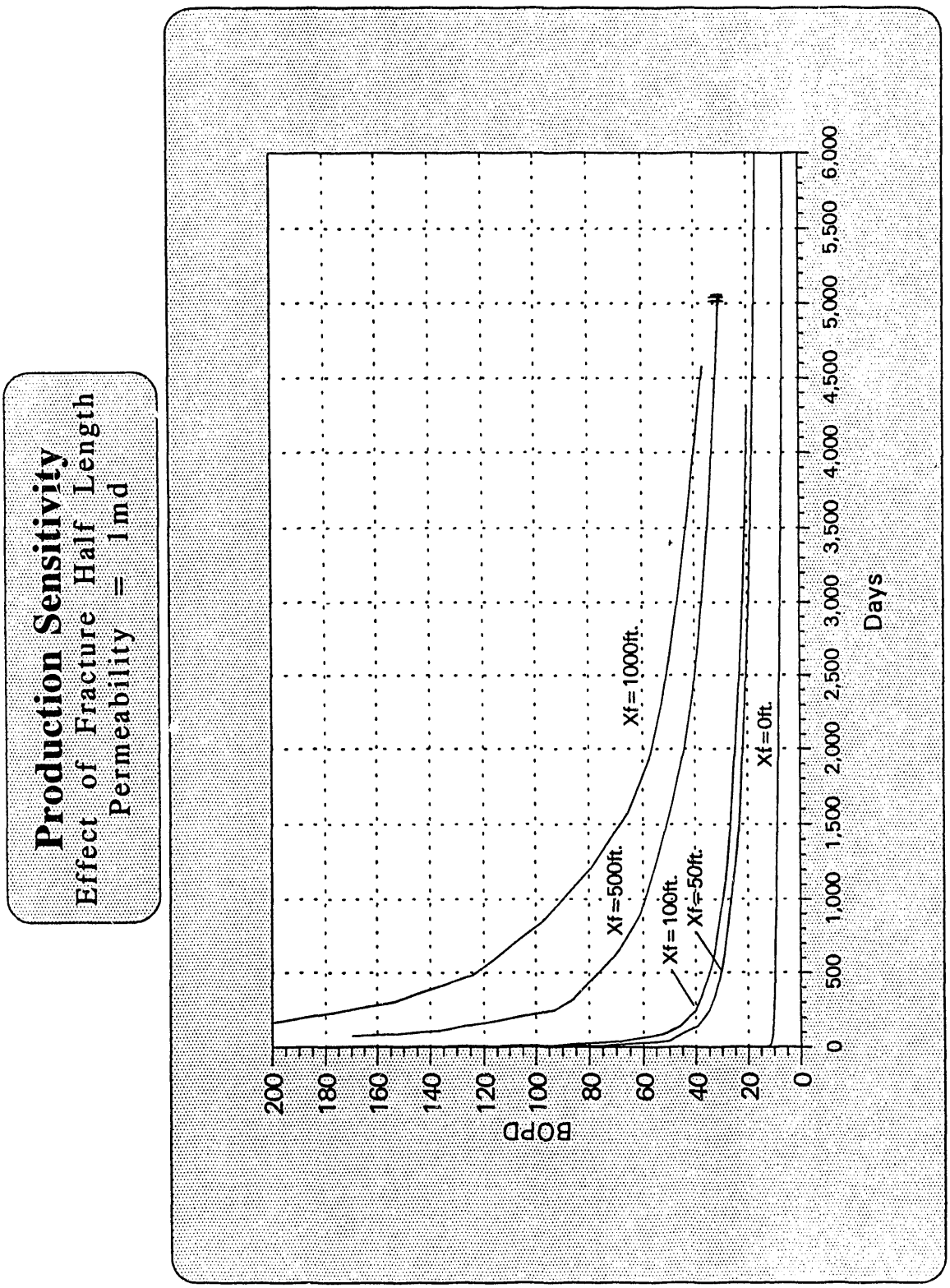
$$De = \infty$$

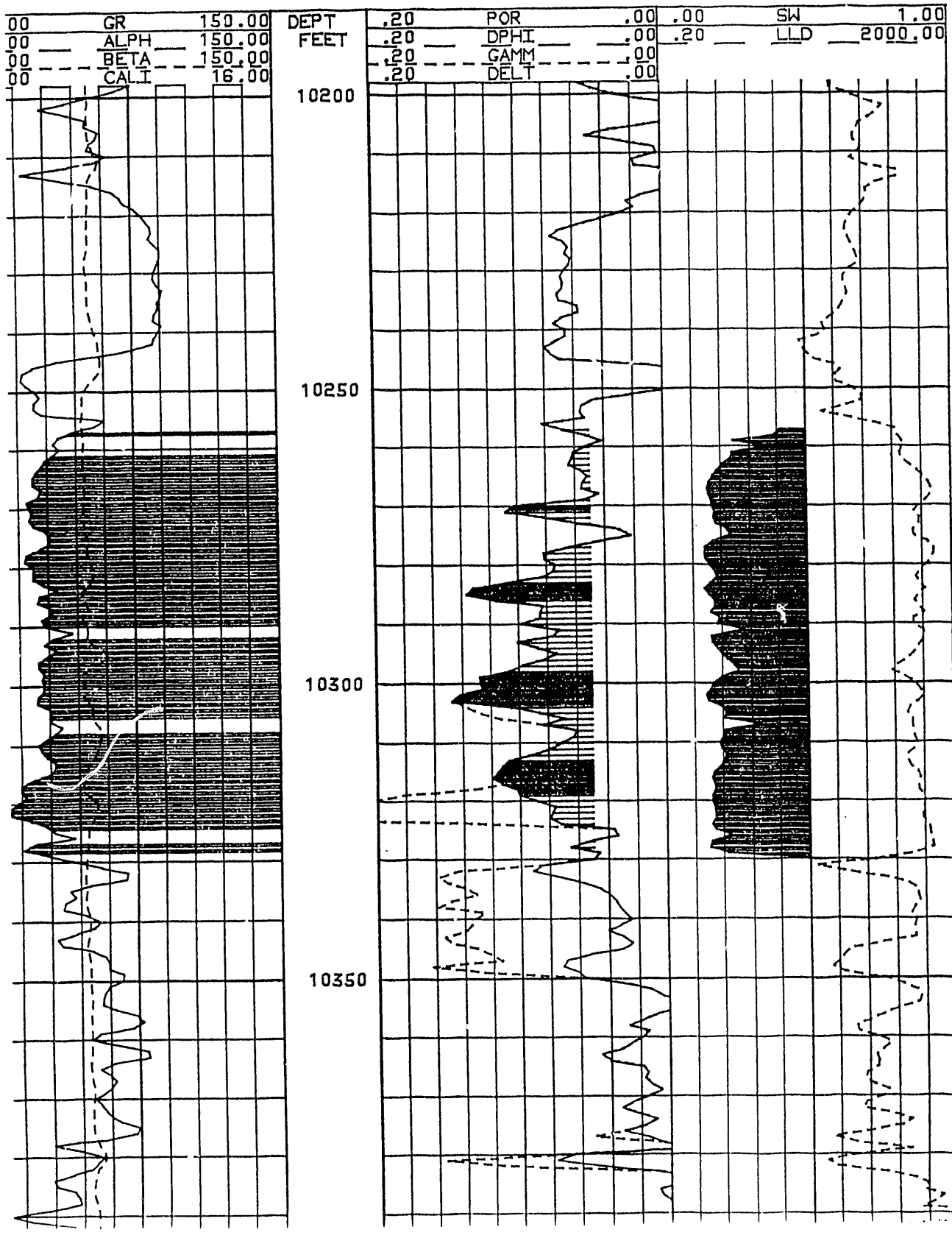
* **Consider Both Reaction and Mass Transfer**

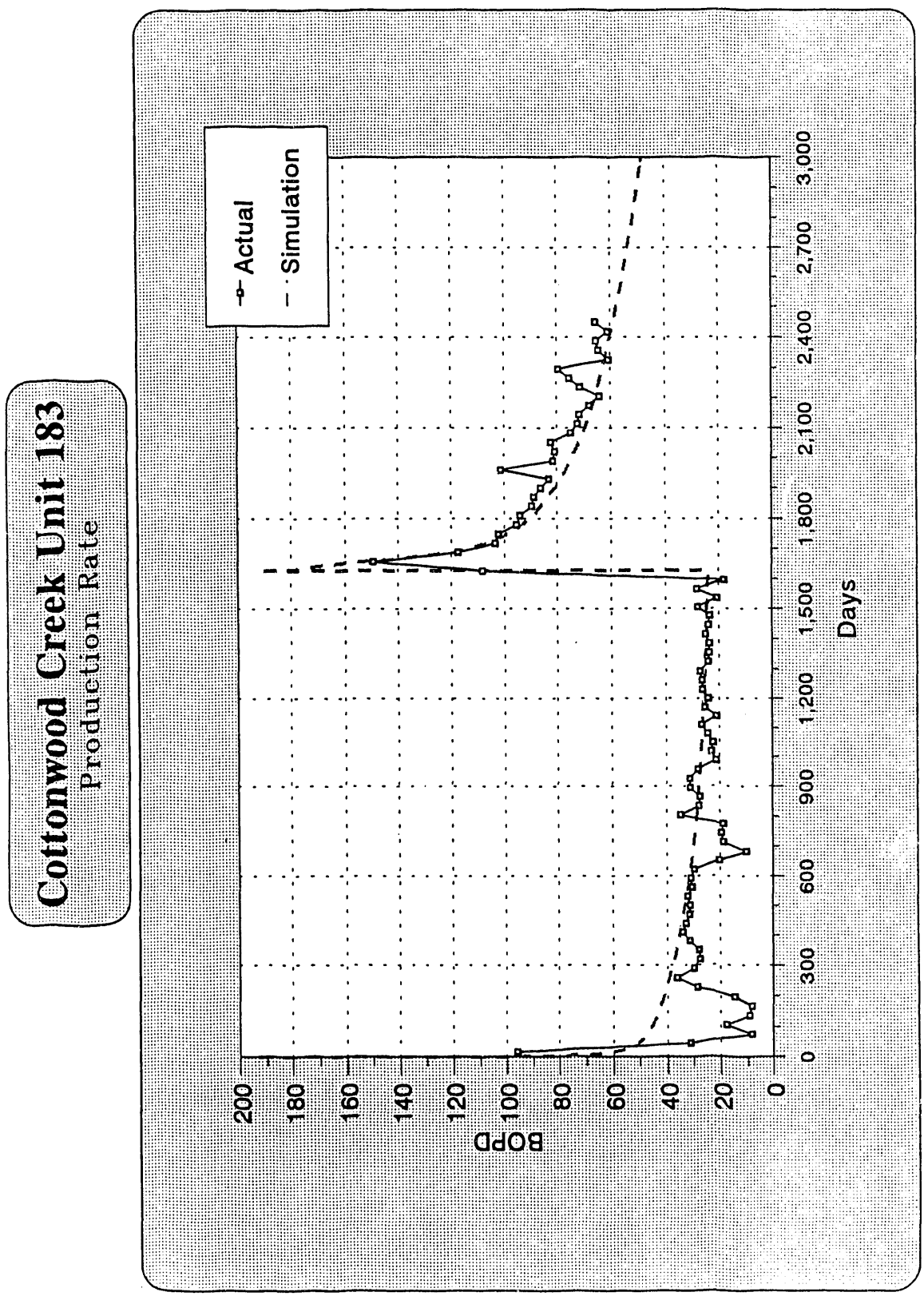
$$Kmt\ (Cb - Cs) = KCs^{n}$$



Four Layer Model, High Perm = 10.0 md, Low Perm = 0.2 md
FRAC1 200 ft (1000 md ft), FRAC2 400 ft (50000 md ft) Pr = 3101psi


Production Sensitivity
Effect of Fracture Half Length
Permeability = 1 md
BOPD
Days
Xf = 1000ft.
Xf = 500ft.
Xf = 100ft.
Xf = 50ft.
Xf = 0ft.
Pr = 1600 psi, 160 Acres, h = 72 ft


LL NAME: 183 CCU (47911711)
00 GR 150.00
00 ALPH 150.00
00 BETA 150.00
00 CALI 16.00
DEPT
FEET
10200
10250
10300
10350
.20 POR .00
.20 DPHI .00
.20 GAMM .00
.20 DELT .00
.00 SW 1.00
.20 LLD 2000.00



Four Layer Model, High Perm=7.0 md, Low Perm=0.2 md
FRAC1 260 ft (50 md ft), FRAC2 800 ft (From Profile) Pr=1600 psi

A CASE STUDY OF LARGE-VOLUME, HIGH-RATE STIMULATION TREATMENTS PERFORMED IN HORIZONTAL WELLS IN THE NIOBRARA FORMATION, SILO FIELD, LARAMIE COUNTY, WYOMING

Ted D. Brown, Union Pacific Resources Company
Ray Johnson, Jr., BJ Services Company, USA

This presentation is based on SPE 25920, Copyright 1993, Society of Petroleum Engineers, Richardson, TX, Presented at the 1993 Rocky Mountain Regional Meeting/Low Permeability Reservoirs Symposium of SPE, April 26-28, 1993, Denver, CO.

ABSTRACT

In 1991, Union Pacific Resources Company (UPRC) stimulated four horizontal wells in the Niobrara Formation in the Silo field, Laramie County, Wyoming. Stimulation treatments were required due to the rapid production declines seen early in the life of these wells, which were completed in 1990 and 1991. Horizontal and vertical wells in the Austin Chalk formation have been stimulated by injecting large volumes of water (10,000-30,000 bbls) at high rates (50-220 bbl/min) to improve productivity. This stimulation technique was applied in the Silo field because the Austin Chalk and Niobrara reservoirs have similar features; the most important similarity is that productivity requires connection to an adequate natural fracture system. These Niobrara stimulation treatments consisted of 30,000 bbls of water pumped at rates up to 150 bbl/min with wax beads as diverting material.

This presentation describes the job designs, bottom-hole treating pressure (BHTP) trends observed during the job, and post-treatment well production. Early BHTP responses and post-treatment production are related to the extent of natural fracturing exposed within the horizontal (lateral) sections. The lack of sustained productivity after the treatments indicates that Niobrara wells respond differently than Austin Chalk wells after large-volume, high-rate treatments. The most likely explanation for this difference is that fractures opened during Niobrara large-volume, high-rate treatments either close during production or do not provide sustainable connectivity to high-conductivity fractures. Future treatment strategies are discussed concerning fluid selection and the use of diverting materials and proppants.

REFERENCES

1. Pierson, N., Hubbard, D: "New fracture stimulation treatment yields positive results in Austin Chalk," Oil & Gas Journal (September , 1986).

2. Personal conversations: Chuck Price, UPRC, LaGrange, TX, and Clarence Cheatham, Redwood Energy, Giddings, TX

3. Dees, J.M., Freet, T.G., and Hollabaugh, G.S.: "Horizontal Well Stimulation Results in the Austin Chalk Formation, Pearsall Field, Texas," paper SPE 20683 presented at the 65th Annual Technical Conference and Exhibition of SPE, New Orleans, LA, September 23-26, 1990.

4. Meehan, D.N.: "Stimulation Results in the Giddings (Austin Chalk) Field," paper SPE 24783 presented at the 67th Annual Technical Conference and Exhibition of SPE, Washington, DC, October, 1992.

5. Overby, W., Yost, A, and Wilkins, D.: "Inducing Multiple Hydraulic Fractures From a Horizontal Wellbore," paper SPE 18249 presented at the 63rd Annual Technical Conference and Exhibition of SPE, Houston, TX, Oct. 2-5, 1988.

6. Cramer, D. "Guides exist for fracture treatment in horizontal wells," Oil & Gas Journal (March 27, 1989) 41-52.

7. Cramer, D.: "Treating Pressure Analysis in the Bakken Formation," paper SPE 21820, presented at the 1991 Rocky Mountain Regional Meeting and Low Permeability Reservoirs Symposium held in Denver ,CO, April 15-17, 1991.

8. Warpinski, N., "Dual Leakoff Behavior in Hydraulic Fracturing of Tight, Lenticular Gas Sands," paper SPE 18259 presented at the 63rd Annual Technical Conference and Exhibition of SPE, Houston, TX, Oct. 2-5, 1983.

PRESENTERS

Ted D. Brown, Union Pacific Resources Company

Ted is a 1977 graduate of the University of Wyoming, with a B.S. in Mechanical Engineering. His past 15 years of experience includes drilling, completion, and production operations as well as property acquisition analysis in the Rocky Mountain and Mid-Continent regions. Mr. Brown is currently assigned to UPRC's DJ basin operations and is responsible for recommending area-wide development opportunities in addition to evaluating and overseeing completion and production operations. Ted's primary focus in recent years has been in horizontal completion and production techniques within the Silo field of southeastern Wyoming.

Ray Johnson, Jr., BJ Services Company, USA

Ray is a 1980 graduate of Texas A&M University, with a B.A. in Chemistry. He is currently employed as the Region Engineer for BJ Services in Denver, CO. Mr. Johnson has over 12 years experience in primary and remedial cementing and stimulation design and post-job evaluation in the Rocky Mountain, Central/East Texas, and Mid-Continent regions. Ray has designed and evaluated stimulation treatments in many of the reservoirs presently targeted by horizontal drilling technology including the Ratcliffe, Austin Chalk, Mississippi, and Niobrara formations.

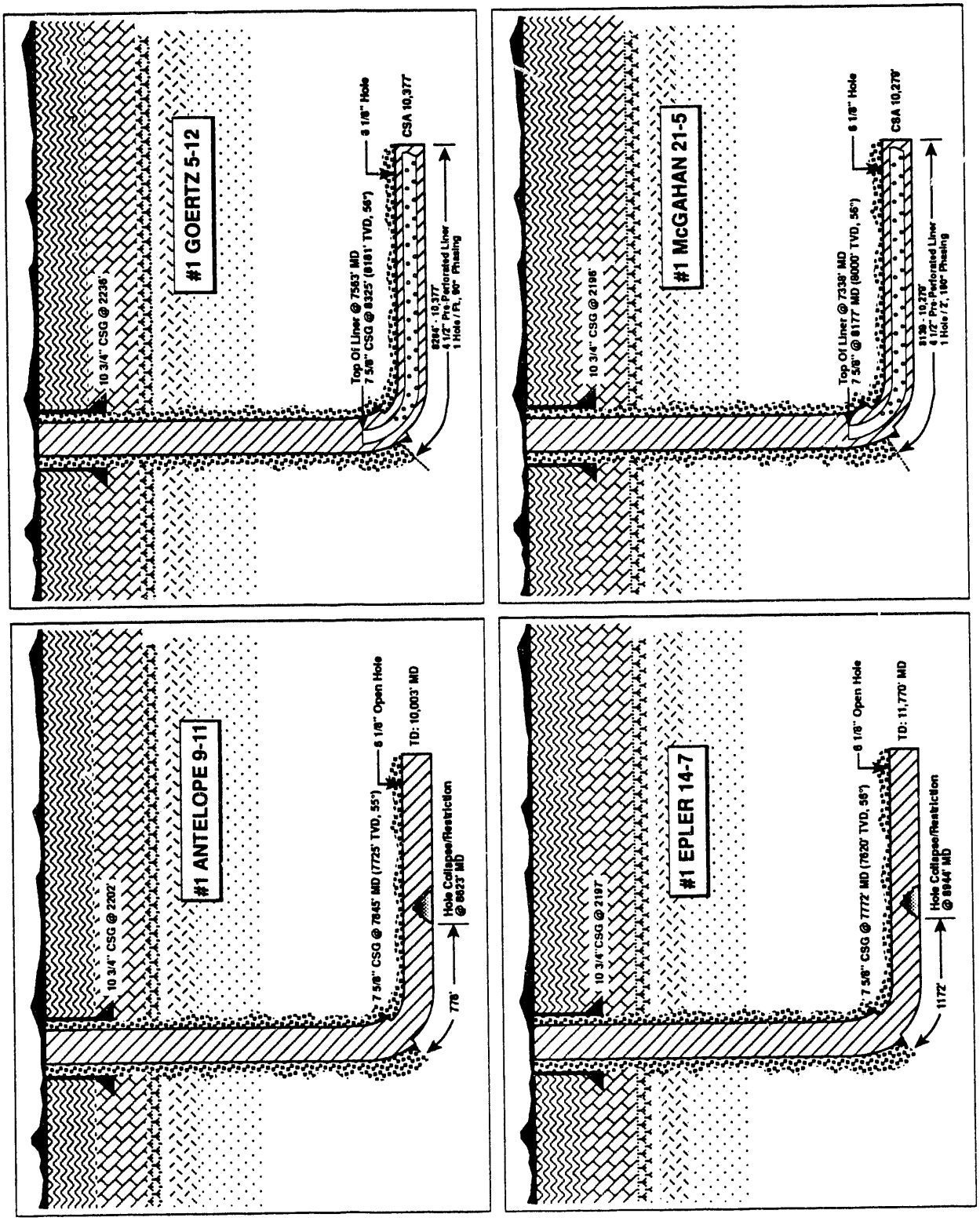


Figure 1 - Wellbore Schematics

TABLE 1 - TREATMENT PUMPING SCHEDULES

STAGE DESCRIPTION	#1 McGAHAN 21-5			#1 EPLER 14-7			#1 GOERTZ 5-12			#1 ANTELOPE 9-11		
	FLUID (BBLS)	DIVERTER CONC. (PPG)	DIVERTER TOTAL (LBS)	FLUID (BBLS)	DIVERTER CONC. (PPG)	DIVERTER TOTAL (LBS)	FLUID (BBLS)	DIVERTER CONC. (PPG)	DIVERTER TOTAL (LBS)	FLUID (BBLS)	DIVERTER CONC. (PPG)	DIVERTER TOTAL (LBS)
SLICKWATER	5000			5000			5000			5000		
DIVERTER	190	0.25	2000	190	0.25	2000	190	0.25	2000	190	0.25	2000
SLICKWATER	500			500			500			500		
SLICKWATER	5000			5000			3000			3000		
DIVERTER	190	0.5	4000	190	0.25	2000	95	0.5	2000	126	0.75	4000
SLICKWATER	500			500			500			500		
SLICKWATER	5000			5000			5000			3000		
DIVERTER	190	0.5	4000	95	0.5	4000	126	0.75	4000	32	1.5	2000
SLICKWATER	500			500			500			500		
SLICKWATER	5000			5000			7750			7000		
DIVERTER	96	0.75	4000	48	1	2000	38	1.25	2000	24	3	3000
SLICKWATER	500			500			500			500		
SLICKWATER	3800			7477			6801			5000		
DIVERTER	114	0.84	4000							30	3	3800
SLICKWATER	500									600		
SLICKWATER	3351									4793		
TOTALS:	**30431**		**18000**	**30000**		**10000**	**30000**		**10000**	**30795**		**14800**

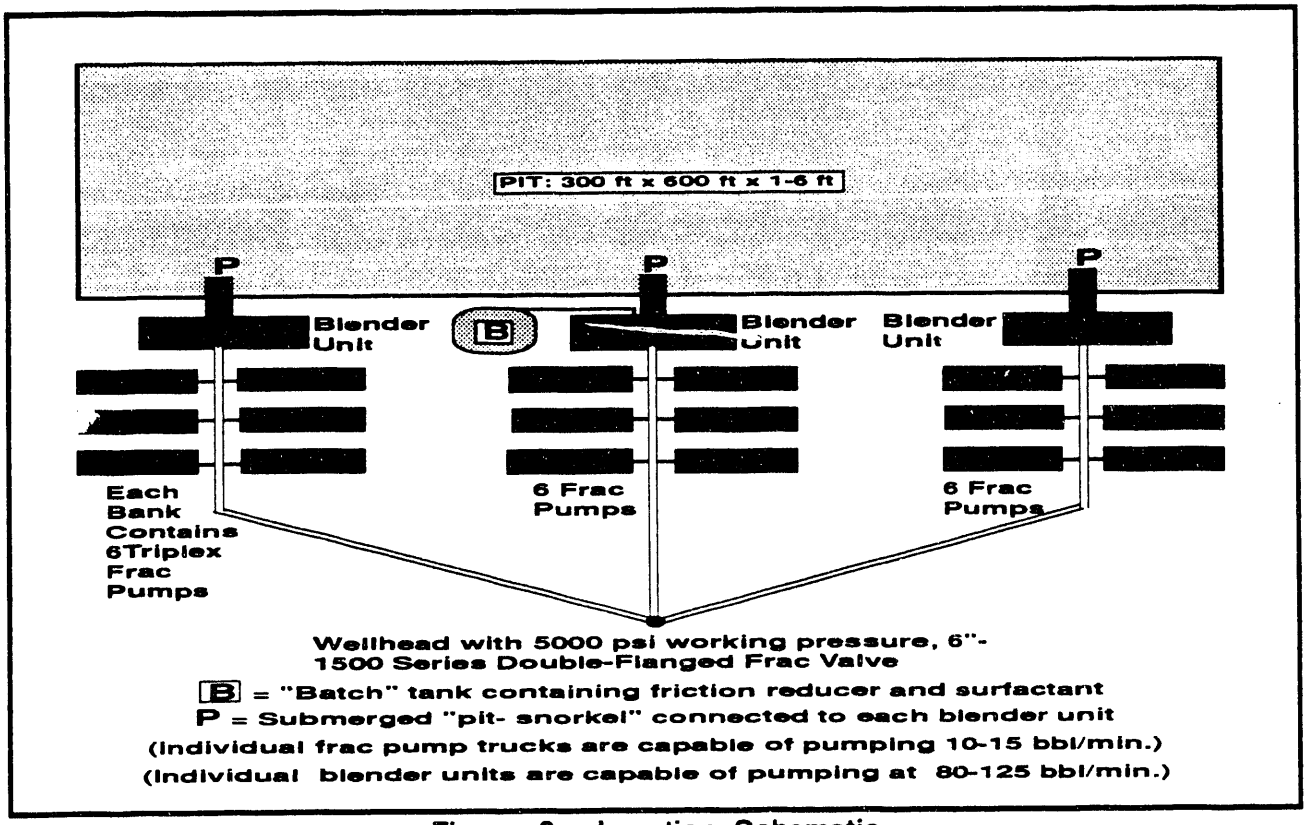


Figure 2 - Location Schematic

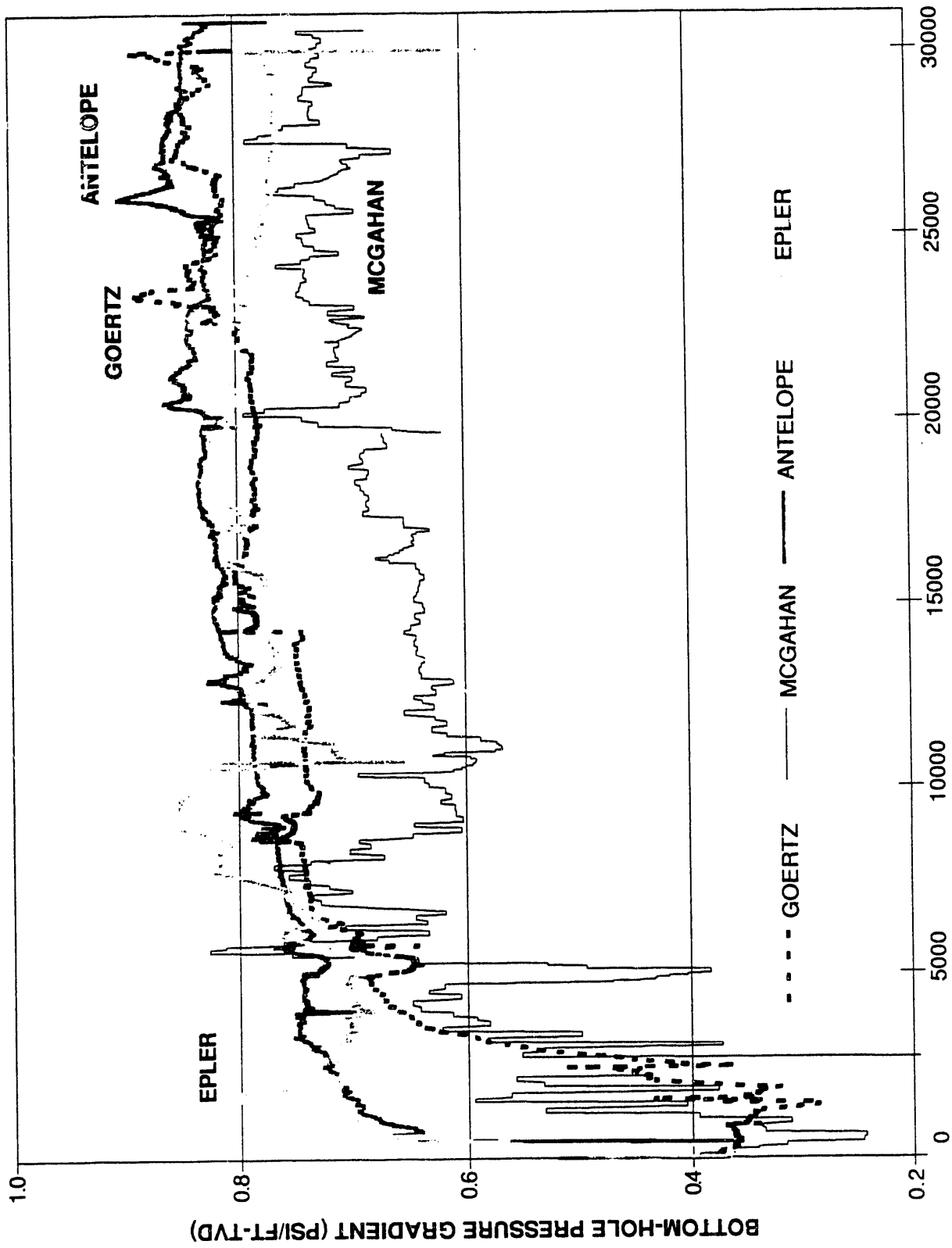


Figure 3 - Bottom-Hole Pressure Gradient (BHPG) Versus Volume

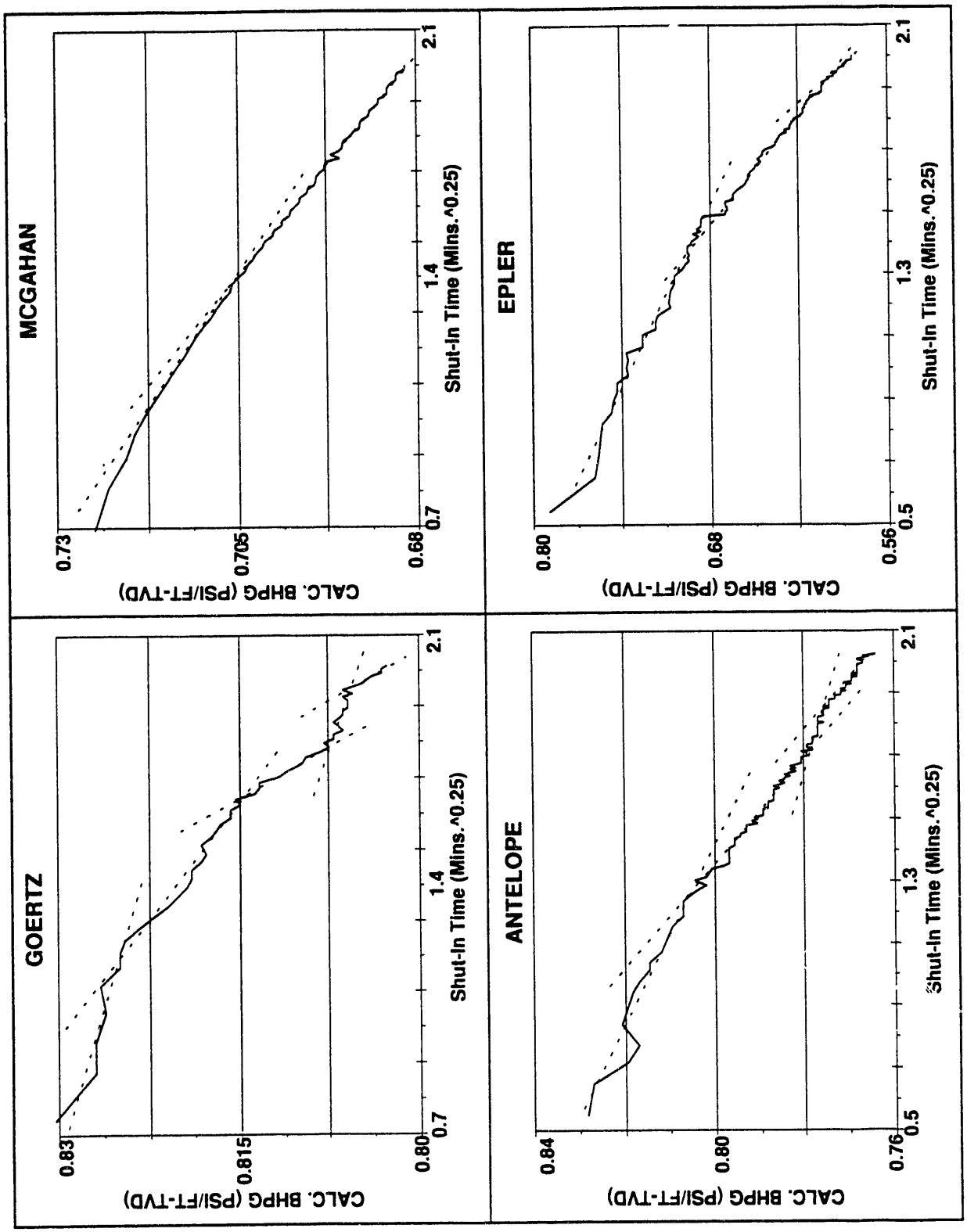


Figure 4 - BHPG Versus Shut-In Time

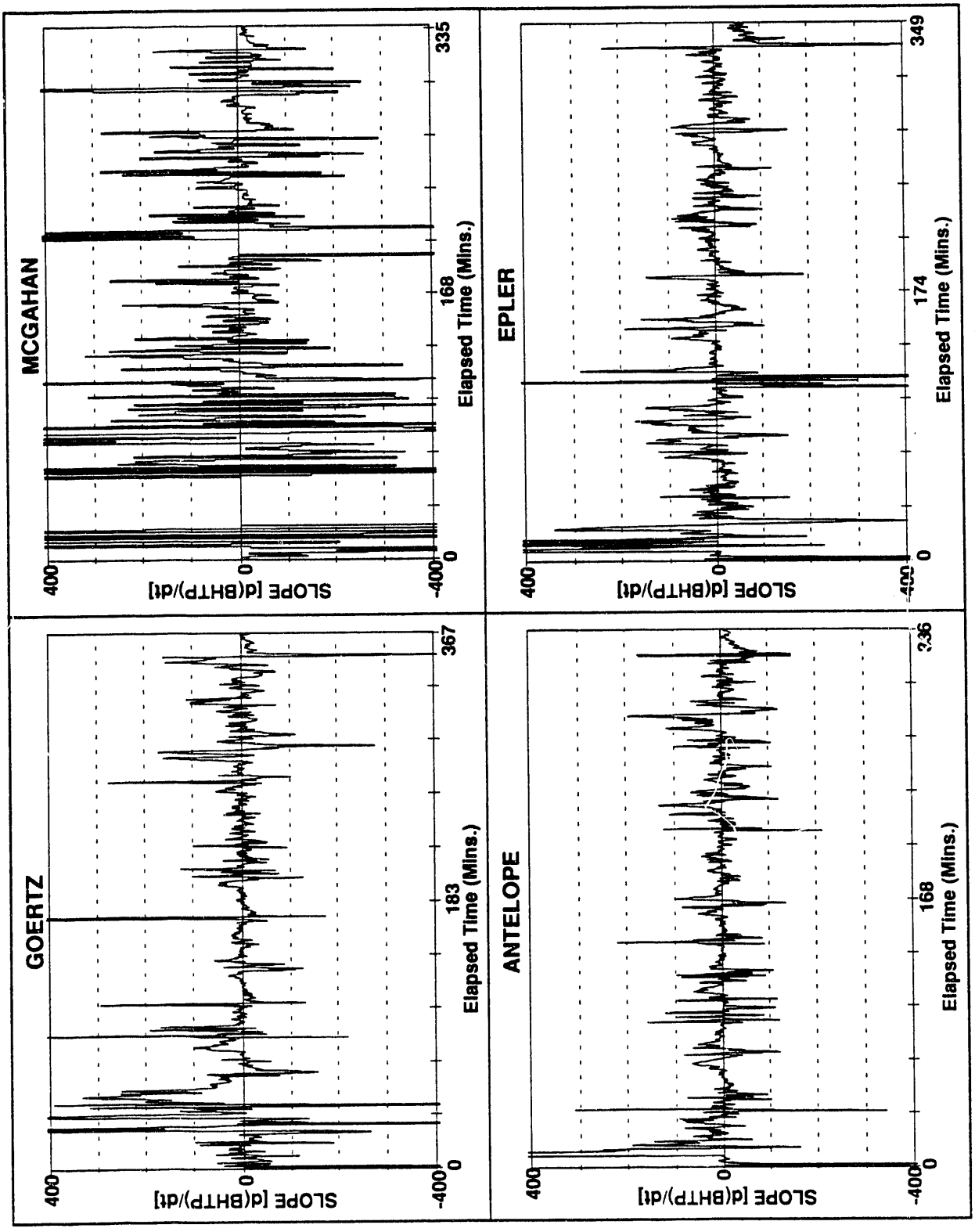


Figure 5 - Slope BHTP (dBHTP/dt) Versus Elapsed Time

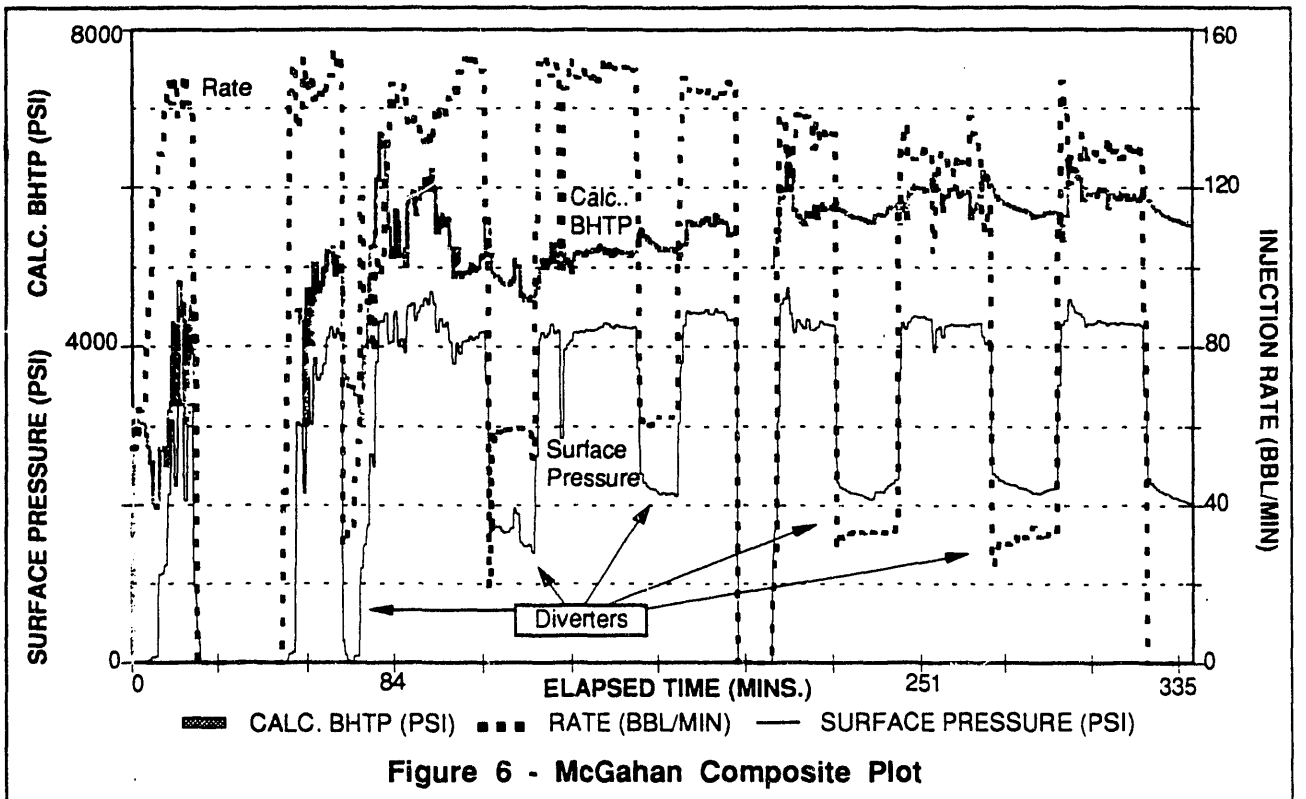


Figure 6 - McGahan Composite Plot

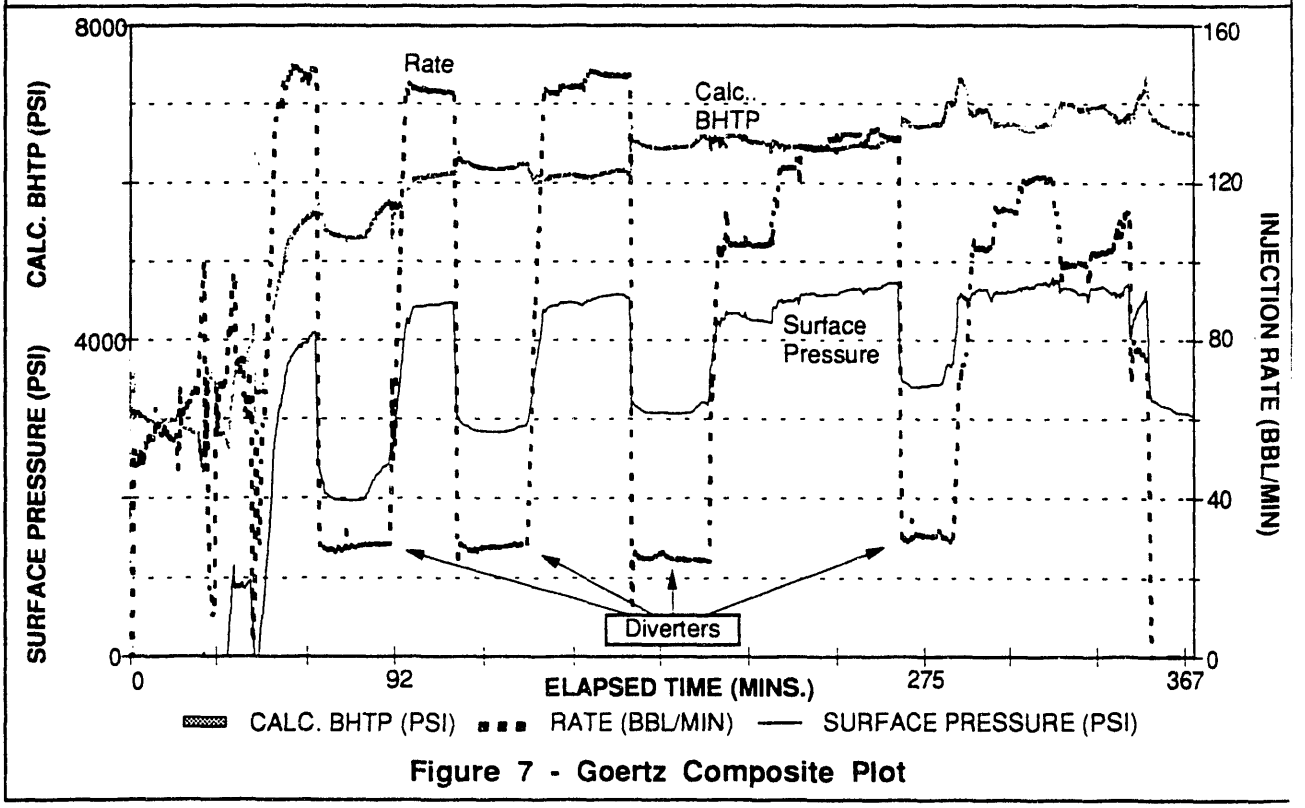


Figure 7 - Goertz Composite Plot

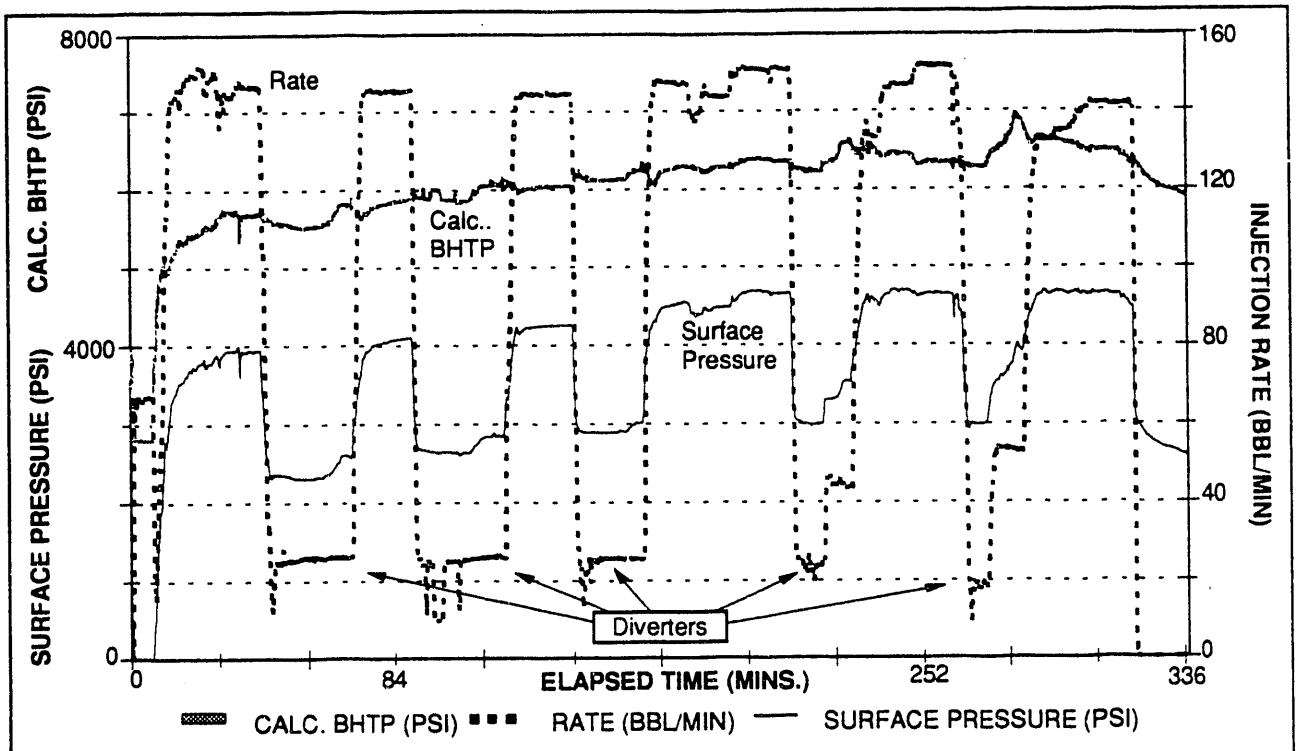


Figure 8 - Antelope Composite Plot

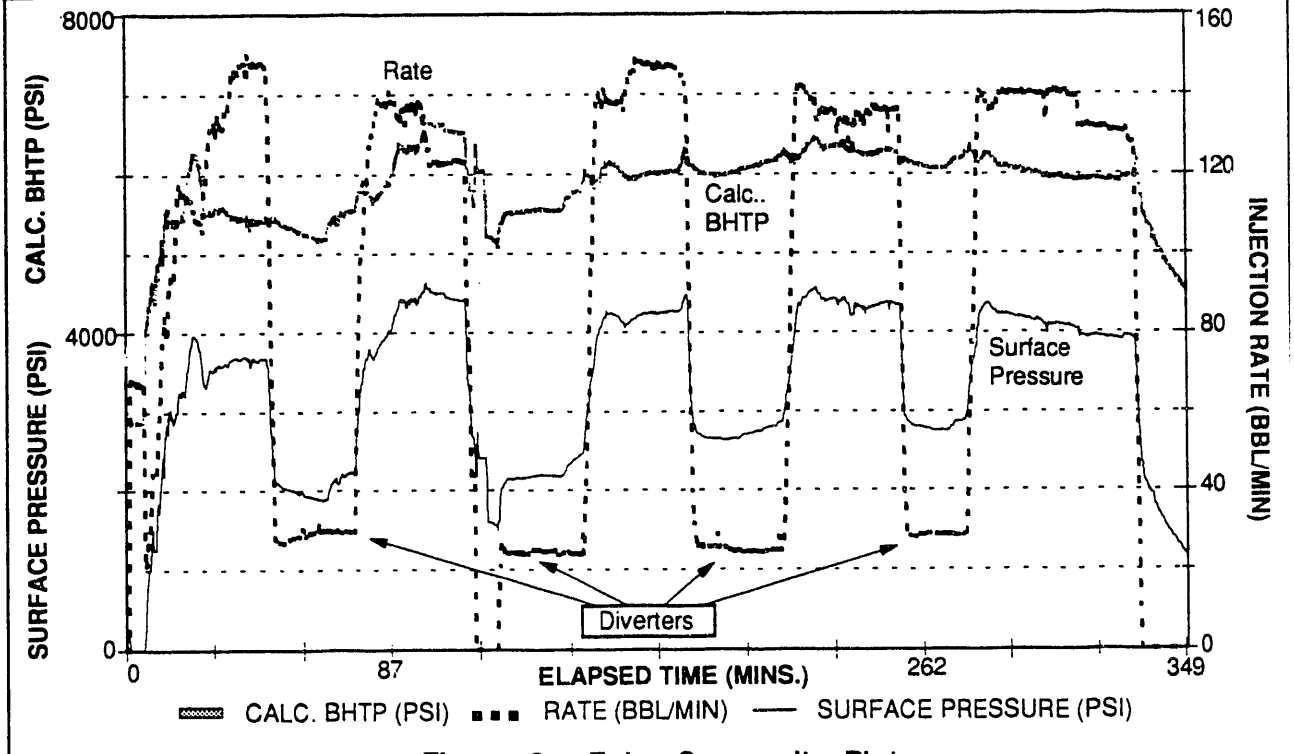


Figure 9 - Epler Composite Plot

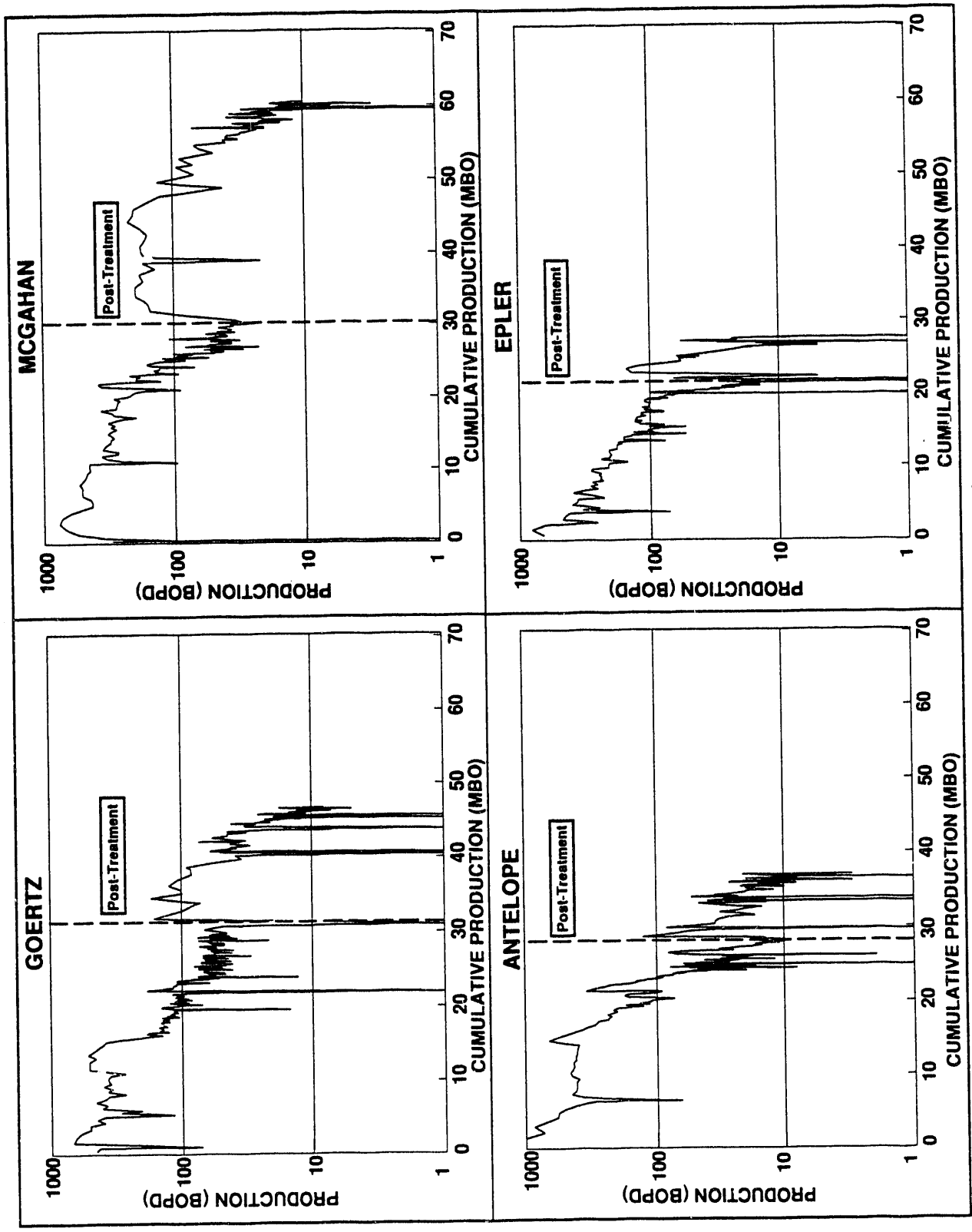


Figure 10 - Production Plots

Coiled Tubing Technology

by Marshall Adkins, Maurer Engineering, Houston, TX

Mr. Adkins will distribute additional material at the session

Coiled-Tubing Technology

The use of coiled-tubing technology has dramatically increased since its introduction to the oil field in the 1960s. The industry's use of and interest in coiled tubing can be gauged by charting the number of articles describing coiled-tubing technology published in recent decades (Figure 1).

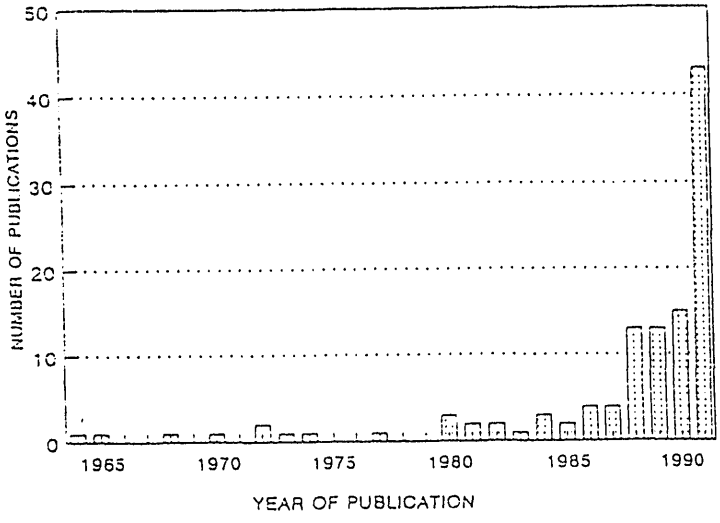


Figure 1. Coiled-Tubing Publications

This sam ling of the literature shows that interest in coiled-tubing technology remained relatively flat from the 1960s to the early 1980s and thereafter increased significantly, with over 40 articles published in 1991 alone. This profile reflects the significant advances in tubing reliability and increased equipment availability and versatility which transformed the field in the early 1980s.

Coiled-tubing rigs have found widespread use worldwide for drilling, completion, and workover operations. In many areas, coiled tubing rigs can reduce costs by 50 to 70% as compared to conventional workovers due to reduced rig costs and reduced time to perform operations. The use of coiled-tubing rigs will expand greatly in the near future due to the development of larger coiled tubing (i.e., up to 3½-inch) and advanced downhole tools (e.g., horizontal drilling tools).

Coiled tubing will also play an important role in the upcoming slim-hole trend. The ability to cost effectively workover wells with 3½ inch and smaller casing will depend upon the ability of coiled tubing to perform any needed workover operation. This talk will briefly review the history of coiled tubing and address a few of the more popular applications for coiled tubing.

Maurer Engineering Inc. with the Drilling Engineering Association and sponsors Texaco (USA) and BP (Europe) has initiated a three-year project to study slim-hole and coiled-tubing technology developments. The objective of this project is to keep members abreast of the latest technical developments in slim-hole and coiled-tubing technology and to assist in expanding the use of this technology as quickly as possible.

J. Marshall Adkins is a Senior Petroleum Engineer with Maurer Engineering and holds a BS Petroleum Engineering and Masters Business Administration, both from The University of Texas. He spent six years in engineering, sales, and finance with B.J. Services before joining Maurer Engineering in 1991. Mr. Adkins helps coordinate the DEA-67 project and is involved in the engineering, schools, and forums related to the slim-hole, coiled-tubing, and horizontal projects.

Multi-String Tubing Completions in East Texas

by Alex Sackeyfio, Production Engineer, Union Pacific Resources, Fort Worth, Texas

Topic: Completion and dewatering methods in the UPRC Stratton Field. Dual completions using 2-7/8" tubing strings cemented in the hole foregoing the use of casing.

Mr. Sackeyfio obtained his M.S. in Petroleum Engineering from the Institute of Petroleum and Gas, Ploiesti, Romania, in 1987. Prior to that, from 1978 to 1981, he spent three years at the University of Science and Technology, Kumasi, Ghana, reading Applied Mathematics. Special interests are reservoir characterization, stimulation, and production methods.

