DOE/BC-02/03/SP

CLASS PROJECT SUMMARY SHEETS

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U.S. DEPARTMENT OF ENERGY

National Energy Technology Laboratory

National Petroleum Technology Office

Oil Recovery Field Demonstration Program

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June 2002

FIELD DEMONSTRATION PROJECTS

CLASS I – FLUVIAL DOMINATED DELTAIC RESERVOIRS

CLASS II – SHALLOW SHELF CARBONATE RESERVOIRS

CLASS III – SLOPE & BASIN CLASTIC RESERVOIRS

ADVANCED CLASS WORK PROGRAM

JUNE 2002

FIELD DEMONSTRATIONS OVERVIEW

Introduction:

The Field Demonstration Program was initiated in FY92 in response to rapidly declining domestic production and the realization that huge volumes of oil are being abandoned in reservoirs because of uneconomic production techniques. This program is just one of the critical elements of the Oil Program necessary to move improved oil recovery (IOR) technology from the conceptual stage through research, pilot scale field experiments, and full-scale field demonstrations to industry acceptance and commercialization. Both successful results and failures of the field demonstrations will provide focus to concurrent research programs. Elements of the field demonstrations that are suitable for broad industry application will be communicated to the industry through the oil program=s technology transfer.

Goals and Objectives:

1) Extend the economic production of domestic fields by a) slowing the rate of well abandonments and b) preserving industry infrastructure (including facilities, wells, operating units, data, and expertise).

2) Increase ultimate recovery in known fields by demonstrating a) better methods of reservoir characterization (both rock and fluid), b) advanced oil recovery and production technologies, c) advanced environmental compliance technologies, and d) improved reservoir management techniques.

3) Use field demonstrations to broaden information exchange and technology application among stakeholders by a) expanding participation in DOE projects to include both traditional and nontraditional participants, b) increasing third-party participation and interaction throughout the life of DOE-sponsored projects, and c) making technology transfer products user-friendly.

4) Integrate Field Demonstration activities with activities of other areas of the advanced oil recovery program by a) actively pursuing demonstration activities from work developed in other program areas, b) assessing Field Demonstration efforts regarding future directions and research needs, and c) informing the research community of research needs and opportunities identified in demonstration projects.

FIELD DEMONSTRATIONS OVERVIEW

Projects:

Class I Fluvial-Dominated Deltaic reservoirs - Four mid-term and ten near-term projects were selected and awarded in FY92 and FY93. Three projects were canceled during Budget Period I. DOE will monitor contractual performance and fund the second budget period of demonstration projects that provided technically and economically feasible in the first budget period. Projects will be completed between FY94 and FY2000. All eleven Class I projects have been completed.

Class II Shallow Shelf Carbonate Reservoirs - Three mid-term and seven near-term field demonstrations in shallow-shelf carbonate reservoirs have been selected and awarded in FY94. DOE will monitor the contractual performance and fund the second budget period as necessary. One project was canceled. Seven of the projects have been completed. An eighth project will be completed in the fall of 2002, and the ninth project ends in 2005.

Class III Slope and Basin Clastic Reservoirs - Four near-term and five mid-term projects in slope and basin clastic reservoirs were selected and awarded in FY95. DOE will monitor contractual performance and fund the second budget period as approved. One project was completed in the fall of 1999. Four projects were completed in 2001. One project will be completed in July 2002. Three projects have been granted no-cost extensions and will end in 2003, 2004 and 2006.

Advanced Class Work - Field-based reservoir characterization and recovery process projects to refine advanced technologies that were demonstrated or identified in the Class demonstration projects. In addition, technologies shown to be promising in laboratory research and development efforts - improved recovery methods and reservoir characterization technologies - will be considered for demonstration in Advanced Class activities all three projects have been completed.

Class Revisit – Ten new projects were awarded in October 1999. The ten projects include Fluvial-dominated Deltaic, Shallow Shelf Carbonate and Slope and Basin Clastic reservoirs, and both light and heavy oil projects. These new projects have become active as Class I, II and III projects. The projects will have three phases, reservoir characterization, field implementation and monitoring. All phases will provide Technology Transfer to the oil industry and public. One project was completed in early 2002.

CLASS PROJECT INTERNET URLS

Class I

Binger Operations East Binger Unit, Oklahoma (Class Revisit)
http://www.eastbingerunit.com

University of Kansas Stewart Field (Finney C.) and
Savonburg Field (Allen C.) Kansas
http://crude2.kgs.ukans.edu/PRS/County/def/finney.html

Oklahoma Geological Survey Fluvial-Dominated deltaic systems in Oklahoma
http://www.ou.edu/special/ogs-pttc

Class II

Michigan Technical University Crystal Field, Michigan Basin, Michigan
http://www.geo.mtu.edu./svl

Michigan Technical University Vernon Field, Michigan Basin, Michigan
(Class Revisit)
http://www.geo.mtu.edu./svl

Luff Exploration Armor Field, North Dakota (Class Revisit)
http://www.luffdoeproject.com

Utah Geological Survey Blanding Subbasin, Utah and Colorado
(Class Revisit)
http://www.ugs.state.ut.us/paradox2/paradox2.htm

University of Kansas Schaben Field, Kansas
http://crude2.kgs.ukans.edu/DPA/County/ness.html

Hall-Gurney Field, Kansas
http://www.kgs.ukans.edu/ERC/CO2Pilot/index.html

University of Tulsa West Carney Field, Oklahoma (Class Revisit)
http://www.tucrs.utulsa.edu

Class III

City of Long Beach Wilmington Field, Block IIA, California (BC14939)
http://www.usc.edu/dept/peteng/topko.html

Bureau of Economic Geology East Ford Field, Texas
http://www.utexas.edu/research/beg/delaware_project/index.html

City of Long Beach Wilmington Field, Blocks IV and V, California (BC14934)
http://pangea.stanford.edu/~moos/DOE_home.html

Pioneer Natural Resources Spraberry Trend , Texas
http://pumpjeak.tamu.edu/faculty/schechter/baervan/cover3_front.html

Advanced Class Work

University of Kansas Center for Research, Inc.
http://www.kgs.ukans.edu/PRS/software/pfeffer1.html

DOE Publications from the Class Program

The following DOE publications on the Class projects are available from the U. S. Department of Energy free of charge. Contact Bernadette Ward, National Petroleum Technology Office, One West Third Street, Suite 1400, Tulsa, OK 74103-3519; FAX 918-699-2005, Email Bernadette.Ward@npto.doe.gov

Project Title	Project number	Code	Location	Type of Report
CLASS I				
University of Tulsa	BC14951-5	94000137	Glenn Pool F. OK	1993/4 Annual
University of Tulsa	BC14951-10	95000146	Glenn Pool F. OK	1994/5 Annual
University of Tulsa	BC14951-16	96001236	Glenn Pool F. OK	1995/6 Annual
University of Tulsa	BC14951-19	97007190	Glenn Pool F. OK	1996 Annual
University of Tulsa	BC14951-22	98000479	Glenn Pool F. OK	1997Annual
University of Tulsa	BC14951-26	OSTI:13821	Glenn Pool F. OK	FINAL
Utah Geological Survey	BC14953-10	95000171	Bluebell F. UT	1994 Annual
Utah Geological Survey	BC14953-14	96001227	Bluebell F. UT	1995 Annual
Utah Geological Survey	BC14953-19	96001297	Bluebell F. UT	1996 Annual
Utah Geological Survey	BC14953-20	98000481	Bluebell F. UT	1997 Annual
Utah Geological Survey	BC14953-21	OSTI:6089	Bluebell F. UT	1998 Annual
Utah Geological Survey	BC14953-26	750285	Bluebell F. UT	FINAL
Utah Geological Survey	BC14953-27	758140	Bluebell F. UT	Completion Tech
Utah Geological Survey	BC14953-28	758141	Bluebell F. UT	Well Models
Diversified Operating	BC14954- 5	95000170	Sooner U. CO	1993 Annual
Diversified Operating	BC14954- 14	96001265	Sooner U. CO	FINAL
American Oil Recovery	BC14955-8	95000184	Mattoon F. IL	1994-5 Annual
Oklahoma Geological S.	BC14956-16	98000547	Oklahoma reservoirs	FINAL
University of Kansas	BC14957-7	95000161	Stewart/Savonburg KS	1993/4 Annual
University of Kansas	BC14957-14	96001242	Stewart/Savonburg KS	1994/5 Annual
University of Kansas	BC14957-16	96001261	Stewart/Savonburg KS	1995/6 Annual
University of Kansas	BC14957-23	OSTI: 2715	Stewart/Savonburg KS	1997 Annual
University of Kansas	BC14957-27	OSTI756344	Stewart/Savonburg KS	FINAL
Lomax Exploration	BC14958-8	95000113	Green River Fm. UT	1994 Annual
Lomax Exploration	BC14958-11	95000182	Green River Fm. UT	1995 Annual
Lomax Exploration	BC14958-15	96001264	Green River Fm. UT	FINAL
University of Texas BEG	BC14959-8	94000132	Vicksburg Fault Z. TX	1993 Annual
University of Texas BEG	BC14959-13	95000160	Vicksburg Fault Z. TX	1994 Annual
University of Texas BEG	BC14959-15	95000190	Vicksburg Fault Z. TX	Topical
University of Texas BEG	BC14959-17	96001211	Vicksburg Fault Z. TX	1995 Annual
University of Texas BEG	BC14959-21	96001255	Vicksburg Fault Z. TX	FINAL
Texaco E & P	BC14960-8	95000173	Port Nueces F. TX	1994 Annual
Texaco E & P	BC14960-19 (4 volumes)	791330-791332	Port Nueces F. TX	FINAL
Hughes Eastern	BC14962-7	95000177	N. Blowhorn F. AL	1994 Annual
Hughes Eastern	BC14962-10	96001218	N. Blowhorn F. AL	1995 Annual
Hughes Eastern	BC14962-16	97008691	N. Blowhorn F. AL	1996 Annual

Hughes Eastern	BC14962-21	98000551	N. Blowhorn F. AL	1997 Annual
Hughes Eastern	BC14962-22	OSTI:8243	N. Blowhorn F. AL	1998 Annual
Hughes Eastern	BC14962-24	750872	N. Blowhorn F. AL	Final
Amoco	BC14963-10	96001225	W. Hackberry F. LA	1994/5 Annual
Amoco	BC14963-16	96001287	W. Hackberry F. LA	1995/6 Annual
Amoco	BC14963-19	OSTI:2711	W. Hackberry F. LA	1997/8 Annual
Amoco	BC14963-21	792224	W. Hackberry F. LA	Final

CLASS II

Laguna	BC14982-12	98000462	Foster & S. Cowden F. TX	1996/7 Annual
Laguna	BC14982-16	OSTI:7917	Foster & S. Cowden F. TX	1998 Annual
Laguna	BC14982 -20	OSTI:7917	Foster & S. Cowden F. TX	FINAL
Michigan Tech. Univ.	BC14983-5	95000181	Crystal F. MI	1994/5 Annual
Michigan Tech. Univ.	BC14983-9	96001240	Crystal F. MI	1995/6 Annual
Michigan Tech. Univ.	BC14983-14	98000536	Crystal F. MI	FINAL
Luff Exploration	BC14984-5	95000186	Williston Basin MT,ND	1994 Annual
Luff Exploration	BC14984-10	96001254	Williston Basin MT,ND	1995 Annual
Luff Exploration	BC14984-13	98000486	Williston Basin MT,ND	Topical - Drilling
Luff Exploration	BC14984-14	98000487	Williston Basin MT,ND	Top. - Red River
Luff Exploration	BC14984-15	98000488	Williston Basin MT,ND	Top. - Ratcliffe
Luff Exploration	BC14984-16	98000489	Williston Basin MT,ND	FINAL
Texaco E & P	BC14986-3	95000142	Central Vacuum F. NM	1994 Annual
Texaco E & P	BC14986-11	96001252	Central Vacuum F. NM	1995 Annual
Texaco E & P	BC14986-13	98000468	Slaughter F. TX	1996 Annual
Texaco E & P	BC14986-14	OSTI:3831	Slaughter F. TX	FINAL
University of Kansas	BC14987-5	96001245	Schaben F. KS	1995 Annual
University of Kansas	BC14987-10	97008689	Schaben F. KS	1996 Annual
University of Kansas	BC14987-10	97008689	Schaben F. KS	Bud. Period 1
University of Kansas	BC14987-12	OSTI:8525	Schaben F. KS	1997/8 Annual
University of Kansas	BC14987-16	787973	Ness City North F. KS	FINAL
Utah Geological Survey	BC14988-8	96001268	Paradox Basin UT	1995/6 Annual
Utah Geological Survey	BC14988-9	96001301	Paradox Basin UT	1996/7 Annual
Utah Geological Survey	BC14988-10	98000493	Paradox Basin UT	1997/8 Annual
Utah Geological Survey	BC14988-12	14245	Paradox Basin UT	1998/9 Annual
Utah Geological Survey	BC14988-13	758925	Paradox Basin UT	1999/00 Annual
Fina Oil & Chemical	BC14989-10	96001262	North Robinson F. TX	1994/5 Annual
Fina Oil & Chemical	BC14989-11	96001263	North Robinson F. TX	1995/6 Annual
Fina Oil & Chemical	BC14989-14	96001271	North Robinson F. TX	Topical
Fina Oil & Chemical	BC14989-21	OSTI:5128	North Robinson F. TX	1997/8 Annual
Fina Oil & Chemical	BC14989-23	OSTI752175	North Robinson F. TX	FINAL
Oxy, USA	BC14990-14	97000793	W. Welch F. TX	Budget Period 1
Oxy, USA	BC14990-23	784113	W. Welch F. TX	1998 Annual
Phillips	BC14991-7	96001234	S. Cowden F. TX	1994/5 Annual
Phillips	BC14991-11	96001283	S. Cowden F. TX	1995/6 Annual

Phillips	BC14991-13	98000461	S. Cowden F. TX	1996/7 Annul
Phillips	BC14991-14	OSTI:2714	S. Cowden field, TX	1997/8 Annul
Phillips	BC14991-17	OSTI:14468	S. Cowden field, TX	1998/9 Annul
Phillips	BC14991-22	791831	S. Cowden field, TX	2000/1 Annual

CLASS III

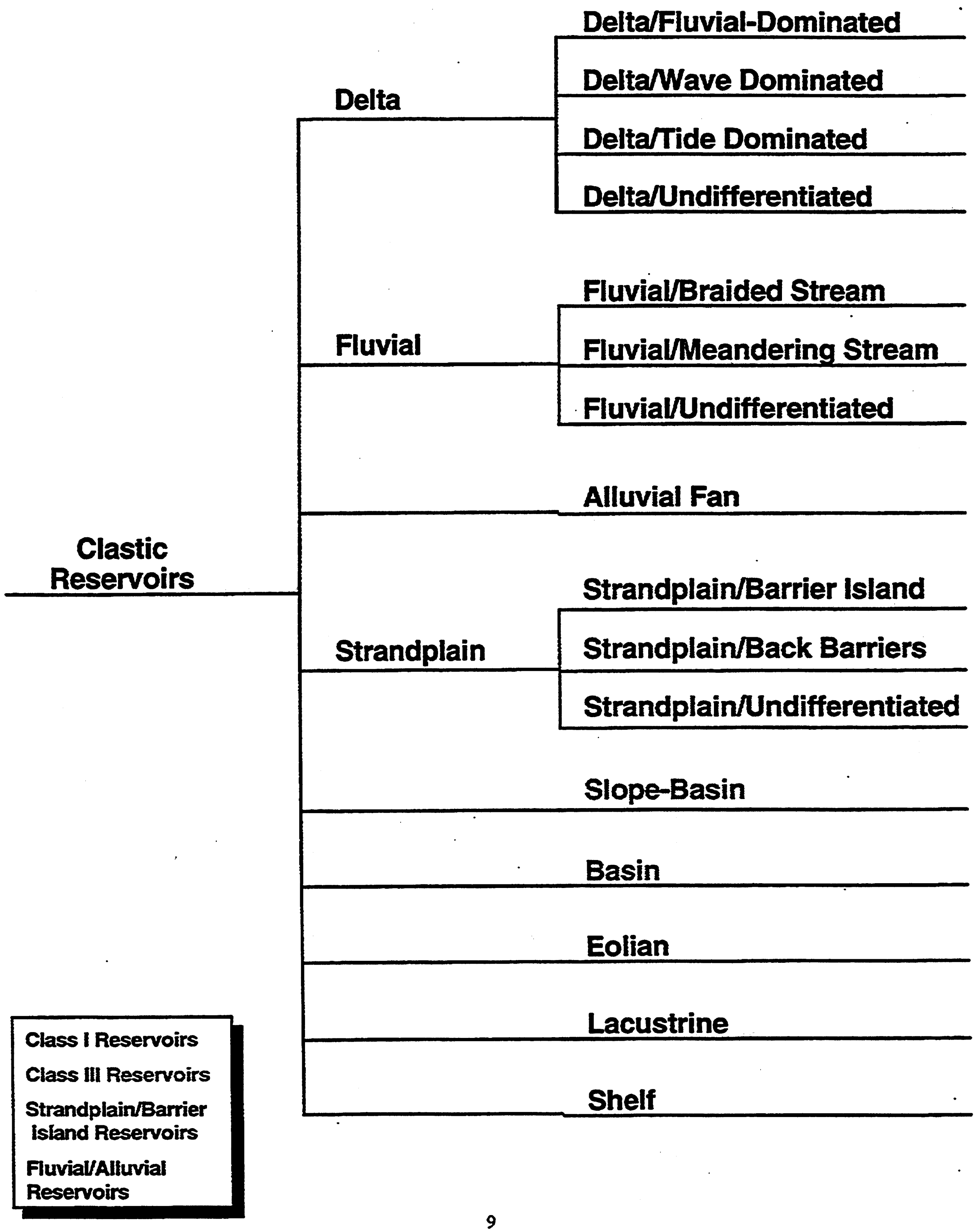
City of Long Beach	BC14934-7	96001299	Wilmington F. CA	1995/6 Annual
City of Long Beach	BC14934 -8	98000538	Wilmington F. CA	1997 Annual
City of Long Beach	BC14934-13	784131	Wilmington F. CA	2000/1 Annual
Pacific Operators Offshore	BC14935-6	98000466	Carpinteria F. Ca	1996 Annual
Pacific Operators Offshore	BC14935-9	98000466	Carpinteria F. Ca	Budget Period 1
Pacific Operators Offshore	BC14935-15	776910	Carpinteria F. Ca	FINAL
University of Texas BEG	BC14936-5	96001244	Delaware Basin TX	1995 Annual
University of Texas BEG	BC14936-9	98000456	Delaware Basin TX	1996 Annual
University of Texas BEG	BC14936-10	98000477	Delaware Basin TX	Topical
University of Texas BEG	BC14936-10 A I	98000474	Delaware Basin TX	Appendix I
University of Texas BEG	BC14936-10 A II	98000475	Delaware Basin TX	Appendix II
University of Texas BEG	BC14936-10 A III	98000476	Delaware Basin TX	Appendix III
University of Texas BEG	BC14936-11	OSTI:7432	Delaware Basin TX	1998 Annual
University of Texas BEG	BC14936-12	OSTI:9727	Delaware Basin TX	Topical
University of Texas BEG	BC14936-15	755452	Delaware Basin TX	1999/2000 Ann
University of Texas BEG	BC14936-17	780435	Delaware Basin TX	2000/2001 Ann
University of Texas BEG	BC14936-18	789251	Delaware Basin TX	FINAL
University of Utah	BC14937-7	98000531	Midway-Sunset F. CA	1996 Annual
University of Utah	BC14937-8	OSTI:3258	Midway-Sunset F. CA	1997 Annual
University of Utah	BC14937-9	OSTI:8524	Midway-Sunset F. CA	1998 Annual
University of Utah	BC14937-11	753924	Midway-Sunset F. CA	1999Annual
University of Utah	BC14937-12	772932	Midway-Sunset F. CA	2000Annual
University of Utah	BC14937-13	791735	Midway-Sunset F. CA	FINAL
Chevron	BC14938-7	98000460	Buena Vista Hills F. CA	1996 Annual
Chevron	BC14938-8	98000484	Buena Vista Hills F. CA	1997 Annual
Chevron	BC14938-12	OSTI:5127	Buena Vista Hills F. CA	1998 Annual
Chevron	BC14938-15	753983	Lost Hills F. CA	1999 Annual
Chevron	BC14938-16	776907	Lost Hills F. CA	2000 Annual
Chevron	BC14938-in press		Lost Hills F. CA	2001 Annual
City of Long Beach	BC14939-8	97008690	Wilmington F. CA	1995 Annual
City of Long Beach	BC14939-9	OSTI:8076	Wilmington F. CA	1996 Annual
ARCO	BC14940-5	96001285	Yowlumne F. CA	1995/6 Annual
Strata	BC14941-6	97008428	Nash Draw F. NM	1996 Annual
Strata	BC14941-12	98000532	Nash Draw F. NM	1997 Annual
Strata	BC14941-13	OSTI:3257	Nash Draw F. NM	1998Annual
Strata	BC14941-14	OSTI:3800	Nash Draw F. NM	Budget Period I

Strata	BC14941-19	791819	Nash Draw F. NM	2001 Annual
Pioneer Natural Resources	BC14942-4	98000463	Spraberry Trend, TX	1996 Annual
Pioneer Natural Resources	BC14942-6	98000494	Spraberry Trend, TX	1997 Annual
Pioneer Natural Resources	BC14942-7	OSTI:3333	Spraberry Trend, TX	1998 Annual
Pioneer Natural Resources	BC14942-9	753525	Spraberry Trend, TX	1999 Annual
Pioneer Natural Resources	BC14942-12	788818	Spraberry Trend, TX	2000/1Annual

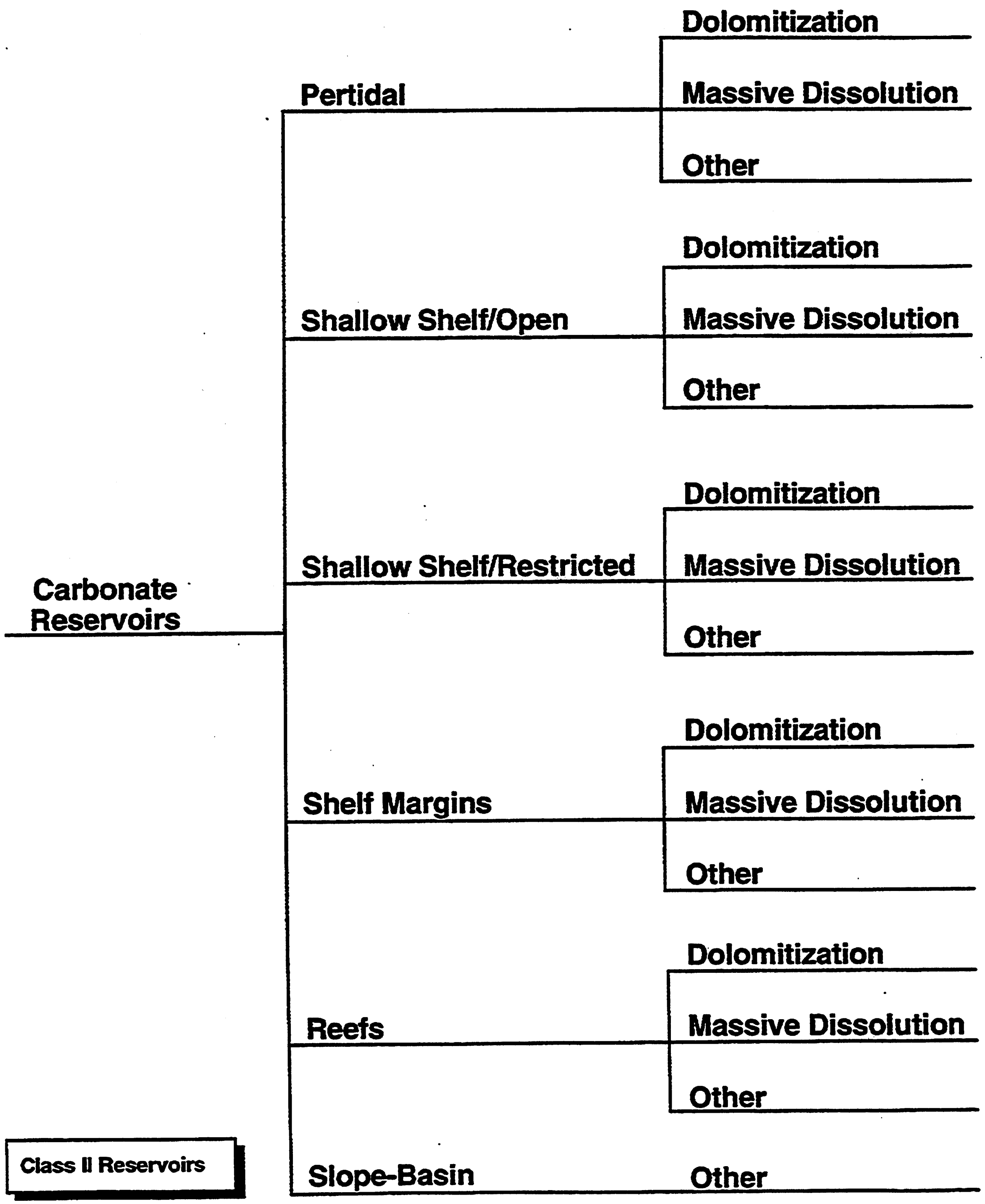
CLASS REVISIT

Ensign Operating Co.	BC15121-1	792461	Eva South Unit, OK	FINAL
Michigan Tech Univ.	BC15122-1	784133	Vernon Field, MI	2000 Annual
University of Tulsa	BC15125-3	793150	West Carney F. OK	Budget Per. 1
Utah Geological Survey	BC15128-1	777920	Blanding Subbasin, UT	2000 Annual
Utah Geological Survey	BC15128-2	788886	Blanding Subbasin, UT	2001 Annual
University of Alabama	BC15129-1	784129	Womack Hill F. AL	2000 Annual

Classification of Clastic Reservoirs

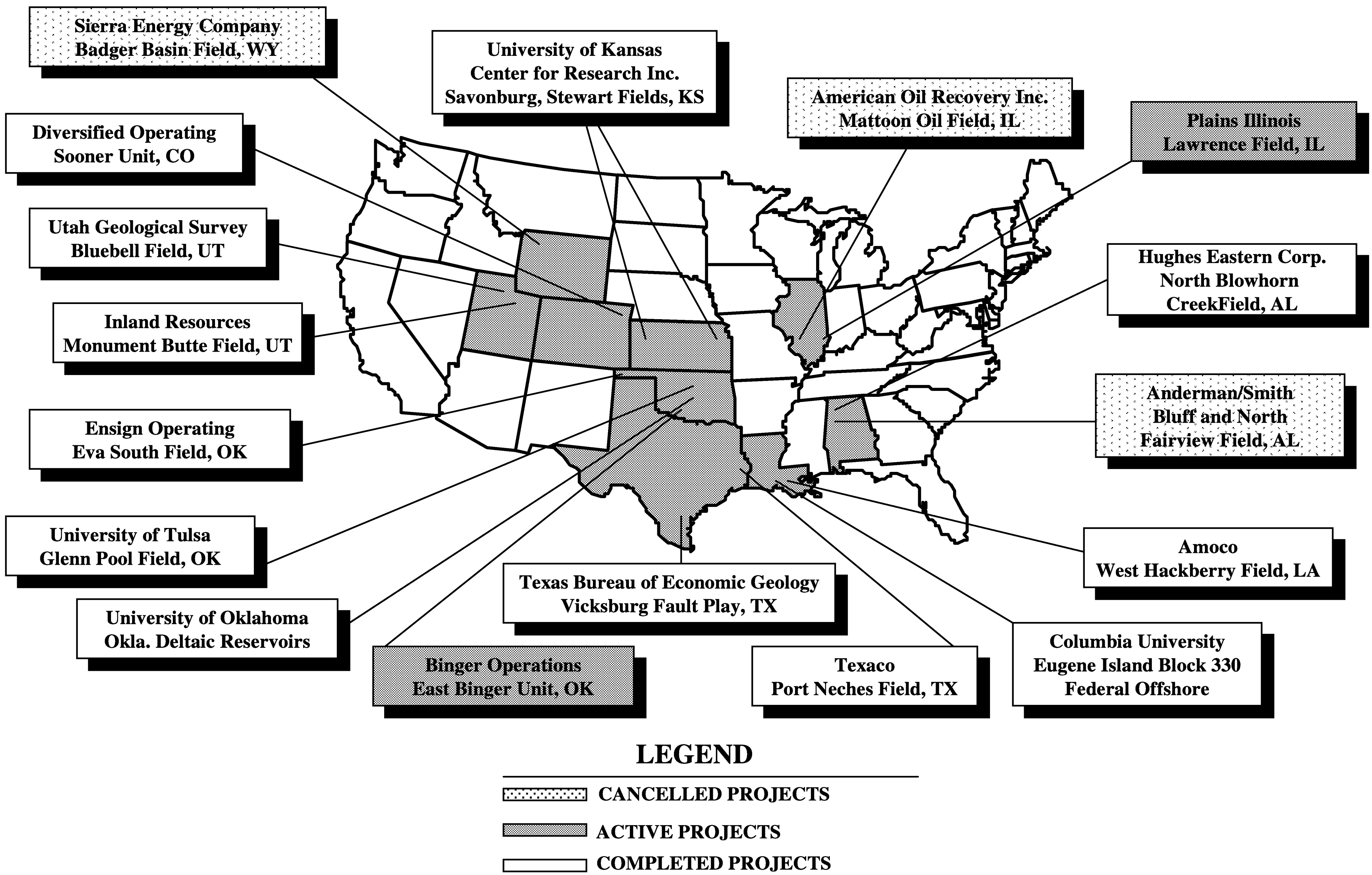


Classification of Carbonate Reservoirs



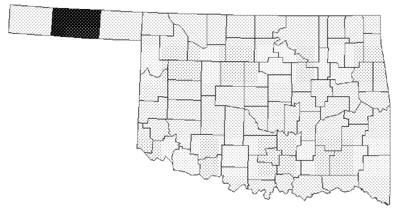
CLASS I

Class I Oil Recovery Projects



Advanced Reservoir Characterization and Development Through High Resolution 3C3D Seismic and Horizontal Drilling: Eva South Morrow Sand Unit, Texas County, OK/Class Revisit

Ensign Operating Company



Morrow Formation	Eva South Field
@ 5,600 ft.	Texas County, OK
Pennsylvanian Age	Anadarko Basin (Hugoton Embayment)

DE-FC26-00BC15120

Contract Period:
2/29/2000 to 7/31/2001

DOE Project Manager:
Daniel J.Ferguson
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Contractor:
Ensign Operating Company
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Denver, CO 80202

Principal Investigator:
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303/ 295-6168
denver@ensignoil.com

Objective: Improve waterflood sweep efficiency.

Technologies Used: High resolution 3C3D seismic, horizontal drilling.

Background: Eva South Unit is a combination structural/ stratigraphic trap at approximately 5600 feet in depth. Estimated ultimate primary recovery is 1,288 MBO, representing a 17.8% recovery factor. Ensign Operating Company acquired the field in 1993 and initiated a waterflood project. The field responded in nine months. Secondary recovery is estimated to be 1, 276 MBO. Due primarily to compartmentalization, it has been determined that an additional 450 MBO could be recovered if sweep efficiency could be improved.

Four reservoir compartments, formed by abandoned channel-fill deposits and faulting, have been defined at Eva South Unit. Synthetic seismic models were constructed that indicated the compartmentalization could be resolved through high-resolution 3D seismic. In additional to the standard compressional (P-wave) component, two mode-converted shear-wave (S-wave) components are recorded (3C3D) This is a relatively new technology for land-based operations.

Incremental Production: Horizontal well producing at 250 BOPD.

Expected Benefits and Applications: Improve understanding with respect to where horizontal wells should be located, and improve waterflood efficiency.