STRATTON FIELD

DISCOVERED IN THE EARLY 1930'S

USED TO BE MAINLY OIL PRODUCTION

IT IS NOW A PREDOMINANTLY GAS FIELD

GEOLOGY

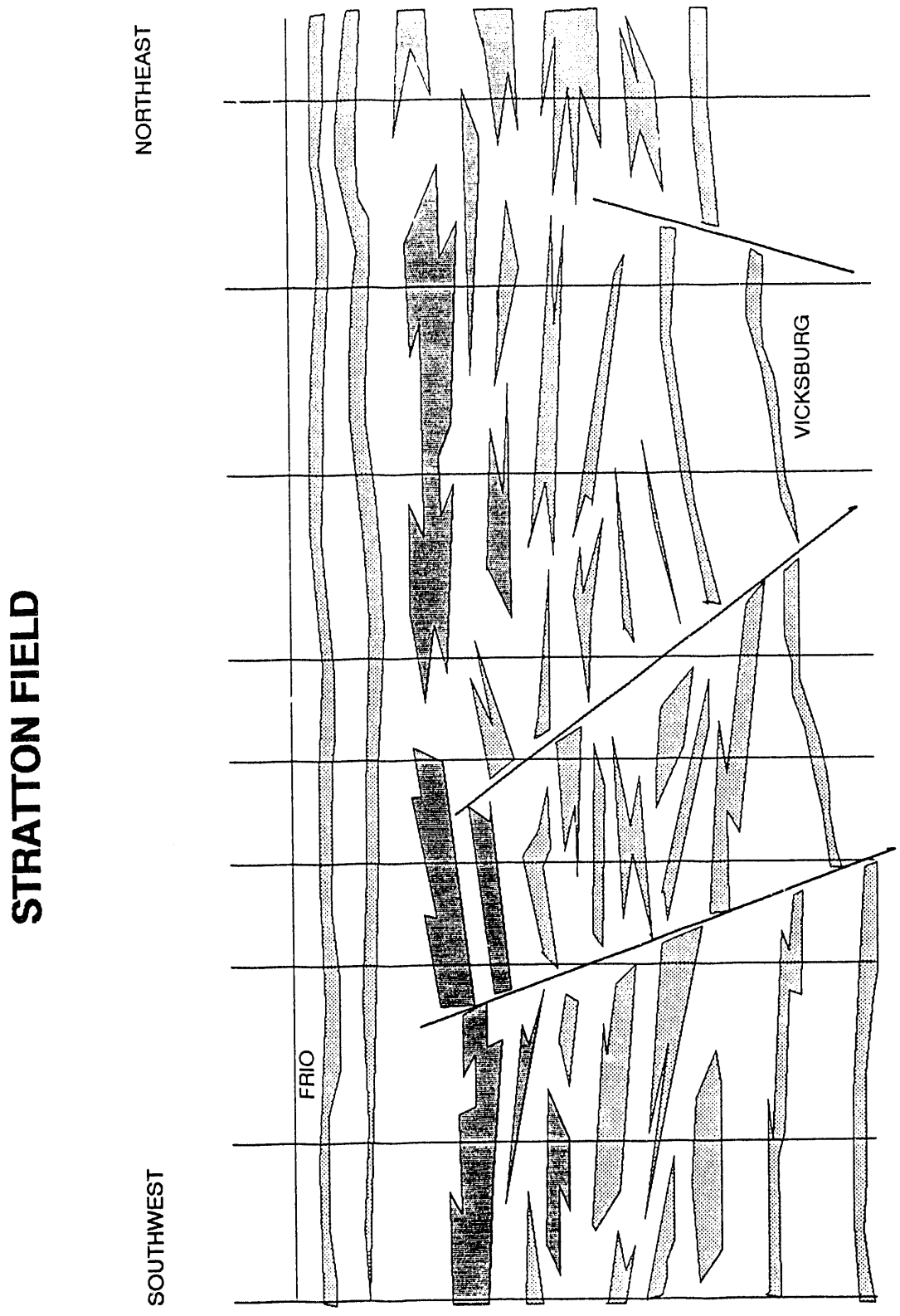
HIGHLY LENTICULAR AND COMPARTIMENTED

WITH LIMITED AREAL EXTENT

COMPLETION AND RECOMPLETION

THE LARGEST TUBING GUN IS 2-1/16"

SWAB RIG AND A WIRELINE COMPANY

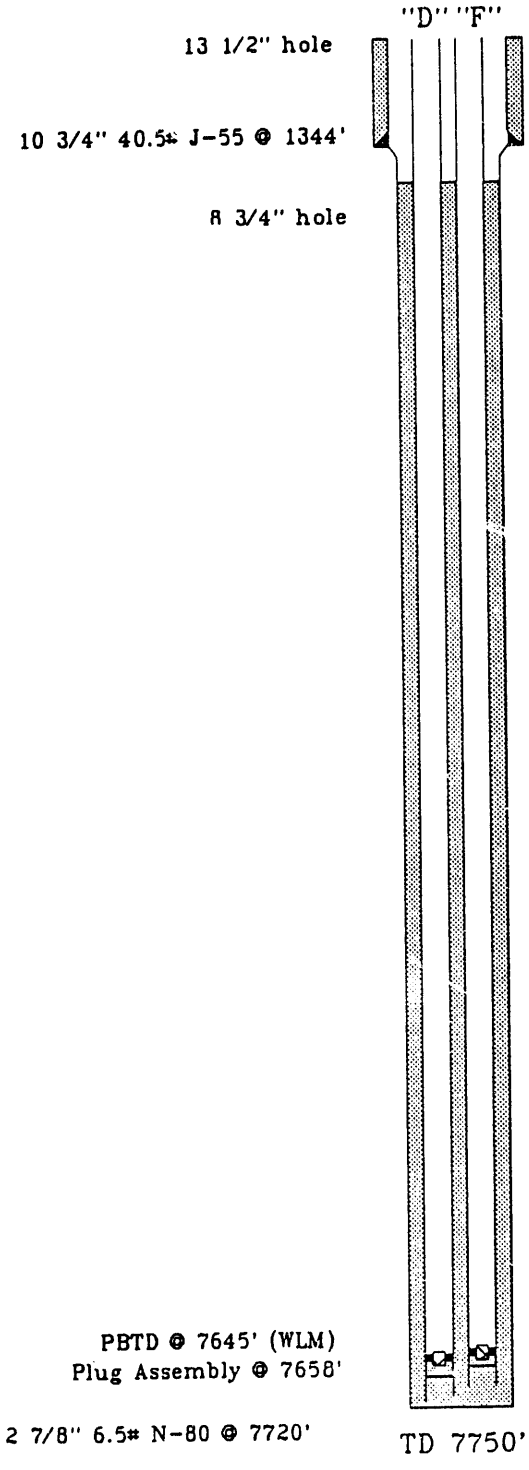

STRATTON FIELD
NORTHEAST
SOUTHWEST
FRIO
VICKSBURG

WELL NAME: STRATTON WELL
SPUD DATE: 00/00/00

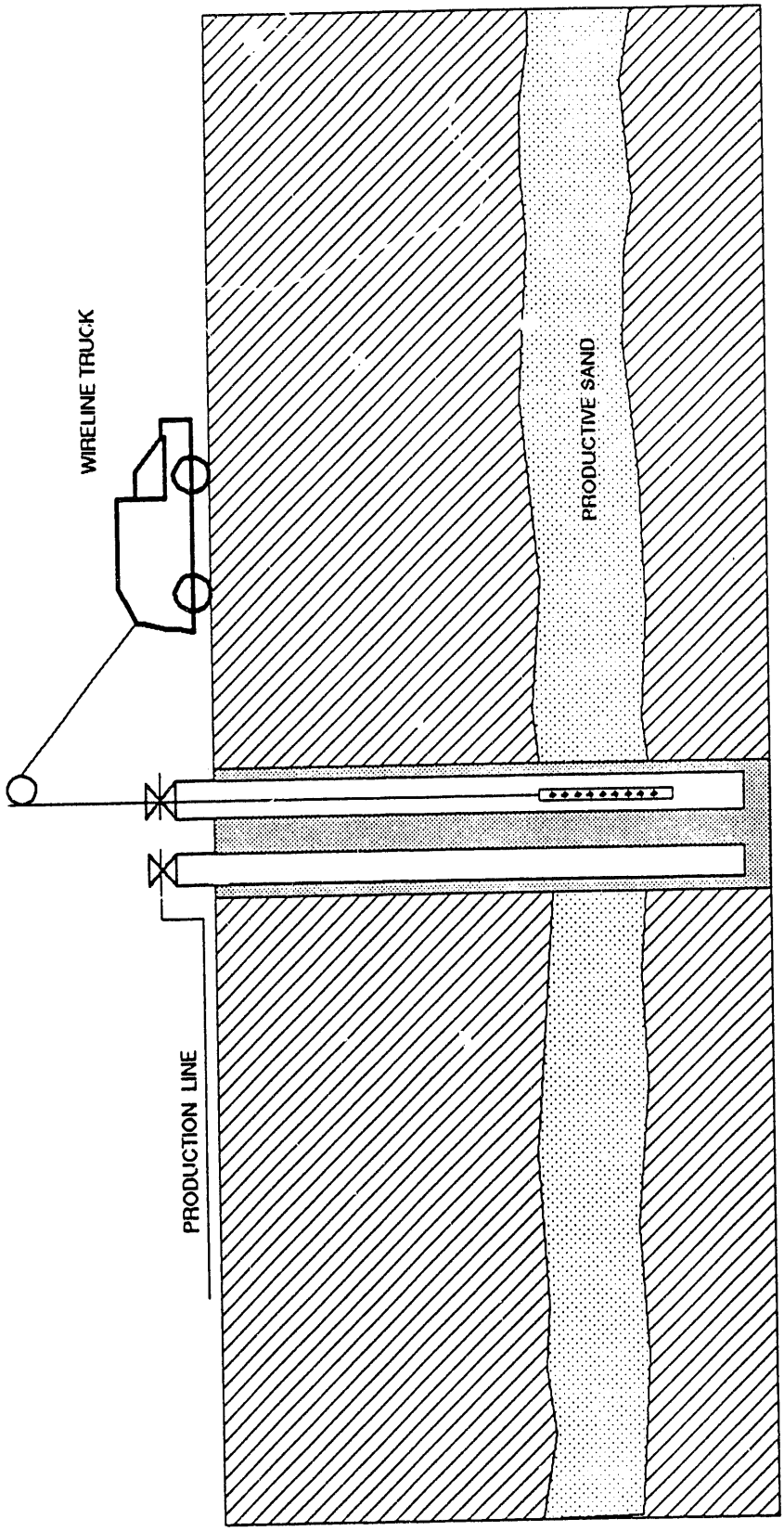
DATE: 00/00/00
BY: AHS

FIELD: STRATTON

"CURRENT"

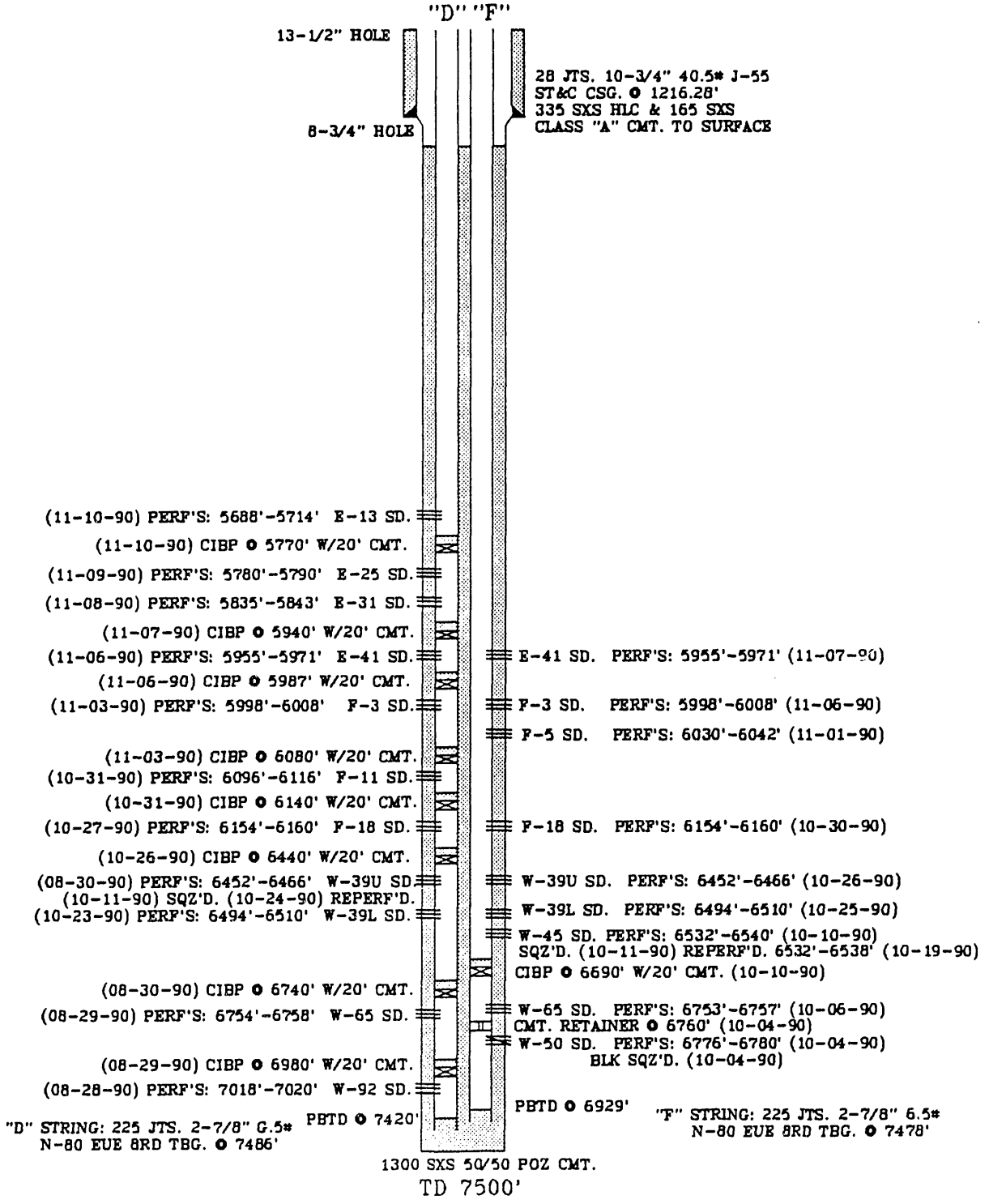


SCHEMATIC



WELL NAME: WARDNER, G. P. 213 DATE: 07/11/91
SPUD DATE: 08/06/90 BY: WFB

FIELD: STRATTON "CURRENT"
API NO. 42-355-32817

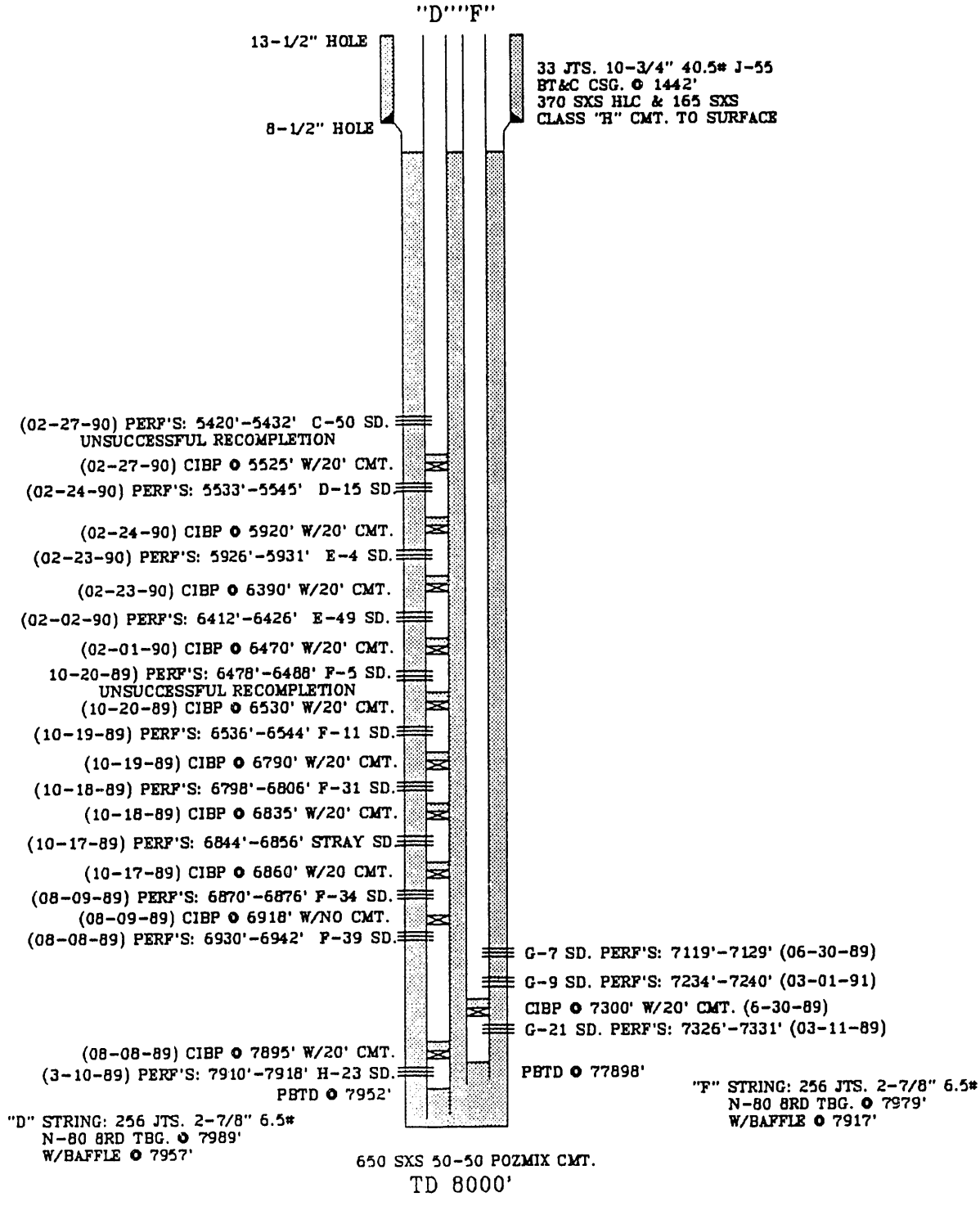


WELL NAME: Wardner, G. P. 206
SPUD DATE: 02/20/89

DATE: 04/12/91
BY: WFB

FIELD: STRATTON
API NO. 42-273-32138

"CURRENT"



DEWATERING METHODS

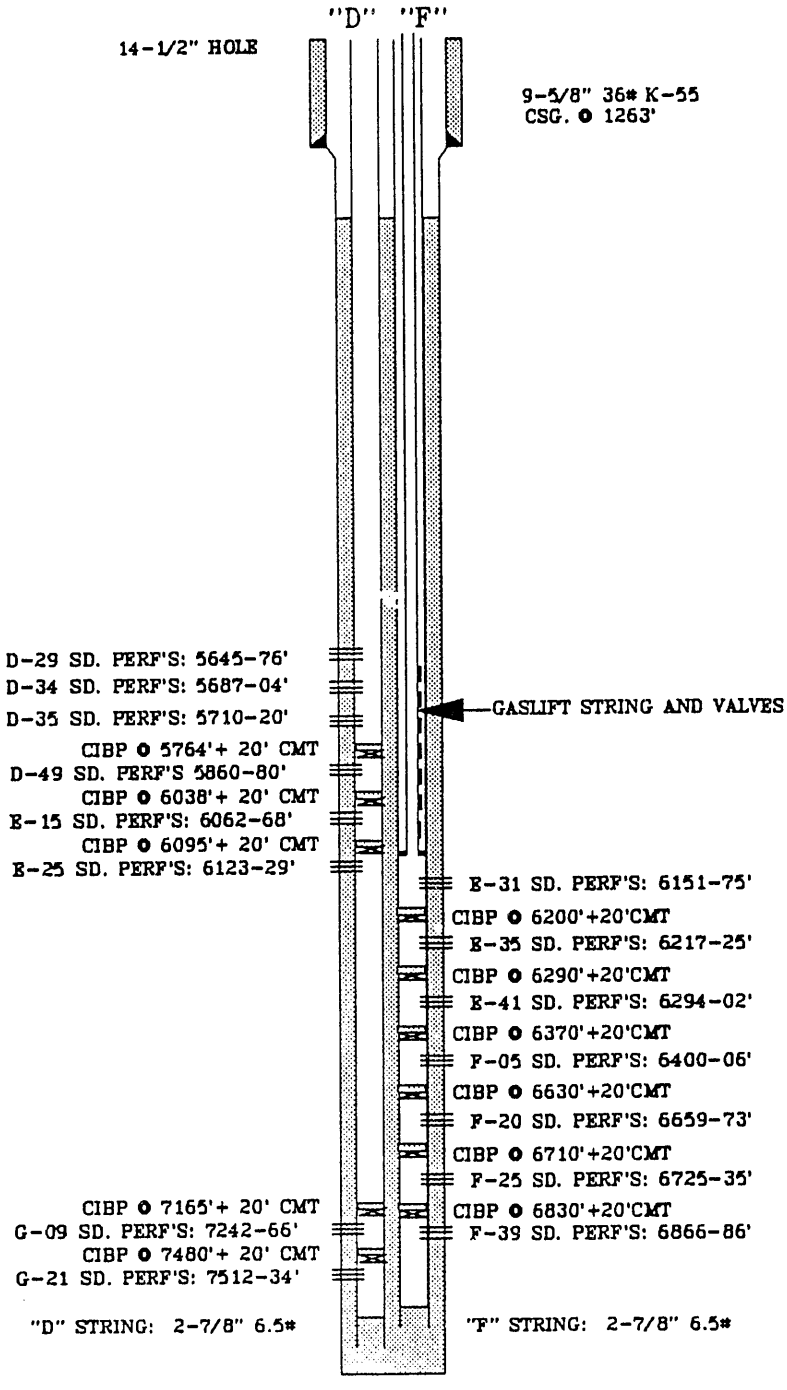
- PLUNGER LIFTS
- VELOCITY STRINGS
- GAS LIFTS

WELL NAME: ELLIFF, J.S. No.29
SPUD DATE: 03/29/88

DATE: 03/31/93
BY: AHS

FIELD: STRATTON
API NO. 42-355-32651

"PROPOSED"



TD 8000'

LIMITATIONS

- CANNOT BE USED AS DISPOSAL WELLS IN TEXAS
- RESTRICTED ON THE FRACTURE STIMUALTION SIZE
- CANNOT USE PUMPING UNITS ON THESE WELLS
- RESTRICTED ON THE SIZE OF PERFORATION GUNS USED

ADVANTAGES

- COST EFFECTIVE
- TIME SAVING
- LESS MAN POWER NEEDED

PLANNING AND EXECUTING A SUCCESSFUL SLIM-HOLE HORIZONTAL RE-ENTRY

Chip Abrant
Technical Manager
BecField Drilling Services

INTRODUCTION

The obvious object to drilling an oil well is to recover in-place oil. With the advent of horizontal drilling technology, it became feasible to maximize exposure to the pay zone through a grass roots project or a re-entry. There are thousands of existing wellbores that are completed using $5^1/_2$ or $4^1/_2$ inch casing. Many of these wells have experienced a standard decline in production, may have experienced coning problems, or simply missed a more prolific producing zone. Slim hole drilling technology has advanced to the point that re-entering wells with the stated casing sizes and drilling a horizontal (or directional) well has become routine. Historically, there have been perceived limitations to the number of wells that may be successfully re-entered, the most common of which is the minimum hole size that could be drilled. Although there are some exceptions, the practical limit to date has been a $4^1/_4$ inch hole (re-enter 5 inch casing). This perceived limitation was a result of such items as strength of tubulars, inability to survey, poor and/or unpredictable tool (motor) performance. The current state of technology now makes it possible to re-enter wells with existing $4^1/_2$ inch casing and drill a $3^7/_8$ inch lateral, or multiple lateral, extensions.

The information presented in this paper is hoped to be useful as a practical guideline for planning a slim hole horizontal re-entry. We will define a slim hole re-entry as any well that is to be drilled from existing casing with an outside diameter of $5^1/_2$ inches or smaller.

QUALIFYING THE WELL

A number of items should be considered during the evaluation process of prospective candidate wells. The weight of the casing should be verified as this relates directly to the size of the bit that may be used. For $5^1/_2$ inch casing, a $4^3/_4$ or $4^1/_2$ inch bit would be utilized based upon casing weight/drift diameter. Similarly, for $4^1/_2$ inch casing a $3^7/_8$, $3^3/_4$, or a $3^1/_2$ inch bit may be utilized depending on the weight/drift. Please see TABLE 1 on the following page for use as a general guideline.

It should be noted that in some zones if the original well was stimulated (i.e. acidized with water flush or dendritic fracture) potential problems may be encountered during horizontal drilling operations due to degradation of the formation resulting from the original wellbore stimulation.

TABLE 1

5 1/2 Inch Casing

Wt/Ft (lb/ft)	Nominal ID (in)	Drift Diameter (in)	Bit Size (in)	Diametrical Clearance (in)
13.0	5.044	4.919	4.75	0.169
14.0	5.012	4.887	4.75	0.137
15.5	4.950	4.825	4.75	0.075
17.0	4.892	4.767	4.75	0.017
20.0	4.778	4.653	4.50	0.153
23.0	4.670	4.545	4.50	0.045
26.0	4.548	4.423	4.25	0.173

4 1/2 Inch Casing Table

Wt/Ft (lb/ft)	Nominal ID (in)	Drift Diameter (in)	Bit Size (in)	Diametrical Clearance (in)
9.5	4.090	3.965	3.875	0.090
10.5	4.052	3.927	3.875	0.052
11.6	4.000	3.875	3.750	0.125
13.5	3.920	3.795	3.500	0.295
15.1	3.826	3.701	3.500	0.201

From Halliburton Cementing Tables

EXITING CASING

There are several methods of exiting casing on a slim-hole re-entry. Regardless of the method to be used it is necessary to have an accurate survey of the existing wellbore. Accurate surveys of the existing well are necessary for a number of reasons such as; a tie-in is necessary for the re-entry to be planned, to report an accurate bottom hole location of the re-entry well once it is drilled, and to ensure that the existing well is not inadvertently intersected at depth (this applies to wells originally drilled as directional wells). If a survey does not exist, a gyro multi-shot is required to determine the location of the existing well thus providing the necessary tie-in survey for the planned re-entry horizontal well. Even if the well is known to be "vertical", it is strongly recommended that a gyro multi-shot be run to verify the inclination, azimuth, and location of the kickoff point. In fact, some state regulatory agencies require a full survey of the well from surface to total depth. The operator should check with the pertinent state authority to verify survey requirements and reporting procedures.

The methods of exiting pipe would include:

A deepening in which one would drill out from under the existing casing shoe. This method is utilized if a deeper zone is to be exploited and is the quickest and simplest method of re-entering a well.

The second method is to utilize a whipstock to mill a window. There are certain advantages in milling a window such as minimum quantity of metal to clean from hole and mud, a definite preferred direction at the kickoff point (due to angled face of whip), and in some instances the whip is retrievable and reusable. The primary drawbacks of a window is the risk of setting the whipstock at the wrong depth and/or at the wrong azimuth. If a window is elected as the method of exiting casing it is recommended that the amount of rathole drilled off the whip be minimized, and when possible kept to less than ten feet. Gyro orientations are required during whipstock setting procedures and during initial drilling operations.

The last method is to cut a section by means of a section mill. This requires that a significantly greater quantity of metal be cut and removed from the hole and mud than if a window were milled. However, due to 360° removal of the casing there is no risk of being misaligned at kickoff point. After the section is cut, it is recommended that the section length be underreamed to the original hole size prior to the plug being set and polished. This ensures that the integrity of the new cement plug is maximized and reduces potential problems during the kickoff. The minimum section length recommended to successfully complete the sidetrack is open to debate. For the purpose of this article it is recommended that a minimum section length of fifty (50) feet be cut. Obviously a longer section may be useful in areas that difficulty is expected executing the sidetrack. Although a fifty foot section is adequate to complete the sidetrack, it is **not** sufficient to ensure that magnetic interference will be eliminated thereby affecting the accuracy of a magnetic survey tool. It therefore becomes necessary to utilize a gyroscopic orientation, trust a gravity high-side (if some angle is present) toolface from the magnetic survey tool, or perform a blind kickoff. In order to eliminate the affects of magnetic interference on the magnetic survey tool at kickoff point, it would be necessary to cut approximately eighty (80) feet of section. The difference in the quantity of metal removed using a section versus a window is significant and is illustrated by TABLE 2. Although this should not be the deciding factor in selecting a window as opposed to a section, it is a consideration.

TABLE 2

Window vs Section - Approximate Quantity of Metal Removed

Casing Diameter (inches)	Nominal Weight (lb/ft)	Section Mill 80 foot section Weight of Metal Removed (lbs)	Milling Window Weight of Metal Removed (lbs)	Length of Window (ft)
4.5	10.5	840	42	8
	13.5	1080	54	8
5.5	15.5	1240	70	9
	20.0	1600	90	9

The weight, grade, and condition of the casing should also be verified so that no surprises arise during casing exiting operations. This applies primarily if a section or a window will be cut, not if the well is a deepening. A collar locator log should be run to determine the location of the casing collar, as it is undesirable to initiate a cutout at a collar. If a cement bond log (CBL) is not available, it is recommended that one be obtained to ensure that the section or window is cut at a point that is adequately supported with cement.

DRILLING OPERATIONS

At this point the directional drilling tools will be run into the hole. Time-drilling operations will commence until the bit is clearly into formation (new hole). Once the kickoff has been completed, the drilling parameters may be adjusted to optimize directional drilling operations. If a section has been cut and the well is being kicked off a cement plug, it should be expected that time drilling procedures will be adhered to for a minimum of six to eight hours.

If the well is planned as a medium-radius directional well a single or double bend motor will be utilized for the kickoff and curve portion of the well. The actual motor configuration (single or double bend and magnitude of bend(s)) is a function of desired build rate, hole size, lithology, etc. The motor configured for the curve normally operates in the slide only (rotary table locked) mode. Depending upon the directional requirements, the motor may have a lift pad in addition to the bends to further enhance the build capability of the motor. If a pad is necessary, it should be placed at the bend point of the bent housing or in close proximity to the bent housing. In the event that the pad is not an integral part of the housing the minimum height should be one-quarter (.25) inches to allow for maximum weld strength.

BUILD RATE CAPABILITIES

Calculations based upon a geometrical model indicate that build rates in excess of 60° per 100 feet (95 foot radius) are possible. Higher build rates may be possible under ideal conditions. The normal build rate utilized for a $4^1/_2$ or $5^1/_2$ inch casing re-entry is approximately 20 to 25° per 100 feet. This as stated is the **average** build rate used, not the maximum proven build rate possible. Build rates up to 45° per 100 feet (127 foot radius) are possible with existing conventional equipment. As stated higher build are possible with minor modifications to the standard equipment. It must be remembered that utilizing higher build rates (>35° per 100 feet) reduces the total horizontal displacement possible.

At the completion of the curve, the double bend assembly is replaced with a single bend steerable assembly. This assembly operates in either the sliding mode or the rotating mode depending on the directional requirements. Stabilizers may be used, but in many instances are not necessary and have proven on slim hole drilling to adversely affect drilling performance due to stacking and torque.

BIT CONSIDERATIONS

The options available with regard to bit selection remain somewhat limited. With advance notice of the bit requirements it is possible to obtain natural diamond, thermally stable synthetic diamond (TSP), or polycrystalline diamond compact (PDC) bits. An limited number of rock bits are available, and to date very good results have been achieved using $4^3/_4$ inch sealed journal bearing tricone bits. The useful downhole life of non-sealed, journal bearing bits and is very low and as such these bits are not recommended, especially if a high speed motor is utilized. TABLE 3 below indicates the types of bits available for various hole sizes.

TABLE 3

	Casing O.D.					
		$4^1/_2$			$5^1/_2$	
Bit Size (in)	$3^1/_2$	$3^3/_4$	$3^7/_8$	$4^3/_8$	$4^1/_2$	$4^3/_4$
Natural Diamond	Y	Y	Y	Y	Y	Y
TSP	Y	Y	Y	Y	Y	Y
PDC	Y	Y	Y	Y	Y	Y
Sealed Jrnl Brg Insert	N	N	Y	N	Y	Y

* Note: $3^7/_8$ inch sealed journal bearing insert bit is under development, but currently unavailable.

In ideal conditions, it may be possible to exceed 2,000 feet of displacement in a $3^{7}/_{8}$ inch hole, but for planning purposes it is recommended that 1,000 to 1,500 feet be utilized. The maximum displacement achieved for a $4^{3}/_{4}$ inch hole is over 4,000 feet. The average displacement for this hole size in 1992 was approximately 2,500 feet, with several wells drilled with total displacements exceeding 3,000 feet. The amount of lateral displacement possible is a function of many items. These include formation type, drilling fluid chemistry, variation in dogleg severity, and drillstring design. Perhaps of most concern is the size of tubulars available for this application. Please refer to TABLE 4 below for general specifications on tubulars and connections that are available.

TABLE 4

Tubulars

Drillpipe or Tubing	OD (in)	Wt/Ft (lb/ft)	ID (in)
Drillpipe	2.375	4.85	1.995
Drillpipe	2.375	6.65	1.815
Tubing	2.375	4.70	1.901
Tubing	2.375	5.95	1.773
Drillpipe	2.875	6.85	2.441
Drillpipe	2.875	10.40	2.151
Tubing	2.875	6.50	2.347
Tubing	2.875	8.70	2.165

Connections

Type	OD (in)	ID (in)	Makeup Torque (ft-lb)
$2^{3}/_{8}$ NC26	3.375	1.750	3,540
$3^{3}/_{8}$ Slimhole H90	3.250	1.375	2,800
$2^{3}/_{8}$ PAC	2.875	1.375	2,500
$2^{3}/_{8}$ PH6	2.906	1.805	2,800
$2^{3}/_{8}$ CS Hydril	**2.750**	**1.890**	**1,500**
$2^{7}/_{8}$ NC51	4.125	2.125	6,000
$2^{7}/_{8}$ Slimhole H90	3.875	2.156	5,700
$2^{7}/_{8}$ OH	3.875	2.156	4,500
$2^{7}/_{8}$ NC26	3.375	1.750	3,540
$2^{7}/_{8}$ PAC	3.125	1.500	3,100
$2^{7}/_{8}$ PH6	**3.438**	**2.265**	**3,500**
$2^{7}/_{8}$ NST	3.063	1.950	3,000

Dimensional and makeup information taken from Tri-State Engineering Handbook and Joy "What Keeps Your String Together"

Author not responsible for errors in contents of TABLE 4. Please confirm specifications with supplier of tubulars to ensure proper dimensional data and optimum make-up of connections. Dimensional clearances for all survey and logging tools should be verified.

GUIDANCE

At this time MWD technology is available on a limited basis utilizing $3^1/_2$ inch collars, which is acceptable for hole sizes down to $4^1/_2$ inches. Hole sizes smaller than $4^1/_2$ inches (drilled out of 5 or $4^1/_2$ inch casing) currently preclude the use of MWD tools as the survey device. Due to the internal restrictions of the tubulars, no commercial MWD units are available that will fit inside. An alternative to MWD would be wireline steering tools. When drilling a $4^1/_2$ or $4^3/_4$ inch hole, $2^7/_8$ inch tubulars are used. The internal dimensions of these allow the use of a standard $1^3/_4$ inch steering tool. If a $3^7/_8$ inch hole is to be drilled, normally $2^3/_8$ inch tubulars will used in the open hole. Internal dimensions of the $2^3/_8$" tubulars would necessitate the use of a "pee-wee", or $1^3/_8$ inch steering tool to monitor the position of the well and the toolface orientation.

When a steering tool is elected as the guidance method, there are several possible techniques available to run the equipment. Possibly the most convenient technique is the use of a top-entry swivel. This method eliminates the risk of pinching the wireline between the tubulars and casing or surface well control equipment. If a top-entry swivel is not available a side-entry sub will be utilized to pass the wireline from within the drill pipe/tubing to outside the drill string below the rotary table. As a result the steering tool does not have to be tripped out of the hole at every connection. This is the normal technique for steering tool operation during the drilling of the curve, when the drill string is not rotated.

If the side-entry sub was used during lateral drilling operations, when the drill string is alternately rotated and locked (slide mode), it require that the steering tool probe be retrieved before each rotating set and re-seated prior to each slide set. To minimize the amount of time spent tripping wireline in the lateral a segmented wireline, or KwikTrip™, system was designed. This type of system utilizes a conventional wireline steering tool, but one major modification has been made. The survey tool and the majority of the wireline is prewired and remains downhole at all times. The steering tool probe is in its normal location inside the non-magnetic collars above the downhole motor. Wireline is run from the probe to a hang-off sub some distance up the drillstring (normally several thousand feet, depending on kick-off depth). A spear point is affixed to the wireline, tension is applied to the wireline, and then hung off in a special sub. When a survey is required, a minimal amount of wireline is run in the hole with a socket connector at the bottom of the wireline. The connector lands on the spear point making a electronic connection, allowing a survey to be taken. If a correction run (sliding mode) is required after taking the survey, the wireline is placed in a side-entry sub,packed off, and the

correction is made. Toolface readings and surveys are available as long as the connection is intact. Upon completion of the correction, the socket connector is retrieved via the upper wireline, and drilling continues in the rotating mode. The steering tool probe and the majority of the wireline remains in place downhole, ready to be used for the next survey and/or correction.

To further illustrate the capabilities of a slim-hole re-entry program, several case histories are presented below. The time required to exit casing is not included in the number of days. A good, safe average time required to exit casing regardless of the method used is between 2 and 3 days.

CASE HISTORY NUMBER 1
Job Number 92-090

Milled Section

Location: San Juan County, NM Number of Days 6

	Proposed		Actual	
Hole Size for Curve	$4^1/_2$	inches	$4^1/_2$	inches
Bit Type for Curve	PDC		PDC	
Kick-off Depth (MD)	5,673	feet	5,670	feet
Kick-off Depth (TVD)	5,673	feet	5,553	feet
Initial Angle @ KOP	0	degrees	17.9	degrees
True Vert. Depth @ End of Curve	5,950	feet	5,785	feet
Measured Depth @ End of Curve	6,173	feet	6,045	feet
Displacement @ End of Curve	344	feet	265	feet
Inclination @ End of Curve	90	degrees	80.3	degrees
Build Rate of Curve	21.0	°/100'	16.6	°/100'
Number of BHA's Run in Curve	1	BHA	1	BHA
Hole Size for Lateral	$4^1/_2$	inches	$4^1/_2$	inches
Bit Type for Lateral	PDC		PDC	
True Vert. Depth @ End of Lateral	5,950	feet	5,907	feet
Measured Depth @ End of Lateral	7,050	feet	7,017	feet
Inclination @ End of Lateral	90	degrees	61	degrees
Number of BHA's Run in Lateral	1	BHA	1	BHA
Polar Coordinates of Bottom Hole Location				
Displacement	1,221	feet	1,225	feet
Azimuth	27.5	degrees	26.8	degrees

CASE HISTORY NUMBER 2
Job Number 92-147

Set Whipstock

Location: Lee County, Texas Number of Days 10

	Proposed		Actual	
Hole Size for Curve	4 3/4	inches	4 3/4	inches
Bit Type for Curve	Tricone		Tricone	
Kick-off Depth (MD)	7,519	feet	7,526	feet
Kick-off Depth (TVD)	7,519	feet	7,525	feet
Initial Angle @ KOP	0	degrees	2.0	degrees
True Vert. Depth @ End of Curve	7,837	feet	7,823	feet
Measured Depth @ End of Curve	8,007	feet	7,974	feet
Displacement @ End of Curve	307	feet	268	feet
Inclination @ End of Curve	88	degrees	83.9	degrees
Build Rate of Curve	18.0	°/100'	18.9	°/100'
Number of BHA's Run in Curve	1	BHA	1	BHA
Hole Size for Lateral	4 3/4	inches	4 3/4	inches
Bit Type for Lateral	PDC		PDC	
True Vert. Depth @ End of Lateral	7,912	feet	7,897	feet
Measured Depth @ End of Lateral	10,109	feet	10,121	feet
Inclination @ End of Lateral	88	degrees	87.8	degrees
Number of BHA's Run in Lateral	2	BHA	2	BHA
Polar Coordinates of Bottom Hole Location				
Displacement	2,407	feet	2,407	feet
Azimuth	147.8	degrees	148.0	degrees
Footage in Lateral Drilled Sliding			364	feet
Footage in Lateral Drilled Rotating			1,846	feet
% of Lateral Footage Drilled by Rotating			83.5	%

CASE HISTORY NUMBER 3
Job Number 92-067

Set Whipstock

Location: Sabine County, Texas Number of Days 15

	Proposed		Actual	
Hole Size for Curve	$3^7/_8$	inches	$3^7/_8$	inches
Bit Type for Curve	PDC		PDC	
Kick-off Depth (MD)	7,449	feet	7,447	feet
Kick-off Depth (TVD)	7,449	feet	7,446	feet
Initial Angle @ KOP	0	degrees	2.5	degrees
True Vert. Depth @ End of Curve	7,680	feet	7,687	feet
Measured Depth @ End of Curve	7,802	feet	7,830	feet
Displacement @ End of Curve	221	feet	244	feet
Inclination @ End of Curve	87.5	degrees	88.7	degrees
Build Rate of Curve	24.8	°/100'	23.5	°/100'
Number of BHA's Run in Curve	1	BHA	2	BHA
Hole Size for Lateral	$3^7/_8$	inches	$3^7/_8$	inches
Bit Type for Lateral	PDC		PDC	
True Vert. Depth @ End of Lateral	7,757	feet	7,733	feet
Measured Depth @ End of Lateral	9,582	feet	8,897	feet
Inclination @ End of Lateral	87.5	degrees	88.3	degrees
Number of BHA's Run in Lateral	2	BHA	2	BHA
Polar Coordinates of Bottom Hole Location				
Displacement	2,000	feet	2,407	feet
Azimuth	157.0	degrees	161.0	degrees

SUMMARY

This procedures, recommendations, and ideals presented in this paper are a result of experience gained by drilling over 300 slim-hole re-entry wells. As is normally the case there are exceptions for every rule and as such, experience and common sense are irreplaceable. It has been said and written many times, the ultimate key to the success of any drilling project is proper planning, good communications, (and a little luck). Based upon our experience we have found that proper well planning and continued good communication minimizes the need to rely on good luck.

ENHANCED OIL RECOVERY SESSION

Friday, May 7, Morning: 8:00 AM to 11:30 AM

Session Chairmen: George H. Fancher, Fancher Oil Company, and Jim Mack, TIORCO

Introduction.....ii
Jim Mack

Waterflooding the Minnelusa with Aluminum Citrate Gelled Polymer..... 1
Walt King, Petroleum Engineer, Denver,CO

CO2 Tertiary Projects and the Independent Producer..... 7
Loren H. Stiles, Exxon (ret.), Midland, Texas

Emerging Gas Injection Technology.....15
Hiemi Kim Haines, Marathon Oil, Littleton, CO

Marathon's MARCIT Gel Technology.....29
George Southwell, Marathon Oil, Littleton, CO

Status Report on the TIOR-KOH Process to Stabilize Clays and Reduce Residual Oil Saturation.....33
Ben Sloat, TIORCO, Englewood, CO

Enhanced Oil Recovery

Introduction

The Enhanced Oil Recovery Session highlights technology that can improve oil recovery in Rocky Mountain reservoirs. A combination of chemical flooding techniques and gas injection projects are reviewed.

In the broad category of chemical flooding technology, processes to improve sweep and to stabilize clays have proven effective in improving waterflood performance. Walt King, Petroleum Engineer, discusses polymer and gelled polymer processes to improve in-depth sweep efficiency in matrix reservoirs. In the past ten years, Marathon Oil has developed a technology to improve sweep in fractured reservoirs. George Southwell of Marathon Oil reviews both injection-well and producing-well gelled treatments to reduce water recycling and add oil reserves. The presence of clays in the oil producing formation can sabotage the benefits of a water injection project. Ben Sloat, TIORCO, describes clay stabilization technology that has proven effective in altering the near wellbore clays of an injection well to allow sustained injection rates.

Gas injection has been proved to be beneficial in increasing oil recovery. CO2 flooding has been implemented in a number of reservoirs throughout the United States. Loren Stiles, Exxon, explains the technology and shows how CO2 flooding has fared in a number of reservoirs and can be implemented by the independent. Aside from CO2, there are a number of other low cost, gas-injection methods that have proven effective in enhancing oil recovery. Hiemi Haines, Marathon Oil, presents case histories for air injection and for cyclic gas injection, the double-displacement process.

WATERFLOODING THE MINNELUSA WITH ALUMINUM CITRATE GELLED POLYMER

Walter A. King
WALT KING, PETROLEUM ENGINEER

Polymerflooding the Minnelusa began in the early 1970's. It is a well known, well documented procedure in the Powder River Basin.

Polymer is mixed with injected water to increase the insitu viscosity of the water. This improves areal sweep. But, most important, in the Minnelusa, it reduces water channeling through high permeability streaks. Under the right circumstances, it increases oil production and reduces water production.

Polymer is a long chain (in microns) organic material. When injected, the polymer coats the pore throats of the rock and has an apparent viscosity (SCREEN FACTOR) as much as 10 to 20 times that of water. The addition of aluminum ions causes the polymer to gel.

Polymer achieves its viscosity because it has length, and because electrical charges are distributed along its length. If the chain is broken, the polymer looses its insitu viscosity. Experience indicates the polymer chain is fragile and can be broken easily. If the electrical charges are not evenly distributed or are neutralized both viscosity and the ability to gel are diminished.

Frequent field testing is required to determine if the desired insitu viscosity is being achieved. Polymer quality can be reduced mechanically by sudden pressure drops. It can be reduced chemically by the introduction of cationic biocides and scale inhibitors, or the action of sulfate reducing bacteria. Polymer may fail to hydrate if the water contains magnesium or calcium or if it was poorly manufactured. And finally, the well may become plugged if the polymer mixing unit is not working correctly, or the injected water is not properly filtered.

As injections progress, additional data about the reservoir will become apparent. Office monitoring of production and injection data is required to periodically update the polymer and gel concentrations.

Polymer augmented waterflooding can be expected to increase recovery by about 5% of the original oil in place. However, you cannot design it in the laboratory and with the computer and forget it. It must be continuously tested and its design updated.

MINNELUSA WATERFLOODING ENVIROMENT

I. THERE IS NO STANDARD INJECTION PATTERN –
(Often Inject Updip, 40 Acre Spacing)

II. WATER WET ROCK –
Relative Permeability to Water at Floodout – .09 – .125

III. OIL/ INJECTION WATER VISCOSITY RATIO – 13 – 20

IV. MOBILITY RATIO – 2 – 10

V. DYKSTRA-PARSON PERMEABILITY VARIATION – .4 – .8

VI. INJECTION WATER (FOX HILLS) –

TDS	2,780	1,051
CA ++	8.6	0
MG ++	4.8	0

VII. GENERALIZED POLYMER INJECTION PLAN –

i. INJECT FRESH WATER FOR 30 DAYS
ii. 2% PV CATIONIC POLYMER
iii. 2% PV ANIONIC POLYMER
iv. 18% PV ANIONIC POLYMER WITH ALUMINUM CITRATE

POLYMER/AL+++ RATIO 20 to 40

POLYMER CONCENTRATION 300 to 1,000 mg/l

VIII. DRY POLYMER MIXED ON THE FLY

IX. LIQUID ALUMINUM CITRATE (3% ACTIVE AL+++)

HISTORY OF POLYMER FLOODING IN THE POWDER RIVER BASIN

CATIONIC – ANIONIC – 1973.

POWDER ALUMINUM CITRATE SLUG BETWEEN ANIONIC – 1975.

LIQUID ALUMINUM CITRATE SLUG BETWEEN ANIONIC – 1979.

CONTINUOUS SURFACE MIXING OF ANIONIC AND LIQUID ALUMINUM CITRATE – 1985.

MINNELUSA FORMATION CHARACTERISTICS

.NDSTONE - FINE GRAIN - SLIGHTLY CALCAREOUS - OCCASIONAL ANHYDRIT

OCCASIONAL THIN CALCAREOUS ZONES

AEOLIAN - COASTAL DUNES SEQUENCE

	MINIMUM	AVERAGE	MAXIMUM
OOIP (MMBBLS)	1	5	14
POROSITY	12%	17%	25%
PERMEABILITY (MD)	1	70	2,000
PERM VARIATION	0.4	0.7	0.8
WATER SATURATION	10%	25%	40%
DEPTH (FT)	4,000	7,000	10,000
RESERVOIR TEMP (F)	140	160	220
WELL SPACING (AC)	VAR	40	80
NUMBER OF WELLS	2	7	15

MINNELUSA FLUID AND RECOVERY STATISTICS

	OIL RECOVERY MINIMUM	OIL RECOVERY AVERAGE	OIL RECOVERY MAXIMUM
PRIMARY	6%	10%	15%
SECONDARY	20%	25%	30%
POLYMER	2%	5%	10%
TOTAL	28%	40%	55%
FLUID CHARACTERISTICS - OIL			
GRAVITY (DEG API)	20	23	30
SOLUTION GAS (FT3/BBL)	3	20	160
BUBBLE PT PRESS (PSI)	100	200	900
VISCOSITY - CP	1	7	7
RES VOL FACTOR (RVB/STB)	1.04	1.08	1.16
FLUID CHARACTERISTICS - FORMATION WATER			
TDS-	15,000	30,000	150,000

POLYMER FLOODING OPERATIONS

POLYMER INJECTION

DRY POLYMER THROUGH EDUCTOR INTO PUMP SUCTION

MEASURE WITH TURBINE METER (Recalibrate).
INJECTION PUMP FOR EACH INJECTION WELL

PRODUCED WATER IS FILTERED AND STORED IN SEPARATE TANK

ADJUST POLYMER CONCENTRATION TO
GRADUALLY INCREASE HALL SLOPE TO 3 PSI/BWIPD

SULFATE REDUCING BACTERIA
INJECT BACTERICIDE AS A SLUG PERIODICALLY (30 days)
DO NOT MIX CATIONIC BACTERICIDE WITH ANIONIC POLYMER

START UP PROCEDURE

BEGIN INJECTING FRESH FILTERED WATER

INJECT FOR ONE TO TWO WEEKS TO ESTABLISH INJECTION PRESSURE AND RATE STABILIZATION

RUN TRACER AND TEMPERATURE SURVEY TO DETERMINE PROFILE AND IF INJECTIONS ARE GOING IN ZONE

RUN FALLOFF TEST TO DETERMINE IF WELLBORE DAMAGE EXISTS

RUN STEP RATE TEST TO DETERMINE PARTING PRESSURE

COMMENCE CATIONIC POLYMER INJECTIONS ABOUT 30 DAYS AFTER COMMENCEMENT OF INJECTIONS

RECORD KEEPING

DAILY INJECTION RATE AND PRESSURE - EACH INJECTION WELL

DAILY POLYMER AND ALUMINUM CITRATE - EACH INJECTION WELL

DAILY PRODUCTION OF OIL AND WATER - EACH PRODUCING WELL

CALCULATE/PLOT (EACH PRODUCTION/INJECTION WELL)

DAILY HALL SLOPE (PSI/BPD)
DAILY CUMULATIVE INJECTIONS
DAILY CONCENTRATION (MG/L) POLYMER, AL CIT, POLYMER/AL+++ RATIO

DAILY OIL AND WATER RATE
DAILY WATER/OIL RATIO
CUMULATIVE OIL AND WATER PRODUCTION

INJECTION/PRODUCTION RATIOS FOR FIELD
AND
VARIOUS INJECTION/PRODUCTION WELL COMBINATIONS

FIELD TESTING

LABORATORY TEST OF SCREEN FACTOR WITH INJECTION WATER (BASELINE

WELLHEAD SCREEN FACTOR TESTS

SULFATE REDUCING BACTERIA TESTS

INJECTION WELL COUPON TESTS, NIPPLE TESTS, MATERIAL IN FILTER

PERIODIC FALLOFF TESTS

THINGS TO LOOK FOR -

RATIO OF SCREEN FACTOR TO BASE
- IF LOW:
  - PARTIALLY CLOSED VALVE OR METER
  - MIXING BACTERICIDE OR SCALE INHIBITOR
  - SULFATE REDUCING BACTERIA
- IF HIGH:
  - CONCENTRATION HIGHER THAN PLANNED

HALL SLOPE
- IF LOW:
  - INJECTION/PRODUCTION RATIO
  - POOR POLYMER QUALITY
  - POLYMER SHEARING
- IF HIGH:
  - REDUCE POLYMER CONCENTRATION
  - DISCONTINUE ALUMINUM CITRATE

FALLOFF TESTS:
- COMPARE HISTORICAL TESTS
- IS PRESSURE IN PLUGGED PERFS OR IN FORMATION?

CO2 TERTIARY PROJECTS AND THE INDEPENDENT PRODUCER

L. H. Stiles, Exxon, Ret.
2504 Camarie Ave.
Midland, TX 79705
(915) 682-7724

INTRODUCTION

CO2 miscible injection is one of the leading tertiary processes that is being used to recover additional oil from reservoirs that have been mostly depleted by primary and secondary methods. Hadlow[1] recently identified 45 active CO2 projects in the United States. The geographical location of these projects and the main sources of CO2 supply are shown on Figure 1.

In the CO2 miscible process, CO2 is injected into a reservoir to reduce the residual oil that is left after waterflooding. Figure 2 is a schematic drawing that illustrates the CO2 miscible process. Under most reservoir conditions, CO2 is not initially miscible with the reservoir oil, miscibility is achieved and maintained by multiple contacts with the oil. Since the sweep efficiency of CO2 is less than that of water, the CO2 is commonly injected in alternate slugs with water to improve sweep efficiency.

STATUS OF FIELD APPLICATIONS

Hadlow[1] also showed several examples of performance of currently active CO2 projects. Figure 3 shows the production history of four of these fields. Notice that in each of these fields, there has been an actual increase in oil production above the rate when CO2 injection began. The increase attributable to CO2 injection is much larger when existing decline rates are considered.

Since the cost of the CO2 injected would be much greater than water, most operators implemented improved reservoir management programs prior to the beginning of CO2 injection. This preparation achieved improvement in current operations as well as additional recovery from CO2 injection. The Means San Andres Unit in Andrews County, Texas is a good example of a total program to improve recovery. The CO2 tertiary project was implemented as part of an integrated reservoir management plan that included in addition to CO2 injection, reservoir characterization, infill drilling, pattern changes and expansion of the Grayburg waterflood outside the CO2 project area. Estimated incremental recovery from the total project has been allocated to three components as shown on Figure 4.[2,3]

What about ultimate incremental recovery from CO2 miscible projects? Although each of the projects discussed has shown definitive response in oil production, it is still too early to determine accurately the ultimate additional recovery. There is at least one commercial scale CO2 project that has been completed. CO2 injection began in the SACROC Unit as a secondary project in 1972. Although response to CO2 injection was obvious, quantitative evaluation of incremental was difficult. In 1981, the SACROC operator Chevron implemented a CO2 tertiary project, called the SACROC 4-Pattern Area[4], on 610 acres into which CO2 had never been injected. At the time CO2 injection began, the area was nearing depletion with a 95% watercut. Figure 5 shows the performance of this project. Oil production increased from 800 BOPD to 3200 BOPD within 13 months. Not only did oil production increase, but the water-oil ratio decreased from 20 to 1 to 7 to 1. At the conclusion of CO2 injection, the project was again nearing depletion. Incremental recovery

was estimated to be approximately 10 percent of the original oil in place with a cumulative CO2 utilization of about 10 mcf per barrel of incremental oil. Approximately 2/3 of the CO2 was recovered for use in other parts of the Unit.

CO2 MISCIBLE PROJECTS AND THE INDEPENDENT OPERATOR

Is there a place for CO2 projects for the independent? Although most of the CO2 projects to date have been implemented by majors, at least three projects are operated by independents. These are the Two Freds and Hanford San Andres units in the Permian Basin the Hansford Marmaton Unit in the Texas Panhandle. In addition, many independents have participated in the larger CO2 projects as non-operating working interest owners. Some of the details of analysis and implementation may differ, but the basics are the same for both majors and independents.

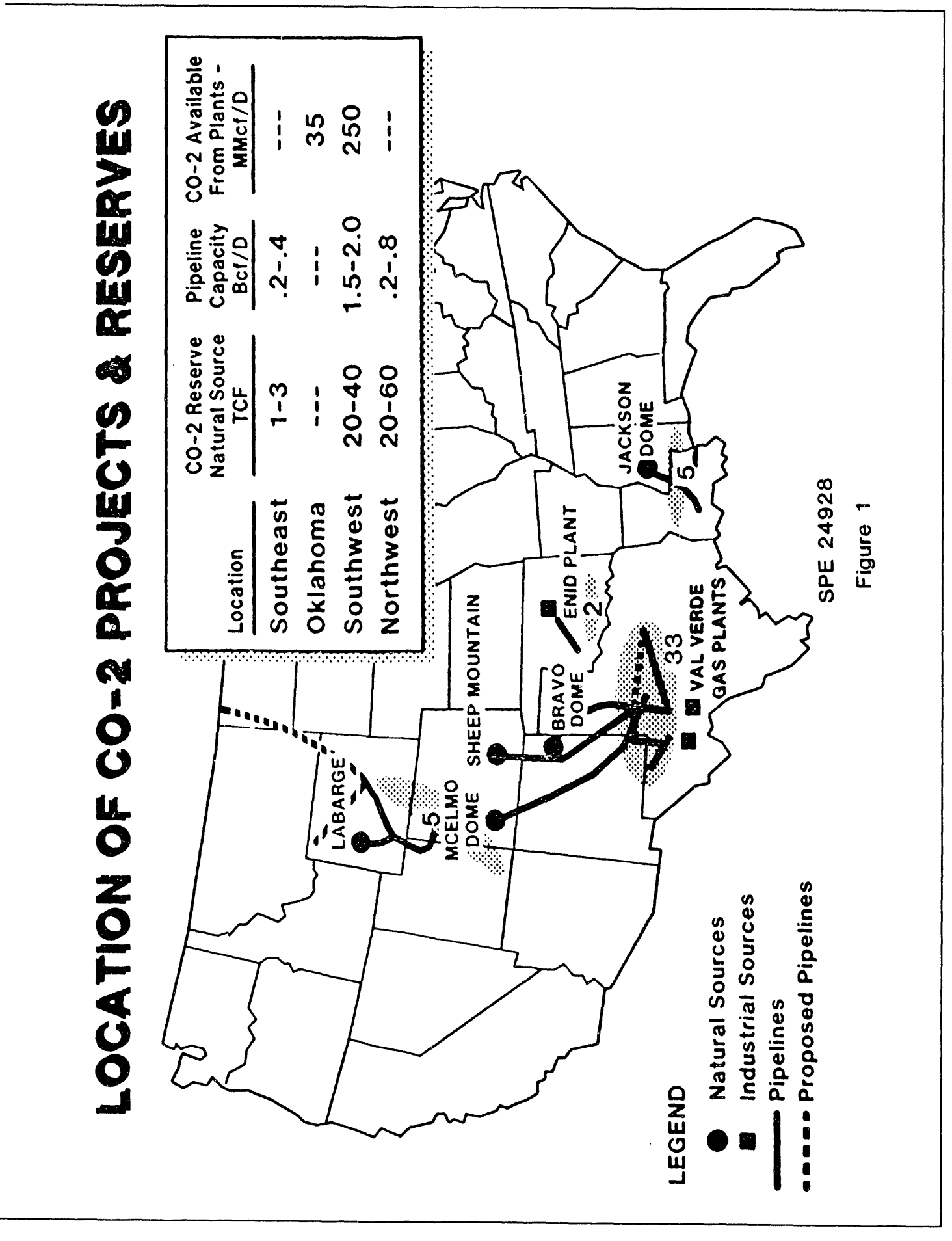
When evaluating a potential CO2 project, there are several factors to be considered. To be considered, a project must be of sufficient size to develop a pattern (probably 15 to 20 contiguous wells). A large upfront investment will usually be required; and the cost of purchased and recycled CO2 is large compared with waterflooding. Increased operating expenses can also be assumed.

On the positive side, there is no exploration risk. The location of the remaining oil is known from previous operations. Also, there are opportunities for innovative operations that can reduce investment and operating expenses. These possibilities include staged implementation, rented equipment and the potential for federal and/or state tax incentives. In some fields where waterflooding may not be feasible or practical, CO2 injection as a secondary injectant may be especially attractive.

For implementation of CO2 miscible projects in today's economic climate, some economic rethinking may be required. With the large front-end investment required, lower rates of return than traditional opportunities must be accepted. This lower return is partially compensated by the accompanying lower risk than on many traditional ventures. The diminishing opportunity for traditional petroleum investments such as drilling wells may provide a transition to tertiary projects to increase the nation's oil reserves.

REFERENCES

1. Hadlow, R.E.: "Update of Industry Experience with CO2 Flooding," Paper SPE 24928, presented at the 67th Annual Technical Conference and Exhibition, Washington, D.C., Oct. 4-7 1992.
2. Magruder, J. B., Stiles, L.H. and Yelverton, T.D.: "A Review of the Means, San Andres Full-Scale CO2 Tertiary Project,"JPT (May 1990) 638-44; Trans., AIME 289.
3. Stiles, L.H. and Magruder, J.B.: "Reservoir Management in the Means San Andres Unit," JPT (April 1992) 469-75.
4. Langston, M.V., Hoadley, S.F. and Young, D.N.: "Definitive CO2 Flooding Response in the SACROC Unit," Paper SPE/DOE 17321 presented at the SPE/DOE Enhanced Oil Recovery Symposium, Tulsa, Oklahoma, april 17-20, 1988.



SPE 24928

Figure 1

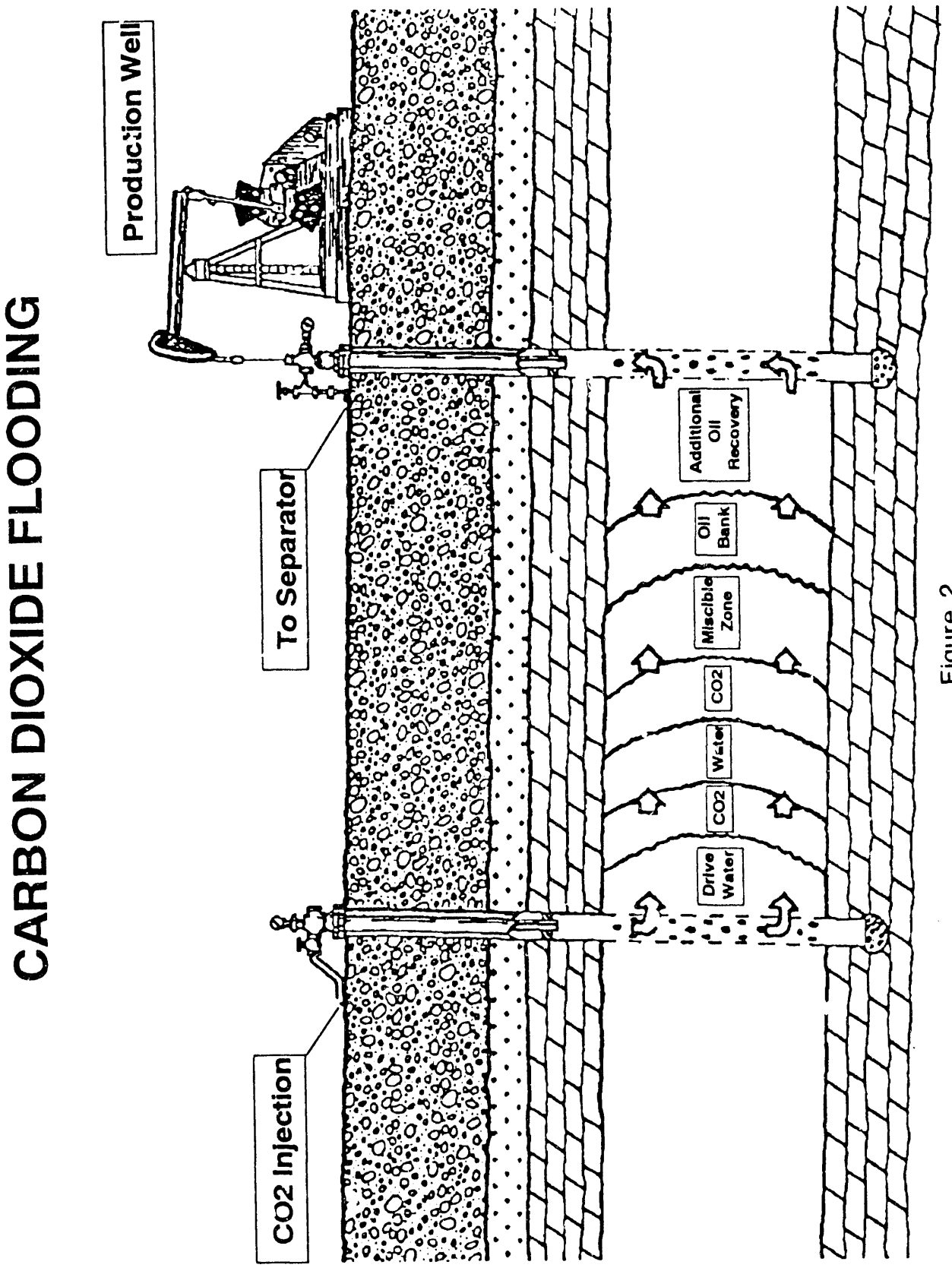

CARBON DIOXIDE FLOODING
Production Well
To Separator
CO2 Injection
Additional Oil Recovery
Oil Bank
Miscible Zone
CO2
Water
CO2
Drive Water

Figure 2

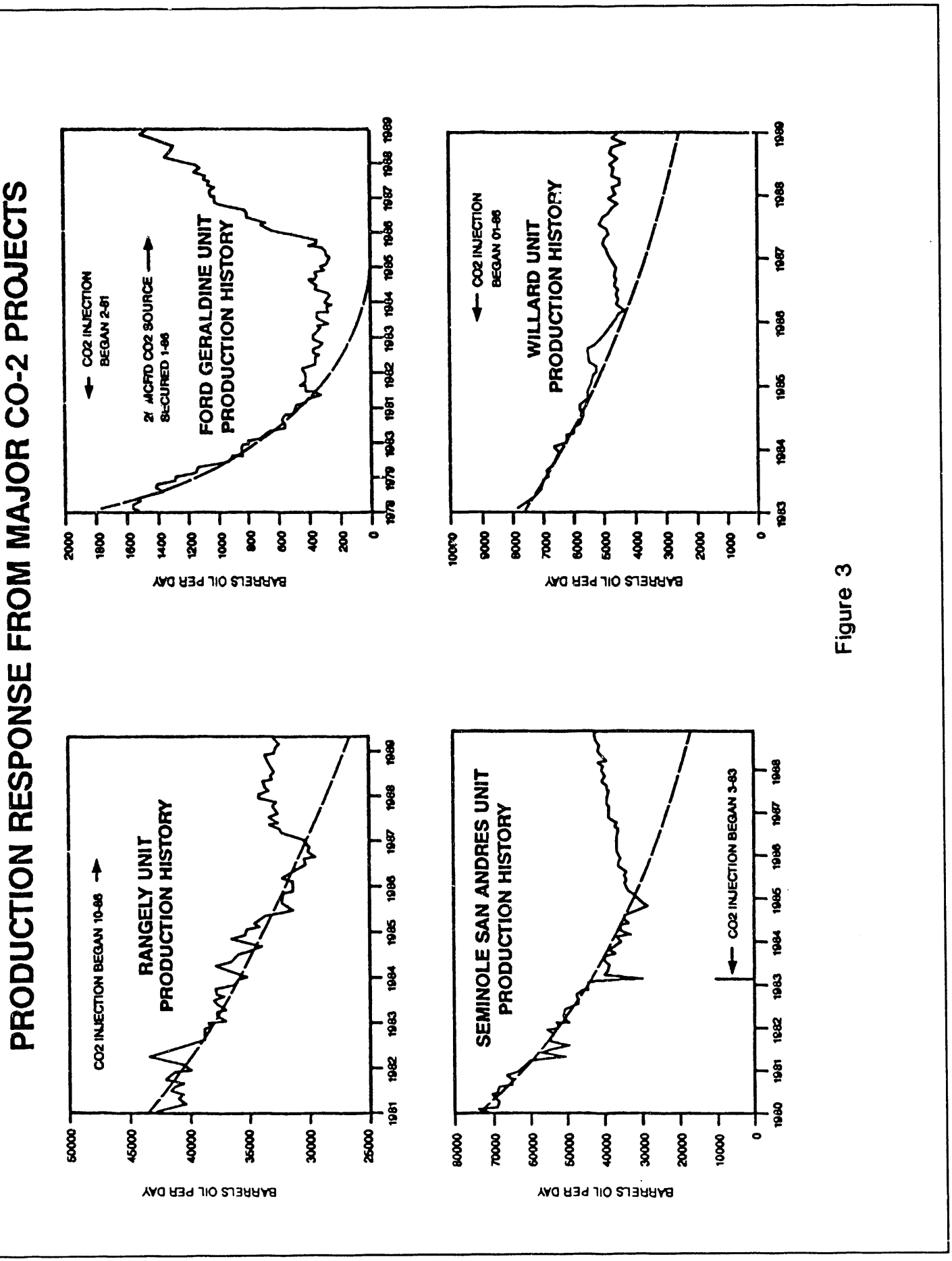

PRODUCTION RESPONSE FROM MAJOR CO-2 PROJECTS
FORD GERALDINE UNIT
PRODUCTION HISTORY
CO2 INJECTION
BEGAN 2-81
21 MCF/D CO2 SOURCE
SECURED 1-86
BARRELS OIL PER DAY
WILLARD UNIT
PRODUCTION HISTORY
CO2 INJECTION
BEGAN 01-86
BARRELS OIL PER DAY
RANGELY UNIT
PRODUCTION HISTORY
CO2 INJECTION BEGAN 10-86
BARRELS OIL PER DAY
SEMINOLE SAN ANDRES UNIT
PRODUCTION HISTORY
CO2 INJECTION BEGAN 3-83
BARRELS OIL PER DAY

Figure 3

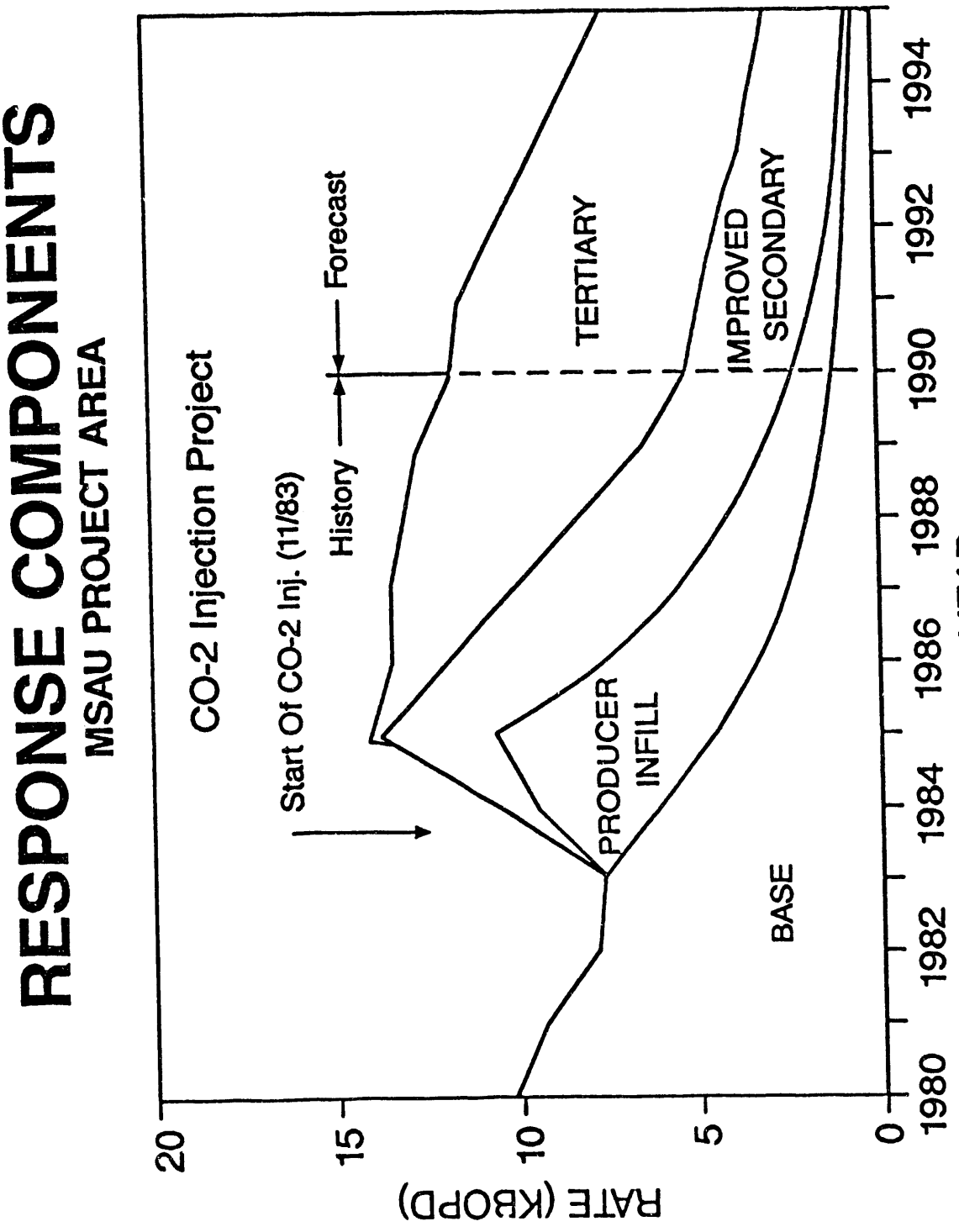
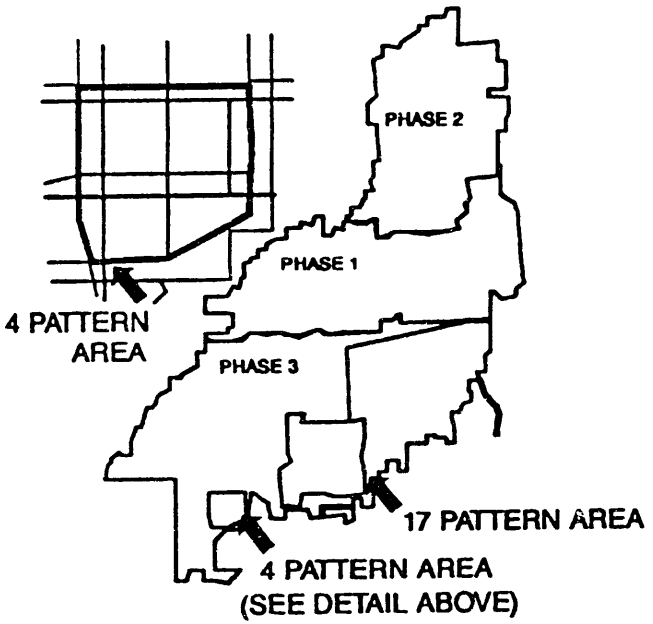
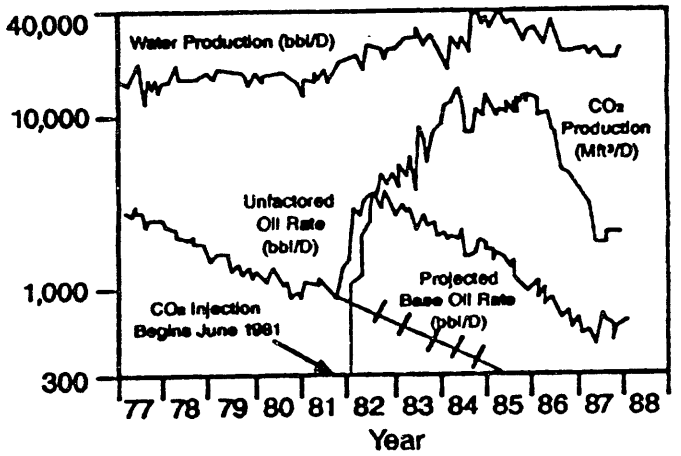
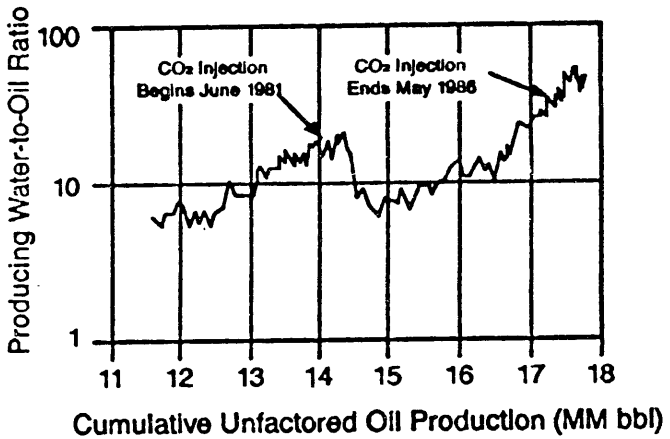

RESPONSE COMPONENTS
MSAU PROJECT AREA
CO-2 Injection Project
Start Of CO-2 Inj. (11/83)
History
Forecast
TERTIARY
IMPROVED SECONDARY
PRODUCER INFILL
BASE
RATE (KBOPD)
YEAR
0
5
10
15
20
1980
1982
1984
1986
1988
1990
1992
1994

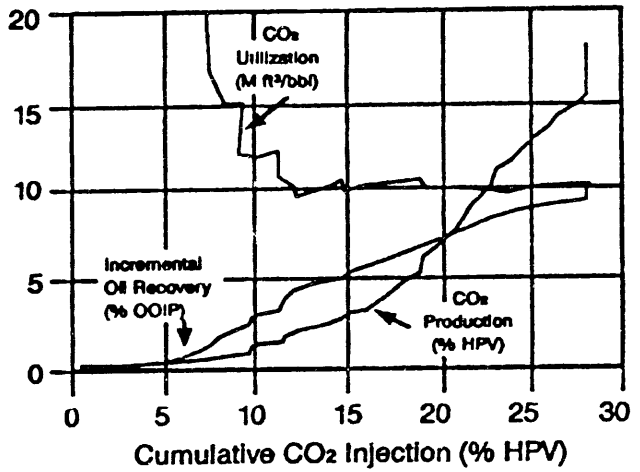
Figure 4

DEFINITIVE CO_2 FLOODING RESPONSE OF PATTERN AREA - SACROC UNIT









SPE/DOE 17321

Figure 5

NOTES

Emerging Gas Injection Technology

by Hiemi Kim Haines, Marathon Oil Company
7400 S. Broadway St.
Littleton, Colorado 80122
(303)347-5484

Abstract

Submitted to the New Technology for Independent Producers Workshop
to be held in Denver, Colorado, May 7, 1993

An overview will be presented of low cost gas injection methods. Case histories will be reviewed for cyclic gas injection, the Double Displacement Process and air injection.

Compared to field-wide enhanced oil recovery (EOR) methods, the risks associated with single-well injection/production processes (cyclic or huff 'n' puff) are considerably less, upfront investments are lower, and payback is more rapid. Cyclic gas injection thus offers a timely approach to increasing reserves in a low oil price environment. Cyclic CO_2 field performance for the Gulf Coast indicated that incremental oil could be recovered under diverse reservoir conditions with favorable CO_2 utilizations. Experience in Rocky Mountain fields has been less promising primarily due to poor containment of injected gas. Salt Creek Field's natural gas huff 'n' puff injection mimicked that of a successful cyclic CO_2 test.

The Double Displacement Process (DDP) is gas displacement of a water-invaded oil column with production by gravity drainage. DDP can be applied to any field where water drive has become inefficient (low oil rate and high WOR) and a gas source is available. Candidate reservoirs require sufficient bed dip for efficient gravity drainage. Oil gravity drainage can be improved by (1) increasing the density difference between oil and the displacing fluid, (2) increasing the oil relative permeability, (3) decreasing the oil viscosity, and (4) decreasing the interfacial tension. Thus, oil gravity drainage will improve significantly by switching from water injection to gas. Hawkins Field Unit has been under successful DDP, and recovery efficiency by gas drive is approaching 80% compared to 60% by waterdrive.

Some operators have not attempted DDP due to (1) the sizable initial investment for surface facilities, (2) the high operating costs during gas injection, and (3) the slow response to gravity drainage. When an inexpensive source of gas is not available, air injection could be considered. Screening criteria include reservoir depth greater than 6000ft and reservoir temperature greater than 175°F. At these conditions, injected air spontaneously ignites with oil in place to generate in-situ flue gas. Examples of successful Rocky Mountain field projects include the Sloss COFCAW project in Nebraska and several successful high pressure in-situ combustion projects in South and North Dakota operated by Koch Exploration Company.

BIBLIOGRAPHY

CYCLIC GAS INJECTION

Haskin, H.K. and Alston, R.B. "An Evaluation of CO_2 Huff 'n' Puff Tests in Texas, *JPT*, February 1989, 177-84.

Thomas, G.A. and Monger-McClure, T.G. "Feasibility of Cyclic CO_2 Injection for Light Oil Recovery," *SPE Reservoir Engineering*, May 1991, 179-84.

Simpson, M.R.: "The CO_2 Huff 'n' Puff Process in a Bottomwater-Drive Reservoir *JPT*, July 1988, 887-93.

Haines, H.K. and Monger, T.G. "A Laboratory Study of Natural Gas Huff 'n' Puff," paper CIM/SPE 90-78 presented at the 1990 International Technical Meeting jointly hosted by the Petroleum Society of CIM and the Society of Petroleum Engineers, Calgary, June 10-13.

Patton, J.T., Coats, K.H. and Spence, K. "Carbon Dioxide Well Stimulation: Part 1-A Parametric Study," *JPT* (August 1982) 1798-1804.

Miller, B.J., "Design and Results of a Shallow-Light Oil Field Wide Application of CO_2 Huff 'n' Puff Process," paper SPE/DOE 20268 presented at the 1990 SPE/DOE Symposium on Enhanced Oil Recovery, Tulsa, April 22-25.

Smith, L.K., MacGowan, D.B. and Surdam, R.C. "Scale Prediction During CO2 Huff 'n' Puff Enhanced Recovery, Crooks Gap Field, Wyoming", paper SPE 21838 presented at the 1991 SPE Rocky Mountain Regional/Low Permeability Reservoirs Symposium, Denver, April 15-17.

Olenick, S., Schroeder, F.A., Haines, H.K. and Monger-McClure, T.G., "Cyclic CO_2 Injection for Heavy Oil Recovery in Halfmoon Field: Laboratory Evaluation and Pilot Performance", paper SPE 24645 presented at the 1992 SPE Annual Technical Conference and Exhibition, Washington D.C., October 4-7.

DOUBLE DISPLACEMENT PROCESS

Carlson, L.O. "Performance of Hawkins Field Unit Under Gas Drive-Pressure Maintenance Operations and Development of an Enhanced Oil Recovery Project," presented at SPE/DOE Enhanced Oil Recovery Symposium, SPE 17324, (April 1988).

Van Dijkum, C.E. and Walker, T.: "Fractured Reservoir Simulation and Field Development, Natih Field, Oman," presented at 66th SPE Fall meeting, SPE 22917 (Oct. 1991).

Murty, C.R.K., Saleh, N.S. and Dekessian, B.A., "Forty-Seven Years of Gas Injection in a Preferentially Oil-Wet, Low-Dip Reservoir," presented at the SPE Middle East Oil Show, SPE 13749, (March 1985).

O'Neill, N., "Fahud Field Review: A Switch from Water to Gas Injection," presented at the 5th SPE Middle East Oil Show, SPE 15691, (March 1987).

Petroleum Engineer International, June 1992, p.13, "DOE Selects 14 EOR Research Projects for Federal Support," Hackberry Field, LA.

Shahsavari and Dabbous, M.K.: "Monitoring and Evaluation of an Immiscible Gas Injection Pilot in Massive Carbonate Reservoir with a Strong Water Drive," presented at the SPE Middle East Oil Show, SPE 21356 (Nov. 1991).

AIR INJECTION

Buxton, T.S. & Pollock, C.B. "The Sloss COFCAW Project - Further Evaluation of Performance During and After Air Injection," *JPT*, Dec 1974, pp. 1439-1448.

Enhanced Recovery Week, Pasha Publications, Arlington, VA, July 23, 1984. pp. 1-4.

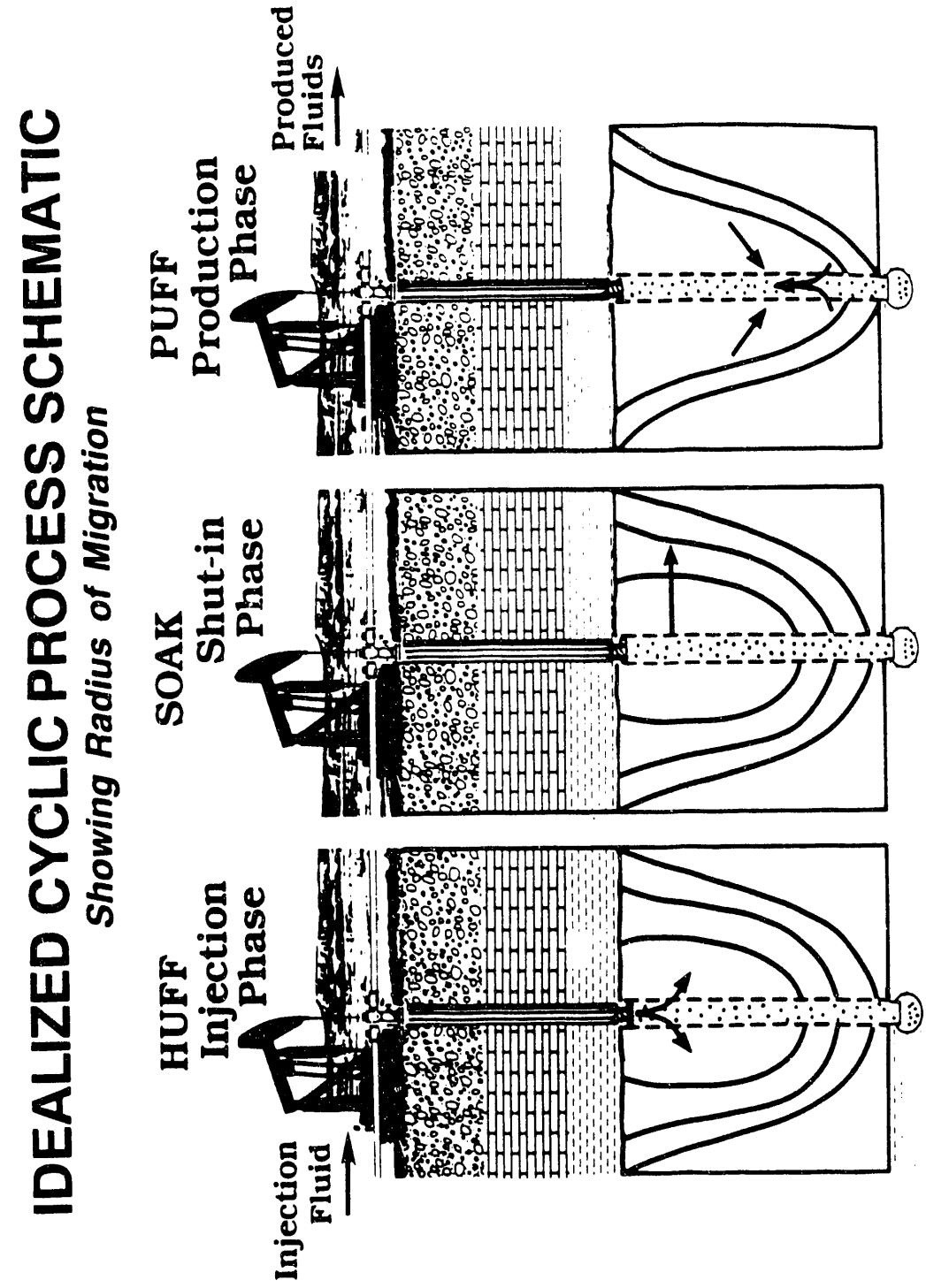
Gates, C.F. & Sklar, I. "Combustion as a Primary Recovery Process - Midway Sunset Field," *JPT*, 8/71, pp. 981-986.

Oil and Gas Journal, PennWell Publishing, Tulsa, OK, Aug. 12, 1985, p.60.

Western Oil Reporter, Hart Publications, Denver, CO, May 1985, p.38.

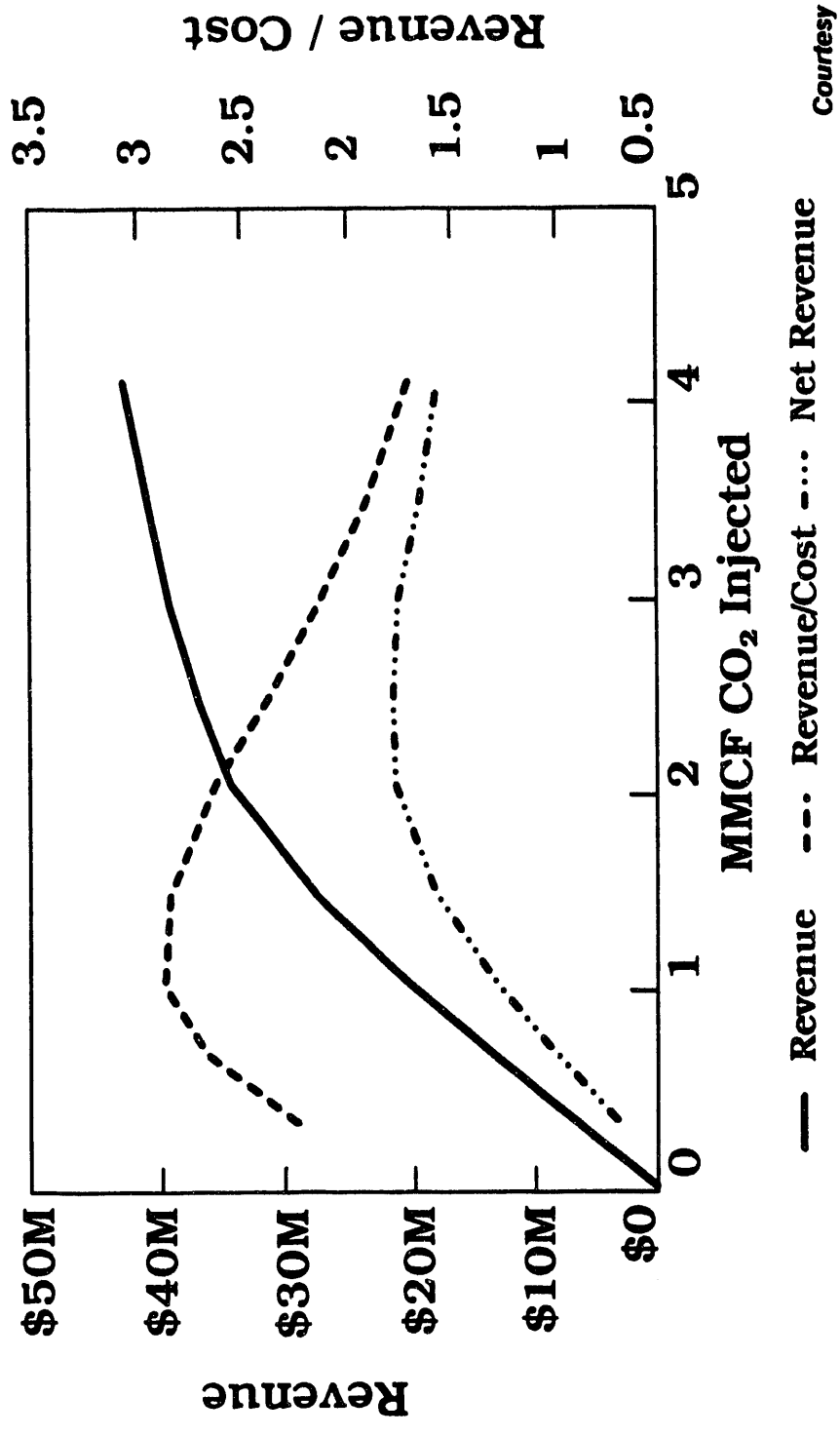
Yannimaras, D.V., Sufi, A.H. and Fussihi, M.R. "The Case for Air Injection into Deep, Light Oil Reservoirs", 6th European IOR - Symposium, Norway, May 1991.

EMERGING GAS INJECTION
TECHNOLOGY
by
Hiemi Kim Haines
MARATHON
Petroleum Technology Center

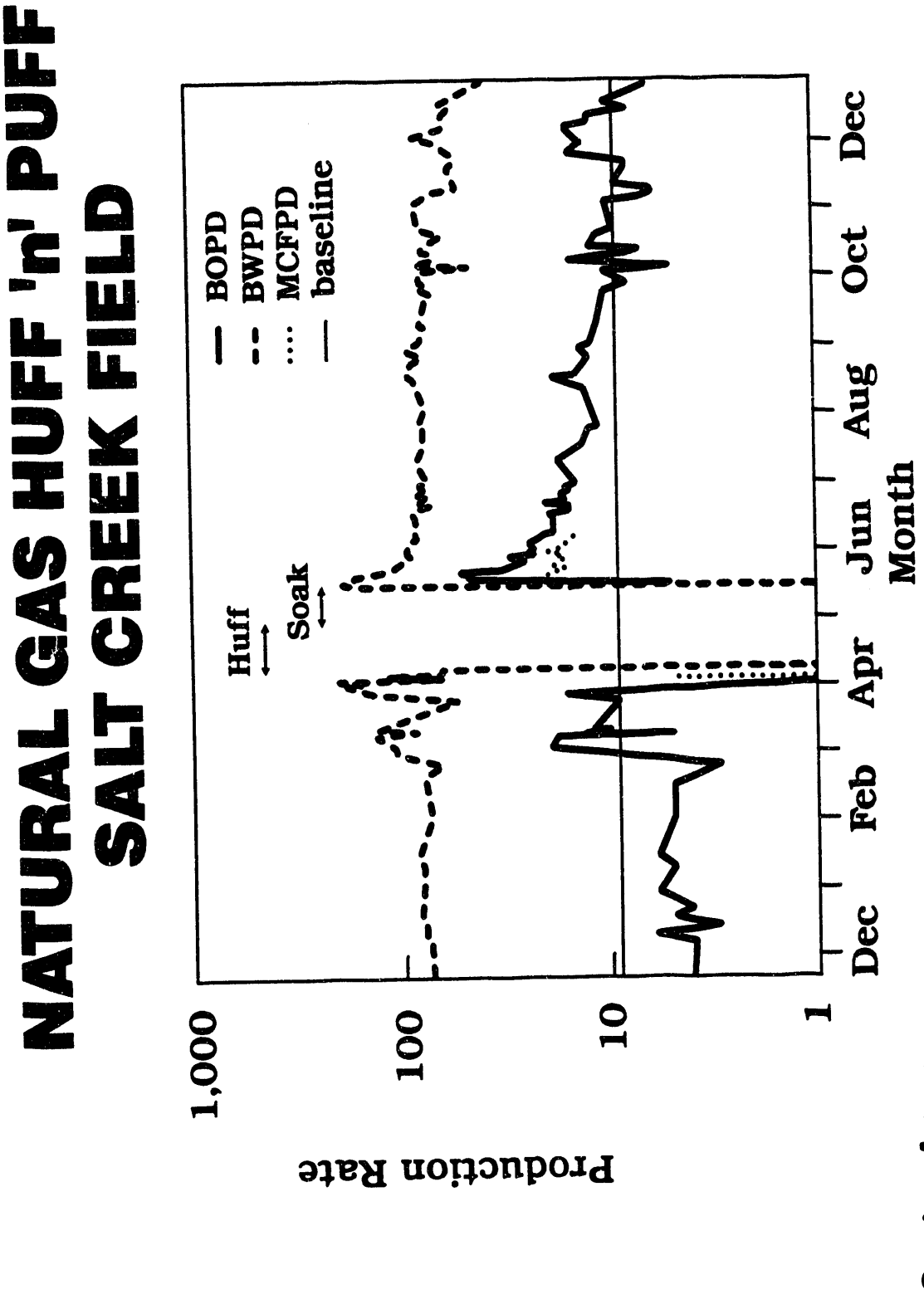

IDEALIZED CYCLIC PROCESS SCHEMATIC
Showing Radius of Migration
HUFF
Injection
Phase
SOAK
Shut-in
Phase
PUFF
Production
Phase
Injection
Fluid
Produced
Fluids

SLUG SIZE CAN BE TAILORED TO DESIRED ECONOMICS

Cyclic CO_2 - Big Sinking Field



Courtesy Bretagne


NATURAL GAS HUFF 'n' PUFF
SALT CREEK FIELD
BOPD
BWPD
MCFPD
baseline
Huff
Soak
1,000
100
10
1
Production Rate
Dec
Feb
Apr
Jun
Aug
Oct
Dec
Month
Courtesy Amoco

CYCLIC GAS INJECTION RECOMMENDATIONS

Reservoir Parameters

- thick pay interval
- immiscible conditions
  below CO_2 MMP undersaturated
- no "thief zones"
- S_{or} appropriate for E_r

Operational Concerns

- Gas Handling
  - exceeding parting pressure
  - cold shock
  - gas locking
  - submersible pump failure
  - change in total fluid
  - drawdown
  - corrosion
  - CO_2 contamination of produced gas
- Rock / Fluid Interactions
  - scaling
  - asphaltene / paraffin deposition
  - emulsification / foaming

RISING BUBBLE APPARATUS (RBA)

— Mimimum Miscibility Pressure (MMP)
is lowest possible operating pressure
at which gas miscibly displace oil.

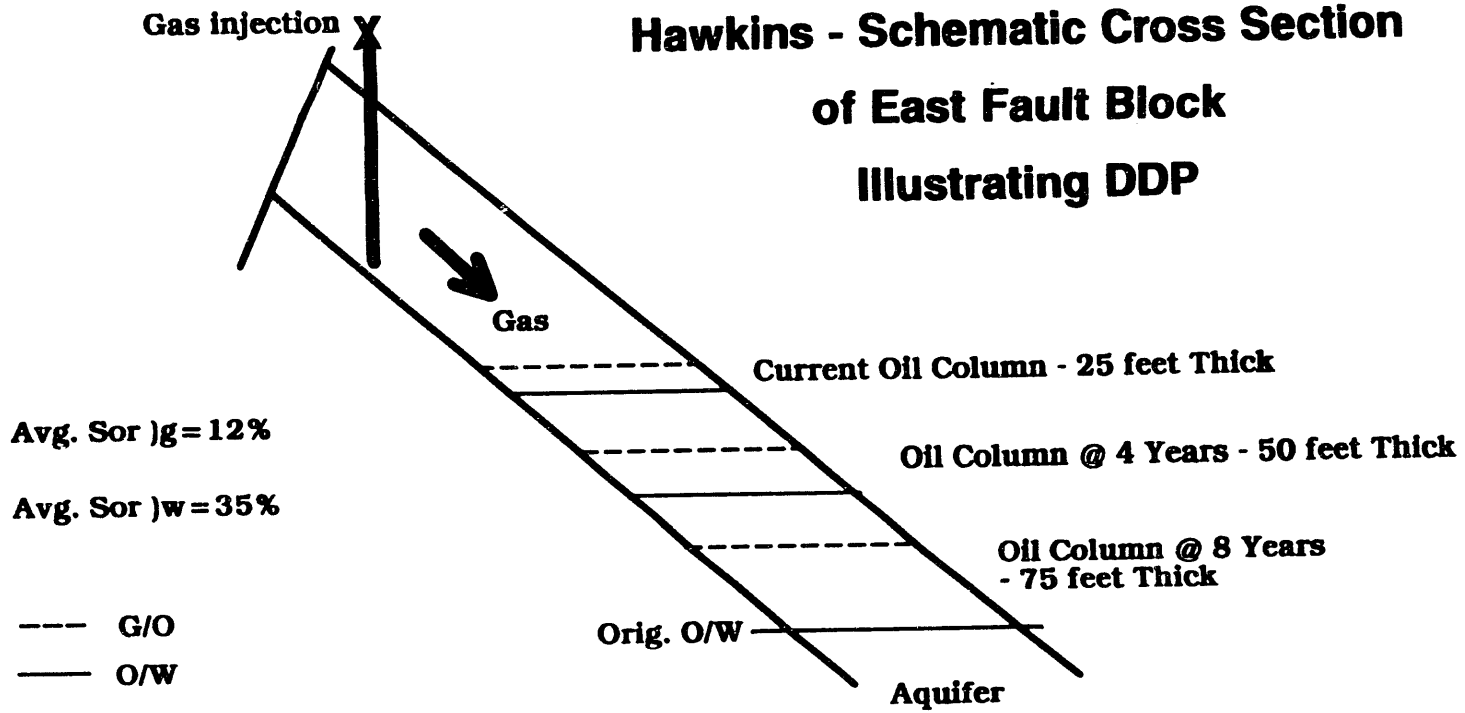
— RBA measures MMP by direct visual
observation of miscibility development
at the phase boundary of a rising bubble.

— RBA approach is much more rapid,
lower cost and requires less sample
than the conventional slim-tube technique.

DOUBLE DISPLACEMENT PROCESS (DDP)

The DDP is gas displacement of a water-invaded oil column with production by gravity drainage.

$$\text{Gravity Drainage Rate} \propto \frac{\Delta\rho \quad k_v}{\mu_o \quad \sigma_{g/o} \quad \Phi} \qquad \frac{dk_{ro}}{dS_o}$$



Double Displacement Process Operational concerns and Reservoir consideration

- Gas availability and handling
- Slow response to gravity drainage
- Sufficient bed dip

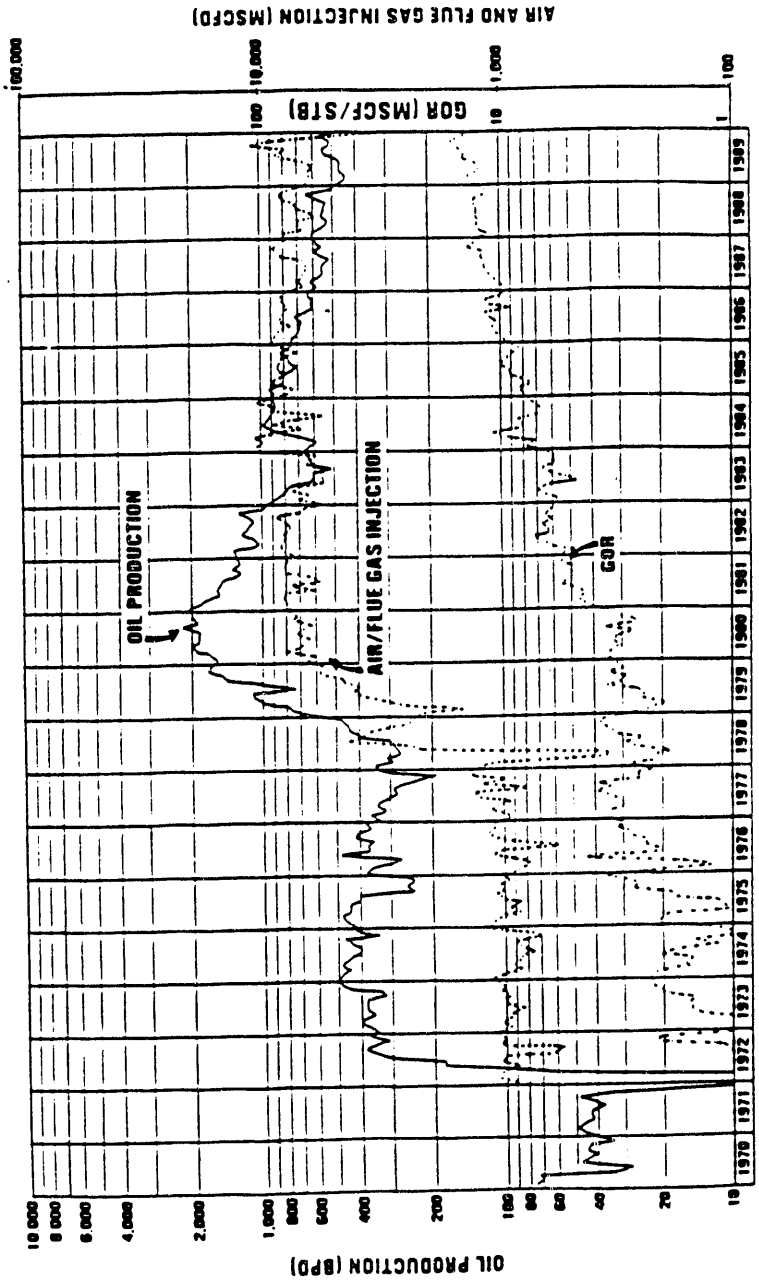
HIGH PRESSURE AIR INJECTION

Air injected into a high pressure and high temperature oil reservoir can result in a spontaneous ignition with the oil in place to generate in-situ flue gas.

Potential advantages:

1. reservoir pressurization.
2. mobilization of combustion oil.
3. flue gas displacing reservoir oil.
4. oil swelling.
5. improvement in the density and viscosity contrast between injected gas and resident oil and water.
6. siginificant economic advantage.
7. spontaneous oil ignition and complete oxygen utilization.
8. miscible and near-miscible effects between generated flue gas and in-place oil.
9. supercritical steam extraction of hydrocarbons.

Figure I-1: Performance of the West Heidelberg Pressure Maintenance Operation



AIR INJECTION
OPERATIONAL CONCERNS AND RESERVOIR CONSIDERATIONS

- complete utilization of injected air (Safety issues)
- vapor recovery unit
- corrosion - resistant tubulars
- reservoir and mechanical wellbore integrity
- high temperature required for self-injection
- vertical relief and reservoir dip

NOTES

CONCLUSIONS

Cyclic gas injection

- **gas is contained and efficiently returned**
- **uniform contact of a thick producing interval**
- **effective gas handling**
- **containing high remaining oil**

Double Displacement Process

- **gas availability and handling**
- **structual dip required for efficient**
- **gravity drainage**

Air injection

- **high temperature and high pressure**
- **safety concerns**

Marathon's MARCIT[SM] and MARA-SEAL[SM] Polyacrylamide Gel Technologies

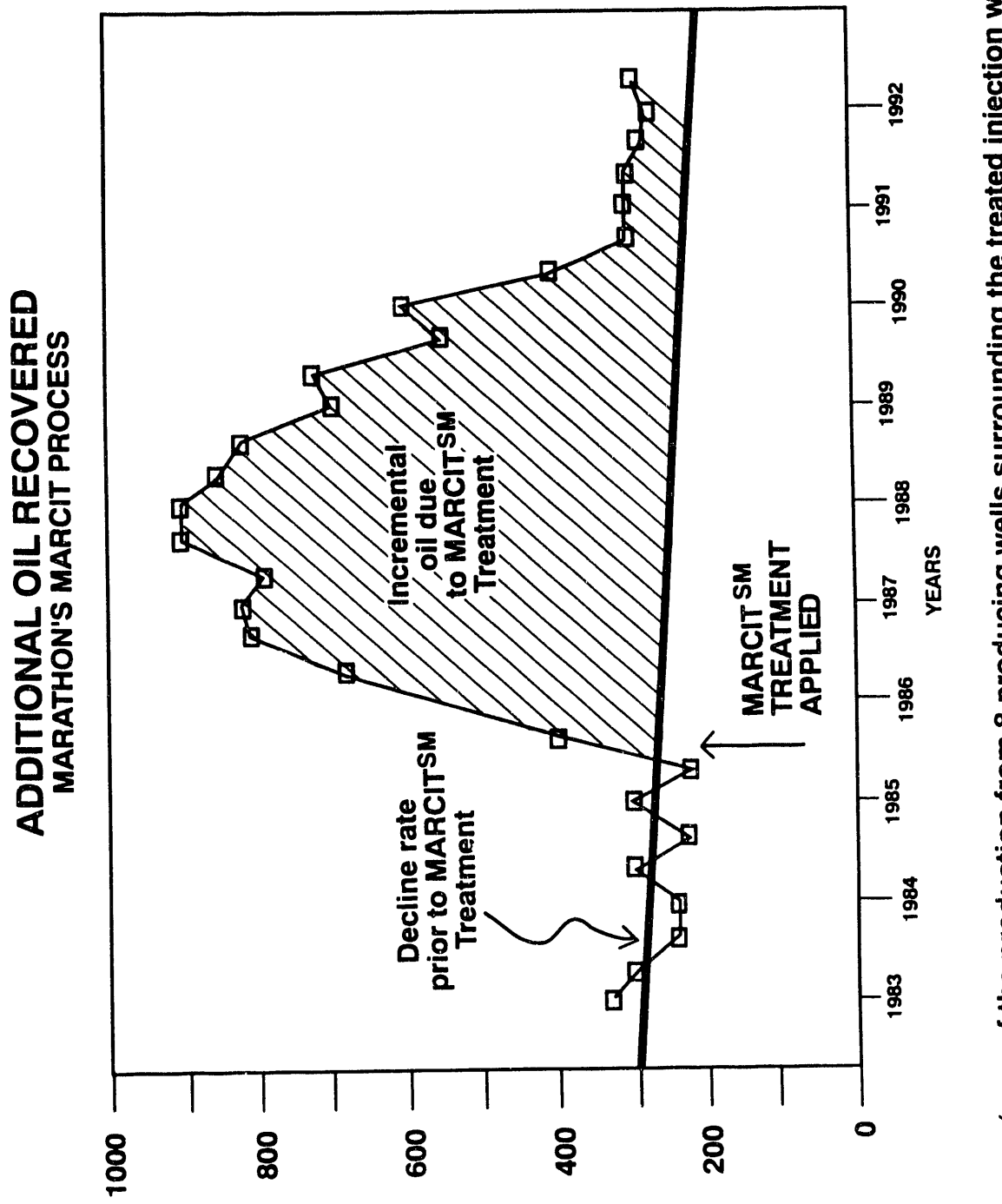
George P. Southwell
Senior Engineer
Marathon Oil Company
PO Box 269
Littleton, CO 80122

Marathon Oil Company has developed a technology for treating injection and production conformance problems for better sweep efficiency. This MARCIT[SM] process is applicable over a wide range of conformance problems and is suitable in hostile reservoir environments. Using similar chemistry; near wellbore treatments provide a complete shut off for zone abandonment's, water or gas shut-off or behind pipe remedial squeezes. This aspect of Marathon's technology is referred to as the MARA-SEAL[SM] Process. Marathon holds 24 patents which cover these technologies and has applied them extensively in the Big Horn Basin of Wyoming, the Yates Field of West Texas, and other locations within the company.

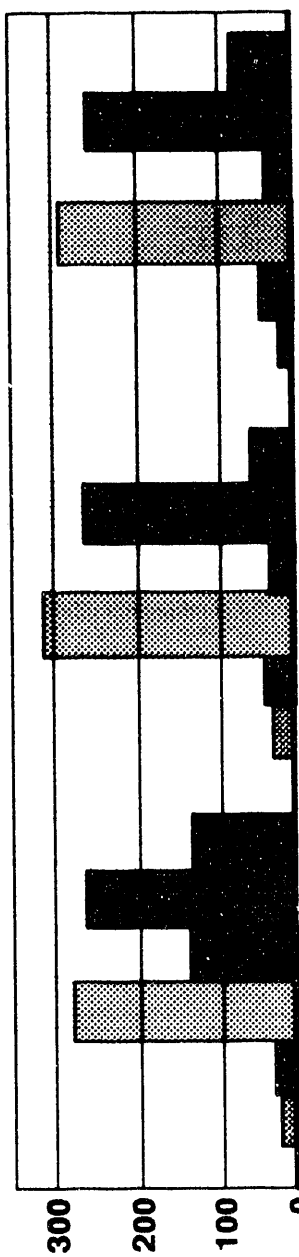
Examples of applications in the Oregon Basin Field, Little Buffalo Basin, and the Pitchfork Fields in Wyoming will be discussed. Each case will demonstrate how this technology is used to develop incremental reserves in Marathon's properties. Further examples of MARA-SEAL[SM], particularly as it is applied in Marathon's Yates Field Unit for sealing the open hole curved section of short radius horizontal re-entries will be presented.

The MARCIT [SM] Process involves the use of low concentration high molecular weight polyacrylamide crosslinked with chrome acetate to produce a flowing gel. This gel, when placed in naturally fractured reservoirs, reduces the flow through the most conductive fractures or channels resulting in redirection of injection fluid to higher oil saturation portions of the reservoir. The same idea is applied to producing wells in natural water drive reservoirs,.particularly where natural fractures provide a conduit to an underlying aquifer. Results of this will be discussed on Marathon's Little Sand Draw and Big Lake (West Texas) projects.

The MARA-SEAL[SM] Process uses low molecular weight polymer at a relatively high concentration and is crosslinked with chrome acetate to form a rigid gel which when placed in a reservoir provides a total shut off. These treatments are typically less than 200 barrels in size and have a wide range of application.


ADDITIONAL OIL RECOVERED
MARATHON'S MARCIT PROCESS
1000
800
600
400
200
0
1983
1984
1985
1986
1987
1988
1989
1990
1991
1992
YEARS
Incremental oil due to MARCIT℠ Treatment
Decline rate prior to MARCIT℠ Treatment
MARCIT℠ TREATMENT APPLIED
(sum of the production from 8 producing wells surrounding the treated injection wel

Results of Producing Well MARCIT℠ Treatments
Big Lake Field



OIL - BEFORE	20	23	18
OIL - AFTER	23	27	39
WOR - BEFORE	269	303	283
WOR - AFTER	134	27	31
EXP/DAY - BEFORE	250	250	250
EXP/DAY - AFTER	125	50	70
COST, $M	70	30	35

OIL - BEFORE ▨ WOR - BEFORE ■ EXP/DAY - BEFORE

OIL - AFTER ■ WOR - AFTER ■ EXP/DAY - AFTER

NOTES

A Status Report on the TIOR-KOH® Process

Ben Sloat
TIORCO, INC.
1795 W. Warren Ave.
Englewood, CO 80110

BACKGROUND

Technology to stabilize clays permanently and to reduce residual oil saturation has now matured in the Powder River Basin and is standard practice on most new Cretaceous sand waterfloods. The process is little known and seldom used outside of the Basin and, in this sense, presents an excellent opportunity for technology transfer.

THE PROBLEM

Early core work showing the effect of a salinity change on the permeability contrast of a suite of Sussex sand cores is summarized in Table 1 and shown graphically in Figure 1. Permeability variation is magnified three-fold when fresh Fox Hills water is used to flood the cores following the Sussex sand formation water.

EARLY FIELD TESTS

Figure 2 documents one of the early pump-in/pump-out tests run in an Almy sand in the Green River Basin. The pump-in portion of the test is shown graphically along with tabular data describing the rock and fluid properties and the effect that various alkaline agents have on interfacial tension (IFT). Potassium hydroxide reduces the IFT from 31.1 dynes to 0.2 dynes at concentrations as low as 0.2 weight percent.

Figure 3 overlays the pump-out portion of the test on the original pump-in volume and tracks the pH of the produced water and the volume of oil actually mobilized and recovered as a result of the alkaline action.

Figure 4 compares the Hall plot for TIOR-KOH® treated injection well #86 with three existing injection wells in the same pattern area. Conventional treatment for clay stabilization in this field utilized potassium chloride soaks followed by the coating action of cationic polymer. Injection well #86 was the first to receive the potassium hydroxide process. The resulting Hall slope is interpreted to show that residual oil is being moved from the near wellbore area since it is decreasing with cumulative water injection. The other three wells show no slope change.

PROCESS DESIGN

Figure 5 is a typical design based on 1 porosity-foot of treatment zone. Ten feet of 10% porosity would equal 1 porosity-foot. The preflush volume and concentration of potassium chloride (TIOR-KOH® 899) required to remove divalent ions from the near wellbore area is shown along with a diversion step. Potassium hydroxide is then added over a 48 hour period at a concentration that is inversely proportional to reservoir temperature. The post flush displaces potassium hydroxide from the near wellbore area and allows any excess to be adsorbed or reacted with formation surfaces. Treatment costs are for the chemical components of the process. When the necessary equipment to do the job is figured in, the total for budget purposes is $16,000 per vertical porosity-foot.

RESULTS

Results of applying the TIOR-KOH® Process to Upper Cretaceous reservoirs in the Powder River Basin are summarized in the three tables that appear on Attachment 6. The Shannon sand wells, treated mainly in 1985, showed a stabilized injection rate in barrels per porosity-foot per day of 193. The Sussex and Teapot sands, treated in much the same way, showed 119 barrels per porosity-foot per day. An extremely tight Newcastle sand with one very good response well (CTU-29) factored out resulted in 84 barrels per day per porosity-foot.

ECONOMICS

Attachment 7 summarizes the first ten years of activity with the technology. One hundred ninety-five (195) wells have been treated up through February of 1993. Slightly over 3 million pounds of 100% active potassium hydroxide has been utilized in stabilizing the clays in these injection wells and in reducing residual oil saturation. The average well treated received 15,713 lbs. of potassium hydroxide and together with the preflush and equipment costs totaled $25,141 per well.

The process has three basic pay outs. First is the value of oil mobilized in the near wellbore area as a result of the IFT action of the potassium hydroxide. This effect pays out at any net oil price above $11.73/bbl. Combining this oil with the effect of improved relative permeability and higher injection rates results in an ultimate recovery of 26,300 bbls/well. The incremental cost of these added reserves is $0.96 per barrel.

TABLE 1

THE EFFECT OF A CHANGE IN WATER COMPOSITION
ON PERMEABILITY CONTRAST*

		Core #1	Core #2	Core #3	Permeability Contrast (Hi ÷ Lo)
Air Permeability - md		21	0.63	8.4	33.3
Liquid to Air Perm. Ratio	-Initial	0.45	0.30	0.10	4.5
Sussex	-2 PV	0.475	0.33	0.10	4.75
Formation	-20 PV	0.55	0.33	0.11	5.0
Water	-Final	0.67 (216 PV)	0.32 (48 PV)	0.12 (26 PV)	5.5
Fresh	-2 PV	0.61	0.26	0.10	6.1
Fox Hills	-20 PV	0.455	0.18	0.035	13.0
Supply	-Final	0.43 (61 PV)	0.16 (95 PV)	0.03 (31 PV)	14.3

* Data from State #16-1 Triangle U Unit - Sussex Sand

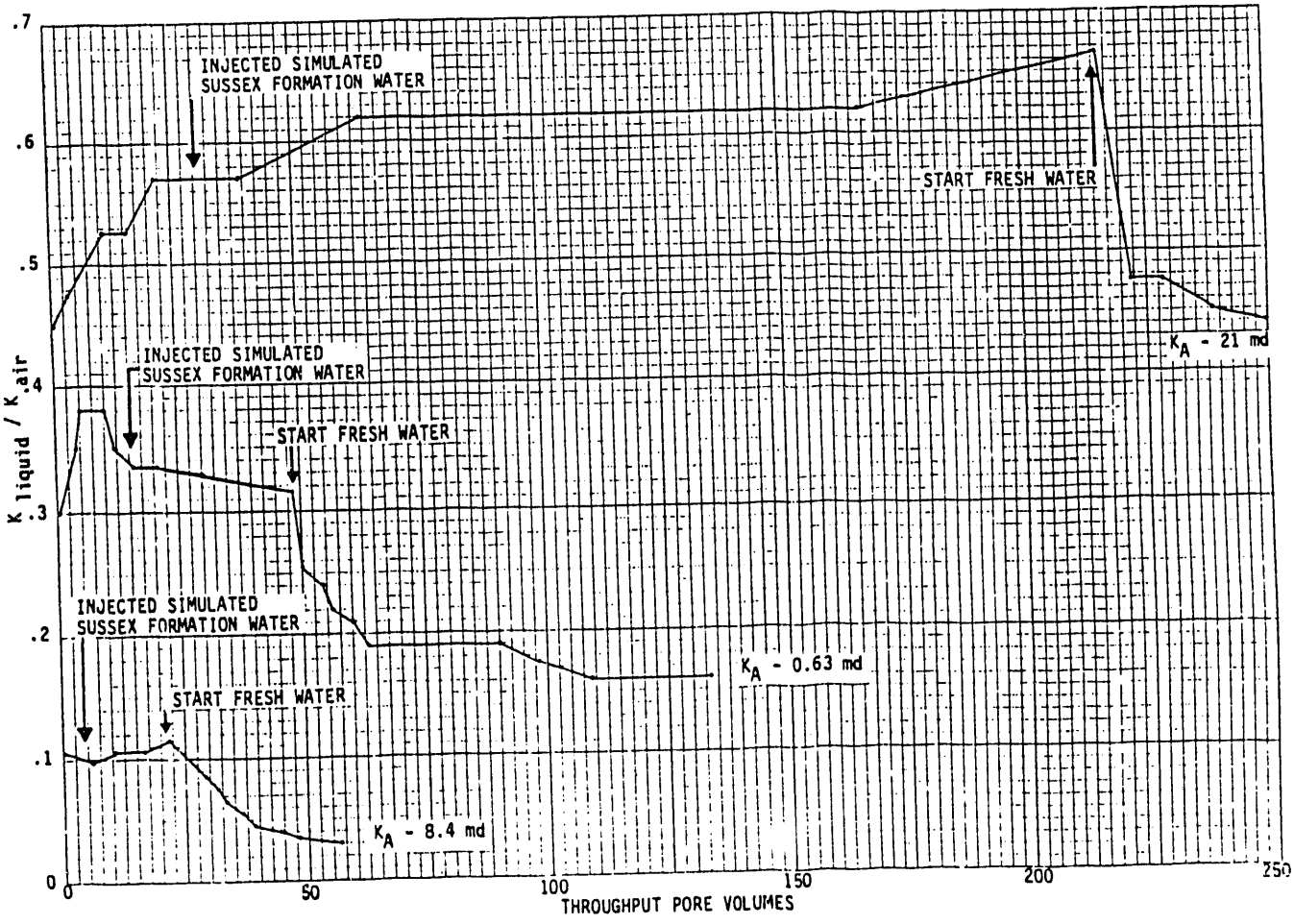


Figure 1 - Coreflood Data for Sussex Sand with Formation Water and Fresh Fox Hills Supply

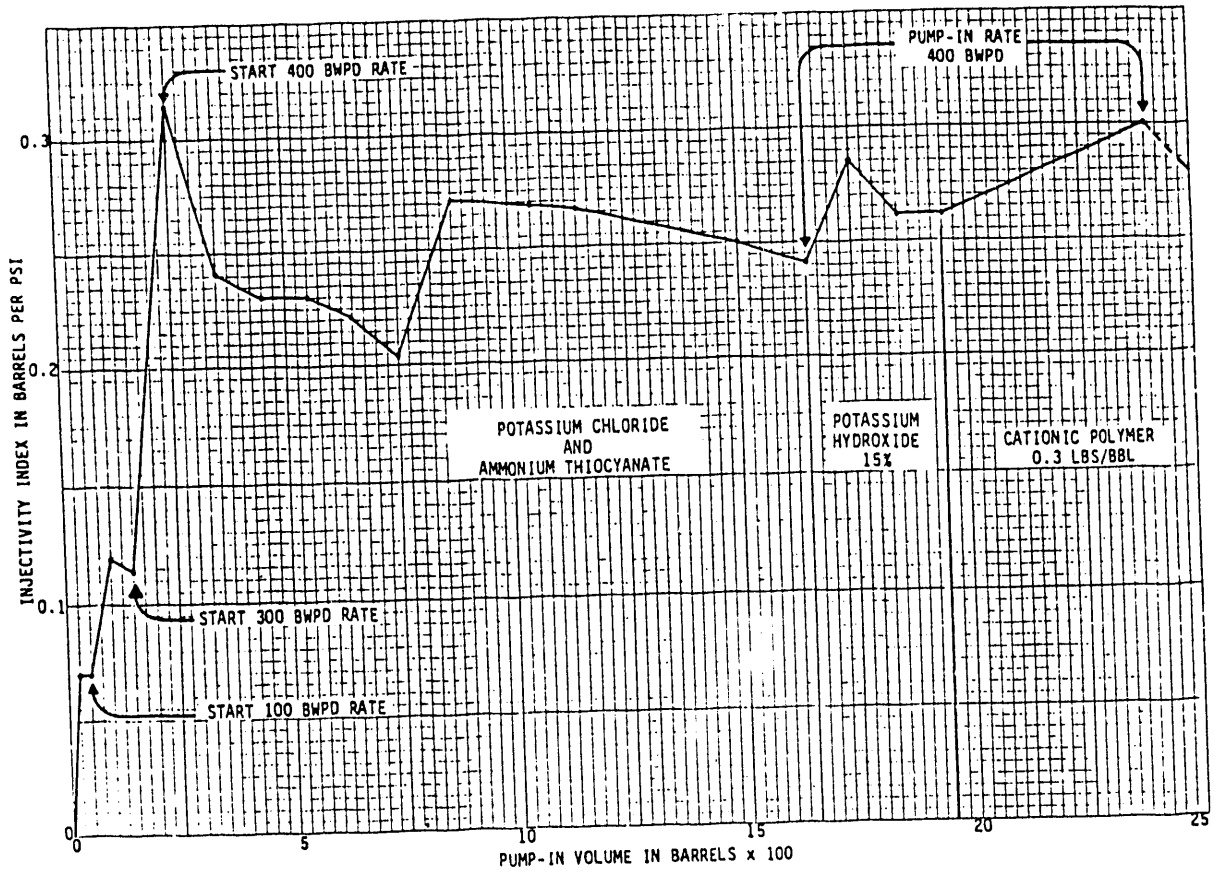


Figure 2 - Ruben Unit 8-Injectivity Index vs. Cumulative Injection Volume

TABLE 2

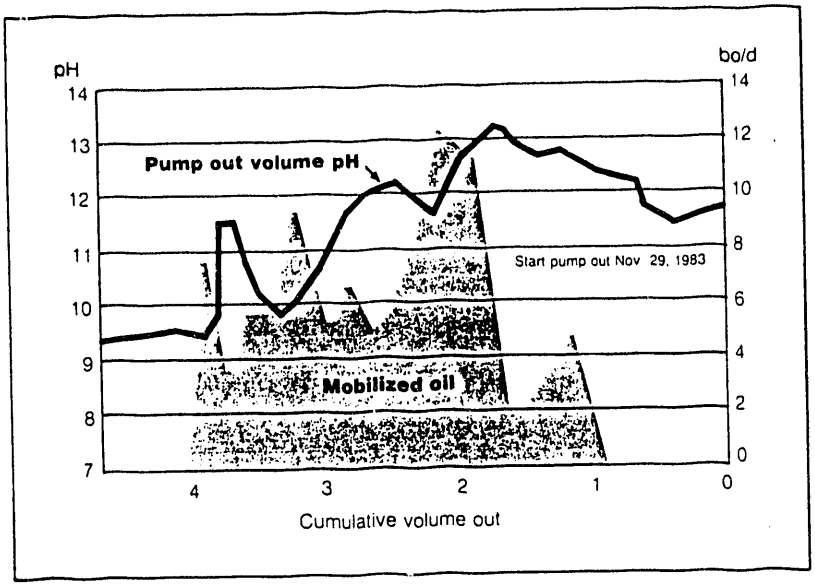
RUBEN UNIT - S-4 ZONE
PERTINENT ROCK and FLUID PROPERTIES

Formation	Almy (Tertiary)
Depth	3,500 Feet
Thickness (Oil Column)	17.3 Feet
Porosity	14.4%
Permeability	4 - 33 md V = 0.55
Shaliness	10% (estimated)
Temperature	95°F
Oil Gravity	43° API
Oil Viscosity	0.9 cps @ Bubble Point
Connate Water	41.5 % PV
Residual Oil	20 %

TABLE 2-A

EFFECT OF ALKALINE AGENTS
ON UNTREATED ALMY SAND CRUDE OIL
FROM RUBEN UNIT #6 - S-4 ZONE

Wt. % Alkali	Interfacial Tension in Dynes		
	Potassium Hydroxide	Soda Ash	Sodium Ortho Silicate
0	31.1	31.1	31.1
0.1	6.1	19.7	
0.2	0.2	16.7	23.6
0.4	0.1	10.7	
0.6	0.1	7.0	9.0
0.8	0.2	6.0	
1.0	0.2	4.8	3.1
1.5	0.1	1.9	
2.0	0.2	0.2	0.2
3.0	0.2	0.2	
4.0	0.3	0.1	0.1



Belco's Ruben Unit 8 - Figure 3

Measurable oil production occurred on the fourth day of a two-week pumpout test and rose to 13 b/d. Total recovery was 16 bo/acre-ft or 1.4% pore volume. (Source: Tiorco)

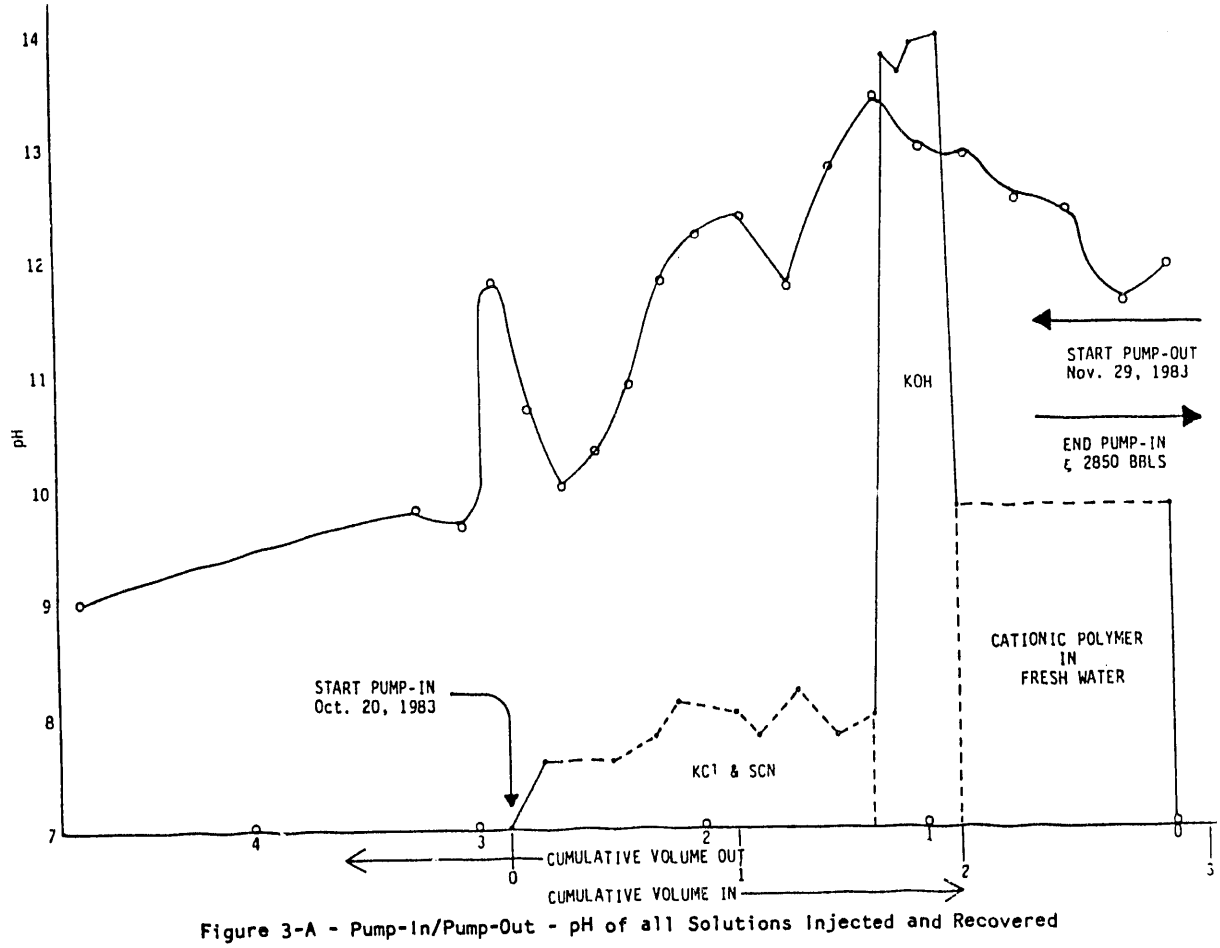
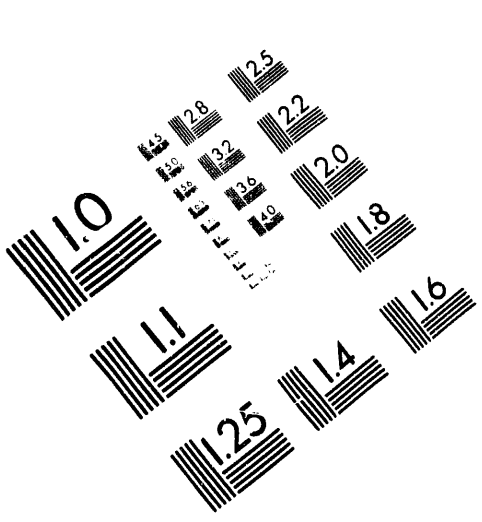


Figure 3-A - Pump-In/Pump-Out - pH of all Solutions Injected and Recovered

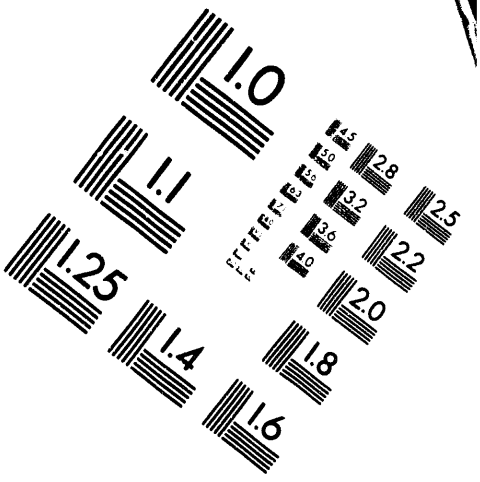


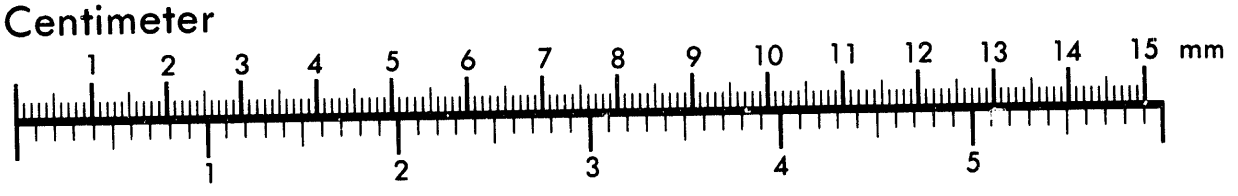


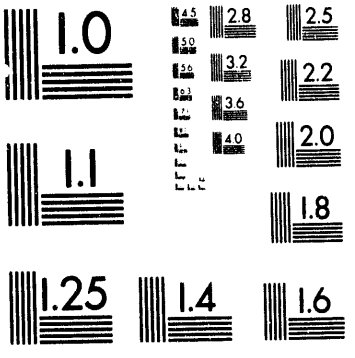
Association for Information and Image Management

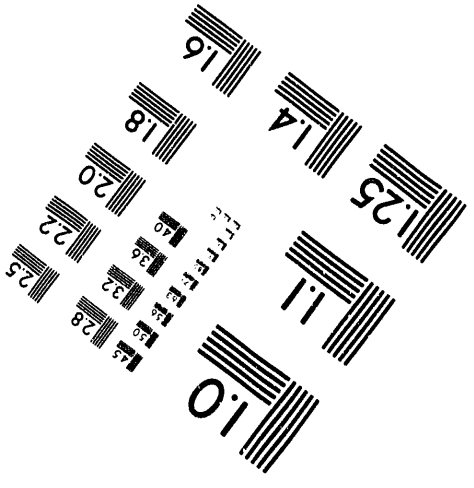
1100 Wayne Avenue, Suite 1100
Silver Spring, Maryland 20910

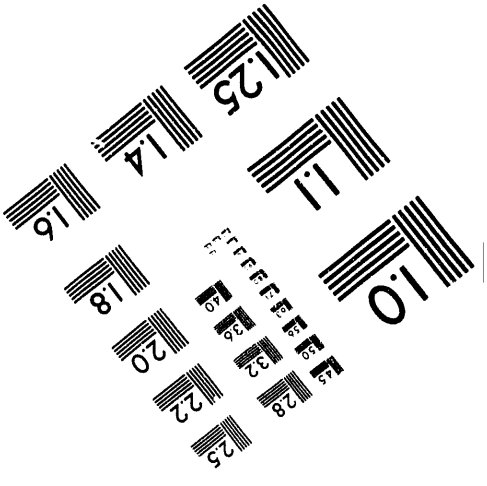
301/587-8202











MANUFACTURED TO AIIM STANDARDS
BY APPLIED IMAGE, INC.

4 of 5

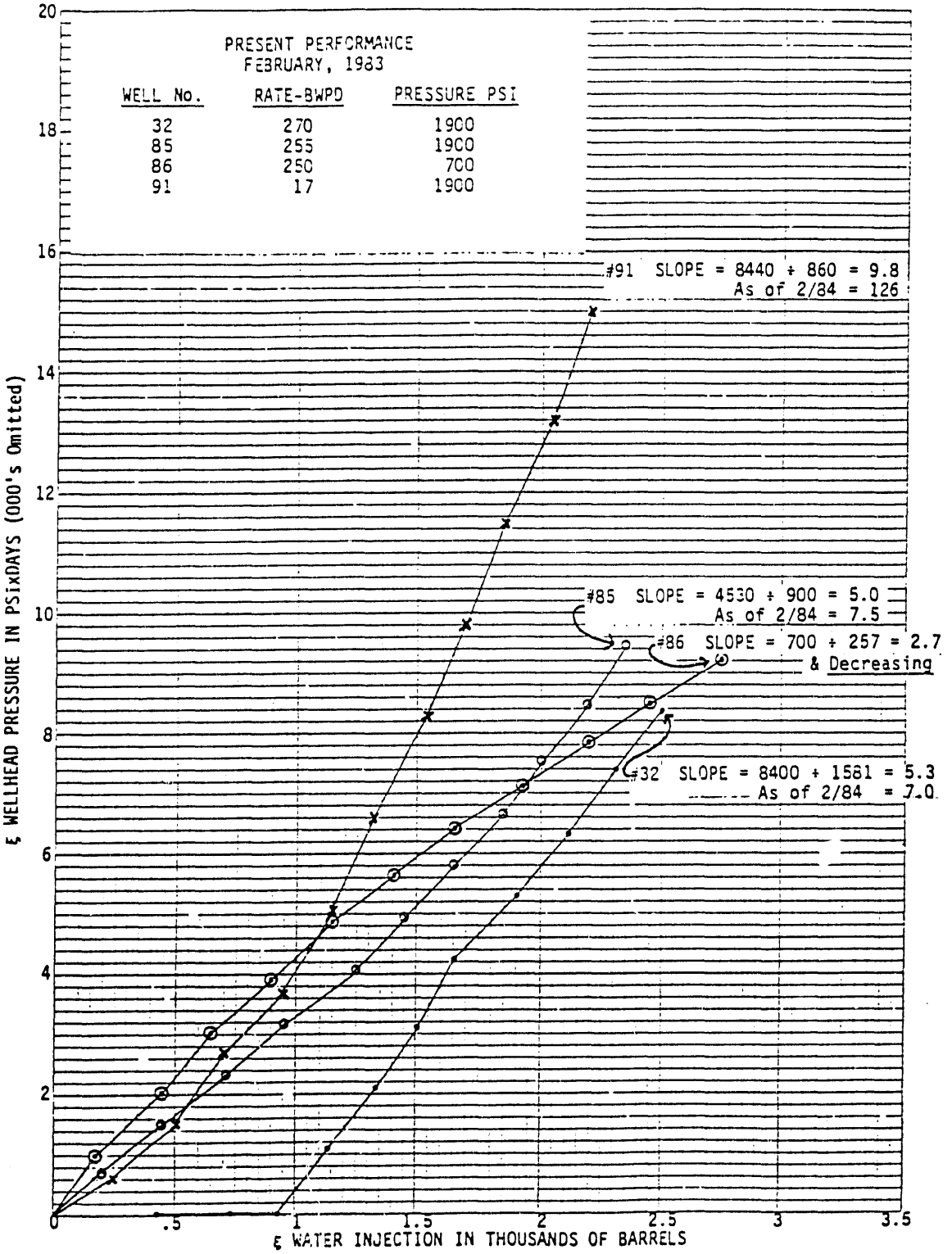


Figure 4 - San Miguel Sand Unit - Hall Plots for Injection Wells 32, 85, 86, and 91

FIGURE 5

TIOR-KOH® PROCESS DESIGN FOR PRETREATMENT OF
INJECTION WELLS TO STABILIZE CLAYS
Basis: One Porosity x Foot

	BOTTOM HOLE TEMPERATURE	
PREFLUSH	**GREATER THAN 150°F**	**LESS THAN 150°F**
Volume - BBLS	1,000	1,000
TIOR-KOH® 899 - Tons	5	5
TIOR-KOH® 899 - $	1,900	1,900
DIVERSION [1]		
Volume - BBLS	100	100
TIOR-KOH® 899 - Tons	7	7
TIOR-KOH® 899 - $	2,660	2,660
TIOR-KOH® TREATMENT - ADDED OVER 48 HOURS		
TIOR-KOH® 845 - BBLS	45	45
TIOR-KOH® 845 - LBS	23,000	23,000
TIOR-KOH® 845 - $	10,350	10,350
MAKEUP WATER - BBLS	131	33
TIOR-KOH® 815 - BBLS	176	-
TIOR-KOH® 830 - BBLS	-	78
POST FLUSH		
Volume - BBLS	500	500
TIORCO® 535 - LBS	25	25
TIORCO® 535 - $	44	44
TOTAL/WELL - SOFT WATER - BBLS	1,731	1,633
COST W/O DIVERSION - $	12,294	12,294
DIVERSION - $	2,660	2,660
TOTAL COST PER WELL - $	14,954	14,954

[1] Half added midway through the preflush with the balance halfway through the TIOR-KOH® 815 or 830 treatment.