Accomplishments: 3C3D seismic interpretations are approximately 75% complete. Drilled and set production casing in the 13-H horizontal well. Horizontal well was drilled and in production 1st quarter 2000. Seismic definition allowed the well be be drilled parallerl and within 200 feet of the Teepee Creek fault in an area thought to contain additonal reserves. The reservoir development was as expected, approzimatley 1000 feet of horizontal drilling was achiecved. The well was successful in adding 122 MBO of incremental reserves, representing 1.7% of the original oil in place in the field. A fessibility study indicated that only 1 horizontal well in Eva South Unit was justified, so plans for possible 2nd and 3rd wells were discontinued. The project arrived at several recommendations on drilling horizontal wells in the Morrow formation: (1) operators should review the drilling records of all wells in the area for indications of lost circulation prior to directional drilling, and plan corrective action as part of the drilling program. (2) Horizontal wells in the Morrow should be drilled until a few feet of the reservoir has been encountered, then casing should be set immediately to minimize the potential for sloughing or caving of the shale intervals. Conclusions are that high-resolution 3C3D seismic and horizontal wells are effective tools for improving reservoir characterization and sweep efficiency in Morrow and other Class I reservoirs.

Publications: (1) Wheeler, D., J. Pope, W. A. Miller, 2000. "Improved Recovery at Eva South Unit"; The Class ACT, National Petroleum Technology Office, Tulsa, OK, Vol 6, No. 2. (2) No author. 2000. Old Dog, New Tricks. Hart's E & P, May 2000, p 13. (3) Van Dok, R. and J. Gaiser, 2001. "Stratigraphic description of the Morrow Formation using node-converted shear waves: Interpretation tools and techniques for three land surveys". The Leading Edge, Society of Exploration Geophysicists, Vol. 20, No. 9, pp. 1042-1047.

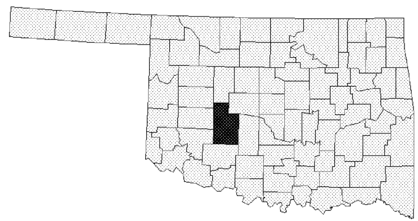
Recent/Upcoming Technology Transfer Events:
(1) Presentation at South Mid-Continent PTTC meeting, Norman, OK, March 2000.
(2) Presentation at Rocky Mountain Geological Society, 3-D Seismic Symposium, Denver CO, April 2000.
(3) Pope, J. and D. Wheeler, "Advanced Reservoir Characterization and Development through high-resolution 3C3D seismic and horizontal drilling: Eva South Morrow Sand Unit, Texas County, Oklahoma"; SPE Denver Section Formation Evaluation, Denver, CO, May 2000.
(4) Wheeler, D. M. 2000. Advanced Reservoir Characterization and Development through high-resolution 3C3D seismic and horizontal drilling: Eva South Morrow Sand Unit, Texas County, Oklahoma: National Petroleum Technology Office, DOE, Oil Technology Program Contractor Review Meeting, June 27, 2000.
(5) Wheeler, D. M., W. A. Miller and T. C. Wilson. 2001. Reservoir Characterization and Development of Valley Fill Deposits with 3C3D Seismic and Horizontal Drilling, Eva South Morrow Sand Unit, Oklahoma; AAPG National Meeting, Denver, CO, June 3-6, 2001.

(6) Miller, W. and D. Wheeler, 2000. 3C-3D Seismic Characterization of the Eva South Morrow Sand Unit, Texas County, Oklahoma; 6th annual 3-D Seismic Symposium, RMAG.
(7) Wilson, T., T. Davis, D. Wheeler, W. Miller and M. Sterling, Improved recovery at Eva South Unit, International SEG Convention, San Antonio, TX, September 2001.

Project Status: Project completed July 2001. Final report published March 2002.

Improved Miscible Nitrogen Flood Performance Utilizing Advanced Reservoir Characterization & Horizontal Laterals in a Class I Reservoir - East Binger (Marchand) Unit/Class Revisit

Binger Operations, LLC



Upper Marchand Sand (Hoxbar Group) Fm. East Binger Unit

@ 9,900 to 10,010 ft. Caddo County, OK

Upper Pennsylvanian Age Anadarko Basin

DE-AC26-00BC15121

Contract Period:
4/11/2000 to 4/10/2005

DOE Project Manager:
Gary D.Walker
918/ 699-2083
gwalker@npto.doe.gov

Contractor:
Binger Operations, LLC
1401 Sheridan Ave.
Suite 205
Cody, WY 82414

Principal Investigator:
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P.O. Box 2850
Cody, WY 82414
307/ 587-2445
307/ 527-4943
binger@myavista.com

Objective: Demonstrate use of nitrogen as a widely available, cost-effective and environmentally superior injectant for miscible floods, and demonstrate the effectiveness of horizontal wellbores in reducing gas breakthrough and cycling.

Technologies Used: Nitrogen miscible flood, horizontal drilling.

Background: The Pennsylvanian Upper Marchand sand reservoir at East Binger Unit is located at a depth of 9,000 to 10,100 ft in the Anadarko Basin. OOIP for the Marchand sand unit of the Hoxbar Group is 115 MMBO. The Marchand reservoir covers 13,000 acres at East Binger Unit. 5,300 acres are on Indian lease lands. Phillips experimented with flue gas injection at Binger in the 1970s, but had immediate gas break through. In 1986 the change was made to nitrogen injection. Nitrogen has the advantages of being widely available, cost-effective, and environmentally superior as an injectant for miscible floods. Nitrogen facilities in the field produce the nitrogen used for injection. Binger Operations took over as the field operator in 1998 with 47 producers and 24 injectors. Cumulative production is 19.8 MMBO. Current production is at 850 BOPD, using 16 MMCFD N_2 injection. The problems at East Binger are early injection breakthrough and cycling of injected nitrogen, resulting in a loss of miscible pressure. The project plans to demonstrate the effectiveness of horizontal wellbores in reducing gas breakthrough and cycling.

Incremental Production: Production 1st quarter 2001 stands at 850 BOPD using 16 MMCF/D N_2 injection. By the end of the 4th quarter 2001 production was steady at 75 BOPD incremental oil and 2500MCF/D gas.

Expected Benefits and Applications: In is expected that the demonstration will lead to implementation of nitrogen injection projects in areas without readily available CO2 sources.

Accomplishments: (1) Binger Operations brought the local nitrogen generation plant and will be able to produce nitrogen for injection at $0.35 per MCF, which will be very cost effective as an injectant. (2) Drilled the 1st horizontal well in the 1st quarter 2001. Achieved a lateral length of 1,500 ft. (3) Drilled the horizontal injection well 2nd quarter 2001. (4) Gathered all pre-drilling reservoir data – pressure surveys on 13 wells, injection profiles on 4 wells, production profiles on 2 wells, and gas compositions on 50 of the Unit's 55 producing wells (the other 5 wells are all in fringe areas unlikely to be impacted, or have been shut-in for an extended period due to a high nitrogen content in the produced gas). (5) The horizontal well was hydraulically fractured in November 2001, following repeated attempts to improve production by other means. Early production performance has been very positive. The well was originally intended for injection service, but was changed to production to learn as much as possible about horizontal performance. After two months post-frac, oil production is 50% higher than before treatment and the gas rate is five times higher.

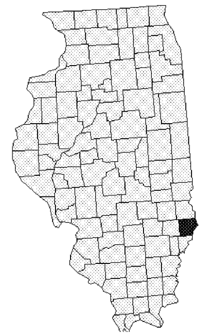
Publications:

Recent/Upcoming Technology Transfer Events:
(1) Muhic, Teresa, 2000. Improved miscible nitrogen flood performance utilizing advanced reservoir characterization & horizontal laterals in a Class I reservoir – East Binger (Marchand) Unit: National Petroleum Technology Office, DOE, Oil Technology Program Contractor Review Meeting, June 27, 2000. (2) A web site (www.eastbingerunit.com) has been set up with field and project information and quarterly reports.

Project Status: Budget Period II

Alkaline-Surfactant-Polymer Flooding and Reservoir Characterization of the Cypress and Bridgeport Reservoirs of the Lawrence Field/Class Revisit

Plains Illinois, Inc.



Bridgeport and Cypress Formation	Lawrence Field
@ 3,000 ft.	Lawrence County, IL
Pennsylvanian and Mississippian Age	Illinois Basin

DE-FC26-00BC15126

Contract Period:
12/7/1999 to 9/12/2005

DOE Project Manager:
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Objective: Determine lower cost flood patterns, comparison of EOR techniques, field expansion, and cost efficiencies of flooding multiple reservoirs simultaneously.

Technologies Used: Core analysis, ASP design linear corefloods, radial corefloods and alkaline-surfactant-polymer injection.

Background: Sandstones of the Pennsylvanian Bridgeport and Mississippian Cypress formations at Lawrence field, Illinois are producing at less than a 3% oil cut and are approaching their economic limit. The 60-acre alkaline-surfactant-polymer ASP project will utilize reservoir characterization of the fluvial dominated deltaic sandstone reservoirs. Lawrence field at 96 years old was reaching a "now or never point" in development with an estimated 40 to 70% of OOIP remaining in place. The ASP flood is designed to target the residual oil and maintain long-term cost flow for Lawrence field. This enhanced oil recovery project will utilize three flood patterns with simultaneous ASP injection in the Bridgeport and Cypress sandstones. In addition, a comparison will be made between the project's results to two previous unpublished Lawrence field Maraflood projects. This will help determine lower cost flood patterns, comparison of EOR techniques, field expansion, and cost efficiencies of flooding multiple reservoirs simultaneously.

Incremental Production:

Expected Benefits and Applications: The potential for the Bridgeport and Cypress reservoirs at Lawrence field is 1 billion barrels OOIP. Previous surfactant floods have demonstrated the effectiveness in this field, but have not been cost-effective. The blend of ASP chemicals is expected to increase production in a cost-effective manner, which would benefit other independent producers in the Illinois Basin. The pilot at Lawrence field targets 42,000 MBO reserves for the 60-acre EOR demonstration.

Accomplishments: During the reservoir characterization phase of the project, si were drilled and cored. The data was used to map porosity and permeability zones, defining five units in the Cypress sandstone and dividing the Brigeport into A (3 units), B (3 units) and D (2 units) at Lawrence field. The Cypress sandstone, characterizaerd by fine scale bedding features and thin units of rip-up clasts, which form premeabililty barriers, , is interpreted as tidal deposition. He reservoir in the Bridgeport B sandstone was identified as tidal channels encased in miced mud flats. Thin coal units are found thhrough out the Cypress and Bridgeports. Field implementation began in July 2000. A feasibility and cost study of EOR technologies was conducted early in the project. This confirmed that the use of low-concentration injection techniques for alkaline-surfactant-polymer flooding could reduce cost to $4 to $8 per barrel of oil recovered. This compares very favorably to the $20 to $37 cost for earlier surfactant floods in the Bridgeport and Cypress formations. Based on a price of $20 per barrel of oil, modeling indicated that ASP flooding would be economic at as low as 1% oil cut. An area of seven sq. miles at Lawrence field has been identified for prospective ASP flooding by Plains Illinois. Based on the initial response of the ASP flood the full field project is anticipated to be self-funding after 3 years. Reservoir life will be extended for an additional 14 years.

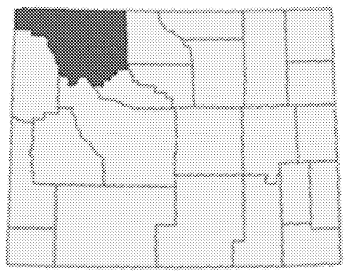
Publications:
Seyler, B., 2002. ASP Pilot Lawrence Field, Illinois; The Class ACT, DOE's newsletter, Vol. 8, No. 2, June 2002.

Recent/Upcoming Technology Transfer Events:
(1) PTTC workshop on the Cypress and Bridgeport Formations, Illinois Geological Survey, March 8, 2001. (2) Seyler, B. J. P. Grube, B. G. Huff, and C. S. Blakley, 2002. Reservoir characterization for an alkaline-surfactant-polymer flood of Pennsylvanian and Cypress Sandstone Reservoirs in Lawrence Field, Illinois: AAPG Annual Convention, poster, Houston, TX, March 13, 2002.

Project Status: Budget Period II

Enhanced Oil Recovery Utilizing High-Angle Wells in the Frontier Formation, Badger Basin Field, Park County, Wyoming -- Class I

Sierra Energy Company



Frontier Formation	Badger Basin Field
@ 8,000 ft.	Park County, Wyoming
Cretaceous Age	Bighorn Basin

DE-FC22-93BC14950

Contract Period:
10/21/1992 to 12/31/1994

DOE Project Manager:
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Objective: This study of the Frontier Formation in Badger Basin Field, Park County, Wyoming, will use 3-D seismic and core data to analyze the diagenetic history, rock properties, and the natural fracture system. It is expected that this approach will be the basis for increasing recovery using slant and horizontal wells to intersect oil-bearing fractures.

Technologies Used: 3-D seismic, core analysis, drill slant or horizontal well

Background: Badger Basin Field was discovered in 1931 by drilling a surface structure. To date only 15% of the 25 million barrels of original oil in place has been produced from this fractured reservoir. The field is not under any pressure maintenance system at this time, although water and gas have been injected into the field in the past. Almost 40% of field production has come from one of the twenty field wells. The low and variable recovery points to both compartmentalization (common to fluvial dominated deltaic systems) and fracturing. These production problems are common in other Wyoming fields. The Frontier reservoir is located at a depth of approximately 8,000 ft in Badger Basin Field.

Incremental Production: None.

Expected Benefits and Applications: Overcome producibility problems in the Frontier sandstone reservoirs. The objective is to increase the recoverable reserves from Badger Basin Field through an integrated approach using geological, geophysical, and engineering methods. Spacing and orientation of the fracture systems will be analyzed in a slant well, and used to design a horizontal well, which will validate the fracture characterization studies.

Accomplishments: Core and thin section analysis has been completed and well log and production data has been interpreted to define the directional heterogeneity and its relation to natural fracture systems. A 17 square-mile 3-D seismic survey has been acquired and processed and interpretation has been completed. Well location has been selected based on the reservoir strides.

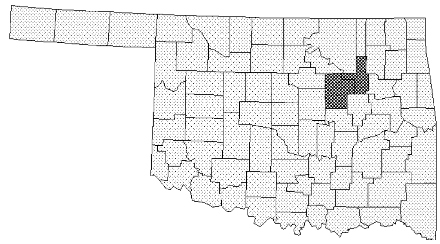
Publications: Walker, J.P. and R. G. Fortmann, 1994. "Enhanced Oil Recovery Utilizing High-angle wells in the Frontier Formation", Badger Basin Field, Park County, Wyoming: Annual Report, National Petroleum Technology Office, U.S. Department of Energy, Tulsa, Oklahoma.

Recent/Upcoming Technology Transfer Events: None

Project Status: Project terminated in Budget Period I.

Integrated Approach Towards the Application of Horizontal Wells to Improve Waterflooding Performance (Glenn Pool Field, OK) -- Class I

University of Tulsa



Bartlesville Sandstone	Glenn Pool Field
@ 1,500 Ft.	Tulsa & Creek Co., OK
Pennsylvanian Age	Cherokee Platform

DE-FC22-93BC14951

Contract Period:
1/1/1993 to 8/31/1999

DOE Project Manager:
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Objective: This project, in Glenn Pool Field, Tulsa County, Oklahoma, addresses the producibility problems of lack of reservoir continuity and poor injectivity, and attempts to improve secondary recovery performance through reservoir characterization studies and horizontal well injection technology. Project will compare the cost/benefit of using state-of-the-art data over conventional data for waterflood optimization and horizontal well placement. The technology transfer plan will target regional independent operators through technical workshops.

Technologies Used: Core/fluid analysis, FMI logging tool, well tests, reservoir modeling, cross-borehole tomography, numerical simulation, geostatistics.

Background: The Glenn Pool Field has been producing since 1905. Although the field has produced over 90 years, large portions of oil still remain underground. Specifically, a part of the Glenn Pool Field, William B. Self Unit, has only produced 21% of the original oil in place since the beginning of the production. By using an integrated approach, a detailed reservoir description will help in locating additional pockets of oil yet to be displaced. Considering the highly heterogeneous nature of the reservoir, and implementing appropriate reservoir management strategies, large portions of the mobile oil could be contacted, thereby postponing the abandonment of the field. The project addresses the producibility problems of lack of reservoir continuity and poor injectivity, and attempts to improve secondary recovery performance of a marginal oil field through the use of reservoir characterization studies and optimized reservoir management plan.

Incremental Production: Based on the partial implementation of the reservoir management plan, total oil production from the unit has increased to about 50 bbls/day (200% increase). Individual increases from the five recompleted wells range from 5 bbls/day to 10 bbls/day. After 3 years the field is producing 10 bbl incremental oil per day above the base rate. After complete implementation of the reservoir management plan, the overall oil production should reach 80 to 100 bbls/day. Technology developed in the Self Unit has been applied to the Berryhill Unit. By December 1999 the Berryhill Unit had produced 95,000 bbl of incremental oil.

Expected Benefits and Applications: The project offers operators important new information on techniques to collect reservoir data and technologies to extend the life of marginal oil fields. The application of the state-of-the-art reservoir characterization and reservoir management techniques can recover potential bypassed oil. One objective was to compare the cost/benefit of using state-of-the act data over conventional data for waterflood optimization. All technologies except cross-borehole tomography proved to be useful in improving reservoir performance.

Accomplishments: 1) Preliminary reservoir description and flow simulation have been completed. 2) Based on the evaluation of the results, a vertical test well was drilled in December 1993. 3) The cross-borehole seismic data were collected using the vertical test well as a source well and three adjoining wells as receiver wells. 4) The core from the test well have been analyzed. 5) The revised reservoir description based on the additional geological and geophysical information is finished. 6) Based on the revised description and the flow simulation studies, drilling of a horizontal injection well was observed to be economically unfeasible; instead, a revised reservoir management plan coupling recompletion and stimulation is recommended. 7) The proposed management plan has been partially implemented. 8) The oil production has increased by 200% based on the partial implementation of the reservoir management plan and additional increases are expected as the plan is further implemented. 9) Stage II of the project covering other parts of the Glenn Pool Field was started in late 1995. Geological description and basic engineering analysis is complete. Areas of potential recovery have been identified for future evaluation. Based on detailed simulation, a reservoir management plan is proposed for Tract 7 and Tract 9. 10) Four technology transfer workshops were held in the Fall of 1996, and in the Spring of 1997. 11) A reservoir management plan of drilling a horizontal well in the expanded area, Tract 9, was proposed. Bids from drilling contractors were evaluated and drilling began in December, 1998 using rotary steerable drilling technology. 12) There has been an estimated 2-5% increase in Original Oil In Place recovery extending the life of the field an additional ten years. 13) The Berry Hill Unit has produced 95,000 barrels of incremental oil production. Results from this project are being applied in Berryhill Glenn Sand Unit, which is located north of the Self Unit. Based on partial implementation of the reservoir management plan, a 200 percent increase in the oil production in the Self Unit has been observed. 14) Throughout the course of the project 26 publications and 10 presentations were made, four workshops were conducted and two newsletters were distributed.

Publications: (1) M. Kelkar, and D. Richmond, 1997. "Implementation of Reservoir Management Plan -- Self Unit, Glenn Pool Field": Proceedings of the 12th Oil Recovery Conference, Wichita, KS, Contribution #14, Tertiary Oil Recovery Project, pp. 69-74.

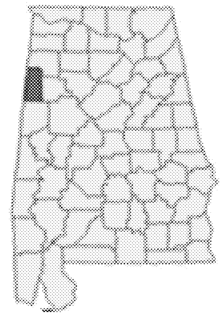
(2) Kerr, D., Ye, L., Hahar, A., Kelkar, M. and Montgomery, S.: "Glenn Pool Field, Oklahoma: A Case of Improved Production from a Mature Reservoir," AAPG Bulletin, Vol. 83, No 1, p. 1-18. (3) Ye, L. D. Kerr and K. Yang, 1999, "Facies Architecture of the Bluejacket Sandstone in the Eufaula Lake Area, Oklahoma: Implications for Reservoir Characterization of the Subsurface Bartlesville Sandstone" *in* Editor R. Schatzinger and J. F. Jordan, Reservoir Characterization - Recent Advances, AAPG Memoir 71, AAPG, Tulsa, OK, p. 29-44. (4) Kelkar, M., C. Liner and D. Kerr, 1999. "Integrated Approach Towards the Application of Horizontal Wells to Improve Waterflooding Performance": Final Report, DOE/BC/14951-16. October 1999. (5) Ye L. and D. Kerr. 2000. "Sequence stratigraphy of the Middle Pennsylvanian Bartlesville Sandstone, Northeastern Oklahoma: A case of an underfilled incised valley": AAPG Bull. Vol. 84, No. 8, p. 1185-1204.

Recent/Upcoming Technology Transfer Events: (1) Kerr, D., et al, "Application of borehole imaging for reconstruction of meandering fluvial architecture; Examples from the Bartlesville sandstone, Oklahoma"; AAPG Annual convention, San Antonio, TX, April 11-14, 1999. (2) Kelkar, M. , "Improvement in Performance of a Mature Oil Field Through horizontal Well Drilling", DOE Oil & Gas Conference, June 28-30, 1999, Dallas, TX.

Project Status: Project is Complete. The Final report published October 1999.

Secondary Oil Recovery From Selected Carter Sandstone Oil Fields -- Class I

Anderman/Smith Operating



Carter Sandstone	Bluff and North Fairview fields
@ 2,500 ft.	Lamar County, Alabama
Mississippian Age	Black Warrior Basin

DE-FC22-93BC14952

Contract Period:
10/21/1992 to 11/30/1994

DOE Project Manager:
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N/A

Objective: The project will initiate waterflooding of Carter sandstones at three sites in the Bluff and North Fairview fields in the Black Warrior Basin, Lamar County, Alabama, where the major production constraints are low bottomhole pressures and reservoir heterogeneity. The quantification of heterogeneities will use standard geological and production/reservoir studies and reservoir computer simulation. The project will develop a methodology for optimum application of geologic and engineering reservoir characterization technologies. Workshops, technical publications and presentations will transfer the project results to the industry.

Technologies Used: Waterflooding, recompletion technologies, log analysis.

Background: Three Carter sandstone reservoirs in the Black Warrior Basin, Lamar County, Alabama are at the end of their economic lives. Anderman/Smith Operating Company will conduct waterflood feasibility studies, operations, and performance analysis to optimize operations on two reservoirs to determine the viability of waterflooding the largest and most costly of the three sites. If viable, the third site will be waterflooded. The project will initiate secondary recovery at three sites in the Carter sandstones in bluff and North Fairview fields in the Black Warrior Basin, Alabama, where the major production constraints are low bottomhole pressures and reservoir heterogeneity.

Incremental Production: Oil production increased 45 STBD after initiation of waterflood.

Expected Benefits and Applications: : Previous waterflooding of the Carter sandstone in adjacent fields has led to increased incremental production. The quantification of heterogeneities through standard geological and production/reservoir data and extensive reservoir computer simulation will improve the waterflood.

Accomplishments: Water injection has begun and construction of the water injection facility is almost complete at the North Fairview Unit. Water injection began at the North Fairview Unit on June 26, 1993. No significant production response was observed.

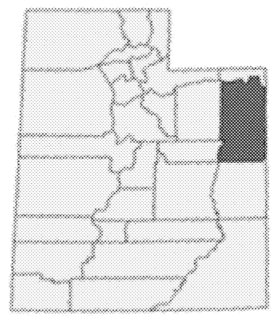
Publications: Anderson, J and G. Pauling, "Secondary Oil Recovery from selected Carter sandstone oilfields -black Warrior Basin, Alabama", Annual report December 1, 1992 to November 30, 1993, DOE/BC 14952.

Recent/Upcoming Technology Transfer Events: None.

Project Status: Project terminated in Budget Period I.

Increased Oil Production and Reserves from Improved Completion Techniques in the Bluebell Field -- Class I

Utah Geological Survey



Green River & Wasatch Fm.	Bluebell Field
@ 10,000 to 14,000 ft.	Duchesne County, Utah
Eocene Age	Uinta Basin

DE-FC22-93BC14953

Contract Period:
9/30/1993 to 9/29/1999

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Objective: The project will develop a multidisciplinary reservoir characterization approach to overcoming low petroleum recovery caused by poor completion practices in fractured, clayey reservoirs in the Bluebell field, Uinta Basin, northeast Utah. A well recompletion, a well redrill, and a new well will demonstrate the application of multidisciplinary geological and engineering techniques, such as facies analysis and fracture trend analysis to improve production and increase reserves. The technology transfer plan will include workshops and database distribution.

Technologies Used: Outcrop analysis, well testing and hydraulic fracturing, geostatistics, numerical simulation, borehole imaging logs, and infill drilling, improved completion techniques.

Background: The Uinta Basin in northeast Utah is the most prolific petroleum province in Utah. Most of the production in the giant Altamont-Bluebell-Cedar Rim fields complex is from multiple, low-matrix-porosity sandstone units that were deposited in lacustrine fluvial-delta systems. The primary problem with completing wells in the Bluebell field is adequately identifying pay zones in the thick, heterogeneous sequence. As a result, existing well completions suffer from thief zones, unperforated oil-bearing zones, and inefficient placement of chemical treatments. Bluebell field has produced 118 million barrels of oil. Technology has the potential to increase production by 5 -10%.

Incremental Production: Michelle Ute 1-7 well incremental production is averaging 10 bbls per day. Malnar Pike 1-17A1E well incremental production is averaging about 30 bbls per day. Completion of the new well, John Chasel 3-6A2, has been re-designed. The original completion failed due to collapsed casing. The well was completed at shallower intervals.

Expected Benefits and Applications: To identify oil-bearing beds, improved well completion techniques, and extended overall recovery rate per well and field. The unique features of Bluebell field include: (1) a very thick pay zone, (2) no interwell correlation of producing horizons, (3) a low matrix reservoir porosity, and (4) nonuniform completion techniques. The gains made in the recompletion work in the first two wells were applied to completion work in the third demonstration well. Logging analysis applied to the John Chasel 3-6A2 well greatly reduced the number of beds that were perforated and identified several potential high-water beds which were avoided.

Accomplishments: Pre-completion logging analysis was instrumental in reducing the number of zones selected for completion in the John Chasel 3-6A2 well. Typically 40 to 60 beds are selected for completion based mainly on drilling shows. In the new well, 19 zones were selected for completion based on TDT and dipole shear log analysis and exceptional drilling shows. The benefits include lower completion costs, increased productivity of treated zones, and a reduction in produced water. Chasel 3-6A2 was drilled in August 1998 to a TD just under 16,000 feet. The Flagstaff Member of the Green River Formation was the target. This is only the second well drilled to this depth in the Bluebell field. The objective is to use the geophysical logs to select and limit the number of non oil bearing formation beds perforated during well completions. The gains made in the recompletion work in steps one and two were applied to completion work in step three of the Demonstration Program. Logging analysis applied to the John Chasel 3-6A2 well greatly reduced the number of beds that were perforated and identified several potential high-water beds which were avoided. A series of problems were encountered which were unsurmountable and the original perforated beds have been abandoned.

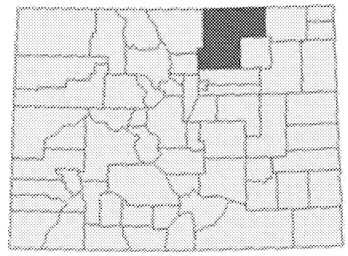
Publications: (1) Montgomery, S.L., and Morgan, C.D., 1998, "Bluebell Field, Uinta Basin: Reservoir Characterization for Improved Well Completion and Oil Recovery": American Association of Petroleum Geologists Bulletin, v.82, no. 6, p. 1113-1132. (2) Morgan, C., 1999, "Application of the bed isolation completion technique in a mature well in the Bluebell field, Uinta Basin, Utah", The CLASS ACT, Vol. 5, No. 2, Summer, 1999. (3) Morgan, C. D., and M. D. Deo, 1999, "Increased oil production and reserves from improved completion techniques in the Bluebell Field, Uinta Basin, Utah", Annual report October 1, 1997 to September 30, 1998, DOE/BC14953-21 (OSTI ID: 6089)

Recent/Upcoming Technology Transfer Events: (1) Morgan, Craig, "Increased Oil Production and Reserves from Improved Completion Techniques in the Bluebell Field, Uinta Basin, Utah": Fractured Reservoirs: A Symposium on Current Research, Modeling, and Enhanced Recovery Techniques, Salt Lake City, Utah, October 23, 1998. (2) Recompletion results were also presented at Petroleum Days in Vernal, UT, May 13-14, 1998. (3) Deo, Milind, "Fractured Reservoir Modeling in the Bluebell Field, Uinta Basin, Utah": Fractured Reservoirs: A Symposium on Current Research, Modeling, and Enhanced Recovery Techniques, Salt Lake City, Utah, October 23, 1998. (4) Display on the Bluebell field project, PTTC Symposium, and Interstate Oil and Gas Commission Compact meeting, Salt Lake City, UT, December 6-8, 1998. (5) C. D. Morgan, "Using detailed Gamma-Ray log correlations to understand depositional patterns of a fluvial-deltaic lacustrine reservoir", poster; AAPG Annual Convention, San Antonio, TX, April 11-14, 1999. (6) Morgan, C., "Bed-isolation treatments of a mature well in the Bluebell field of the Uinta basin, Utah, that have undergone numerous high volume shot-gun completions", Poster, DOE Oil & Gas Conference, Dallas, TX, June 28-30, 1999. (7) The project may be accessed through its Homepage at www.ugs.state.ut.us/bluebell.htm.

Project Status: Project completed**.** Final report published January 2000. Two topical reports with additional results published July 2000.

Improved Secondary Recovery Demonstration for the Sooner Unit -- Class I

Diversified Operating Corp



Muddy (D) Formation	Sooner Unit
@ 6, 300 ft.	Weld County, CO
Cretaceous Age	Denver-Julesburg Basin

DE-FC22-93BC14954

Contract Period:
10/21/1992 to 11/30/1995

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Objective: The objectives of the project are to demonstrate the cost-effectiveness of geologically targeted infill drilling and improved reservoir management to increase waterflood recovery of the Cretaceous Muddy 'D' formation in the Denver-Julesburg Basin, northeast Colorado.

Technologies Used: 3-D seismic imaging, selective infill drilling and reservoir management, reservoir simulation, transient well tests, production tests, multidisciplinary reservoir characterization.

Background: The Cretaceous 'D' Sand has good primary recovery but disappointing waterflood performance. The majority of waterflood projects have produced only about 20% of the OOIP. Several previous waterflood projects in the general vicinity of the Sooner Unit had marginal to negative incremental reserves compared to primary production extrapolations. Poor waterflood recovery is attributed to reservoir heterogeneity and poor reservoir management practices. Three-dimensional seismic had not been used in the D-J Basin for exploration or development of 'D' Sand reservoirs prior to this project.

Incremental Production: As of February, 1996 daily production from the Sooner Unit has increased more than 100% above the trend established before the project was initiated. Incremental proved-producing reserves attributed to activities performed during the project is placed at 305,000 bbl. Recovery had been boosted from 15% OOIP to 20% by mid 1996. Follow-up field experiments with gel injection for profile modification is expected to boost production to as much as 30% OOIP.

Expected Benefits and Applications: The use of 3-D seismic data analysis techniques to identify reservoir architecture and tailoring well spacing and injection patterns to the reservoir compartments can be applied to many fields in the D-J Basin to increase waterflood recovery. The project demonstrates the use of under-utilized technologies for achieving economical secondary oil production in an area where waterflooding has been uneconomical. Project demonstrates the use of under-utilized technologies for achieving economical secondary oil production in an area where waterflooding has been uneconomical.

Accomplishments: A seismic attribute correlation technique that successfully quantified prediction of gross and net pay thickness was developed. The project was successful in demonstrating that reservoir development methodology can be used for selective infill drilling based on reservoir compartments. This project has demonstrated that waterflooding can yield secondary oil equal to that obtained by primary depletion in the Sooner 'D' Sand Unit. An effective tool for targeting infill and edge locations has been developed using attribute correlation of 3-D seismic with petrophysical data. The 3-D survey at the Sooner Unit has precipitated an additional 13 3-D surveys in the D-J Basin for the purpose of 'D' Sand development and exploration

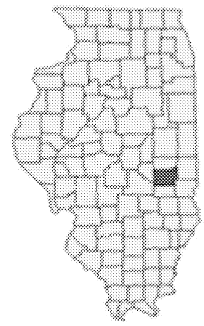
Publications: (1) Sippel, M.A., D.S. Singdahlsen, "Waterflood Success at the Sooner 'D' Sand Unit," Petroleum Technology Transfer Council workshop, entitled Reservoir Characterization: Does it Help? Case Studies of 3 Fields in Eastern Colorado, November 17, 1995, Denver, Colorado. (2) Sippel, M.A., D.S. Singdahlsen, "Advanced Secondary Recovery Demonstration for the Sooner Unit," presented at the DOE-PTTC traveling Technology Workshops series, January-February 1996. (3) Montgomery, S.L., 1997, "Sooner Unit, Denver Basin, Colorado: Improved waterflooding in a fluvial-estuarine reservoir (Upper Cretaceous D sandstone)": AAPG Bulletin, Vol. 81, No. 12, p 1757-1974.