[2] Diversions:
1) 50 BBL fresh water
2) Mix saturated solution (from chart) for temperature
3) Heat solution to reservoir temperature
4) Flow 15 BBLS into well
5) Add dry TIOR-KOH® 899 (300# x Ø/ft)
6) Flow remainder saturated solution into well

ATTACHMENT 6

UPPER CRETACEOUS SHANNON SAND, NORTHEAST WYOMING (depth = 9,500 ft; BHT > 190°F)

Line	Date	Well	Vertical Porosity (porosity-ft)	KOH Used (lbm)* Total	KOH Used (lbm)* Per Porosity-Foot	Stabilized Rate** (B/D)	Injectivity (bbl/porosity-ft/D)	Hall/Slope (psi-D/bbl)
7	April 1985	52-43	0.97	10,600		167	172	18.5
8	May 1985	51-42	1.25	12,500		160	128	9.1
9	June 1985	51-44	0.49	4,985		132	269	15.4
10	June 1985	51-33	2.76	28,085		227	82	4.8
11	July 1985	52-52	2.17	22,050		147	68	8.2
12	Sept. 1985	41-53	3.07	31,640		201	65	8.5
13	Aug. 1985	42-33	2.34	23,880		138	59	6.7
14	April 1985	H-15	1.28	12,860		311	243	7.0
15	April 1985	C-5	1.1	8,405		211	192	11.2
16	May 1985	C-3	1.09	10,930		268	246	8.2
17	May 1985	A-5	1.36	14,190		619	455	2.9
18	June 1985	A-4	1.24	13,160		584	471	2.9
19	June 1985	H-5	0.88	9,185		484	550	3.1
20	June 1985	C-16	1.01	10,240		145	144	16.5
21	June 1985	C-24	0.93	8,730		287	309	7.3
22	June 1985	K-1	1.55	13,010		473	305	4.4
23	June 1985	K-2	1.18	12,075		392	332	5.6
24	June 1985	H-1	1.12	11,690		334	298	6.2
25	June 1985	H-21	0.78	7,855		134	172	18.7
26	June 1985	H-9	1.35	13,910		118	87	21.9
27	June 1985	H-34	1.76	17,730		222	126	11.2
28	June 1985	H-32	1.12	11,480		277	247	8.4
29	June 1985	H-18	1.88	19,290		172	91	13.8
30	June 1985	C-19	0.88	8,800		285	323	9.1
		Totals	33.56	337,280	10,050	6,488	193	—

*All treatment solution strengths were 15 wt%. Values are in dry-weight (100% active) pounds.
**After more than 35,000 bbl of cumulative water injection.

UPPER CRETACEOUS, SUSSEX AND TEAPOT SANDS, NORTHEAST WYOMING (depth = 7,500, BHT > 170°F)

Line	Date	Well	Vertical Porosity (porosity-ft)	KOH Used (lbm)* Total	KOH Used (lbm)* Per Porosity-Foot	Stabilized Rate** (B/D)	Injectivity (bbl/porosity-ft/D)	Hall Slope (psi-D/bbl)
31	Sept. 1985	14-29	1.44	14,620	10,152	302	210	6.1
32	Sept. 1985	3-9	1.17	24,938	21,315	88	75	35.3
33	Dec. 1987	2	1.4	13,901	9,929	294	210	6.5
34	Dec. 1987	24-32	1.7	17,449	10,264	144	121	7.6
35	Sept. 1987	4-14	5.6	56,600	10,107	350	63	1.1
36	Sept. 1987	2-14	2.4	23,731	9,888	125	52	3.2
37	Oct. 1987	2-23	4.5	45,136	10,030	675	150	0.6
38	Nov. 1987	4-13	2.7	28,019	10,377	450	167	0.9
39	Dec. 1987	13-19	3.5	34,778	9,937	483	138	Vacuum
		Totals	24.41	259,172	10,617	2,911	119	—

*All treatment solution strengths were 15 wt%. Values are in dry-weight (100% active) pounds.
**After more than 10,000 bbl of cumulative water injection.

CRETACEOUS NEWCASTLE SAND, NORTHEAST WYOMING (depth = 4,500, BHT = 130°F)

Line	Date	Well	Vertical Porosity (porosity-ft)	KOH Used (lbm)* Total	KOH Used (lbm)* Per Porosity-Foot	Stabilized Rate* (B/D)**	Injectivity (bbl/porosity-ft/D)	Hall Slope (psi-D/bbl)
40	Sept. 1985	CTU-29	1.5	15,264	10,176	500	333	1.4
41	Feb. 1986	7-28	1.2	12,000	10,000	102	85	15.2
42	Feb. 1986	7-4	1.6	16,000	10,000	107	67	15.6
43	Feb. 1986	8-1	1.8	18,000	10,000	144	80	9.3
44	Feb. 1986	2-2	1.6	16,000	10,000	136	85	10
45	Feb. 1986	2-5	2.0	20,000	10,000	178	89	5.6
46	Feb. 1986	3-7	1.8	18,000	10,000	175	97	2.7
		Totals	11.5	115,264	10,023	1,342	117	—

*All treatment solution strengths were 30 wt%. Values are in dry-weight (100% active) pounds.
**After more than 10,000 bbl of cumulative water injection.

ATTACHMENT 7

TIOR-KOH® Process Summary

YEAR	NUMBER OF TREATMENTS	POTASSIUM HYDROXIDE 100% ACTIVE LBS/YEAR	POTASSIUM HYDROXIDE 100% ACTIVE LBS CUMULATIVE	INCREASED OIL IFT EFFECT	RECOVERY IFT & Krw	CUMULATIVE INCREASED OIL RECOVERY
1983	2	40,000	40,000	5,457	64,000	64,000
1984	4	70,000	110,000	9,550	112,000	176,000
1985	45	625,084	735,084	85,277	1,134,000	1,486,000
1986	14	144,028	879,112	19,649	230,445	1,716,445
1987	9	202,847	1,081,959	27,674	324,555	2,041,000
1988	11	168,685	1,250,644	23,013	269,896	2,310,896
1989	10	109,868	1,360,512	14,989	175,789	2,486,685
1990	10	187,955	1,548,467	25,642	300,728	2,787,413
1991	30	467,279	2,015,746	63,749	747,646	3,535,059
1992	37	490,595	2,506,341	66,930	784,952	4,320,011
1993	23	557,705	3,064,046	76,085	892,328	5,212,339
TOTALS	195	-	3,064,046	418,015	-	5,212,339

Average Treatment Size: 15,713 lbs.
Average Treatment Cost: $25,141

Pay Out:
- IFT Effect Only - 2,144 bbls
  Break Even Oil Price - $11.73/bbl
- Combined Effect of IFT, Krw and
  Increased Injection Rates - 26,300 bbls
  Cost per Incremental Barrel Oil - $0.96

3-D SEISMIC & AMPLITUDE VARIATION WITH OFFSET (AVO)SESSION

Friday, May 7, Morning: 8:00 AM to 11:30 AM

Session Chairman: R. Randy Ray, R ^{3} Exploration Corporation

See in 3-D: Introduction and Session Overview 1
R. Randy Ray, R^{3} Exploration Corporation, Lakewood, CO

An Overview of 3d Seismic in Exploration, Development, and Production Environments 5
Tony Rebec, Halliburton Geophysical Services, Inc.,

Fundamental 3-d Seismic Survey Design 9
Stuart Wright, Western Geophysical, Englewood, CO

Ojo Encino Field: An Entrada Dune Defined by 3-D Seismic 15
L. Douglas Endsley, Consulting Geologist, Farmington, NM

3D Seismic Reservoir Characterization: Sooner Unit, Weld County, CO 19
D. Scott Singdahlsen, Interactive Earth Sciences Corporation, Denver, CO

Coalbed Methane Multicomponent 3-D Reservoir Characterization Study, Cedar Hill Field, San Juan Basin, NM 23
Dr. Tom Davis, Colorado School of Mines, Golden CO

Detecting Subsurface Reservoir States Using Seismic AVO (Amplitude Variation with Offset) 27
R. H. (Dick) Angerer, Associated Geophysical Analysts, Inc., Lakewood, CO

NOTES

"SEE in 3-D": INTRODUCTION AND SESSION OVERVIEW

R. Randy Ray
R3 Exploration Corporation
9277 W. Alameda Ave., Ste. 206
Lakewood, CO 80226

The use of 3-D seismic is sweeping across the US domestic exploration front. Recent successes in West Texas reef plays have pointed out the economic benefits of using 3-D seismic in delineating small traps that have slipped through the existing grid of 2-D seismic coverage. Because 3-D seismic more completely images the subsurface, it helps reduce the risk of finding and developing additional reserves.

3-D seismic surveys have the advantage of more completely imaging the subsurface by increasing the number of points sampled in an area. They commonly reveal a picture which is more complex than envisioned by mapping of scattered well control and a grid of 2-D seismic profiles. Surveys often show a detailed pattern of faulting or an intricate design of stratigraphic variation which dramatically improves the geologic understanding of hydrocarbon traps and reservoirs. As a result, new wells may be successfully positioned to test a trap at its optimum position or to drain untapped compartments within existing fields.

When deciding whether a 3-D survey would be helpful for an area one must ask two key questions. First: Can the geologic objective be resolved on conventional 2-D seismic profiles? The geologic interval must be thick enough to be seismically visible and laterally mappable. If you can see it on 2-D lines then you will see it better in 3-D. Second: Do you have enough geological or geophysical control to have the prospect targeted? It must be within a reasonable size area, usually a few square miles,so you can afford to 3-D image it. A 3-D survey builds fold to the center of the area imaged, similar to building fold on a 2-D seismic line. Therefore, the surface area of a survey will be larger than the required subsurface coverage. Probably the smallest 3-D survey that would be shot would be about 2 square miles to image a subsurface area of 1 square mile.

Proceeding with a 3-D survey requires advanced planning and expertise (see attached checklist). After the geologic objective is defined, a survey design is made. This requires an experienced and knowledgeable geophysicist who can understand the resolution limitations of the seismic tool as applied to the specific case. Normally , a geophysically ideal design is laid out with high fold and closely spaced samples. Then, by reviewing costs, it is refined down to an "optimum" design which balances data quality versus costs. For the independent, a key

benchmark for 3-D survey costs becomes the cost of a dryhole. They are usually willing to spend close to the cost of a dryhole for information but beyond that they would rather have the chance of finding the field. With a survey design in hand, acquisition bids can be obtained from seismic contractors.

After a seismic crew has been lined up to shoot the survey, a series of steps begin. The survey must be permitted for access across the surface and minerals. Since a 3-D survey occupies more of the surface than a conventional profile, the access costs and damages can be many times more. Normally 3-D permits are paid on an acreage basis instead of linear mileage basis. If crops must be purchased over a survey area then the cost of the survey will dramatically increase. Once the area is permitted, the surface locations for geophones and source points must be carefully surveyed. Next, the seismic crew is mobilized and sent out to acquire the data. Some onsite testing may be required to finalize acquisition parameters.

After the data is acquired in the field it is returned to a computer center where it is processed. Computer manipulation of the data is in three-dimensions for making weathering corrections, line statics, velocity analysis and stacking. Most data sets will be migrated to reposition the reflections to their true subsurface location. Proper 3-D migration of seismic containing structural or stratigraphically dipping horizons is one of the most powerful advantages of the 3-D survey.

Finally, after the 3-D volume of data is processed, it is loaded onto a computer workstation for interpretation. The data set can be viewed in profile or map form. Commonly, key horizons are correlated through the data cube and horizon maps are displayed. These powerful images show detailed fault patterns and stratigraphic patterns that aid in understanding reservoir geometries and traps. With a more complete view of the subsurface, reserve additions can be accomplished with less risk. 3-D surveys are proving themselves to be very cost effective.

The speakers in this session will cover a range of applications for 3-D seismic. An overview of 3-D seismic uses for exploration, field development and production settings will be presented. One speaker will focus on how to set up a 3-D survey for your particular objective or prospect. Finally, three case histories from the Rockies will show examples that illustrate potential applications. The case histories include the Muddy "D" Sand at the Sooner Unit in the DJ Basin, the Entrada Sand at the Ojo Encino Field in the San Juan Basin and a coalbed methane reservoir at Cedar Hill Field in the San Juan Basin. Finally, a review of AVO (amplitude variation with offset) will illustrate higher level aspects of analyzing seismic data for reservoir characteristics.

3-D SEISMIC CHECKLIST

I. Can the geologic objective be seen on conventional 2-D seismic profiles?

If structural: Is the reservoir horizon a seismically mappable event?
If stratigraphic: Is it thick enough to be seismically visible?

II. Can a 3-D survey be positioned accurately enough to completely image the prospect/field and delineate a drillsite?

III. Proceeding with a 3-D survey requires expertise, time and expense to complete the following sequence of steps:

1) SURVEY DESIGN
   Based on specific area's geologic objectives

2) ACQUISITION BIDS/CONTRACTS
   Based on the survey design parameters and the geographic location of the survey, various seismic contractors will give costs to acquire the data

3) DATA ACQUISITION
   1) Mobilization of the crew
   2) Permitting access & damages
   3) Surveying - all source & receiver points
   4) Testing of shooting parameters
   5) Shooting data

4) PROCESSING DATA
   Manipulation of the raw data in the computer center to correct for 3-D statics, weathering, velocities, stacking, migration and final display of data volume

5) INTERPRETATION
   Geophysicist studies data volume by generating time & horizon slice views, maps and seismic profiles on computer workstation

NOTES

An Overview of 3D Seismic In Exploration, Development and Production Environments.

By

Tony Rebec
Halliburton Geophysical Services, Inc.
700 Halliburton Center
5151 San Felipe, Houston, Texas 77056
Tel: 713-624-2216/Fax: 713-624-2464

The three dimensional seismic method, 3D for short, has played a far more important role in the exploration, development and production areas in the last half a decade than simply redefining the structural and stratigraphic subsurface picture. 3D today is emerging as a key technology to focus the disciplines which the industry is struggling to integrate together.

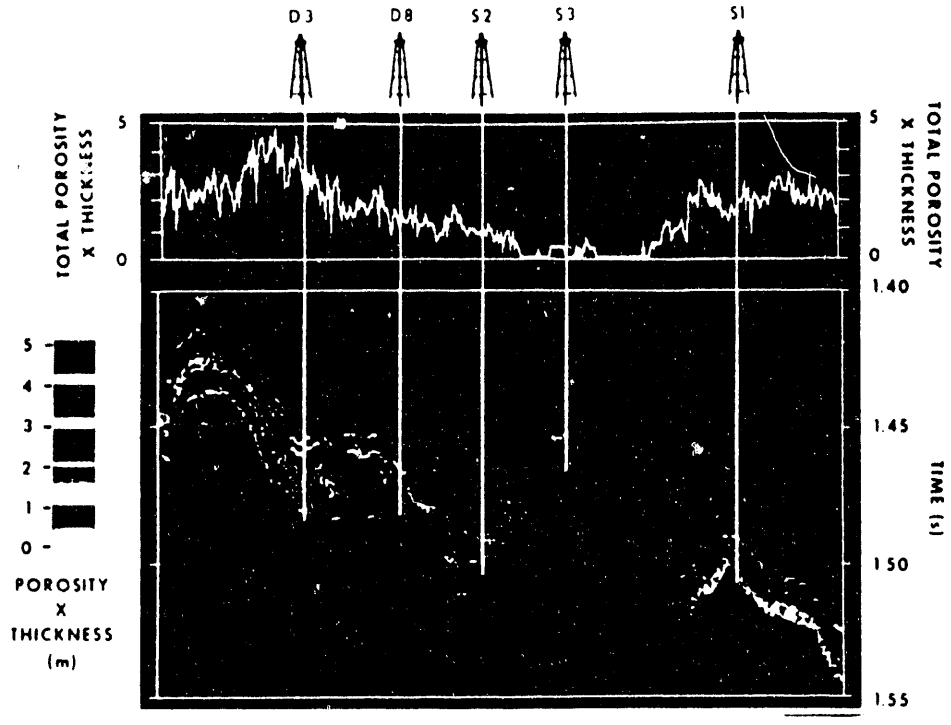
With it's superior lateral resolution, 3D seismic has brought about a renewed emphasis and recognition of the subtle structural and stratigraphic features directly associated with the majority of hydrocarbon reservoirs illuminated with the 3D technique. Exploited by the use and manipulation of today's highend graphics workstation it is rapidly becoming the basis for characterizing the reservoir in the interwell space.

Detailed reservoir characterization is a requirement for the most effective recovery of in-place hydrocarbons. This characterization of the reservoir requires the consistent integration across different data types. Geologic, well log and core data are traditionally the most commonly used data sets in reservoir model building. Well log and core data provide detailed information about the vertical variation of many reservoir properties, but they are restricted to regions adjacent to the borehole.

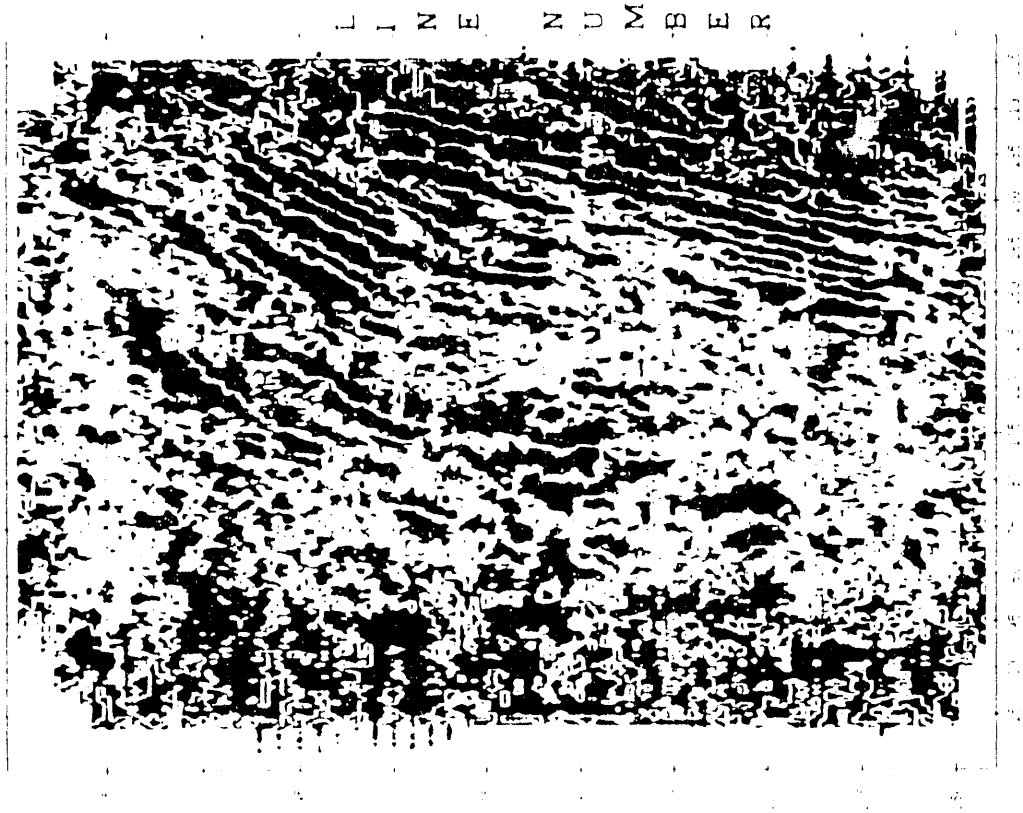
More recently, 3D seismic data has played a significant part in defining the model between the well control. It is well known that the seismic amplitude variations are linked to changes in acoustic impedance that can be related to reservoir properties, including lithology and porosity. With careful calibration of the seismic amplitude to borehole responses and petrophysical modelling both high vertical and good lateral resolution can be combined through the use of inversion schemes to produce an effective approach to the characterizing of the reservoir in three dimensions.

The ability to differentiate seismic responses generated by lithology and fluid variations is key for any successful exploration project. To have the ability to differentiate between fluid types would obviously lower the risk of both exploration and development efforts. Utilizing well log responses in the immediate vicinity of the borehole to constrain seismic processing and calibrate the seismic response is an important step towards this goal. Petrophysical modelling plays a critical part in this process. Exploiting the changes of seismic amplitude for differing angles of incidence is a methodology which has been used with mixed results. With the improved three dimensional resolving power of the 3D seismic technique in conjunction with exploitation of seismic amplitude responses there is renewed hope.

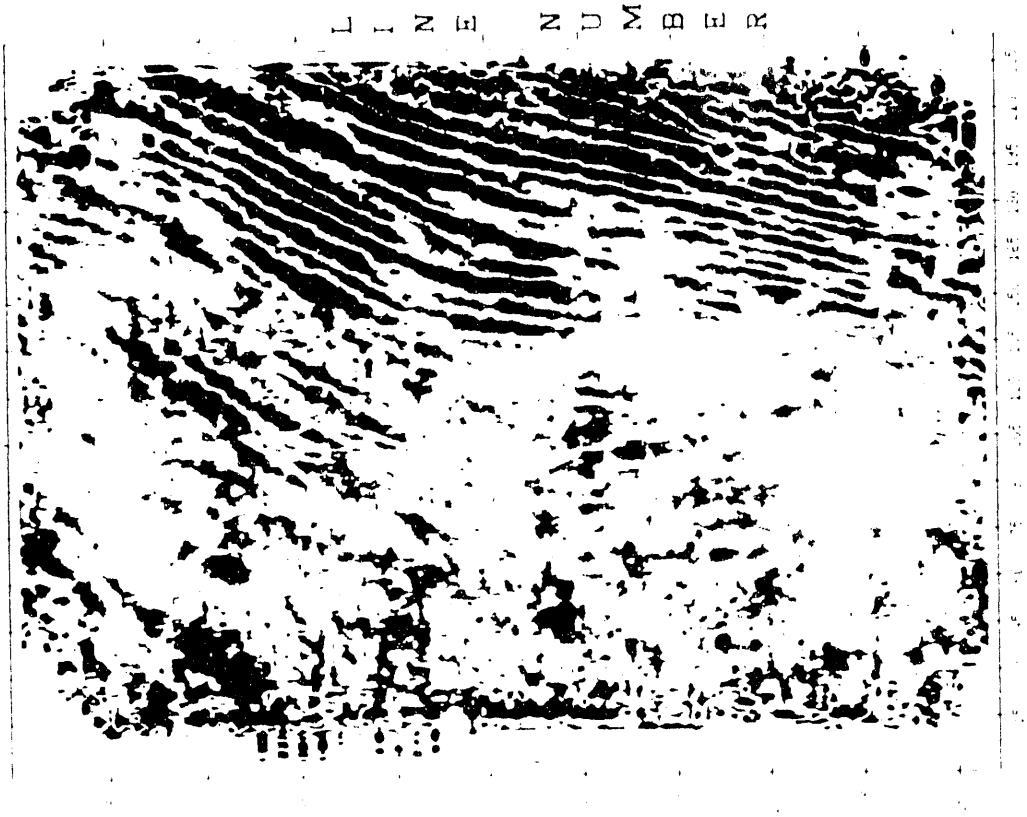
With the evolving use of 4D technology, the repeated use of 3D over time, an improved understanding of the seismic response to changes in fluid saturations and effects is on the near horizon. The subtle variations due to fluid changes can be readily observed on difference volumes obtained from the calibrated 3D data sets. This 4D technology integrated with other disciplines has the potential opportunity to aid in the monitoring of hydrocarbon production.



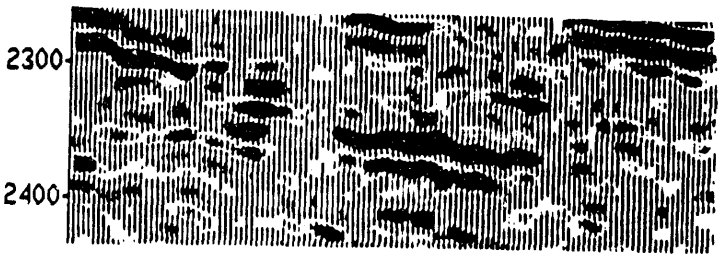
Well profile from a 3D seismic volume showing potential reservoir zones. The plot at the top shows the lateral variation of porosity x thickness where potential reservior criteria are satisfied. A product of an inversion scheme based on well x seismic control.



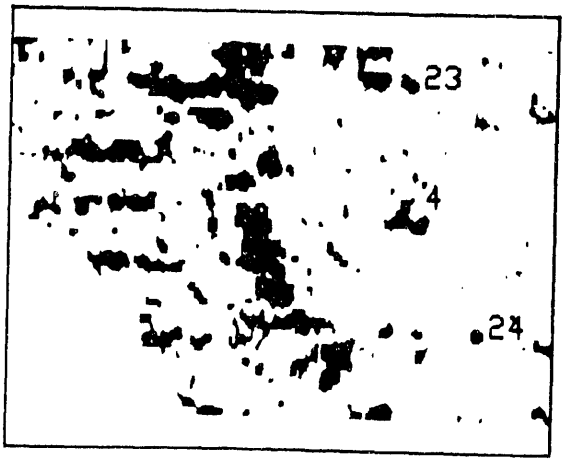
Time slice of AVO response (gradient) from a 3D volume.



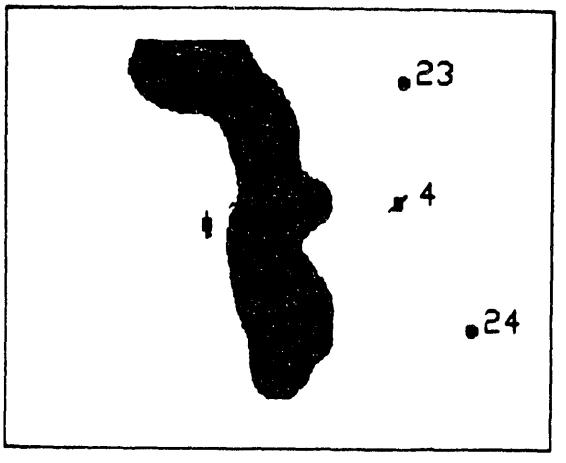
Time slice of PWAVE response from a 3D volume.



Seismic difference section (vertical) taken from the 3D lines shot 16 months apart showing gas water contact anomaly



Horizon amplitude difference map from two 3D Survey showing spatial change in gas/oil contact



Gas Saturation difference map produced from well production history

FUNDAMENTAL 3-D SEISMIC SURVEY DESIGN

BY: STUART WRIGHT - WESTERN GEOPHYSICAL
7229 S. ALTON WAY
ENGLEWOOD, COLORADO 80112
(303) 770-8660

1. INTRODUCTION

The reasons for shooting 3-D seismic surveys are numerous, compelling and convincing but can be summarized with one phrase - risk reduction. Note however, the phrase is risk reduction and not, risk elimination. Seismic data shot in 3-D is not a panacea but a very powerful tool that when properly applied can produce significantly improved economic results. Proper application of this tool begins with the design process. 3-D survey design should be both interactive and iterative. The 'best' 3-D survey for a given play is a function of the following considerations:

- Reservoir Geology
- Surface Location
- Available Equipment
- Geophysical Requirements
- Economics

2. RESERVOIR GEOLOGY

The geology of the reservoir rock will define the critical parameters of most 3-D seismic surveys. The following rock characteristics should receive special consideration.

2.1 Seismic Definition

The nature of the reservoir must be such that the seismic tool can help determine its extent. This may sound like a trivial statement, but there is no point in conducting a 3-D survey if the key rock properties (i.e. thickness, velocity and density) render the reservoir seismically invisible.

2.2 Depth of Objective

The depth of the primary drilling objective affects a variety of design attributes - most significantly, it determines the size of the survey aperture and the number of geophones in the detector pattern. Deep objectives usually require a larger aperture than do structurally similar shallow units. Despite the larger aperture requirements of a deep event, shallow ones tend to be the most expensive to image. Velocity and mute patterns make far offset geophones useless, which in turn requires more source effort per square mile to achieve the desired fold. It is not economically possible to get full benefit of today's high channel crews when trying to image a shallow reservoir.

2.3 Structural Dip

Steeply dipping objectives typically cost much more to image than do relatively flat ones (less than 10°). The calculated size of the migration aperture increases geometrically with dip, but only proportionately with depth. For a 30° dipping event at 8,000' the straight ray migration aperture is approximately 4,600'. Doubling the depth, doubles the aperture. Doubling the dip on the other hand, increases the aperture to almost 14,000'. Furthermore, steeply dipping events require smaller cell (or bin) sizes to avoid spatial aliasing. Changing from a 110' x 110' cell to 55' x 55' can increase field effort by a factor of four.

2.4 Extent and Complexity of Reservoir

One of the first things to determine when designing a 3-D survey is the size of the area to be shot. Obviously, this is a function of the anticipated size of the reservoir in the case of both development programs and single prospect exploration programs. In the case of large exploration programs, it is determined by the size of the geologic trend, or the nature of the client lease position on that trend.

The stratigraphic and structural complexity of the reservoir - like structural dip - can have an impact on the cell size. Flat but highly complex rocks require greater density of data than do simple objectives. This typically increases both spatial resolution (smaller cells) and temporal resolution (source effort) requirements.

3. SURFACE LOCATION

Once an understanding of the geology of the reservoir has been attained, the nature of the survey location must be determined. The most economic and efficient survey design varies widely in relation to topography, vegetation and culture. Line spacing and source type are two design features greatly affected by surface imposed restrictions. Often, the theoretical 'best' survey bears little resemblance to the type survey allowed by such 'unscientific' factors as crops, road access, etc.

4. AVAILABLE EQUIPMENT

As with surface location, the 3-D survey considered to be the most efficient and economic varies greatly with the equipment available to conduct the survey. As a generalization, it is less expensive to shoot large surveys with large crews and small surveys with small crews. However, it is often possible to design very economic surveys that circumvent this generalization. For example, in cases where heliportable sources are required it is usually cheaper to use a large crew, even for very small surveys. For a big program, recording a large number of channels for each source point almost always reduces survey costs. These savings are not however, without geophysical risks. There is a point of diminishing returns when it comes to switching on more and more channels. A high channel, receiver limited survey can take longer and cost more to shoot than a well balanced survey. It is also routine to change this source effort/receiver effort balance depending on the type of source to be used.

5. GEOPHYSICAL REQUIREMENTS

As stated before, the design of the optimum 3-D survey is determined by the geology of the reservoir, the nature of the surface location, and the equipment available for data acquisition. It is necessary to address geophysical requirements within the framework of these factors.

5.1 Survey Size: Aperture

After outlining the area of geologic interest, aperture must be added. The size of this aperture must be at least as large as the largest of the following four considerations.

5.1.1 Migration Consideration

For a properly imaged migration it is necessary to record an aperture with width equal to $z\tan\theta$ (where z is equal to the objective depth and θ is the structural dip of that objective. This formula assumes a straight ray, single velocity model.)

5.1.2 Fresnel Consideration

Even in areas with little or no dip it is necessary to record beyond the image area. Migration in 3-D helps to focus the energy (collapse the Fresnel zone) for flat, purely stratigraphic reservoirs just as helps to properly position dipping events.

5.1.3 Fold Considerations

The nominal fold requirement for the edge of the image area should be no different from that at the center. To achieve full fold at the image area boundary requires some combination of both sources and receivers outside of the area of desired coverage. This is analogous to shooting 2-D data. To properly acquire one mile of 2-D data often requires shooting a 3 mile line.

5.1.4 AVO Considerations

If AVO analysis of the 3-D data volume is anticipated, careful attention must be paid to the distribution of offsets acquired. The required aperture width will be equal to one half the maximum offset needed for proper AVO analysis.

5.2 Cell Size

The issue of cell size is that of sampling sufficiency. The cell size should be as large as possible without exceeding the following requirements.

5.2.1 Spatial Aliasing:

Steeply dipping data will be spatially aliased if the cell size is larger than that determined by this formula: $x = v/4F \sin\theta$ where x is the largest cell size, v is RMS velocity, F is the dominant frequency at the event of interest, and θ is the structural dip.

5.2.2 Reservoir Complexity

In cases where spatial aliasing is not an issue, it is often necessary to keep the cells small due to reservoir complexity. Subtle, short-lived stratigraphic events and highly faulted reservoirs can impose much more stringent restrictions than aliasing concerns. It is also important to bear in mind that the reservoir is probably much more complicated than pre-survey mapping would indicate. The literature is full of pre-survey and post-survey maps that support this conclusion.

5.2.3 Equipment Limitations

In almost all cases, cell size is determined by the receiver spacing in the inline direction and source spacing in the crossline direction. By and large it is possible to achieve whatever cell size is desired in the crossline, or source direction. However, in most cases cable design will not allow inline cell size to exceed 110′ to 165′. Understanding the specific crew limitations is necessary before designing he optimum survey.

5.3 Fold Requirements

The cost of most 3-D seismic surveys is directly proportional to the fold or multiplicity of the data acquired. The minimum fold required to properly image a reservoir in three dimensions is often determined by examining existing 2-D data. Examination of the 2-D data should include not only a determination of fold, but a determination of effective fold. Was the 2-D overshot? How much of the acquired data was actually stacked and how much was muted out before stack? The rule of thumb that says 3-D data need only be half the fold of 2-D data is a good place to start, but it doesn't tell the whole story. It takes into account the increased image clarity provided by 3-D migration and the ability to examine a data volume rather than a data slice. It does not, however, take into account today's larger vibrator trucks, digital systems, or mistakes made on the 2-D data.

5.4 Other Geophysical Attributes

It is beyond the scope of this presentation to discuss some of the more subtle but nevertheless important geophysical attributes. Suffice it to say that the following considerations must play very important roles in survey design.

- Sampling in the offset domain
- Azimuthal anisotrophy, azimuth distribution
- Minimum offset requirements
- Survey orientation

6. ECONOMIC CONSIDERATIONS/CONCLUSION

The primary goal of any 3-D seismic survey is to acquire data that will enhance understanding of the earth's subsurface and thereby reduce the risks associated with drilling for oil and gas. After designing the survey that best addresses the geologic and geophysical requirements of a given play it is often necessary to make changes that will reduce the cost of the program. It is important to understand that such cost cutting is not without its corresponding geophysical loss, and that a cheap survey that does not meet the objective of risk reduction, is a failed survey.

7. ACKNOWLEDGEMENTS

I would like to thank Western Geophysical for permission to present this material. I am particularly indebted to Dan Wisecup for his willingness to provide me with help every step of the way.

Ojo Encino Field: An Entrada Dune Defined by 3-D Seismic, San Juan Basin, New Mexico

by

L. Douglas Endsley

Consulting Geologist
713 Rosa
Farmington, New Mexico 87401

A "postage stamp" size (one-half mile square) 3-D survey helps to detail the areal extent of an Entrada sand dune. An amplitude dim-out drilled by the initial well proved to be a marginally economic location. Reprocessing and detailed stratigraphic analysis of the seismic incorporated with Merrion's geologic experience lead to a geologically refined interpretation.

Seismic inversion of the data suggested a better location southeast of the initial well as reported in the Oil & Gas Journal article of March 1992 (attached, reprinted with permission from the Oil & Gas Journal). The results of the subsequent drilling will be discussed and compared to the previous interpretations.

This case history illustrates the affordability and feasability of 3-D seismic for the independent producer, as well as the best application for such technology.

EXPLORATION

How an independent put inexpensive 3-D seismic to good use in New Mexico

Douglas C. Nester *Landmark/Concurrent Solutions Houston*
Douglas Endsley *Merrion Oil & Gas Corp. Farmington N.M.*

As major oil companies focus their attention offshore and overseas, independents in the U.S. continue to find and develop onshore reserves using their traditional strengths.

Those strengths have been low overhead, nimble decisionmaking, and hard-won experience within a particular geologic region.

Today many of these companies are emerging as even tougher competitors by applying 3-D seismic along with the multidisciplinary knowhow and the interactive workstations needed to interpret it.

The recent experience of Merrion Oil & Gas Corp. Farmington, N.M., offers a case in point.

Merrion has worked in the San Juan basin for 32 years. For the first 26 years the company specialized in gas development drilling.

But when oil prices collapsed in 1986, Merrion saw the chance to venture into exploration at low cost. Ever since, the company has devoted its resources to exploring for oil in the basin's Entrada sand dunes, a complex stratigraphic play found at 6,000 ft.

Entrada play

The San Juan basin cuts northwest to southeast through the Navajo Indian reservation tucked into New Mexico's northwest corner.

The basin measures approximately 150 by 140 miles. Its half dozen Entrada fields were discovered primarily from 2-D seismic and detailed subsurface studies.

The Entrada prospects are generally found in the basin's south-central region. Merrion had acquired several fields there, including Ojo Encino in McKinley County, a marginal producer.

Fig. 1

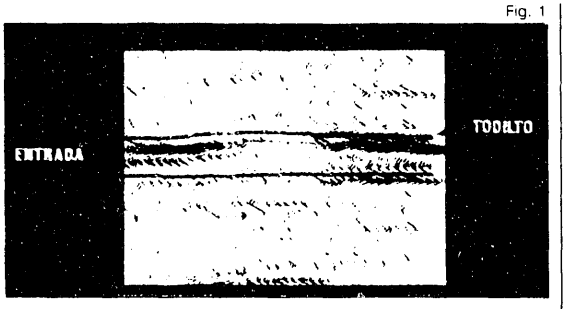


Fig. 2

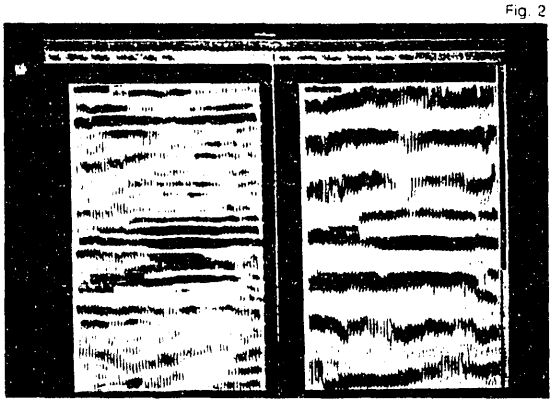
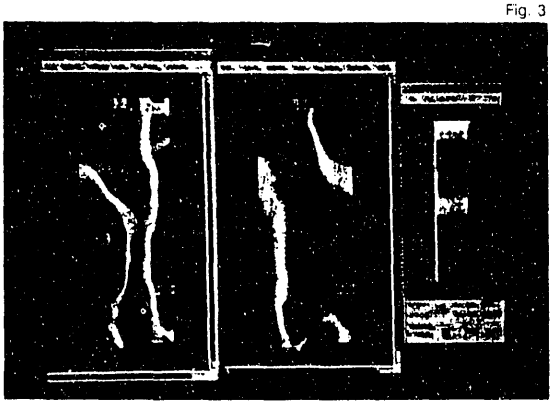


Fig. 3



However, well control and Merrion's extensive knowledge of hydrodynamics within the Entrada suggested that hydrocarbons were migrating south. Also, existing 2-D seismic indicated possible additional closure to the south—an apparent extension of the same large dune complex.

The company therefore targeted an area about ¼ mile south of Ojo Encino.

Merrion's basic exploration model had long been confirmed by discoveries and developments in the Entrada.

The model describes a primary depositional feature—a structural high consisting of the Entrada sand dunes overlain by Todilto anhydrite that filled in around the dunes but only to the level of their crests. Thus the anhydrite is typically thin or absent at the crest, yet can measure 30-120 ft or thicker along the flanks.

The Entrada sandstone makes a good reservoir. Relative to the overlying anhydrite, the Entrada sands have a low seismic velocity, giving rise to a strong reflection at the interface and giving interpreters a high amplitude marker to track.

As the anhydrite thins out at the crest of a dune, the marker gradually weakens or disappears. The resulting amplitude dim-out forms the basis of Merrion's historically successful exploration model (Fig. 1).

3-D seismic

The 2-D seismic acquired south of Ojo Encino seemed to fit the model—a dim-out associated with a structural high—but resolution and coverage weren't good enough to pick a drilling location with confidence.

An economically viable dune could easily hide between the lines on a quarter-mile 2-D grid.

Merrion believed the com-

EXPLORATION

pany needed a better picture of the subsurface. Also, Merrion wanted to gain its first experience using 3-D seismic. The company considered 3-D an increasingly important competitive advantage for the 1990s.

Merrion acquired a postage stamp 3-D survey, approximately one half mile square. The $30,000 survey consisted of 16 lines spaced at 165 ft with approximately 8 shot points/line.

Merrion determined that the resulting 3-D data set was small enough to be interpreted using traditional paper-based methods, which to date had proven adequate for 2-D interpretation of the Entrada play.

The manual interpretation of 3-D seismic indicated the presence of a classic Entrada dune structure, an elongate ridge. But when the company drilled its vertical exploratory well, 1-28 Federal, the Entrada sand came in 35 ft low to the mapped structure.

To be economic, wells producing from Entrada must have at least 20 ft of pay; 30-35 ft is typical. However, the 1-28 Federal encountered only 13-14 ft of pay, and thicker-than-expected Todilto anhydrite.

The results shook Merrion's confidence in 3-D seismic and the existing model's applicability to this prospect.

Was the dune much narrower than expected? Did the crest drop off more severely? Had the dune ridge been severely eroded? Or was the problem entirely different.

The company had to know before drilling its planned No. 2 well, located one half mile south on apparently similar stratigraphy.

Team and technology

Merrion asked Landmark/Concurrent Solutions to put an analysis and interpretation team to work on the project.

Concurrent Solutions, a consulting organization, had pioneered the application of advanced 3-D technology to better understand mature fields.

Fig. 4

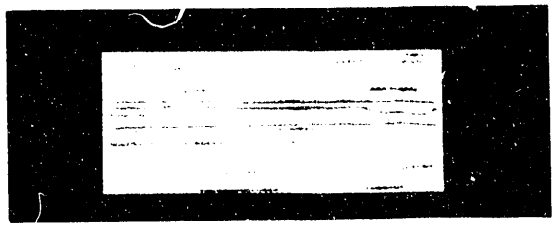
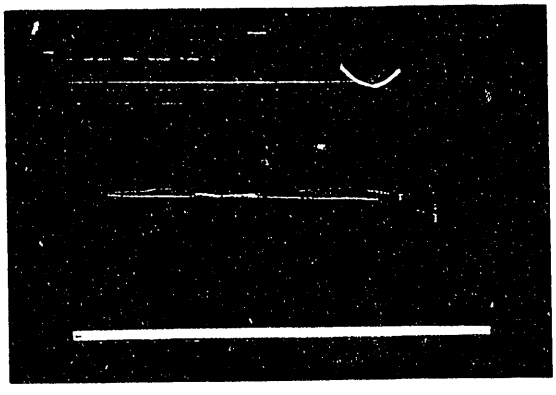


Fig. 5



The Concurrent Solutions team would reinterpret Merrion's 3-D seismic using an arsenal of advanced tools and techniques. As the project unfolded in unexpected ways, poststack seismic reprocessing techniques would prove pivotal to the team's success.

The team set forth its strategy:

1. Gain a better understanding of the seismic response produced by the top and bottom of the Entrada and the overlying Todilto.

2. Build a synthetic seismogram based on the 1-28 Federal control and, from it, an analog representing a vertical slice of the target formation.

3. Compare the analog to the actual seismic data set, looking for discrepancies.

4. Resolve each discrepancy to develop the interpretation.

The Concurrent Solutions team first characterized the target's reflectivity in significant details and generated the synthetic. The team then built a stratigraphic analog of the target section using the existing model as the basis.

The interpretation

Having thus gained an understanding of "what we should be looking for," as one team member put it, the team began its interpretation.

The [illegible] seismic contained an abundance of relatively low frequency signals of around 50 Hz, not suitable for detailed imaging of a target whose thickness was typically less than 250 ft.

To effectively study such a small target, higher frequencies of 60-65 Hz would have to be isolated from the background "noise" and amplified. To accomplish this, the team's seismic processor, using interactive software on a standard workstation and working closely with the geophysicist, reprocessed the data via post-stack spectral enhancement.

The reprocessed seismic matched the model and provided an unprecedented, high resolution view of Merrion's Entrada play. The dune's image, its location, and internal structure now emerged from the data (Fig. 2).

The team confirmed that the anomaly was real: a positive closure was associated with the amplitude dim-out. Further, the reprocessed seismic "predicted" what Merrion's drillbit had found: the 1-28 Federal had penetrated outside the area of greatest amplitude dim-out—off the dune crest (Fig. 3).

Turning their attention to the planned No. 2 location, the Concurrent Solutions team confirmed that a real anomaly also exists there: positive closure, and dimming of the Todilto marker on the crest. However, several other points about this anomaly stood out on the data.

First, working interactively with 3-D seismic interpretation software, the team mapped a relatively broad structural high associated with the closure that extends deep into the sediments below the Entrada—possibly a deep-seated fault.

By further analyzing the reprocessed data, the team evolved a dramatically different and unexpected interpretation, suggesting a different Entrada top on the high. The alternate interpretation made a trough in the Entrada on the crest of the structure—a trough probably filled with younger sediments which, if suitably fast, could account for the dim-out (Fig. 4).

The team now faced a dilemma.

Was the second location on a prospective dune or an interdune facies likely to be hard and dry?

Inversion solves puzzle

To resolve the question, the team turned to seismic inversion, a process that could estimate the velocity of the unidentified facies from its seismic reflection.

The inverted seismic revealed that the dim-out was indeed caused by sediments whose seismic character virtually matched that of the overlying anhydrite.

The Concurrent Solutions

EXPLORATION

THE AUTHORS



Nester



Endsley

Douglas C. Nester is director of technology for Landmark/Concurrent Solutions, a consulting organization. While a geophysicist at Pennzoil, Nester headed programs exploring the Gulf of Mexico and overseas basins. At Bechtel Corp. he served as an engineering geologist. He has a BS in geology from the University of Pennsylvania and an MBA from the University of St. Thomas.

Douglas Endsley is geology manager at Merrion Oil & Gas Corp., where he has been involved in the acquisition and evaluation of more than 1 million lease acres in the San Juan basin and other western U.S. leaseholds and exploration and development within them. Before joining Merrion he was a wellsite geologist at Geological Services Inc. He has a BS in geology from Fort Lewis College.

team hypothesized that the unidentified sediments, probably Todilto anhydrite, fill an erosional channel. If so, the dim-out marked a structural low rather than a high—and the No. 2 would have to be repositioned (Fig. 5).

Merrion reported that erosional channels filled with anhydrite-like material had been encountered in other Entrada fields.

The consulting team generated isopachs from the top to the bottom of the Entrada. They indicated a significant thinning to the south, toward the No. 2 wellsite—confirmation that a dune wasn't present there.

Amplitude extraction performed on the Entrada itself showed the expected dune-associated amplitude decline at the 1-28 Federal and an exceptionally large decrease at the No. 2 site, now believed caused by the section's thinning out.

The team presented its interpretations to Merrion, and the alternate model was accepted.

As a result, Merrion has repositioned the 2-28 Federal approximately 1,000 ft northeast of its original location.

Conclusion

The economical use of 3-D seismic and advanced interpretation tools and techniques provided an independent E&P company with a substantial competitive advantage in exploring a stratigraphically complex play.

The operator's extensive knowledge of the region, combined with sophisticated, multidisciplinary analysis and interpretation produced important results that otherwise could not have been achieved.

An important success factor was the interpretation team's emphasis on understanding the geology, examining even seemingly minor discrepancies, resolving contradictions between the interpretation and the data and combining advanced techniques with cutting-edge technology to extract useful information from the data.

Independent E&P companies increasingly find that the use of such tools and methods is affordable and, in fact, becoming a necessity as operators and explorers strive to increase their competitive position in the 1990s.

Reference

1. Vincelette, Richard R., and Chittum, William E., Exploration for Oil Accumulation in Entrada Sandstone, AAPG Bull., Vol. 65, No. 12, 1981, pp. 2,446-2,570.

NEVADA

Skippy Oil Co., Ketchum, Idaho, has staked a remote wildcat in far western Pine Valley of Eureka County.

The company's 1 Cortez, in 12-28n-50e, 21 miles southeast of Beowawe, is projected to 10,500 ft.

Petroleum Information notes the location is in an undrilled township 7 miles west-northwest of one well Three Bar field, a Miocene Humboldt oil discovery recompleted in 1991 in Tertiary volcanics by Gary-Williams Co.

Pioneer Oil & Gas, Midvale, Utah, has staked a remote wildcat in White Pine County.

The 27-33 Yankee Mine Unit, in 27-21n-57e, is on the western edge of Long Valley (OGJ, July 15, 1991, p. 74). It is also 70 miles north of oil fields in Railroad Valley and 50 miles southeast of Blackburn field.

The location is 14 miles southwest of Pioneer's Alligator Ridge Unit, where the company has four locations staked, PI reported.

EP Operating Co., Dallas, has staked an east offset to a Eureka County wildcat that PI reported has reached total depth.

The 1 Stagecoach-Federal 17-1, in 17-15n-54e, is in Little Smoky Valley about 1 mile northwest of the juncture of Eureka, White Pine, and Nye counties.

It is just east of EP's 1 Stagecoach-Federal 17-2, projected to 6,500 ft.

Apache Corp. has staked two more wells in Grant Canyon field in Nye County.

The locations are in 20- and 21-7n-57e, near the company's 7 Grant Canyon Unit completed last fall flowing 3,200 b/d of 25° gravity oil from Devonian Guilmette at about 3,700 ft.

OGJ author's guide available

The exploration editor of the Oil & Gas Journal is pleased to receive and review manuscripts from new or experienced authors worldwide. A brief author's guide outlining our needs and answering other questions is available from: Exploration Editor, Oil & Gas Journal, P.O. Box 1260, Tulsa, Okla. 74101-1260; Ph. (918) 832-9307; Fax (918) 831-9497.

API MONTHLY WELL COMPLETIONS*

	Oil wells	Footage	Gas wells	Footage	Dry holes	Footage	Total wells†	Footage
January 1992	1,150	5,091,530	966	5,798,421	881	4,486,652	3,078	15,618,441
December 1991	958	3,509,545	664	3,651,803	611	3,075,516	2,321	10,421,643
January 1991	873	4,360,960	802	4,318,065	576	2,984,967	2,310	11,779,837

* Total wells reported to API during January 1992. † Includes oil, gas, and dry holes plus service wells and stratigraphic and core tests.

3D SEISMIC RESERVOIR CHARACTERIZATION SOONER UNIT, WELD COUNTY, COLORADO

D.S. Singdahlsen, M.T. Kramer, and E.F. Jaynes
INTERACTIVE EARTH SCIENCES CORPORATION
1616 Glenarm Place, Suite 2050
Denver, Colorado 80202

and

M.A. Sippel, and R.W. Pritchett
RESEARCH & ENGINEERING CONSULTANTS, Inc.
7600 East Orchard Road, Suite 106-South
Englewood, Colorado 80111

Geologic heterogeniety is known to be an important control on fluid flow in petroleum reservoirs. Interpretation of 3D seismic data provides a technique for analysis of the spatial characterization of reservoir features and properties. In combination with detailed analysis of engineering and geologic field data, 3D seismic can provide information on reservoir character on a scale not readily available from borehole information. Wellbores provide direct investigative reservoir data, but commonly at a scale (well spacing) greater than the scale of reservoir heterogeneity. 3D seismic surveys provide a much greater sampling density of reservoir data (100 ft vs 40 acres). Integration of these datasets is required to successfully characterize the reservoir.

As part of a DOE sponsored program on enhanced recovery in fluvial-deltaic reservoirs, a multi-disciplinary reservoir characterization study of the Muddy 'D' reservoir in the Sooner Unit of the Denver-Julesburg Basin has been undertaken. Historically, Muddy 'D' reservoirs produce only 20 to 25% of the original oil in place after primary and secondary recovery efforts. Reservoir characterization in the Sooner Unit has encompassed interpretation of 3D seismic data, detailed stratigraphy, and well log analysis. Future work will incorporate reservoir flow simulation, transient well testing, and production flow testing. Project goals include the identification of optimal infill drilling locations, relocation and optimization of injection patterns, and improved reservoir management through scheduling of production/withdrawl rates.

The approximately 7.7 square mile Sooner Unit 3D seismic survey was acquired in October, 1992 by Western Geophysical. The survey consists of twenty receiver lines, oriented east - west, and spaced 800 feet between lines. Twenty-four source lines were spaced 600 feet apart and oriented north - south. Both geophone group interval and source point interval were 200 feet resulting in a bin size of 100x100 feet. The acquisition geometry resulted in 20 fold coverage over most of the survey. The 3D seismic data were processed through a conventional 3D data processing flow including a two step, finite difference, migration by Western Geophysical's Denver Processing Center.

All seismic interpretation work was performed using the Schlumberger-GeoQuest Interactive Exploration System software package on an UNIX based Sun Sparc2 workstation platform. 2D

seismic modeling has shown that relative amplitude and instantaneous frequency can be used to delineate spatial variations in stratigraphic layer thickness. Detailed seismic models of stratigraphic thickness variation in both the Muddy 'D' and Huntsman Shale intervals, based on stratigraphic log correlation, were constructed across the Sooner Unit and 3D seismic survey. This modeling of gross 'D' sand thickness variations indicates that relative amplitude and instantaneous frequency exhibit a corresponding variation in seismic attribute response. Because of tuning phenomenon, the amplitude of the Muddy 'D' seismic event reflection peak decreases as the stratigraphic thickness of the 'D' sand decreases. The fact that the seismic amplitude behaves in a predictable manner can be of great benefit in inferring how subtle stratigraphic changes in the reservoir may be reflected in maps of the spatial variation of the Muddy 'D' amplitude. As a result, 3D seismic attribute data can be used to delineate the lateral extent of potentially productive Muddy 'D' reservoir. The relative magnitude of these attributes can be employed to characterize the relative thickness of geologic units and general reservoir properties.

2D seismic modeling has shown a cause and effect relationship between stratigraphic thickness and seismic attribute response. An attempt was made to mathematically relate seismic relative amplitude and a series of wellbore log derived reservoir properties. Center weighted averaging of the nine nearest bin center amplitudes at well locations were calculated for the 3D seismic data volume. These values were then cross-plotted against wellbore log data, and a least squares best fit linear regression relationship was calculated for each data set. All cross-plots show a "fair to good" relationship based on regression correlation coefficient and standard error of regression calculations. Estimation of reservoir properties with a range of plus or minus one standard deviation of wellbore data is realistic from this data set. Since the 3D seismic data points sample much greater density of reservoir heterogeneity than do wells drilled at a uniform spacing, seismic remote sensing and prediction of reservoir properties may be a valuable tool in observing the spatial distribution of reservoir variability.

Amplitude mapping of the Muddy 'D' seismic horizon reveals that the lateral distribution of potential reservoir rocks extends over a broader area than previously mapped. The strongest 'D' amplitudes are mapped seismically in a northwest-southeast axial orientation. It is interpreted that the spatial distribution of the Muddy 'D' amplitudes corresponds to the location of the axis of maximum incision into the Huntsman Shale unit and infilling by 'D' sand deposition. This interpretation is in concert with geologic modeling, based on core analysis and log correlation, for the sequence stratigraphic setting of the Sooner Unit. A thicken interval of 'D' sandstone is inferred to extend beyond the northern most wells in the Sooner Unit, and the orientation of incised valley fill suggests the existence of a possible connection to the Lilli Field. A strong correlation of mapped seismic amplitudes to gross 'D' thickness exists across the Sooner Unit. Gross 'D' isopach contours on the 'D' horizon amplitude map shows the direct relationship. A similar relationship also exists between the isopach and an isochron from the top 'D' to the base 'D'.

Discontinuity of seismic amplitude character and the identification of laterally and vertically persistent lineaments at the Muddy 'D' and Huntsman Shale horizons suggests that the Sooner reservoir may be broken into a number of major reservoir compartments. Three major orientations of lineaments are mapped in the 3D seismic data volume. The orientation and persistent nature of the mapped lineaments suggests that they may reflect a fundamental structural grain across the region. These lineaments are coincident in location and orientation

with faults that are observed to offset shallower and deeper horizons than the Muddy 'D' seismic horizon. These lineaments may also represent lateral stratigraphic changes resulting from facies changes, paleostructural control of depositional style and orientation, or diagenetic features. Production and pressure data from unit wells suggests low permeability barriers or baffles between wells. The proposed locations of reservoir pressure compartments exhibit a strong correlation with the 3D seismic anomalies supplying supporting evidence that they represent reservoir compartment boundaries with varying degrees of fluid flow restriction.

Interpretation of the Sooner Unit 3D seismic survey supports reservoir compartmentalization. At least five major reservoir compartments are identified by mapping of seismic amplitude and lineament location on the Muddy 'D' horizon. These compartments have individual production and pressure characteristics, and water flood design must account for the compartment size, geometry, and boundary configuration. Geologic interpretation of core analysis and log correlations has identified four major depositional cycles within the Muddy 'D' sequence. Each depositional cycle appears to be separated by an erosional surface and overlain by a variable thickness of impermeable "non-reservoir" strata. This interpretation suggests that vertical stratigraphic compartmentalization of the reservoir may also greatly impact the producing characteristics of the unit.

Preliminary results from the interpretation of the Sooner 3D seismic data suggest that undrilled areas within the unit boundaries contain opportunities for recovering additional incremental reserves. Of special interest is the northern end of the unit where undeveloped acreage exists. Northern unit wells have historically been poor producers due to poor petrophysical rock quality. Mapping of Muddy 'D' seismic amplitude has revealed that all the northern unit wells lie in close proximity to identified lineaments. Poor rock quality in the northern unit wells may be explained by secondary reduction in porosity and permeability resulting from proximity to the lineaments. Offset drilling of wells away from the lineaments may yield greatly improved reservoir quality rock. Additionally, a potentially undrained reservoir compartment has been identified northwest of existing wells within the unit boundary.

3D seismic data has become a valuable geophysical tool in applied reservoir characterization. 3D seismic provides higher density sampling of reservoir heterogeneity than does conventional 2D seismic or log data from standard well spacing. As a result, 3D seismic commonly provides reservoir information that can not be observed or gathered by other means. When integrated with detailed geologic interpretation and reservoir engineering analysis, 3D seismic reservoir characterization provides the necessary information to enhance reservoir description, develop more acurate reservoir models, reduce risk associated with project development, and provide improved reservoir management.

3D seismic also shows great promise as both an exploration and exploitation tool in the Denver-Julesburg Basin. The Sooner study has shown that mapping of 3D seismic amplitude provides greatly improved geophysical prediction of Muddy 'D' stratigraphic thickness. Detailed seismic mapping of Muddy 'D' incised valley fill sequences is now possible with well planned and executed 3D seismic surveys. 3D seismic also provides a cost effective method to identify infill and step-out drilling locations, characterize reservoir properties and geometries, and develop exploration plays with reduced risk.

NOTES

Coalbed Methane Multicomponent 3-D Reservoir Characterization Study, Cedar Hill Field, San Juan Basin, New Mexico

Thomas L. Davis, Edward L. Shuck, and Robert D. Benson,*
Colorado School of Mines
Department of Geophysics
Golden, Colorado 80401
303/273-3938

Summary

Seismic detection of enhanced coalbed fracture permeability can reduce risk and uncertainty in coalbed methane development. At West Cedar Hill field, San Juan Basin, New Mexico tectonically enhanced fracture permeability occurs in proximity to east-west strike-slip faults mapped in the subsurface from multicomponent 3-D data. Enhanced permeability in the shear zone, as predicted from shear wave polarization and other anisotropy attributes, has been confirmed by the Hamilton #3R well. This well was completed with a cavity method and shows ten times the productivity of the original well. Pressure tests in this well suggest that the reservoir is bounded by the faults that have been observed on the 3-D seismic data. This fault-bounded shear zone is exhibited on a 3-D shear wave polarization map overlain on the P-wave time structure (Figure 1). Slower split shear wave (S2) amplitude anomalies also correspond to this shear zone, indicating a preferential opening of the northwest-trending natural fractures or cleats by this shear zone (Figure 2).

On the eastern side of the map area and in the central field area, the northeast-trending face cleats are the dominant control on directional permeability. This permeability is induced by local overpressuring. This feature may be seen on the faster split shear wave (S1) amplitude map of Figure 3.

Trends of higher well productivity in the Cedar Hill field generally correspond to zones of lower in situ stress. The capability to predict local stress variance, along with permeability orientation and magnitude, has a direct bearing on well placement and spacing for maximum drainage and efficient production. New cavity completion of vertical wells placed in shear zones or horizontal wells drilled into the shear zones should maximize recovery and minimize risk at Cedar Hill field and elsewhere in the basin.

Cedar Hill Multicomponent 3-D Reservoir Characterization

Cedar Hill is the oldest producing coalbed methane field in the San Juan Basin. Production at Cedar Hill field is extremely variable (.5 to 5 MMCF / D / well) due to the presence or absence of fracture permeability in the coalbed methane reservoir. Due to the

high compressibility of the coals, natural fractures or cleats are generally closed at reservoir depths that approach 3000 feet in the bottom part of the basin. In the central portion of the field, enhanced coalbed permeability occurs due to stress relief caused by local overpressuring. On the western side of the field, strike slip movement along faults has created local stress relief and fracture enhanced permeability in the coals proximal to the faults. Individual well productivity on the western side of the field depends on whether or not the well encountered an open fracture system. Economic coalbed methane production in this area is dependent on siting wells to optimize the chances of encountering better fracture permeability zones in the coal. Subsequent application of new drilling, completion and production technologies to sustain or enhance this production is also an important factor in economic coalbed methane development.

A 3-D multicomponent seismic survey shot by Northern Geophysical for CSM's Reservoir Characterization Project on the western side of the Cedar Hill field has imaged faults and zones of enhanced fracture permeability proximal to the fault. Local stress relief occurs in proximity to the faults as indicated by the polarization map of Figure 1. The dominant fracture direction that is opened within the central fault block is aligned to the northwest, perpendicular to the minimum horizontal stress. Areas or zones of open fractures and enhanced fracture permeability aligned northwest are observed on the S2 amplitude map (Figure 2). To the east, the face cleats dominate the directional permeability because of local overpressuring (see Figure 2.) A well recently drilled as a twin to the original Hamilton 3 well was completed with a cavity completion. This well has exhibited production rates 10 times greater than the original well. The increased production in the Hamilton 3R well cannot be attributed to new completion technology alone. This well hit a brecciated zone proximal to the fault. The increased fracturing of the reservoir assisted the cavity completion performance by improving the drainage area to the well bore. Similar results and improved production performance could probably be gained by horizontal drilling. In fact, horizontal drilling based on multicomponent 3-D data could improve production performance over a cavity completion by intersecting additional fracture area and effectively increasing drainage to the well bore. The identification of high permeability zones in advance of drilling is important to commercial coalbed methane production and development.

Well spacing is currently set by the assumption of uniformity of the coal and cleat systems whereby the face cleats are considered the dominant permeability direction. The multicomponent 3-D and VSP data indicate that in some sectors of the reservoir the butt cleats (northwest-trending) are the dominant open fracture set. Moreover, some of the faults may be sealing faults as evidenced by well pressure tests and reservoir simulations. Spacing units for effective coalbed methane development should be designed and allocated on reservoir drainage criteria and not intuitive assumptions about reservoir continuity.

Conclusion

Imaging of enhanced fracture permeability by multicomponent 3-D surveys could substantially improve the production and development of fractures reservoirs.

Acknowledgements

The authors gratefully acknowledge industry sponsors of the CSM Reservoir Characterization Project - Phase IV who enthusiastically support this multicomponent seismic research, including: Advance Geophysical;AGIP; AMOCO; Canadian Hunter; Chinese Petroleum Corporation; CGG American Services, Inc.; CNG Producing Company; Conoco; Elf Aquitaine; Exxon; Gas Research Institute; Golden Geophysical, Inc.; Halliburton Geophysical Services; ICF Resources; INTEVEP, S.A.; Japan National Oil Corp.; Japan Petroleum Exploration Co. Ltd.; Marathon Oil Co.; Meridian Oil Co.; Mesa Limited Operating Partnership; Norcen Energy; Northern Geophysical of America; ORYX Energy Co.; Resource Enterprises, Inc.; Schlumbeger Well Services; Soekor; Texaco Inc.; Transworld Energy International; Union Pacific Resources, Inc.; and UNOCAL.