Recent/Upcoming Technology Transfer Events: Sippel, M., "Integration of 3-D Seismic to Define Functional Reservoir Compartments and Improve Waterflood Recovery in a Cretaceous Reservoir, Denver Basin": AAPG/EAGE Research Symposium, October 20-23, 1996 Houston, TX.

Project Status: Project completed. Final report published November 1996.

Applications of Advanced Petroleum Production Technology and Water Alternating Gas Injection - Class I

American Oil Recovery, Inc.



Cypress Sandstone	Mattoon Field
@ 1,800 ft.	Coles County, Illinois
Mississippian Age	Illinois Basin

DE-FC22-93BC14955

Contract Period:
1/1/1993 to 3/31/1995

DOE Project Manager:
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Objective: This two year project in the Mattoon Oil Field, Illinois, aims to characterize the Cypress Sandstone and design and implement water- alternating-gas (WAG) injection utilizing carbon dioxide. This project emphasizes the development of a numerical model that will be used to select test sites for the demonstrations. WAG will be compared to waterflooding and cyclic gas injection in different parts of the reservoir.

Technologies Used: 3-D modeling, fluid compatibility tests, CO2 injection, reservoir simulation

Background: Mattoon field was discovered in June, 1940. Oil production was from the Cypress, Rosiclare and Aux Vases sandstone reservoirs of the Mississippian system. Secondary waterflood began in 1952. Cumulative oil production was 21 million barrels in 1993. Cypress sandstones have produced more than 1 billion barrels of oil in the Illinois Basin. These Chesterian (late Mississippian) sandstones are the most widespread, thickest (up to 200 ft), and productive sandstones in the Illinois Basin. The project objectives are to characterize the Cypress Sandstone reservoirs, identify and map facies-defined waterflood subunits, design and implement an improved oil recovery program using CO2.

Incremental Production: None.

Expected Benefits and Applications: The objective of the two year project, in Mattoon Oil field, Illinois is to continue reservoir characterization of the facies-defined waterflood subunits of the Cypress Sandstone, at a depth of 1,88 ft. and to design and implement water-alternating –gas (WAG) injection utilizing carbon dioxide.

Accomplishments: Approximately 85 to 90 percent of the reservoir geology is complete including detailed stratigraphic cross sections, structure maps, isopach maps, lithofacies maps and 3-D reservoir computer model using STRATAMODEL software. Five distinct facies defined waterflood sub-units (FDWS) have been identified and injectivity tests using carbon dioxide are well under way. Nearly six thousand tons have been injected so far. These tests are providing preliminary information, based on well response, concerning permeability variations and sweep efficiencies within the FDWS, and the data is being fed into a 3-D compositional simulator computer model which will be continuously updated throughout the life of the project. The simulator will be used to verify and enhance our reservoir characterization work and aid in the site selection and design of the WAG scheduled for part two. Laboratory testing such as produced gas analysis and oil PVT tests are nearing completion as well. The site of our infill well/core hole has been narrowed down based upon the results of our reservoir geology and injectivity tests and we expect to commence drilling in July. A full 100 foot core will be analyzed, including routine core analysis, thin sections and SEM/EDX analysis with the results used to update both the STRATAMODEL and 3-D simulator model.

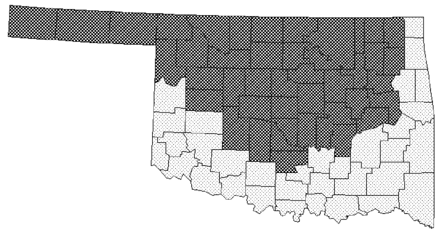
Publications: Applications of Advanced Petroleum production technology and water alternating gas injection for enhanced oil recovery - Mattoon Oil Field, Illinois: Annual report, DOE/BC/14955-8.

Recent/Upcoming Technology Transfer Events: "Enhanced recovery opportunities in Illinois Basin using carbon dioxide" Illinois Oil and Gas Association annual meeting in Evansville, Indiana Mar 2-4, 1994.

Project Status: Project terminated at the end of Budget Period I.

Identification and Evaluation of Fluvial-Dominated Deltaic Reservoirs -- Class I

University of Oklahoma



Geologic Plays: Morrow, Booch, Statewide

Layton-Osage Layton, Skinner and Pru,

Red Fork, Tonkawa, Cleveland and Peru,

Bartlesville, Oklahoma

Pennsylvanian Age

DE-FC22-93BC14956

Contract Period:
1/15/1993 to 12/31/1997

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Objective: The Oklahoma Geological Survey, with the Geo Information Systems department and the School of Petroleum and Geological Engineering at the University of Oklahoma, will conduct a comprehensive collection and multi-disciplinary evaluation of information on Oklahoma fluvial-dominated deltaic oil reservoirs to identify conventional recovery technologies that have been (or could be) applied with commercial success. The project has implemented a technology transfer program targeted for the operators of studied reservoirs.

Technologies Used: The OGS Computer Facility is equipped with PCs, CD-ROM readers, an inkjet plotter, a laser printer, and scanning equipment. Geologic and engineering software, such as Geographix, ArcView, Rockworks, Toolkit, various reservoir and production simulators and models, and programs for pump optimization, log analysis and fracture analysis, are available for public use.

Background: This project is conducting a comprehensive collection and multi-disciplinary evaluation of information on Oklahoma fluvial-dominated deltaic oil reservoirs to identify conventional recovery technologies that have been (or could be) applied with commercial success. While a wealth of experience and knowledge exists regarding these technologies and reservoirs, much of it is in a form which is inaccessible or inconvenient to those who could benefit most from it: the operators of FDD reservoirs. This is the first such comprehensive statewide program of study addressing a specific geologically defined reservoir group.

Incremental Production: Not applicable

Expected Benefits and Applications: Light oil production from Class I reservoirs is a major component of Oklahoma's crude oil production. Nearly 1,000 fluvial-dominated deltaic (FDD) reservoirs provide an estimated 15% of the state's crude oil production. Most Class I reservoir production in Oklahoma is by small companies and independent operators who commonly do not have ready access to the information and technology required to maximize exploitation of these reservoirs. Thus, production from Class I reservoirs in Oklahoma is at high risk because individual well production is low (1-3 barrels per day) and operating costs are high. Without positive intervention, most of the production from Oklahoma Class I reservoirs will be abandoned early in the next century. This is the first such comprehensive statewide program of study addressing a specific geologically defined reservoir group.

Accomplishments: The response to this program from the Oklahoma industry has been very positive, with numerous attendees returning to attend multiple workshops. There is strong support from industry for the Survey to continue the 'play-based' workshop and publication series for other depositional environments once this FDD program is completed. The publication and workshop materials for each play include an overview of FDD depositional environments, a regional overview of each play, and field studies of selected reservoirs. All of the information collected from each of the plays is being included in a digital format in the OGS Computer Facility. Also included in the computer facility is the Natural Resources Information System (NRIS), a set of digital data files on petroleum information in Oklahoma. The Oklahoma Geological Survey (OGS), in cooperation with Geo Information Systems and the School of Petroleum and Geological Engineering of the University of Oklahoma, has completed the investigation of fluvial-dominated deltaic light-oil reservoirs in Oklahoma. The study produced the identification of 10 plays that were incorporated into 8 publications: Morrow Play, Booch Play, Layton and Osage-Layton Play, Skinner and Prue Plays, Cleveland and Peru Plays, Red Fork Play, Tonkawa Play, and Bartlesville Play. A total of 14 workshops were presented on these plays with a total attendance of 1,200 operators and other interested parties at these workshops. Responses to each of the workshops were uniformly high with most attendees indicated that this was the best thing ever done for them. The 8 publications produced through this program are among the all time best sellers for the Oklahoma Geological Survey. Complementary copies of the publications were made available to operators within these plays who were not able to attend the workshops. Play publications were produced as Oklahoma Geological Survey Special Publications, and are available for the Oklahoma Geological Survey.

Because of this strong response and requests from those who were unable to attend these workshops when they were scheduled, an agreement has been reached with the Oklahoma City Geological Society (OCGS) to present jointly each of the workshops again in a one-half day format. The first of the workshops repeated the Tonkawa Play to be presented on March 31, 1998 at the Home Builders Association Building in Oklahoma

City. The OCGS or the OGS may be contacted for more details. The remaining workshops will be presented on a periodic basis to be determined in the near future. Because of the strong interest shown by operators and other interested parties in play-based workshops, the Oklahoma Geological Survey decided to continue the program with in-house resources and has begun work on the development of the Hartshorne Play. This play will include the development of coal-bed methane in the Hartshorne Coal. Presentations of this information were made on September 30, 1998 at the Francis-Tuttle VoTech in Oklahoma City and again at the Indian Area VoTech in Muskogee on November 4, 1998. A novel concept added to this workshop is an optional two-day field trip that examined outcrops of various Hartshorne depositional environments that produce hydrocarbons in the subsurface in adjacent areas. The field trip was held November 11-12, 1998.

Publications: The following eight publications have been produced through this program: (1) OGS SP 95-1 "Fluvial-Dominated Deltaic (FDD) Oil Reservoirs in Oklahoma: The Morrow Play." (2) OGS SP 95-3 "Fluvial-Dominated Deltaic (FDD) Oil Reservoirs in Oklahoma: The Booch Play." (3) OGS SP 96-1 "Fluvial-Dominated Deltaic (FDD) Oil Reservoirs in Oklahoma: The Layton and Osage-Layton Play." (4) OGS SP 96-2 "Fluvial-Dominated Deltaic (FDD) Oil Reservoirs in Oklahoma: The Skinner and Pru Plays". (5) OGS SP 97-1 "Fluvial-Dominated Deltaic (FDD) Oil Reservoirs in Oklahoma: The Red Fork Play". (6) OGS SP 97-3 '"Fluvial-Dominated Deltaic (FDD) Oil Reservoirs in Oklahoma: The Tonkawa Play". (7) OGS SP 97-5, "Fluvial-Dominated Deltaic (FDD) Oil Reservoirs in Oklahoma: The Cleveland and Peru Plays". (8) OGS SP 97-6, "Fluvial-Dominated Deltaic (FDD) Oil Reservoirs in Oklahoma: The Bartlesville Play". (9) Banken, M. K, 1998, "Identification and Evaluation of Fluvial-Dominated Deltaic (Class I Oil) Reservoirs in Oklahoma": Final Report, Oklahoma Geological Survey, University of Oklahoma, Norman, Oklahoma; November 1998, DOE/BC/14956-16 (DE98000547).

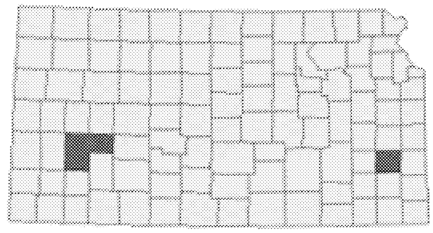
Recent/Upcoming Technology Transfer Events: Project Homepage http://www.ou.edu/special/ogs-pttc
(1) Jock A. Campbell, "FDD Reservoir Systems in Oklahoma: the Osage-Layton field study", Tulsa Geological Society, February 23, 1999. (2) Jock A. Campbell, "Major Pennsylvanian Fluvial-Deltaic Light Oil Reservoir Systems in Oklahoma", Oklahoma Geological Survey; DOE Oil and Gas Conference, June 28-30, 1999, Dallas Texas.

Project Status: Project completed. Final report published November 1998.

Improvement of Oil Recovery in Fluvial-Dominated Deltaic Reservoirs in Kansas -- Class I

University of Kansas

Morrow Sandstone	Stewart Field
@ >1,000 ft.	Finney County, KS
Cherokee Sandstone	Savonburg Field
@ >1,000 ft.	Allen County, Kansas
Pennsylvanian Age	Kansas Uplift



DE-FC22-93BC14957

Contract Period:
6/18/1993 to 9/30/1999

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Objective: The University of Kansas has combined with two oil operators to demonstrate the applications of current technologies for increasing oil recovery in Kansas. The demonstration sites are the Savonburg Field (Cherokee sandstone) and Stewart Field (Morrow sandstone).

Technologies Used: Reservoir modeling, numerical simulation, core analysis, petrophysical properties, interference test/tracer, pressure testing, permeability modification, infill drilling, waterflooding, and improved reservoir management.

Background: The University of Kansas geological and engineering groups, along with a group of operators, have demonstrated the applications of current technologies for increasing the recovery efficiency and economics in Cherokee and Morrow sandstone fluvial-dominated deltaic reservoirs in Kansas. Two field demonstration sites were selected - the Savonburg and Stewart fields. The projects include a broad range of technologies: (1) reservoir management, (2) polymer flooding, (3) in-situ permeability modification, and (4) infill drilling for bypassed mobile oil. The production problems include: (1) poor volumetric sweep due to reservoir heterogeneity, (2) clogging of injection wells with solids during waterflooding, and (3) poor waterflood sweep efficiency (4) lack of optimization of production through reservoir simulation and management.

Incremental Production: Waterflood optimization and reservoir management in the Savonburg Field have offset the production decline rate and have yielded estimated incremental oil of 31,000 barrels. Stewart Field is currently producing in excess of 100,000 barrels of oil per month. Production increase in the Stewart Field resulting from water injection is approximately 3,000 barrels of oil per day. Total incremental production for the Stewart Field is 1,634,782 BO through July1999.

Expected Benefits and Applications: Application of the air flotation process for water injection cleanup will be applicable to several fields that have common water injection problems. This technology will reduce well cleanup costs and lower operating costs. Optimizing the waterflood patterns and improving the injection water quality by installing an air flotation unit will be applicable in many fields. The project has demonstrated that proper reservoir management can significantly improve oil recovery.

Accomplishments: Engineering and geologic studies were carried out on the Savonburg Field. The studies identified areas of high potential for unrecovered mobile oil. An in-fill well was drilled and cored, which confirmed the results from these studies. Based on this work, well workover plans and waterflood pattern changes are being developed which target high potential areas. Waterflood water quality was studied and a water clean-up system incorporating air flotation was designed and installed in the field. Injection water quality has been improved significantly with a 90% decrease in solids content. The incremental production from Savonburg Field is estimated at 363,000 barrels of oil. Air flotation was successfully implemented as a method to improve water quality. Different techniques concerning wellbore cleanup were developed, and the technologies were transferred to local service companies for widespread use in the shallow slim-hole completed wells of eastern Kansas.
Engineering and geologic studies including the computer simulation of the Stewart Field have been accomplished. Primary production was history matched with the computer model. Simulation and study of polymer-augmented waterflooding indicated that this process would not be economical on the Stewart Field. Several alternative waterflood designs were examined with the simulator. Based on the simulations, waterflooding appears to be technically and economically attractive. Laboratory studies have indicated that the reservoir has some sensitivity to water. Based on these studies, a waterflood was designed and implemented in the Stewart Field. A reservoir management strategy has been developed which incorporates continued multidisciplinary analysis of waterflood data and updating the computer model in an attempt to optimize secondary recovery. The Stewart Field has responded favorably to water injection with oil production increasing from less than 300 BOPD to over 3150 BOPD. Incremental production from Stewart Field from March 1996 to July 1999 is 1.64 million barrels of oil and the ultimate recovery is estimated to be 4 million barrels. The Stewart Field project was awarded, "Best Advanced Recovery Project in the Mid-Continent" by Hart's Oil & Gas World for 1995. Lowered operating costs for production water treatment. Improved quality of injected and produced water. Optimized waterflood oil recovery through improved reservoir management techniques in the Stewart Field. General methodologies were developed and disseminated for the evaluation and exploitation of mature oil reservoirs.

Publications: (1) Reynolds, R.R., G.P. Willhite, M. Jensen, 1997. "Implementation and Monitoring of the Stewart Field Waterflood": Proceedings of the Twelfth Oil Recovery

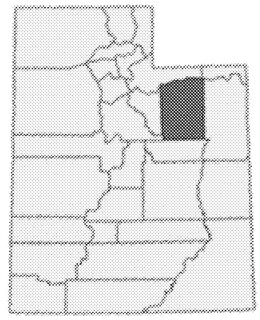
Conference, Wichita, Kansas, Tertiary Oil Recovery Project, The University of Kansas, Contribution 14, Lawrence, Kansas. (2) Barnett, B., 1997. "Savonburg Project progress report": Proceedings of the Twelfth Oil Recovery Conference, Wichita, Kansas, Tertiary Oil Recovery Project, The University of Kansas, Contribution 14, Lawrence, Kansas. (3) Michnick, M., 1997. "Problems in the use of air flotation for cleaning produced water": Proceedings of the Twelfth Oil Recovery Conference, Wichita, Kansas, Tertiary Oil Recovery Project, The University of Kansas, Contribution 14, Lawrence, Kansas. (4) A paper published on the Stewart Field project in the "PTTC/World Oil Case Study Digest." (5) Articles on both the Stewart and Savonburg projects were highlighted in a North Mid-continent PTTC newsletter in the Spring of 1999. (6) Reynolds, R. R., D. W. Green, G. Paul Willhite, M. J. Michnick and D. McCune, 1999, "Improved Oil Recovery in fluvial-dominated deltaic reservoirs of Kansas": The Class ACT, DOE Newsletter, Vol. 5, No. 1, Winter 1999. (7) Green, D. W., G. P. Willhite, A. Walton, R. Reynolds, M. Michnick, L. Watney, D. McCune, 1999, "Improved Oil Recovery In Fluvial Dominated Deltaic Reservoirs of Kansas - Near Term": Annual Report June 17, 1997 to June 17, 1998, University of Kansas, Center for research Inc. Lawrence, Kansas; January 1999, DOE/BC/14957-23 (OSTI_ID: 2715). (8) Reynolds, R. 1999. "Waterflood in Kansas field should boost recovery by five million bbl", Petroleum Technology Digest, September 1999, p. 1-4.

Recent/Upcoming Technology Transfer Events: : (1) Bill Guy , "Log Analysis Case Studies of Many Kansas Formations": PTTC Modern Techniques in Wireline Logging Workshop, November 19, 1998, Wichita, Kansas. (2) A presentation on the Stewart Field project was made at the North American Prospect Expo (NAPE) in Houston, TX on January 27-28, 1999. (3) Presentation made at the Society of Independent Earth Scientists (SIPES) 1999 annual convention and seminar in Wichita, KS on March 10-12, 1999. (4) Sizemore, J., "Maximizing oil recovery rates in the Stewart Field waterflood", 13th Tertiary Oil Recovery Conference, Wichita, KS, March 17-18, 1999. (5) Michnick, M. J. and B. Barnett, "Field experience in obtaining high quality injection water using air flotation in the Savonburg Field", 13th Tertiary Oil Recovery Conference, Wichita, KS, March 17-18, 1999. (6) Case study presentations on both the Stewart and Savonburg projects were presented at a North Midcontinent PTTC technology workshop on waterflooding during the summer of 1999.Green, D, "Improved Oil Recovery in fluvial Dominated Deltaic Reservoirs of Kansas", DOE Oil & Gas Conference, June 28-30, 1999, Dallas, TX. (7) Presentation at KIOGA meeting, Wichita, KS, August 27-29, 2000. (8) Presentation at 14th Tertiary Oil Recovery Conference, Wichita, KS March 14-15, 2001.

Project Status: Project completed December 1999. Final report published June 2000.

Green River Formation Water Flood Demonstration Project -- Class I

Inland Resources, Inc.



Green River Formation	Monument Butte Unit
@ 5,600 ft.	Duchesne County, UT
Eocene Age	Uinta Basin

DE-FC22-93BC14958

Contract Period:
10/21/1992 to 3/31/1996

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Objective: This project is designed to (1) evaluate the success of the Monument Butte Unit waterflood and determine the recovery mechanisms, (2) extend the waterflooding technology to the nearby Travis and Boundary Unit project areas, (3) develop new techniques to characterize reservoir heterogeneity and evaluate the response of the reservoir to the waterflood, and (4) transfer the technology to operators, regulators, other government agencies, and the final community.

Technologies Used: Core/Fluid analysis, numerical simulation, logging tool, paraffin control, characterization, drilling tests, waterflood, reservoir modeling.

Background: Waterflooding technology was not commonly used in the Uinta Basin due to the low permeability, heterogeneity and paraffinic oil of the reservoirs. Contrary to convention, Lomax successfully implemented a waterflood on their Monument Butte property. Primary methods produced about 5% of the original oil in place (OOIP). Production from waterflooding indicated an estimated recovery of 20% OOIP. This project was developed to identify the recovery mechanisms operating in the successful waterflood of the fluival deltaic reservoir, and to test the applicability of the process to other nearby, similar fields. The project is a waterflood demonstration project in the Green River Formation of the Uinta Basin. This project was started by Lomax Exploration, which was sold to Inlands Resources during the course of the project.

Incremental Production: As of December 1994, a total of 241,768 bbl of incremental oil have been produced from the Monument Butte and Travis Units since project start in October 1992.

Expected Benefits and Applications: Both the waterflooding process demonstrated and the techniques used are expected to apply to other fields in the area, as well as to other high-paraffin, heterogeneous reservoirs. The widespread application of the waterflooding technology to other high-paraffin oil reservoirs could add reserves as much as tens of millions of barrels of oil. Thirteen waterflood projects have been initiated by other companies in the area. More than 300 wells will ultimately be waterflooded based on the technologies demonstrated by the project.

Accomplishments: Case studies for Monument Butte, Travis, and Boundary Units have been completed. Five wells in Monument Butte, two wells in Travis Unit, and two wells in the Boundary Units have been drilled and completed. Full-diameter core, FMI logs, side wall cores, porosities, permeabilities, detailed isopach maps, relative permeabilities, PVT properties, and bulk fluid properties have been completed. Comprehensive history match from numerical simulations, performance predictions, unit expansions, infill analysis, visualization, wax precipitation, heat transfer, bulk properties, compositions, PVT properties, and corefloods have been completed. Case study of reservoir models, expanded reservoir models, infill models, and wax models have been completed. Geostatistical analysis of reservoir properties and sand connectivities has been completed. Demonstration of the use of waterflooding technology in high-paraffin oil reservoirs has been very successful and the has been adopted by other companies in the Rocky Mountains.

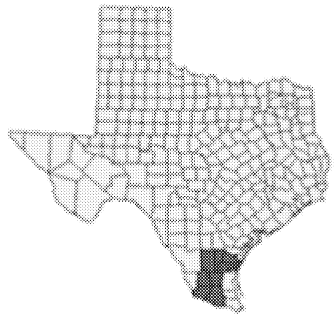
Publications: (1) Pawar, et al., "Effect of Scale and Connectivity on Primary and Secondary Recovery". SPE/DOE 10th Symposium on Improved Oil Recovery, April 21-24, Tulsa, OK. (2) Deo, M., Miharia, A., and Kumar, R., 1995, "Solid Precipitation in Reservoirs Due to Non-isothermal Injections", SPE Paper 28967, presented at the SPE International Oilfield Chemistry Symposium, San Antonio, TX, February 1995. (3) Deo, M. D., Neer, L. A., Whitney, E. M., Nielson, D. L., Lomax, J. D. and Pennington, B. I., 1995, "Description and Performance of a Lacustrine Fractured Reservoir", SPE 28938, presented in the Poster Session of the Annual Fall Meeting of the Society of Petroleum Engineers. (4) B. Marin, "Advanced fracture modeling in the Uinta Basin (Utah) for optimizing primary and secondary recovery", 4th Naturally Fractured Reservoir Symposium, October 27, 1998, Socorro, New Mexico. (5) Gill, Douglas, 1998. "Uinta Basin", Oil and Gas Investor, Vol. 18, No. 3, March 1998, pp. 26-37.

Recent/Upcoming Technology Transfer Events: An invited paper was presented on the results of the comprehensive geologic characterization and reservoir simulations at the American Association of Petroleum Geologists Rocky Mountain regional meeting in July 1996, Billings, Montana.

Project Status: Project initiated by Lomax Exploration company which sold to Inland Resources Inc. during the course of the project. Project completed. Final report published November 1996.

Revitalizing Mature Oil Play Strategies for Finding and Producing Unrecovered Oil in Frio Fluvial-Deltaic Reservoirs of South Texas -- Class I

Bureau of Economic Geology



Frio Formation	Vicksburg Fault Zone
@ 2,000 ft.	Nine South Texas Counties
Oligocene	Texas Coastal Plain

DE-FC22-93BC14959

Contract Period:
10/21/1992 to 8/31/1996

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Objective: The objectives of this project are to develop interwell-scale geological facies models and assess engineering attributes of Frio fluvial-deltaic reservoirs in selected fields in order to characterize reservoir architecture, flow unit boundaries, and the controls that these characteristics exert on the location and volume of unrecovered mobile and residual oil. Technology transfer will be coordinated through producer organizations.

Technologies Used: 3-D seismic, methods of evaluating old electric logs, Visual Basic 4.0 and Access Software, and StrataModel Software.

Background: The Bureau of Economic Geology has focused efforts on the Frio fluvial/deltaic sandstone associated with the Vicksburg Fault Zone in South Texas; Hidalgo, Starr, Brooks, Jim Hogg, Jim Wells, Duval, Kleberg, and Nueces Counties. Seventy reservoirs out of 129 in this oil play have already been abandoned. Estimates are that 1.6 billion bbl of unrecovered mobile oil will remain unproduced unless advanced reservoir characterization techniques are applied. Advanced reservoir characterization techniques including high-frequency stratigraphic analysis, stratigraphic analysis of 3-D seismic data, and 3-D reservoir modeling will be applied to selected reservoirs in the Frio fluvial-Deltaic Sandstone (Vicksburg Fault Zone) trend of South Texas.

Incremental Production: 500 Mcfd

Expected Benefits and Applications: The results of these studies will lead directly to the identification of specific opportunities to exploit these heterogeneous reservoirs for incremental recovery by recompletion and strategic infill drilling Development of an illustrated microcomputer-based guide to reservoir characterization, Geologic Advisor Software.

Accomplishments: Development of Geologic Advisor Software which will allow more detailed, accurate, and rapid analysis of mature oil reservoirs. The computer program takes the results beyond the geological interpretation to statistical and engineering models. Reservoirs were screened from fields within the Frio Fluvial-Deltaic Sandstone (Vicksburg Fault Zone) oil play of South Texas, and two fields were selected for detailed study: T-C-B Field, located in the northern part of the trend in Jim Wells Co., and Rincon Field, located in the south in Starr Co. Regional reservoir characterization, including statistical analysis of the remaining oil resource potential of the play, has been completed, and a Topical Report explaining statistical methodology and results has been published. Detailed characterization studies have targeted those reservoirs in T-C-B and Rincon fields that have the greatest potential for untapped compartments and new pools. A Topical Report, summarized the multidisciplinary characterization methods used, with specific examples from Rincon Field. Results of this work were the focus of a workshop developed by the Bureau of Economic Geology and TIPRO in cooperation with GRI, DOE, the State of Texas, and PTTC and presented to operators within the play in the summer of 1995. A model has been developed that allows the prediction of reservoir architecture and heterogeneity based on position within a depositional cycle. This model was presented to representatives of eight major U.S. and foreign oil companies as part of a field trip sponsored by GRI in the summer of 1995 Technology Transfer for this project has included 15 publications, plus presentations at 8 technical conferences.

Publications: (1) McRae, L. E., and M. H. Holtz, 1995, "Strategies for Optimizing Incremental Recovery from Mature Reservoirs in Oligocene Frio Fluvial-Deltaic Sandstones, Rincon Field, South Texas": Transactions, Gulf Coast Association of Geological Societies, v. 45, p. 423-433. (2) Knox, P. R., and L. E. McRae, 1995, "Application of Sequence Stratigraphy for Prioritizing Mature Reservoirs for Incremental Growth Opportunities, An Example from Frio Fluvial-Deltaic Reservoirs", T-C-B Field, South Texas: Transactions, Gulf Coast Association of Geological Societies, v, 45, 0. 341-350. (3) Holtz, M. H., 1996, "Reservoir Characterization Methodology to Identify Reserve Growth Potential": SPE/DOE Improved Oil Recovery Conference, April 22, Tulsa, Oklahoma, Transactions. (4) Knox, P. and M. Barton, 1999. "Predicting interwell heterogeneity in fluvial-deltaic reservoirs: Effects of progressive architecture variation through a depositional cycle from outcrop and subsurface observations" *in* R. Schatzinger and J. F. Jordan, Editors, Reservoir Characterization - Recent Advances, AAPG Memoir 71, AAPG, Tulsa, OK, p. 57-72.

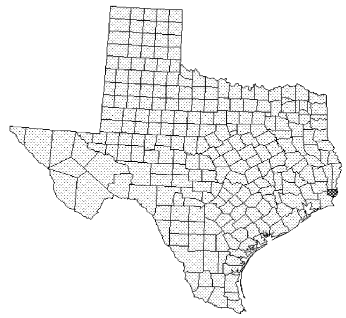
Recent/Upcoming Technology Transfer Events: (1) May 19-22, 1996, AAPG Annual Meeting, P. R. Knox, "Accommodation-Based Controls on Fluvial-Deltaic Reservoir Compartmentalization: Examples from the Oligocene Frio Formation, South Texas", San Diego, CA. (2) June 6, 1996, Houston Geological Society Continuing Education

Shortcourse, "New Oil from Old Fields: Identifying Opportunities for Reserve-Growth Potential in Mature Fields of the Frio Fluvial-Deltaic Sandstone Play, Vicksburg Fault Zone", Houston, Texas. (3) October 4, 1996, GCAGS Annual Meeting, P.R. Knox, "Determining Between-Well Reservoir Architecture in Deltaic Sandstones Using Only Well Data: Oligocene Frio Formation, Tijerina-Canales-Blucher Field, South Texas". (4) Knox, Paul and Mark Barton, Mar 2-4 1997. "Predicting Interwell Heterogeneity in Fluvial-Deltaic Reservoirs: Outcrop Observation and Applications of Progressive Facies Variation Through a Depositional Cycle": Fourth International Reservoir Characterization Technical Conference; Houston, Texas. (5) Paul Knox, "The Reservoir Characterization Advisor": University of Texas, BEG, Software Demonstration, DOE Oil and Gas Conference, Workshop, June 28-30, 1999, Dallas Texas.

Project Status: Project completed. Final report published September 1996.

Post Waterflood CO_2 Miscible Flood in Light Oil Fluvial-Dominated Deltaic Reservoirs -- Class I

Texaco E&P



Frio Formation — Port Neches Field

@ 5,900 ft. — Orange County, TX

Oligocene Age — East Texas Basin

DE-FC22-93BC14960

Contract Period:
6/1/1993 to 12/31/1997

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504/ 680-1728
504/ 680-6577

Objective: This project will use a combination of a CO_2 miscible flood and horizontal gas injection to increase production in a watered-out salt dome reservoir. The site of the proposed project is the Port Neches Field in southeastern Texas. The process will be compared in two adjacent fault-block reservoirs, one producing under partial water drive conditions and the other post-waterflood.

Technologies Used: Core Analysis: Sidewall and conventional. Fluid Analysis: PVT analysis of recombined fluids. Log Analysis: Porosity to permeability transforms. Well tests: Production tests; radioactive tracer test. Seismic: 3-D seismic. Reservoir modeling: 3-D model incorporating porosity-permeability data, layering, and honoring seismic and biased model based on knowledge of depositional model. Recompletion: Workover existing wells. Horizontal drilling: Drilled horizontal CO_2 injection well injecting at O/W contact. CO_2 injection: CO_2 WAG injection; CO_2 huff-'n'-puff treatments.

Background: This project involves CO_2 flooding of pressure-depleted Marginulina sands in the Port Neches field. Production was discovered in 1929. Two fault blocks are involved in this project with the strength of water drive varying between fault blocks. In the larger fault block, reservoir pressure had declined 2,700 psi to 100 psi when waterflooding was started in 1965. Water drive support was somewhat stronger in the smaller fault block, which had not been waterflooded. Primary production in the larger and smaller fault blocks was 40.4% and 42.9% of the OOIP, respectively. Waterflooding had recovered an additional 14.4% of the OOIP from the larger fault block. Before the project, production from the larger fault block was only 25 BOPD and 1,200 BWPD. One well in the smaller fault block produced 5 BOPD and 50 BWPD.