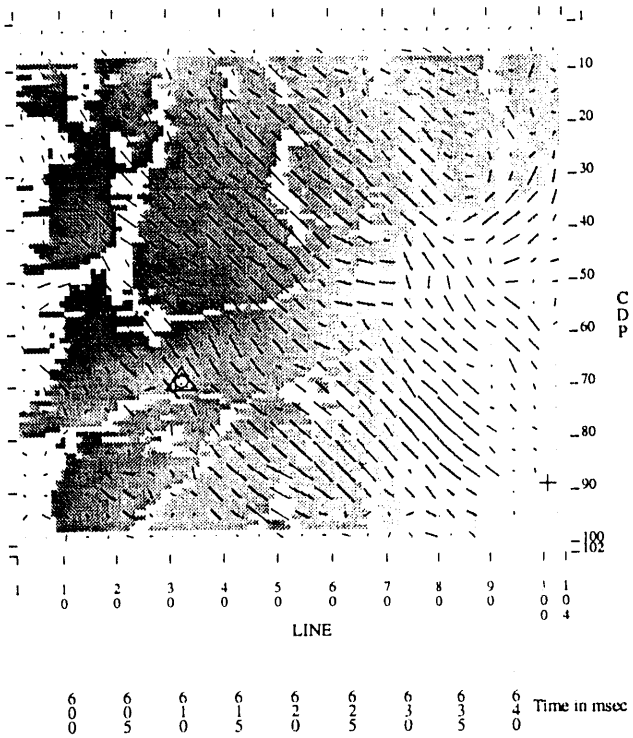


Figure 1. P-wave time structure for top of lower basal coal reflection with 3-D shear-wave polarization overlay. White zones within the survey have been identified as fault zones.

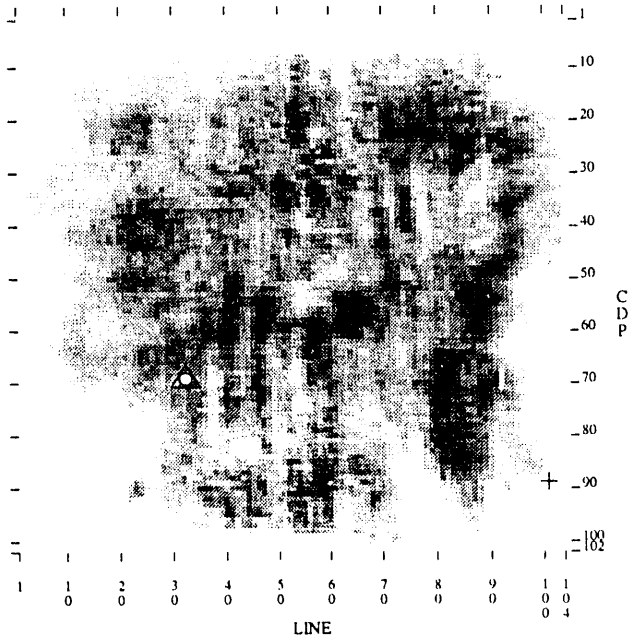


Figure 3. Fast split shear wave (S1) amplitude map on top of lower basal coal reflection.

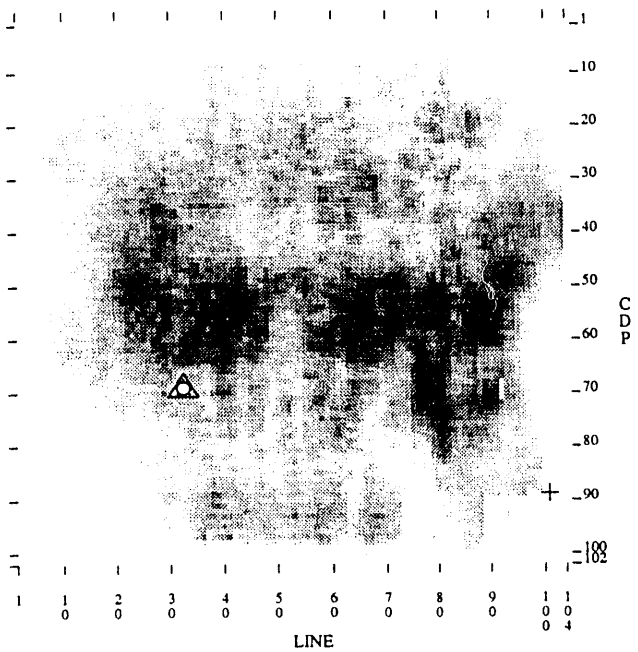


Figure 2. Slow split shear wave (S2) amplitude map on top of lower basal coal reflection.

DETECTING SUBSURFACE RESERVOIR STATES
using
SEISMIC AVO (Amplitude Variation with Offset)

by

R.H. Angerer
ASSOCIATED GEOPHYSICAL ANALYSTS, INC.
Box 280888, Lakewood, Colorado (303-933-0211)

The reflection seismic tool has been used since the 1930s for the exploration and development of hydrocarbons resources. This usage, until more recently, has been primarily involved in the analyses of subsurface structure as indicated by seismic reflection times. Significant improvements in modern-day equipment and understanding of the seismic technique have made stratigraphic interpretations realizable, and foremost in these applications has been the analysis of the amplitudes of seismic reflections. The manner in which seismic events vary in amplitude as a function of the distance between the energy source and the seismic detectors has proven to be particularly useful.

These new developments in the seismic industry are often making it possible to determine not only the presence, but also the precise distribution, of gas and live oil in the subsurface. The principles of elastic wave (seismic) propagation are becoming sufficiently well understood to recognize that seismic Amplitude Variation with Offset (AVO) can be quantitatively analyzed to more fully understand how variations in economically important reservoir states (such as porosity, pore fluids, pressure, mineralogy or temperature) are distributed within a reservoir.

Seismic measurements (which have been calibrated in the laboratory and in the field to stratigraphic, petrophysical and engineering characteristics) are being used on a regular basis to assist in the efficient exploration, development and production of hydrocarbons. This presentation will illustrate, with examples and models, some of the more useful (and striking) state-of-the-art applications presently being used in the management of oil and gas reservoirs.

BIOTECHNOLOGY FOR FIELD APPLICATIONS SESSION

Friday, May 7, Afternoon: 1:15 PM to 4:45 PM

Session Chair: Rebecca S. Bryant, NIPER

Introduction.....ii

Surfactant-Based Permeability Modification Treatment.... 1
Feliciano M. Llave, NIPER, Bartlesville, OK

Basics of Microbial EOR Processes 9
Anita K. Stepp, NIPER, Bartlesville, OK

Field Projects Using Microorganisms 21
Rebecca S. Bryant, NIPER, Bartlesville, OK

Microbial Culture Products--Environmentally Sound
& Cost Effective Applications in
the Petroleum Industry 31
Dennis R. Schneider, Micro-Bac
International, Inc, Austin, TX

DOE Programs in Microbial Technology 41
Rhonda Patterson Lindsey, Department
of Energy, Bartlesville, OK

Biotechnology for Field Applications

Introduction

Biological techniques have not been widely exploited in the Rocky Mountains. The experience of operators in other petroleum basins should be applicable in many reservoirs in the Rockies. Inexpensive techniques such as these will allow the prudent operator to prolong the lives of his wells.

NIPER Paper EPR/OP-93/13

SURFACTANT-BASED PERMEABILITY MODIFICATION TREATMENT

By Feliciano M. Llave

Prepared for the New Technology for Independent Producers Conference
May 6-7, 1993
Denver, Colorado

Work Performed for the
Department of Energy
Under Cooperative Agreement
DE-FC22-83FE60149

Copyright Waiver

By acceptance of this article for publication, the publisher recognizes the Government's (license) rights in any copyright and the government and its authorized representatives have unrestricted right to reproduce in whole or in part said article under any copyright secured by the publisher.

DISCLAIMER

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, makes any warranty, expressed or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise, does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

IIT Research Institute
National Institute for Petroleum and Energy Research
Box 2128
Bartlesville, Oklahoma 74005
918 336-2400

SURFACTANT-BASED PERMEABILITY MODIFICATION TREATMENT

by Feliciano M. Llave

EXTENDED ABSTRACT

The performance of oil recovery processes is dependent on both microscopic displacement and volumetric sweep efficiency. The volumetric sweep efficiency of the processes can have a significant impact on the overall oil recovery. Variations in permeability and inherent reservoir heterogeneities can significantly affect the efficiency of these processes. Within a typical reservoir, there are zones or regions present that are relatively more permeable to fluid flow. The injected fluid or drive fluid has a tendency to preferentially flow through these high permeability zones, bypassing the amount of oil that may be present in the regions of lower permeability. Significant permeability contrast within the reservoir can result in poor contact between the drive fluid and the target oil, thereby severely limiting the efficiency of the displacement process.

Several methods for improving reservoir sweep through permeability modification have been proposed. In recent years, there has been considerable interest in applications of crosslinked polymer technology to alleviate problems associated with reservoir heterogeneity. The application of polymer technology for permeability modification has, however, several key issues and limitations that have not been fully addressed. Problems associated with these treatments include (1) polymer precipitation and degradation under harsh reservoir conditions, (2) limited depth of penetration, (3) loss of injectivity, (4) loss of viscosity caused by shear degradation, (5) control of polymer gelation rates, and (6) environmental concerns over crosslinking agents. There is a need for the development of a new technology that preferentially diverts the injected fluid from the high permeability zones to the less permeable zones that retain most of the remaining oil without the restrictions of current methods.

In this work, a surfactant-based permeability modification treatment method was developed as an alternative for improving sweep efficiency in reservoirs with highly permeable zones. The treatment process involves the injection of a pre-determined surfactant/alcohol slug composition. Blends of a proprietary series of surfactants and alcohol were used in tests conducted to identify conditions that yielded favorable solution properties. The chemical system when injected as a slug has been found to achieve controllable depth of penetration and reduce permeability contrast resulting in diversion of the primary drive fluid. Permeability modification is achieved upon the development

of sufficiently high solution viscosity resulting mainly from the separation of the chemical components of the original injected formulation and is not dependent on any cross-linking/reaction mechanism. The mechanism is based primarily on the preferential chromatographic separation of the chemical components in the slug. The natural tendency of these blends would be for the alcohol component to separate from the bulk of the slug leaving behind a surfactant-rich bulk phase that "gels" or forms a viscous-plugging phase. The degree of initial slug penetration is controllable by varying the component concentrations in the formulation, and the propagation of the permeability barrier can be facilitated by subsequent injection of alcohol slugs. Loss of injectivity and formation damage are minimized since the injected chemical slug is initially of low viscosity.

The method has several distinct operational advantages over conventional polymer-based treatment methods. These include (1) a controllable depth of penetration can be achieved without premature loss of injectivity; (2) capability to propagate the viscous barrier farther through the porous media after being set in place; (3) applicable in both hard and fresh brines; (4) environmentally acceptable; and (5) reduced logistic requirements pertaining to mixing and well-pre-treatment (conditioning) required in conventional gelled-polymer systems.

The method is currently slated for field testing. NIPER is seeking the assistance of candidate field operators for participation in a demonstration field test of this surfactant-based permeability modification treatment method. The treatment can be applied over a broad range of reservoir conditions. The ideal candidate for the application of this type of treatment would be sandstone-type reservoirs where severe permeability contrast and crossflow problems have been identified.

SURFACTANT-BASED
PERMEABILITY MODIFICATION
TREATMENT

NIPER-IITRI

OUTLINE

- OBJECTIVE
- BACKGROUND
- TREATMENT MECHANISM
- SCOPE OF WORK
  - SCREENING TEST
  - FLOW EXPERIMENTS
  - FLUID DIVERSION AND OIL DISPLACEMENT
  - RESERVOIR COMPATIBILITY
  - FIELD TEST *
- SUMMARY
  - * pending

NIPER-IITRI

OBJECTIVE

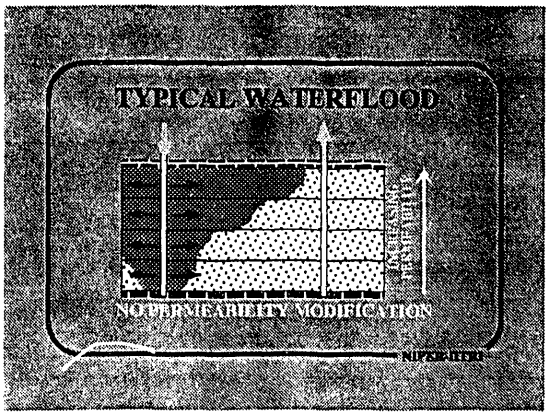
DEVELOP AN IMPROVED METHOD OF ACHIEVING IN-DEPTH PERMEABILITY MODIFICATION IN POROUS MEDIA USING SURFACTANT AND ALCOHOL BLENDS

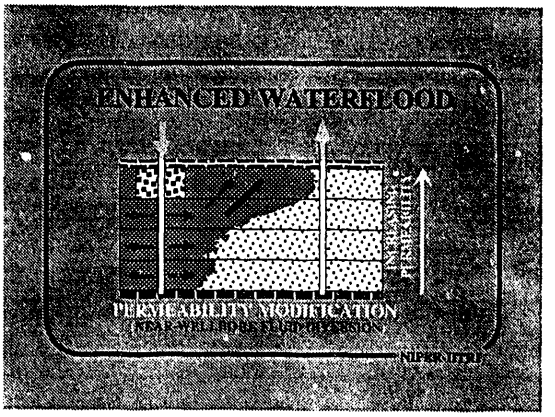
NIPER-IITRI

BACKGROUND

PERMEABILITY MODIFICATION TREATMENT

NIPER-IITRI





CONVENTIONAL POLYMER TREATMENT

PROBLEMS ASSOCIATED WITH POLYMER

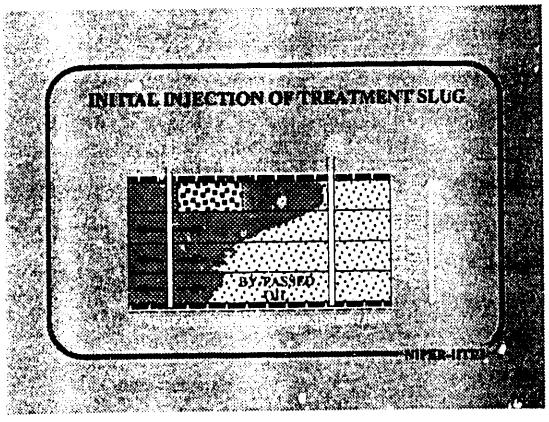
- LIMITED PENETRATION
- LOSS OF INJECTIVITY - FORMATION DAMAGE
- GEL DEGRADATION
- POLYMER PRECIPITATION
- ENVIRONMENTAL CONCERNS - CHROMIUM
- LIMITED CONDITIONS OF APPLICATION

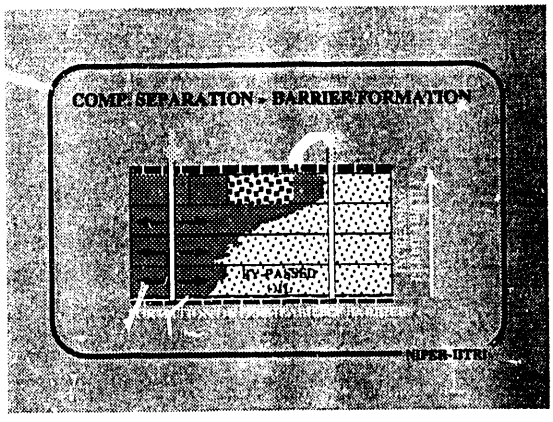
NIPER-IITRI

MECHANISM

SURFACTANT-ALCOHOL TREATMENT

NIPER-IITRI





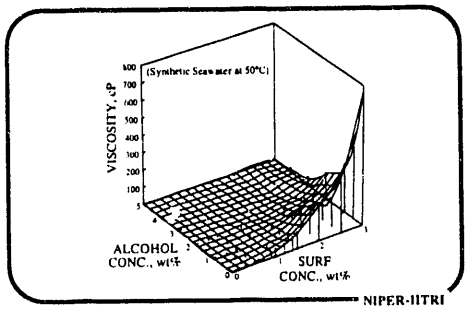
SCREENING STUDIES

IDENTIFY SYSTEMS AND CONDITIONS

ARMOSTIM™ PF-1 to PF-8 SURFACTANTS

- SOLUTION VISCOSITY
- CHEMICAL STABILITY
- INTERACTION TEST
- ADSORPTION TEST

NIPER-IITRI



RANGE OF CONDITIONS

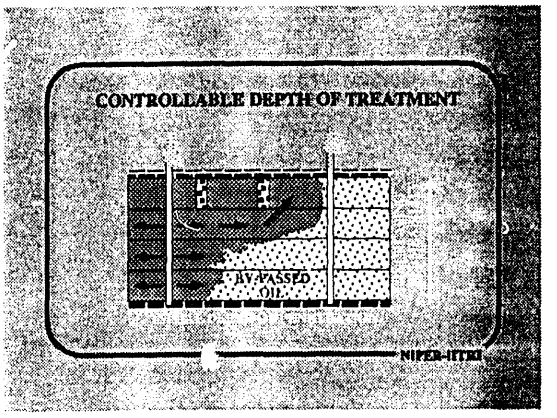
- TEMPERATURES UP TO 200° F
- BRINE SALINITIES (AT LEAST UP TO 85,000 PPM TDS)
- HARDNESS (AT LEAST UP TO 7,000 PPM Ca+Mg)
- pH RANGE AT LEAST 6 TO 9

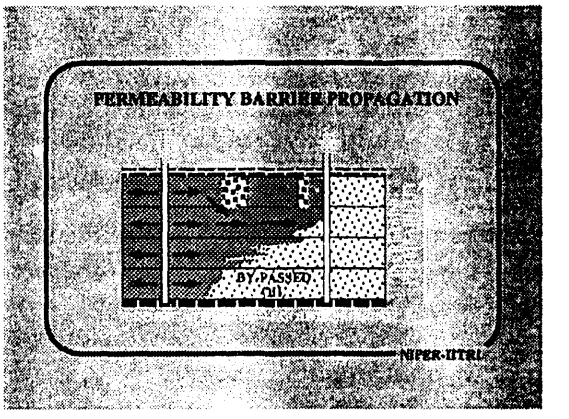
NIPER-IITRI

FLOW EXPERIMENTS

- CONFIRM MECHANISM OF PERMEABILITY MODIFICATION
- DETERMINE INJECTION STRATEGY
  - SLIM TUBE EXPERIMENTS
  - COREFLOOD EXPERIMENTS

NIPER-IITRI





RESULTS/OBSERVATIONS

SLIM TUBE AND COREFLOOD EXPERIMENTS

- THE ALCOHOL COMPONENT IN THE SLUG PROPAGATED THROUGH THE SYSTEM FAIRLY INTACT, LEAVING BEHIND THE BULK OF THE SURFACTANT COMPONENT TO FORM THE PERMEABILITY BARRIER
- THE INJECTION OF THE SURFACTANT-ALCOHOL BLENDS RESULTED IN SOME DEGREE OF PERMEABILITY REDUCTION (20 - 50%)
- THE DEGREE OF INITIAL SLUG PENETRATION WAS CONTROLLABLE BASED ON THE COMPONENTS IN THE BLEND
- THE PERMEABILITY BARRIER, ONCE IN PLACE, CAN BE PROPAGATED BY ADDITIONAL INJECTIONS OF ALCOHOL SLUGS

NIPER-IITRI

COMPARISON STUDIES

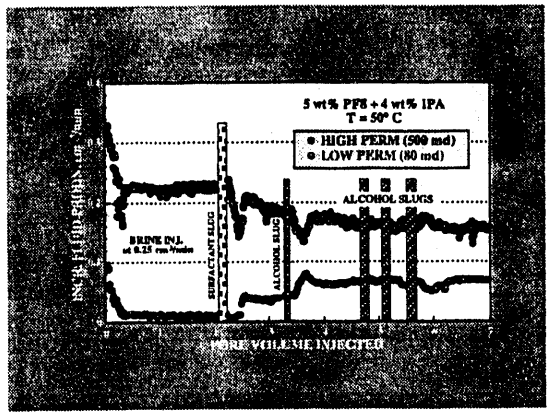
PARALLEL COREFLOOD EXPERIMENTS

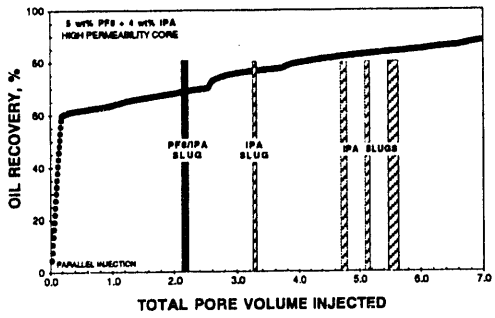
- FLUID DIVERSION POTENTIAL
- IMPROVED OIL DISPLACEMENT

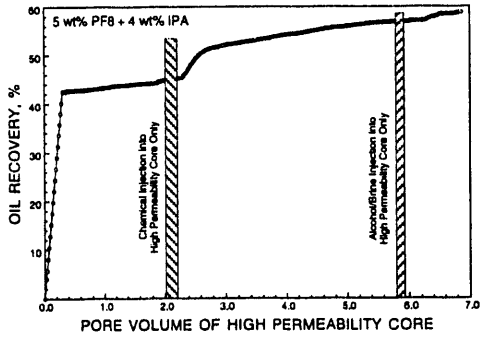
NIPER-IITRI

SURFACTANT/ALCOHOL TREATMENT

NIPER-IITRI





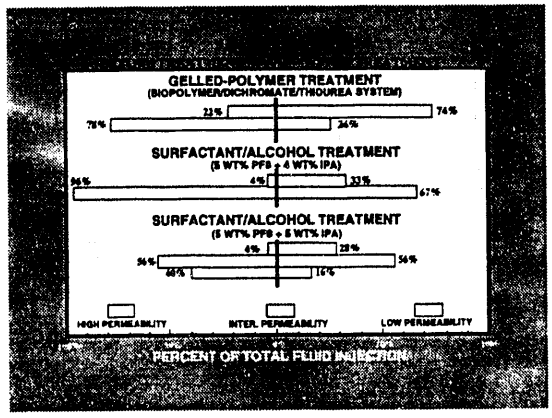


RESULTS/OBSERVATIONS

SURFACTANT/ALCOHOL TREATMENT

- PERMEABILITY MODIFICATION IN THE HIGH PERMEABILITY CORE RESULTED IN FLUID DIVERSION INTO THE LOW PERMEABILITY CORE
- FAVORABLE INTERFACIAL TENSIONS DUE TO PRESENCE OF THE SURFACTANT MAY HAVE CONTRIBUTED TO SOME OF THE IMPROVEMENT IN OIL RECOVERY FROM THE HIGH PERMEABILITY CORE.
- THE INITIAL DEPTH OF PENETRATION WAS ABOUT 50 TO 75% OF THE LENGTH OF THE HIGH PERMEABILITY CORE.
- NO INJECTIVITY PROBLEMS WERE ENCOUNTERED.

NIPER-IITRI



TREATMENT COMPARISON

- FLUID DIVERSION WAS ACHIEVED USING BOTH METHODS.
- INJECTIVITY PROBLEMS WERE ENCOUNTERED DURING THE GELLED-POLYMER INJECTION.
- THE SURFACTANT-ALCOHOL TREATMENT ACHIEVED IN-DEPTH PENETRATION COMPARED TO MORE NEAR-INJECTION REGION TREATMENT FOR THE GELLED-POLYER

NIPER-IITRI

SUMMARY

- BLENDS OF SELECTED SURFACTANTS AND ALCOHOLS SHOW PROMISE FOR USE AS PERMEABILITY MODIFICATION AGENTS OVER A BROAD RANGE OF CONDITIONS.
- THESE FORMULATIONS CAN BE USED TO PREFERENTIALLY IMPART A PERMEABILITY REDUCTION IN THE HIGH PERMEABILITY ZONES.
- THE METHOD OFFERS SEVERAL UNIQUE FEATURES:
  - CONTROLLABLE IN-DEPTH PENETRATION, IMPROVED INJECTIVITY
  - PERMEABILITY BARRIER CAN BE PROPAGATED THROUGH THE POROUS MEDIA
  - SURFACTANT BASED - FAVORABLE IFT'S
  - OVERCOMES SOME CONSTRAINTS OF GELLED-POLYMER TREATMENT

NIPER-IITRI

ADVANTAGES

SURFACTANT/ALCOHOL BLENDS

- IMPROVED INJECTIVITY
- USEFUL FOR IN-DEPTH TREATMENTS (CAN BE PROPAGATED)
- APPLICABLE IN BOTH HARD AND FRESH BRINES
- REDUCTION IN WATER HANDLING COSTS
- ENVIRONMENTALLY ACCEPTABLE

NIPER-IITRI

BASICS OF MICROBIAL EOR PROCESSES

By Anita K. Stepp

Prepared for New Technology for Independent Producers Conference
May 6-7, 1993
Denver, Colorado

Work Performed for the
Department of Energy
Under Cooperative Agreement
DE-FC22-83FE60149

COPYRIGHT WAIVER

By acceptance of this article for publication, the publisher recognizes the Government's (license) rights in any copyright and the government and its authorized representatives have unrestricted right to reproduce in whole or in part said article under any copyright secured by the publisher.

DISCLAIMER

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, makes any warranty, expressed or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise, does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

IIT Research Institute
National Institute for Petroleum and Energy Research
Box 2128
Bartlesville, Oklahoma 74005
918 336-2400

BASICS OF MICROBIAL EOR PROCESSES

By Anita K. Stepp

Extended Abstract

Microbial enhanced oil recovery (MEOR) is a feasible technology to improve production. An understanding of the basic concepts of MEOR is necessary before deciding whether MEOR can be useful in a particular situation. Concepts which will be covered in this presentation include types of microbes used, microbial products and their relationship to oil recovery, and mechanisms of microbial oil recovery. Other topics included will be reservoir screening, selection of microorganisms, and compatibility testing of microbes and reservoir fluids. By careful consideration of these and other important factors, a higher success rate can be achieved with the use of MEOR.

Microorganisms are attractive for oil recovery applications for several reasons. Bacteria are self-replicating and relatively inexpensive to produce, nutrients required to sustain growth of bacteria are inexpensive, and bacteria can produce many of the same chemicals that are used in other enhanced oil recovery technologies. The operating costs of a MEOR project can be as low as that of a waterflooding project. There are different types of bacteria used in MEOR, depending upon the goal of the project. Some bacteria produce products such as gases, surfactants, acids, and alcohols which aid in the release, mobilization, and recovery of oil. Other bacteria produce polymers which can cause permeability modification. What makes MEOR unique is that products which enhance oil recovery are produced underground, at the oil/water/rock interface. Some of the key mechanisms of MEOR caused by these products are wettability alteration, surface and interfacial tension effects, oil viscosity reduction, permeability modification, and fluid diversion.

MEOR can be used in several different ways to improve oil recovery. It can be used in single-well stimulation for near wellbore cleanup and improved recovery efficiency. Another application is microbial-enhanced waterflooding, which also can improve displacement efficiency. MEOR can also be used for profile modification to improve sweep efficiency, and for well coning mitigation.

There are several reservoir conditions limiting recovery efficiencies to consider when using MEOR. These include temperature, salinity, permeability, and heavy metals. Bacteria can usually grow well up to 160° F, and up to 10% salinity. A permeability of greater than 75 md is preferable, however, MEOR projects have been successful in fields with lower permeability. Pressure is not usually a problem as long as the temperature is not too high. Abnormally high concentrations of heavy metals will be toxic to the microbes.

Laboratory design of a microbial system is one of the most important steps in considering MEOR for a field. Compatibility testing is done at reservoir conditions. The oilfield brine is tested

for total dissolved solids and for indigenous microorganisms. Different microbial formulations are grown in the presence of the oilfield brine, oil, and rock to make sure they are compatible. More extensive testing can also be done, such as corefloods with field core.

Microbial EOR methods are not the answer to every problem. For successful applications, one must use the same engineering principles as would be used for any other EOR method. With the proper application of reservoir and production engineering methods, MEOR field projects can be designed and implemented by independent oil producers in a manner that produces acceptable rates of return on investment.

HISTORY OF MICROORGANISMS IN THE PETROLEUM INDUSTRY

- 1940s - INTERACTIONS BETWEEN MICROBES AND OIL FIRST RECOGNIZED - FOR OIL FORMATION
- 1950s - OILFIELD CORROSION PROBLEMS
- 1960s - LOW COST OF OIL - USE AS A NUTRIENT FOR MICROORGANISMS - SINGLE CELL PROTEIN
- 1970s - ENVIRONMENTAL CONCERNS - OIL DEGRADATION BY MICROORGANISMS
- 1980s - BIOTECHNOLOGY EMERGES
  - INCREASED INTEREST IN FOSSIL FUELS
  - USE OF MICROBES FOR CLEANUP

NIPER RESEARCH FACILITIES FOR MICROBIAL EOR

- MICROBIAL CULTURE BANK
- MEOR FIELD PROJECT DATA BASE
- MICROBIAL EOR TRAINING PROGRAMS AND SHORT COURSES
- LABORATORY FACILITIES FOR:
  - MICROBIAL FIELD SAMPLING
  - COMPATIBILITY TESTING
  - COREFLOOD & MICROMODEL STUDIES
  - MICROBIAL TRANSPORT STUDIES
  - BIOCIDE EVALUATIONS
  - FIELD TESTS

NIPER'S ROLE IN DEVELOPMENT OF BIOTECHNOLOGY FOR EOR

- 9 YRS OF LABORATORY RESEARCH, INCLUDING ENVIRONMENTAL EFFECTS OF MEOR PROCESSES
- CONDUCTED 2 DOCUMENTED MICROBIAL ENHANCED WATERFLOOD FIELD PROJECTS
- DEVELOPED NUMERICAL SIMULATION MODEL FOR MICROBIAL EOR PROCESSES

MICROBIAL EOR

- COST EFFECTIVE TECHNOLOGY FOR THE 1990s
- MINIMIZES USE OF HAZARDOUS SUBSTANCES
- CAN BE USED FOR A VARIETY OF PETROLEUM RESERVOIRS AND APPLICATIONS

MICROBES FOR IN SITU EOR

CLOSTRIDIUM	GASES, ACIDS, ALCOHOLS, SURFACTANTS
BACILLUS	ACIDS, SURFACTANTS
ARTHROBACTER	SURFACTANTS, ALCOHOLS
ENTEROBACTER	GASES, ACIDS
BACILLUS	POLYMER
LEUCONOSTOC	POLYMER
KLEBSIELLA	POLYMER

MICROBIAL PRODUCTS	OIL RECOVERY MECHANISM
GASES	• REDUCE OIL VISCOSITY • DISSOLVE CARBONATE ROCK • DISPLACE TRAPPED OIL
SURFACTANTS	• REDUCE IFT • CREATE EMULSIONS • ALTER WETTABILITY
ACIDS	• MODIFY RESERVOIR ROCK • STIMULATE IN SITU SURFACTANTS IN CRUDE
SOLVENTS	• DISSOLVE CRUDE • ACT AS CO-SURFACTANTS
POLYMERS/BIOMASS	• SELECTIVELY PLUG • CONTROL MOBILITY

KEY MECHANISMS OF MEOR

- FERMENTATION PRODUCTS AT THE OIL/WATER/ROCK INTERFACE CAUSE:
  - WETTABILITY ALTERATION
  - SURFACE AND INTERFACIAL TENSION EFFECTS
  - EMULSION FORMATION
  - OIL VISCOSITY REDUCTION
  - PERMEABILITY MODIFICATION
  - FLUID DIVERSION
  - PHYSICAL OIL DISPLACEMENT BY GAS

MICROBIAL EOR PROCESSES

- SINGLE-WELL STIMULATION
- MICROBIAL-ENHANCED WATERFLOODING
- MICROBIAL PERMEABILITY MODIFICATION
- MICROBIAL WELLBORE CLEANUP
- WELL CONING MITIGATION

SINGLE-WELL STIMULATION

- USE OF MICROORGANISMS THAT PRODUCE GASES, ACIDS, ALCOHOLS, AND SURFACTANTS
- SHUT-IN PERIOD
- MUST TREAT AGAIN AFTER SOME PERIOD OF TIME

MICROBIAL-ENHANCED WATERFLOODING

- USE OF MICROORGANISMS THAT PRODUCE GASES, ACIDS, ALCOHOLS, AND SURFACTANTS
- REQUIRES MORE DETAILED DESIGN OF TREATMENT
- CONTINUOUS SUPPLY OF NUTRIENT

MICROBIAL PERMEABILITY MODIFICATION

- USE OF MICROORGANISMS THAT PRODUCE POLYMER OR BIOMASS
- REQUIRES GREATER DETAILED DESIGN OF TREATMENT
- HAS NOT BEEN DEMONSTRATED IN THE FIELD

MICROBIAL WELLBORE CLEANUP

- USE OF MICROORGANISMS THAT PRODUCE SURFACTANTS AND ACIDS, AND/OR HYDROCARBON DEGRADERS
- LOW COST - SIMILAR TO CHEMICAL TREATMENTS
- DOESN'T ALWAYS WORK

GOALS OF LABORATORY OPTIMIZATION

- MICROBES MUST BE ABLE TO LIVE IN RESERVOIR ENVIRONMENT
- MICROBES MUST MAKE THE PRODUCTS THAT IMPROVE OIL RECOVERY

LABORATORY DESIGN OF MEOR SYSTEM

- COMPATIBILITY TESTS AT RESERVOIR CONDITIONS
- PRELIMINARY SELECTION OF MICROBIAL SYSTEM
- OPTIMIZATION
- FIELD INJECTIVITY/COMPATIBILITY TESTS
- FINAL SELECTION OF MICROBIAL FORMULATION

COMPATIBILITY TESTING

- TESTS SHOULD BE CONDUCTED WITH MICROBES UNDER RESERVOIR CONDITIONS WITH THE FOLLOWING:

  - INJECTION WATER
  - CRUDE OIL
  - PRODUCED WATER
  - NUTRIENTS
  - LONG-TERM STABILITY TESTING (2-3 WKS)
  - TEMPERATURE
  - PRESSURE

OPTIMIZATION

- TESTS MUST BE CONDUCTED UNDER RESERVOIR CONDITIONS WITH THE FOLLOWING:

  - ROCK
  - OIL
  - BRINE
  - MICROORGANISMS
  - NUTRIENT
  - SHORT AND LONG-TERM TESTING IN CORES

NOTES

FIELD PROJECTS USING MICROORGANISMS

By Rebecca S. Bryant,

Prepared for the New Technology for Independent Producers Conference
May 6-7, 1993
Denver, Colorado

Work Performed for the
Department of Energy
Under Cooperative Agreement
DE-FC22-83FE60149

Copyright Waiver

By acceptance of this article for publication, the publisher recognizes the Government's (license) rights in any copyright and the government and its authorized representatives have unrestricted right to reproduce in whole or in part said article under any copyright secured by the publisher.

DISCLAIMER

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, makes any warranty, expressed or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise, does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

IIT Research Institute
National Institute for Petroleum and Energy Research
Box 2128
Bartlesville, Oklahoma 74005
918 336-2400

FIELD PROJECTS USING MICROORGANISMS

Rebecca S. Bryant, IITRI/NIPER

EXTENDED ABSTRACT

Oil production using enhanced oil recovery technology is increasing even with the lower cost of oil in the world. According to an article in the April 20, 1992 *Oil and Gas Journal*, in the United States, oil produced from EOR projects now exceeds 10% of the domestically produced oil. Enhanced oil production technology is now being applied worldwide, and can only be expected to increase, due to the diminishing development of new fields and the decline of more mature ones.

Microbial enhanced oil recovery (MEOR) has been recognized as a potentially cost-effective method, particularly for stripper well production. Microbial methods for improving oil recovery are particularly well suited to be applied in today's economic climate. Adequate data exist to demonstrate both the viability and variety of options for using microbial technology for improved oil production. Although MEOR field applications are not widespread or conducted in large enough reservoirs to account for a significant amount of oil, the number of producers and oilfields that have been treated is crucial to the domestic petroleum industry.

To determine the feasibility of improving oil recovery and the economics of microbial enhanced waterflooding in mature oil wells in the United States, NIPER conducted two field pilots. Candidate fields were screened to determine whether they have any potential for a microbial system developed at NIPER, and microbial compatibility tests were conducted in the laboratory to select the target field. A specific microbial formulation was selected that was compatible with the reservoir environment, and had been shown to recover oil after waterflooding in Berea sandstone and field core. Both field tests were conducted in fluvial dominated deltaic reservoirs, designated as Class 1 by the U. S. Department of Energy.

A microbial treatment requires careful design and sound reservoir enginecring practice, as does any enhanced oil recovery (EOR) method. The methodology for designing and optimizing MEOR field tests is still an ongoing effort; however, the literature and laboratory experience indicate that certain procedures are necessary to implement a microbial-enhanced waterflood. These particular field experiments were designed to use microorganisms that produced chemicals

(surfactants, gases, alcohols, and fatty acids) for improved oil mobilization, and had the ability to transport through porous media.

A 20-acre pilot test was initiated in October 1986, and completed December 1989. This pilot was designated as the Mink Unit of Delaware Childers field, and produced from the Bartlesville sandstone. A fluorescein tracer test showed communication occurred among the four targeted injection wells and 15 surrounding producers. Single well injectivity and compatibility testing showed that the microbial formulation did not plug the formation and survived and multiplied in the reservoir environment. Results from this pilot demonstrated that microorganisms could be injected into an ongoing waterflood and that such injection could increase oil production by at least 13%. Water-oil ratios of wells in the pilot area decreased, some by as much as 35%.

A larger test (520 acres) was completed in the same formation to evaluate the feasibility of commercial application of the technology. This field pilot was injected with microorganisms and molasses from a centralized injection station in June 1990. All 19 injection wells were treated and oil production was monitored from the 47 production wells. Injection well volumes and pressures did not significantly change after microbial injection. These are important parameters when monitoring a microbial injection. Significant plugging problems have not occurred. The hyperbolic decline curve analysis indicates that oil production has increased after microbial treatment. An incremental 3,228 bbl of oil has been produced over the projected hyperbolic decline curve through December 1992, which corresponds to approximately 16% improvement in oil production.

These microbial-enhanced waterflood field projects demonstrated the feasibility of microbial technology in a manner that an independent operator could implement. It is noteworthy that no operating problems were encountered before or during either project. No corrosion problems were experienced; in fact, the sulfate-reducing bacterial populations remained relatively low compared to the baseline counts. There were no problems with injectivity. The Phoenix project has demonstrated the commercial applicability of microbial-enhanced waterflooding and has shown an improvement in oil production to date of 16%. Although these two pilots have shown the potential for microbial waterflooding technology, there are many other MEOR processes and types of applications that merit further field testing. Use of microorganisms for permeability modification is a technique that can greatly enhance oil production in the near term. Development of microbial waterflooding and single-well stimulation techniques for a wide variety of reservoirs is critical, both for the United States and other oil-producing nations.

TABLE 1 Number of Reservoirs by State With Potential for MEOR Technology

State	Total no. of reservoirs	No. of reservoirs that fit the criteria	%	Reserves, bbl
OK	97	16	17	4.4×10^9
TX	461	134	29	1.6×10^{10}
LA	190	28	15	8.3×10^9
KS	39	18	46	3.8×10^9
CA	179	106	59	2.5×10^{10}
CO	40	28	70	4.4×10^8
MS	44	4	9	1.4×10^8
NM	65	3	5	1.3×10^8
WY	67	28	42	3.0×10^8
IL	46	16	35	2.0×10^9
TOTAL	1,228	381	31	6.3×10^{10}

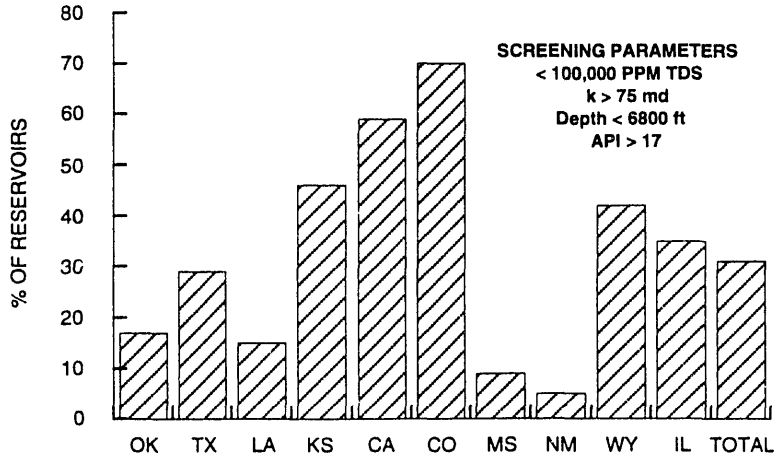


FIGURE 1 — Graph showing percent of reservoirs in major oil-producing states that have potential for MEOR processes.

TABLE 2 A Classification of Different Microbial Reservoir Treatments

MEOR process	Production problem	Type of microorganism used
Well stimulation	Formation damage Low oil relative permeability	Surfactant, gas, acid, and alcohol producers
Enhanced waterflooding	Trapped oil due to capillary forces	Surfactant, gas, acid, and alcohol producers
Permeability modification	Poor sweep efficiency Channeling	Microorganisms that produce polymer and/or copious amounts of biomass
Wellbore cleanup	Paraffin problems Scaling	Microorganisms that produce emulsifiers, surfactants, and acids Microorganisms that degrade hydrocarbons
Microbial polymerflooding	Unfavorable mobility ratio Low sweep efficiency	Microorganisms that produce polymer
Mitigation of coning	Water or gas coning	Microorganisms that produce polymer and/or copious amounts of biomass

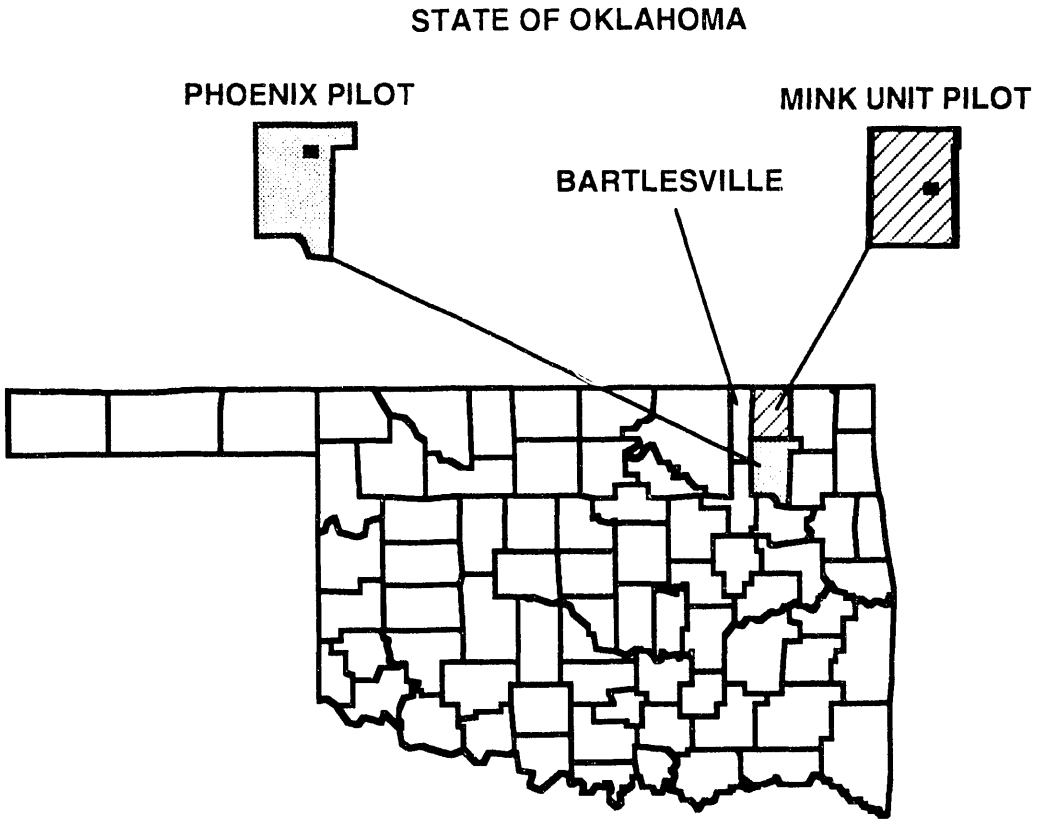


FIGURE 2 — Sites of NIPER's microbial enhanced waterflood field pilots.

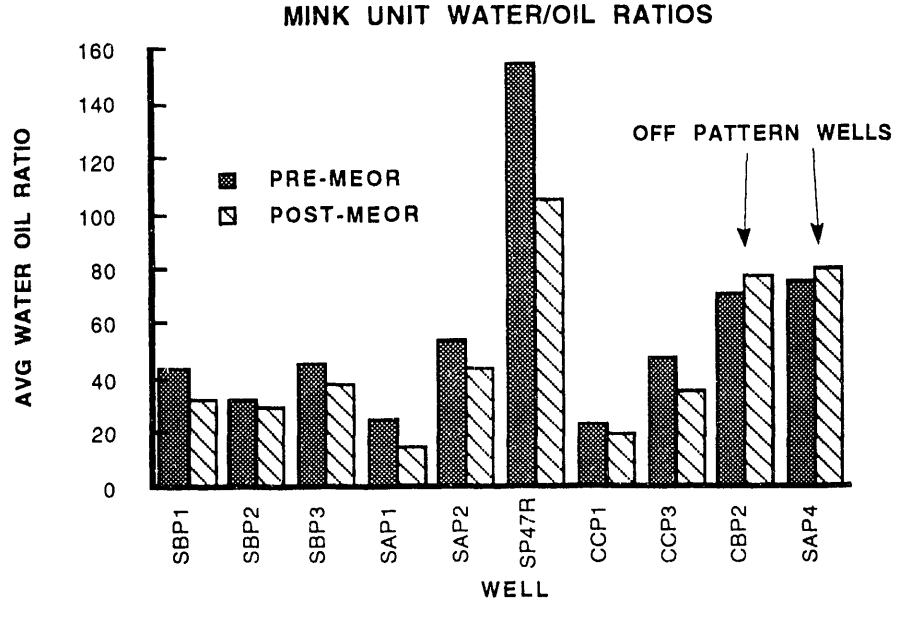


FIGURE 3. — Average water-oil ratios of monitored Mink Unit producers.

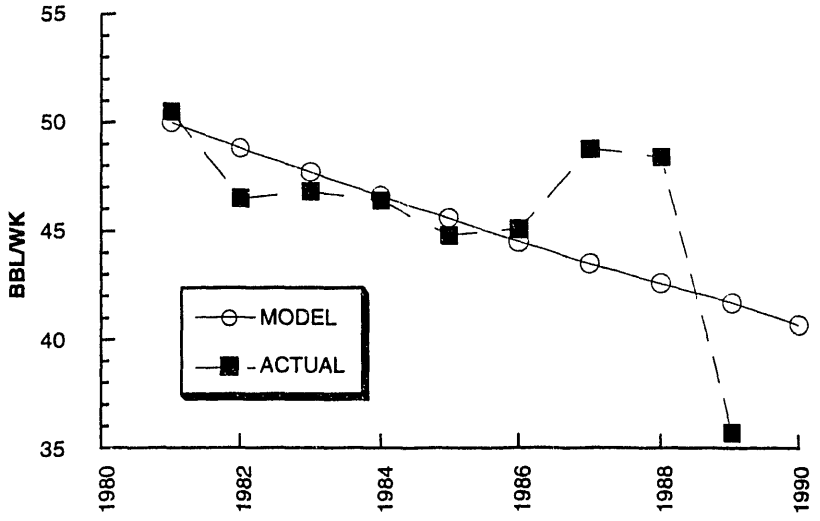


FIGURE 4. — Predicted and actual average oil production for Mink Unit during 1981-1990.

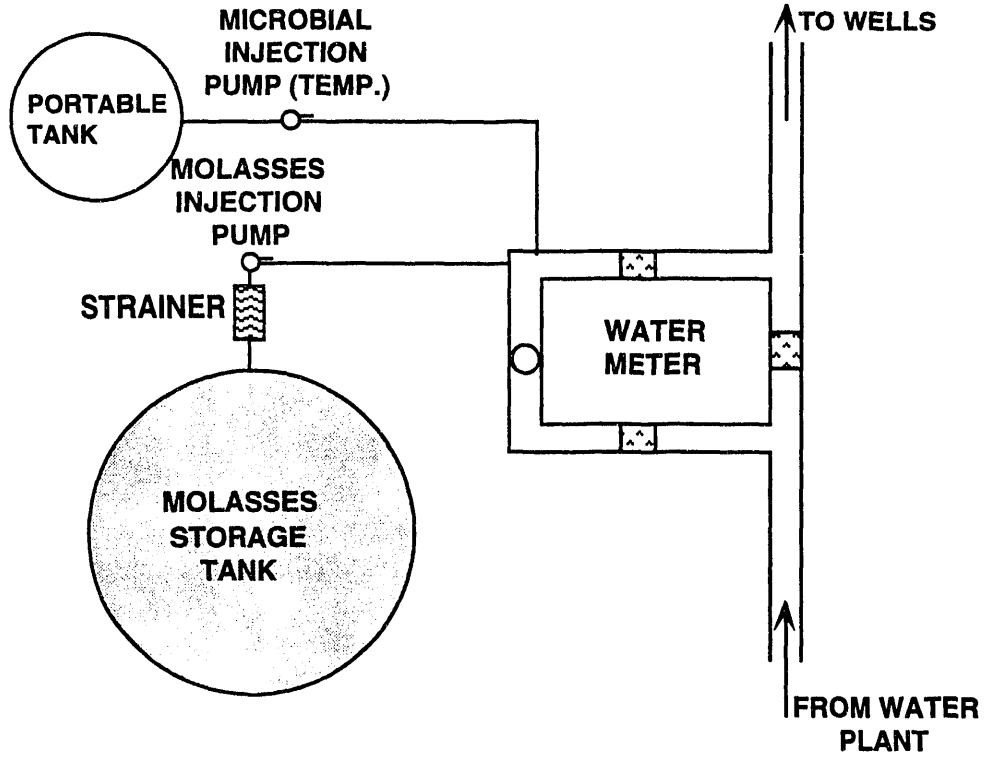


FIGURE 5 — Diagram of the Phoenix injection facilities.

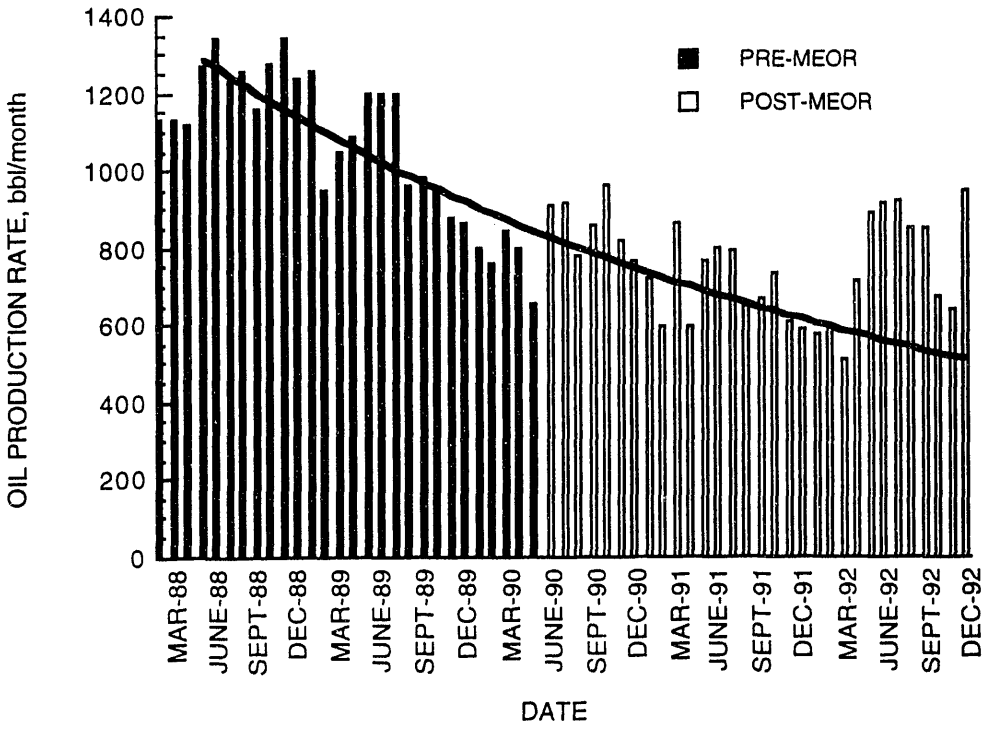


FIGURE 6 — Oil production from the Phoenix field site.

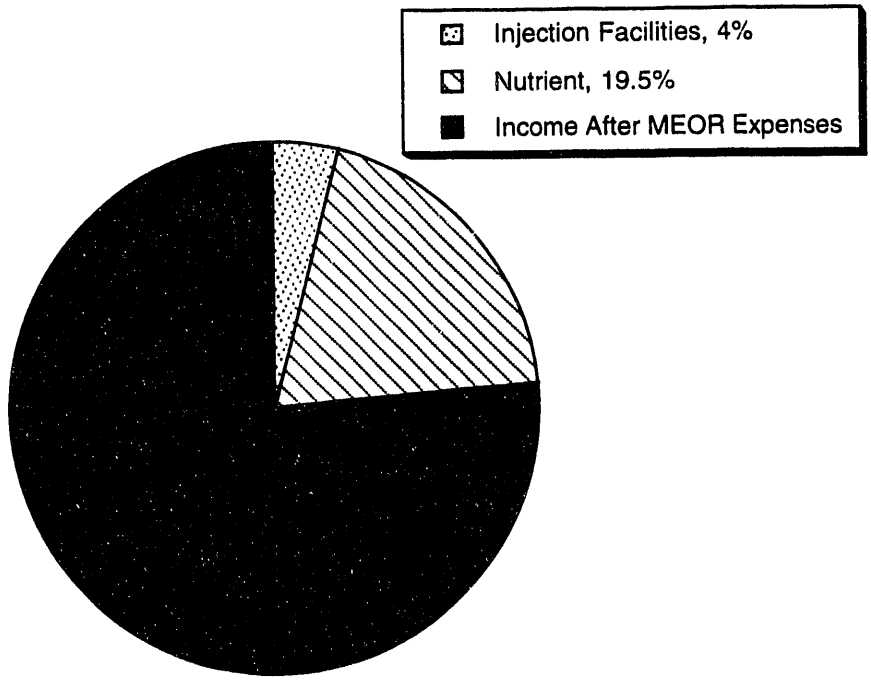


FIGURE 7 — Economic scenario from the Phoenix pilot results.

NOTES

Microbial Culture Products--Environmentally Sound and Cost Effective Applications in the Petroleum Industry.

D.R. Schneider, A. Whiteside, and L.C. Entzeroth
Micro-Bac International, Inc., 9607 Gray Blvd., Austin, TX 78758
512-837-1145, FAX 512-837-5968

The success of a new technology is dependent upon its supplying a better, cost-effective alternative to old methods. This is especially true in the oil industry where the economic limit of production is controlled by commodity market forces beyond the control of domestic suppliers. Microbial culture products have proven their applicability in reducing production costs by becoming a growing and accepted alternative technology in a time period where the domestic industry has been in a state of decline due to depressed or stable crude prices. Significantly, the development of this new industry has taken place with virtually no government or major oil company funding. As the majority of customer base for such products remains with independent producers, it is clearly a technology designed for this segment of the petroleum industry.

A necessary component of any new technology is adequate technical support. Other technologies have traditionally been pioneered by major oil companies and then been adopted by the independents. The microbial products industry was developed in exactly the opposite fashion. The first wells treated with these products were those of independents. Thus, as the role of the majors in domestic oil production continues to decline, we see new technologies coming forward out of the resource base of the independents.

A variety of microbial treatments are possible for various types of production problems and to enhance production. Products exists which can be used for paraffin, scale and corrosion control as well as to enhance long-term oil production. Examples of case histories utilizing these products are seen in Figures 1, 2, 3, and 4. Clearly, not only are substantial benefits obtained as far as cost savings but additional benefits result from either improved operating efficiency or production enhancement. The products can be utilized in a variety of oil field production settings including water floods and tank bottom treatments. The use of such products over an extended period time has been documented in several Society for Petroleum Engineering publications (Pelger, 1992, Brown, 1992, Streeb amd Brown, 1992)

On another level, microbial products can also be used to remediate contamination associated with oil spills. As can be seen in Figure 5, a crude oil contaminated sand can be bioremediated of approximately fifty percent of its original hydrocarbon content in a three week period of time with a single application of microbial product and appropriate nutrients. Successful bioremediation depends upon appropriate microbial engineering as as well as an understanding of regulatory requirements and site engineering. (Schneider and Billingsley, 1991)

The degradation of crude oil is particularly complex as one is dealing with a mixture of hundreds of different compounds spanning a wide range of structural diversity and chemical reactivity. Microbial degradation can selectively attack certain components in crude oil. Thus, it is necessary to evaluate the chemical nature of the degradation process at a molecular level.

As can be seen in Figure 6, the degradation taking place in the crude oil saturated sand shows a slight selectivity for normal alkanes over isoprenoids based on whole oil gas chromatography.

Proper chemical analyses need to be conducted throughout the course of a bioremediation project to ensure that the clean-up is proceeding efficiently and in compliance with regulatory requirements. Conventional determine of "TPH" concentrations by infrared techniques (i.e. EPA Method 418.1) do not adequately evaluate the concentration and composition of petroleum-derived hydrocarbons in polluted soils and waters. These conventional techniques are inadequate because they cannot distinguish between different petroleum components or between pollutant and indigenous organic matter. To accurately evaluate a potential site and to effectively monitor the progress of a particular bioremediation project more advanced analytical techniques are required. Techniques such as gas chromatography are much more powerful because they are capable of providing information on the composition of the pollutant at a molecular level as well as concentration levels.

References:

Brown, F.G.: "Microbes - The Practical and Environmental Safe Solutions to Production Problems, Enhanced Production and Enhanced Recovery" SPE Paper 23955 (Mar. 1992)

Pelger, J.W.: "Wellbore Stimulation Using Microorganisms To Control and Remediate Existing Paraffin Accumulations. SPE Paper 23813 (February, 1992)

Schneider, D.R. and R.J. Billingsley, "Bioremediation-A Manual for the Environmental Professional" 1991. Cahners Publishing Co.

Streeb, L.P. and F.G. Brown: "MEOR--Altamont/Bluebell Field Project" SPE Paper 24334 (May, 1992)

CASE HISTORY OF PARAFFIN CONTROL AND PRODUCTION INCREASE

WELL DESCRIPTION:

FIELD:	Sooner Trend
COUNTY:	Alfalfa, OK.
DEPTH:	7,800' +/-
FORMATION:	Red Fork

TOTAL PRODUCTION PRIOR TO TREATMENT:	38 Barrels/Day
WATER CUT PRIOR TO TREATMENT:	30%
TOTAL PRODUCTION SINCE TREATMENT STARTED:	120 Barrels/Day
WATER CUT SINCE TREATMENT STARTED:	8%

HISTORY PRIOR TO MICROBIAL TREATMENT:

The well was being hot oiled once per month and the stock tanks needed to be treated to sell the crude.

TREATMENT STARTING DATE:	October, 1989
TREATMENT SCHEDULE:	Once per month

CURRENT RESULTS:

Oil production has increased over 300%. The flowline has been hot oiled one time; however, the well has not needed hot oiling. The oil has sold without treating the tanks.

FIGURE 1

Information provided by Bio Tech, Inc., an authorized distributor for Micro-Bac® International, Inc.

FIGURE 2

CASE HISTORY OF PARAFFIN AND CORROSION CONTROL

WELL DESCRIPTION: 13 WELLS

FIELD: Panhandle, S.E. Pampa
COUNTY: Gray, TX
DEPTH: 3,200' +/-
FORMATION: Granite Wash

TOTAL PRODUCTION PRIOR TO TREATMENT: 126-135 Barrels/Day
WATER CUT PRIOR TO TREATMENT: 75%

TOTAL PRODUCTION SINCE TREATMENT STARTED: 156 Barrels/Day
WATER CUT SINCE TREATMENT STARTED: 45%

HISTORY PRIOR TO MICROBIAL TREATMENT:

The 13 well lease was averaging 1 to 1 1/2 stripping jobs per week and corrosion inhibitors were batch treated once per month.

TREATMENT STARTING DATE: September 28, 1988
TREATMENT SCHEDULE: Once per month

CURRENT RESULTS:

In the eighty-two weeks that the lease was treated, only three wells needed to be pulled without being stripped. In the same time frame, 82-123 stripping jobs would have been performed. Cost savings per stripping job, $2,500.00 covers the cost of one months microbial treatment.

ECONOMICS OF RESULTS:

* Operating Expenses Saved: $2,500.00 per well @ 100 stripping jobs saved	=	$250,000.00
* Field Production Increase: (20 BOPD @ 574 days) $19.00 per Bbl. average	=	$218,120.00
* Bio Tech, Inc. treatment cost to date:	=	$(57,371.00)

SUMMARY OF ECONOMICS:

$250,000.00 + $218,120.00 - $57,371.00	=	$410,749.00

Information provided by Bio Tecn, Inc., an authorized distributor for Micro-Bac® International, Inc.

CASE HISTORY OF H_2S AND IRON SULFIDE SCALE

WELL DESCRIPTION:

FIELD:	Greenwood
COUNTY:	Morton, KS
DEPTH:	2,900-3,100'
FORMATION:	Topeka - Lakompta

TOTAL FLUID PRODUCTION:	25 Barrels/Day
WATER CUT:	100%
TOTAL GAS PRODUCTION:	130 MCFD
H_2S (S.R.B. CAUSED) - PRIOR:	18 ppm
H_2S (S.R.B. CAUSED) - CURRENT:	7 ppm

HISTORY PRIOR TO MICROBIAL TREATMENT:

Well was being bleach treated at a cost of $.20/mcf. The pump would plug and stick with iron sulfides twice per year causing a pulling job and replacement of rods and pump.

Bleach Treatment:	4 drums 10% Sodium Hypochlorite 3 pounds 67% Pool Chlorine Spearhead Bleach Flush with 2% KCL, shut-in 24 hours

TREATMENT STARTING DATE:	August 27, 1990
TREATMENT SCHEDULE:	Once per month

CURRENT RESULTS:

Cost to control H_2S and corrosion has been reduced to less than $.05/mcf. A reduction of iron sulfide scale in the surface equipment has been noticed.

FIGURE 3

Information provided by Bio Tech, Inc., an authorized distributor for Micro-Bac® International, Inc.

CASE HISTORY OF CORROSION, SCALE AND EMULSION CONTROL

LEASE DESCRIPTION: WATERFLOOD

FIELD: East Leonard Dutcher Sand Unit
COUNTY: Tulsa, OK
DEPTH: 1,250'
FORMATION: Dutcher Sand

PRODUCTION PRIOR TO MICROBIAL TREATMENT:

INJECTION WELLS	42,	15,400 BWPD
SOURCE WATER (ARKANSAS RIVER)		5,300 BWPD
PRODUCING WELLS	28,	130 BOPD
TOTAL LEASE INJECTION RATE		20,700 BWPD
INJECTION PRESSURE		400 PSIA

HISTORY PRIOR TO MICROBIAL TREATMENT:

1. Treated with scale and corrosion inhibitors for iron
2. Treated with scale and corrosion inhibitors and oxygen scavengers at the injection station.
3. Acidizing injection wells every 60-75 days.
4. Treated 3 producing wells with paraffin solvents.

TREATMENT STARTING DATE: FEBRUARY 11, 1991
TREATMENT SCHEDULE: ONCE A WEEK

CURRENT RESULTS:

1. Injection rate increased 40-50% (Injection rate increased over 300% on several wells)
2. Electricity reduced by removing two 350-375 H.P. pumps.
3. Injection pressure dropped 50 PSI
4. Have not had to acidize any injection wells to date.
5. Presence of microorganisms in producing wells are decreasing showing vertical movement in formation as well as horizontal movement.
6. Production stabilized @ 130 BOPD.

ECONOMICS OF RESULTS:

- OPERATING EXPENSES SAVED
  MONTHLY CHEMICAL COST OF WATERFLOOD $10,000.00/MONTH
- MONTHLY ACIDIZING COSTS: (250 TO 400 GALS/WELL)
  $1.14/GAL (325 GALS/WELL) (42 WELLS) - 2 MONTHS $7,780.00/MONTH
- ELECTRICITY SAVINGS:
  (350 H.P. PUMP REMOVED) $13,000 to $15,000/MONTH
- BIO-TECH TREATMENT COST TO DATE: <$6,981.00/MONTH

SUMMARY OF ECONOMICS AFTER 6 MONTHS:

$60,000 + $46,680 + $84,000 - ($41,886) = $148,794.00

Information provided by Bio Tech, Inc. an authorized distributor for Micro-Bac International, Inc.

FIGURE 4

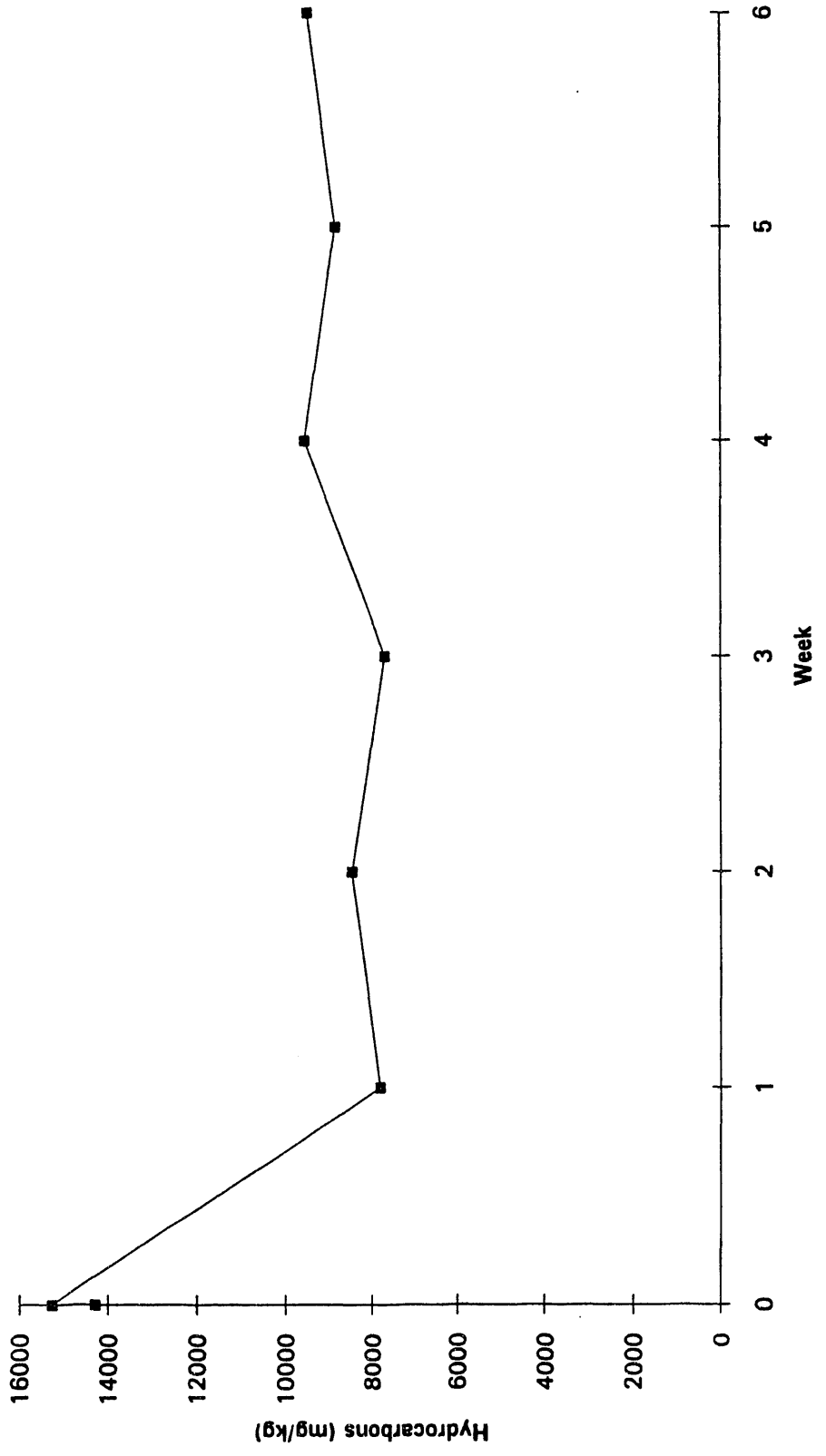


Figure 5. Hydrocarbon Concentration in Oil Saturated Sand Versus Time Since Microbial Inoculation.

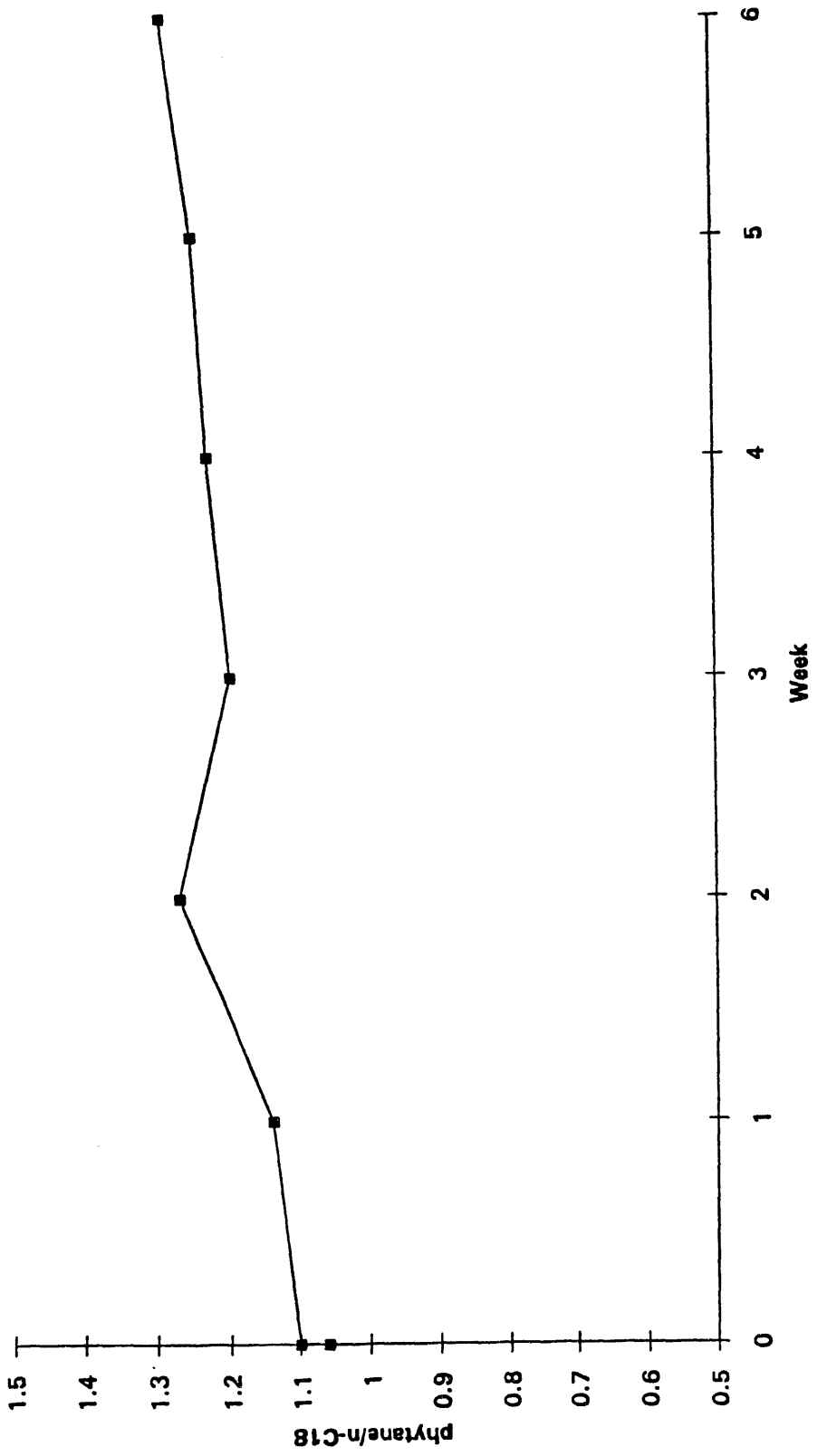


Figure 6. Isoprenoid/N-Alkane in Oil Saturated Sand Versus Time Since Microbial Inoculation.

NOTES

New Technology for Independent Producers
An Oil and Gas Industry Conference
May 6 & 7, 1993
The Warwick Hotel, Denver, CO

ABSTRACT

DOE Programs in Microbial Technology

by Rhonda Patterson Lindsey
Department of Energy

The Department of Energy (DOE) funding of research on the effects of microbes in oil recovery and possible benefits to the producers began as early as 1980, with studies at Oklahoma State University. By 1986, the Bartlesville Project Office of Fossil Energy had designed a coordinated research program for microbial enhanced oil recovery (MEOR). Maximum annual MEOR funding was reached in 1990, when the DOE supported 13 different MEOR projects. The contracts were well distributed among NIPER, the national labs, universities, and private industry. By 1993 funding decreased and the projects numbered only three. Plans for increased funding in FY94 are being reviewed.

Many of the projects are recently completed and the results and conclusions are being transferred to the producers. Three field project final reports will be published in 1993. One project is moving from the laboratory investigation stage to a field trial this year. Laboratory research in MEOR indicates possible application for the technology in other areas, such as bioremediation and processing as well as enhanced oil recovery. Improvements to a complex process simulator are continuing in an effort to completely represent the reservoir response to MEOR. DOE would like to see a PC-based user-friendly program developed.

After evaluation of the current needs and research results in recent years, the DOE is developing a program plan to address single well treatments for scale and paraffin problems with applications of microbial technology. It is important that basic laboratory research continue to identify microbes and their characteristics as related to oil recovery. In addition, DOE will continue to support research in improved waterflooding using MEOR technology.

WELL LOGGING TECHNOLOGY SESSION

Friday, May 7, Afternoon: 1:15 PM to 4:45 PM

Session Chair: Suzanne G. Cluff, The Discovery Group

Introduction ..... *ii*

Suzanne G. Cluff, The Discovery Group, Denver, CO

Reveiw of New Developments in Well Logging Technology *1*

Stephen E. Prensky, U.S. Geological Survey, Denver, CO

The MRIL: The First Pulse-Echo Magnetic Resonance Well Log and Its Applications to Formation Evaluation of Porosity, Saturation and Permeability *29*

George R. Coates, NUMAR, Kingwood, TX

A New Generation of Sonic Logging Tools and Their Applications *43*

Wayne D. Pennington, Marathon Oil Company, Lakewood, CO

Evaluation Techniques and Applications of Subsurface Image Logs *53*

David Thorn, Schlumberger, Aurora, CO

Well Logging Technology

In these times of reduced profit margins, it is especially important that as much information as possible be gleaned from every well drilled. Precise and accurate information is necessary to make informed decisions regarding completions, potential development locations, and future exploration. Many opportunities are also found in unconventional targets which have traditionally been difficult to evaluate. Several new logging tools introduced over the past few years, but not widely used by independent producers , contribute important information which may clarify these decisions. The nuclear magnetic resonance tool measures a value related to pore size and hydrogen index so it can be used for quantitative determinations including permeability, irreducible water saturation, movable hydrocarbons, and porosities not dependent on lithology. The dipole sonic tools provide shear data which helps to improve hydraulic fracture design, predicting sand strength, and finding gas behind casing. The borehole imaging tool is especially useful in locating fracture systems but is also useful in dip and sedimentary interpretation.

RECENT DEVELOPMENTS AND EMERGING TECHNOLOGY IN WELL LOGGING AND FORMATION EVALUATION WITH A SELECTED BIBLIOGRAPHY

Stephen E. Prensky
U.S. Geological Survey, Denver, Colorado

SUMMARY

Recent and near-term (1-3 years) developments in logging and formation evaluation consist primarily of evolutionary improvements in current technology. The current economics of the petroleum industry, expressed as a need for ever more cost-effective technology, combined with the need to evaluate thin-bed reservoirs serve as both the controlling factor and driving force respectively, in developing new logging technology. These developments include:

1. *Advances in wireline technology*
   - Improvements in downhole microprocessor-based technology and high-speed digital telemetry over conventional 7-conductor cable; makes possible (a) the use of high data-rate array and imaging tools, and (b) increased combinability of different tool types and can result in reduced rig time for logging.
   - Concurrent improvements in computer processing . New visualization and interpretation techniques have been introduced to facilitate the assimilaton of these massive amounts of data.
   - The increased use of array-type tools that acquire (a) multiple independent measurements of electrical and acoustic parameters at different vertical resolutions and depths of investigation, (b) the complex parts of conductivity, and (c) shear-wave dipole components.
   - Improvements in acoustic and electric borehole imaging.
   - Development of (a) induction- and laterolog-array devices for improved thin-bed analysis and saturation imaging, (b) through-casing resistivity tools, (c) a new generation of wireline nuclear magnetic logging (NML) tools.
   - Introduction of (a) neutron accelerators in place of radioactive source for neutron porosity devices, (b) new C/O logs using high-density detectors, (c) increased use of neutron-activation logging, (d) improved elemental-analysis (geochemical) logging, (e) new developments in tracer logging for evaluation of well stimulation.
   - Enhanced vertical resolution of traditional logging devices through new computer processing techniques.
   - Improvements in borehole gravity meters.
2. *MWD (measurement while drilling) and logging horizontal wells*
   - Improvements in current resistivity and nuclear technology and introduction of additional services: (a) multiple depth of investigation resistivity, (b) borehole calipers, and (c) spectral gamma and density tools.
   - Prototype testing of acoustic sensors.
   - Increased use of slimhole and coiled-tubing logging technology.
3. *Borehole geophysics*
   - Rapid advances in the theory and practice of crosswell imaging (tomography) for (a) monitoring changes in fluid saturation during EOR, (b) determinations of reservoir lateral continuity, (c) interwell porosity and permeability, and (d) interwell geologic structure.
   - Introduction of borehole radar systems for characterization of fractures.
4. *Core methods*
   - Advances in coring technology, core imaging, and determination of surface permeability.

WIRELINE DATA TELEMETRY

To accomodate the current generation of high data-rate array-type and imaging tools using conventional wireline-telemetry systems, it was necessary to increase the rate of data transmission. This was made possible through a combination of new digital signal-processing microprocessors and existing techniques (e.g. use of adaptive digital filters) using conventional 7-conductor wireline. Data rates have increased from 80-100 Kbits/sec to 300-500Kbits/sec in the most recent logging units. Systems capable of 700-1,000 Kbits/sec are on the horizon. Although optic-fiber cable is now in use with downhole television systems, the near-term (1-3 years) emphasis in wireline logging will be continued use of current wireline technology employing data-compression techniques to achieve data rates exceeding 5 Mbits/sec.

ACOUSTIC LOGGING

Recent developments in acoustic logging are largely driven by the need to evaluate fractured reservoirs (low-permeability chalks, shales, and sandstones) and for improved seismic calibration. Developments in technology fall into two general classes, (a) transmission (full-waveform data) and (b) reflection (pulse-echo) imaging.

Full-waveform acoustic data consist of compressional, shear, and tube (Stoneley) waves. The compressional-wave velocity (delta t), the basis of the traditional sonic log, is used for porosity determination; the ratio of shear to compressional velocities is used for lithology identification and gas detection; the shear-wave amplitude (using monopole and dipole sources) is used for fracture identification; the amplitude and velocity data of both compressional- and shear-wave data are used for (a) cement-bond evaluation, (b) correlation with and calibration of seismic data, (e) for generating synthetic seismograms, and (d) measuring formation mechanical properties. The tube-wave attenuation is used for characterization of fractures and determination of permeability.

Recent developments include:

1. **Tool design** - Improvements in (a) full-waveform tools (an array-type tool that can be used in open and cased holes), (b) ultrasonic pulse-echo tools (borehole-televiewer type) that measure acoustic reflectivity (time and amplitude)of the open borehole or theinside of casing or cement outside of casing . These devices have application to (a) borehole imaging (see below), (b) borehole calipers, (c) dipmeters (in electrically non-conductive oil-based mud), (d) determination of cement bond (problems with channeling), and (e) evaluation of casing corrosion..
2. **Dipole measurements** - Acquisition of the polarized components of the shear-wave velocity (shear-wave dipole tools) for improved measurement shear-wave data in a broader range of formations, particularly in soft formations, and also in hard formations, in both open and cased holes.
3. **Fractures** - New laboratory and field experience gained in the application of full-waveform data (shear-, tube-wave) to fracture identification and analysis.
4. **Well completion** - Use of full-waveform data for (a) full-borehole coverage in cement-bond evaluation, (b) measuring depth of perforating penetration and, (c) analyzing hydraulic fracture height, in combination with density and/or nuclear spectrometry tools.
5. **Wellbore resonance** - A technique to enhance otherwise weak acoustic signals in open and cased holes and for generating Q logs (a measure of seismic damping related to lithology) used in seismic modeling and formation evaluation.
6. **Downhole seismic** - Improved tools that produce better VSPs which are needed for improving the calibration of synthetic seismograms to surface seismic data.
7. **Behind-pipe flow** - Evaluation of "active listening", a potential alternative to nuclear-activation logging.

ELECTROMAGNETIC LOGGING

The need for improved invasion profiles and better vertical resolutions for thin-bed analysis have served as the guiding factors in new technology. Recent developments include:

1. **Measurement** - Improved accuracy of measurement of basic parameters; improved processing.
2. **Vertical resolution** - Improved radial and vertical resolution through use of array-type tools. Induction-, laterolog-, and dielectric-type tools now use multiple coil spacings, multiple frequencies, and multiple receivers for obtaining independent measurements with different vertical resolutions and depths of investigations. Both the in-phase (R) and quadrature (X) components of the electromagnetic signal can be obtained. This results in more accurate determination of radial depths of investigation and these data can be used for imaging fluid saturations (e.g. invasion profiles) around the borehole. Microresistivity array tools (multipad, multielectrode, multifrequency) devices are used for evaluating casing corrosion (cathodic protection) and casing wear (through measurement of casing thickness). Macro-array data can be combined with micro-array (borehole imaging) data for improved representation of resistivity in and around the borehole. Improvements in high-resolution dipmeters include increasing the number of arms from 4 to 6 and extracting standard dipmeter data from imaging-tool data.
3. **Nuclear magnetic logging** - First available in the late 1960s and 1970s, a second generation of tools is now available. These tools use pulsed (spin-echo) NMR technology to measure free-fluid index and spin-lattice relaxation times. These values are related to pore sizes and hydrogen content, and can be used for quantitative determinations of lithology-independent porosity, permeability, effective bed thickness, irreducible water saturation (water-cut), and movable hydrocarbons. Doping the drilling mud to eliminate the influence of borehole fluid is no longer required.
4. **Cased-hole resistivity logging** - Prototype tools are in development and testing. Test data are in agreement with equivalent openhole laterolog measurements. Potential applications are in (a) MWD, (b) evaluating old wells for by-passed pay, and (c) monitoring production and flooding.
5. **Borehole magnetometer** - These tools, commonly used for ore mineral exploration in crystalline rocks, provide a continuous log of magnetic susceptibility, a measure of the iron minerals present in the rock. Magnetic minerals can be products of various digaenetic and alteration processes and their presence can be used to infer depositional environment. Also, magnetic susceptibility can be use for determining the natural remnant magnetization polarity, a method of stratigraphic dating. Applications in sedimentary rocks include (a) lithostratigraphic correlation, (b) formation age dating through magnetostratigraphy, (c) examination of formation alteration (diagenesis), and (d) analysis of depositional environments.

BOREHOLE IMAGING

Borehole-imaging devices, both acoustic and electrical, provide an a partial or full image (map) of the borehole wall or casing. The acoustic-imaging devices use a rotating, focused ultrasonic transducer (borehole-televiewer-type devices) to measure reflectivity times (pulse-echo) from the borehole wall or from inside the casing . While these devices are not affected by the type of borehole fluid they are not used in high-weight mud because of signal attenuation. Electrical-imaging devices evolved from dipmeter design and use pad-mounted microelectrical arrays and are limited to holes with conductive mud. Borehole coverage has been greatly increased by the use of additional pads and sensors. The application of 2-D and 3-D computer visualization techniques are applied to both electric and acoustic imaging data for enhanced interpretation.

The very fine resolution of these tools makes them extremely valuable for obtaining positive identification and analysis of (a) natural and induced fractures, (b) borehole breakouts, (c) thin beds, (d) geologic structure (strike, dip, faults) in ,and near the borehole, (e) improved core orientation and

core-log correlation, (f) sedimentary features and interpretation of depositional environment, (g) for casing inspection (corrosion, wear, or damage), (h) use as borehole calipers.

CROSSWELL IMAGING (TOMOGRAPHY)

Rapid advances have been made in both the technology and processing used for crosswell imaging and many field-tests are in progress. These geophysical methodssurface sesimic imaging, use receivers and either electrical or acoustic sources placed in the borehole. Applications include (a) improved reservoir characterization, (b) monitoring fluid movement in producing fields, and (c) to aid in the remediation of underground contamination.

Displacement of formation fluids and changes in temperature produce changes in reservoir rock properties (saturation, resistivity, pressure, and velocity) that are detectable by both electrical and acoustic (seismic) methods. In order to monitor the progress of flooding (water, miscible, and thermal) during enhanced recovery, it is necessary to know the vertical and horizontal distribution of flood fronts between wells that may be hundreds of feet apart. Well logs, even the newest generation of array tools (both electrical and acoustic) can image formations only a few feet away from the borehole.

Electrical or seismic sources and receivers are placed along the borehole in adjacent wells and seismic signal or low-frequency electrical current is recorded by each receiver/electrode in each well. The resulting data by are processed into images and tomograms that can be used for visualizing fixed or time-lapse sequences of fluid movement. The effective distance for these techniques is dependent on the source strength and is generally less than 2000 ft. Vertical resolution can be several feet. Cross-well continuity logging is a specialized form of crosswell seismography that can be used for determining lateral reservoir continuity between wells. Geologic structure and stratigraphic heterogeneity can also be imaged with these techniques.

Borehole radar - Different versions of borehole radar systems (an electromagnetic method) are available or under development. The vertical resolution of the currently available system ranges from 3 to 10 ft and has range of investigation (depending on operating mode) from 300 to 1000 ft in crystalline rock. In sedimentary rocks, the investigation range is lower because the presence of pore fluids results in signal attenuation. The receiving antenna registers the electromagnetic pulse as a function of time which allows the system to operate in single-well or crosswell reflection mode and crosswell tomography mode. Current applications include (a) characterization of fractures, and (b) obtaining quantitative values of dielectric permeability and conductivity.

NUCLEAR TOOLS

Recent developments in nuclear logging (open and cased hole) have been largely evolutionary, i.e. incremental improvements in current technology and processing. More of the newer tools use spectral measuring systems rather than discrete windows. Significant advances include:

1. **Neutron logging**
   Sources- A high-energy neutron accelerator has been used in a new dual-neutron tool in place of a radioactive source. This change provides (a) a more accurate measurement, (b) a higher vertical resolution, and (c) operation in a pulsed mode to obtain thermal- and epithermal-neutron porosity and neutron slowing-down time (capture cross section, sigma).
   Detectors - (a) Use of higher-density materials , i.e., bismuth germinate (BGO) and gadolinium oxyorthosilicate (GSO), in scintillation dectectors in place of NaI (sodium iodide). in pulsed-neutron-capture tools. This change provides improved gamma-ray detection and larger dynamic

range of sensitivity. (b) Use of lithium-6 glass scintillation detectors in place of helium-3 in MWD neutron sensors to meet the needs for robust measurement in a rugged environment.

2. **Spectrometry logging**

Induced Spectrometry

Carbon/Oxygen logging - New tools that use the higher-density detectors for improved measurements of behind-casing fluid saturations, e.g., residual-oil saturation and monitoring reservoir flooding (water, miscible, and thermal) reservoir flooding), and faster logging speeds. One version is a small-diameter, dual-detector through-tubing tool that can make continuous measurements in flowing wells. These tools can also be used to obtain relative elemental concentrations in cased hole.

Elemental analysis (geochemical) logging - In geochemical logging, several natural and induced-gamma spectrometry sondes are combined into a single tool used to measure elemental abundances. These values are transformed into mineralogical concentrations and these in turn, are related to grain size, porosity, permeability, and cation exchange capacity for improved rock and clay typing. The current tool, a multisonde device, measures 10 elements and is generally run in open hole (to avoid the the complications introduced by cement and casing). A new geochemical logging tool, currently in field testing is smaller and provides improved statistical precision at twice the previous logging speed. Some of the newer induced-gamma spectrometry tools, that use the high-density detectors are being used for cased-hole determination of a more limited group of elemental concentrations.

Activation logging - The need to detect flow behind casing (testing well integrity and zonal isolation), both in petroleum and groundwater applications, has generated renewed interest in neutron activation techniques. New methods and modified PNC tools, permit (a) direct detection of water movement (oxygen activation), and (b) evaluation of gravel-pack quality (silicon activation).

Natural spectrometry

Design - New tools are now employing BGO detectors

Tracer logging - Well stimulation materials tagged with different radioisotopes are detected by natural spectrometry (KUT-type) tools with high spectral resolution. The depth, height, and radial distribution of hydraulically induced fractures can be determined and the effectiveness of well stimulation projects can be evaluated. The addition of a directional gamma-ray device allows determination of fracture-plane orientation.

3. **Gamma-ray logging of outcrops**

Improvements in the use of hand-held and truck-mounted tools for obtaining continuous gamma-ray logs of formation outcrops for correlation with subsurface (wireline and MWD) logs, improved interpretation of these logs, and lateral continuity of reservoir rocks.

MEASUREMENT-WHILE-DRILLING LOGGING

Although there is increased drilling of horizontal wells, advancements in MWD technology have been largely incremental (improvements to existing technology). Acoustic sondes eagerly awaited by industyr, are curently in prototype development and testing. Recent developments include:

1. **Electrical devices** - (a) Use of electromagnetic phase shift as an MWD caliper, (b) an increased number of measurements from 2 to 4 (phase shift and amplitude) to provide additional independent depths of investigation. Data presentation for these tools is similar to a dual-induction log.
2. **Nuclear devices** - Improvements to current measurements (gamma-ray, density, neutron porosity, and spectral gamma-ray and spectral density), and "real-time" determination of formation pressures.

3. **Acoustic devices** - Introduction of ultrasonic pulse-echo caliper devices; other acoustic devices are in field-test phase.
5. **Electronics and telemetry**- improved microprocessors for storing data and increased rates of data transmission. The latter provides more "real-time" data for (a) drill-bit guidance ("geosteering") for optimizing drilling, particularly in horizontal wells, and (b) for formation analysis. Research on high data-rate tools for improved vertical resolution at typical rates of bit penetration, is in progress.

The general feeling in industry is that MWD has matured to where it can replace conventional wireline logging in many situations, both in exploratory and production wells and the introduction of acoustic devices will further secure the role of MWD.

SLIMHOLE AND COILED-TUBING LOGGING

New improvements in slimhole drilling technology and MWD and coiled-tubing logging and the resulting cost decrease (up to 50 percent over conventional wells) has increased interest in this type of drilling, particularly in exploration drilling and especially in remote locations and driven development of a new class of logging methods and devices. There are presently four methods of drilling slimhole wells (a) rotary, (b) continuous coring, (c) downhole-motor drilling with drill rods, and (d) drilling with coiled tubing. Wells depths exceeding 12,000 ft have been achieved with these methods.

BOREHOLE GRAVITY LOGGING

A new tool design permits improved vertical resolution. A movable internal gravity sensor can be adjusted, while on station, to obtain readings with a resolution up to 1 mm. This wireline device measures the vertical component of the acceleration due to gravity with extreme accuracy thereby enabling direct determination of formation bulk density and porosity. The previous standard resolution of 10 ft made this an excellent tool for measuring density in very rugose (especially karstic carbonates) and cased hole, conditions where standard wireline open- and cased-hole porosity logs, that have very shallow depths of investigations, were limited. Advantages of the large spacing are (a) a very large radius of investigation that results in an average density value for a more representative volume of formation than other logging devices, and (b) tool insensitivity to hole size, washout and rugosity, number and size of casing strings, mudcake, mud invasion, cement, acidization effects, and lithology. This tool has applications in old cased wells where no density or saturation log data are available and for monitoring saturation changes during field production. If a baseline survey is made prior to, or at the beginning of production, time-lapse measurements (log-produce-log method) can be used for analyzing changes in residual oil saturation.

WIRELINE FORMATION TESTING

A new multiprobe formation testing tool represents a significant advance in wireline testing tools. This tool has a modular design that permits various operational configurations to meet different needs, e.g., bottomhole testing, single- or multiple-probe testing, and use of multiple sampling chambers. In a multiprobe configuration, direct in-situ determination of both vertical and horizontal permeability can be made (unlike a single-probe device) and works over a larger range of permeabilities. Other improvements are (a) new sensors that provide more accurate measurements in less time reducing the time needed for each test, (b) improved real-time surface control that allows for point-by-point pressure tests which can be used to determine gas, oil, and water contacts, (c) ability to pump formation fluid for an extended period of time until a representative reservoir fluid sample is obtained (as measured by a flow-line resistivity device).

CORING AND CORE IMAGING

Recent developments fall into three categories:

1. **Coring techniques** -(a) Improvements in mechanically drilled sidewall core plugs. (b) Development of sidetrack coring--the use of radial drilling technology--to obtain full-diameter sidewall cores up to 50 ft in length, *after* completion of drilling and logging. This results in less rig time and better targeting of desired intervals and the larger samples can provide more representative analyses. (c) Development of techniques for core acquisition in horizontal wells, including coiled-tubing coring systems. (e) Slimhole coring systems.
2. **Core imaging** - (a) Use of thermal neutron imaging, and (b) improvements in X-ray computer tomography (CT scanning), nuclear magnetic resonance for non-destructive core analysis and for visualizing distribution and movement of fluids within rock pores. These techniques permit determination of fluid saturations, petrophysical properties (porosity, relative permeability, capillary pressure), mineral distributions, and depositional textures. (c) New electrical imaging techniques and acoustic techniques compliment and calibrate data obtained from wireline logs (electric imaging and full-waveform acoustic logs).
3. **Permeability** - Introduction of a new probe minipermeameter, that uses an unsteady-state pressure-decay methodto obtain rapid and more accurate measurements of surface permeability on core and thin sections.

ENHANCED VERTICAL RESOLUTION AND THIN-BED EVALUATION

Recent exploration and reservoir characterization efforts have concentrated on thin-bed, laminated reservoirs (both clastic and complex lithologies) where vertical resolutions of less than 1 ft, and prefereably on the centimeter scale, are necessary for accurate evaluation. Newer tools, e.g., array-type induction and laterolog, can measure data at this scale and still provide invasion profiles; existing dipmeters and borehole imaging devices can resolve beds down to the millimeter range. Concurrent with development of these new tool designs have been efforts to enhance the vertical resolution of older nuclear and resistivity tools as well as old data, through new computer processing techniques. Recent developments include new processing techniques for enhanced tool resolution and for thin-bed analysis.

OUTLOOK

The economics and resulting restructuring of the petroleum industry, in general, over the past seven years and the continuing unsettled state of the U.S. domestic industry, in particular, have and will continue to exert a chilling effect on the development of new logging technology.

1. Virtually all the major producers have eliminated their in-house research efforts in logging technology. Much of the technology developed by these now defunct efforts has or is being licensed.

2. There is now a heavy, almost total, reliance on the logging service companies to generate new hardware and software technology. Since development costs are extremely high and the payoff increasingly uncertain in the current economic climate, these companies have sought to spread the risk by developing joint research efforts and partnerships with operating companies. The operators in turn, have a vital interest in exerting an influence on the direction and pace of development of new technology.

3. Because of the high costs of running the latest technology and the unwillingness or inability of operators to pay the price, especially since many remain unconvinced of the cost/benefits, service companies are offering tiered service to avoid pricing themselves out of the domestic market:

customers can choose to run just a basic suite of logs using the older technology or the newer, advanced services.

4. Many recent developments are the end-product of a development process initiated 5 to 10 years earlier. Because of the cash-flow crises of the past seven years, many promising research and development efforts were canceled (this is apparent in the reduced offerings in new technology by some companies in the past few years). Future advances will continue to be incremental, i.e., evolutionary rather than revolutionary.

5. Data interpretation and application lag data acquisition. Future advances will be weighted towards the interpetation side: development of user-friendly software that not only integrates all forms of log data but includes advanced new interpretation techniques.

6. To avoid having tools viewed as optional luxuries, the users of logging technology, from the geologist/engineer up through managers, must be better informed of the benefits derived from all logging devices and especially the more recent "exotic" tools. There must be a fundamental shift away from viewing logging data only in the context of fluid saturations. This process should start at the advanced college undergraduate and university graduate levels in both geology and engineering courses. Emphasis should be placed on developing integrated models for use in exploration and reservoir management using data and information derived from the entire range of logging devices, especially the latest and most advanced technology. Logging service companies who once provided seminars for college faculty, must become reinvolved, as a matter of self interest, since the knowlegeable student now, may become tomorrow's customerof advanced technology.

7. The current climate where cost-effective operation is foremost, places a high degree of reliance on the integration of geology, geophysics, petrophysics, engineering and on computer processing to effect this integration. The geologist, geophysicist, or engineer necessarily becomes a data generalist. There is a concern that a future lack of specialists who are able to apply the advanced processing and interpretation techniques needed to get the most out of the advanced tools may inhibit the acceptance and wider use of new technology by many companies.

8. Environmental assessment and remediation is a promising new market for developing logging technology.

SELECTED BIBLIOGRAPHY

(For a more detailed bibliography see Prensky, S.E., 1992, Bibliography of well-log applications, cumulative edition to September 30, 1992: U.S. Geological Survey Open-File Report 92-390, 620 p.)

GENERAL

Savostianov, N.A., 1991, Advances in cased hole logging and completion technology, *in* 13th world petroleum congress proceedings, v. 2, Exploration and production: John Wiley & Sons, New York, p. 437-442.

Timur, A.; 1991, Advances in open hole well logging, *in* 13th world petroleum congress proceedings, v. 2, Exploration and production: John Wiley & Sons, New York, p. 425-435.

TELEMETRY SYSTEMS

Adoumieh, R., Berneking, D., Olsen, B., Kumar, R., and Phillips, J., 1990, The MAXIS system--imaging for reservoir characterization: Schlumberger Oilfield Review, v. 2, no. 2, p. 31-42/

Gardner, W.R., and Goodman, K.R., 1992, An adaptive telemetry system for hostile environment well logging, SPE-25013, *in* European petroleum conference proceedings: Society of Petroleum Engineers, p. 531-540.

Gardner, W.R., and Sanstrom, W.C., 1992, Real-time compression of logging data, SPE-25015, *in* European petroleum conference proceedings: Society of Petroleum Engineers, p. 557-566.

ACOUSTIC LOGGING

Bigelow, E.L., 1990, Cement evaluation: Atlas Wireline Services, Houston, TX, 142 p.

Burns, D.R., 1991, Predicting relative and absolute variations of in-situ permeability from full-waveform acoustic logs: The Log Analyst, v. 32, no. 3, p. 246-255.

Dominguez, H., and Perez, G., 1991, Permeability estimation in naturally fractured fields by analysis of Stoneley waves: The Log Analyst, v. 32, no. 3, p. 120-128.

Griffith, J.E., Sabins, F.L., and Harness, P.E., 1992, Investigation of ultrasonic and sonic bond tools for detection of gas channels in cements, SPE-24573, *in* SPE annual technical conference and exhibition proceedings, v. delta, Drilling: Society of Petroleum Engineers, p. 245-260.

Halleck, P.M., Wesson, D.S., Snider, P.M., and Navarette, M., 1991, Prediction of in-situ shaped-charge penetration using acoustic and density logs, SPE-22808, v. pi, Production operations and engineering: Society of Petroleum Engineers, p. 483-490.

Harrison, A.R., Randall, C.J., Aron, J.B., Morris, C.F., Wignall, A.H., Dworak, R.A., Rutledge, L.L., and Perkins, J.L., 1990, Acquisition and analysis of sonic waveforms from a borehole monopole and dipole source for the determination of compressional and shear speeds and their relation to rock mechanical properties and surface seismic data [DSI], SPE-20557, *in* SPE annual technical conference exhibition proceedings, v. omega, Formation evaluation and reservoir geology: Society of Petroleum Engineers, p. 267-282

Hayman, A.J., Hutin, R., and Wright, P.V., 1991, High-resolution cementation and corrosion imaging by ultrasound, paper KK, *in* 32nd annual logging symposium transactions: Society of Professional Well Log Analysts, 25 p.

Jutten, J., and Morriss, S.L., 1990, Cement job evaluation, chapter 16, *in* Nelson, E.B., ed., Well cementing: Elsevier, Amsterdam, Developments in Petroleum Science No. 28, p. 16-1--16-44.

Katahara, K.W., Kyle, D.G., Siegfried, R.W., Gard, M.F., Goodwill, W.P., Schasteen, T., and Petermann, S.G., 1988, Detection of external pipe defects with a modified borehole televiewer, paper UU, *in* 29th annual logging symposium transactions: Society of Professional Well Log Analysts, 20 p. Later reprinted in 1990, *in* Borehole imaging reprint volume: Society of Professional Well Log Analysts, p. 251-263.

Lloyd, T.A., 1992, Taking advantage of shear waves: Schlumberger Oilfield Review, v. 4, no. 3, July, 52-54.

Medlin, W.L., 1991, Fracture diagnostics with tube wave reflection logs, SPE-22872, *in* SPE annual technical conference exhibition proceedings, v. pi, Production operations and engineering: Society of Petroleum Engineers, p. 541-555.

Medlin, W.L., and Alhilali, K.A., 1990, Shear-wave porosity logging in sands, SPE-20558, *in* SPE annual technical conference exhibition proceedings, v. omega, Formation evaluation and reservoir geology: Society of Petroleum Engineers, p. 283-293. Later published in 1992: SPE Formation Evaluation, v. 7, no. 1, March, p. 106-112.

Medlin, W.L., and Schmitt, D.P., 1992, Acoustic logging based on wellbore resonance, SPE-24686, *in* SPE annual technical conference and exhibition proceedings, v. omega, Formation evaluation and reservoir geology: Society of Petroleum Engineers, p. 273-285.

Menger, S., and Schepers, R., 1988, Method to derive high-resolution caliper logs from borehole televiewer traveltime data, *in* 1988 annual meeting expanded abstracts with biographies, volume 1: Society of Exploration Geophysicists, p. 554-556.

Paillet, F.L., 1991, Qualitative and quantitative interpretation of fracture permeability using acoustic full-waveform logs: The Log Analyst, v. 32, no. 3, p. 256-270.

Paillet, F.L., Cheng, C.H., and Pennington, W.D., 1992, Acoustic-waveform logging--advances in theory and application: The Log Analyst, v. 33, no., 3, p. 239-258.

Patterson, D., 1993, Fracture evaluation from tube wave reflection and attenuation effects [abs., SPWLA 34th annual logging symposium]: The Log Analyst, v. 34, no. 2, p. 47.

Pilkington, P.E., 1992, Cement evaluation--past, present, and future, SPE-20314: Journal of Petroleum Technology, v. 44, no. 2, p. 132-140.

Poulton, H.N., and Strozeski, B.B., 1989, Ultrasonic Diplog; a system for measuring dips in wells drilled with oil-base mud, paper GG, *in* 12th international formation evaluation symposium transactions: Society of Professional Well Log Analysts, Paris Chapter (SAID), 15 p.

Rambow, F.H.K., 1990, Active listening--an alternative method for detecting flow and measuring flow velocity behind casing, paper P, *in* 31st annual logging symposium transactions: Society of Professional Well Log Analysts, 18 p. Later published in 1991: The Log Analyst, v. 32, no. 6, p. 645-653.

Sanders, L., 1993, Hydrocarbon detection using the neutron porosity and shear wave travel time in sandstone reservoirs [abs., SPWLA 34th annual logging symposium]: The Log Analyst, v. 34, no. 2, p. 41.

Schlumberger, 1991, Dipole Shear SonicImager (DSI): Schlumberger Educational Services, Houston, TX, Document SMP-9200, 26 p.

Sutherland, A., and Smith, P.M., 1991, Recent developments in borehole seismic surveys, offshore northern Australia: APEA [Australian Petroleum Exploration Association] Journal, v. 31, part 1, p. 250-258.

Winterstein, D., 1992, How shear-wave properties relate to rock fractures--simple cases: Geophysics--the Leading Edge of Exploration, v. 11, no. 9, p. 21-28.

Zemanek, J., Williams, D.M., and Schmitt, D.P., 1991, Shear-wave logging using multipole sources: The Log Analyst, v. 32, no. 3, p. 233-241.

ELECTROMAGNETIC LOGGING

RESISTIVITY LOGGING

Barber, T.D., and Rosthal, R.A., 1991, Using a multiarray induction tool to achieve high-resolution logs with minimum environmental effects [AIT], SPE-22725, *in* SPE annual technical conference and exhibition proceedings, v. omega, Formation evaluation and reservoir geology: Society of Petroleum Engineers, p. 637-651.

Chemali, R., Su, S.M., Goetz, J.F., Maute, R.E., and Osborn, F.F., 1990, Methods for improved dip determination in water-based mud with the six-arm dipmeter, paper O, *in* 31st annual logging symposium transactions: Society of Professional Well Log Analysts, 25 p. Later published in 1991: The Log Analyst, v. 32, no. 3, p. 298--308.

Davies, D.H., Faivre, O., Gounot, M-T., Seeman, B., Troullier, J-C., Benimeli, D., Ferreira, A.E., Pittman, D.J., Smits, J-W., Randrianavony, M., Anderson, B.I., and Lovell, J., 1992, Azimuthal resistivity imaging--a new generation laterolog [ARI], SPE-24676, *in* SPE annual technical conference and exhibition proceedings, v. omega, Formation evaluation and reservoir geology: Society of Petroleum Engineers, p. 143-153.

De, B.R., and Nelson, M.A., 1992, Ultrabroadband electromagnetic well logging--a potential future technology, paper A, *in* 33rd annual logging symposium transactions: Society of Professional Well Log Analysts, 23 p.

Gas Research Institute, 1992, Through-casing logging--GRI research aims to tap the lowest-cost gas resource: Chicago, Illinois, Report GRI-92/0543, 4 p.

Hunka, J.F., Barber, T.D., Rosthal, R.A., Minerbo, G.N., Head, E.A., Howard, A.Q., Jr., Hazen, G.A., and Chandler, R.N., 1990, A new resistivity measurement system for deep formation imaging and high-resolution formation evaluation [AIT], SPE-20559, *in* SPE annual technical conference exhibition proceedings, v. omega, Formation evaluation and reservoir geology: Society of Petroleum Engineers, p. 295-307.

Imamura, S., 1991, Near-borehole resistivity imaging using normal resistivity logs [abs.], BG5.6, *in* 1991 technical program with expanded abstracts with biographies: Society of Exploration Geophysicists, p. 145-147. Later published in 1992 in expanded form as, Imaging technique of near-borehole resistivity structure from normal resistivity logs, paper F, *in* 33rd annual logging symposium transactions: Society of Professional Well Log Analysts, 21 p.

Khokhar, R.W., and Johnson, W.M., Jr., 1989, A deep laterolog for ultrathin formation evaluation, paper SS, *in* 30th annual logging symposium transactions: Society of Professional Well Log Analysts, 10 p.

Maute, R.E., 1992, Electrical logging--state-of-the-art: The Log Analyst, v. 33, no. 3, p. 206-227.

Rau, R., Davies, R., Finke, M., and Manning, M., 1991, Advances in high frequency dielectric logging, paper S, *in* 32nd annual logging symposium transactions: Society of Professional Well Log Analysts, 19 p.

Saxena, V., and Sibbit, A.M., 1990, Deep saturation in lo' '-salinity reservoirs from dual-laterolog quadrature signals, SPE-20560, *in* SPE annual technical conference exhibition proceedings, v. omega, Formation evaluation and reservoir geology: Society of Petroleum Engineers, p. 309-320.

Schlumberger, 1992, AIT Array Induction Imager Tool: Schlumberger Educational Services, Houston, TX, Document SMP-9240, 36 p.

Silva, C., and Spooner, D., 1991, High resolution induction logging--a comparison with conventional induction as used in thin sands in the Texas Gulf Coast region, paper WW, *in* 32nd annual logging symposium transactions: Society of Professional Well Log Analysts, 22 p.

Strickland, R., Chemali, R., Su, S.M., Gianzero, S., Klein, J., Sakurai, S., and Walker, M., 1992, New developments in the high resolution induction log, paper D, *in* 33) d annual logging symposium transactions: Society of Professional Well Log Analysts, 20 p.

Vail, W.B., and Momii, S.T., Woodhouse, R., Alberty, M., and Peveraro, R., 1993, Formation resistivity measurements through metal casing [abs., SPWLA 34th annual logging symposium]: The Log Analyst, v. 34, no. 2, p. 44-45.

Vallinga, P.M., 1993, Accurate hydrocarbon saturations in complex reservoirs from multi-electrode resistivity measurements [abs., SPWLA 34th annual logging symposium]: The Log Analyst, v. 34, no. 2, p. 44.

Vallinga, P.M., Harris, J.R., and Yuratich, M.A., 1991, A multi-electrode tool allowing more flexibili'v in resistivity logging, paper E, *in* 14th European formation evaluation symposium transactions [THAMES symposium]: Society of Professional Well Log Analysts, London Chapter, 12 p.

White, J., 1993, Enhanced reservoir description using induction and laterolog imaging tools [abs., SPWLA 15th European formation evaluation symposium]: The Log Analyst, v. 34, no. 1, p. 95.

DETECTION AND EVALUATION OF CASING CORROSION

Monrose, H., and Boyer, S., 1992, Casing Corrosion--Origin and Detection: The Log Analyst, v. 33, no. 4, November-December, p. 507-519.

Schlumberger, 1992, Corrosion evaluation: Schlumberger Educational Services, Houston, Texas, Document SMP-9110, 43 p.

NUCLEAR MAGNETIC RESONANCE LOGGING

Coates, G.R., Peveraro, R.C.A., Hardwick, A., and Roberts, D., 1991, The Magnetic Resonance Imaging Log characterized by comparison with petrophysical properties and laboratory core data, SPE-22723, *in* SPE annual technical conference and exhibition proceedings, v. omega, Formation evaluation and reservoir geology: Society of Petroleum Engineers, p. 627-635.

Cunningham, A.B., and Jay, K.L., 1991, Field experience using the nuclear magnetic logging tool for quantifying microporosity and irreducible water saturation, paper EE, *in* 32nd annual logging symposium transactions: Society of Professional Well Log Analysts, 23 p.

Howard, J.J., Kenyon, W.E., and Straley, C., 1990, Proton-magnetic-resonance and pore-size variations in reservoir sandstones, SPE-20600, in SPE annual technical conference exhibition proceedings, v. omega, Formation evaluation and reservoir geology: Society of Petroleum Engineers, p. 733-742.

Kleinberg, R.L., Sezginer, A., Griffin, D.D., and Fukuhara, M., 1992, Novel NMR apparatus for investigating an external sample: Journal of Magnetic Resonance, v. 97, p. 466-485.

Miller, M.N., Paltiel, Z., Gillen, M.E., Granot, J., and Boouton, J.C., 1990, Spin-echo magnetic-resonance logging--porosity and free-fluid index, SPE-20561, *in* SPE annual technical conference exhibition proceedings, v. omega, Formation evaluation and reservoir geology: Society of Petroleum Engineers, p. 321-334.

Morriss, C., MacInnis, J., Snardyk, J., Freedman, B., Straley, C., and Kenyon, W., 1993, Field test of an experimental pulsed nuclear magnetism tool [abs., SPWLA 34th annual logging symposium]: The Log Analyst, v. 34, no. 2, p. 45.

Reik, B.A., 1993, Field experience with second generation nuclear magnetic resonance tools [abs., SPWLA 34th annual logging symposium]: The Log Analyst, v. 34, no. 2, p. 45.

MAGNETIC-SUSCEPTIBILITY LOGGING

Barber, T., Anderson, B., and Mowat, G., 1992, Using induction tools to identify magnetic formations and to determine relative magnetic susceptibility and dielectric constant, paper C, *in* 33rd annual logging symposium transactions: Society of Professional Well Log Analysts, 22 p.

Bosum, W., 1992, Magnetic field measurements in the KTB-Oberfalz VB using a three-axis borehole magnetometer: Scientific Drilling, v. 3, no. 3, p. 49-62.

Desvignes, G., Barthes, V., and Tabbagh, A., 1992, Direct determination of the natural remnant magnetization effect in a hole drilled in layered ground from magnetic field and susceptibility logs: Geophysics, v. 57, no. 7, p. 872-884.

Eick, P.M., and Schlinger, C.M., 1989, Multi-frequency magnetic susceptibility variations in ash-flow sheets and their relevance to borehole stratigraphic correlations, paper M (Abstract only): Third International Symposium on Borehole Geophysics for Minerals, Geotechnical, and Groundwater Applications, Proceedings.

Lalanne, B., Bouisset, P., and Pages, G., 1991, Magnetic logging--borehole magnetostratigraphy and absolute datation in sedimentary rocks, SPE-21437, *in* SPE Middle East oil show proceedings: Society of Petroleum Engineers, p. 841-850.

Manley, W.F., MacLean, B., Kerwin, M.W., and Andrew, 1993, Magnetic susceptibility as a Quaternary correlation tool--examples from Hudson Strait sediment cores, eastern Canadian Arctic, *in* Current Research, part D, eastern Canada and national and general programs: Geological Survey of Canada Paper 93-1D, p. 137-145.

Nelson, P.H., and Mikesell, J., 1993, Magnetic susceptibility logs from sedimentary environments [abs., SPWLA 34th annual logging symposium]: The Log Analyst, v. 34, no. 2, p. 45.

BOREHOLE IMAGING

Paillet, F.L., Barton, C., Luthi, S., Rambow, F., and Zemanek, J., 1990, Borehole imaging and its application in well logging--an overview, chapter 1, *in* Borehole imaging: Society of Professional Well Log Analysts Reprint Volume, p. 1-23.

ACOUSTIC IMAGING

Allan, G.W., and Manly, G.L., 1991, Porosity determination from acoustic borehole imaging logs, paper X, *in* 13th formation evaluation symposium transactions: Canadian Well Logging Society, 8 p.

Dudley, J.W., II, 1993, Quantitative fracture identification with the borehole televiewer [abs., SPWLA 34th annual logging symposium]: The Log Analyst, v. 34, no. 2, p. 58.

Ma, T.A., and Bigelow, E.L., 1993, Borehole imaging tool detects well bore fractures: Oil and gas Journal, v. 91, no. 2, January 11, p. 33-36.

Seiler, D., Edmiston, C., Torres, D., and Goetz, J., 1990, Field performance of a new borehole televiewer tool and associated image processing techniques, paper H, *in* 31st annual logging symposium transactions: Society of Professional Well Log Analysts, 20 p.

Torres, D., Strickland, R., and Gianzero, M., 1990, A new approach to determining dip and strike using borehole images, paper K, in 31st annual logging symposium transactions: Society of Professional Well Log Analysts, 20 p. Also published in 1990 as paper JJ, *in* 13th European formation evaluation symposium transactions: Society of Professional Well Log Analysts, Budapest Chapter, 16 p.

Verdur, H., Stinco, L., and Naides, C., 1991, Sedimentological analysis utilizing the circumferential borehole acoustic image, paper II, *in* 32nd annual logging symposium transactions: Society of Professional Well Log Analysts, 19 p.

ELECTRICAL IMAGING

Bourke, L.T., 1992, Sedimentological borehole image analysis in clastic rocks--a systematic approach to interpretation, *in* Hurst, A., Griffiths, C.M., and Worthington, P.F., eds., Geological applications of wireline logs II: The Geological Society, London, Special Publication No. 65, p. 31-42.

Delhomme, J.P., 1992, A quantitative characterization of formation heterogeneities based on borehole image analysis, paper T, *in* 33rd annual logging symposium transactions: Society of Professional Well Log Analysts, 25 p.

Hornby, B.E., Luthi, S.M., and Plumb, R.A., 1990, Comparison of fracture apertures computed from electrical borehole scans and reflected Stoneley waves--an automated interpretation, paper L, *in* 31st annual logging symposium transactions: Society of Professional Well Log Analysts, 25 p. Later published in 1992: The Log Analyst, v. 33, no. 1, p. 50-66. Also published in 1992 as Hornby, B.E., and Luthi, S.M., 1992, An integrated interpretation of fracture apertures computed from electrical borehole scans and reflected Stoneley waves, *in* Hurst, A., Griffiths, C.M., and Worthington, P.F., eds., Geological applications of wireline logs II: The Geological Society, London, Special Publication No. 65, p. 179-184.

Koepsell, R.J., Jensen, F.E., and Langley, R.L., 1989, Gulf Coast fault orientation determined by formation imaging techniques, paper VV, *in* 30th annual logging symposium transactions: Society of Professional Well Log Analysts, 25 p. Also published in 1989 in condensed form as Formation imaging, part 1, Formation imaging yields precise fault orientation, minimizes dry offsets; part 2, Imaging aids visualization of faults: Oil and Gas Journal, v. 87, no. 49, December 4, p. 55-58; v. 87, no. 50, December 11, p. 85-86.

McNaboe, G.J., 1991, Comparison of Formation MicroScanner images to cores in sandstone reservoirs, Saudi Arabia, SPE-21436, *in* SPE 7th Middle East oil show conference proceedings: Society of Petroleum Engineers, p. 831-839.

Safinya, K.A., Le Lan, P., Villegas, M., and Cheung, P.S., 1991, Improved formation imaging with extended microelectrical arrays [FMI], SPE-22726, *in* SPE annual technical conference and exhibition proceedings, v. omega, Formation evaluation and reservoir geology: Society of Petroleum Engineers, p. 653-664.

Salimullah, A.R.M., and Stow, D.A.V., 1992, Application of FMS images in poorly recovered coring intervals--examples from ODP Leg 129, *in* Hurst, A., Griffiths, C.M., and Worthington, P.F., eds., Geological applications of wireline logs II: The Geological Society, London, Special Publication No. 65, p. 71-86.

Schlumberger, 1992, FMI fullbore Formation MicroImager: Schlumberger Educational Services, Houston, TX, Document SMP-9210, 42 p.

Serra, O., 1989, Formation MicroScanner image interpretation: Schlumberger Educational Service, Houston, SMP-7028, 117 p.

Sovich, J., and Newberry, B., 1993, Quantitative applications of borehole imaging [abs., SPWLA 34th annual logging symposium]: The Log Analyst, v. 34, no. 2, p. 49.

Standen, E., 1991, Tips for analyzing fractures on electrical wellbore images: World Oil, v. 212, no. 4, April, p. 99-117.

Standen, E., and Nurmi, R., Ozkanli, M., El Wazeer, F., 1993, Quantitative applications of wellbore images to reservoir analysis [abs., SPWLA 34th annual logging symposium]: The Log Analyst, v. 34, no. 2, p. 49.

Straub, A., Kruckel, U., and Gros, Y., 1991, Borehole electrical imaging and structural analysis in a granitic environment: Geophysical Journal International, v. 106, no. 3, September, p. 635-646.

Williams, G.R., and Sharma, M.M., 1991, The Formation Microscanner as a measure of heterogeneity in core-log studies: Gas Research Institute Report No. GRI-91/0239, 118 p.

CROSSWELL IMAGING (TOMOGRAPHY)

Daily, W., and Owen, E., 1991, Cross-borehole resistivity tomography: Geophysics, v. 56, no. 8, p. 1228-1235.

Greaves, R.J., Beydoun, W.B., and Spies, B.R., 1991, New dimensions in geophysics for reservoir monitoring, SPE-20170: SPE Formation Evaluation, v. 6, no. 2, p. 141-50.

Harris, J.M., Noeln-Hoeksema, R., Rector, J.W., III, Van Schaack, M., and Lazaratos, S.K., 1992, High resolution cross-well imaging of a west Texas carbonate reservoir, part 1--data acquisition and project overview [abs.], BG1.2, *in* 1992 technical program expanded abstracts with biographies: Society of Exploration Geophysicists, p. 35-37.

Inderwiesen, P.L., and Lo, T-W., 1990, Cross-hole seismic tomographic imaging of reservoir inhomogeneities in the Midway-Sunset field, California, BG2.1, *in* Expanded abstracts with biographies, 1990 technical program, v. 1: Society of Exploration Geophysicists, p. 22-25. Later published in 1991 as, Lo, T.-W., Inderwiesen, P.L., Melton, D.R., Howlett, D.L., Lewis, A.V., Poenk, M.F., Livingston, N.D., and Hatcher, W.B., 1991, The benefit and reliability of using cross-well tomography for reservoir characterization, SPE-22757, *in* SPE annual technical conference and exhibition proceedings, v. omega, Formation evaluation and reservoir geology: Society of Petroleum Engineers, p. 927-936. Also published in 1992 as, Lo, T.-W., and Inderwiesen, P.L., Reservoir characterization with crosswell tomography--a case study in the Midway-Sunset field,

California, SPE-22336, *in* SPE international meeting on petroleum engineering [Beijing], proceedings: Society of Petroleum Engineers, p. 87-96.

Johnston, P.F., Andersen, G.R., Wachi, N., Lee, D.S., Martens, F.G., and Han, D.H., 1992, Integration of seismic monitoring and reservoir simulation results for a steamflood at south Casper Creek oil field, Wyoming, SPE-24712, *in* Annual technical conference and exhibition proceedings, v. omega, Formation evaluation and reservoir geology: Society of Petroleum Engineers, p. 513-519.

Justice, J.H., Mathisen, M.E., Vassiliou, A.A., Singh, S., Cunningham, P.S., and Bulau, J.R., 1991, Acoustic tomography for reservoir surveillance, *in* The integration of geology, geophysics, petrophysics, and petroleum engineering in reservoir delineation, description, and management [proceeding of the first Archie conference, Houston, Texas, October 22-25, 1990]: AAPG, Tulsa, OK, p. 159-170. Later published in 1992, *in* Sheriff, R.E., ed., Reservoir geophysics: Society of Exploration Geophysicists, p. 321-334.

Justice, J.H., Mathisen, M.E., Vassilou, A.A., and Shiao, I., 1992, Crosshole seismic tomography--recent case histories [abs.], BG2.1, *in* 1992 technical program expanded abstracts with biographies: Society of Exploration Geophysicists, p. 67-69.

Krohn, C.E., Cross-well continuity logging using guided seismic waves: The Leading Edge, v. 11, no. 7, p. 39-45.

Lawson, D.A., 1991, Interwell geology from geophysical data, *in* Lake, L.W., Carroll, H.B., Jr., and Wesson, T.C., eds., Reservoir characterization II: Academic Press, Inc., San Diego, California, p. 442-459.

Lines, L.R., Miller, M., Tan, H., Chambers, R., and Treitel, S., 1993, Integrated interpretation of a borehole and crosswell data from a west Texas field: The Leading Edge, v. 12, no. 1, 13-16.

Link, C.A., McDonald, J.A., and Zhou, H.W., Jech, J., and Evans, B.J., 1993, Crosshole tomography in the Seventy-Six West field: The Leading Edge, v. 12, no. 1, 36-40.

Mansure, A.J., Meldau, R.F., and Weyland, H.V., 1990, Field examples of electrical resistivity changes during steamflooding, SPE-20539, *in* SPE annual technical conference exhibition proceedings, v. omega, Formation evaluation and reservoir geology: Society of Petroleum Engineers, p. 109-119. Later published in 1993: SPE Formation Evaluation, v. 8, no. 1, p. 57-64.

Paulsson, B.N.P., Smith, M.E., Tucker, K.E., and Fairborn, J.W., 1992, Characterization of a steamed oil reservoir using cross-well seismology: Geophysics--the Leading Edge of Exploration, v. 11, no. 7, p. 24-32.

Ranganayaki, R.P., Akturk, S.E., and Fryer, S.M., 1992, Formation resistivity variation due to steam flooding--a log study: Geophysics, v. 57, no. 3, p. 488-494.

Tittman, J., 1990, CAT-scanning the subsurface: Schlumberger Oilfield Review, v. 2, no. 2, p. 4-6.

Turpening, W.R., Chon, Y-T., Pepper, R.E.F., Szerbiak, R., Schultz, T., Thielmier, G., and Ballard, R., 1992, Detection of bed continuity using crosswell data--a Gypsy pilot site study, SPE-24711, *in* SPE annual technical conference and exhibition proceedings, v. omega, Formation evaluation and reservoir geology: Society of Petroleum Engineers, p. 503-511.

Wang, Z., Hirsche, W.K., and Sedgwick, G., 1990, Seismic monitoring of water floods? A petrophysical study, RP2.1 [abs.], *in* Expanded abstracts with biographies, 1990 technical program: Society of Exploration Geophysicists, v. 1, p. 811-815. Later published in expanded form in 1991: Geophysics, v. 56, no. 10, p. 1614-1623.

BOREHOLE RADAR

Baker, P.L., 1991, Fluid, lithology, geometry, and permeability information from ground-penetrating radar for some petroleum industry applications, SPE-22976, *in* SPE Asia-Pacific conference proceedings: Society of Petroleum Engineers, p. 277-287.

Chang, H-T., 1989, Borehole directional radar system for subsurface scanning, SPE-19609, *in* SPE annual technical conference and exhibition, proceedings, v. omega, Formation evaluation and reservoir geology: Society of Petroleum Engineers, p. 395-402.

Sandberg, E., Olsson, O., and Falk, L., 1989, Combined interpretation of fracture zones in crystalline rock using single hole, crosshole, tomography, and directional borehole radar data, paper G, *in* 3rd international symposium on borehole geophysics for minerals, geotechnical, and groundwater applications, proceedings: Society of Professional Well Log Analysts, Minerals and Geotechnical Logging Society, Chapter-at-Large, p. 97-116. Later published in 1991: The Log Analyst, v. 32 , no. 3, p. 108-119.

NUCLEAR LOGGING

Barnette, J.C., Copoulos, A.E., and Biswas, P.B., 1992, Acquiring production logging data with pulsed neutron logs from highly deviated or non-conventional production wells with multiphase flow in Prudhoe Bay, Alaska, SPE-24089, *in* SPE western regional meeting proceedings: Society of Petroleum Engineers, p. 611-620.

Bayless, J.R., Burkhart, C.P., and Kuthi, A. 1993, Advances in X-ray and neutron source technologies for logging applications [abs., SPWLA 34th annual logging symposium]: The Log Analyst, v. 34, no. 2, p. 57.

Blount, C.G., Copoulos, A.E., Myers, G.D., 1990, A channel detection technique using the pulsed neutron log, SPE-20042, *in* SPE California regional meeting, proceedings: Society of Petroleum Engineers, p. 255-263.

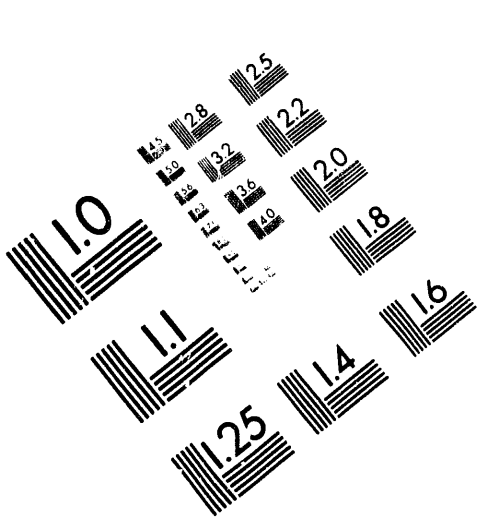
Bonnie, R.J.M., 1991, Evaluation of various pulsed neutron capture logging tools under well-defined laboratory conditions, paper OO, *in* 32nd annual logging symposium transactions: Society of Professional Well Log Analysts, 11 p.

Flanagan, W.D., Bramblett, R.L., Galford, J.E., Hertzog, R.C., Plasek, R.E., and Olesen, J.R., 1991, A new generation nuclear logging system, paper Y, *in* 32nd annual logging symposium transactions: Society of Professional Well Log Analysts, 25 p.

Gadeken, L.L., Gardner, M.L., Sharbak, D.E., and Wyatt, D.F., 1989, The interpretation of radioactive-tracer logs using gamma-ray spectroscopy measurements, paper KK, *in* 12th international formation evaluation symposium transaction: Society of Professional Well Log Analysts, Paris Chapter (SAID), p. Later published in 1991: The Log Analyst, v. 32, no. 1, p. 25-34.

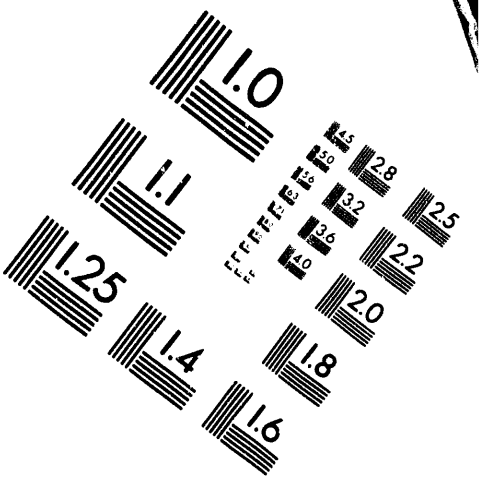
Gadeken, L.L., Ginzel, W.J., Sharbak, D.E., Shorck, K.A., Sitka, M.A., and Taylor, J.L., III, 1991, The determination of fracture orientation using a directional gamma-ray tool, paper AA, *in* 32nd annual logging symposium transactions: Society of Professional Well Log Analysts, 13 p. Also published in 1991 as paper AA, *in* 14th European formation evaluation symposium transactions [THAMES symposium]: Society of Professional Well Log Analysts, London Chapter, 15 p.

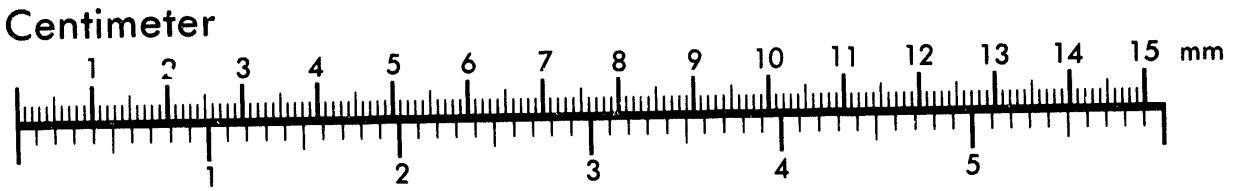
Jacobson, L.A., Beals, R., Wyatt, D.F., Jr., and Hrametz, A., 1991, Response characterization of an induced gamma spectrometry tool using a bismuth-germanate scintillator, paper LL, *in* 32nd annual logging symposium transactions: Society of Professional Well Log Analysts, 18 p.

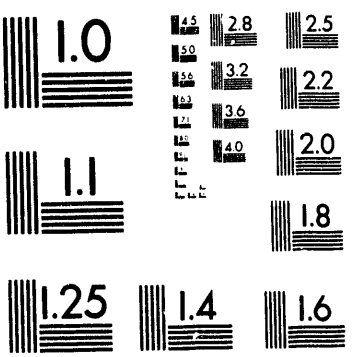


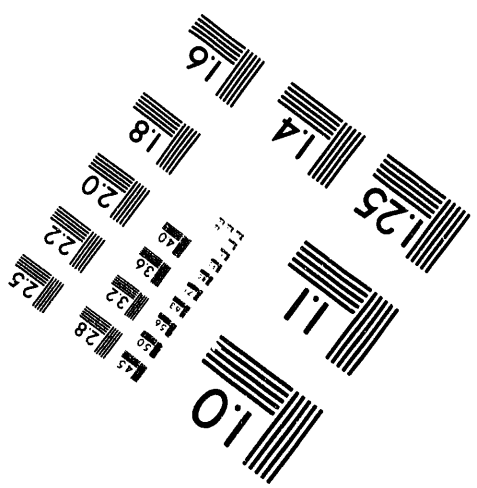


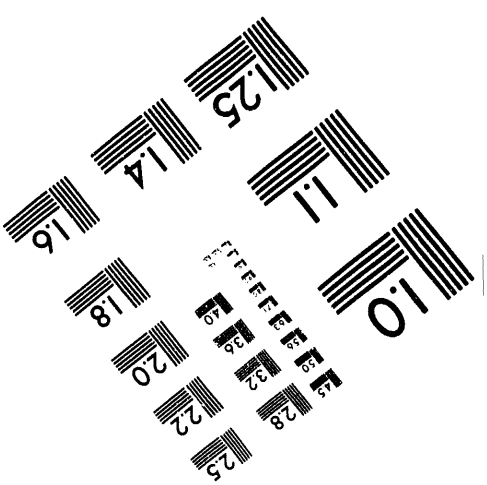
Association for Information and Image Management
1100 Wayne Avenue, Suite 1100
Silver Spring, Maryland 20910
301/587-8202











MANUFACTURED TO AIIM STANDARDS
BY APPLIED IMAGE, INC.