Incremental Production: Peak - 480 BOPD @ 10/94; 350 BOPD @ April 1995. Primary production in the larger fault block was 40.4% OOIP. Waterflooding has recovered an additional 14.4% of the OOIP.

Expected Benefits and Applications: If successful, process would be applicable to a large number of Gulf Coast reservoirs. The project plans to demonstrate the benefits of CO2 flooding in a watered-out salt dome reservoir using a horizontal CO2 huff-'n'-puff injection well. CO2 flooding in watered-out salt dome reservoir; horizontal CO2 huff-'n'-puff injection well.

Accomplishments: The project required the installation of CO2 facilities. Liquid CO2 was purchased, transported to the field via a four-inch pipeline, then injected. Initial operations focused on the larger fault. Texaco injected salt water to raise reservoir pressure, then began injecting CO2 in 1993 in vertical injection wells. The planned horizontal CO2 injection well was drilled in early 1994, but mechanical problems limited the horizontal section to only 250 ft rather than the planned 1,500 ft. To control premature CO2 breakthrough, CO2 and water are alternately being injected in the injection wells. The 3-D seismic data indicate that the smaller fault block area is too small to justify CO2 flooding, so CO2 huff-'n'-puff treatments are being used. A software model for screening candidate reservoirs was developed (streamtube screening model). Ten workovers completed, unitization approved, and reservoir pressure raised from 1850 psi to 2350 psi. Conducted an extensive 3-D compositional simulation study to model reservoir performance. Developed, in conjunction with LSU Petroleum Engineering Department, a reservoir model screening tool for the CO2 miscible process. One hundred and ninety seven light oil, waterflooded Louisiana reservoirs were screened for CO2 applicability. Developed a reliable analytical method for tertiary reserves prediction, production rates and CO2 volumes using type curves. Proved the WAG process to be an effective mobility control method in highly permeable sands. The technology has not spread to other fields.

Publications: (1) Bou-Mikael, S., "Post Waterflood CO2 Miscible Flood in Light Oil, Fluvial-Dominated Deltaic Reservoir," Annual Report to DOE for period Oct. 1, 1993-Sep 30, 1994, DOE/BD/14960-8, July 1995. (2) Bou-Mikael, S., "Post Waterflood CO2 Miscible Flood in Light Oil, Fluvial-Dominated Deltaic Reservoir," Interim Project Report to DOE for period Sept. 30, 1994-May 31, 1995, Aug. 1995. (3) Bou-Mikael, S., "A New Analytical Method to Evaluate, Predict, and Improve CO2 Flood Performance in Sandstone Reservoirs," SPE 35362, SPE/DOE Improved Oil Recovery Symposium, Tulsa, OK, April 21-24, 1996.

Recent/Upcoming Technology Transfer Events: None scheduled.

Project Status: Project completed December 1997. Final report published February 2002.

Dynamic Enhanced Recovery Technologies -- Class I

Columbia University

Multiple sandstones	Eugene Island Block 330
@ 9,000 to 12,000 ft	Offshore Federal Waters, LA
Pleistocene Age	Gulf of Mexico

DE-FC22-93BC14961

Contract Period:
7/15/1993 to 4/30/1996

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Objective: This project will test the concept that the growth faults in a Gulf of Mexico field are conduits through which the producing reservoirs are charged and that enhanced production can be developed by producing from the fault zone. The field demonstration will be accomplished by drilling and production testing of growth fault systems associated with the Eugene Island Block 330 operated by Pennzoil in Federal waters off Louisiana.

Technologies Used: Core and fluid analysis, biostratigraphic analysis, 4-D seismic (time as the 4th dimension), borehole image and other advanced logging techniques, well testing, reservoir modeling and numerical simulation, infill drilling.

Background: The Eugene Island Block 330 field covers portions of 7 blocks near the southern edge of the Louisiana Outer Continental Shelf in water depths of 210 to 266 ft. The field consists of two rollover anticlines, bounded to the north and east by a large arcuate, down to the basin growth fault system. More than 25 Pleistocene sandstones are productive at depths of 4,300 to 12,000 ft. Faulting and permeability barriers separate these sands into more than 100 oil and gas reservoirs. Previous work, which incorporated pressure, temperature, fluid flow, heat flow, and seismic, production, and well log data, indicated active fluid flow along fault zones. The EI 330 Field is ideally suited for this study because it represents a discrete subbasin in which fluid flow has unquestionably occurred very recently in geological terms, thus providing a strong temperature and pressure signal. Hydrocarbon production there is from thermally immature sediments as young as 400,000 years BP, but the oils are from a source that is at least Cretaceous in age. Thus, recent mitigation and trapping must have occurred in these reservoirs.

Incremental Production: One million barrels of incremental oil produced.

Expected Benefits and Applications: This work could reshape the oil producer's view of where productive reservoirs might lie. If the new strategies are successful, producers in the future may avoid drilling large numbers of expensive, deep dry holes. Rather than trying to drill vertically through thousands of feet of rock-hard salt to deep hydrocarbon sources, they may be able to take advantage of the growth fault fracture system to tap deep-seated hydrocarbons as they migrate upward. These new insights could increase production from existing Gulf Coast oil fields and lead to significant upward revisions of supply estimates in the U.S. Gulf of Mexico Basin. Benefits may also extend to other similar sedimentary basins, such as those in Nigeria, the North sea, Indonesia, and the Caspian Sea. This project explores (1) the concept that Pleistocene reservoirs in the Offshore Louisiana Gulf Coast may be undergoing active 'recharge' by hydrocarbons migrating along growth faults and (2) the possibility that producing wells might be established by completion in the growth fault migration pathways.

Accomplishments: Pathfinder well was drilled into a major growth fault bounding Eugene Island 330 reservoirs. Over 350 ft of core was retrieved from the fault zone. Fluid samples were also obtained. Production could not be established in the fault zone because fracture permeability closed with production. Success in coring that introduced new technology and success in predicting the location of oil flow has promoted other fault zone tests by industry. Real-time visualization database is online and accessible by project partners. Research results have been presented to industry partners through semiannual meetings and publications, and hands-on exhibits have been presented at national technical society meetings. An oil company team member used the technology gained in this project to drill a 1,500 bbl/day well. AKCESS.BASIN basin modeling program has been released commercially. 4-D Seismic Analysis Software (with time as the fourth dimension) was developed as a product of this project. 4-D technology had spread to 60 field by 1999.

Publications: (1) Anderson, R., P. Flemings, S. Losh, and R. Woodhams, 1994b, "Gulf of Mexico growth fault drilled, seen as oil, gas migration pathway": Oil & Gas Journal, Vol. 92, (June 6) p. 97-103. (2) Anderson, R., P. Fleming, S. Losh, J. Whelan, L. Billeaud, A. Austin and R. Woodhams. 1994, "The Pathfinder Drilling program into a major growth fault in Eugene Island 330, Gulf of Mexico: Implications for behavior of hydrocarbon migration pathways": CD-ROM, Columbia, Lamont-Doherty Earth Observatory. (3) Losh, S. and J. Wood, 1994, "Brine chemistry, South Eugene Island Blocks 316 and 330": in R. Anderson, ed. Results of the Pathfinder Drilling Program into a major growth fault: GBRN/DOE Dynamic Enhanced Recovery Project in south Eugene Island 330 Field, Gulf of Mexico, CD-ROM, Lamont-Doherty Earth Observatory. (4) Losh, S., 1998, "Oil Migration in a Major Growth Fault: Structural Analysis of the Pathfinder Core, South Eugene Island Block 330, Offshore Louisiana": AAPG Bulletin, Vol. 82, No. 9, p. 1694-1710. (5) Losh, S., L. Eglinton, M. Schoell and James Wood, 1999, "Vertical and Lateral Fluid Flow Related to a Large Growth Fault, South Eugene

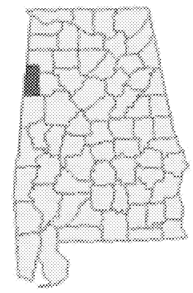
Island Block 330 Field, Offshore Louisiana": AAPG Bulletin, Vol, 83, No. 2, p. 244-276.

Recent/Upcoming Technology Transfer Events: None

Project Status: Project is completed. Final report edited for format and length and included on Class I CD released by DOE June 2001.

Utilization of the Microflora Indigenous to and Present in Oil-Bearing Formations to Selectively Plug the More Porous Zones Thereby Increasing Oil Recovery During Waterflooding -- Class I

Hughes Eastern Corporation



Carter Sandstone	North Blowhorn Creek Field
@ 2,300 ft.	Lamar County, Alabama
Mississippian Age	Black Warrior Basin

DE-FC22-94BC14962

Contract Period:
1/1/1994 to 6/30/1999

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N/A

Objective: Test the ability of indigenous microorganisms to preferentially plug the more porous zones of previously waterswept areas of the Carter sandstone in North Blowhorn Field, Lamar County, Alabama, thereby increasing oil recovery during waterflood.

Technologies Used: Core analysis: microorganism counts, porosity/permeability, core description, SEM, relative permeability; coreflooding. Chemical/microbial and petrophysical analysis completed. Fluid analysis, tracer studies.

Background: This project is designed to test the ability of indigenous microorganisms to preferentially plug the porous zones of previously waterswept areas of the Carter sandstone in North Blowhorn Creek Field, Lamar County, Alabama, thereby increasing oil recovery during waterflood. Incremental production of 0.5 to 1.0 million barrels of oil is possible if the technology is expanded field wide. The project differs from other MEOR projects by using inorganic nitrogen and phosphorus fertilizer (recently an addition of molasses) to stimulate the growth of indigenous microorganisms. The nutrients are injected in carefully controlled concentrations and sequences to preclude overgrowth. Live cores from newly drilled wells were employed to validate the nutrient injection scheme and make any necessary adjustments to ensure maximum efficiency. The efficacy of the process was evaluated by comparison of results to injector producer complexes not receiving nutrient supplementation.

Incremental Production: Incremental production rate is 100 BOPD. As of Dec 1998 69,000 BO had been produced by MEOR.

Expected Benefits and Applications: Low cost process for improving waterflood sweep efficiency. Waterflood sweep improvement by stimulating growth of in-situ microorganisms by nutrient (inorganic nitrogen and phosphorus fertilizers, plus molasses) injection. The concept is designed to test the ability of indigenous microoganisms to preferentially plug the more porous zones of previously waterswept areas of the Carter Sandstone in North Blowhorn Field, Alabama. The potential for application to other reservoirs is high.

Accomplishments: Waterflood fluid diversion in the reservoir through stimulation/growth of in-situ microoganisms. Extended life of reservoir by 5 years with a total increase of 595,000 bbls of oil above natural decline. The 1997 annual report reveals that after 34 months of nutrient supplementation to 10 injection wells for 22 producing wells in the test patterns, 11 show positive response, 9 remain in natural decline and 2 show signs of improvement. Five wells have been drilled and placed on production. The cores indicate that much oil in the reservoir has been bypassed or unswept by historic water-flood. The amount of residual oil in the cores underscores the need for improving conventional water-flood technology in stratified reservoirs. Chemical and microbiological analysis of the live cores recovered in 1994 and 1996 have been completed. The live core flooding tests confirmed that indigenous bacteria in the subject reservoir rock could be stimulated to grow by supplying the bacteria with sufficient amounts of nitrogen and phosphorous. Restriction of flow through the cores was accomplished as predicted, and electron microscopy demonstrated numerous micro-organisms in the treated cores. Chemical, microbiological, and petrophysical baseline data on the wells in the test patterns (both control and test) were completed. The test pattern injection wells accepted the nutrient injection for over three years with no noticeable adverse effects on injectivity other than a gradual decline, which may be the result of microbial permeability restriction in the reservoir. Experimental technology; application has not spread to other fields, but has spread within North Blowhorn field. Because of positive results, project was expanded from 4 to 10 test injectors in July 1997. Since then 12 out of 19 producers have responded positively. Waterflood fluid diversion was successful in the reservoir through stimulation/growth of in-situ microorganisms. Project received the 1998 Hart's Award for Best Advanced Recovery Project in the Gulf Coast Section. Operators in fields in several other states are considering implementing the microbial technology as the results of presentations on this project.

Publications: (1) Brown, L. and Vadie, A. A., "The Utilization of the Microflora Indigenous to and Present in Oil-Bearing Formations to Selectively Plug the More Porous Zones Thereby Increasing Oil Recovery During Waterflooding," Annual Report to DOE for period Jan. 1-Dec. 31, 1995. (2) Brown, L.R., Vadie, A. A., Stephens, J. O., and Azadpour, A., "Enhancement of the Sweep Efficiency of Waterflooding Operations by In-Situ Microbial Population of Petroleum Reservoirs," Paper presented at Fifth International Conference on Microbial Enhanced Oil Related Technology for Solving Environmental Problems, Plano, Texas, September 11-14, 1995. (3) Brown, L.R., Vadie, A. A., and Stephens, J. O., "Utilization of Indigenous Microflora in Permeability Profile Modification of Oil-Bearing Formations" SPE 35448, SPE/DOE Improved Oil

Recovery Symposium, Tulsa, OK, April 21-24, 1996. (4) "Going Underground to Spy on MEOR Microbes and Finding Way MEOR Barrels of Incremental Oil" L.R. Brown, A. A. Vadie, and J. O. Stephens; The Class Act Vol. 4/1, Winter, 1998. (5) L.R. Brown, A.A. Vadie, J. O. Stephens, “Slowing Production Decline and Extending the Economic Life of an Oil Field: New MEOR Technology”, SPE 59306, SPE 12th Improved Oil Recovery Symposium, Tulsa, OK, April 2-5, 2000.

Recent/Upcoming Technology Transfer Events: (1) Brown, L. "Field Demonstration of the ability of in-situ microorganisms in the oil-bearing formations to modify waterflooding profiles": AAPG Eastern, Lexington, KY, September 28-30, 1997. (2) Lewis Brown, "Using Microorganisms to Improve Oil Recovery" March 13, 1998, Department of Biology, University of Nevada at Las Vegas. (3) Lewis Brown, "Microbial Enhanced Oil Recovery" October 10, 1998, Ann. Meeting Southern Great Lakes Sec. Society of Industrial Microbiology, Michigan State University. (4) Lewis Brown, "Microbial Enhanced Oil Recovery", October 21, 1998, Long Beach, CA Chapter SPE. (5) A workshop, "Microbial enhanced Oil Recovery: North Blowhorn Creek Unit, Black Warrior Basin, Northwest Alabama", Jackson, Mississippi, November 4, 1998. (6) J. O. Stephens, L.R. Brown and A. A. Vadie made presentation on MEOR at Bartlesville, OK SPE meeting on 2/18/99. (7) J. O. Stephens and L.R. Brown made presentations on MEOR at Midland, TX SPE Reservoirs Study Group on 2/11/99. (8) MEOR presentation at PTTC workshop in Morgantown, WV, 3/30/99. (9) MEOR presentation at PTTC workshop Rocky Mountain SPE Section, Gillette, WY, May 1999. (10) Jim Stephens, Lewis Brown and Alex Vadie, "Microbial Enhanced Oil Recovery North Blowhorn Creek Unit": PTTC Workshop, June 3, 1999, Midland, TX. (11) James O. Stephens, "A Low Cost Solution for Enhanced Waterflood Performance", Hughes Eastern Corporation; DOE Oil and Gas Conference, June 28-30, 1999, Dallas Texas. (12) Brown, Lewis, “Enhanced Oil Recovery using Microbial Permeability Profile Modification Technology”; AAPG Pacific/ SPE Western Regional Joint Meeting, Long Beach, CA, June 19-22, 2000.

Project Status: Project complete. Final report published November 1999.

West Hackberry Tertiary Project -- Class I

Amoco Exploration and Production Co.

Hackberry Formation	West Hackberry Field
@ 8,000 ft.	Cameron Parish, Louisiana
Oligocene Age	Mississippi Salt Basin

DE-FC22-93BC14963

Contract Period:
9/3/1993 to 7/2/2002

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Objective: Amoco and the DOE are field testing the concept that air injection can be combined with the double displacement process (gas displacement of a water-invaded oil column to generate tertiary oil recovery through gravity drainage) to create a new EOR process for light oil reservoirs that would be profitable in today's economic environment. Although other gasses such as nitrogen or carbon dioxide can be combined with the double displacement process, air is lower cost and universally accessible even in remote or environmentally sensitive areas.
Technologies Used: Reservoir fluid and gas analysis, injectivity tests, production tests, reservoir modeling, directional drilling, open hole and closed hole logging, air injection, and gravity drainage.

Background: In fluvial-dominated deltaic reservoirs, miscible gas floods (involving CO_2) are considered the strongest candidates for generating tertiary oil recovery. Few CO_2 floods have been attempted in these reservoirs due to the poor accessibility and high cost of CO_2. In steeply dipping West Hackberry oil reservoirs, gravity drainage recovers 80% - 90% of the OOIP while waterdrive recovers 50% - 60% of the original oil in place. By injecting air into a watered out or low pressure reservoir with a thin oil rim, a gas cap can be created or expanded to allow gravity drainage to occur thereby generating recoveries similar to miscible floods. Additionally, air injection combines excellent accessibility with low cost. The limiting factors to this process are the need for sufficient reservoir temperature for spontaneous combustion and sufficient bed dip for gravity drainage. Spontaneous combustion is required to prevent problems associated with oxygen breakthrough to producing wells.

Incremental Production: On the north flank of the field air injection has increased oil production by 120% above the decline in three low pressure reservoirs. As of November 1998 air injection has increased production by 300 BOPD with a total of 165,000 barrels of incremental oil production.

Expected Benefits and Applications: Over 3 million barrels of incremental oil recovery is expected from West Hackberry. Air injection is less costly than CO2 and can be applied in areas where CO2 is unavailable. It can be applied to many similar reservoirs throughout the Gulf Coast and other areas of the U.S. where deep reservoirs contain steeply dipping strata and high temperature environments. The double displacement process will be used to produce oil by gravity drainage. Air injection and in-situ combustion will repressurize the reservoir and create a front of combustion gases accelerating the gravity drainage process. The double displacement process will be used to produce oil by gravity drainage. Air injection and in-situ combustion will repressurize the reservoir and create a front of combustion gases accelerating the gravity drainage process.

Accomplishments: First economically viable EOR process which utilizes air injection in low pressure reservoirs. Evidence of in situ combustion and increased reservoir pressure in both high pressure and low pressure reservoirs by 1997-8. In July of 1997, air injection in the low pressure Cam C reservoir on the North Flank of the field was interrupted when the injection well became plugged with iron oxide. As of November 1998, air injection had increased oil production in the North Flank Cam C by 300 BOPD greater than the expected decline. By August 1998 over 165,000 barrels of incremental oil have been produced from the North Flank with an estimated 3 million barrels of incremental production expected from this project over the next twenty years. Air injection rates in the SL 42 No. 155 have averaged only 400 to 500 thousand standard cubic feet per day (MSCFD) due to iron oxide plugging the wellhead filter. To increase injection rates, facilities modifications are being implemented which are expected to relieve the plugging problem. One additional injector, the SL 42 No. 221, was added to the Cam C Reservoir during the fourth quarter of 1998 to increase injection rates and to provide a backup injector for the reservoir. Air injection began in the North Flank Cam D in December of 1997. The Cam D has one injector and two producers. The Cam D is by far the largest of the three low pressure North Flank reservoirs and thereby contains the most reserves. As of November 1998, air injection had increased production by 40 BOPD over the established decline. As a result of recent success in the low pressure reservoirs, two operators are looking at the process in their fields.

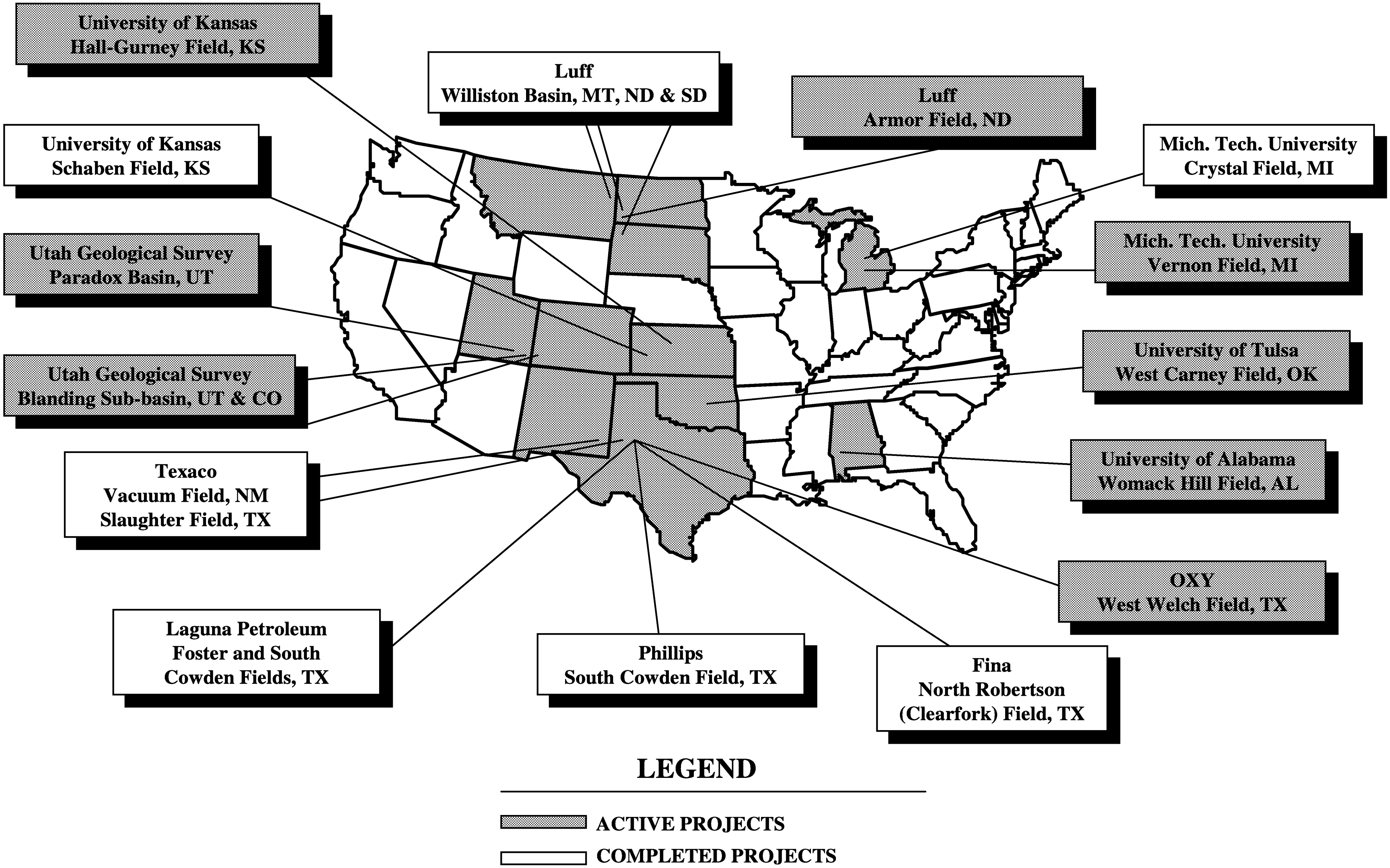
Publications: (1) During the last week of October 1997, an article discussing the West Hackberry Air Injection Project appeared in the Enhanced Energy Recovery News. (2) The November, 1997, issue of World Oil included an article entitled "A New/Economically Viable EOR Process for the U.S. Gulf Coast" which was co-authored by representatives from Amoco and LSU.

Recent/Upcoming Technology Transfer Events: (1) On October 6, 1997, "Keys to Increasing Production Via Air Injection in Gulf Coast Light Oil Reservoirs", T. Sullivan, SPE Annual Technical Conference and Exhibition in San Antonio, Texas. (2) On October 17, 1997, "Air Injection Enhanced Oil Recovery and 3-D Seismic: Revitalizing an Aging South Louisiana Oil Field" at the Gulf Coast Association of Geological Societies' (GCAGS) Annual Convention in New Orleans, Louisiana. (3) On October 30, 1997, Amoco personnel reviewed the West Hackberry project at a technology transfer event in Houston, Texas, for the Texas Railroad Commission. (4) On January 23, 1998, a talk entitled "Air Injection: Low Cost IOR for Gulf Coast Reservoirs" was given at a technology transfer conference in New Orleans sponsored by LSU's Basin Research Institute. (5) On February 10, 1998, a West Hackberry talk was presented to the monthly meeting of the Mississippi Geological Society in Jackson, Mississippi. (6) T. Gillham, "Low Cost IOR: An Update on the West Hackberry Air Injection Project", SPE/DOE Eleventh Symposium on Improved Oil Recovery was held on April 19-22, 1998, in Tulsa, Oklahoma. (7) A talk on the West Hackberry project was presented to the Society of Professional Earth Scientists on January 21, 1999, in Houston, TX. (8) Gillham, T., "Air injection in a Gulf Coast light oil field", DOE Oil & Gas Conference", June 28-30, 1999, Dallas, TX.

Project Status: Project terminated at end of Budget Period I June 1999. Final report published March 2002.

CLASS II

Class II Oil Recovery Projects



Using Recent Advances in 2D Seismic Technology and Surface Geochemistry to Economically Redevelop a Shallow Shelf Carbonate Reservoir: Vernon Field, Isabella County, MI/Class Revisit

Michigan Technological University

Dundee Formation | Vernon Field

@ 2,950 to 3,000 ft. | Isabella County, MI

Devonian Age | Michigan Basin

DE-AC26-00BC15122

Contract Period:
3/20/2000 to 3/19/2005

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Objective: Develop and execute an economical and environmentally sensitive plan for recovery of hydrocarbons from an abandoned shallow-shelf carbonate field.

Technologies Used: 2D seismic, surface geochemistry (iodine, microbial, enzyme leaching, soil gas analysis), multilateral horizontal drilling, coiled tubing technology and well logging.

Background: Vernon field produces from the Dundee and Trenton formations in the Michigan Basin. Vernon field is one of the earliest oil and gas developments in the Michigan Basin, dating back to 1930. The field predates all other Dundee discoveries in the state except for Port Huron, Muskegon and Mt. Pleasant. An excellent producer, Vernon totaled 5,000,000 barrels of oil from the 78 original wells. The average recovery per acre drilled is 5,700 barrels. Estimated recovery for this prospect is 1,500,000 barrels of oil utilizing a 50% recovery factor.

The producing zone in Vernon is the upper Dundee "Rogers City" member. The reservoir rock type is secondary dolomite that characteristically has good porosity and permeability with abundant vugs and fractures. Although the field is situated atop a prominent plunging anticline, the oil pool is primarily the result of an updip permeability barrier type stratigraphic trap. The southern updip lateral seal for the reservoir dolomite is impervious limestone. The "top of porosity" over Vernon coincides with the nearly 100% altered (dolomitized) rock. This is a very common feature in Michigan reservoirs and most hydrocarbon production in fields of this type comes from this zone. Producibility problems, which the projects will address: 1) locating remaining oil, 2) characterizing the reservoir architecture (structure, alternation and facies distribution), and 3) efficiently draining remaining hydrocarbons. Economic considerations are paramount: 3D seismic is too expensive, yet the structure and extent of dolomitization needs to be better known prior to drilling. Recent advances in 2D seismic acquisition and interpretation for the first time permit resolution of structure beneath the glacial till and surface geochemical surveys have been shown to be reliable in mapping hydrocarbon anomalies that may identify regions of poorly drained or by-passed pay.

Incremental Production:

Expected Benefits and Applications: Provide a technology to image beneath glacial till. Use cost-effective 2D seismic and surface geochemistry to map hydrocarbons concentrations. Geochemical survey samples are easy to collect, easy to interpret, and are inexpensive (around $20 per sample).

Accomplishments: (1) A surface geochemistry survey employing 5 different techniques (surface iodine, microbial, enzyme leaching, soil gas, and subsurface iodine) was carried on in the Spring and Summer of 2000 and a demonstration well was drilled in Vernon Field in the fall of 2000. (2) The demonstration well was selected and drilled based on geological considerations and surface geochemistry. (3) Over 800 samples were collected and analyzed over the drill site for the horizontal well. A good anomaly was detected near the proposed well site. (4) The vertical well was drilled to a depth of 3157 ft, and two laterals were drilled and hydrocarbons located in a zone approximately 175 in length. However it was determined that the pay zone was too small and high water production prevented putting the well in production. The sell was shut in and abandoned in January 2001. The post mortem revealed the presence of unmapped shale plug crossing the fist lateral. The shale was detected by the geochemical survey, but its significance was not appreciated at the time. Vernon field and the demonstration well will be used to calibrate future geochemical data. (5) The geochemical survey suggested the best results can be obtained from microbial data, but note that direct measurement of soil gas demonstrates promise if they can be made easier to interpret. (6) The project tentatively concluded that horizontal wells do not provide a cost-effective solution in this setting and suggest that geochemical anomalies be investigated via a single vertical well or multiple vertical wells. (7) The detailed mapping of the Central Michigan Basin has revealed for the first time the presence of eleven major faults that control the location of many of the reservoirs in the Michigan Basin. These faults appear to control the location of many of the large anticlinal structures in the Michigan Basin and likely controlled fluid movements as well.

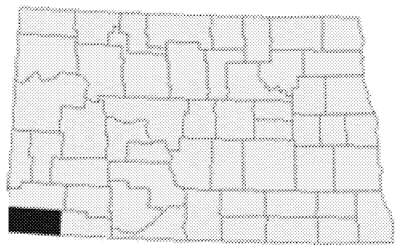
Publications:
(1) Wood, J. R., T. J. Bornhorst, W. B. Harrison, D. A. Barnes, W. Quinlan and E. Taylor. 2001. Multi-lateral well pays off in Vernon Field, MI. *The Class ACT*, DOE newsletter, Winter 2001, Volume 7, no. 1, p. 8-10.

Recent/Upcoming Technology Transfer Events: (1) A mini-workshop held in Traverse City, Michigan at the May meeting of the Michigan Oil and Gas Association. (2) Wood, James, "Economic Use of Geochemistry and 2-D seismic technology to redevelop a shallow shelf carbonate reservoir, Vernon field, Michigan", Joint Pacific AAPG and SPE Western Regional Meeting, *Working In Concert*, Long Beach, CA, June 19-22, 2000. (3) Harrison, W. B. 2000. Using recent advances in 2-D seismic technology and surface geochemistry to economically redevelop a shallow shelf carbonate reservoir: Vernon Field, Isabella County, MI. National Petroleum Technology Office, DOE, Oil Technology Program. (4) Wood, J. R. T. J. Bornhorst, S. D Chittick, W. B. Harrison, W. Quinlan, and E. Taylor, Results of recent drilling at Vernon Field, MI, and a Geological Model for the top of the Dundee Fm. At Vernon Field, Isabella County, MI: AAPG Eastern Section, Kalamazoo, MI, September 23-25, 2001.

Project Status: Budget Period II

Intelligent Computing System for Reservoir Analysis and Risk Assessment of Red River Formation/Class Revisit

Luff Exploration Company



Red River Formation	Amor Field
@ 9,500 ft.	Bowman County, ND
Ordovician Age	Williston Basin

DE-FC26-00BC15123

Contract Period:
3/1/2000 to 9/30/2003

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Objective: Develop an intelligent computing system and apply to reservoir-production models for analysis of seismic and geologic data relating to management, development and exploration problems in Class II reservoirs.

Technologies Used: Intelligent Computer System (ICS) based on clustering and neural networking, 3-D seismic.

Background: Twenty five years of data collected on the Red River formation, a shallow shelf carbonate in the Williston Basin will be assimilated into a computer based reservoir analysis system. The Red River is widespread in the Williston Basin of North Dakota, South Dakota and Montana, but successful drilling locations are often difficult to identify and extensive seismic survey are expensive for small independent operators. The goals of this project are to locate and produce oil reserves that may not be targeted with existing methodologies. This technology will be used to identify and map nonlinear relationships between 3-D seismic, production, geological and petrophysical data in the Red River formation. The method will focus on neural-net computing, fuzzy logic, genetic computing and probabilistic reasoning in conjunction with conventional techniques such as geostatistical and classical pattern recognition.