5 of 5

Jordan, D.W., Slatt, R.M., D'Agostino, A., and Gillespie, R.H., 1991, Outcrop gamma ray logging--truck-mounted and hand-held scintillometer methods are useful for exploration, development, and training purposes, SPE-22747, *in* Annual Technical Conference and Exhibition Proceedings, v. omega, Formation evaluation and reservoir geology: Society of Petroleum Engineers, p. 841-852. Also published in 1991 as, Applications of outcrop gamma-ray logging to field development and exploration, *in* The integration of geology, geophysics, petrophysics, and petroleum engineering in reservoir delineation, description, and management [proceeding of the first Archie conference, Houston, Texas, October 22-25, 1990]: AAPG, Tulsa, OK, p. 104-122. Later published in 1992 as, Gamma-ray logging of outcrops by a truck-mounted sonde: AAPG Bulletin, v. 77, no. 1, p. 118-123. Also published in 1992 as, Outcrop gamma-ray logging to improve understanding of subsurface well log correlations, *in* Hurst, A., Griffiths, C.M., and Worthington, P.F., eds., Geological applications of wireline logs II: The Geological Society, London, Special Publication No. 65, p. 3-19.

Mills, W.R., Stromswold, D.C., and Allen, L.S., 1991, Advances in nuclear oil well logging: Nuclear Geophysics, v. 5, no. 3, p. 209-227.

Moake, G.L., 1991, A new approach to determining compensated density and Pe values with a spectral-density tool, paper Z, *in* 32nd annual logging symposium transactions: Society of Professional Well Log Analysts, 24 p.

Myers, G.D., 1992, A review of nuclear logging: The Log Analyst, v. 33, no. 3, p. 228-238.

Schweitzer, J.S., 1991, Nuclear techniques in the oil industry: Nuclear Geophysics, v. 5, no. 1/2, p. 65-90

Scott, H.D., Stoller, C., Roscoe, B.A., Plasek, R.E., and Adolph, R.A., 1991, A new compensated through-tubing carbon/oxygen tool for use in flowing wells, paper MM, *in* 32nd annual logging symposium transactions: Society of Professional Well Log Analysts, 25 p.

Stoller, C., Scott, H.D., Plasek, R.E., Lucas, A.J., Adolph, R.A., 1993, Field tests of a slim carbon/oxygen tool for reservoir saturation monitoring, SPE-25375, *in* SPE Asia Pacific oil and gas conference and exhibition proceedings: Society of Petroleum Engineers, p. 481-487.

van den Berg, F.G., 1989, The capability of pulsed neutron capture logging to determine oil and gas saturations, SPE-19614, in SPE annual technical conference and exhibition, proceedings, v. omega, Formation evaluation and reservoir geology: Society of Petroleum Engineers, p. 437-446.

Wyatt, D.F., Jr., 1993, Advances in carbon/oxygen logs clarify reservoir behind casing: Oil and Gas Journal, v. 91, no. 6, February 8, p. 54-61.

Wyatt, D., Jacobson, L.A., Durbin, D., and Lasseter, E., 1992, Logging experience with a new induced gamma spectrometry tool, paper Y, *in* 33rd annual logging symposium transactions: Society of Professional Well Log Analysts, 18 p.

Wyatt, D.F., Jacobson, L.A., and Hashmy, K.H., 1993, Elemental yields and complex lithology analysis from the pulsed spectral gamma log [abs., SPWLA 34th annual logging symposium]: The Log Analyst, v. 34, no. 2, p. 54.

GEOCHEMICAL LOGGING

Anderson, R.N., Dove, R.E., and Pratson, E., 1990, Geochemical well logs; calibration and lithostratigraphy in basaltic, granitic, and metamorphic rocks, *in* Hurst, A., Lovell, M.A., and Morton, A.C., eds., Geological applications of wireline logs: Geological Society of London Special Publication No. 48, p. 177-194.

Hastins, A.F., 1990, Log-derived elemental concentrations to improve the accuracy of fluid saturations determined from well logs: Nuclear Geophysics, v. 4, no. 3, p. 305-319.

Herron, M.M., and Herron, S.L., 1990, Geological applications of geochemical well logging, *in* Hurst, A., Lovell, M.A., and Morton, A.C., eds., Geological applications of wireline logs: Geological Society of London Special Publication No. 48, p. 165-175.

Herron, S.L., Herron, M.M., Grau, J.A., and Ellis, D.V., 1992, Interpretation of chemical concentration logs and applications in the petroleum industry, *in* Pieters, C., and Englert, P., eds., Remote geochemical analysis--elemental and mineralogical composition: Lunar and Planetary Institute and Cambridge University Press, 55 p. [in press].

Herron, S.L., Petricola, M.J.C., and Dove, R.E., 1991, Geochemical logging of a Middle East carbonate reservoir, SPE-21435, *in* SPE 7th Middle East oil show conference proceedings: Society of Petroleum Engineers, p. 821-830. Later published in 1992: Journal of Petroleum Technology, v. 44, no. 11, p. 1176-1183.

van den Oord, R.J., 1990, Experience with geochemical logging, paper T, *in* 31st annual logging symposium transactions: Society of Professional Well Log Analysts, 25 p. Later published in 1991: The Log Analyst, v. 32, no. 1, p. 1-12.

Wendlandt, R.F., and Bhuyan, K., 1990, Estimation of mineralogy and lithology from geochemical log measurements: AAPG Bulletin, v. 74, no. 6, p. 837-856.

NEUTRON -ACTIVATION LOGGING

McKeon, D.C., Scott, H.D., and Patton, G.L., 1991, Interpretation of oxygen activation logs for detecting water flow in producing and injection wells, paper BB, *in* 32nd annual logging symposium transactions: Society of Professional Well Log Analysts, 23 p.

Olesen, J.R., Carpenter, W.W., and Hudson, T.E., 1989, Gravel pack quality control by neutron activation logging, SPE-19739, *in* Annual technical conference and exhibition proceedings, v. pi, Production operations and engineering: Society of Petroleum Engineers, p. 375-388.

Scott, H.D., Pearson, C.M., Renke, S.M., McKeon, D.C., and Meisenhelder, J.P., 1991, Applications of oxygen activation for injection and production profiling in the Kuparuk River field, SPE-22130, *in* SPE international Arctic technology conference [May 29-31, Anchorage, Alaska] proceedings: Society of Petroleum Engineers, p. 555-565.

Watson, J.T., Carpenter, W.W., Carroll, J.F., and Smith, B.C., 1990, Gravel pack field examples of a new pulsed neutron activation logging technique, OTC-6464, *in* Offshore technology conference proceedings, v. 4: Society of Petroleum Engineers, p. 351-356. Also published in 1991 as SPE-20877: SPE Formation Evaluation, v. 6, no. 4, p. 500-504.

Yahia, Z., and Elshawai, H.M.R., 1993, Reulst of trial using silicon activation gravelpack evaluation tool (SGPT) in Bokor, SPE-25363, *in* SPE Asia Pacific oil and gas conference and exhibition proceedings: Society of Petroleum Engineers, p. 383-390.

MEASUREMENT-WHILE-DRILLING LOGGING

Allen, D.F., Anderson, B.I., Liu, Q-H., and Luling, M.G., 1993, Supporting interpretation of complex, axisymmetric invasion by modeling wireline induction and 2-MHz LWD resistivity tools [abs., SPWLA 34th annual logging symposium]: The Log Analyst, v. 34, no. 2, p. 56.

Allen, D.F., Sheppard, M.C., Rasmus, J.C., and Ahmed, U., 1991, Real-time formation analysis can help drilling decisions, SPE/IADC-21914, *in* SPE/IADC drilling conference proceedings: Society of Petroleum Engineers, p. 153-165.

Ball, S., Hendricks, W., Verhoeff, E.K., Chelini, V., Cheng-Dang, Z., Zhen-Wu, J., and Xi-Ling, W., 1993, Formation evaluation utilizing a new measurement-while-drilling multiple depth of investigation resistivity sensor [abs., SPWLA 15th European formation evaluation symposium]: The Log Analyst, v. 34, no. 1, p. 96.

Bonner, S., Clark, B., Holenka, J., Voisin, B., Dusang, J., Hansen, R., White, J., and Walsgrove, T., 1992, Logging while drilling--a three-year perspective: Schlumberger Oilfield Review, v. 4, no. 3, July, p. 4-21.

Brami, J.B., 1991, Current calibration and quality control practices for selected measurement-while-drilling tools, SPE-22540, in SPE annual technical conference and exhibition, v. delta, Drilling: Society of Petroleum Engineers, p. 49-64.

Burgess, T., and Voisin, B., 1992, Advances in MWD technology improve real time data: Oil and Gas Journal, v. 90, no. 7, February 17, p. 51-61.

Cantrell, L.A., Paxson, K.B., Keyser, B.L., and Ball, S., 1992, Case histories of MWD as wireline replacement--an evolution of formation evaluation philosophy, SPE-24673, *in* SPE annual technical conference and exhibition proceedings, v. omega, Formation evaluation and reservoir geology: Society of Petroleum Engineers, p. 115-130.

Cunningham, A.B., and Opstad, E.A., 1990, Use of MWD Formation Evaluation in the Endicott Reservoir, North Slope, Alaska, USA, paper C, *in* 13th European formation evaluation symposium transactions: Society of Professional Well Log Analysts, Budapest Chapter, 21 p. Later published in 1992: The Log Analyst, v. 33, no. 5, p. 439-449.

Fredericks, P.D., Hearn, F.P., and Wisler, M.M., 1989, Formation evaluation while drilling with a dual propagation resistivity tool, SPE-19622, *in* SPE annual technical conference and exhibition, proceedings, v. omega, Formation evaluation and reservoir geology: Society of Petroleum Engineers, p. 521-536. Also published in 1989 as paper L, *in* 12th international formation evaluation symposium transactions: Society of Professional Well Log Analysts, Paris Chapter (SAID), 12 p.

Gaudin, D.B., and Beasley, J.C., 1991, A comparison of MWD and wireline steering tool guidance systems in horizontal drilling, SPE-22536, *in* SPE annual technical conference and exhibition, v. delta, Drilling: Society of Petroleum Engineers, p. 7-18.

Genrich, D.S., Prusieki, C.J., and Dunlop, F.L., 1993, Fully retrievable, slimhole gamma ray MWD system minimizes the risk of horizontal drilling, SPE/IADC-25691, *in* SPE/IADC drilling conference proceedings: Society of Petroleum Engineers, p. 161-168.

Habashy, T., and Anderson, B., 1991, Reconciling differences in depth of investigation between 2-MHz phase shift and attentuation resistivity measurements, paper E, *in* 32nd annual logging symposium transactions: Society of Professional Well Log Analysts, 20 p.

Hanson, J.M., and Tibbitts, G.A., 1991, Pore pressure ahead of the bit, SPE/IADC-21916, *in* SPE/IADC drilling conference proceedings: Society of Petroleum Engineers, p. 179-188.

Harris, R. Cheruvier, E., Laurent, P., Cross, B., 1993, Time lapse analysis of logging-while-drilling and wireline data: invasion radius from forward and inverse modelling [abs., SPWLA 34th annual logging symposium]: The Log Analyst, v. 34, no. 2, p. 55.

Hutchinson, M.W., 1991, Comparisons of MWD, wireline, and core data from a borehole test facility, SPE-22735, *in* SPE annual technical conference and exhibition proceedings, v. omega, Formation evaluation and reservoir geology: Society of Petroleum Engineers, p. 741-754.

IMS Eastern Hemisphere Technology Committee, 1991, Compatibility of formation evaluation MWD data and wireline log data (guidelines to optimise FEMWD quality) paper O, *in* 14th European formation evaluation symposium transactions [THAMES symposium]: Society of Professional Well Log Analysts, London Chapter, 36 p.

Locke, S., Dudek, J., Barnett, C., and Hubner, B., 1991, Theory, response, and calibration of an MWD neutron porosity sensor employing sidewall-mounted Li6 glass scintillation neutron detectors and spectral processing, paper F, *in* 32nd annual logging symposium transactions: Society of Professional Well Log Analysts, 23 p.

Logan, R.B., Schroeder, T.S., and Zoeller, W.A., 1990, Applications of an MWD propagation resistivity and neutron porosity tool, paper B, *in* 13th European formation evaluation symposium transactions: Society of Professional Well Log Analysts, Budapest Chapter, 16 p.

Montaron, B.A., Hache, J-M.D., and Voisin, B., 1993, Improvements in MWD telemetry--"the right data at the right time," SPE-25356, *in* SPE Asia Pacific oil and gas conference and exhibition proceedings: Society of Petroleum Engineers, p. 337-346.

Nordy, P., and Henry, K., 1992, Logging-while-drilling (LWD) results in Indonesia, OTC-6862, *in* 24th annual offshore technology conference proceedings: Society of Petroleum Engineers, p. 447-461

Oberkircher, J., Steinberger, G., Robbins, B., 1993, Applications for a multiple depth of investigation MWD resistivity device [abs., SPWLA 34th annual logging symposium]: The Log Analyst, v. 34, no. 2, p. 48.

Orban, J.J., Dennison, M.S., Jorion, B.M., and Mayes, J.C., 1991, New ultrasonic caliper for MWD operations, SPE/IADC-21947, *in* SPE/IADC drilling conference proceedings: Society of Petroleum Engineers, p. 439-448.

Paske, W.C., Mack, S.G., Rao, R.L., Spross, and J.R. Twist, 1990, Measurement of hole size while drilling, paper F, *in* 31st annual logging symposium transactions: Society of Professional Well Log Analysts, 24 p. A similar paper was also published in 1990 as, Theory and implementation of a borehole-caliper measurement made while drilling, SPE-20562, *in* SPE annual technical conference exhibition proceedings, v. omega, Formation evaluation and reservoir geology: Society of Petroleum Engineers, p. 335-344. Later published in 1992: SPE Formation Evaluation, v. 7, no. 2, June, p. 145-150.

Rasmus, J.C., and Stephens, D.M.R.G., 1990, Real-time pore pressure evaluation utilizing MWD/LWD measurements and drilling-derived formation strength, SPE-20443, *in* SPE annual technical conference and exhibition, proceedings, v. delta, Drilling: Society of Petroleum Engineers, p. 403-411. Later published in 1991: SPE Drilling Engineering, v. 6, no. 4, December, p. 264-272.

Rodney, P.F., Mack, S.G., Bittar, M.S., Bartel, R.P., 1991, An MWD multiple depth of investigation electromagnetic wave resistivity sensor, paper D, *in* 32nd annual logging symposium transactions: Society of Professional Well Log Analysts, 25 p. A similar paper also published in 1991 as, Bittar, M.S., Rodney, P.F., Mack, S.G., and Bartel, R.P., A true multiple depth of investigation electromagnetic wave resistivity sensor--theory, experiment, and prototype field test results, SPE-22705: Society of Petroleum Engineers, presented at 66th Annual Technical Conference and Exhibition [not included in proceedings], 18 p. A condensed version later published in 1992 as, Mack,

S.G., Rodney, P.F., and Bittar, M.S., MWD tool accurately measures four resistivities: Oil and Gas Journal, v. 90, no. 21, May 25, p. 42-46.

Rosthal, R.A., Best, D.L., and Clark, B., 1991, Borehole caliper while drilling from a 2-MHz propagation tool, SPE-22707, *in* SPE annual technical conference and exhibition proceedings, v. omega, Formation evaluation and reservoir geology: Society of Petroleum Engineers, p. 491-502.

Sakurai, S., Hedges, P.L., and Wolcott, D., 1992, Wireline--MWD logoff for formation evaluation, Kuparuk River unit, Alaska: The Log Analyst, v. 33, no. 5, p. 451-460.

Shen, L.C., 1991, Investigation depth of coil-type MWD resistivity sensor, paper C, *in* 32nd annual logging symposium transactions: Society of Professional Well Log Analysts, 23 p. Also published in 1991 as, Theory of a coil-type resistivity sensor for MWD application: The Log Analyst, v. 32, no. 5, p. 603-611.

Shray, F.P., 1992, LWD detects changes in formation parameters over time: Petroleum Engineer International, v. 64, no. 4, p. 24-31.

Sinclair, P., Chemali, R., and Su, S-M., 1993, A new dual-spaced compensated wave resistivity device for measurement while drilling [abs., SPWLA 15th European formation evaluation symposium]: The Log Analyst, v. 34, no. 1, p. 91.

Spross, R., Burnett, T., Freeman, J., Jones, D., Paske, W., and Zannoni, S., 1993, Formation density measurement while drilling [abs., SPWLA 34th annual logging symposium]: The Log Analyst, v. 34, no. 2, p. 48.

LOGGING IN HORIZONTAL WELLS

Aguilera, R., Cordell, G.M., Nicholl, G.W., Artindale, J.S., Ng, and Runions, M.C., 1991, Well logging, chapter 4, *in* Horizontal wells: Gulf Publishing Company, Houston, Texas, p. 127-155.

Alcock, T., Carlson, B., and Oliveira, A., 1993, Optimising log data acquisition in horizontal wells [abs., SPWLA 15th European formation evaluation symposium]: The Log Analyst, v. 34, no. 1, p. 90.

Betts, P., Blount, C., Broman, B., Clark, B., Hibbard, L., Louis, A., and Oosthoek, P., 1990, Acquiring and interpreting logs in horizontal wells: Schlumberger Oilfield Review, v. 2, no. 3, July, p. 34-51.

Bigelow, E.L., and Cleneay, C.A., 1992, A new frontier--log interpretation in horizontal wells, paper OO, *in* 33rd annual logging symposium transactions: Society of Professional Well Log Analysts, 13 p.

Broman, W.H., Jr., Schmohr, D.R., and Schnorr, D.R., 1992, Horizontal well operations at Prudhoe Bay, SPE-22383, *in* SPE international meeting on petroleum engineering [Beijing], proceedings: Society of Petroleum Engineers, p. 541-549.

Clavier, C., 1991, The challenge of logging horizontal wells: The Log Analyst, v. 32, no. 2, p. 63-84.

Ding, Z., Wu, S., Chaffe, W., and Jordan, C., 1993, Production logging in highly deviated and horizontal wells [abs., SPWLA 15th European formation evaluation symposium]: The Log Analyst, v. 34, no. 1, p. 95.

Donahue, M.T., Nice, S.B., and Lincecum, V.J., 1991, A review of formation evaluation practices in horizontal wells, SPE-23542, 2nd Archie conference proceedings: Society of Petroleum Engineers, p. 69-80.

Evans, H.B., 1991, Evaluating differences between wireline and MWD systems: World Oil, v. 212, no. 4, April, p. 51-61, 136.

Hammons, L.R.B., Barnett, W.C., Fisher, E.K., and Sellers, D.H., 1991, Stratigraphic control and formation evaluation of horizontal wells using MWD, SPE-22538, *in* SPE annual technical conference and exhibition, v. delta, Drilling: Society of Petroleum Engineers, p. 25-38. Later published in 1992: Journal of Petroleum Technology, v. 44, no. 10, p. 1134-1140.

Jacobsen, S.J., Fett, T.H., Singer, J.M., and Ahmed, U., 1991, Horizontal wells--concepts in reservoir evaluation, SPE-21837, *in* Rocky Mountain regional and low-permeability reservoirs symposium, proceedings: Society of Petroleum Engineers, p. 317-335. Later published in 1992 in condensed form as, Ahmed, U., 1992, Formation evaluation critical for application of technology [3-part series]: American Oil and Gas Reporter, v. 34, no. 6, June, p. 27-32; v. 34, no. 7, July, p. ; v. 34, no. 8, August, p. 25-31.

Leake, J., and Shray, F., 1991, Logging while drilling keeps horizontal well on small target: Oil and Gas Journal, v. 89, no. 38, September 23, 191, p. 53-59.

Robertshaw, S.E., Peach, S.C., and Jensen, R.E., 1991, Completion and evaluation of cased horizontal wells, paper Z, *in* 13th formation evaluation symposium transactions: Canadian Well Logging Society, 10 p. Later published in 1992, as Well illustrates challenges of horizontal production logging: Oil and Gas Journal, v. 90, no. 24, June 15, p. 33-38.

Singer, J.M., 1992, An example of log interpretation in horizontal wells: The Log Analyst, v. 33, no. 2, p. 85-95.

Svor, T.R., and Meehan, D.N., 1991, Quantifying horizontal well logs in naturally fractured reservoirs, part I, SPE-22704, *in* SPE annual technical conference and exhibition proceedings, v. omega, Formation evaluation and reservoir geology: Society of Petroleum Engineers, p. 469-480.

Svor, T.R., and Meehan, D.N., 1991, Quantifying horizontal well logs in naturally fractured reservoirs, part II, SPE-22932, *in* SPE annual technical conference and exhibition, v. sigma, Reservoir engineering: Society of Petroleum Engineers, p. 471-480.

LOGGING IN SLIMHOLES AND ON COILED-TUBING

Ackers, M., Doremus, D., and Newman, K., 1992, An early look at coiled-tubing drilling: Schlumberger Oilfield Review, v. 4, no. 3, p. 45-51.

Blount, C.G., and Walker, E.J., 1992, Coiled tubing--operation and services, part 6, Tubing assisted logging and perforating: World Oil, v. 213, no. 5, May, p. 89-96.

Corrigan, M., Hoyer, C., and Gaston, C., 1990, Logging on coiled tubing--a proven technique for highly deviated wells and other applications, *in* 4th Abu Dhabi petroleum conference proceedings: Abu Dhabi National Oil Company, p. 50-56. Later published in 1991 as, SPE-21314: Society of Petroleum Engineers, unsolicited paper, 7 p.

Harness, P.E., Hansen, M.D., Terzian, G.A., Fowler, S.H., Jr., and Golino, F.J., 1990, An overview of reeled-tubing-conveyed production logging capabilities in California, SPE-20028, *in* SPE California regional meeting proceedings: Society of Petroleum Engineers, p. 155-163

Littleton, J., 1992, Refined slimhole drilling technology renews operator interest: Petroleum Engineer International, v. 64, no. 6, June, p. 19-26.

MacEwen, H., 1988, Coiled-tubing-conveyed logging systems, SPE-18350, *in* SPE European petroleum conference [London] proceedings: Society of Petroleum Engineers, p. 167-171.

Randolph, S.B., and Jourdan, A.P., 1991, Slimhole continuous coring and drilling in Tertiary sediments, SPE/IADC-21906, *in* SPE/IADC drilling conference proceedings: Society of Petroleum Engineers, p. 81-91.

Samworth, J.R., 1992, Quantitative open-hole logging with very small diameter wireline tools, paper NN, *in* 33rd annual logging symposium transactions: Society of Professional Well Log Analysts, 24 p.

Walker, S.H., and Millheim, K.K., 1989, An innovative approach to exploration and exploitation drilling--the slim-hole high-speed drilling system, SPE-19525, *in* Annual technical conference and exhibition, v. delta, Drilling: Society of Petroleum Engineers, p. 73-83. Later published in 1990: Journal of Petroleum Technology, v. 42, no. 9, p. 1184-1191. Later reprinted in 1991 as paper SCA-9101, *in* 5th annual technical conference preprints: Society of Core Analysts, Society of Professional Well Log Analysts Chapter-at-Large, v. 3, 26 p.

Worrall, R.N., van Lujik, J.M., Hough, R.B., Rettberg, A.W., and Makohl, F., 1992, An evolutionary approach to slim-hole drilling, evaluation, and completion, SPE-24965, *in* European petroleum conference proceedings: Society of Petroleum Engineers, p.47-54.

BOREHOLE GRAVITY LOGGING

Adams, S.J., 1991, Gas saturation monitoring in North Oman reservoir using a borehole gravimeter, SPE-21414, *in* SPE 7th Middle East oil show conference proceedings: Society of Petroleum Engineers, p. 669-678.

Black, A.J., 1992, Borehole gravity shuttle system for enhanced deep densities at small depth intervals [abs.], BG6.8, *in* 1992 technical program expanded abstracts with bibliographies: Society of Exploration Geophysicists, p. 225-226.

Popta, J.V., Heywood, J.M.T., Adams, S.J., and Bostock, D.R., 1990, Use of borehole gravimetry for reservoir characterization and fluid saturation monitoring, SPE-20896, *in* Europec 90, SPE European petroleum conference [October 22-24, The Hague] proceedings: Society of Petroleum Engineers, v. 1, p. 151-160.

ResTech Houston, 1988, Borehole gravity and gradiometry, workshop proceedings: Gas Research Institute Report No. GRI-88/195, variously paginated

Robbins, S.L., 1989, Borehole gravimetry reviews; part 1, What is borehole gravimetry; part 2, Borehole gravity measurements, data reduction and precision; part 3, Bibliography with abridged abstracts of borehole gravimetry and corresponding in-place rock density measurements: U.S. Geological Survey Circular 890, 64 p.

Schultz, A.K., 1989, Monitoring fluid movement with the borehole gravity meter: Geophysics, v. 54, no. 5, p. 1,267-1,273.

ADVANCED FORMATION TESTER

Colley, N., Ireland, T., Reignier, P., Richardson, S., Joseph, J., Zimmerman, R., Traboulay, I., and Hastings, A., 1992, The MDT tool--a wireline testing breakthrough: Schlumberger Oilfield Review, v. 4, no. 2, April, p. 58-65.

Zimmerman, T., MacInnis, J., Hoppe, J., Pop, J, 1990, Application of emerging wireline formation testing technologies, OSEA-90105, in 8th offshore South East Asia conference [December 4-7, Singapore] preprints: Society of Petroleum Engineers, p. 83-95.

CORING TECHNIQUES

Gardes Directional Drilling, 1992, Radial coring: Gardes Energy, Inc., Lafayette Louisiana, sales brochure, 13 p.

Nieto, J.A., and Yale, D.P., 1991, Integration of core and downhole acoustic measurements--shear and compressional, *in* Worthington, P.F., and Longeron, D., eds., Advances in core evaluation II--reservoir appraisal: Gordon and Breach Science Publishers, Philadelphia, p. 215-237.

Shade, M.E., and Hansen, D.K.T., 1991, Drilled-sidewall cores aid in interpretation of complex clastic Tertiary reservoirs, paper R, *in* 13th formation evaluation symposium transactions: Canadian Well Logging Society, 31 p. Later published in 1992 as, Drilled sidewall cores aid in interpretation of the Tertiary Wasatch Formation, Natural Buttes field, Utah, *in* Fouch, T.D., Nuccio, V.F., and Chidsey, T.C., Jr., eds., Hydrocarbon and mineral resources of the Uinta Basin, Utah and Colorado, 1992 field symposium: Utah Geological Association, Salt Lake City, Utah, Guidebook No. 20, p. 193-217.

Skopec, R.A., Mann, M.M., Jeffers, D., and Grier, S.P., 1990, Horizontal-core acquisition and orientation for formation evaluation, SCA-9017, in Annual technical conference preprints: Society of Professional Well Log Analysts, Society of Core Analysts Chapter-at-Large, v. 3, 32 p. Also published in 1990 as SPE-20418, in SPE annual technical conference and exhibition, proceedings, v. delta, Drilling: Society of Petroleum Engineers, p. 153-166. Later published in 1992: SPE Drilling Engineering, v. 7, no. 1, p. 47-54.

Skopec, R.A., 1992, Recent advances in rock characterization: The Log Analyst, v. 33, no. 3, p. 270-285.

CORE IMAGING

Aas, M., Bacri, J-C., Frenois, C., Salin, D., and Woumeni, R., 1990, 3-D acoustic scanner, SPE-20599, *in* SPE annual technical conference exhibition proceedings, v. omega, Formation evaluation and reservoir geology: Society of Petroleum Engineers, p. 725-732.

Auzerais, F.M., Dussan, E.B., and Reischer, A.J., 1991, Computed tomography for the quantitative characterization of flow through a porous medium, SPE-22595, *in* SPE annual technical conference and exhibition, v. gamma, EOR/general petroleum engineering: Society of Petroleum Engineers, p. 83-95.

Bourke, L.T., 1991, Permeability imaging for detailed reservoir characterization, *in* Worthington, P.F., and Longeron, D., eds., Advances in core evaluation II--reservoir appraisal: Gordon and Breach Science Publishers, Philadelphia, p. 407-427.

Chardaire, C., and Roussel, J-C., 1990, NMR imaging of fluid saturation distributions in core samples using a high magnetic field, *in* Worthington, P.F., ed., Advances in core evaluation, accuracy, and precision in reserves estimation [Reviewed proceedings of the first Society of Core Analysts European core analysis symposium, May 21-23, London, UK]: Gordon and Breach Science Publishers, New York, p. 301-315.

Georgi, D.T., and Jones, S.C., 1992, Application of pressure-decay profile permeametry to reservoir description, SPENC-9212: Society of Petroleum Engineers, presented at 16th Annual SPE (Nigeria Council) International Conference and Exhibition [August 26-27, Lagos, Nigeria), 12 p.

Halvorsen, C., and Hurst, A., 1990, Principle s, practice, and applications of laboratory minipermeametry, *in* Worthington, P.F., ed., Advances in core evaluation, accuracy, and precision in reserves estimation [Reviewed proceedings of the first Society of Core Analysts European core analysis symposium, May 21-23, London, UK]: Gordon and Breach Science Publishers, New York, p. 521-549.

Jackson, P.D., Lovell, M.A., Harvey, P.K., Ball, J.K., Williams, C., Ashu, P., Flint, R., Meldrum, P., Reece, G., and Zheng, G., 1992, Electrical resistivity core imaging--theoretical and practical experiments as an aid to reservoir characterization, paper VV, *in* 33rd annual logging symposium transactions: Society of Professional Well Log Analysts, 13 p.

Jones, S.C., 1992, The profile permeameter--a new, fast, accurate minipermeameter, SPE-24757, *in* SPE annual technical conference and exhibition proceedings, v. omega, Formation evaluation and reservoir geology: Society of Petroleum Engineers, p. 973-983.

Krilov, Z., Steiner, I., Goricnik, B., Wojtanowicz, A.J., and Cabrajac, S., 1991, Quantitative determination of solids invasion and formation damage using CAT scan and barite suspensions, SPE-23102, *in* Offshore Europe conference proceedings: Society of Petroleum Engineers, p. 55-66.

Lanza, R.C., McFarland, E.W., and Poulos, G.W., 1991, Computerized neutron tomography for core analysis, SCA-9128, *in* 5th annual technical conference proceedings: Society of Professional Well Log Analysts, Society of Core Analysts Chapter-at-Large, v. 3, 12 p.

Lewis, J., Williams, A., Enwere, P.M., Archer, J.S., and Taylor, D.G., 1990, Applications of magnetic resonance imaging in special core analysis studies, *in* Worthington, P.F., ed., Advances in core evaluation, accuracy, and precision in reserves estimation [Reviewed proceedings of the first Society of Core Analysts European core analysis symposium, May 21-23, London, UK]: Gordon and Breach Science Publishers, New York, p. 317-345.

Peters, E.J., and Hardham, W.D., 1990, Visualization of fluid displacements in porous media using computed tomography imaging: Journal of Petroleum Science and Engineering, v. 4, p. 155-168.

Tomutsa, L., Doughty, D., Mahmood, S., Brinkmeyer, A., and Madden, M.P., 1991, Imaging techniques applied to the study of fluids in porous media--topical report: U.S. Department of energy Report NIPER-485, 31 p.

ENHANCED VERTICAL RESOLUTION AND THIN-BED ANALYSIS

Bateman, R.M., 1990, Thin-bed analysis with conventional log suites, paper II, *in* 31st annual logging symposium transactions: Society of Professional Well Log Analysts, 24 p. Also published in 1990, as paper IPA 90-149, *in* 19th annual convention proceedings: Indonesian Petroleum Association, Jakarta, v. 2, p. 179-196.

Descalzi, C., Rognoni, A., and Spotti, G., 1990, Quantitative evaluation of thin bedded reservoirs through a 'cluster analysis' using high resolution tools, SPE-20945, *in* Europec 90 conference proceedings: Society of Petroleum Engineers, p. 87-94.

Forsyth, D., Nawawi, H., and Ho. T.C., 1993, Review of techniques for the interpretation and evaluation of thin sand sequences, SPE-25357, *in* SPE Asia Pacific oil and gas conference and exhibition proceedings: Society of Petroleum Engineers, p. 347-355.

Jacobson, L.A., Wyatt, D.F., Jr., Gadeken, L.L., and Merchant, G.A., 1990, Resolution enhancement of nuclear measurements through deconvolution, paper TT, *in* 31st annual logging symposium transactions: Society of Professional Well Log Analysts, 15 p. Later published in 1991: The Log Analyst, v. 32, no. 6, p. 663-670.

Lawrence, T.D., and Mezzatesta, A.G., 1989, Thin-bed analysis using high-resolution measurements, paper 6, *in* Log analysis software evaluation and review (LASER) symposium transactions: Society of Professional Well Log Analysts, London Chapter, 13 p.

Nelson, R.J., and Mitchell, W.K., 1990, Improved vertical resolution of well logs by resolution matching, paper JJ, *in* 31st annual logging symposium transactions: Society of Professional Well Log Analysts, 25 p. Later published in 1991: The Log Analyst, v. 32, no. 4, p. 339-349.

Ruhovets, N., Rau, R., Samuel, M., Smith, H., Jr., and Smith, M., 1992, Laminated reservoir evaluation using logs with different vertical resolution, paper CC, *in* 33rd annual logging symposium transactions: Society of Professional Well Log Analysts, 25 p. Also published in 1992, *in* Hurst, A., Griffiths, C.M., and Worthington, P.F., eds., Geological applications of wireline logs II: The Geological Society, London, Special Publication No. 65, p. 99-121.

Tittman, J., 1991, Vertical resolution of well logs--recent developments: Schlumberger Oilfield Review, v. 3, no. 3, July, p. 24-28.

NOTES

MAGNETIC RESONANCE WELL LOGGING

Magnetic resonance, as a method to enhance the evaluation of rocks, caught the attention[1] of the oil and gas industry more than 30 years ago. This interest prompted the development of a well logging tool[2] that failed to systematically deliver the promises given by the laboratory studies.

However, laboratory research, especially on the clinical side, continued and many successful advances were accomplished, especially pertaining to methods that were useful for maximizing signal strength.

In October, 1990 a new magnetic resonance well logging tool was introduced to the oil and gas industry.[3] This device incorporated several design features that addressed the shortcomings of previous technology and, in June 1991, the first commercial service was accomplished. Since then, more than 140 wells have been logged, primarily in the U.S. but also in Italy, U.K. North Sea, and Canada.

The laboratory promises are finally being realized. Direct measure of such petrophysical parameters as porosity, permeability, capillary bound pore fluids, as well as links to fluid properties and pore size are bringing solutions to many of today's unanswered formation evaluation questions. For example:

- Will it produce water free?
- What is the porosity in a mixed lithology?
- What is the permeability?
- Where is the gas-oil contact in a mixed lithology reservoir?
- When the next location must be spotted, is it a channel or bar?

Example #1:	Travis Peak -- low resistivity pay
Example #2:	Hugoton -- mixed lithology
Example #3:	Utah -- permeability
Example #4:	Colorado -- permeability

H-0145.93

NUMAR CORPORATION

Magnetic Resonance Imaging Log Example

Location: Panola County, Texas - Travis Peak Formation

Application: Swirr determination between oil and water, grain size variation.

Description: The example is a typical well in the Travis Peak formation in East Texas. This formation is a classic example where, due to grain size, deposition complicates formation evaluation. Reservoirs consist chiefly of sandstone of fluvial origin. Consequently, difficulties arise in attempting to predict possible permeability and, ultimately, potential hydrocarbon production.

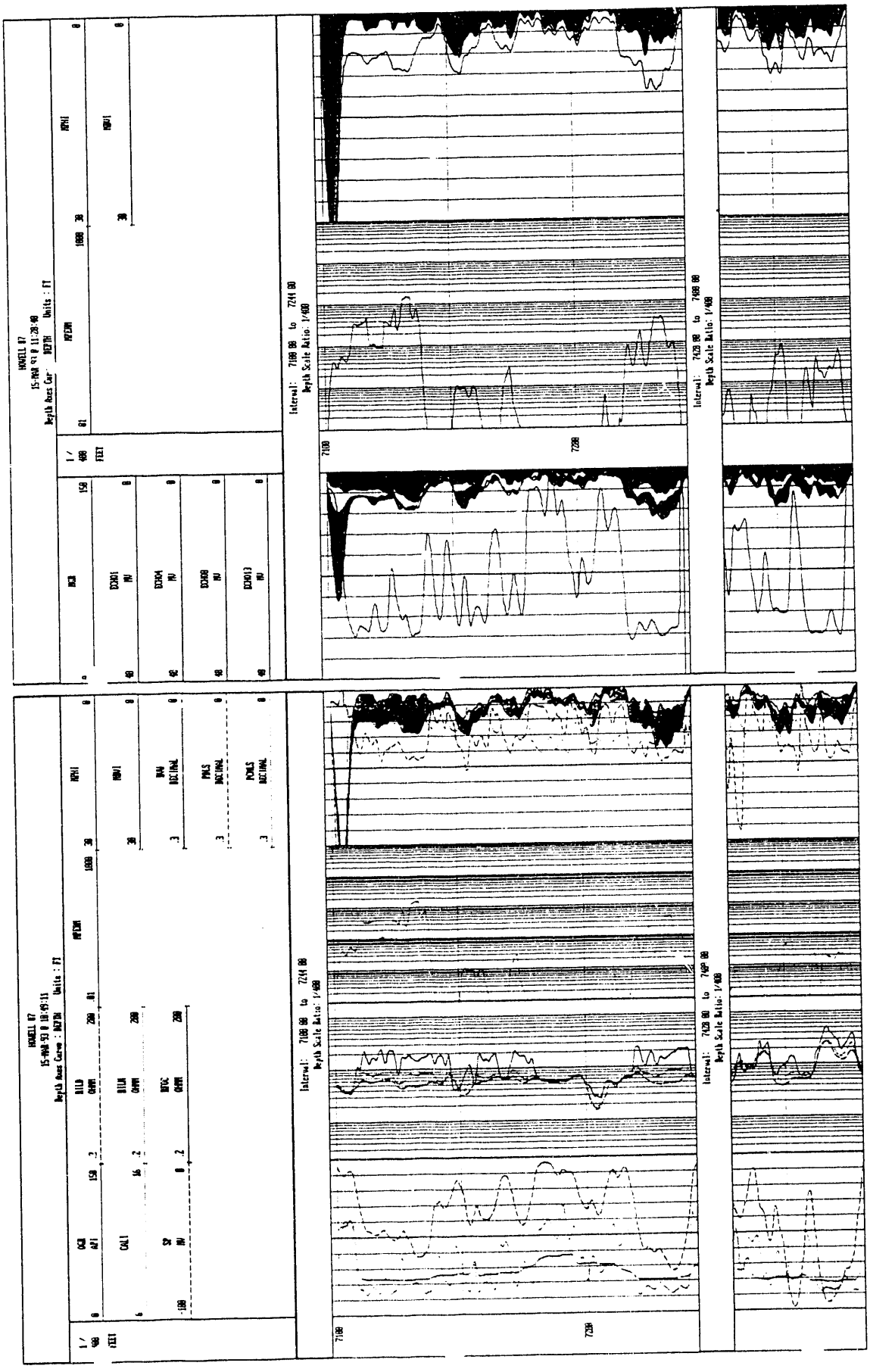
Evaluation: A. Compare the two zones, (1) 7108 - 7138 with (2) 7220 - 7241:

The GR, resistivity curves, invasion profile, $\emptyset_D + \emptyset_N$ are essentially the same. The SP in the lower sand is slightly cleaner than the upper, but the character is identical. The Sw calculates the same in both zones at 60%. Notice the very high BVWirr in the bottom zone. That zone is at irreducible and produced water free. The sand grains are much smaller than the upper interval, therefore, "holding" more irreducible water. The upper zone has a very low BVWirr and produces gas and water.

B. Zones in the lower section, (1) 7448 - 7454 and (2) 7460 - 7478:

The lower zone is at 20 ohm-m and the upper interval is at 4 ohm-m. Normally, the operator would only produce the lower zone "worried" about isolation from the upper zone. Notice the very high BVWirr in the 4 ohm-m interval. However, the MRIL shows both zones to be at irreducible. The grain sizes in the upper zone are finer than the lower, therefore, holding more water.

Results: The intervals initially tested 150 thousand cubic feet of gas/day before treatment. After treatment, production was 2.8 MMCFD, 30 barrels of condensate and seven BWPD. The zone from 7220 - 7241 has produced 2.2 bcf (billion) in an adjacent well only 3000' away.


HOWELL #7
15-MAR-93 @ 11:28:00
Depth Axes Curve : MDTM Units : FT
Interval: 7100.00 to 7244.00
Depth Scale Ratio: 1/400
Interval: 7428.00 to 7480.00
Depth Scale Ratio: 1/400
HOWELL #7
15-MAR-93 @ 10:49:11
Depth Axes Curve : MDTM Units : FT
Interval: 7100.00 to 7244.00
Depth Scale Ratio: 1/400
Interval: 7428.00 to 7480.00
Depth Scale Ratio: 1/400

NUMAR CORPORATION

Magnetic Resonance Imaging Log Example

Location: Morton County, Kansas - Hugoton Gas Field

Application: Grain size variation, gas-water contact complex lithology, establishing better reservoir characteristics.

Description & Evaluation:

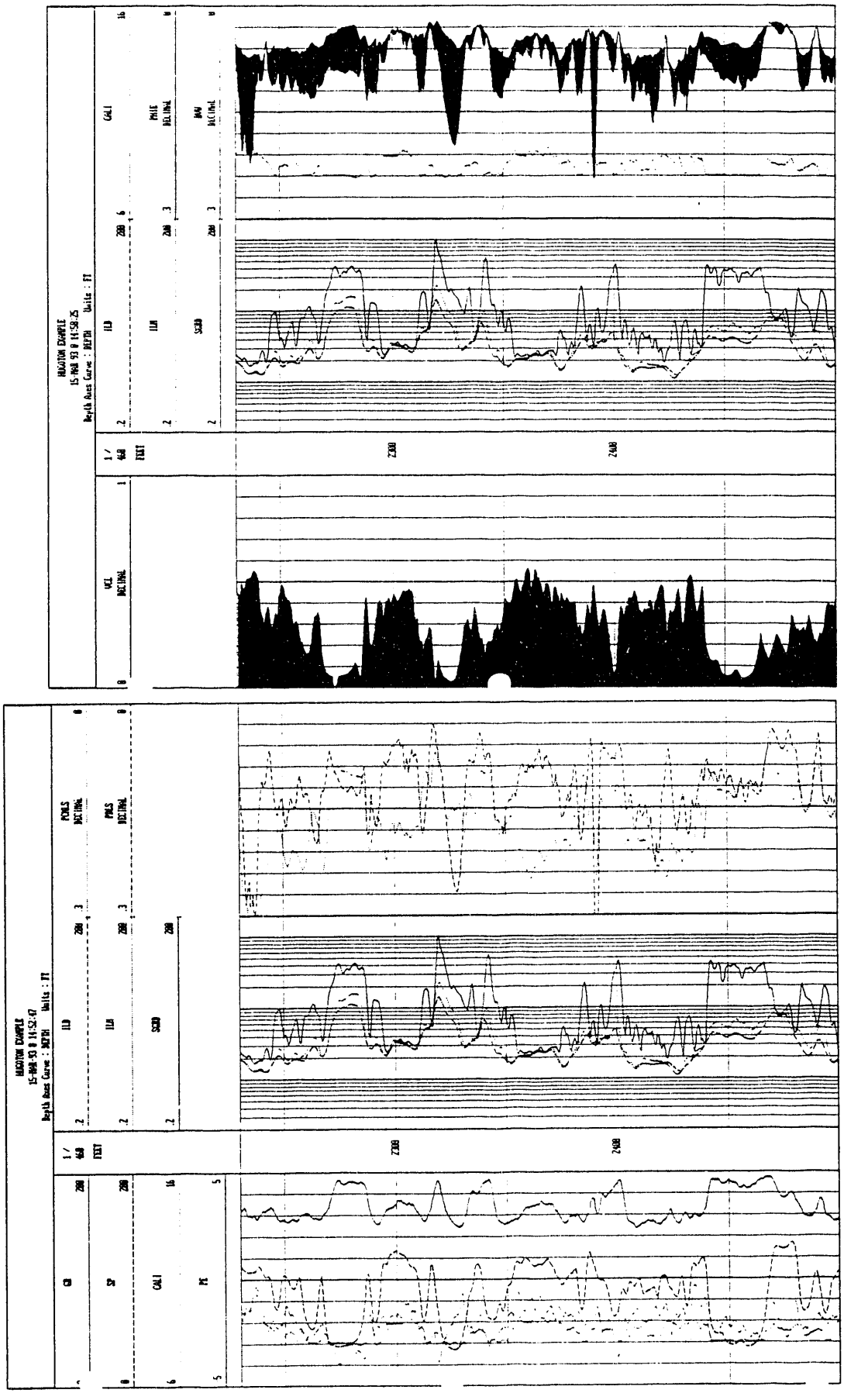
The Hugoton gas field is a very well developed and large gas field with well defined parameters located in Kansas, Oklahoma, and Colorado. The main information needed concerns the presence of the water contact in the Hugoton. As can be seen, the resistivity tool is non-conclusive when calculating Sw due to variations within the zones. The upper zone (2,245 - 2,295) resistivity is measured at only 2 ohm-m but increasing to 10 ohm-m in the bottom of this zone. This would indicate either a water leg on top of hydrocarbons or a coarsening downward sequence. The latter is the case and is confirmed by the MRIL. The interval is at irreducible water conditions and will produce gas with no water.

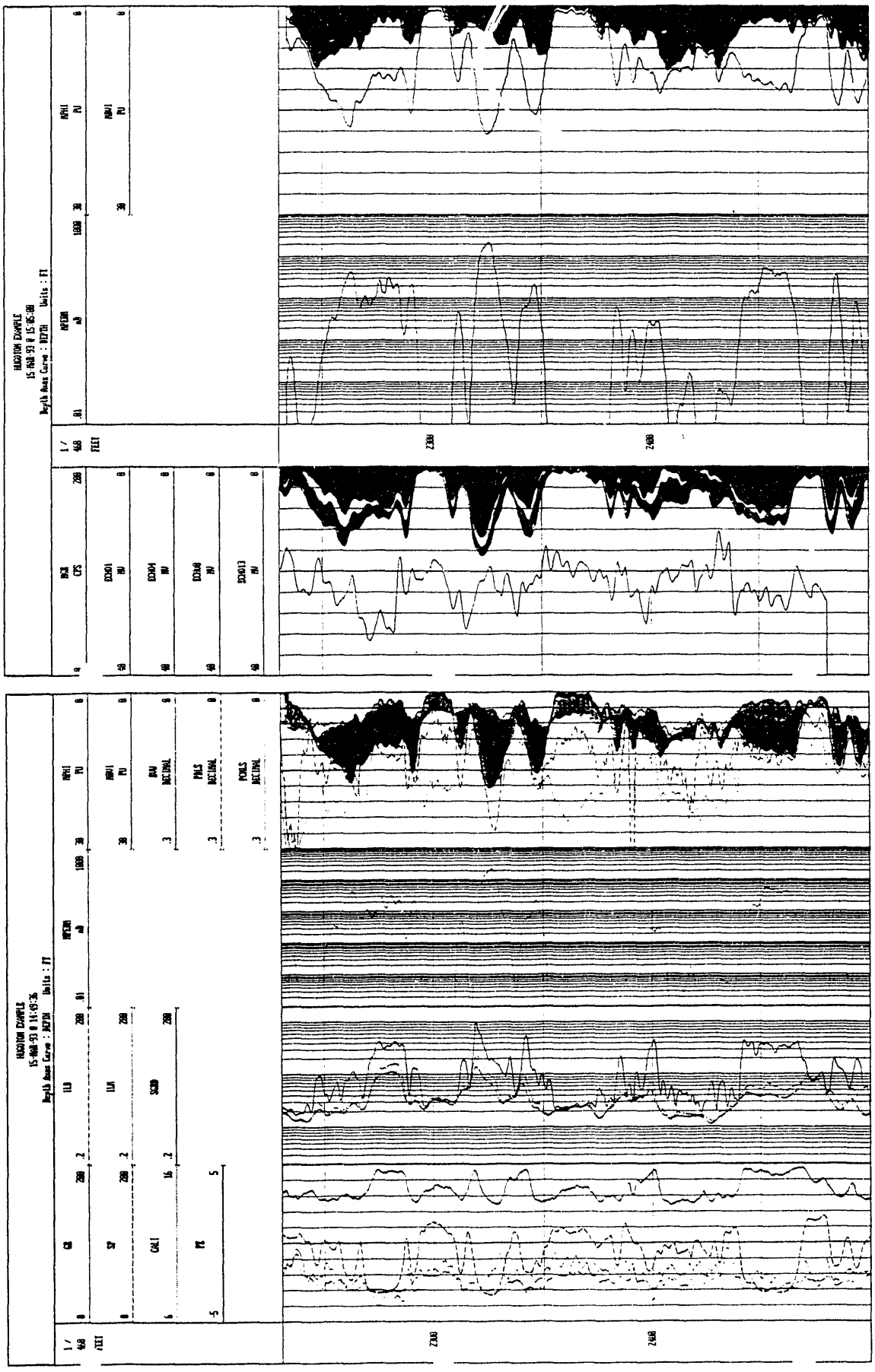
The sands located at 2,310 - 2,355 exhibit a different character. There appears to be a transition zone located in each of the major lobes. Resistivity starts at 8-12 ohm-m and drops in the zones to 2-3 ohm-m at the bottom. The MRIL indicates that the zones are actually classic fining downward sequences. The lower resistivity is associated with water but it is bound to the surface of the finer grain sands present rather than free water in the pore space. The MRIL has increased the net feet of pay in this well.

In the 2,400 - 2,470 zone, the resistivity only gets down to 4 ohm-m, higher than all of the zones above. However, the water present in this sand is not bound to fine grains but is associated with moveable water located in the pore space between large grains. NOTE the value of the MRIL in differentiating low resistivity pay zones from higher resistivity water zones.

According to the operator, this information will enable him to more fully exploit these reservoirs.

Results: The gas/water contact was identified at 2440 which booked some additional reserves and helped the operator in designing an optimum completion on the well.

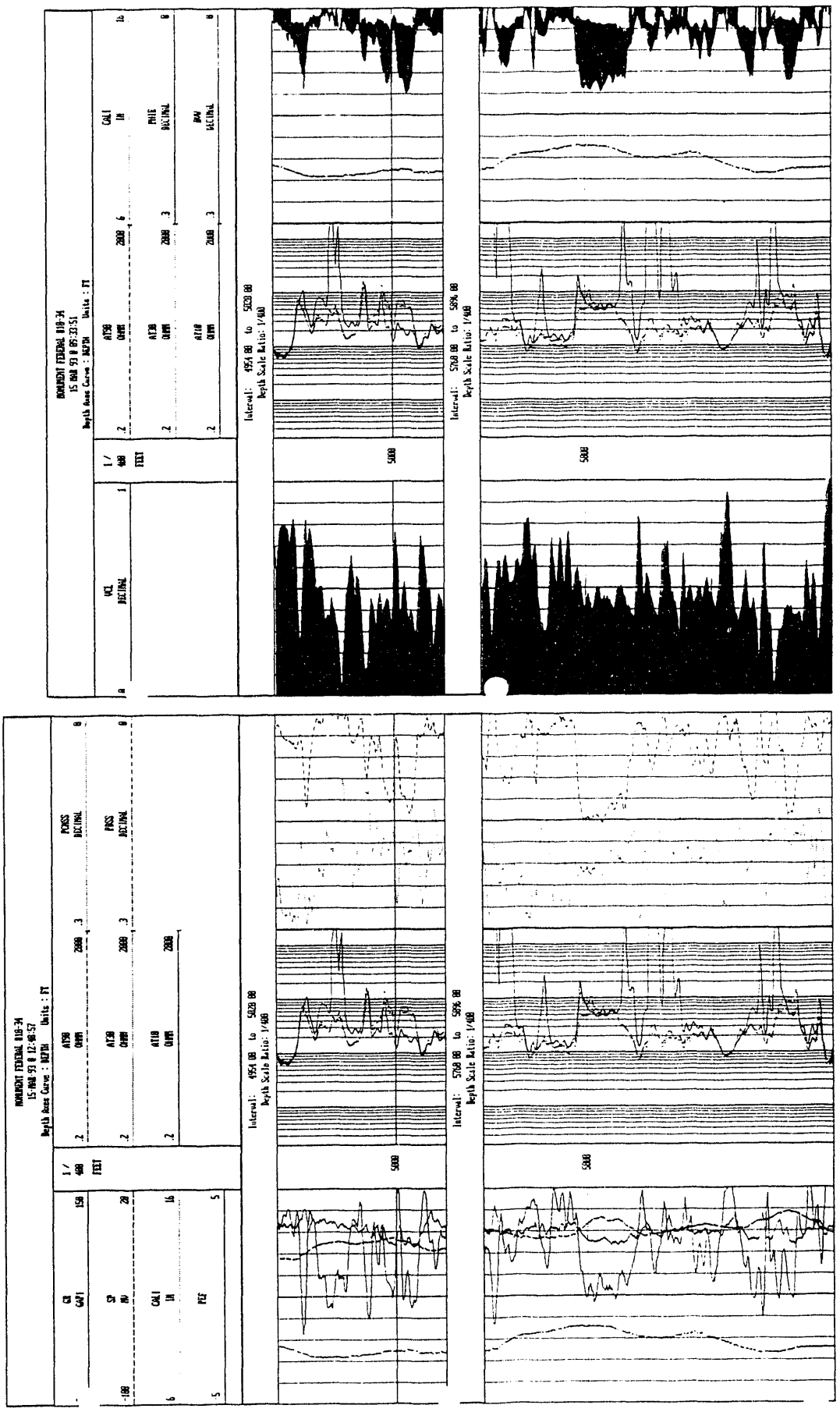

2300
2400
2300
2400

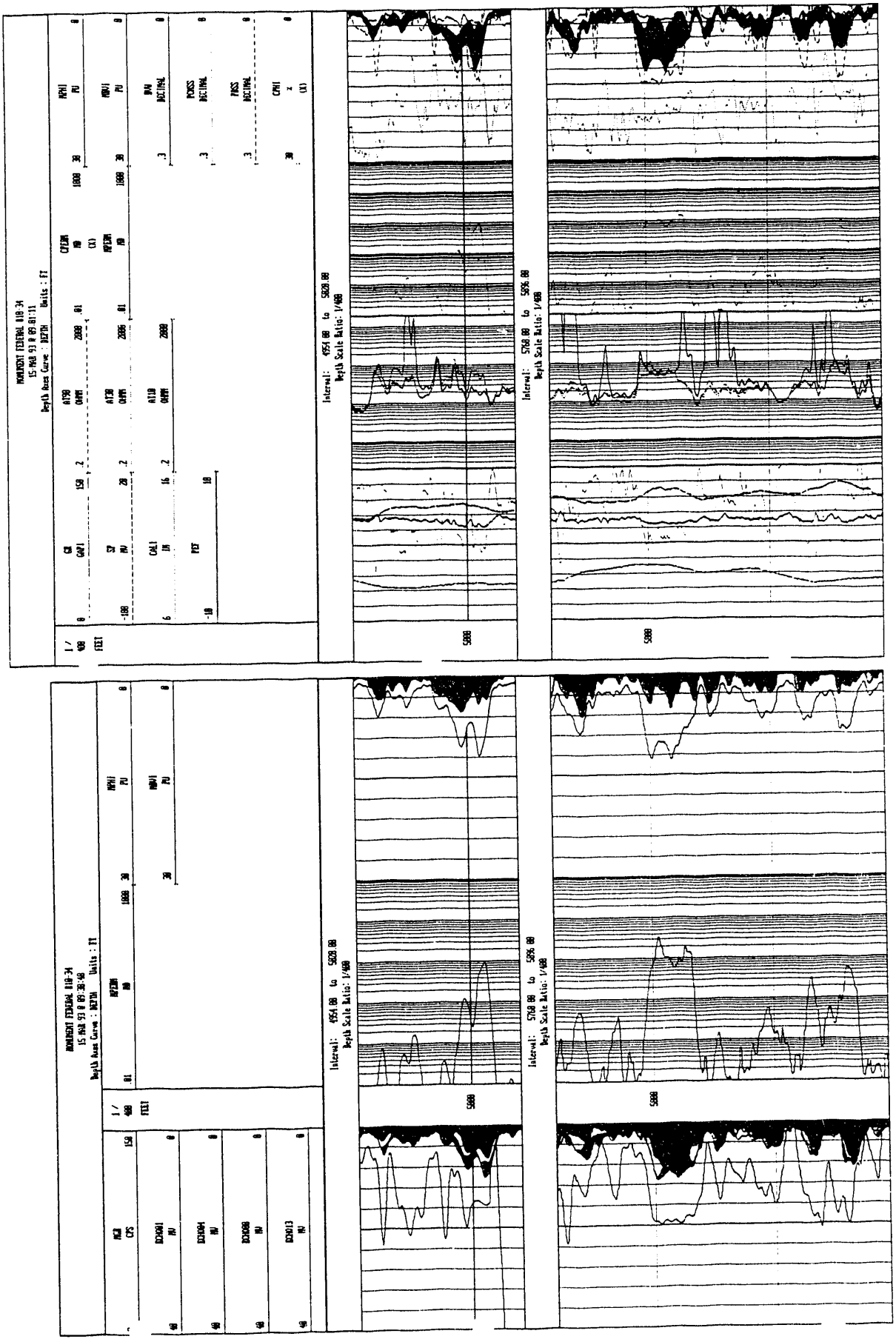


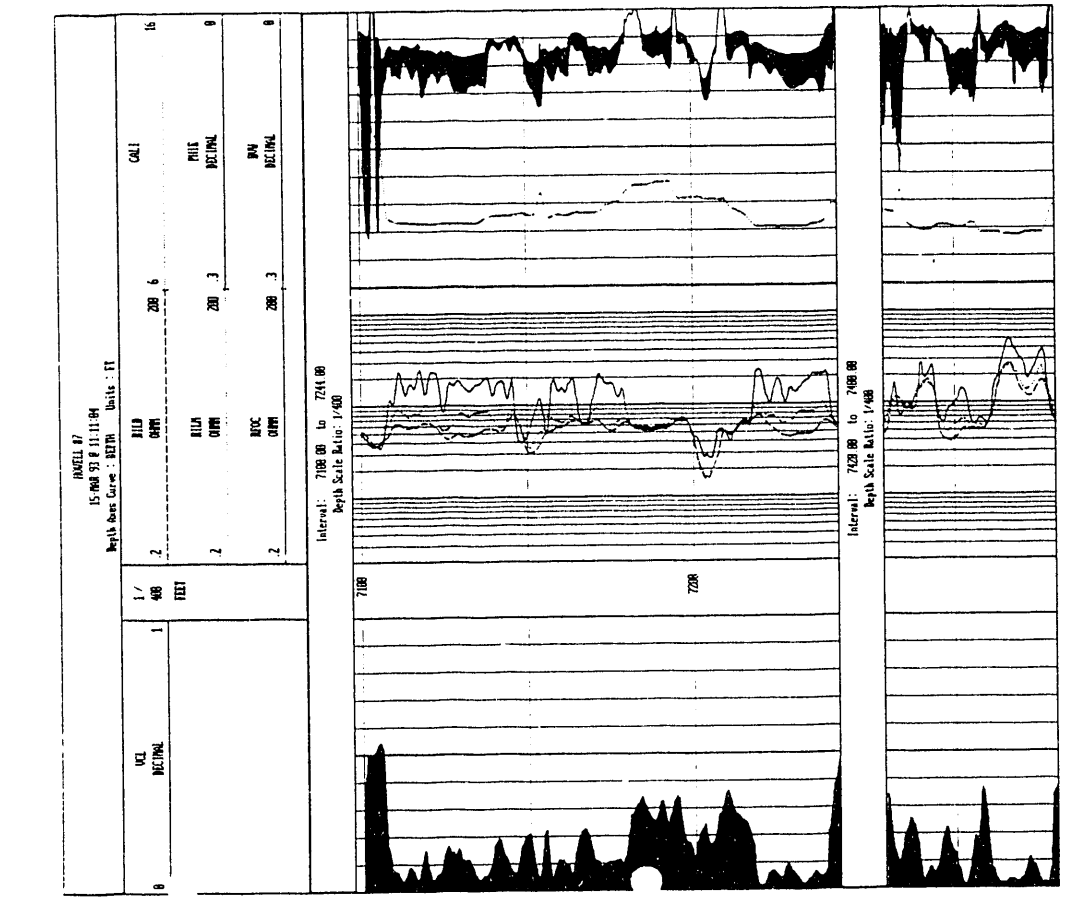
NUMAR CORPORATION

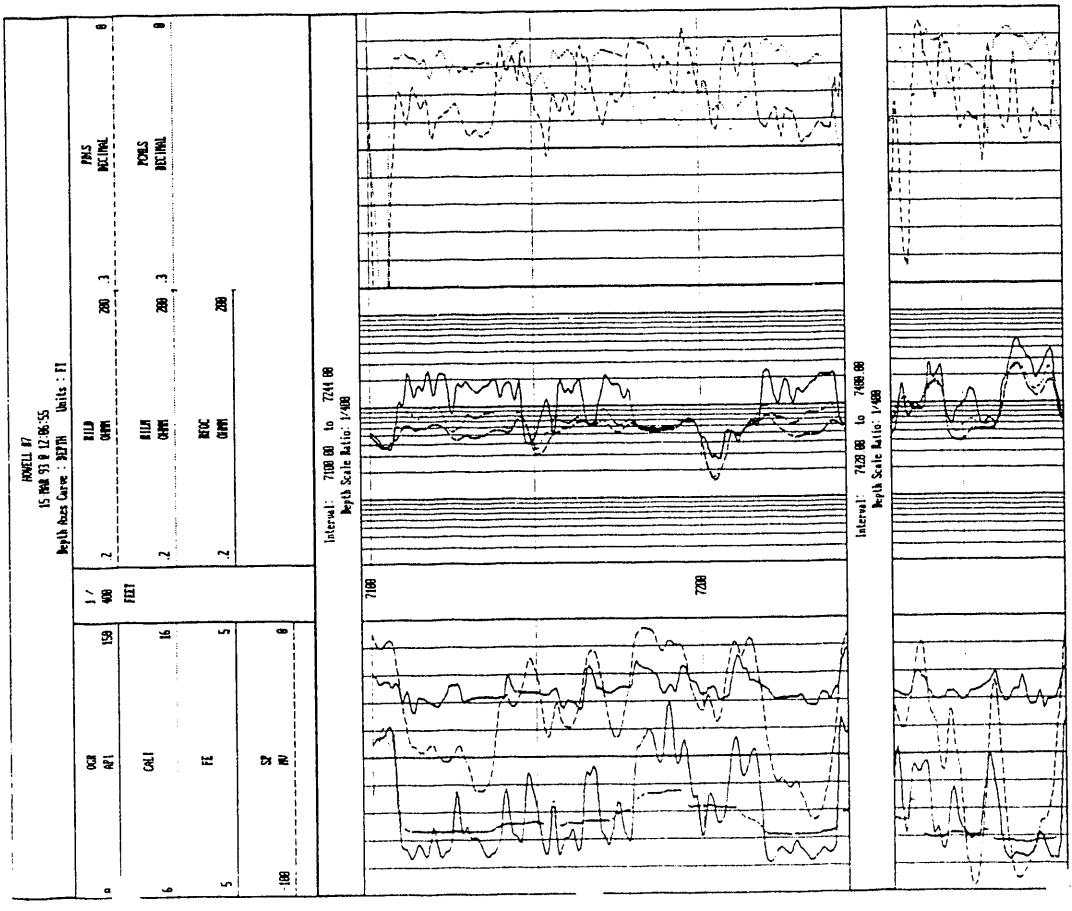
Magnetic Resonance Imaging Log Example

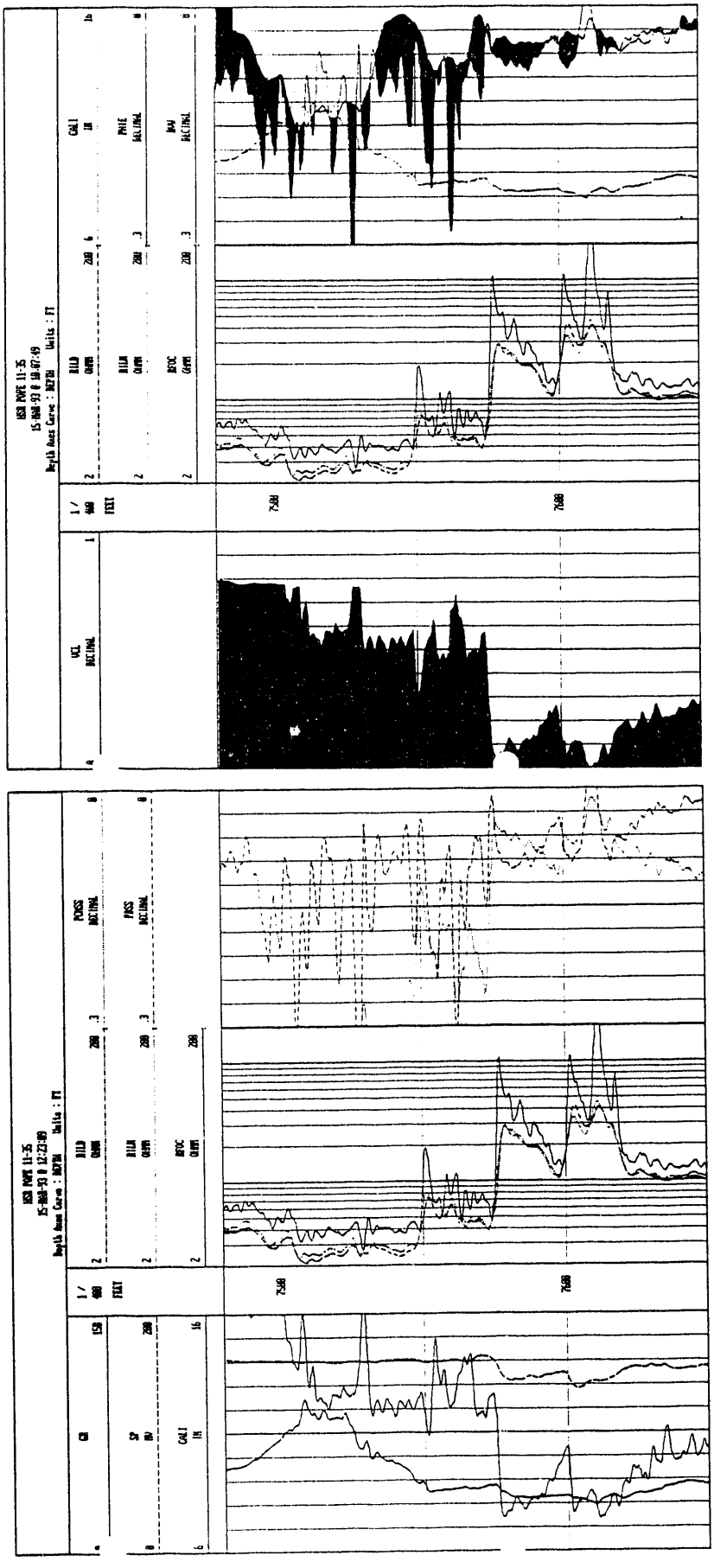
Location:	Uinta County, Utah
Application:	Shaley sand, laminated with varying reservoir quality, permeability and grain size.
Description:	This example illustrates a variety of sand packages that are thinly bedded with medium to high clay content. Depositionally, these sands are of fluvial origin. Consequently, difficulties arise in determining permeability and ultimately the potential to predict hydrocarbon production.
Evaluation:	To help predict hydrocarbon production, several techniques are utilized to determine permeability. The most common is to extract sidewalk core information and generate porosity and permeability data. Core data is also used for future water flood consideration. Secondary evaluation techniques utilize the resistivity profile as well as separation between neutron/density log curves.
Example Results:	Core data indicated the zone from 5798 - 5810, to be very poor quality rock with perms as low as .07 md. The three zones from 4996 - 5010, 5798 - 5810 and 5878 - 5882 were completed in stages, co-mingled and produced 130 bopd. The 5798 zone was perforated and flowed oil to the surface. Currently, this well produces better than any well in the field.