Incremental Production:

Expected Benefits and Applications: Intelligent Computing System (ICS) is being used for reservoir characterization to identify drilling location s in carbonate reservoirs in the southern Williston Basin. ICS employs clustering and neural network or fuzzy logic techniques to make predictions of reservoir quality and position of oil/water contacts that have guided horizontal drilling on structural features in the Red River formation at 9,500 ft. Phase I version ICS, software is free and can be downloaded from the project website, **http://www.luffdoeproject.com/**

Accomplishments: Provided the oil chemistry data to develop source rock report fall 2001. All available for electronic well information has bee provided for Basin Model and Oil Maturation report September 2001. A capillary study has begun from well logs and cores to complete a rock-typing report of the Red River. Seismic data has been incorporated into a seismic model and attribute study. Software tools in ICS are completed for evaluating data sets from seismic, geological and engineering sources. The Intelligent Computing System is being developed as a set of modules for different data sets and reservoir characterization objectives. These modules are organized in a fashion after human-thought processes involved in prospect evaluation. The first module is aimed at characterizing the depositional setting. The next nodule will attempt to characterize the growth history (tectonic movement) after deposition to present time. The next module will attempt to predict reservoir development directly from various seismic attributes obtained from 3D seismic surveys. Related to the 3D seismic-attribute module is a module that will work with 2D seismic data. Another module will also use attributes from 3D seismic survey s but will be focused on predicting fluids, i.e. higher oil saturation. A module for estimating the reservoir entrapment potential will also be developed.

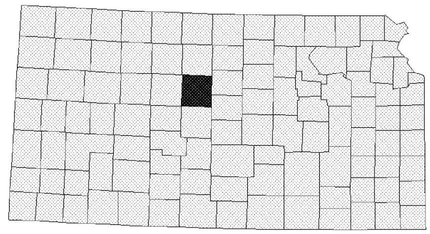
Publications:

Recent/Upcoming Technology Transfer Events: (1) Luff, K. D. 2000. Intelligent computing system for reservoir analysis and Risk assessment of Red River Formation. National Petroleum Technology Office, DOE, Oil Technology Program Contractor Review Meeting, June 27, 2000. (2) An internet website with update information of the project has been constructed and activated. **http://www.luffdoeproject.com/**

Project Status: Budget Period II.

Field Demonstration of Carbon Dioxide Miscible Flooding in the Lansing-Kansas City Formation, Central Kansas/Class Revisit

University of Kansas



Lansing-Kansas City Formation | Hall-Gurney Field

@ 2,985 ft. | Russell County, KS

Upper Pennsylvanian Age | Central Kansas Uplift

DE-FC26-00BC15124

Contract Period:
3/8/2000 to 3/7/2006

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Objective: Demonstrate the viability of carbon dioxide miscible flooding in the Lansing-Kansas City formation on the Central Kansas Uplift and to obtain data concerning reservoir properties, flood performance, and operating costs and methods to aid operators in future floods. The project addresses the producibility problem that these Class II shallow-shelf carbonate reservoirs have been depleted by effective waterflooding leaving significant trapped oil reserves. The objective is to be addressed by performing a CO_2 miscible flood in a 40-acre pilot in a representative oomoldic limestone reservoir in the Hall-Gurney Field, Russell County, Kansas. At the demonstration site, the Kansas team will characterize the reservoir geologic and engineering properties, model the flood using reservoir simulation, design and construct facilities and remediate existing wells, implement the planned flood, and monitor the flood process. The results of this project will be disseminated through various technology transfer activities.

Technologies Used: Core analysis, air-brine capillary pressure tests, wireline log analysis, CO_2 injection.

Background: Over the last century Kansas has produced over 6 billion barrels of oil, however, current production is only 1/3 of producing rates in the 1950's. Unless new technology is introduced, many of the 6,000 fields in Kansas will be abandoned with substantial remaining oil left in place. Carbon dioxide (CO_2) miscible flooding is the only oil recovery process that has potential of recovering additional oil from reservoirs in Kansas that have been waterflooded either naturally or by planned development. The economic potential of CO_2 miscible flooding in Kansas is enormous with possible additional estimated recovery of 250 million to one billion barrels of oil, equivalent to 6 to 25 years of additional Kansas production at current rates. Although the potential for CO_2 miscible flooding is great, technical questions concerning potential recovery and economics must be answered and the process proven to work on Kansas reservoirs before operators are willing to invest in this technology, and before financial investment in a pipeline to bring CO2 into the state can be established.

Incremental Production:

Expected Benefits and Applications: Demonstrate the viability of CO2 flooding to independent operators in Kansas.

Accomplishments: (1) Activities in Budget Period I involved reservoir characterization, modeling, and assessment of the Lansing-Kansas City reservoir and the feasibility of CO2 flooding. Testing of the Carter-Colliver #1 CO2 well indicates that the reservoir in this area of the lease is highly layered with a high permeability interval or that there is a high permeability region around the wellbore or a fracture that is tied to the reservoir with permeability less than 5 md. Modeling to distinguish between these scenarios is being performed. Injection testing of the Colliver #7 indicates a total permeability-height greater than one Darcy-foot. This injectivity confirms that this area of the lease exhibits sufficient injectivity for a demonstration within the time period of the DOR project. Computer reservoir simulations and volumetric calculation indicate that a 70-acre pattern with a single injector located between the Colliver #10 and the Colliver #7 and with surrounding producers (#3, #5, #6, #12, #1, and #8) should produce between 76,000 and 89,000 BO. Economic analysis indicates that for projected costs this recovery is sufficient for break-even for MV Energy or up to 15% internal rate of return for the higher recovery estimate.
(2) The ethanol plant in Russell, KS is operating. The owners of the plant, U.S. Energy Partners LLP reserved sufficient CO2 for the DOE pilot at Hall-Gurney field. The CO2 miscible flood demonstration project represents the first use of CO2 for enhanced oil recovery in Kansas. There have been no miscible CO2 floods in Kansas primarily due to the distance to the sources for CO2. Originally the project proposed to encourage Kansas Independents to bring a pipeline from the Texas Panhandle, however a closer more efficient source has been identified. The electrical co-generation, ethanol fuel production and CO2 enhanced oil recovery project in Kansas is a unique scalable model for linked energy systems. Waste heat from a 15-megawatt gas-fired turbine municipal generator provides heat inputs for a 40 million gallon per year ethanol plant. CO2, a fermentation process byproduct of ethanol production, will be utilized by the CO2 miscible flood project in Hall-Gurney field.
(3) Alan Pyrnes, Martin Dubois, Lynn Watney recieded the Jules Brunstein Memorial Award at the AAPG National Convention March 10, 2002 for their 2001 AAPG Poster "Field Development and Renewed Reservoir Characterization for CO2 Flooding of the Hall-Gurney Field, Central Kansas"

Publications: (1) Bradley, R. T., CO2 Breathes New Life into Old Fields: American Oil & Gas Reporter, March 2001, pp. 124-129. (2) M. K. Dubois, S. W. White, T. R. Carr and A. Brynes, 2002. CO2 Enhanced Oil Recovery, Co-generation, Ethanol Production Linked: The Class ACT, DOE newsletter, Vol. 8, No 2.

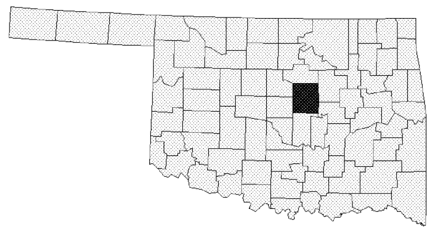
Recent/Upcoming Technology Transfer Events: (1) Byrnes, Alan P. 2000. Field demonstration of carbon dioxide miscible flooding in the Lansing-Kansas City Formation, Central Kansas. National Petroleum Technology Office, DOE, Oil

Technology Program Contractor Review Meeting, June 27, 2000. (2) A web site has been constructed for the demonstration project and for data file exchange between project participants:http://www.kgs.ukans.edu/ERC/CO2Pilot/index.html. (3) "Southwest Kansas Carbon Dioxide Initiative", 14th TORP Conference, Wichita, Kansas, March 14-15, 2001. (4) M. K. Dubois, A. P. Byrnes, W. L. Watney. 2001. Field Development and Renewed Reservoir Characterization for CO_2 Flooding of the Hall-Gurney Field, Central Kansas: AAPG National Convention, Denver, CO, June 3-6, 2001. (5) Dubois, M. K., S. W. White, T. R. Carr, 2002. Co-generation, Ethanol production, and CO_2 enhanced oil recovery: A model for environmentally and economically soung linked energy systems: AAPG Annual Convention, poster, Houston, TX, March 13, 2002.

Project Status: Budget Period I extended to July 2003.

Exploration and Optimization of Reservoir Performance in Hunton Formation, OK/Class Revisit

University of Tulsa



Hunton Formation — West Carney Field

@ 5,000 ft. — Lincoln County, OK

Ordovician to Early Devonian Age — Arkoma Basin

DE-FC26-00BC15125

Contract Period:
3/7/2000 to 3/6/2005

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Objective: Understand the mechanism under which the oil is produced from Hunton Formation and to propose techniques to optimize performance of these reservoirs using various technologies.

Technologies Used: Core analysis, reservoir characterization, improved well completion technologies.

Background: The Hunton formation is a shallow shelf-carbonate reservoir of Ordovician to Early Devonian age overlying the Woodford shale. Historically the Hunton has seen little oil production because of high water production. Current development in West Carney field, in Lincoln County, Oklahoma in expanding rapidly. The oil trapping mechanism is a combination of stratigraphic and structural components. In the 1970s wells drilled in the Hunton experienced excess water production and water disposal costs became to high to produce oil. In 1995 a new well was drilled when cheaper water disposal was available. Production curves from the 1995 well indicated that the ratio of water / oil was changing. Oil increased as water production decreased. The decrease in water cut caused resurgence in drilling in West Carney field. The field has 30,000 acres in the Hunton reservoir at an average depth of 5,000 ft. Because of the high water cut waterflooding is not a cost-effective option for West Carney field.

Incremental Production:

Expected Benefits and Applications: Understanding the primary mechanism behind the oil/water ratio and disposal of excess water production would benefit other operators in the Hunton formation. The Hunton formation covers 2.7 million acres in Oklahoma and extends into Texas, New Mexico and Arkansas. The Hunton reservoir has been under exploited because of the high water cut. The project plans to improve well completions to further minimize water production.

Accomplishments: (1) Forty wells have been drilled – thirty-eight vertical and two horizontal. Thirty-four wells have been cored. The evaluations of the core data from fourteen wells have been completed. Based on geological analysis of the fourteen cored wells a facies model has been established. Relatvie permeability data was measured on several cores. The results confirm the field observations. Four distict rock types were characterized – fine matrixm coarse matrix, vugs, and fractures. (2) Based on the evaluation of production data and principal component analysis, most of the water is stored in the coarse matrix and vugs, whereas, most of the oil is stored in the fine matrix and fractured rock. (3) A method to extrapolate geological facies to non-cored wells has been developed. A reservoir model has been built and simulated to test various characteristics of the reservoir. The model has successfully simulated the anomalous behavior of the reservoir performance. (4) A computer program is being developed to evaluate the production performance of existing wells. This program provides information about reservoir properties based on prouduction data only.

Publications: (1) Mohan Kelkar, et al, 2001. Unlocking the Secrets of the Hunton Formation: Hunton News, Tulsa University Center for Reservoir Studies newsletter, Vol. 1. No. 1, 2nd quarter 2001. (2)) Marwah, V., M. Kelkar, B. Keefer, 2002. Reservoir Mechanism for Hunton Formation Production; SPR 75127 SPE/DOE 13th Symposium on Improved Oil Recovery, Tulsa, OK April 13-17, 2002. (3) Federick, J. M. Kelkar, and B. Keefer, 2002. Production Type Curves of the Hunton Formation; SPE 75248, SPE/DOE 13th Symposium on Improved Oil Recovery, Tulsa, OK April 13-17, 2002. (4) Kho, T. and M. Kelkar, 2002. History Matching Using Triple Loop Procedure; SPE 7520, SPE/DOE 13th Symposium on Improved Oil Recovery, Tulsa, OK April 13-17, 2002. (5) Derby, J., J. Podpechan, and J. Andrews, 2002. Petroleum Geology of West Carney Hunton Field; The Shale Shaker, Oklahoma City Geological Society, 2nd Quarter 2002.

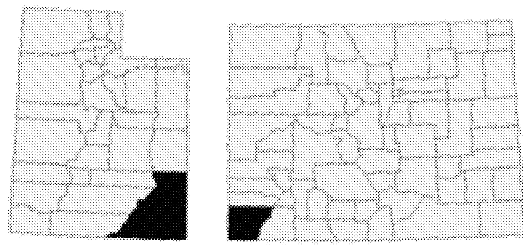
Recent/Upcoming Technology Transfer Events: (1) Derby, J. R., Kelkar, M., J. Podpechan, B. Keefer and J. Mueller. "Exploitation and optimization of reservoir performance in a retrograde-oil-cut (ROC) Hunton reservoir, West Carney field, Lincoln Co., Oklahoma: A 5-year, U. S. DOE sponsored study"; Petroleum Systems of Sedimentary Basins in the Southern Midcontinent, Oklahoma City, OK, March 28-29, 2000. (2) Kelkar, M. 2000. Exploration and optimization of reservoir performance in Hunton Formation, OK. National Petroleum Technology Office, DOE, Oil Technology Program Contractor Review Meeting, June 27, 2000. (3) Derby, J. and J. Podpechan, November 2001, Geological Description of the West Carney Field, OK, Hunton formation DOE project: Tulsa Geological Society, Tulsa, OK. (4) Derby, J. and J. Podpechan, January 2002, Geological Description of the West Carney Field, OK, Hunton formation DOE project: Oklahoma City Geological Society, Oklahoma City, OK. (5) Dan

Ferguson, February 21, 2002, Study of the West Carney Hunton Field: Lincoln & Logan Counties, Oklahoma: A Preliminary Report: Tulsa SPE monthly luncheon presentation, Tulsa, OK. (6) Kelkar, M. Production from Hunton Formation: Engineering Perspective; New Mexico Institute of Technology, September 12, 2001, and Texas A&M University, October 18, 2001. (7) **Project website:** http://www.tucrs.utulsa.edu (8) TUCRS Hunton News annual newsletter published 2nd quarter 2001, mailed to over 5,000 operators.

Project Status: Budget Period II.

Heterogeneous Shallow-Shelf Carbonate Buildups in the Blanding Sub-Basin of the Paradox Basin, Utah and Colorado: Targets for Increased Oil Production and Reserves Using Horizontal Drilling Techniques/Class Revisit

Utah Geological Survey



Ismay and Desert Creek Fm. Blanding Sub-basin

@ 5,700 ft. San Juan Co., UT & Montezuma Co., CO

Pennsylvanian Age Paradox Basin

DE-AC26-00BC15128

Contract Period:
4/6/2000 to 4/5/2005

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Objective: Increase production and reserves from the shallow-shelf carbonate reservoirs in the Ismay and Desert Creek zones of the Paradox basin.

Technologies Used: Core analysis, lithologic mapping, petrophysical analysis, reservoir modeling, horizontal wells.

Background: Over 400 million barrels of oil have been produced from shallow-shelf carbonate reservoirs in the Pennsylvanian Paradox Formation (primarily the Ismay and Desert Creek zones) in the Paradox Basin of Utah, Colorado and Arizona. The Ismay zone is dominantly limestone comprising equant buildups of phylloid-algal with local, rapidly changing small-scale subfacies. The Desert Creek zone is dominantly dolomite, comprising regional shoreline trends with highly aligned, linear facies tracts. With the exception of the giant Greater Aneth field in Utah, 100 plus oil fields in the basin typically contain 2 to 10 million barrels of OOIP per field. Most of these fields are characterized by extremely high initial production rates followed by a very short production life, and early abandonment. Only 15 to 25 % of that oil is recoverable from conventional vertical wells under primary production. At least 200 million barrels of oil is at risk of being left behind in these small fields because of inefficient development practices and undrained heterogeneous reservoirs. Proper geological evaluation of the reservoirs may increase production by 20 to 50 % by the application of horizontal, possibly multilateral horizontal drilling projects at lower costs than vertical wells.

Incremental Production:

Expected Benefits and Applications: At least 200 million barrels of oil is at risk of being left behind in small Ismay and Desert Creek fields because of inefficient development practices that leave undrained heterogeneous reservoirs. The detailed reservoir characterization and analysis of horizontal wells by the Utah and Colorado Geological Surveys will provide information and assessment of horizontal drilling prospects in the Blanding Subbasin of the Paradox Basin which small independent operators could not afford on their own. Work by the Geological Surveys will also not be restricted to individual leases or time constraints and can thus provide a more comprehensive and objective analysis.

Accomplishments: Continued to describe thin sections from samples taken from core to determine porosity types and general diagenetic history. Samples were selected and prepared for stable carbon and oxygen isotope analysis of diagenetic components such as cementing minerals and different generations of dolomites; strontium isotopes for tracing the origin of fluids responsible for different diagenetic events; scanning electron microscope (SEM) analysis of various dolomites; and dolomite pore casts to determine reservoir quality of the dolomites as a function of diagenetic history. Epi-fluorescence and cathodoluminescence petrography was begun to also determine the sequence of diagenetic events. The types and effectiveness of porosity, pore throats, and permeability in each reservoir for Ismay and Desert Creek fields were analyzed using capillary pressure/mercury injection testing.

Using the project log-based correlating scheme, began correlating representative filed and wildcat wells to construct regional maps and cross sections of facies, shales, anhydrites, etc. of the Desert Creek and Ismay Zones. Continued constructing numerous structure and isopach maps for various reservoir units in the case-study fields (Cherokee –Ismay, and Bug –Desert Creek) that will be incorporated into three-dimensional models to determine potential undrained zones suitable for horizontal drilling.

Publications: (1) Articles on the project have appeared in the Utah Geological Survey's *Petroleum News* and *Survey Notes*. (2) T. Chidsey, Jr., 2002. Carbonate Buildups in the Paradox Basin, Targeted for Horizontal Drilling; The Class ACT, DOE newsletter, Vol. 8, No 1, Winter 2002.

Recent/Upcoming Technology Transfer Events: (1) A WebPage for the project has been established by the Utah Geological Survey.
http://www.geology.utah.gov/emp/paradox2/index.html

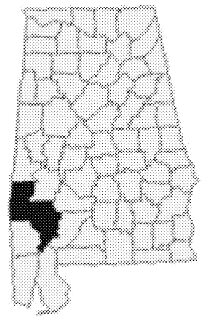
(2) Wray, L. L. 2000. Heterogeneous shallow-shelf carbonate buildups in the Blanding Sub-basin of the Paradox Basin, Utah and Colorado: Targets for increased oil production and reserves using horizontal drilling techniques. National Petroleum Technology Office, DOE, Oil Technology Program Contractor Review Meeting, June 27, 2000. (3) Eby, David, 2000. Heterogeneous shallow-shelf carbonate buildups in the Blanding Sub-basin of the Paradox Basin, Utah and Colorado: Targets for increased oil production and reserves using horizontal drilling techniques: 10th Annual National Indian Energy & Minerals Conference, Bureau of Indian Affairs, Colorado School of Mines, Golden, Colorado, June 21, 2000. (4) Eby, D. E. and T. C.

Chidsey, Jr. 2001. Heterogeneous Carbonate Buildups in the Blanding Sub-Basin of the Paradox Basin, Utah and Colorado: Targets for Increased Oil Production Using Horizontal Drilling Techniques: (Poster and Core Workshop) AAPG National Convention, Denver, CO, June 3-6, 2001. (5) L. L. Wray, N. DeShazo, D. E. Eby, 2002. Buildups in the Colorado Portion of the Blanding sub-Basin of the Paradox Basin, Colorado and Utah: Possible Targets for Increased Oil Production Using Horizontal Drilling Techniques: AAPG Annual Convention, poster, Houston, TX, March 13, 2002.

Project Status: Budget Period I extended to 1/5/2003.

Improved Oil Recovery from Upper Jurassic Smackover Carbonates (Class II Reservoir) Through the Application of Advanced Technologies at Womack Hill Oil Field, Choctaw and Clarke Counties, Alabama, Eastern Gulf Coastal Plain/Class Revisit

University of Alabama



Smackover Formation	Womack Hill Field
@11,270 ft.	Choctaw and Clark Counties, AL
Upper Jurassic Age	Mississippi Interior Salt Basin

DE-AC26-00BC15129

Contract Period:
5/1/2000 to 4/30/2006

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Objective: Increase profitability thereby extending the reservoir life.

Technologies Used: Advanced reservoir characterization, data integration, data mining and neural networks, 3-D stratigraphic and structural modeling, 3-D seismic imaging, strategic infill drilling, and immobilized enzyme applications.

Background: In the eastern Gulf Coastal Plain (Mississippi, Alabama, Florida) alone, 902 million barrels of oil have been produced from Upper Jurassic Smackover carbonates from over 150 fields. This does not include Smackover production from Louisiana, Arkansas and Texas. The project is a focused, comprehensive, integrated and multidisciplinary study of Upper Jurassic Smackover carbonates, involving reservoir characterization and 3-D modeling. The demonstration site, Womack Hill field, has estimated reserves of 119 million barrels of oil. 30 million barrels of oil have been produced since Womack Hill was discovered in 1970. Conservatively (additional 10 to 20 %), another 12 to 24 million barrels of oil can be recovered using advanced technologies in optimizing field management and production. Womack Hill field is one of 57 Smackover fields in the fault trend play of the Interior Salt Basin. The fields in this play have a common petroleum trapping mechanism (faulted salt anticlines), petroleum reservoir (microbial carbonate mudstones), overburden section, and timing of trap formation and oil migration. The field operator, Pruet Production Company, will be an active partner in the research.

Incremental Production:

Expected Benefits and Applications: It is assumed that the 902 million barrels of oil produced from the Smackover, represents a 30 % recovery. An additional 10 to 20 % of the oil in these fields can be recovered using advanced technologies. 300 to 600 million barrels of oil remain to be recovered from existing Smackover fields in the Eastern Gulf Region. The work at Womack Hill field is directly applicable to 57 fields in the Smackover fault trend in the Interior Salt Basin and can be transferred to Smackover fields located along this fault trend from Florida to Texas,

Accomplishments: (1) Budget Period I has focused on geoscientific reservoir characterization, mainly the description of cores and preparation of stratigraphic and structural cross sections of the upper Jurassic Smackover carbonates of Choctaw and Clark Counties, Alabama. These subtasks have been completed. Microbial characterization and petrophysics and engineering property characterization work are underway for Womack Hill field. Microbial characterization is on schedule although no microbial growth has been observed to date from field core, oil or produced water samples.

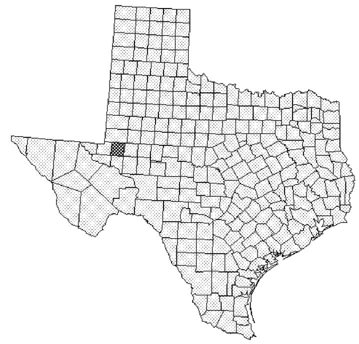
Publications: (1) Mancini, E. A. 2000. Improved recovery from Smackover carbonates at Womack Field. *The Class ACT*, DOE newsletter, Volume 7, no. 1, Winter 2001, p. 8-10.

Recent/Upcoming Technology Transfer Events: (1) Mancini, E. A. 2000. Improved oil recovery from Upper Jurassic Smackover carbonates (Class II reservoir) through the application of advanced technologies at Womack Hill oil field, Choctaw and Clarke Counties, Alabama, Eastern Gulf Coastal Plain. National Petroleum Technology Office, DOE, Oil Technology Program Contractor Review Meeting, June 27, 2000.
(2) Mancini, E. A., W. C. Parcell. 2001. Integrated Carbonate Exploration approach for Upper Jurassic Smackover Reef and Shoal reservoirs, Northeastern Gulf of Mexico: AAPG National Convention, Denver, CO, June 3-6, 2001. (3) Tedesco, W. A., R. P. Major, 2002. Stratigraphic and Diagenetic controls on production from Smackover Formation reservoirs, Womack Hill Field Eastern Gulf Coastal Plain; AAPG Annual Convention, poster, Houston, TX, March 13, 2002. (4) Mancini, E. A., W. C. Parcell. 2002. Upper Jurassic Smackover Carbonate Shoal and Reef Reservoirs of the Eastern Gulf Coastal Plain and Outcrop analogs from Western Europe: AAPG Annual Convention, poster, Houston, TX, March 13, 2002. (5) T. L. Hopkins, and W. M. Ahr, 2002. Determining Reservoir Quality by combined stratigraphic, petrographic and petrophysical methods as part of optimized recovery programs: Womack Hill Smackover Field, Clarke and Choctaw Counties, Alabama: AAPG Annual Convention, oral presentation, Houston, TX, March 11, 2002.

Project Status: Budget Period I extended to 4/30/2003.

An Integrated Study of the Grayburg/San Andres Reservoir, Foster and South Cowden Fields, Ector County, Texas -- Class II

Laguna Petroleum Corp.



Grayburg/San Andres Fm.	Foster & South Cowden fields
@ 4,200 ft.	Ector county, TX
Early Permian Age	Permian Basin

DE-FC22-93BC14982

Contract Period:
8/2/1994 to 8/2/2000

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Objective: Address production problems typically associated with shallow shelf carbonate reservoirs. This project will demonstrate that 3-D seismic data can be used to aid in identifying porosity zones, permeability barriers, and thief zones and thereby improve waterflood design.

Technologies Used: Core/Fluid analysis, 3-D seismic, reservoir modeling, numerical simulation, well stimulation, recompletions, infill drilling/coring, waterflood redesign.

Background: Reservoirs in the Foster and South Cowden fields were approaching economic limit and the 68 year old lease would be abandoned within 10 years. A multi-disciplinary approach to waterflood design and implementation, along with selective infill drilling and deepening is planned to increase reserves, extend reservoir life, and improve production. Reservoir characterization can be improved by integrating seismic derived reservoir properties, geological characterization techniques, and 3-D reservoir simulation. Additionally, with the advent of low cost state-of-the-art computer hardware and software packages, independent operators can economically afford a similar development effort.

Incremental Production: Added reserves from the project alone should be approximately 2.5 million bbl. Potential incremental addition of reserves, if applied to domestic shallow shelf carbonate reservoirs, should be greater than 1.5 billion bbl. From June 1998 to September 1998 field production increased from 9,700 BOPM to 14,000 BOPM. Incremental production as of September 2000 was 190,000 barrels of oil. Four wells in Foster/S. Cowden fields demonstrate a 7-fold production increase. Estimates of reserves arrived at in 1996 were 403,000 bbl with nine years of reservoir life remaining. In September 1999 the new estimate of reserves based on decline curves was 973,000 bbl with 16 years of reservoir life remaining.

Expected Benefits and Applications: The use of 3-D seismic data in field development will provide data for the design and interpretation of reservoir simulation, optimize infill locations, and improve implementation and monitoring of waterflood projects. Potential incremental reserves, if applied to Permian Basin shallow shelf carbonate reservoirs, could be several hundred million barrels. The use of seismic inversion model analysis, calibrated with log and core analysis, determines reservoir properties between wells.

Accomplishments: (1) 3-D seismic data were inverted to remove the seismic wavelet, producing log-like traces that have a direct relationship with carbonate rock porosity. Seismic derived porosity maps used in conjunction with a modified production history has lead to a program of plug-backs, re-stimulations and new well drilling during 1998-99. (2) 570,000 new reserves identified by seismic survey and new interpretation techniques. (3) Improved "pipeline Frac" in Wicher #2 produced 12,000 bbl in 1997. (4) Tests show that improved Frac does not penetrate the San Andres and prevents water influx into the producing Grayburg intervals. Operator savings of $30,000 per well realized by not penetrating the San Andres reservoir. (5) Lease production has increased 60%. Initial production risen from 120 BOPD to 320 BOPD. (6) Cost-effective seismic techniques estimated at only $0.20 per barrel of added reserves. (7) Redesign of waterflood to concentrate on Upper Grayburg and not penetrate the San Andres. (8) Incremental production to September 2000 is 190,000 barrels of oil with an estimated 2.5 million barrels of incremental reserves. (9) The Foster-Peque # 8 was fraced in 1998 and treated with 25, 174 gallons of cross-linked gel; and 118,580 pounds of 16/30 sand. Production rates prior to stimulation were 2 BOPD, 15 BWPD. After the frac and stimulation the well had stabilized at 22 BOPD, 450 BWPD and held for over 60 days with no indication of decline. (10) Cost-effective testing of wells has improved the selection of good recompletion candidates. (11) Proven reserves increased by 600,000 barrels during project. (12) Re-fracs increased oil production by sever-fold. (12) Incremental oil produced and future reserves developed at a cost of $3.80 per barrel. (13) cumulative production for Foster-S. Cowden project area (Section 36) reached 6.6 MMBO by the end of 2000. (14) Ultimate recovery for the Upper Grayburg increased from 18% to 21%. (15) Recompletion strategies continue to be used on the lease after the end of the project in September 2000. One well was reentered in December 2000, and additional unswept areas in the Foster lease, south of the project area have been taken over by Laguna for development. (16) Current production stands at 8,000 barrels of oil per month, four times the production in 1993 when Laguna took over the lease.

Publications: (1) Weinbrandt, R. M., R. C. Trentham, and W. Robinson, "Incorporating Seismic Attribute Porosity into a Flow Model of the Grayburg Reservoir in the Foster-

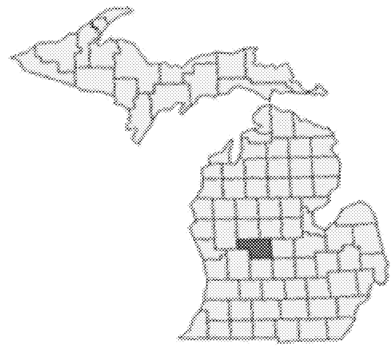
South Cowden Field": Texas West Texas Geological Society Fall Symposium, October 29-30, 1998, Midland, Texas. Published *in,* The Search Continues into the 21st Century, WTGS Publication 98-105, eds., W. D. DeMis and M. K. Nelis. (2) Robinson, W., 1998, "The Role of Seismic Inversion Modeling in Describing Reservoir Characteristics: A Case Study, Part I": West Texas Geological Society Bulletin, Vol. 38, no. 4, p. 4-11, December, 1998. (3) Robinson, W., 1999, "The Role of Seismic Inversion Modeling in Describing Reservoir Characteristics: A Case Study, Part II": West Texas Geological Society Bulletin, Vol. 38, no.5, p. 4-14, January, 1999. (4) Trentham, Robert C., 1999, "A tale of two simulations or how 3D seismic was used to improve production in an old field": *The Class ACT*, DOE Newsletter, Vol. 5, No. 1, Winter 1999. (5) Trentham, R. C. and K. Widner, 1999, "Using produced water analyses to evaluate production problems and recompletions in an Old Waterflood; Foster-South Cowden Fields, Ector County, Texas: *in* J. Campell, ed,. Mapping the Future: Fundamental Geology/ New Technology Transactions and abstracts of the AAPG SW Section Convention, Abilene Geology Society, Publication 99-1, p. 95. (6) Trentham, R. C. and K. Widner, 1999, "Using produced water analyses to evaluate production problems and recompletions in an Old Waterflood; Foster-South Cowden Fields, Ector County, Texas: *in* Luftholm, P. and G. Hinterlong, eds., Permian Basin: Providing Energy for America: West Texas Geological Society Symposium, p. 9-18. (7) Weinbrandt, R. M., R. C. Trentham, W. C. Robinson, K. L. Widner, 2000, " A case history of waterflood optimization: Grayburg reservoir in the Foster-South Cowden field": SPE 59277, SPE Permian Basin Oil and Gas Recovery Conference, March 2000, Midland, Texas.

Recent/Upcoming Technology Transfer Events: (1) West Texas Geological Society 1998 Fall Symposium, October 29th & 30th, B. Trentham and W. Robinson, "An Integrated Study of the Grayburg/San Andres Reservoir, Foster and South Cowden Fields, Ector County, Texas". Update of SPE paper from IOR Symposium, Tulsa. (2) Society of Independent Professional Earth Scientists, Midland Chapter, 1998 fall Seminar, Nov 8th, "The Role of Seismic Inversion Modeling in Describing Reservoir Characteristics, a Case Study". (3) Weinbrandt, R. M., R. C. Trentham, and W. Robinson, "Incorporating Seismic Attribute Porosity into a Flow Model of the Grayburg Reservoir in the Foster-South Cowden Field": SIPES 3-D Symposium, November 11, 1998. (4) Robinson, Bill "South Cowden field, use of two simulations of 3D seismic to improve production in an old field": Permian Basin Geophysical Society**,** Midland, TX, January 13, 1999. (5) Robinson, W., "Results of Laguna Petroleum corp./ DOE – Foster, South Cowden seismic inversion modeling and porosity mapping project": Oklahoma City Geophysical Society, Oklahoma City, OK, Feb, 15, 1999. (6) Trentham, R., "Use of Water Chemistry to solve oil production problems": South West AAPG annual meeting**,** Abilene, TX, March 1, 1999. (7) Robinson, W. C., The role of seismic inversion modeling in describing reservoir characteristics: A case study: Abilene Geological Society, March 18, 1999, Abilene Texas. (8) Robert Trentham, "Incorporating Seismic Attribute Porosity into a Flow Model of the Grayburg Reservoir in the Foster-South Cowden Field", DOE Oil and Gas Conference, June 28-30, 1999, Dallas Texas. (9) Weinbrandt, R. M., R. C. Trentham, W. C. Robinson, K. L. Widner, 2000, " A case history of waterflood optimization: Grayburg reservoir in the Foster-South Cowden field": SPE 59277, SPE/DOE Improved Oil Recovery Symposium, April, 2000, Tulsa, OK.

Project Status: Project completed August 2, 2000. Final report published April 2001.

Recovery of Bypassed Oil in the Dundee Formation Using Horizontal Drains -- Class II

Michigan Technological University



Dundee Formation	Crystal Field
@ 2,350 ft.	Montcalm County, MI
Devonian Age	Michigan Basin

DE-FC22-93BC14983

Contract Period:
4/28/1994 to 12/31/1997

DOE Project Manager:
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Objective: This project has demonstrated by a field trial that horizontal wells can substantially increase oil production in older reservoirs at or near their economic limit.

Technologies Used: Horizontal drilling, MWD (Measurement While Drilling), new computer modeling and analysis.

Background: The Dundee Formation is Michigan's all-time leader with 352 million barrels of oil and 42 billion cubic feet of gas. Only 32% of the original oil in place and 80% of the original gas in place is usually recovered from hydrocarbon reservoirs during the initial production phase. Because most of Michigan's Dundee Formation reservoirs were developed with only 'primary' production techniques and most were discovered before 1960, recoveries are much less, perhaps only 10-15%. Analysis of production data for Crystal Field suggests that an additional 200,000 bbls of oil can be produced using one strategically located horizontal well. Total additional production from the Crystal Field could be greater than 2 million bbls. Spin-offs from the technology developed in this project have the potential to increase Dundee production in Michigan by 35%, adding 80-100 MMBO.

Incremental Production: : 75,000+ bbls of oil; 0 bbls water from the TOW 1-3 (Oct., 1995 - December, 1997). The TOW 1-3 repaid the entire federal investment within 24 months and has continued to pay out over 40 months from the completion date.
An update as of December 2000 indicates the TOW 1-3 well has produced over 200,000 bbl of incremental oil.

Expected Benefits and Applications: The TOW 1-3 has stimulated interest in the use of horizontal drain wells in the Dundee Formation of Michigan. This is confirmed by the number of recent permits (over 60 as of July, 1997) compared to only 1 (the TOW 1-3) in the last 20 years. Demonstrated that a short horizontal well (less than 100 feet) can drain the field economically. Also showed how to determine an optimal hydrocarbon production rate with no water coning by simple experiment i.e. by increasing flow from low (50 bbls/day) to high (100 bbls/day) over period of 3-4 months.

Accomplishments: (1) three horizontal wells (TOW 1-3, Happy Holidays 1-3, Frost 5-3) have been drilled in the Dundee at Crystal Field. All encountered unrecovered oil. The project demonstration well, the TOW 1-3, has produced over 65,000 bbls of oil through December 31, 1997. The well is presently producing at a rate of 50 bbls/day with zero water cut. (2) 60 feet of core from the demonstration well was analyzed for porosity, permeability and fluid saturation. (3) Characterization of the Crystal Field has yielded a new reservoir model and a revised set of formation tops. (4) An electronic atlas of 30 Dundee fields similar to the Crystal Field has been completed and is available on the Internet (5) A set of well logs, drillers reports and scout tickets for the 30 Dundee fields involved in this project have been in digitized and entered into an online EXCELL database. (6) Field maps and cross sections have been generated from these data for 30 fields in a seven county area and are also online. (7) Well logs have been obtained for all fields and input into a log evaluation computer program. Cross-sections have been generated. (8) Project booths were set up at 4 national and 3 regional meetings, (9) The final version of the project CD ROM summarizing the project to date has been completed and distributed to project members and to companies that have inquired. (10) Results have been communicated to the independent oil community through a newsletter and press releases. (11) partly as a result of this project, at least 20 Dundee wells Drilled and completed since the TOW #1-3 HD-1 well. This represents an additional investment of Industry dollars of about $10,000,000 in the Dundee Formation alone. (12) This project has also encouraged companies to drill horizontal wells in other Devonian horizons in Michigan: The Traverse Lime, Richfield and Detroit River sections have an additional 7 wells for an additional investment of $3,500,000. Following the drilling of the TOW 1-3, total development costs for new horizontal wells in Michigan to date are about $13,000,000. (13) Major technology transfer events include: Paper and booth at GSA in October; workshop in Traverse City, MI in January1997; project exhibit at AAPG in Dallas in April, 1997; paper at the Canadian Association of Petroleum Geologists in May, 1997; DOE contractors meeting in June1997; DOE workshop in Long Beach, CA in June, 1997. (14) Based on values of taxes paid from the production of the TOW well and subsequent development wells ($2,150,000), the total cost of the Michigan Dundee study was returned to the state and federal government through taxes within 18-24 months. Additional investment of private capital is estimated to be about 15 times the DOE costs and represents significant stimulus of economy of the State of Michigan in this sector. (15) As a result of this project, important additional oil production has been achieved,

preventing the waste of millions of barrels that were originally bypassed. Additional wells have been drilled on the flanks of the Crystal Field, the Frost 5-3 and the Happy Holidays 6-3. These wells are currently producing about 10 BOPD each with a 90% water cut. Permits have been obtained for two more wells, the Robbins and Cronus-Danforth. These wells were drilled on the crest of the Crystal structure this summer (1998). Numerous other permits (20-30) have been obtained by other companies to drill Crystal Field 'look alikes'. Annual Value of New Horizontal Wells in Devonian of Michigan based on 27 Current Wells: 1) Total daily production -- 810 bbls/day; 2) Total annual production -- 300,000 bbls; 3) Total gross value (at $17/bbl) -- $5,000,000; 4) Royalties to mineral owners -- $630,000; 5) State Severance taxes (at 5%) -- $250,000; 6) Federal, State, and Local Taxes Paid (at 33%) -- $1,650,000 The first horizontal well in Crystal Field, the TOW 1-3, spudded October, 1995. This well has since produced 75,000 bbls of oil at an average rate of 100 bbls/day with zero water cut. The TOW 1-3 demonstration well was a financial success as indicated by the metrics. Reservoir data from 30 Dundee fields have been compiled into an EXCEL database and version 1.0 is now available for user downloading on the Internet at:
http://www.geo.mtu.edu/svl/michproj/index.html
http://www.geo.mtu.edu/svl/michproj/index.html.

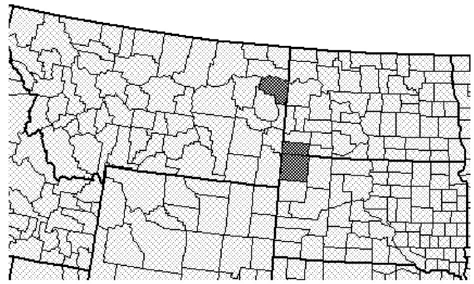
Publications: (1) Wood, J. R. et al., "Horizontal well taps bypassed Dundee oil in Crystal Field, Michigan", Oil and Gas Journal, Oct. 21, 1996, pp. 60-64. (2) Wood, J. R. et al., "Horizontal well success spurs more Devonian work in Michigan", Oil and Gas Journal, Oct. 28, 1996, pp. 60-64. (3) Montgomery, Scott L., James R. Wood and William B. Harrison III, 1998. "Devonian Dundee Formation, Crystal Field, Michigan Basin: Recovery of Bypassed Oil Through Horizontal Drilling": AAPG Bulletin, V. 82 No. 8, P. 1445-1462. (4) Wood, J. R. and W. D. Pennington, 1998, "Recovery of Bypassed Oil in the Dundee Formation (Devonian) of the Michigan Basin Using Horizontal Drains": Final Report, April 28, 1994 to December 31, 1997, September 1998, DOE/BC/14983-14 .

Recent/Upcoming Technology Transfer Events: (1) Workshop, September 18, 1997 MOGA meeting in Grand Rapids, MI.; (2) Wood, J. presentation, September 29, 1997 at Eastern AAPG Regional Meeting in Lexington, KY. (3) Two poster presentations at AAPG National Convention Salt Lake City, Utah, May 17-20, 1998. W. D. Pennington, J. R. Wood, W.B. Harrison, III: "Horizontal Drilling in Old Fields of Michigan's Dundee Formation". W. D. Everham, J.E. Huntoon: "A New Interpretation of the Subsidence History of the Michigan Basin Based on Thermal Modeling". (4) Harrison, W. B., "Crystal Field, Dundee Formation, Michigan": Midwest Region Workshop: Wireline logging applications for the Michigan Basin, February 18, 1999, Mount Pleasant, MI. (5) T. E. Bulloch, W. D. Pennington, "The use of seismic data and attributes for reservoir characterization in Crystal Field, Michigan"; AAPG Annual Convention, San Antonio, TX, April 11-14, 1999. (6) James Wood, "Basin-scale mapping and visualization of dolomite "chimneys" in the Michigan Basin", DOE Oil and Gas Conference, June 28-30, 1999, Dallas Texas. (7) Wood, J. and W. Harrison, "Improved recovery using horizontal drilling in the Dundee formation Michigan Basin", Poster, AAPG/SPWLA Hedberg Research Symposium, Oct 10-13, 1999, The Woodlands, TX.

Project Status: Project complete. Final report published September 1998.

Improved Recovery Demonstration for Williston Basin Carbonates -- Class II

Luff Exploration Company



Red River Formation	Several fields
@ 9,500 ft	Bowman County, ND
Ordovician Age	Harding County, SD
Ratcliffe Formation	Richland County, MT
@ 8,500 ft.	
Mississippian Age	Williston Basin

DE-FC22-93BC14984

Contract Period:
6/10/1994 to 12/31/1997

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N/A

Objective: Define geological characteristics of two reservoirs in the southern Williston Basin of Montana, South Dakota and North Dakota through the use of 3D seismic surveys. Test lateral completion technology such as horizontal re-entry in existing wells. Infill drilling will be targeted to areas where additional producible oil remains. If successful, a water injection pilot will follow.

Technologies Used: 3D seismic surveys, multi-component seismic, targeted infill drilling, horizontal drilling, lateral completions (jetting lance, steered mud-motor drilling),waterflooding.

Background: Exploration for Red River reserves in the Williston Basin began in the 1940s on the Cedar Creek Anticline. Single-point seismic data extended the Red River exploration into South Dakota in the 1950s. 2-D seismic technology in the 1960s allowed delineation of small, deep structures. Both the Red River and Ratcliffe study areas have been successfully explored with 2D seismic methods. Reservoir characterization of the four porosity zones of the Red River should improve drilling efficiency, and identify the best intervals in both the Red River and Ratcliffe for completion. Lateral completions should improve economics for both primary and secondary recovery where low permeability is a problem and higher density drilling is limited by drilling cost. Seismic surveys will reveal bypassed oil-bearing pay zones in complex carbonate reservoirs. The project will demonstrate whether waterflooding is technically and economically feasible in Red river and Ratcliffe formations in the Williston Basin.

Incremental Production: Three new wells penetrated by-passed reserves. Initial production per well averaged 190 bbl oil per day. Extrapolation of production data indicates more than 600,000 bbl of oil will be produced, in aggregate, by these wells.

Expected Benefits and Applications: If techniques are successful, the project will add nearly 6000,000 bbl of increased oil reserves. Application of techniques by other operators could boost recovery from their fields by about one-third. Prolong the economic life of existing oil wells. 3D seismic surveys will help identify bypassed oil areas. Lateral completion methods will improve oil productivity and injectivity to water. This will improve economics of infill drilling for additional primary reserves and new waterflood projects. The project will test lateral completion techniques, including high pressure jetting lance technology and short-radius lateral drilling to enhance completion efficiency. Additional locations containing probable by-passed reserves were identified within the 3-D seismic surveys.

Accomplishments: Four half-day workshops were presented in Denver and Billings in 1996-97. Descriptions and images of cores are published on an Internet site under the Petroleum Technology Transfer Council, Rocky Mountain Region, home page. Three wells were drilled based on study of 3D seismic surveys in Bowman Co., North Dakota. These wells encountered by-passed oil in complex carbonate reservoirs at locations near old wells. The new wells were completed with an average initial rate of 190 bbl oil per day. Recoverable reserves from the demonstration wells are expected to equal or exceed reserves produced by their old neighbors. Cumulative production from the oil wells is 637,000 bbl oil. In addition to the reserves developed by the project wells, further development potential has been identified within the 3D seismic areas and will be tested in the near future. Thirty-day water injection tests were performed in both a vertical and horizontal well in Harding Co., SD. Data from these tests were used to predict long-term injection and oil recovery. These predictions precipitated a 12-month injection pilot. Several technologies were evaluated for re-entry drilling of horizontal drain holes through casing. Tests of short and medium-reach jetting lance technologies were unsuccessful. Reservoir depths of 8500 to 9500 ft are greater than appropriate for the mechanical capability of these tools. Steered, mud-motor drilling was mechanically successful. A re-entry lateral completion in the Ratcliffe was mechanically successful but did not increase production. A new horizontal well was drilled between two vertical wells that produce from a partially depleted Red River reservoir. Production and injection tests in this well indicate two to three times productivity of nearby vertical wells. A topical report was written that discusses these activities and their results. Reservoir characterization studies of Ratcliffe and Red River reservoirs were completed. Two 3D seismic surveys were obtained in the Red River area of Bowman Co., ND. These surveys revealed the complexity of reservoir porosity and were used to target wells for by-passed oil. A 3D seismic survey and a special shear-wave seismic survey were obtained in the Ratcliffe area of Richland Co., MT. The shear-wave survey was a failure. Fracture characterization in the Ratcliffe includes acquisition of an oriented core and a special electrical log at North Sioux Pass Field, Richland Co., MT. Topical reports covering geological and engineering characterization studies discuss reservoir characteristics, producibility problems and improved-recovery technologies. Additional locations containing probable by-passed reserves were also identified within the 3D seismic surveys obtained during the project term. Luff Exploration Company is continuing to apply techniques developed during the project and plans to drill more locations from the 3D seismic surveys. Application of techniques by other operators could boost recovery from some fields by about one-third. If techniques are successful, the project will add nearly 600,000 bbl of increased oil reserves.

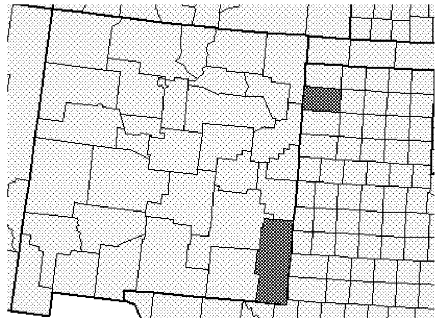
Publications: (1) Sippel, Mark A. and Michael L. Hendricks. 1997. "Geological and Engineering Characterizations of the Upper Red River Formation in the Southwest Williston Basin." SPE 38371, Society of Petroleum Engineers, Rocky Mountain regional meeting, Casper, Wyoming. May 18-21, 1997. (2) Sippel, Mark A. 1997. "Characterization of Red River Reservoirs from 3D Seismic at Cold Turkey Creek Field.", American Association of Petroleum Geologists, Rocky Mountain sectional meeting held in Denver, Colorado. August 24-27, 1997. (3) Mark Sippel, 1998, "Exploitation of Reservoir Compartments in the Red River Formation, Southern Williston Basin": RMAG Compartmentalized Reservoirs in Rocky Mountain Basins, Rocky Mountain Association of Geologists. (4) Case studies from project can be found under Rocky Mountain PTTC Homepage
http://www.mines.edu/research/PTTC/lecrr/lecrr/lecrr01.htm and
http://www.mines.edu/research/PTTC/lecrc/lecrc/lecrc01.htm

Recent/Upcoming Technology Transfer Events: (1) Sippel, Mark A., 1997. "Characterization of Red River Reservoirs from 3D Seismic at Cold Turkey Creek Field", The Denver Geological Study Group, July 24, 1997. (2) Sippel, Mark A., Kenneth D. Luff, and Michael L. Hendricks. 1997. "Red River Reservoir Study - A Success Story." Half-day workshop presented with Petroleum Technology Transfer Council, Rocky Mountain Region in Denver, Colorado and Billings, Montana, November 10 and 14, 1997. (3) Sippel, Mark A. and Kenneth D. Luff. 1997. "Demonstrating Improved Recovery in Williston Basin Carbonates", Emerging Technologies Energy Conference, Independent Petroleum Association of America held in Houston, Texas, November 17, 1997. (4) Bailey, Jim and Mark Sippel, 1998. "Characterization of Red River Reservoirs from 3D Seismic at Cold Turkey Creek Field", 4th Annual 3-D Seismic Symposium, Rocky Mountain Association of Geologists and The Denver Geophysical Society, Denver, Colorado, February 18, 1998. (5) Core and petrographic study of Red River and Ratcliffe reservoirs on the Internet at the PTTC Rocky Mountain Region home page. (6) Core and petrographic study of Red River and Ratcliffe reservoirs on CD-ROM to be distributed by the PTTC Rocky Mountain Region. (7) Mark Sippel, "Pressure Transient Results from a Red River B Horizontal Well": SPE Reservoir/EOR, May 19, 1998, Denver, CO.

Project Status: Project complete. Final report and three topical reports published July 1998.

CO2 Huff-n-Puff Process in Light Oil Shallow Shelf Carbonate Reservoir (Central Vacuum Unit), Vacuum Field, Lea County, New Mexico -- Class II

Texaco E&P



San Andres/Grayburg Fm.

@ 4,550 ft.

Permian Age

Central Vacuum Field

Lea County, NM

Slaughter Field
Hockley County, TX

Permian Basin

DE-FC22-93BC14986

Contract Period:
2/10/1994 to 12/31/1997

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Objective: The principal objective of the Central Vacuum Unit (CVU) and Sundown Slaughter Unit (SSU) CO2 Huff-n-Puff (H-n-P) project is to determine the feasibility and practicality of the technology in a waterflooded shallow shelf carbonate environment. The results of parametric simulation of the CO2 H-n-P process coupled with the CVU reservoir characterization components will determine if this process is technically and economic for field implementation. The technology transfer objective of the project is to disseminate the knowledge gained through an innovative plan in support of the Department of Energy's (DOE) objective of increasing domestic oil production and deferring the abandonment of shallow shelf carbonate (SSC) reservoirs.

Technologies Used: Reservoir characterization, geostatistics, reservoir fluid analysis, reservoir modeling, waterflood review, parametric simulations (compositional), CO2 huff-n-puff.

Background: The principal objective of the Central Vacuum Unit (CVU) and Sundown Slaughter Unit (SSU) CO2 Huff-n-Puff (H-n-P) project is to determine the feasibility and practicality of the technology in a waterflooded shallow shelf carbonate environment. The results of parametric simulation of the CO2 H-n-P process coupled with the CVU reservoir characterization components will determine if this process is technically and economic for field implementation. The ultimate goal will be to develop guidelines based on commonly available data that other operators in the industry can use to investigate the applicability of the process within other fields.

Incremental Production: Equivalent to deferred production of the injection and soak periods. Approximately 4300 barrels of incremental oil, i.e. oil over and above what would have been produced under normal operations, would be required to pay out the project. Actual incremental recovery was just 1388 barrels of oil.

Expected Benefits and Applications: The project objective was to evaluate a proven Gulf-coast sandstone technology (CO2) in a waterflooded carbonate environment. The use of the Huff-'n'-Puff process to determine CO2 injectivity and generate near term revenue parallel to capital commitments and implementation of a full-scale miscible CO2 project in a waterflooded carbonate reservoir, and to reduce risks associated with miscible CO2 flooding. Reservoir characterization found to be of secondary importance in huff-n-puff projects. Recoveries found to be related to the total CO2 volume injected. Gas trapping by hysteresis was found to be the dominant factor influencing recoveries. The Sundown –Slaughter Unit of Slaughter Field was added to Budget Period II to evaluate findings from Budget Period I field demonstration.

Accomplishments: Budget Period No. 2 was initiated September 1, 1995, with CO2 injection beginning in 11/95 at CVU. The second site, SSU, was initiated in 06/97. TEPI et. al. solicited industry partners for a 4-Dimensional, 3-Component seismic survey. The survey was conducted in conjunction with the DOE project at no cost to either TEPI or DOE. The intention of the survey was to dynamically monitor saturation changes and frontal movement associated with the CO2 injectant. The DOE project provides for public access to data, which makes this additional work possible. The findings may help refine the model/simulation following the first demonstration. Results of the seismic work are preliminary at this date--providing exciting information, which will be made available to industry partners at a later date. Individuals interested in the success of this work are referred to the Geophysics Department at Colorado School of Mines. Evaluation and history matching with compositional simulation of the 1st field demonstration is complete. The lack of trapped gas in the near-wellbore vicinity, approximately 100% of the injected CO2 well be recovered suggesting the process cannot be expected to be beneficial in the Central Vacuum reservoir. An interesting relationship has been hypothesized that may shed significant light on future successes of the process. This hypothesis and associated options were integrated at the second demonstration site at SSU for evaluation. The conclusion of the two demonstrations sites is to suggest that the process is not an economical alternative within waterflooded shallow shelf carbonate reservoirs. The addition of a new site (Sundown Slaughter Unit of Slaughter Field) was used to evaluate findings from the first demonstration.
Following the project, technologies used in this field demonstration have been successfully applied in a nearby deeper water carbonate reservoir.

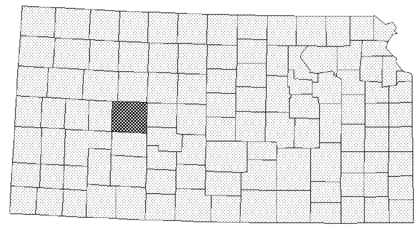
Publications: Boomer, R. J., R. Cole, M. Kovar, J. Prieditis, J. Vogt and S. Wehner, 1999. “CO2, huff-n-puff process in a light oil shallow shelf carbonate reservoir”, Final Report. DOE/BC/14986-14.

Recent/Upcoming Technology Transfer Events: Scott Wehner, "Central Vacuum: New Mexico's Newest CO_2 Flood", The 3rd CO_2 Oil Recovery Forum, October 28, 1998, Socorro, New Mexico.

Project Status: Phase I study in Central Vacuum field, Phase II field demonstration transferred to Slaughter-Sundown Unit of Slaughter field. Project complete. Final report published February 1999.

Improved Oil Recovery in Lower Meramecian (Mississippian) Carbonate Reservoirs of Kansas -- Class II

University of Kansas



Warsaw Dolomite	Schaben Field
@ 4,400 ft.	Ness County, KS
Mississippian Age	Nehama Ridge

DE-FC22-93BC14987

Contract Period:
9/16/1994 to 2/30/2001

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Objective: Demonstrate incremental reserves from lower Meramecian (Mississippian) 'Warsaw dolomite' reservoirs through application of reservoir characterization to identify areas of unrecovered mobile oil. The project addresses producibility problems including inadequate reservoir characterization, drilling and completion design problems, non-optimum recovery efficiency. The results of this project will be disseminated through various technology transfer activities.

Technologies Used: All technologies used have been adapted to be cost-effective for independent operators in mature fields. Technologies include petrophysical analysis (PfEFFER) and visualization (Pseudoseismic), core analysis using NMR, Numerical simulation on a PC, and Internet technology transfer.

Background: Site is located in the upper shelf of the Hugoton Embayment of the Anadarko Basin and produces oil from dolostones and limestones of the Lower Meramecian Warsaw Limestone and Osagian Keokuk Limestone (Mississippian) at depths of 4,350-4410'. Mississippian reservoirs in Kansas have cumulative production of over one billion barrels. The development of a petrophysical analysis package, which is a cost-effective and practical tool for operators, is a goal of the project.

Incremental Production: The additional infill locations drilled and recompletions at the Schaben Demonstration Site have resulted in a documented production increase of 200 BOPD over the last year (1997). Initial results suggest the horizontal well drilled in April 2000 will produce 80,000 to 1000,000 barrels of oil.

Expected Benefits and Applications: Offer operators a basis for evaluating the potential for bypassed and uncontacted oil in Mississippian carbonate reservoirs. The technologies and tech transfer methodologies developed have the potential to extend and enhance production in mature oilfields and basins. The application of cost-effective advanced technologies to reservoir characterization and management to improve recovery in mature Kansas reservoirs. Advanced technologies developed include a spreadsheet petrophysical analysis and reservoir evaluation (PfEFFER), and a petrophysical/seismic approach to well logs (Pseudoseismic). New methods of technology transfer using the Internet are being developed. Work using cost-effective techniques for reservoir characterization and simulation at Schaben Field has demonstrated their value for independent operators. All of the major operators at Schaben field have adopted the results of the reservoir management strategy developed and have located and drilled at least 14 new infill locations.

Accomplishments: The geologic reservoir characterization for Schaben Field was completed and used as input to a full field reservoir simulation. The simulation used a modified version of US DOE's BOAST 3. Much of the geologic, engineering and production data, including maps, cross-sections and core analyses, are available on-line at the reservoir, lease and well levels The Uniform Resource Locator {URL} is http://www.kgs.ukans.edu/ DPA/Schaben/schabenMain.html. The reservoir simulation was used to develop reservoir management techniques and located 10 infill wells and 3 recompletions that have added significant incremental reserves. A low-cost spreadsheet log analysis package (PfEFFER) was initiated as part of this project and developed as a separate project. The program is available to oil operators as a low-cost add-in to Microsoft Excel. PfEFFER Version 2.0/Pro is a cost-effective and practical tool for the real-time, interactive log analysis. Spreadsheet database and graphic features allow both rapid interaction and comparative evaluation of multiple interpretations or best case/worst case extremes. In addition, multiple wells and zones are easily managed. A project file can be generated that assembles reservoir parameter, grids them, and displays them as 2-D maps or 3-D surfaces. Requirements: PfEFFER is an add-in for Excel and requires Excel 97 to run. PfEFFER is used throughout the petroleum industry and independent interpretations based on PfEFFER are appearing in technical journals. Successful short courses using cost-effective technologies for improved management of mature reservoirs typically operated by the independent producer were developed and presented to operators (Lawrence and Wichita, Kansas). The short courses use low cost or freeware programs and cover the Internet, log analysis using spreadsheets and reservoir simulation (using BOAST 3). All short courses are ongoing and use data and results generated as part of the Schaben study. Pseudoseismic subsurface visualization using electric logs has been developed. Total production from Schaben field has increased by 20% and 2.2 million barrels of reserves identified from 14 new infill wells drilled. Project results and products are currently being used by a number of operators in Kansas and elsewhere in the U.S. Workshops for PfEFFER, Reservoir Simulation and Internet Access continue to be in demand by independent operators. All short courses are being developed for

distribution on the North Midcontinent PTTC Internet Site
(http://www.kgs.ukans.edu/ERC/PTTC1/pttccourse.html)
Procedures and computer code have been developed to modify load and display well logs using seismic workstations. The code is available through the Kansas Geological Survey web site (http://www.kgs.ukans.edu/PRS/publication/OFR97-22/ofr9722.html).

The final demonstration of Phase II was drilling a horizontal well. An abandoned vertical well was reentered and used as a kick-off for a horizontal in April 2000. The well was completed in the Warsaw formation (Mississippian) in Ness City North field, Ness County, Kansas. After two months production has stabilized to 48 BOPD and 48BWPD. Post-drilling simulation indicated the horizontal well should ultimately produce significantly better than could be anticipated from a vertical well in the same reservoir. After several months, the open-hole of the horizontal well bore developed caving problems from shales in the karst fractures. All fluid production was lost. A subsequent attempt to reenter the well with coiled tubing was not successful. The horizontal well drilling and simulation represented a learning curve for small independent operators in Kansas. Future recommendations include drilling new wells rather than using existing vertical wells with deteriorating casing and the limitations of a small diameter horizontal section. The operator has subsequently used the simulation results to undertake a targeted recompletion of a neighboring vertical well bore. Production was increased from 2 BOPD to over 20 BOPD.

Publications: (1) Guy, W.J., Byrnes, A.P., Doveton, J.H., and Franseen, E.K., 1998, "Influence of Lithology and Pore Geometry on NMR Prediction of Permeability and Effective Porosity in Mississippian Carbonates", Kansas: 1998 AAPG Meeting, Salt Lake City, Utah. (2) P.M. Gerlach, S. Bhattacharya, and T.R. Carr, 1998, "Application of Cost-Effective PC-Based Reservoir Simulation and Management--Schaben Field (Mississippian), Ness County, Kansas": Proceedings 1998 AAPG Presentations, Salt Lake City. (3) E.K. Franseen, T.R. Carr, W.J. Guy, and S.C. Beaty, 1998, "Significance of Depositional and Early Diagenetic Controls on Architecture of a Karstic-Overprinted Mississippian (Osagian) Reservoir, Schaben Field, Ness County, Kansas": Proceedings 1998 AAPG Presentations, Salt Lake City. (4) Gerlach, P. M., S. Bhattacharya, T. R. Carr, W. J. Guy, S. Beaty and E. K. Franseen, 1998, "Cost-effective PC-based reservoir characterization and simulation: The Schaben Field (Mississippian), Ness County, Kansas": Kansas Geological Survey Bulletin. (5) Watney, W. L., W. J. Guy, J. H., Doveton, S., Bhattacharya, P., Gerlach, G. C., Bohling, T. R., Carr, 1999, "Petrofacies analysis - The petrophysical tool for coherent reservoir characterization and management", *in* R. Schatzinger and J. F. Jordan, Editors, Reservoir Characterization-Recent Advances, AAPG Memoir 71, AAPG, Tulsa, OK, p. 73-92. (6) Gerlach, P. M., S. Bhattacharya, T. R. Carr, W. J. Guy, S. Beaty and E. K. Franseen, 1999, "Cost-effective PC-based reservoir characterization and simulation: The Schaben Field (Mississippian), Ness County, Kansas", *in* Platform Carbonate Reservoirs in the Southern Midcontinent: Oklahoma Geological Survey Special Publication. (7) Carr, T. 1999, "Cost-effective technology for Independent Oil and Gas Producers", The CLASS ACT, Summer 1999 (5/2), DOE newsletter, Tulsa, OK. (8) Montgomery, S. L., E. k. Franseen, S. Bhattacharya, P Gerlach, A. Byrnes, W. Guy and T. R. Carr, 2000. "Schaben Field, Kansas: Improving Performance in a Mississippian shallow-Shelf carbonate": AAPG Bull., Vol 84, No. 8, p. 1069-1086. (9) Bhattacharya, S. and P. Gerlach, 2000. Results of

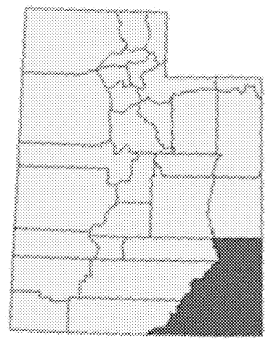
3 Layer Reservoir Simulation Study – Schaben Field, Ness County, Kansas: Kansas Geological survey Open-File Report 2000-78. (10) Bhattacharya, S. 2000. DST Analysis, Super-Pickett Analysis to determine pay cut offs, integration of capillary pressure data with petrophysical log data, and material balance calculations to validate reservoir pressure history and drive mechanism – Schaben Field, Ness County, Kansas: Kansas Geological Survey Open-File report 2000-79, 72 p. (11) Bhattacharya, S., P. Gerlach, T. Carr, and A. Byrnes, 2000. Results of Reservoir Simulation – Horizontal Infill Well, Ness City North Field, Ness County, Kansas: Kansas Geological Survey Open-File Report 2000-80, 15 p. (12) Bhattacharya, S., P. Gerlach, T. Carr, W. J. Guy, S. Beaty and E. K. Farnseen, 2000. PC-based reservoir characterization and simulation of Schaben Field, Ness County, Kansas, *in* K. S. Johnson, ed., Platform Carbonate Reservoirs in the Southern Midcontinent, 1996 Symposium: Oklahoma Geological Survey Circular 101, p. 171-182. (13) Bhattacharya, S., P. Gerlach, T. Carr, 2002 (in press). Cost Effective Techniques for the Independent Producer to Evaluate Horizontal Drilling Candidates in Mature Areas, *in* Horizontal Wells - - Focus on the reservoir, Timothy Carr, Erik Mason and Charles Feazel (editors). (14) Carr, Timothy, Charles Feazel and Erik Mason, 2002 (in press). Horizontal Wells: Focus on the Reservoir – Introduction, *in* Horizontal Wells - - Focus on the reservoir.