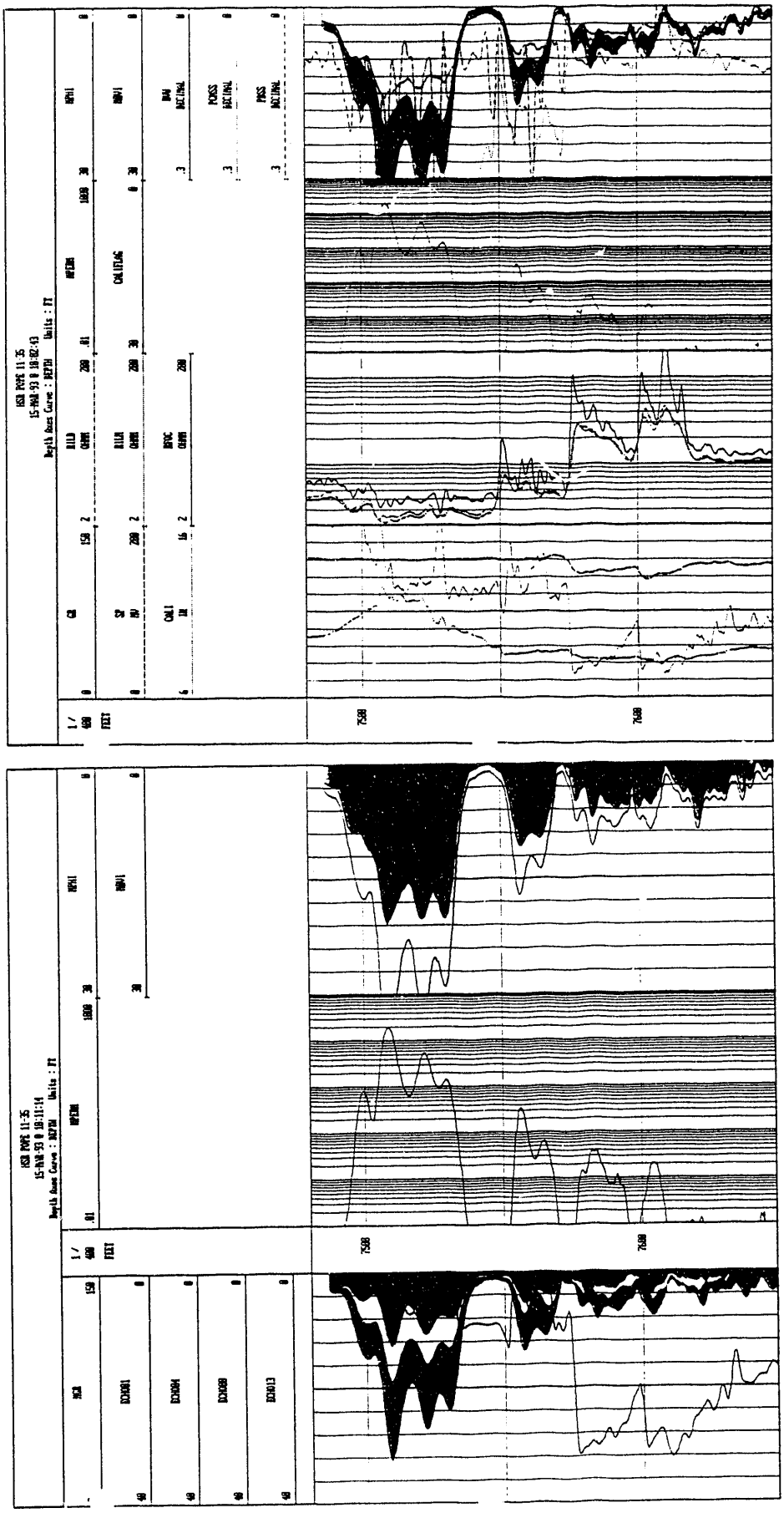





HOWELL #7
15 MAR 93 @ 11:11:04
Depth Axes Curve : DEPTH Units : FT
VCL DECIMAL
1 / 400 FEET
RILD OHMM
RILM OHMM
RXOZ OHMM
CALI
PHIE DECIMAL
PHIA DECIMAL
Interval: 7100.00 to 7244.00
Depth Scale Ratio: 1/400
Interval: 7420.00 to 7488.00
Depth Scale Ratio: 1/400


HOWELL #7
15 MAR 93 @ 12:06:55
Depth Axes Curve : DEPTH Units : FT
GCR API
CALI
FE
SZ MV
1 / 400 FEET
RILD OHMM
RILM OHMM
RXOZ OHMM
PHIS DECIMAL
PORES DECIMAL
Interval: 7100.00 to 7244.00
Depth Scale Ratio: 1/400
Interval: 7420.00 to 7488.00
Depth Scale Ratio: 1/400





NUMAR CORPORATION

Magnetic Resonance Imaging Logging (MRIL)

Location: Weld County, Colorado - Wattenberg Gas Field

Application: Grain size variation, establishing better reservoir characteristics.

Description & Evaluation:

The Wattenberg Gas Field is a very well developed and large gas field with well defined parameters located 20 miles north of Denver, Colorado. The field has produced for over 20 years. The productivity zone in this well was thought to be from 7515 - 7594 and 7600 - 7607. As you can see, RILD ranges from 20-32 ohm-m and cross plot porosity is 9%. This well is in a very marginal area (250 mcf/day) with perm expected around .01 md.

The MRIL was actually run to evaluate a lower zone in the well and an upper zone. The parameters in this zone were thought to be well known. The client was very surprised at the MRIL results. The zone had the expected parameters. However, just above the zone was an interval 7551 - 7567, which looked better. It had porosity of 14-17%, perm was .06-.35 md but RILD was only 4-6 ohm-m. There appeared to be as much gas in this interval as the one below.

According to the operator, this zone was unknown to him and the MRIL information would help him explore his reservoir more effectively.

Results: Both zones were completed together with an increase of expected gas from 250 mcf/day to 800 mcf/day.

NOTES

A New Generation of Sonic-Logging Tools and Their Applications

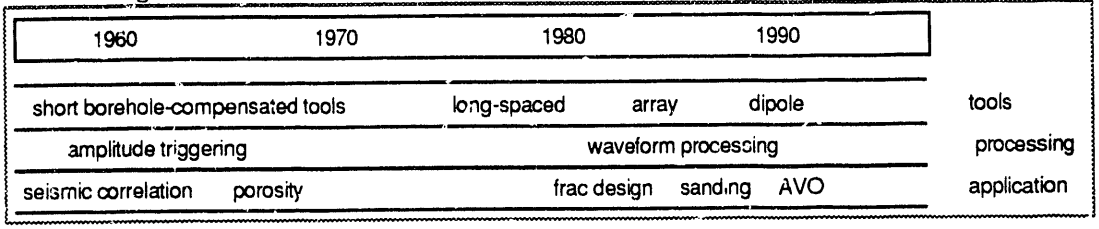
Wayne D. Pennington
Petroleum Technology Center, Marathon Oil Company
P.O. Box 269, Littleton, CO 80160
(303) 347-5727

Summary:
In recent years, sonic logging has become capable of providing high-quality compressional and shear transit times from the use of waveform processing and newly-developed "dipole" transducers. At the same time, significant advances have been made in the applications for which these new tools are run: improving hydraulic fracture design, predicting sand strength in unconsolidated formations, finding gas behind casing (or where other indicators may be ambiguous), and interpreting or modeling seismic data for direct hydrocarbon indicators.

Introduction

Sonic logging was originally devised, in the early 1950's, as a technique to correlate surface seismic data with formations encountered in wells. Since that time, the generation of synthetic seismograms for correlation has become quite routine. Sonic logging quickly became recognized as a tool for determining porosity in most formations, and then, together with other porosity indicators, as a tool for discriminating between primary (intergranular) porosity and secondary (vuggy or fracture) porosity. In recent years, sonic logging has proven useful for providing indications of rock strengths and formation stresses, and various techniques have been developed to aid in completion or stimulation design, based largely on sonic-logging results. (A recent review can be found in the paper by Paillet et al., 1992.)

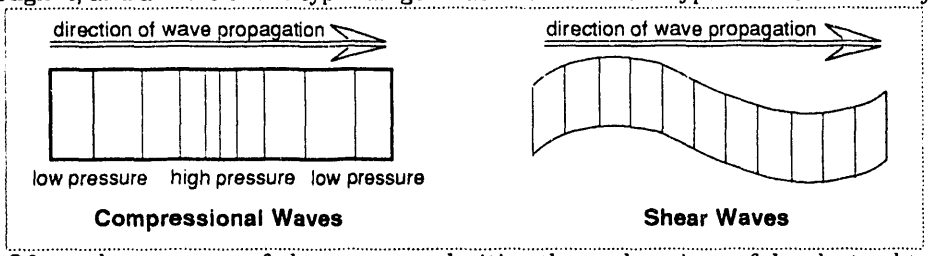
During the time that these applications for sonic data were evolving, the logging tools themselves were undergoing significant changes. Some of the changes were simple improvements in design, such as increasing the spacing between sources and receivers and decreasing the signal frequencies in order to obtain velocities from the uninvaded formation. But some very fundamental changes have taken place over the past several years, particularly in the use of waveform recording from arrays of receivers and in the implementation of a totally new type of transducer. The advent of arrays of receivers (instead of just pairs) and associated waveform processing techniques have greatly improved the quality of data and the elimination of cycle-skipping, as well as permitting the determination of shear-wave velocities in many formations. The implementation of new "dipole" transmitters and receivers, designed to obtain shear-wave velocities in virtually all formations, is revolutionizing the approach to direct-hydrocarbon-indicator evaluation in many formations and leading the way to improved formation-strength determinations.



An Important Aside: What are Compressional and Shear Waves?

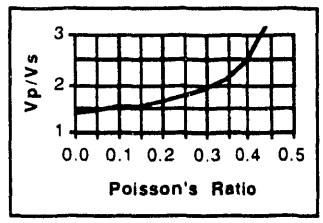
Much of the recent improvement in sonic logging makes use of shear waves in addition to compressional waves, so we need to make sure we understand what they are. We are all used to compressional waves, even if we don't already know about sonic logging, because compressional waves in the air are what we "hear" as "sound" with our ears. They consist of alternating high-pressure and low-pressure vibrations in the air, which cause our eardrums to move back and forth (the insides of our ears are maintained at a more-or-less constant pressure, and the variation of pressure outside them causes the motion). This type of sound can be transmitted easily through most solids, liquids, and gases, but its velocity will depend strongly on the material it is going through; usually, the more compact, or consolidated, the material is, the faster it is that sound, as compressional waves, will travel through it.

Shear waves are a little less intuitive, because they don't travel through air (or water), and we don't ever "hear" them. They can only travel through solids that have some rigidity, and they always travel slower than compressional waves in the same material. They do not change the pressure of the material, but make it move side-to-side, like a wave traveling along a whip. Most sources of "sound" energy in a solid material cause both compressional and shear waves to travel through it, and a wave of one type can generate waves of both types at a discontinuity or boundary.



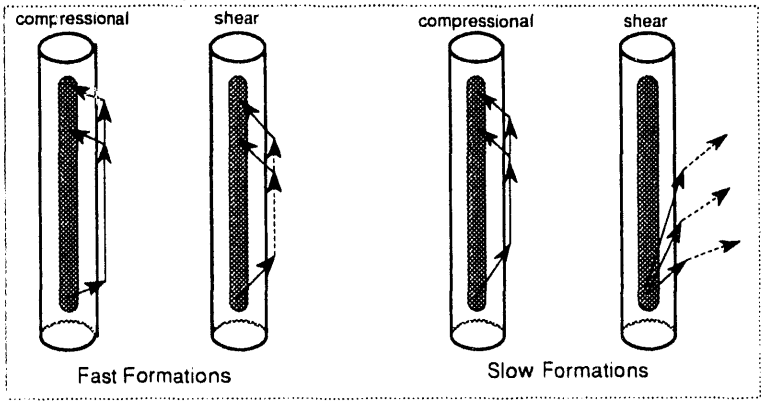
Often, the measure of shear wave velocities themselves is useful only to obtain the *ratio* of compressional-to-shear velocities (Vp/Vs). Another relationship of interest is *Poisson's ratio*, which is usually defined as the ratio of the change in the lateral size of a block of material to the change in axial size, in response to a purely axial load. It just happens that, for purely elastic materials without directionally-dependent properties, the relationship between Vp/Vs and Poisson's ratio can be expressed as follows.

$$\sigma = \frac{\left(V_P/V_S\right)^2 - 2}{2\left[\left(V_P/V_S\right)^2 - 1\right]}, \text{ or } V_P/V_S = \sqrt{\frac{1-\sigma}{.5-\sigma}}$$



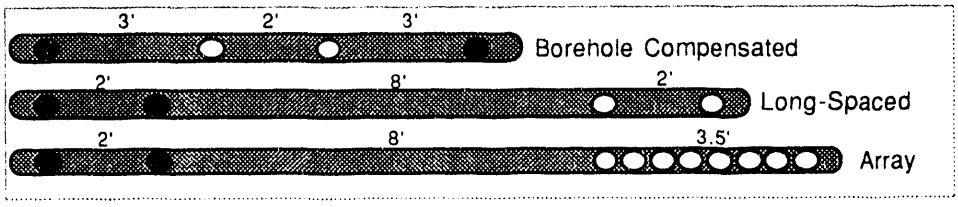
Shear waves, as well as compressional waves, are of interest to us for a couple of reasons. First, the seismic response of *purely compressional* waves from a reflecting boundary depends to large extent on the *shear*-wave contrasts across the boundary; in particular, the amplitude of the reflection as a function of offset (AVO) is controlled by the contrast in Poisson's ratio. Second, the variations of stresses in the formation, which tend to control the migration of hydraulic fractures, may be found, again, from variations in Poisson's ratio. In addition, it is often found that the shear-wave velocity correlates well with rock strength, a parameter of interest particularly in poorly-consolidated formations.

There is one more important aspect to know about shear waves: from a symmetrical compressional-wave source in a fluid-filled borehole, shear waves are created in the formation by a conversion process at the wellbore wall. In a "fast" formation, these shear waves may be refracted along the surface of the wellbore, and recorded, as refracted compressional waves, by the receivers of the sonic tool. But in a "slow" formation, where the shear velocity is *less* than the compressional velocity of the mud in the well, the shear waves are always refracted away from the well, and can never be observed by the receivers in the tool. To find shear-wave velocities in this set of conditions requires the use of the "dipole" tool discussed later in this paper.

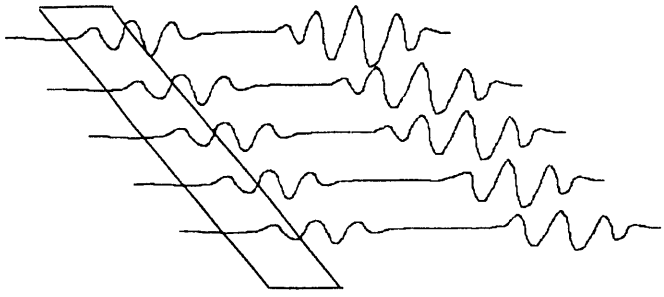


The New Tools, Part I: Arrays and Waveform Processing

The original borehole-compensated sonic tools had pairs of receivers, and only the arrival times were recorded for each receiver. The transit time of the arrival across a pair of receivers from a transmitter a few feet away uphole was averaged with that across a pair of receivers from a transmitter a similar distance downhole. This averaging compensated for borehole rugosity and tool tilt, and the inverse of the averaged transit times determined the velocity in the formation. These tools were very susceptible to cycle-skipping, particularly in gas zones, very slow shales, or hole washouts, and the results were not always reliable. (In fact, it is still commonplace to hear people speak of bad-data zones from sonic logging, as if they were a fact of life, and nothing can be done to improve the data, even though the newer tools can readily obtain very good data in most of these zones.) An intermediate improvement came from recording the waveforms from these older tools, and the adaptation of various signal-processing schemes to extract the arrivals from them. For a time, this was the only means of finding the shear-wave velocity in a formation, because the shear arrivals appear late in the waveform, and the conventional arrival-time types of tools can not detect them. In order to improve the time separation between the compressional and shear arrivals, longer tools (such as the "long-spaced" sonic) were developed, some without built-in borehole compensation. These efforts were only partially successful, however, because it was soon recognized that a single pair of receivers provides little statistical redundancy, and that lower-frequency transducers were required to ensure capture of the shear waves.



The first truly fundamental improvement in tool design was the implementation of arrays of receivers, rather than just pairs, and the subsequent waveform recording and processing to obtain very high-quality compressional velocities and (where possible) shear velocities. These "array" sonic tools also were designed with lower source frequencies and broader frequency ranges. It so happens that the geometry of a wellbore causes a lot of extraneous signal in the form of harmonic "modes" that can be very large compared with the compressional and shear waves. The shear wave, on the other hand, can be maximum amplitude at low frequencies, where some of these other modes disappear; as long as a tool is designed to include those lower frequencies, there is a very good likelihood of recognizing the shear wave properly. The effect of these other modes can also be minimized by using a computer to correlate waveforms across several receivers: the shear wave will correlate nicely, because it does not change character quickly with distance, whereas the troublesome pseudo-Rayleigh modes, in particular, change character from receiver to receiver, and will not correlate well. The use of computer correlation techniques also tends to provide extremely good compressional velocities, even in typical "bad-data" zones, because the correlation technique is very robust whether the signal is large or small, while the conventional tools required a certain signal level to trigger the timing of the arrival.



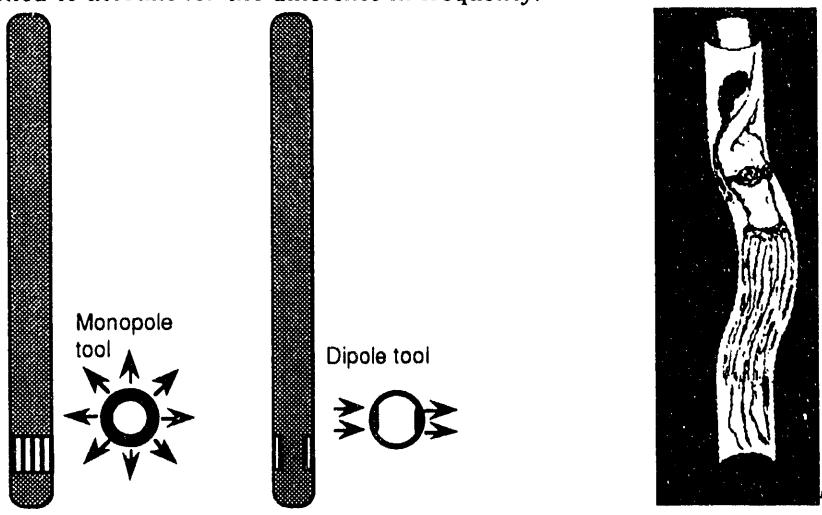
Correlation across waveforms

With the use of array tools and computer processing of waveforms, it is very unusual to encounter a no-data zone for compressional velocities these days. Usually, whenever the data do appear to be poor quality, the contractor can reprocess a section of the log using different parameters, and find good correlations. The shear velocities are generally less well-constrained than the compressional velocities, and they will be completely absent whenever the shear velocity falls below (or near) the compressional velocity of the mud in the wellbore. All the contractors can provide some sort of quality indicators for both the compressional and shear velocities on the logs, if you ask for them to be displayed. Array sonic tools can often be run successfully through one or more strings of casing, although the quality of the results will depend strongly on the quality of the cement bond.

The New Tools, Part II: Dipole Tools for Shear Velocities

In 1967, a conceptual breakthrough was made in sonic logging, but it took roughly two decades before it found its way into commercial use. The original tool for measuring shear-wave velocities in slow formations was called the "Hula" log, because of the strong resemblance of the motion of the transmitter to the motion of the hips of a hula dancer (White, 1967). In fact, the original tool was designed with a variety of motions, similar to the variety of a true hula dancer, but we will only concentrate on the motion put into use by tools today, which is a side-to-side movement. The conventional sonic tools, including the array devices, all use transmitters that expand outward equally in all directions; mathematically, this is referred to as a "monopole" source. The hula log uses a source that moves both sides of the tool in one direction, say, to the "left." Although this causes a compressional wave to go out in both the "right" and "left" directions,

the wave going to the left is a pressure increase, while the wave to the right is a pressure decrease (mathematically described as a "dipole"). The net effect, however, is one that causes the borehole to move slightly to the "left." If we look up or down the borehole, this deflection looks just like a shear wave centered on the borehole and traveling along it! The only requirement for this to be true is that the wavelengths of the waves must be long compared with the distance between the tool and the wellbore wall (or between the hips of the dancer and the wellbore wall). It turns out that this means the tool must be designed with fairly low frequencies (about one kHz), or corrections must be applied to account for the difference in frequency.



The "Hula" log concept

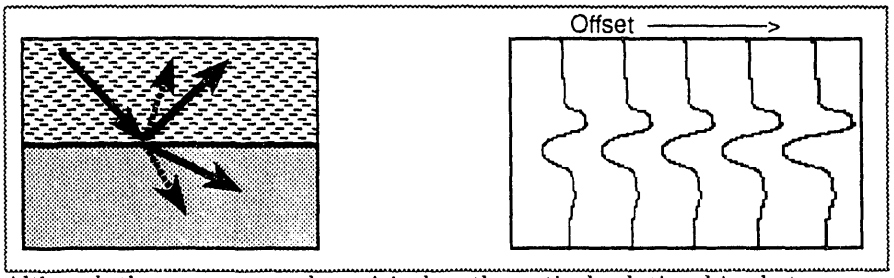
The major contractors all have dipole tools commercially available at this time. They have all taken slightly different approaches to solving some of the grittier technical or engineering aspects of the tool design, and they all have their strengths and weaknesses. Because these tools are still so new, we sometimes find "surprises" in the results, and modifications to the tools are often being made. In general, however, if the well is reasonably in gauge, and the hole is not extremely large, reliable shear velocities can be obtained from extremely slow formations. There are also some smaller wireline companies that have specific dipole or quadrupole designs that may provide improved results in certain environments (the quadrupole is another variation on the original hula log).

Seismic Correlation: Amplitude-versus-Offset

One of the more intriguing uses of the new sonic data comes in seismic correlation for identifying direct hydrocarbon indicators. This can take either of two forms: the conventional "bright-spot" analysis, where low-density fluids, particularly gas, show up on seismic sections as large-amplitude anomalies; and the variation in amplitude of seismic reflections as a function of offset (AVO). We will first discuss the AVO case.

When a seismic wave is reflected from a bed boundary, the "normal-incidence" reflection (the vertical reflection from horizontal beds) has a certain amplitude; that amplitude is determined by the difference in acoustic impedance (velocity times density) between the two layers. Of course, seismic reflection data is acquired over a range of reflection angles, corresponding to a range of distances between sources and receivers on the surface; the seismograms obtained over these "offsets" are typically stretched and shifted according to a model of underground velocities, and

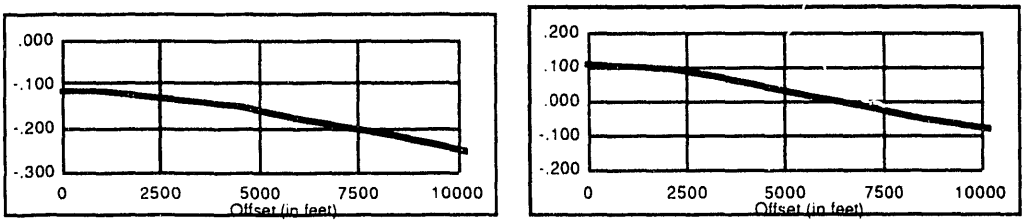
then summed to eliminate multiple reflections, surface waves, and other "noise" and to enhance the primary reflections. But, it turns out that the variations in character of the reflections that are being summed are of interest in themselves, because the changes in their amplitude as the offset increases tells us more about the nature of the reflecting bed boundary than just the variation in impedance. It tells us about the variation in Poisson's ratio across the bed boundary.



Although there are several empirical or theoretical relationships between rock type, fluid type, and Poisson's ratio, the best way to calibrate the seismic behavior is to measure the actual Poisson's ratio with sonic logs. Because this requires both compressional and shear velocities, it means we must run either an array tool or a dipole tool in fast formations, and we must run a dipole tool in slow formations.

For a given rock type, say a porous sandstone, the Poisson's ratio may depend strongly on the fluid present in the pores. It turns out that the fluid compressibility affects the compressional wave velocity quite a bit, but has no significant effect on the shear velocity. Of course, the greater the porosity, or the less well-cemented the rock is, the greater effect that the fluid content will have on the velocity. Other changes in the rock, such as a change in porosity, will also affect the compressional wave velocity, but generally will also affect the shear wave velocity a comparable amount, and the use of Vp/Vs ratios, or Poisson's ratios, tends to minimize this effect.

"Classical" AVO behavior has come to mean an increase in amplitude with offset, for a negative zero-offset reflection coefficient, as an indicator of gas. This is simply the case of a Gulf of Mexico "bright spot" and its AVO character, and is only representative of a certain set of conditions in certain parts of the Gulf. It is definitely not the only diagnostic of gas or oil that AVO behavior can indicate. For instance, if the overlying shale is *less* dense than the target sand, a change in fluid content from water to gas will result in an amplitude *decrease* with offset.



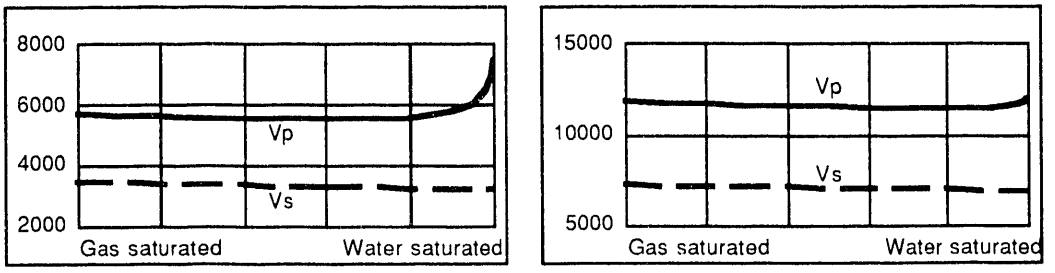
Judicious use of Poisson's ratio information, calibrated as best possible by sonic logging, can greatly enhance the ability of seismic data to differentiate pay and non-pay zones, particularly in porous sandstones associated with gas or a light (high GOR) oil. Indiscriminate use of published relationships between Poisson's ratio and rock types can easily lead to disappointments, however, because clay content and other variables can lead to extremely large variations in velocities and velocity ratios.

"Bright-spot" Analysis and Fluid-Substitution Models:

The classical model of a bright spot is one in which a dense, fast shale overlies a less dense, slower water sand — the sand is even lower density and even slower (to compressional waves) when it is at least partially saturated with gas, giving rise to a greater-amplitude reflection for the gas sand than for the water sand. If we know the densities and velocities of the gas-saturated sand and the water-saturated sand, we can predict the presence of the bright spot. But if we don't already know the various velocities (the densities are easy to figure out), we must rely on some sort of model to predict the velocity at one saturation based on the velocity at another saturation.

It turns out that several models for the sonic behavior of rocks under differing saturation conditions exist in the literature. The most popular model is the Gassmann (1951) model, which can be used with only a minimum of math, and has the advantage of being intuitively pleasing as well. In most implementations of the model, we assume we know the elastic properties of the various grains in the rock matrix, the properties of the fluid, the compressional velocity of the bulk rock (filled with a fluid), and some additional property of the rock, usually the Poisson's ratio of the rock saturated with a light gas (or under a vacuum). There are many cases in the literature where this last parameter, often called the dry-rock Poisson's ratio, is assumed to be known in general, and, if so, the rock's compressional and shear velocities can be predicted under any saturation with any fluid. But there are also many cases in the literature, and doubtless many more unpublished cases, where the model failed to accurately predict the true behavior of the rock. I think the problem lies with our inability to accurately account for the effect of clays on the rock properties at seismic (or sonic-logging) wavelengths and frequencies. At this point in time, the best predictions for rock compressional and shear velocities under various saturations seem to come from using the Gassmann model, but calibrating the dry-rock properties through use of the additional input provided by shear velocities from sonic logging, under whatever saturation conditions are present at the time of logging.

Again, the classical bright-spot behavior was established under certain conditions in the Gulf of Mexico, but an increase in amplitude with gas saturation is not necessarily the rule. The example used above to demonstrate a decrease in AVO also demonstrates a decrease in zero-offset reflection amplitudes with gas saturation. In addition, not all rocks can be expected to exhibit significant velocity or density changes with saturation changes; in particular, rocks that are low-porosity or extremely well-cemented will have very little change in velocity due to differences in fluid content.



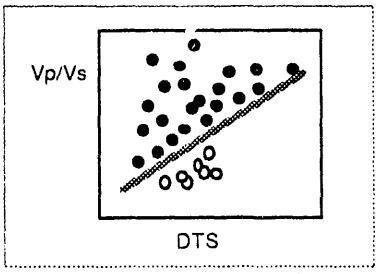
Sonic Logging for Indications of Hydrocarbon Zones

A good logging suite usually contains adequate indications of gas or liquid hydrocarbons, such as resistivity logs or neutron-density logging suites. But sometimes these indicators are insufficient, such as in low-resistivity pays with poor density logs due to washouts; often these logs

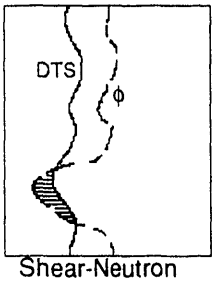
are absent, as in old wells where we may now suspect the presence of gas behind casing. In these cases, the combination of compressional and shear velocities, which may often be obtained through casing with the use of the newer tools, may prove useful in finding gas or light oil in the formation. The basic principle is the same as that just described for the bright-spot analysis: the compressibility of the fluid in the rocks will strongly affect the compressional velocity and the velocity ratios, but not the shear velocity. There are two straightforward ways of implementing these observations. The first involves crossplotting the shear transit time (inverse of the velocity) against the velocity ratio, and the second involves comparing a neutron porosity value with the shear velocity or transit time.

The crossplot of shear transit time with velocity ratio was described by Williams (1991), as an "Acoustic Log Hydrocarbon Indicator." It makes use of the observation that, although the velocity ratio can be affected by changes in porosity, clay content, and fluid content, the shear velocity is not significantly affected by fluid content. Thus, there tends to be a trend for minimum Vp/Vs ratios as a function of DTS (accounting for variations in clay content and porosity) for water-saturated rocks within a certain study area; any Vp/Vs ratios that fall below that minimum trend are likely to be gas-saturated or light hydrocarbon-saturated rocks.

The shear velocity is very sensitive to porosity within a given rock type, but, again is very insensitive to fluid content; on the other hand, the neutron porosity log is highly sensitive to both porosity and to gas saturation. A comparison of the DTS (or Vs) log with the neutron porosity log, either in a crossplot form or in a pair of log traces (much like the usual neutron-density log display) can often be used to readily identify gas zones by their departure from the trend present in the oil or water zones.



Acoustic Log Hydrocarbon Indicator



Shear-Neutron comparison

Hydraulic Fracture Design Aided by Sonic Logging

There are many parameters that go into the design of a successful hydraulic fracture; one of these is the stress in the target bed, as well as the stress in neighboring beds. The lateral or horizontal stresses are those that act against the opening of a fracture, and an increase in lateral stresses away from the target bed will tend to confine the fracture to that bed, whereas a decrease in lateral stresses away from the target bed may result in unconfined vertical growth of the fracture. It is therefore very important to know the variations in lateral stress vertically in the area of the well to be fractured. Again, Poisson's ratio turns out to be the key to this variation in lateral stress.

In many sedimentary environments, the maximum stress is the overburden stress caused simply by the rocks above the bed of interest (this is not necessarily true in tectonically-complex environments, nor at extremely shallow depths). The lateral stresses are often assumed to result simply from the burying of the formation beneath the overburden, and confining it not to expand

out sideways. Given that this is the case, the lateral stresses can be predicted from overburden weight by a simple relationship involving Poisson's ratio (PR):

$$Stress_{lateral} = \frac{PR}{1 - PR} \times Stress_{overburden}$$

Of course, Poisson's ratio is best determined from sonic logging. This relationship generally needs to be calibrated locally and corrected for neglected effects of tectonic stresses, poroelastic effects, and other factors (Ahmed et al., 1988). Shales generally have higher Poisson's ratios than sandstones or carbonate rocks, and their lateral stresses are therefore also higher; this is fortunate, because it generally means that hydraulic fractures will stay confined to the target beds and not propagate easily into the overlying shales. Although the sands or carbonates that are typically stimulated by fracturing may be fast formations, and therefore readily logged for shear velocities by array tools, the surrounding shales may be slow formations, and require the use of a dipole tool for obtaining shear velocities.

Prediction of Sanding Potential

In unconsolidated or poorly-consolidated formations, the rate of production may often be limited by the tendency of the well to flow sand, thereby causing plugging of the well and damage to surface equipment. This sand production may be eliminated by use of certain completion techniques, such as gravel-packing, but these are expensive. It is therefore of interest to determine the maximum rate a well may flow before producing sand, in order to study the economic benefits of alternate completion styles and to better plan the management of the reservoir.

Failure of sand around a wellbore is caused by the stresses concentrated there exceeding the strength of the sand. The stresses may be calculated by a technique similar to that described in the preceding section, but, because precise values are critical in predicting sanding potential, they always should be calibrated at some point in the well, preferably through some sort of fracturing test. In addition, the strengths of the rock should be calibrated by laboratory testing of core samples (Edwards et al., 1988), and the sonic and other logs can be used to interpolate strengths between calibration points. The formations that are typically evaluated for sanding potential are usually slow formations, and acquisition of shear velocities by dipole tools is a prerequisite.

Other Potential Uses of the New Sonic Tools

There are many uses for the newer generations of sonic tools, and perhaps the next generation, that appear to have great potential. The most promising of these include natural-fracture characterization and permeability estimation. To some extent, these are available from contractors at the present time, but complex interaction of various wellbore effects (bed boundaries, borehole rugosity, mudcake variations) often tends to obscure the true trends of the data. It can be readily shown that the amplitude and velocity of a certain low-frequency monopole mode, called the "Stoneley" wave (equivalent to a "tube" wave at the low-frequency limit) are very sensitive to coupling between the wellbore and the fluid in the formation. If the formation permeability increases, the Stoneley amplitude and velocity should both decrease; likewise, if an open fracture is encountered intersecting the wellbore, the Stoneley wave should be similarly affected, and an additional, reflected Stoneley wave should be sent back toward the source. The use of continuous Stoneley wave analysis in a well log should be able to provide continuous logs of permeability, whether that permeability is from open fractures or from matrix properties, and selective completion could easily optimize production from the well as a result.

At the present time, however, it is often difficult to differentiate between reflected Stoneley waves from bed boundaries and from open fractures. In addition, various other effects often tend to mask the true permeability variations that we seek, although a number of published studies appear to have been successful (e. g., Burns, 1991).

Conclusions

The latest improvements in sonic logging include the use of arrays of receivers and digital processing of waveforms to extract extremely high-quality velocities and the use of dipole transducers to obtain shear-wave velocities even in slow formations. The applications to which these data are routinely put include seismic calibration for both AVO and bright-spot analysis, detection of gas behind casing or in other ambiguous situations, improvement of hydraulic fracture design, and prediction of sanding potential. There are other potential applications, only partially realized today, which include permeability estimation and natural-fracture characterization.

References

Ahmed, U., Markley, M.E., Crary, S.F., and Liu, O.Y., 1988, Enhanced in-situ stress profiling using microfrac, core, and sonic logging data, SPE-19004, *in* Rocky Mountain Region/Low Permeability Reservoirs Symposium Proceedings: Society of Petroleum Engineers, p. 70-83.

Burns, D.R., 1991, Prediction of relative and absolute variations of in-situ permeability from full-waveform acoustic logs: *The LogAnalyst*, v. 32, no. 3, p.246-255.

Edwards, D., Jøranson, H., and Spurlin, J., 1988, Field normalization of formation mechanical properties for use in sand control management, paper Y, *in* 29th Annual Logging Symposium Transactions: Society of Professional Well Log Analysts, 19 pp.

Gassmann, F., 1951, Elastic waves through a packing of spheres, *Geophysics*, v. 16, p. 673-685.

Paillet, F.L., Cheng, C.H., and Pennington, W.D., 1992, Acoustic-waveform logging – advances in theory and application, *The Log Analyst*, v. 33, no. 3, p. 239 258.

White, J.E., 1967, The Hula log – a proposed acoustic tool, paper I, *in* 8th Annual Logging Symposium Transactions: Society of Professional Well Log Analysts, 27 pp.

Williams, D.M., 1990, The acoustic log hydrocarbon indicator, paper W, *in* 31st Annual Logging Symposium Transactions: Society of Professional Well Log Analysts, 22 pp.

EVALUATION TECHNIQUES AND APPLICATIONS OF SUBSURFACE IMAGE LOGS

David R. Thorn
Schlumberger Well Services
21250 E. 31st Circle
Aurora, Colorado 80011

The interpretation of images recorded in wellbores is, in many cases, an extension of previous techniques developed for the interpretation of dipmeter logs and core analysis. Tadpole or "Strike and Dip" presentations provide a useful means of summarizing the orientation of events observed in images. The accuracy and resolution of identifying such events has been increased dramatically over previous techniques with the use of wellbore images. New methods, such as fracture aperture calculation and textural analysis, add to the information that can be learned from modern image logs.

Image interpretation generally starts with a two dimensional plot of the wellbore surface presented on an azimuthal plot with depth measured along one axis. The surface of the wellbore is then displayed along the second axis with some reference as the origin such as the north side of the hole for vertical wells, or the top of the hole for horizontal wells. The color, contrast, or intensity of the image may represent any additional measurement such as acoustic attenuation, travel time, or electrical conductivity. This type presentation permits the inspection of all areas the borehole with a single log type format.

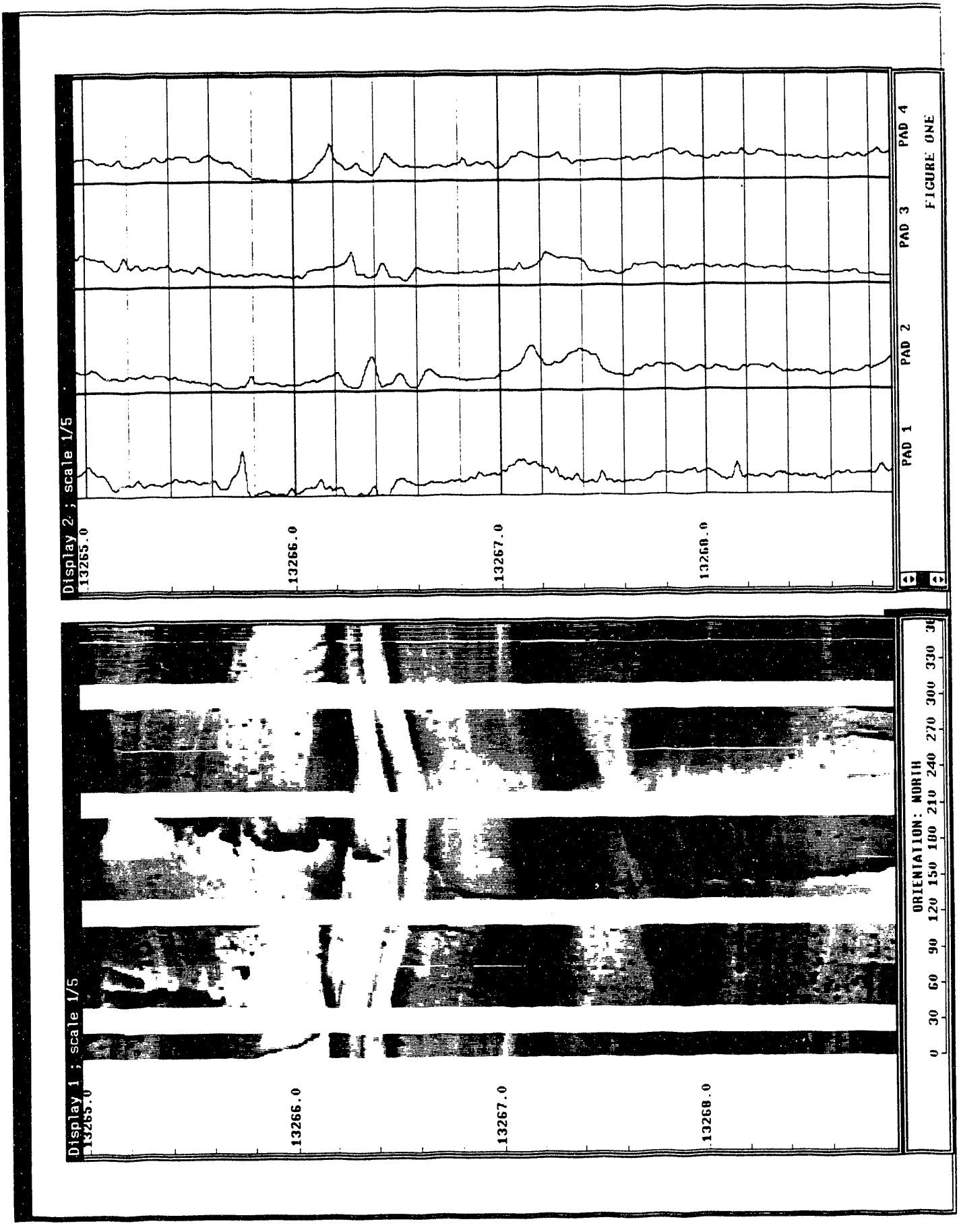
The azimuthal presentation also makes the identification of planar and non planar events straight forward. The intersection of a flat surface with a cylindrical borehole results in a sine wave trace on the azimuthal presentation. The amplitude of the sine wave represents the apparent dip of the event and the trough of the sine wave represents the dip direction. A conventional dipmeter tadpole presentation can be used to summarize the orientation of planar events identified on images. Non planar events may be identified by a tadpole presentation but a more exact description may be necessary for such events.

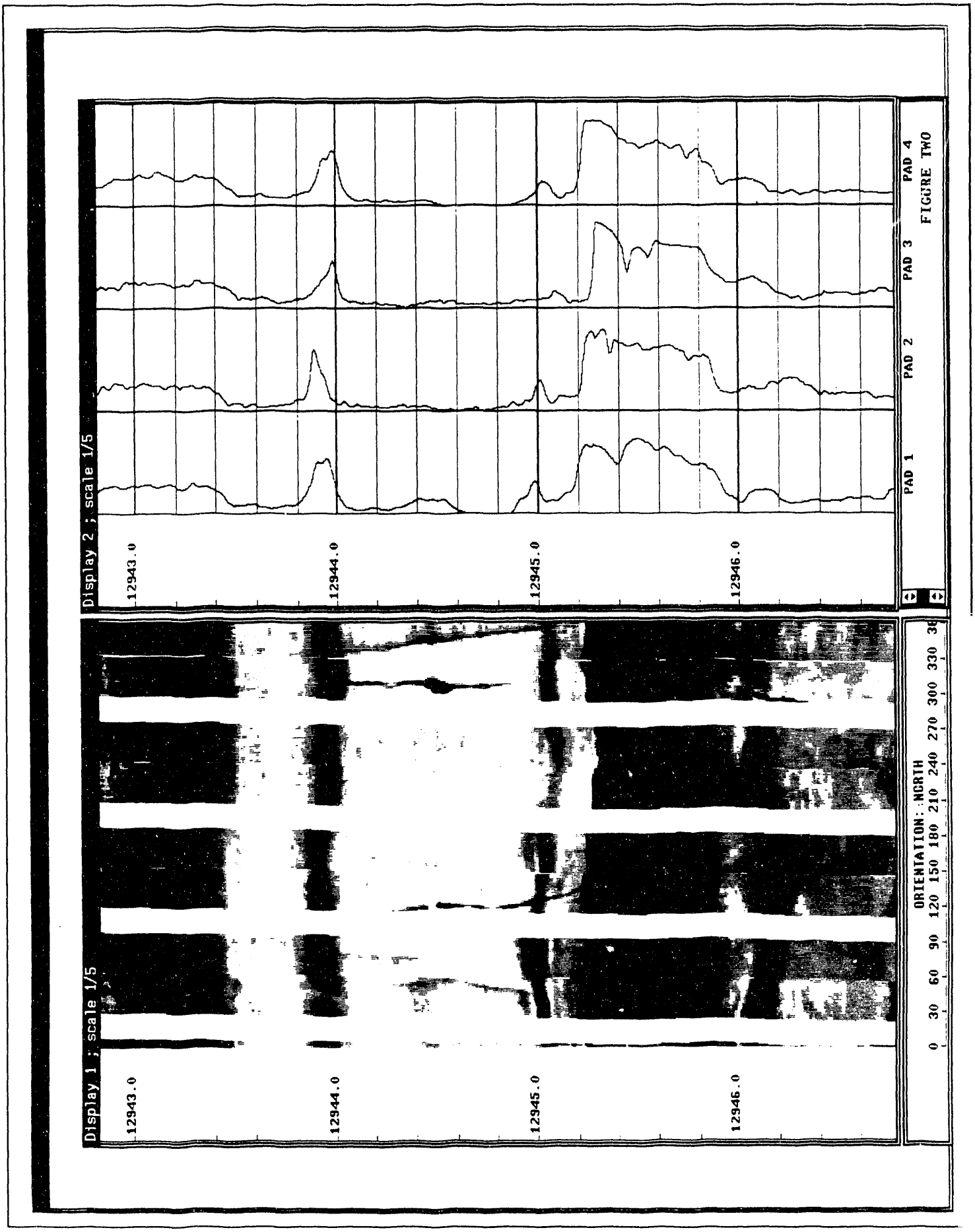
Events such as microfaults, erosional surfaces, fractures and textural changes may be recognized from images. Descriptions of these events, much like descriptions of conventional core observations, convey much of the information learned from these features. Quantitative observations such as the aperture of fractures or the area and conductivity of vuggy porosity add to the interpretation of images. Shale distribution can be characterized by its appearance as laminar, dispersed, or bioturbated.

The analysis of fractures from wellbore images can document not only the presence of fracturing but also information about the orientation, aperture, and spacing of the fractures. The response of an electrical imaging device to an open mud filled fracture is dependent on the aperture of the fractures intersection with the wellbore. This allows an accurate and quantitative evaluation of the width of the fracture and greatly improves the understanding of permeability.

Display 1 ; scale 1/5
13265.0
13266.0
13267.0
13268.0
ORIENTATION: NORTH
0 30 60 90 120 150 180 210 240 270 300 330 360
zoom x100 [130]
elevation [11]
view angle (deg): 80
display : straight
Top depth : 13265.46 Ft
Bottom depth: 13266.98 Ft
N
S
E
W

FIGURE ONE


Display 2 ; scale 1/5
13265.0
13266.0
13267.0
13268.0
PAD 1
PAD 2
PAD 3
PAD 4
FIGURE ONE
Display 1 ; scale 1/5
13265.0
13266.0
13267.0
13268.0
ORIENTATION: NORTH
0 30 60 90 120 150 180 210 240 270 300 330 360


Display 1 ; scale 1/5
12943.0
12944.0
12945.0
12946.0
ORIENTATION: NORTH
0 30 60 90 120 150 180 210 240 270 300 330 36
Display 2 ; scale 1/5
12943.0
12944.0
12945.0
12946.0
PAD 1
PAD 2
PAD 3
PAD 4
FIGURE TWO


Display 1 ; scale 1/5.
13270.0
13271.0
13272.0
13273.0
0 30 60 90 120 150 180 210 240 270 300 330 36
ORIENTATION: NORTH
1/5 DEPTH AND HORIZONTAL SCALE
LOG DEPTH 13272.3 = CORE DEPTH 13270.0
FIGURE THREE
elevation [14]
view angle (deg): 335
display : straight
Top depth : 13271.21 Ft
Bottom depth: 13275.74 Ft
Help
Quit
N
E
S
W

Display 1 ; scale 1/5
13262.0
13263.0
13264.0
13265.0
ORIENTATION: NORTH
0 30 60 90 120 150 180 210 240 270 300 330 36
N
E
S
W

FIGURE FOUR

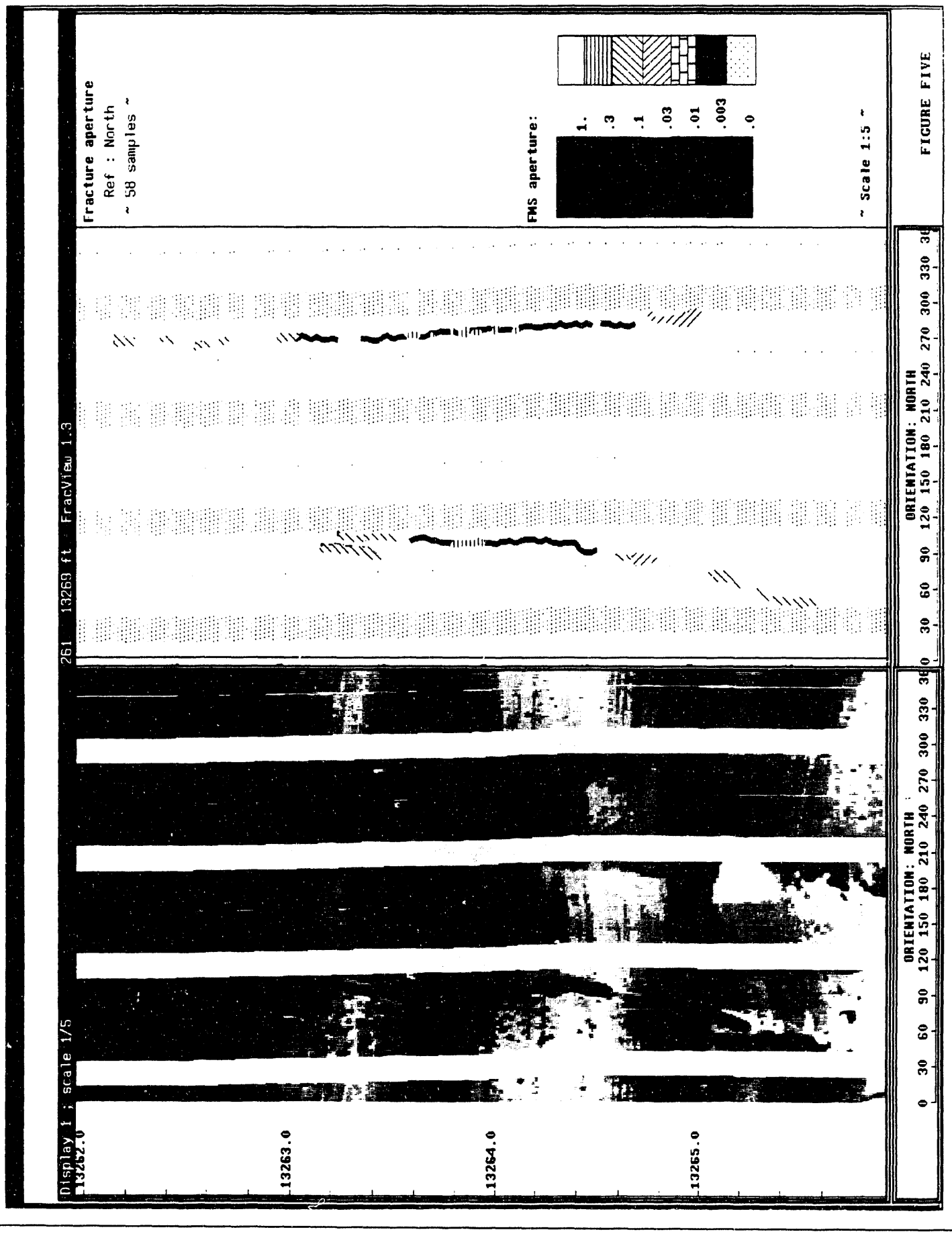

Display 1 ; scale 1/5
261 13269 ft FracView 1.3
Fracture aperture
Ref : North
~ 58 samples ~
FMS aperture:
1.
.3
.1
.03
.01
.003
.0
~ Scale 1:5 ~
13262.0
13263.0
13264.0
13265.0
ORIENTATION: NORTH
0 30 60 90 120 150 180 210 240 270 300 330 360
ORIENTATION: NORTH
0 30 60 90 120 150 180 210 240 270 300 330 360

FIGURE FIVE

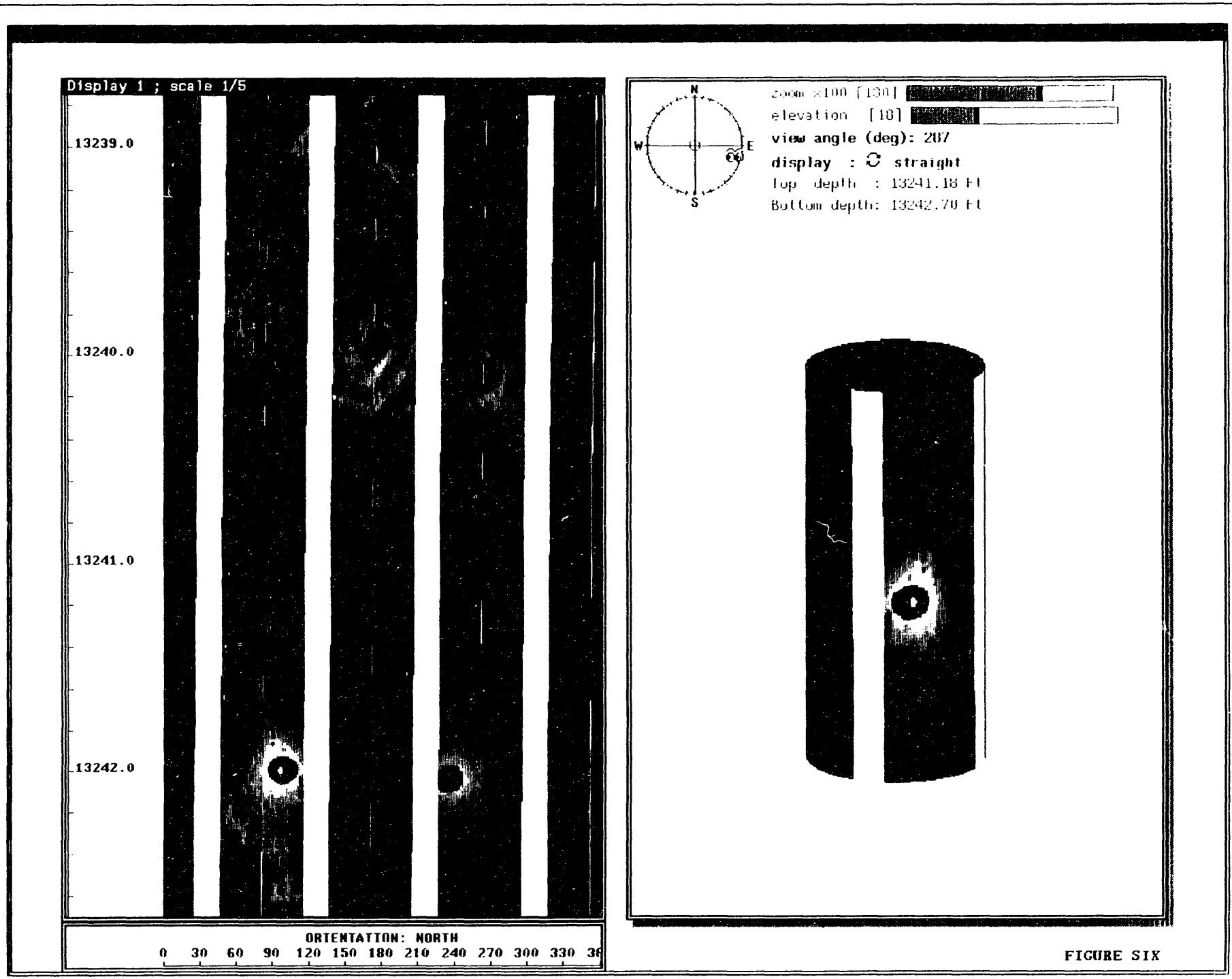
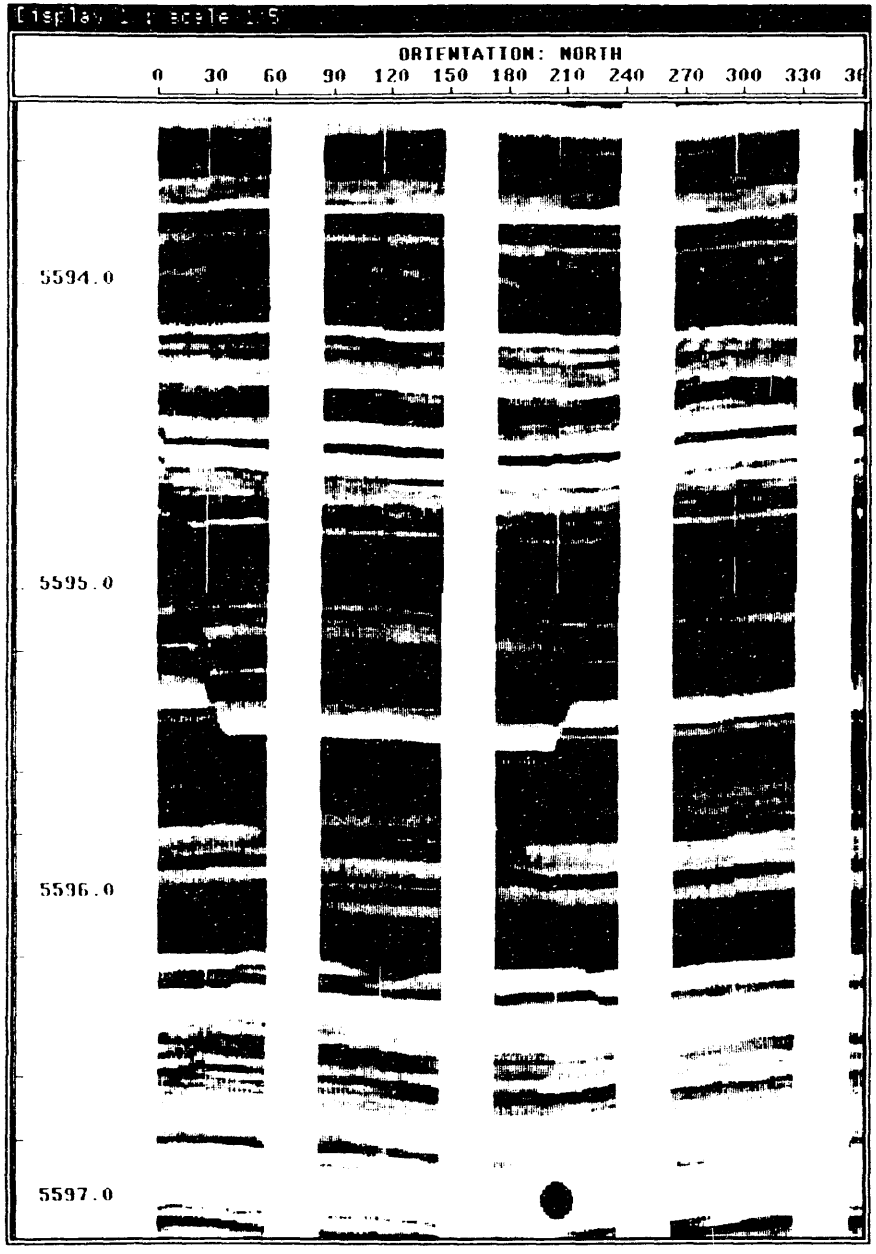

Display 1 ; scale 1/5
13239.0
13240.0
13241.0
13242.0
ORIENTATION: NORTH
0 30 60 90 120 150 180 210 240 270 300 330 36
N
W
E
S
elevation [10]
view angle (deg): 207
display : straight
Top depth : 13241.18 Ft
Bottom depth: 13242.70 Ft

FIGURE SIX



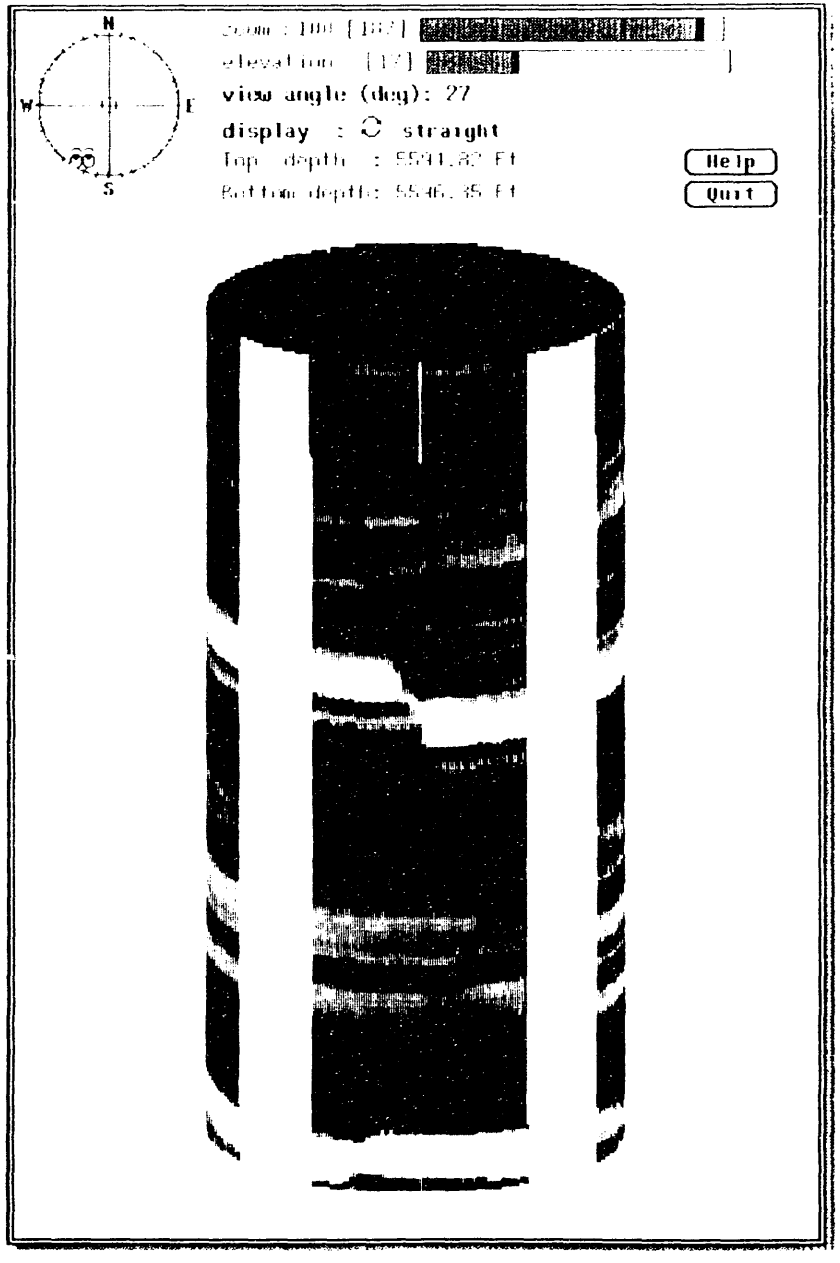


FIGURE SEVEN

DATE
FILMED
9/14/93
END