Recent/Upcoming Technology Transfer Events: (1) PTTC workshop on horizontal drilling, Annual Kansas Independent Oil and Gas Association, Wichita, KS, August 27-29, 2000. (2) Tim Carr, September 5, 2000 Presentation on the success of the horizontal well, Tulsa Geological Society, Tulsa, OK. (3) T. Carr, Presentation at the 14th TORP Conference, Wichita, KS, March 14-15, 2001. (4) Bhattacharya, Saibal, Richard Pancake and Tim Carr, May 9-10, 2001 –Organized and contributed (4 hours) to PTTC workshop "Optimized Exploitation and Horizontal Well Technologies for Independent Operators", Wichita, KS. (5) Gerlach, P. M., S. Bhattacharya, A. P. Byrnes, T. C. Carr. 2001. Demonstration of Cost-Effective Tools for Integrated reservoir Characterization and simulation to Predict performance of Horizontal Infill Well, Ness City North field, Ness County, Kansas: AAPG National Convention, Denver, CO, June 3-6, 2001.

Project Status: Project in the final phase of Budget Period II. Extension granted to drill and evaluate a horizontal well. Project completed February 2001. Final report published October 2001.

Increased Oil Production and Reserves Utilizing Secondary/Tertiary Recovery Techniques on Small Reservoirs in the Paradox Basin, Utah -- Class II

Utah Geological Survey



Paradox Formation	Anasazi, Runway, Blue Hogan, Mule,
@ 5,700 ft.	and Heron North fields
Pennsylvanian Age	San Juan County, UT
Navajo Nation	Paradox Basin

DE-FC22-95BC14988

Contract Period:
2/9/1995 to 8/31/2005

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Objective: Increase production and reserves from the shallow shelf carbonate reservoir in the Paradox Basin of Utah and Colorado through geological and engineering investigations, leading to the application of advanced secondary recovery technology. Technical studies will be conducted on five diverse small fields located within the Navajo Nation to select the best candidate field to be targeted for a pilot demonstration project.

Technologies Used: The following technologies are being used: (1) reservoir characterization, (2) well testing and horizontal drilling (development well), (3) core analysis, (4) log analysis, (5) reservoir simulation, (6) swath seismic acquisition and analysis, and (7) waterflood/CO2 flood development.

Background: More than 400 million barrels of oil have been produced from shallow-shelf carbonate deposits consisting of algal mounds and oolitic-bank deposits in the Ismay and Desert Creek zones of the Pennsylvanian Paradox Formation. The value of secondary or tertiary recovery has not been demonstrated on any of the smaller shallow-shelf carbonate reservoirs in the basin. These fields typically contain 2 to 10 million barrels of original oil-in-place. Only 15 to 20 percent of that oil is recoverable during primary production. Anasazi fields has been selected and approved for Phase II CO2 flood. Modeling of Anasazi field predicts economic return of 62% with payout in 35 months. Modeling of Runway field predicts economic return of 30% with payout in 32 months. The 1st horizontal well in a small algal mound reservoir in the Paradox basin was completed at Mule field in 1997 initially flowing producing at 149 BOPD. Potential oil recovery from CO2 flooding of the Anasazi field is estimated at 2.2 million bbls of oil over primary recovery of 2.0 million bbls.

Potential oil recovery from CO2 flooding of the Runway field is estimated at 1.6 million bbls of oil over primary recovery of 0.8 million bbls. Many similar oil fields are at risk of premature abandonment unless secondary recovery techniques can be effectively demonstrated. In the absence of applying an effective secondary or tertiary recovery technology, an estimated 200 million barrels of oil would be left in the 100 or more known reservoirs of the Paradox Formation in Utah, Colorado, Colorado, and Arizona. Through proper geological and engineering evaluation of the reserves, production may be increased by 175 percent, or an additional 0.5 to 3.5 million barrels per field. Water flooding has proven to be uneconomic and not technically feasible. Success of the CO2 flood project will reveal to operators in the Paradox Basin that production may be increased by the application of selected enhanced recovery projects, and benefit not only the producers but also the royalty owners in a manner similar to that of the Navajo Nation in this project.

Incremental Production: The first successful completion of a lateral well in small carbonate fields in the Paradox Basin was completed in March 1997. The average production rate was of 149 BOPD and 223 BPWD of water. Incremental production for the project will be tested in the Demonstration Phase of the project. Mule field's production for the first 2 ½ months was 3,730 bbl of oil.

Expected Benefits and Applications: The successful application of a secondary/tertiary enhanced oil recovery technique will allow for extended oil recovery from many small fields in the Paradox Basin. Total additional Paradox Basin potential may be more than 200 million bbl of oil. The establishment of the general facies belts and stratigraphic patterns within the shallow-shelf carbonate Desert Creek zone of the Paradox Formation will lead to a better understanding of reservoir heterogeneity and capacity of the five fields being evaluated for the pilot demonstration, and a greater level of predictability of petroleum potential for exploration targets. Outcrops of the Paradox Formation Ismay zone along the San Juan River provide small-scale analogues of reservoir heterogeneity, flow barriers and baffles, lithofacies, and geometry. These analogues can be used in reservoir simulation models for secondary/tertiary recovery of oil from small fields in the basin. No previous waterfloods, CO2 floods, or detailed study of reservoir heterogeneities, and no reservoir simulations have been conducted on small, one-to-three well fields in the Paradox Basin.

Accomplishments: A carbonate facies belt was mapped which identifies the three major facies. Geological characterization on a local scale focused on reservoir heterogeneity, quality, and lateral continuity as well as possible compartmentalization within each of the five project fields. Core and geophysical logs were used to characterize and grade each of the five fields for suitability for enhanced recovery projects. This included the identification of carbonate fabrics, pore types, cements, and determination of diagenetic history in each reservoir. The typical vertical sequence or cycle of lithofacies from each field, as determined from core, was tied to it's corresponding log response. The resultant graphs are used to identify reservoir and non-reservoir rock, determine potential units suitable for water and/or CO2 flood projects, and comparison of field to non-field areas. The cores from the Anasazi and Runway wells have been described and major flow units and barriers identified. The reservoir analysis for the Anasazi and Runway fields utilized a field-scale reservoir simulator. Enhanced recovery through water-flooding and CO2 flooding were evaluated using a compositional simulation. Variations in carbonate lithotypes, porosity, and permeability were incorporated into the simulation in order to accurately predict reservoir response. Completed the 1st study of waterflood and CO2 potential for Paradox Basin small carbonate fields. Continuous CO2 injection without gas processing is recommended for algal mounds. Reservoir modeling used 20 geostatistical models to predict CO2 flood performance history, matches were made by tying to previous production and reservoir pressure history so that future reservoir performance could be confidently predicted. Engineering analysis and reservoir simulation of Anasazi and Runway fields was completed 06/98. Anasazi field has been selected and approved for Phase II CO2 flood based the 1998 reservoir evaluation and geostatistical modeling, which predicts economic return of 62% with payout in 35 months. Completion of the Project Evaluation Report and the CO2 availability study, with the associated pipeline and facilities cost, were completed in June 1998. A two-year no cost extension has been granted while arrangements for CO2 pipelines are being negotiated. Harken Southwest Corp. was purchased by The Rim Energy Companies of Englewood, Colorado in December 2000. The Utah Geological Survey released an issue of Petroleum News to over 300 interested parties and continues to maintain a project page on the survey's Internet web site.

Publications: (1) Lorenz, W.E. Culham, T.C. Chidsey, Jr., and Kris Hartmann, 1998, "A Reservoir Characterization of a Heterolithic Carbonate Mound, Runway Field, Paradox Basin", Utah, AAPG Annual Convention, Extended Abstracts II: p. A-415, D.M.; (2) Petroleum Information/Dwights, 1998, "A Pennsylvanian Carbonate Buildups, Southern Paradox Basin - New Opportunities for Increased Reserves", (3) Scott L. Montgomery, 1998, Petroleum Frontiers, v. 15, no. 4, 76 p., (4) , Scott L. Montgomery, Thomas C. Chidsey, Jr., David E. Eby, Douglas M. Lorenz, and W.E. Culham , 1999, "A Pennsylvanian Carbonate Buildup, Paradox Basin: Increasing Reserves in Heterogeneous, Shallow-Shelf Reservoirs", AAPG Bulletin v. 83, no. 2 (February 1999), p. 193-210; and (5) Thomas C. Chidsey, Jr., 1998,
"A Paradox Basin Project Yields Successful Horizontal Well", UGS Survey Notes, v. 31, no. 1, p. 3-4. (6) Chidsey, T. C. , Jr., D. E. Eby, 1999, "Mule field in the Paradox basin of southeastern Utah – a case study for small carbonate buildups, horizontal drilling, and carbon dioxide flooding (abs.): AAPG Bull. V. 83, no. 7, p. 1180-1181. (7) Eby, D. E., 1999, "Upper Devonian carbonate buildups impersonating Paradox basin phylloid algal mounds: SEPM Newsletter v. 24. No. 4, p. 1-3. (8) Eby, D. M., 1999, "Upper Devonian carbonate buildups impersonating Paradox basin phylloid algal mounds": (abs.) 11th Bathurst Meeting, Cambridge, UK, Journal of conference Abstracts, v. 4, no. 2. P. 915.

Recent/Upcoming Technology Transfer Events: Project materials were displayed at the UGS booth during the following meeting and conventions - (1) American Association of Petroleum Geologists Annual Convention, Salt Lake City, Utah, May 17-20, 1998, (2) Utah Geological survey Sample Library Open House, Salt Lake City, Utah, October 6, 1998, (3) UGS-hosted National Petroleum Technology Council (PTTC) symposium entitled Fractured Reservoirs: A Symposium on Current Research, Modeling, and Enhanced Recovery Techniques, Salt Lake City, Utah, October 23, 1998, (4) Interstate Oil and Gas Compact Commission (IOGCC) Annual Meeting, Salt Lake City, Utah, December 6-8, 1998, (5) PTTC Symposium, and Interstate Oil and Gas Commission Compact meeting, Salt Lake City, UT, December 6-8, 1998. (6) American Association of Petroleum Geologists Annual Convention, San Antonio, Texas, April 11-14, 1999, and (7) American Association of Petroleum Geologists Rocky Mountain Section meeting, Bozeman, Montana, August 8-11, 1999.

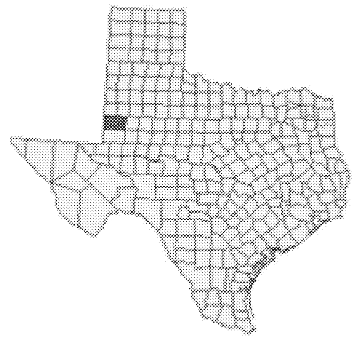
The following presentations were made during 1998 and 1999: (1) "Reservoir Characterization of a Heterolithic Carbonate Mound, Runway Field, Paradox Basin, Utah" by D.M. Lorenz, W.E. Culham, T.C. Chidsey, Jr., and Kris Hartmann: American Association of Petroleum Geologists Annual Convention, Salt Lake City, Utah, May 19, 1998, (2) "Upper Devonian Carbonate Buildups impersonating Paradox Basin Phylloid Algal Mounds" by D.E. Eby: Utah Geological Association monthly meeting lecture, Salt Lake city, Utah, January 11, 1999, (3) "Diagenetic Characterization of Shallow-Shelf Carbonate Reservoirs, Pennsylvanian Paradox Formation, Southern Paradox Basin, Utah" by T.C. Chidsey, Jr., and D .E. Eby: American Association of Petroleum Geologists Annual Convention, San Antonio, Texas, April 12, 1999. (4) Morgan, C., "Increased oil production and reserves utilizing secondary/tertiary recovery techniques on small reservoirs in the Paradox Basin, Utah", DOE Oil and Gas conference, June 28-30, 1999, Dallas, TX. (5) T. C. Chidsey, Jr. and D. E. Eby, "Mule field in the Paradox Basin of southeastern Utah: A case study for small carbonate buildups, horizontal drilling and carbon dioxide flooding": Rocky Mountain Section Meeting, August 8-11, 1999, Bozeman, Montana. (6)

Project Status: This project is in a no-cost extension of Budget Period I pending development of a CO_2 source.

Application of Integrated Reservoir Management and Reservoir Characterization to Optimize Infill Drillings -- Class II

Fina, USA

Clearfork Formation	North Robertson Field
@ 6,500 ft.	Gaines County, TX
Permian Age	Permian Basin



DE-FC22-93BC14989

Contract Period:
6/13/1994 to 6/12/1999

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Objective: Demonstrate the application of advanced secondary recovery technologies to remedy producibility problems in shallow-shelf carbonate reservoirs in the Permian Basin, Texas.

Technologies Used: Core/fluid analysis, crosswell seismic tomography, borehole imaging logging, well tests, reservoir modeling, geostatistics, numerical simulation, well stimulation, infill drilling.

Background: Infill drilling of wells on a uniform spacing, without regard to reservoir performance and characterization, does not optimize reservoir development because it fails to account for the complex nature of reservoir heterogeneities present in many low-permeability reservoirs, and carbonate reservoirs in particular. New and emerging technologies, such as cross-borehole tomography, geostatistical modeling, and rigorous decline type curve analysis, can be used to quantify reservoir quality and the degree of interwell communication. These results can be used to develop a 3-D simulation model for prediction of infill locations. Typical Clearfork reservoirs have recovered only 15% to 22% of the oil they originally contained, and use of targeted infill drilling in combination with waterflooding could recover as much as 2.5 billion barrels of additional oil from these reservoirs alone. Because all shallow shelf carbonate reservoirs to some degree have heterogeneous characteristics similar to the Clearfork, tremendous volumes of additional oil have the potential to be recovered using targeted infill technologies.

Incremental Production: Unit production is currently averaging approximately 2700 BOPD, with the contribution from the 14 project producing wells averaging 400 BOPD. This is a 26% increase in production for the Unit. Cumulative production for the project was not submitted.

Expected Benefits and Applications: At the inception of this project, total production from the 144 producing wells in the North Robertson Unit was only 3,000 bbl/day. Expected recoveries from the geologically targeted infill wells drilled in association with this project are expected to be in the range of 850 to 950 barrels per day. Implementation over the entire unit of the concepts developed in this project could result in the recovery of an additional 16.5 to 22 million bbl of oil, or an additional 6% to 8% of the oil originally in place at the time of discovery. Problems in the reservoir include poor sweep efficiency, poor balancing of injection and production rates in certain areas of the reservoir, and perforation and stimulation treatments that are inadequate for optimal production and injection. This project uniquely focuses on targeting infill wells, such that only wells, which will recover significant and sustainable rates of oil flow will be drilled.

Accomplishments: We have demonstrated that production data, available to all operators, can be used for detailed reservoir characterization in a cost-effective manner. Methods similar to using production data analysis are being developed for analyzing waterflood performance and assessing producibility problems. Cost-effective methods for well testing and other surveillance have been developed and field-tested. In spite of the maturity of waterfloods in the onshore U.S., water quality is often overlooked and partly responsible for poor secondary recovery. Surveillance and enhancement methods have been field-tested. Use of geostatistics for characterizing highly heterogeneous and compartmentalized reservoirs has proven to be valuable even though it is resource intensive. Both conventional and geostatistical based methods are valuable for reservoir management and future field development optimization, but application of conventional simulation technologies often results in over-optimistic production forecasts. Work to date predicts that geologically targeted drilling can capture reserves for nearly half the cost of a blanket drilling program. The initial production rates for the 14 producing wells drilled as part of the program are approximately 18% higher than any previous development program. These 14 wells resulted in an initial incremental production response of approximately 900 BOPD. The project is expected to ultimately produce 1.4 million barrels of incremental oil from North Robertson Unit and 2.2 million incremental barrels of oil from the field. Geostatistical and 3-D reservoir modeling have been 40% more successful in identifying drilling locations. New foam frac technology along with low fluid loss borate gel system increased waterflood production in the North Robertson Unit. A downhole tiltmeter study of the Clearfork reservoir was used to analyze the success of the hydraulic fracturing and stimulation. The analysis suggests that cost-savings may be realized by eliminating the 3rd stage of hydraulic fracing, which appears to be unnecessary. The project has increased field production by 18% since beginning the field demonstration.

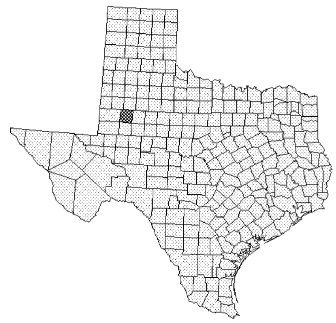
Publications: (1) Doublet, L.D., et al., "An Integrated Geologic and Engineering Characterization of the North Robertson (Clearfork) Unit: A Case Study, Part", SPE 29594 presented at 1995 SPE Low Permeability Reservoirs Symposium, Denver, Colorado, March 19-22, 1995. (2) Nevans, J., 1997. "Environments of Deposition for the Clear Fork and Glorietta Formations, North Robertson Unit, Gaines County, TX", *in* K. S. Johnson, Editor, Oklahoma Geological Society Circular, Platform Carbonates in the Southern Midcontinent, March 1997. (3) Montgomery, S. L., 1998, "Permian Clear Fork Group, North Robertson Unit: Integrated Reservoir Management and Characterization for Infill Drilling, Part II - Geologic Analysis": AAPG Bulletin, Vol. 82, No. 10, p. 1797-1814. (4) Montgomery, S. L., D.K. Davies, R.K, Vessell, J.E. Kais and W.H. Dixon, 1998, "Permian Clear Fork Group, North Robertson Unit: Integrated Reservoir Management and Characterization for infill Drilling, Part II - Petrophysical and Engineering Data": AAPG Bulletin, Vol. 82, No. 1, p. 1985-2002. (5) Nevans, J. W. et al, 1999, "Application of Integrated Reservoir Management and Reservoir Characterization to optimize infill drilling", Annual Report June 13, 1996 to June 12, 1998, DOE/BC/ 14989-21, April 1999. (6) Nevans, J. W., 1999. "An integrated geologic and engineering reservoir characterization of the North Robertson (Clearfork) Unit, Gaines county, Texas", *in* R. Schatzinger and J. F. Jordan, Editors, Reservoir Characterization – Recent Advances, AAPG Memoir 71, AAPG, Tulsa, OK, p. 109-125. (7) Rawn-Schatzinger, V, 2000, "Tiltmeter analysis of the Clearfork formation at North Robertson field": The Class ACT, DOE newsletter, Vol 6, no. 2, p. 6-7, Summer 2000.

Recent/Upcoming Technology Transfer Events: (1) Exhibited core taken during field demonstration portion of project at Permian Basin section/SEPM core workshop at Midland Center, Midland, TX on February 26, 1998. (2) Doublet, L. 1997. "Improved Characterization of Reservoir Behavior by Integration of Reservoir Performance Data and Rock Type Distributions". DOE/BDM 4th International Reservoir Characterization Technical Conference, Oral presentation and poster session on project material, March 2-4, 1997, Houston, TX. (3) Meyerhofer, J. M., S. L. Demetrius, L. G. Griffin, R. B. Bezant, J. Nevans, L. E. Doublet, "Tiltmeter hydraulic fracture mapping in the North Robertson field, West Texas": 2000 SPE Permian basin Oil & Gas Recovery Conference, Midland, TX, March 21-23, 2000.

Project Status: Project completed June 1999. Final report published March, 2000.

Application of Reservoir Characterization and Advanced Technology Improves Recovery and Economics in Lower Quality Shallow Shelf San Andres Reservoirs -- Class II

Oxy USA Inc.



San Andres Formation	West Welch Field
@ 4,800 ft.	Dawson County, TX
Permian Age	Permian Basin

DE-FC22-93BC14990

Contract Period:
8/3/1994 to 9/3/2002

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Objective: This field project will demonstrate the application of cross wellbore tomography, hydraulic fracture orientation detection, 3-D seismic methods, and cyclic CO2 stimulation to improve the economics of conventional CO2 flooding.

Technologies Used: Core analysis, fracture treatment, 3-D seismic, pressure falloff analysis, cyclic CO2 stimulation, tomography interpretation, reservoir modeling, reservoir simulation, infill drilling, CO2 flood design.

Background: In 1991 OXY USA had identified recoverable reserves of 42 MMSTBO from current EOR technology. The project has drilled 5 new wells producing at 100 BOPD. Two new field demonstration wells were completed based on 3-D seismic-guided mapping. Production from these wells has reached 200 BOPD with estimates of 300,000 bbls additional reserves. After proceeding with the CO2 flood at South Welch Unit, which began CO2 injection in 1993, lower oil prices were forecasted. With the lower prices, the estimated recoverable EOR reserves dropped to 17 MMSTBO. OXY USA began evaluation of cyclic CO2 treatments to accelerate production and recover additional oil that would not be recovered by conventional CO2 flooding. Seismic tomography will be incorporated into the reservoir description process. This approach is expected to assist with projects that have marginal economics at current prices.

Incremental Production: The five new wells are producing in the expansion area producing a total of 100 barrels of oil per day. 3-D mapping of 2 new wells completed based on seismic mapping produced 200 BOPD with estimates of 300,000 bbl additional reserves.

Expected Benefits and Applications: Use of tomography and 3-D seismic in field development will enhance reservoir characterization, thus optimizing infill drilling results and the economics of CO2 projects. Successful utilization of cyclic CO2 stimulation will have a rapid impact in the Permian Basin due to the abundance of services available to support CO2 projects. The use of tomography, 3-D seismic, core, and log interpretations will refine the geologic model down to 5 ft vertical resolution between wells. The use of seismic attributes to estimate log properties led to the development of a relationship between pore volume and seismic response.

Accomplishments: 3-D seismic integration improved the history match over the base geologic model results. Reservoir fracture analysis completed. Economics for the project were completed and recommendation to proceed to budget period 2 was made and approved. Software changes improved the depth ties of the cross well seismic lines. The 7 lines completed show reservoir structures, between wells, to 10 vertical resolution. The 3-D Seismic integration has been used to map reserves with an estimated 300,000 bbls of additional reserves for the West Welch Unit. Evaluation of seismic responses led to the development of a statistical relationship between pore volume and seismic attributes. 5 new wells showed the seismic guided mapping was accurate for porosity mapping, and initially produced 100 BOPD.

CO2 is currently being injected into 6 injection wells with each well the center of a 7-spot 40-acre pattern. Project focus in 2001 was to increase the processing rate of the reservoir to improve project economics. Dip-ins (pressure bombs ran in the injection well measuring CO2 bottom hole injection pressure) were run to determine the appropriate CO2 surface pressure for optimal CO2 injection Since running the Dip-ins we have increased the CO2 injection rate approximately 20% which is a significant improvement. A horizontal well was planned and drilled in December 2000 for the purpose of capturing poorly swept oil reserves from the 7-spot pattern and accelerate the reservoir processing rate. The lateral length was 3,500ft and designed to fracture stimulate 6 locations throughout the lateral using a new Halliburton technology – SURGI fracturing tool. Mechanical problems with the tool, stimulation pumping design problems and reservoi4r conditions limited the effectiveness of the stimulation. Even with stimulation issues the well did produce an incremental 30 BOPD, but with high gas production resulting in the well shut-in due to gas plant limitations.

Work continues at addressing the reservoir processing rate and minimal tertiary response observed in offset producing wells. Several well stimulations have been performed or are in progress to remove skin to help initiate tertiary response. Ten well workovers have been done or in progress to enhance wellbore conditions. Positive results have been realized, but not in all wells. A more impressive result has been realized in WWU#4818 a producing well that produced 6 BOPD and 10BWPD prior to being worked over. After the workover, #4818 is testing at 63 BOPD and 31 BWPD. Efforts to improve performance in other wells recently stimulated have been through lift revisions and optimization of the pump off controllers. From the injection profile work done one injection well was identified as having poor conformance and a low injection rate. This well, #4805 has a well stimulation procedure scheduled to address vertical conformance and improve the injection rate.

An induction log was run on observation well WWU#4852 for the purpose of tracking CO2 migration in the reservoir. The evaluation of the log gave inconclusive results. The issue was that at high OHMS the induction log measures resistivity poorly. A previous induction log (1997 logging run) compared to this induction log run did not compare well at high OHMS, which made differences between measurements difficult to determine if the change is due to CO2 in the reservoir. A lateral log and neutron log are to be run that will be compared to a previous lateral log to calculate if CO2 movement within the reservoir can be detected.

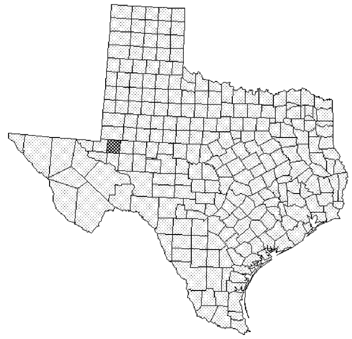
Publications: (1) Taylor, A., 1996, "Fracture Monitoring Using 'Low Cost' Passive Seismic", SPE Permian Basin Oil and Gas Recovery Conference, Midland, Texas, March 1996. (2) Hinterlong, G., "Characterization of Rock Types with Mixed Wettability Using Log and Core Data - DOE Project Welch Field, Dawson County, Texas"; SPE Permian Basin Oil and Gas Recovery Conference, Midland, Texas, March 1996. (3) G.D. Hinterlong, A. R. Taylor, G. P. Watts, K.H. Kumar, "Improving Flow Simulator Performance with a Seismic Enhanced Geologic Model", paper SPE 39809, Journal of Petroleum Technology. (4) G. P. Watts, G. D. Hinterlong and A. R. Taylor, "Seismic Description of a Complex Carbonate Porosity System; Welch field, Permian Basin" Texas West Texas Geological Society Fall Symposium, October 29-30, 1998, Midland, Texas. Published in, The Search Continues into the 21st Century, WTGS Publication 98-105, eds., W. D. DeMis and M. K. Nelis. (5) Justice, James. 2000. Interwell Seismic Imaging Aids in EOR Design and Monitoring: Inside Tech Transfer, DOE newsletter, Summer, 2000. (6) Justice, J., Interwell 4-D Brings High-Resolution Data to Reservoir Characterization: American Oil & Gas Reporter, March 2001, pp. 106-112.

Recent/Upcoming Technology Transfer Events: (1) "Combining Flow Theory and Multiple Log Readings to Improve Permeability Calculations", DOE's Advanced Applications of Wireline Logging for Improved Oil Recovery Workshop, Midland, TX. Nov. 13, 1997 and Denver, CO Jan. 13, 1998. (2) "West Welch Unit CO2 Flood Simulation Using an Equation of State and Mixed Wettability", Taylor, A., Hinterlong, G., Kumar, K., Paper SPE 39808, SPE Permian Basin Oil and Gas Recovery Conference, Midland, TX, March 23-26, 1998. (3) "Improving Flow Simulation Performance with a Seismic Enhanced Geologic Model", Hinterlong, G., Taylor, A., Kumar, K., Paper SPE 39809, SPE Permian Basin Oil and Gas Recovery Conference, Midland, TX, March 23-26, 1998. (4) G .P. Watts, G.D. Hinterlong, A. R. Taylor, 1998, "Improved Modeling of a Shallow Shelf Carbonate Reservoir Using 3-D Seismic Attributes, Welch Field, West Texas": AAPG Annual Convention, May 17-20, 1998, Salt Lake City, UT. (5) James Justice, "Boit-Gassman Equations with Interwell Seismic Data in a CO2 Project", The 3rd CO2 Oil Recovery Forum, October 28, 1998, Socorro, New Mexico. (6) Watts, G. P., G. D. Hinterlong, A. R. Taylor, " Improved modeling of a shallow shelf-carbonate reservoir using 3D seismic attributes, Welch Field , Permian Basin, Texas": Petroleum Systems of Sedimentary Basins in the Southern Midcontinent, Oklahoma City, OK, March 28-29, 2000. (7) Justice, J., C. Woerpel, G. P. Watts, W. H. Waddell, "Reservoir characterization using interwell seismic in a shallow-shelf carbonate reservoir": Petroleum Systems of Sedimentary Basins in the Southern Midcontinent, Oklahoma City, OK, March 28-29, 2000. (8) Justice, J. "Tomography Technology": SPE/DOE 12th Symposium on Improved Oil Recovery, Tulsa, OK, April 2-5, 2000. (9) Justice, J. "Interwell seismic for reservoir characterization and monitoring": AAPG Pacific/ SPE Western Regional Joint Conference, Long Beach, CA, June 19-22, 2000.

Project Status: Project is in Budget Period II. No-cost extension granted to September 3, 2002 to monitor CO2 flood breakthrough.

Design and implementation of a CO2 Flood Utilizing Advanced Reservoir Characterization and Horizontal Injection Wells in a Shallow Shelf Carbonate Approaching Waterflood Depletion -- Class II

Phillips Petroleum Co.



Grayburg/San Andres Fm.	South Cowden Field
@ 4,450 ft.	Ector County, TX
Permian Age	Permian Basin

DE-FC22-94BC14991

Contract Period:
6/30/1994 to 9/2/2001

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Objective: Demonstrate the economic viability and widespread applicability of an innovative reservoir management and carbon dioxide (CO2) flood project development approach for improving CO2 flood project economics in shallow shelf carbonate reservoirs. The use of several horizontal injection wells drilled from a centralized location will reduce the number and cost of new injection wells, wellheads, and equipment; allow concentration of the surface reinjection facilities; and minimize the cost associated with the CO2 distribution system. It is anticipated that the proposed advanced technology will show improved CO2 sweep efficiency and will significantly reduce the capital investment required to implement a CO2 tertiary recovery project relative to conventional CO2 flood pattern developments using vertical injection wells. This technology will be readily transferred to the domestic oil industry.

Technologies Used: Core analysis, 3-D seismic, reservoir modeling, numerical simulation, geostatistics, injectivity and production tests, PTA, infill drilling, horizontal drilling, CO2 flooding, memory-tool injection profile logging under both water and CO2 injection.

Background: The principal objective of this project is to demonstrate the economic viability and widespread applicability of a CO2 flood project utilizing multiple horizontal CO2 injection wells. The Grayburg and San

Andres formations were deposited in shallow carbonate shelf environments along the eastern margin of the Central Basin Platform. The primary target for CO2 flood development under the proposed project is a 150-200 ft gross interval within the San Andres located at an average depth of 4,550 ft. The original oil in place for the South Cowden Unit is estimated to be less than 180 million barrels. The field was discovered in 1940 and unitized for secondary recovery in 1965. The Grayburg-San Andres section had previously been divided into multiple zones mapped as continuous across the field. Previous core studies concluded that reservoir quality in South Cowden field is controlled primarily by distribution of a bioturbated and diagenetically altered rock type

Incremental Production: : Increase of 200 BOPD. The average rate of productivity increase for seven wells was 92%. Total production after twenty months of CO2 injection is 448 BOPD.

Expected Benefits and Applications: Successful application of the horizontal drilling and CO2 flood techniques developed will demonstrate the economic benefits and improved efficiency of CO2 flooding in an area with abundant CO2 supplies and infrastructure present. Techniques applied should recover an additional 3 million bbl of oil from the unit. Application to Permian Basin carbonate reservoirs could recover up to 1 billion bbl. Reduction in capital and drilling costs by using one-third the number of injectors required and improvement of CO2 sweep efficiency by over 25% using horizontal injection wells.

Accomplishments: CO2 injection commenced in two horizontal wells during August 1996, and in the two vertical wells during September 1996. CO2 production commenced during late fall of 1996 in five wells immediately off-stetting the horizontal injection wells. Three leaseline vertical wells were drilled in late 1996. Incremental production of 190 BOPD resulted from CO2 injection in 1996-97. Total production after twenty months of CO2 injection is 448 BOPD. New logging technology using coiled tubing was utilized in obtaining injection profile logs while under both water and CO2 injection in the horizontal injection wells. The compression/reinjection facilities are being utilized to handle CO2-contaminated produced gas. Improvements to withdrawal rates have been achieved with the use of designed scale treatments. 48 producers and 20 injectors were active in 1997. New injection wells were completed in 1996-97 and 2 horizontal and 3 vertical wells were drilled in 1997-98. An additional 16 wells were converted or reactivated. Two surfactants were identified which improve CO2 foam mobility and diversion. Total production after the first 20 months of CO2 injection was 448 BOPD.

Total production rate has been less than originally predicted. A major cause has been identified as out-of-zone injection of CO2. A second problem has been lower than expected production rates for both oil and water. A three-part re-development program was designed to address the problems identified. Short radius lateral drilling was implemented in the first half of 2000 to improve injection rates and to keep the injectant in the target zones. In Phase 1, single laterals were drilled in four producers. In Phase 2A, dual laterals were drilled in four injection wells and a single lateral was drilled in one other injection well. In Phase 2B, single horizontal laterals were drilled in four producers. Phases 1 and 2B have resulted in current production increases of 100 barrels of oil per day each for a total of 200 barrels of oil per day increase in production. These laterals have been moderately successful in keeping CO2 injection "in zone" and increasing the total production rate of oil and water from those pay zones. The DOE participation in this project ended on July 2, 2001.

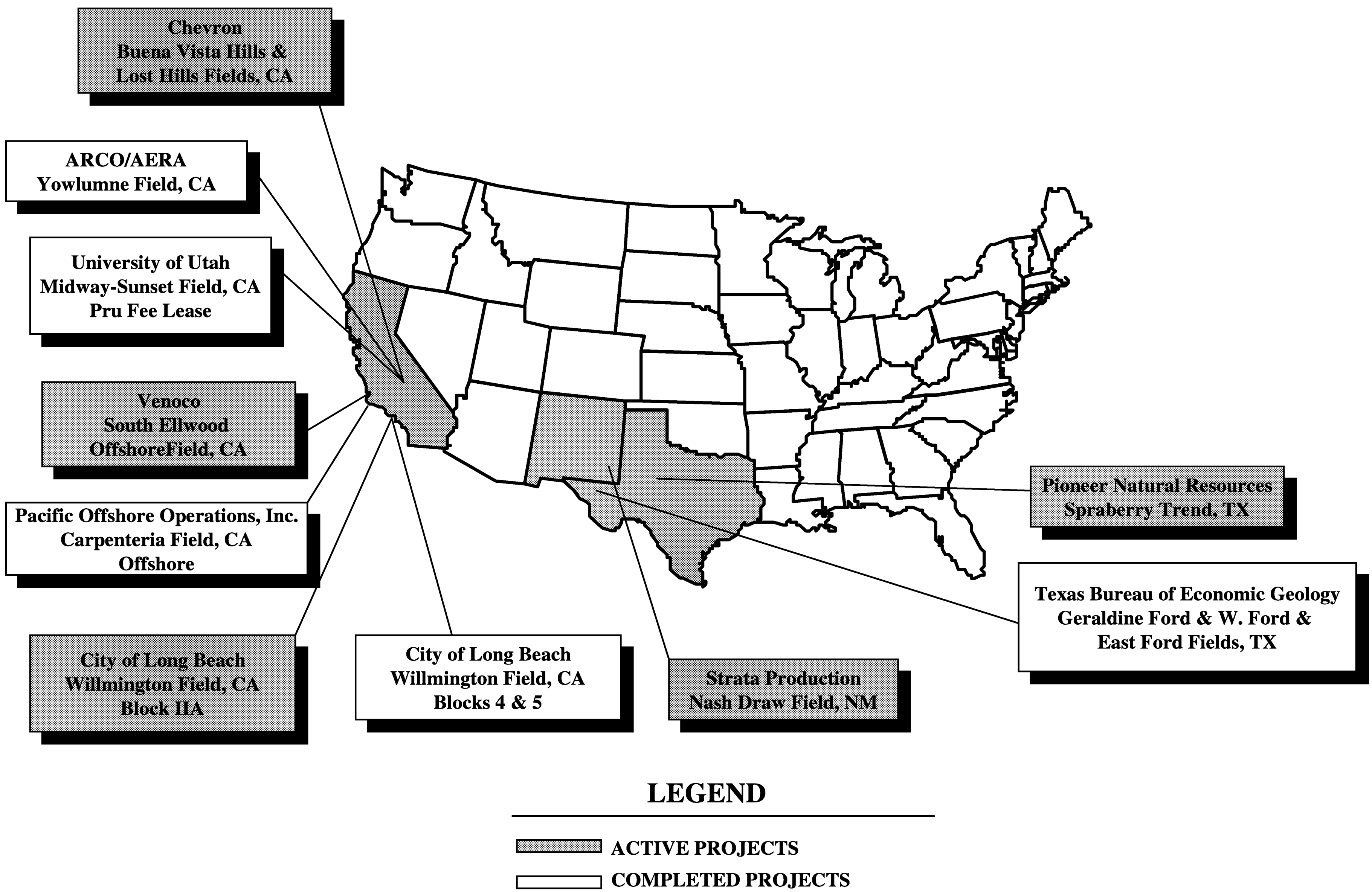
Publications: (1) "How Can Selective Mobility Reduction of CO2-Foam Assist in Reservoir Floods?," Y.S. Esau and J.P. Heeler; Paper SPE 35168, presented at the 1996 Permian Basin Oil Recovery Conference, Midland, TX, March 27-29, 1996. (2) "Effect of Capillary Contact on CO2-Foam Mobility in Heterogeneous Core Samples," H. Yaghoobi and J.P. Heller; Paper SPE 35169, presented at the 1996 Permian Basin Oil and Gas Recovery Conference, Midland, TX, March 27-29, 1996. (3) "Improving CO2 in Heterogeneous Media," H. Yaghoobi and J.P. Heller; Paper SPE/DOE 35403, presented at the SPE/DOE Tenth Symposium on Improved Oil Recovery, Tulsa, OK, April 21-24, 1996. (4) "Design and Implementation of CO2 Flood Utilizing Advanced Reservoir Characterization and Horizontal Injection Wells in a Shallow Shelf Carbonate Approaching Waterflood Depletion," L.D. Hallenbeck, K.J. Harpole and M.G. Gerard; DOE/BC/14991-7 (DE96001234), pp 26-27, May, 1996. (5) "The Evaluation of Two Different Methods of Obtaining Injection Profiles in CO2 WAG Horizontal Injection Wells," K.B. Dollens, B.W. Wily, J.C. Shoemaker, P. Rice, and O. Johannessen, SPE Paper 37470, was presented by Ms. Dollens at the 1997 SPE Production Operations Symposium, March 9-11, 1997 in Oklahoma City, OK. (6) Owen, R., C. R. Robertson, K. J. Harpole, and E. G. Durrett, 1999, "Design and implementation of a CO2 flood utilizing advanced reservoir characterization and horizontal injection wells in a shallow shelf carbonate approaching waterflood depletion", Annual Report July 1, 1997 to June 30, 1998, DOE/BC/ 14991-14, January 1999.

Recent/Upcoming Technology Transfer Events: (1) K.B. Dollens, "The Evaluation of Two Different Methods of Obtaining Injection Profiles in CO2 WAG Horizontal Injection Wells", SPE Paper 37470, Phillips Petroleum Company Exploration and Production (E&P) Technical Symposium in Bartlesville, OK, April 2-4, 1997. (2) K.B. Dollens, "Application of Horizontal Injection Wells in the South Cowden Unit CO2 Flood" at both the 1997 SPE Horizontal Drilling Conference (September 17-18, 1997) and the 1997 SPE CO2 Conference (December 10-11, 1997) in Midland, Texas. (3) Kimberly B. Dollens presented a South Cowden Unit project review at the 1997 CO2 Oil Recovery Forum in Socorro, New Mexico, October 29-30, 1997. (4) Kimberly B. Dollens, K.J. Harpole, and L.D. Hallenbeck. "Field Implementation of a CO2 Flood in a Small Waterflood-Depleted Carbonate Unit," 1998 Southwestern Petroleum Short Course in Lubbock, Texas, April 8-9, 1998. (5) Craig Caldwell and Kimberly B. Dollens, "Reservoir Characterization of an Upper Permian Platform Carbonate in Preparation for a Horizontal-Well CO2 Flood, South Cowden Unit, West Texas" Poster, Permian Basin Section of the Society of Economic Paleontologists and Mineralogists' (SEPM) Permian Basin Core Workshop in Midland, Texas, on Thursday, February 26, 1998. (6) T.F. McCoy, K.J. Harpole, and K.B. Dollens, "Transient Test Analysis Case History for Two Horizontal Miscible Gas Injection Wells", SPE Sixth International Oil and Gas Conference and Exhibition in Beijing, China, November 2-6, 1998. (7) Rex Owen, "CO2 Flood Utilizing Horizontal Injection Wells, poster, DOE Oil and Gas Conference, June 28-30, 1999, Dallas Texas.

Project Status: Project completed September 2001. Final report is in progress.

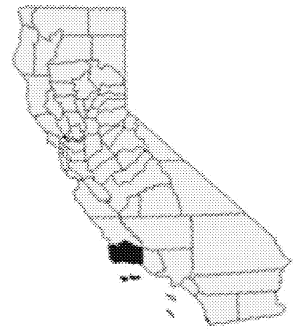
CLASS III

Class III Oil Recovery Projects



An Advanced Fracture Characterization and Well Path Navigation System for Effective Re-Development and Enhancement of Ultimate Recovery from the Complex Monterey Reservoir of the South Ellwood Field, Offshore California/Class Revisit

Venoco, Inc.



Monterey Formation	Ellwood Field, Offshore
@ 4,000 ft.	Santa Barbara County, CA
Miocene Age	Ventura Basin

DE-AC26-00BC15127

Contract Period:
7/31/2000 to 7/30/2005

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Objective: Redevelop the Monterey Formation, a Class III basin reservoir, at the South Ellwood Field, Offshore Santa Barbara, CA.

Technologies Used: Subsurface geophysical surveys, 3-D seismic, cross-well seismic, state-of-the-art reservoir modeling, FMI, dipole sonic logs, downhole water separation.

Background: South Ellwood field is a Class III reservoir producing from the Monterey formation, Offshore Santa Barbara, California. Holly Platform is the oldest platform in the Pacific Ocean offshore California. Fourteen wells were drilled into the Ricon formation at South Ellwood prior to the discovery of oil in the overlying Monterey formation in 1969. The Monterey has become the primary producing horizon at South Ellwood. Due to the tectonic history of the Santa Barbara channel, the geology of the Monterey shale is very complex. As of December 1998, the Monterey sands at South Ellwood field have produced 48.5 MMBO (plus 8 MMBNO from the Rincon) of oil, 29.2 BCF of gas and 38 MMB of water from the Monterey formation. High water cuts, observed across the field rapidly deteriorated the economics. Substantial additional recovery of ROIP can be realized if fracture patterns can be characterized and aquifer movement within the fracture conduits can be managed. A substantial effort must be invested in mapping and identifying fractures and fracture trends as lithological heterogeneity and fracture distributions control well productivity.

Incremental Production:

Expected Benefits and Applications: Development of an innovative fracture network reservoir simulator to monitor and manage the aquifer's role in pressure maintenance and water production would benefit all Offshore California producers.

Accomplishments

(1) The project has completed the information gathering and the first wave of Model prediction formulation stage. A second model prediction formulation stage and new data gathering is underway resulting in better understanding of reservoir facts. Recently performed production logs and pressure tests have produced more accurate conclusions regarding fracture patterns and distribution of oil, water, and gas. Two platforms for the South Ellwood database were considered, a CD-ROM version and a web-based intranet system. The CD-ROM version is a MS Access database. The data was converted into different electronic formats through the use of scanners, log digitizing software, and hand typed Excel sheets. The main CD will contain all of the raw data and the diagnostic data. The two additional CD's will contain the core photos for 3242-19 and a detailed fracture study on those core photos. The web-based version of the database of the South Ellwood Database contains all data that is in the CD-ROM version plus new diagnostic data graphs. There is a search engine for the whole database web site. This will enable a first time user to type in any type of data and all the pages containing that data will be given. A second design aspect is the application of real time to the production diagnostic plots. This will have the diagnostic plots generated directly from the production data and thus as the production data is updated, the diagnostics will reflect that change immediately. This new dynamic version of the database is available via the Internet at www.westcoastpttc.com/venocodoe.

(2) FMI (Formation Micro-Image Log) Only one image log has been run at South Ellwood. This was a borehole televiewer in 208-102. Venoco plans to acquire FMI logs in the two Holly wells to be drilled during 2002.

(3) Dipole-Sonic Venoco plans to acquire Dipole Sonic logs in the two Holly wells to be drilled during 2002.

(4) Production Logs-Wells**:** State of the art production logs (production log advisor, probe and deft tools) were acquired on 5 wells. 3 clear water shut offs were identified. Workovers are scheduled for early 2002 after rig modifications are complete. If the results of the new tools are successful, we will have verified an excellent means of quantifying complex fluid flow in the Monterey fracture systems.

(5) Interference Tests**:** We conducted long term static pressure surveys while the field was shut down in December, 2001. This data is still being analyzed. It will be used to further enhance the performance of the reservoir.

(6) Pressure Build-ups: We measured bottom hole pressure in six long term shut-in wells: - 3120-4, 3120-6-2, 3242-7-1,3242-10-1, 3242-14 and 3242-17. Data from four of the wells shows that the reservoir pressure ranges from 1260-1320 psi at datum. There is no evidence for aquifer support from the northern boundary fault. A higher than normal pressure in 3242-7-1 suggests that influx from the former 308 lease is occurring.

(7) Basic Reservoir studies: Dipmeter reprocessing/analysis was conducted on all available dipmeter logs in the field. Schlumberger recovered archived data from dipmeters from 11 highly deviated wells. No more preserved digital data appears to exist as the remaining wells were drilled prior to 1970. An analysis of regional data suggests

that the maximum stress direction for the South Ellwood field is North-South. Borehole breakouts should be the observable and oriented East-West. Schlumberger completed processing dipmeters for the 11 deviated South Ellwood wells. The breakouts appear to strongly correlate with borehole trajectory. The four arm calipers could not separate the borehole deviation effects from the borehole breakout. Digital dipmeter data for two vertical exploration wells was retrieved. Minimum stress direction is SE in 208-102 and SSW in 309-8. There is a good correlation between the fault orientation in the area of these two wells and the maximum stress orientation from the borehole breakouts.

(8) Initial 3D Geologic Model: a view of the South Ellwood field structure from the west. A geologic model was constructed utilizing existing data (original processing of 3D, adjacent 2D, well control, and limited out crop data). 1980's vintage 3-D Seismic data was processed by Venoco and re-interpreted using SMT. This interpretation demonstrated the utility of the Earth Vision software for creating a 3D earth model of a complex structure. It also identified for the first time that apparent normal faults create part of the hydrocarbon accumulation at South Ellwood and are also directly related to the natural oil and gas seeps on the sea floor. A set of normal faults running north-south were identified for the first time and recognized as the primary control on fracture development. The initial 3D geologic model seen below shows an east-west trending structural anticline with the reservoir bound by two main normal faults at the north and south end of the field. Platform Holly sits on top of the structure.

(9) Initial 3D fracture Models: Pipeline Model Development

The naturally fractured Monterey has proved very difficult to model with conventional reservoir simulation algorithms based on the Warren and Root model. A new model was proposed where the fracture system simulated by a pipeline network. Major progress has been made in the following aspects:

- Formulated a pipeline network theoretical model using Darcy's equation rather than the hydraulic equation to control flow.
- Proposed and derived a semi-implicit finite difference algorithm for the above permeable pipe network model.
- Designed and coded the 2-D pipe network model (PNM).

The new pipe network model is suitable for three-dimensional three-phase flows. The fracture pipeline network model algorithm has been formulated in 3-D. This new simulation model is being coded and will be tested against a conventional dual porosity model available form CMG. The CMG package was purchased an installed at sites at USC and Venoco. A CMG model is being put together for South Ellwood using all the data in the Web database. The pipeline network model will be benchmarked against the CMG model. Should it prove useful for South Ellwood, CMG has committed itself to making the pipeline network model available to users as a simulation option within CMG. The algorithm for the pipeline network model was presented at the annual fall meeting in the SPE.

(10) Fracture Mapping: A Fetkovich type curve analysis of the South Ellwood production data was undertaken to obtain values of permeability to input into the simulation model. This analysis showed that most wells followed a pattern of rapid decline from initially high production rates to more sustainable levels. This is fairly typical for a fractured reservoir where fractures provide the initially high productivity but the storage volume in the matrix acts to insure stable production later in the well's life. The early onset of this support mechanism indicate the South Ellwood wells fit more closely to the dual fracture model rather a conventional dual porosity model.

A parallel study was begun to identify individual fractures from the well log data. All of the South Ellwood wells were frilled before the use of imaging tools became widely available. A pattern recognition technique was developed to distinguish highly fractured intervals from conventional logs such as caliper, resistivity, density/neutron and sonic traces. A strong correlation was established between the wells with greatest number of log derived fracture events and those with the highest cumulative fluid production. Several wells were identified with overlooked potentially productive zones. These wells will be targeted for additional perforations in 2002. The results of this work were presented at regional SPE meeting in Bakersfield.

Publications: (1)Anguiano, J. A., I. Ershagi, and K. Christensen, 2001, "Mapping of permeability structure in a naturally fractured reservoir using field performance data"; SPE 68833, Western Regional SPE, March 25-30, 2001. (2) Wylie, U. I. Ershagi, K. Christensen, 2001. "A new diagnostic method for prediction of producibility and reserves of wells producing from the Monterey Formation using well-log data"; SPE 68834, Western Regional SPE, March 25-30, 2001. (3) Zhan, L. and I. Ershagi, "an integrated Pipe Network Model for Simulation of Highly Fractured Reservoirs"; SPE 71616, SPE annual meeting, New Orleans, LA, Oct6ober 2, 2001.

Recent/Upcoming Technology Transfer Events: (1) Christensen, K. "South Ellwood field, Santa Barbara Channel: New Insight into structures, fractures and seeps"; Pacific AAPG/ SPE Western Regional Joint Meeting, Long Beach, CA, June 19-22, 2000. (2) Christensen, K. "South Ellwood Field, Santa Barbara Channel, Californian: Is a Normal Fault always Normal? GSA/AAPG, April, 10, 2001. (3) Wracher, M. "Three dimensional interpretation of the sockeye Structure: Santa Barbara Channel, California"; GSA/AAPG April 10, 2001. (4) Christensen, K. and I. Ershagi, field trip on geological complexities of the Monterey Formation; PTTC, Jun 20-21, 2001. (5) Christensen, K. 3D seismic processing data results from the Santa Barbara Channel; Pacific Section SEG, June 13, 2001. (6) Christensen, K., "South Ellwood geologic and fracture studies"; Santa Barbara City College Geoseminar, September 28, 2001.

Project Status: Budget Period I.

Increasing Waterflood Reserves in the Wilmington Field through Improved Reservoir Characterization and Reservoir Management -- Class III

City of Long Beach

Puente Formation	Wilmington Field
	Fault Blocks IV and V
@ 3,000 ft.	Los Angeles County, CA
Miocene Age	Los Angeles Basin

DE-FC22-95BC14934

Contract Period:
3/21/1995 to 12/01/2001

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Objective: The transfer of technologies, methodologies, and findings developed and applied in this project to other operators of Slope and Basin Clastic (SBC) Reservoirs. This project will study methods to identify sands with high remaining oil saturation and to recomplete existing wells using readily available advanced completion technology.

Technologies Used: Development of a tube wave absorber to dampen the energy of tube wave arrivals and improve the measurement of formation shear and monopole arrivals. Development of rock-log and fluid-log models used to calibrate, interpret, and understand acoustic log data.

Background: Often R&D benefit risk costs are too high for individual companies, but not for the oil industry as a whole. This fits the case for SBC oil reservoirs in California, which hold tens of billions of barrels of lower quality oil which is recoverable but of economically marginal value. Through improved technology this R&D project seeks to lower operating costs associated with recovery of this oil in a strict California regulatory environment. This project demonstrates application of current R&D technology, including a case history application of forward modeling and inversion processing to enhance understanding of horizontal log response and reservoir structure based on data from a horizontal well drilled onshore in California. The well was drilled in thin Miocene age turbidite sands to test economic recovery potential of remaining reserves in the 60 year old Wilmington Field, using new technology for reservoir characterization, including 3-D geologic modeling, geosteering in thin beds, and modeling the Logging While Drilling (LWD) responses. Pre-well modeling calculations were used for multiple sets of horizontal and vertical resistivity data measurements, based on differing frequencies and transmitter to receiver spacings. Results from post-well modeling were compared with actual data in the pre-well model, this allows for clear interpretation of the structure around the well bore and refinement of the geologic structure for effective placement of future wells.

Incremental Production: As of November 30, 2001, incremental oil production stands at 192,394 bbls oil from six recompleted wells, one redrilled well and one new well.

Expected Benefits and Applications: The federal government, by sharing the cost of new technology with California producers, will benefit the public good by increasing domestic oil, increasing employment in oil and gas production, maintaining U.S. technical leadership and competitive edge in the oil and gas recovery business. Results from this project should help other operators of slope and basin clastic reservoirs by proving readily available technology can economically find bypassed oil and improve recompletion techniques. Application of the logging tools to develop a rock-log model using geophysical parameters and methodologies for interpreting through casing pulsed acoustic logging data. A recompletion technique for unconsolidated sand through steam injection was developed with a second DOE project (DOE/BC 14939) and successfully used to reduce drilling costs. Incremental oil from the project in Fault blocks IV and V could reach 6 million barrels of incremental oil. If expanded to the entire Wilmington field 28 million barrels of incremental oil could be produced. Knowledge expanded to southern California clastic reservoir could produce 733 MMBO.

Accomplishments: In the final year of the project a new horizontal well was drilled into a relatively thin sand and successfullly gravel packed with a wire wrapped screen in place. Previous accomplishments included: developed rock-log and fluid-log models needed to interpret the acoustic log data. Continued to update and refine these models. Input production and injection data for Fault Blocks IV and V. Various reservoirs and areas within these fault blocks have been examined with reservoir managment software. Eight wells have been logged with an acoustin logging tool. A significant new reservoir dubbed the “Hxo” sand has been located using the geologic 3-D model. Recompleted six idle wells; three with optimized waterflood techniques and three wells completed and on production using the novel steam consolidation technique. Redrilled one idle well with horizontal technology, and drilled one new well with similar horizontal technology. Reserachers were able to use a pulling rig to complete the operation on the former well. Created higly accurate 3-D visualizations of the Upper Terminal Zone Fault Block 5 “Hxo” reservoir and the Tar Zone Fault block 5 “Fo” reservoir. The 3-D models helped isolate the data inconsistencies while the 3-D viewers were good for adding data to correct the geologic model.

Publications: (1) Moos, D., J. Dvorkin, and A. Hooks, 1997. "Application of Theoretically Derived Rock Physics Relationships for Clastic Rocks to Log Data - Example from the Wilmington Field, CA", Geophys. Res. Lett., 24(3), 329-332. (2) Chang, C.T., D. Moos, and M.D. Zoback, 1997, "Anelasticity and Dispersion in Dry Unconsolidated Sands", Int. J. Rock Mech. Min. Sci. 34: 3-4, Paper No. 048. The following were presented at the 1997 Stanford Rock and Borehole Geophysics Project

Annual Meeting and published in the Report to Sponsors of the Project: (3) Gutierrez, M. A., D. Moos, A. Nur, and J. Dvorkin, 1997, "Hydrocarbons Identification Using Acoustic Logs in the La Cira Oil Field", SRB Volume 65, Special Paper. (4) Moos, D., 1997, "Hydrocarbon Detection Behind Casing in the Wilmington Field, CA: Summary of the Results of the First Phase of a Class 3 DOE Project", SRB Volume 65, Paper C6. (5) Walker, S. 1997. "Locating and Producing Bypassed Oil: A DOE Project Update". Journal of Petroleum Technology, p. 984-985, September. (6) Walker, S. 1997. "Locating and Producing Bypassed Oil: A DOE Project Update", SPE Paper 38283, SPE Western Regional Meeting, Long Beach, CA, June 24-26. Walker, S. 1997. (7) Koerner, R. D. Clarke, S. Walker, C. Phillips, J. Nguyen, D. Moos, K. Tabor, 1999, "Increasing waterflood reserves in the Wilmington Oil Field through Improved reservoir characterization and reservoir management", Annual report March 20, 1996 to March 21 1997, DOE/BC/ 14934-8, April 1999. (8) Montgomery, S. L., 1998. "Increasing Reserves in a Mature Giant: Wilmington Field, Los Angeles Basin, Part 1: Reservoir Characterization to Identify Bypassed Oil": AAPG Bulletin, V. 82. No. 3 (March 1998), p. 367-385.

Recent/Upcoming Technology Transfer Events: (1) Moos, D. and G. Zwart, 1998. "Acoustic determination of Pore Fluid Properties Using a 2-Component Model": Stanford Rock Physics and Borehole Geophysics Annual meeting, June 1998, Stanford, CA. (2) J. A. Pacht, G. OtotT, S. Prior, S. Roth, "New oil from an Old Giant; implications from analysis of 3-D seismic data in the Long Beach unit of the Wilmington Oil Field, Los Angeles Basin, California", poster; AAPG Annual Convention, San Antonio, TX, April 11-14, 1999. (3) PTTC Workshop Review of Class III Projects, December 10, 1999, University of Southern California, Los Angeles, CA. (4) Clarke, D., "At 68 Wilmington still has life: New technology revitalizes the old field": Pacific AAPG/ SPE Western Regional Joint Conference, Long Beach, CA, June 19-22, 2000. (5) Paper delivered at Gulf Coast Section of Society of Economic Paleontologists and Mineralogists, 20th Annual Research Conference, Deep Water Reservoirs of the World, December 3-6, 2000. (6) Throughout the project presentations were made to local and national organizations: SPE, AAPG, American Geophysical Union, Society of Professional Well Log Analysts, Society of Exploration Geophysicists, PTTC, Stanford Rock and Borehole Physics Consortium.

Project Status: Project completed December 1, 2001. Final report is process.

The Feasibility of Optimizing Recovery and Reserves from a Mature and Geologically Complex Multiple Turbidite Offshore California Reservoir Through the Drilling and Completion of a Tri-lateral Horizontal Well -- Class III

Pacific Operators Offshore

Repetto Formation	Carpinteria Field, Offshore
@ 4,000 ft. (subsea)	Santa Barbara County, CA
Pliocene Age	Ventura Basin

DE-FC22-95BC14935

Contract Period:
8/28/1995 to 8/27/1999

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Objective: Devise an effective redevelopment strategy to combat producibility problems related to the Repetto turbidite sequences of the Carpinteria Field.

Technologies Used: Core analysis, digital well logs, TST and DWD logs, 3-D Geological Modeling, Geosteering, drilling from offshore platform.

Background: The reservoir in the Carpinteria field consists of thin to massive deep water sandstones with intercalated siltstone and claystone. Carpinteria field produces form the Pliocene age Repetto formation at a depth of 2,500 to 5,500 ft and is located three miles offshore California in the Santa Barbara channel. A major problem in producing the field is the large amount of water in the reservoir resulting from a combination of lateral water influx and commingling of water and oil-bearing layers. A total of 29 separate layers have been identified in the producing horizon. Major producibility problems in the field include high water cuts, sand production and poor wellbore mechanical conditions. The reservoir has already produced 43.5 million barrels of oil with 53 million barrels of water and 38 billion cubic feet of gas. New technologies effectively applied could recover and additional 9.2 million barrels of oil As a result of the budget period I study, original-oil-in-place is estimated at 144 to 174 million barrels. Oil recovery simulation predicts 25%-30% of OOIP can be recovered.Without a redevelopment program, the reservoir is facing abandonment due to high water production and high sand production caused by poorly consolidated sands. Without improved recovery, the field and the platforms will be abandoned within five years. The reservoir characterization and production analysis in Budget Period I revealed that the proposed tri-lateral horizontal well would not be cost effective.

Incremental Production: 845 BOPD incremental production from mid 1998 to August 1999 for six project wells. Incremental production at 760 BOPD since September 1999. Total field production has risen to 1,600 BOPD representing a 100% production increase.

Expected Benefits and Applications: This project will allow other operators which produce from similar geological settings to apply this technology. Expand the reservoir drainage and reduce sand problems through horizontal drilling and completion. Application of 3-D geological modeling software and application of horizontal well technology in a mature offshore environment. Application of 3-D geological modeling software and application of horizontal well technology in a mature offshore environment.

Accomplishments: All of the objectives of Budget Period I have been completed. The project has expanded to 4 additional leases to improve Reservoir Characterization. Twenty-nine producing sand intervals have been mapped. A number of target spots for drilling of new development wells have been identified. Computation of recovery form the pilot horizontal wells has established the economic merit of drilling and completing such wells for draining the trapped oil. Tests reveal that re-drilling five vertical wells will be more cost effective than drilling one tri-lateral well. The Budget Period II demonstration phase began January 1998. Completed drilling the sixth well in the redrill package in October 1998. The first two wells were vertical redrills that allowed us to determine the current saturation state of the potential producing zones for the horizontal wells. From the vertical redrills we were able to complete four horizontal redrills in two different fault blocks. The first horizontal well was completed in the F-3 sand and averaged 340BOPD in 1998-9. The second horizontal well was completed in the F-1 sand and averaged 275 BOPD in 1998-9. The horizontal wells were drilled accurately based on the predictive model using Geosteering Gamma Ray and Resistivity data. Each of the horizontal wells averaged 600 to 700 ft in length. Operating 26 producing wells from two offshore platforms, Hogan and Houchi, Pacific Operators has demonstrated that by optimizing recovery, an additional 1.53 million barrels of oil can be recovered over the 13-year life of the field. If the concept is expanded to the entire Carpinteria Field, an estimated 9.18 billion barrels of oil could be recovered.

Results: Six redrilled wells (2 vertical and 4 horizontal) replaced the original trilateral well plan. The vertical redrills were necessary to understand the saturation state of the reservoir to design the horizontals. Reservoir characterization was the key to more than double the initial production on a per well basis. A significant water cut reduction has been achieved for Carpinteria field from 91% water cut in 1994 to 74% water cut in 1999. For the six redrill wells the agerage water cut at the end of the project was 27%.
Recompletion of the horozintal sections of the wellbores using perforated rather than slotted liners with cemet behind casing significantly reduced sanding problems. Production as of August, 2000 averged 760 BOPD for the six wells on Platform Hogan.

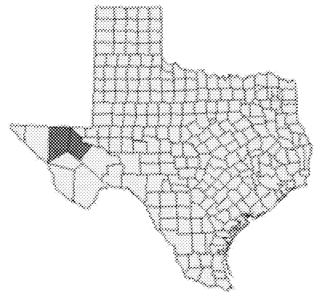
Publications: (1) Whitney, E.M., M. Brinckey, S. Coombs, C.A. Duda and V.K. Duda, 1997. "Integrated Reservoir Management for the long term - The Carpinteria Offshore Field", SPE 38284, SPE Western Regional, Long Beach California, June 23-27, 1997. (2) Coombs, S. F., E. Edward, and W. Fleckenstein, 1999. "Vertical and horizontal redrills tap bypassed reserves", Petroleum Technology Digest, September 1999, p. 21-22. (3) Coombs, S., Summer, 2000. "Horizontal drilling brings important new oil from mature turbidite reservoirs": The Class ACT, DOE newsletter, Vol 6, No. 2. June 2000.

Recent/Upcoming Technology Transfer Events: (1) E. Edwards. Jan 15, 1997. PTTC Focused Technology Workshop, California Geology with and without Computer Graphics, "Carpinteria Field", (2) Whitney, E.M., M. Brinckey, S. Coombs, C.A. Duda and V.K. Duda, 1997. "Integrated Reservoir Management for the long term - The Carpinteria Offshore Field", SPE 38284, SPE Western Regional, Long Beach California, June 23-27, 1997. (3) Edwards, E., " New oil from an oil field: Results of redevelopment from Platform Hogan, Carpinteria Offshore field, California": Pacific AAPG/ SPE Western Regional Joint Conference, Long Beach, CA, June 19-22, 2000. (4) Fleckenstein, W., S. Coombs, E. Edwards, "Redevelopment activities in the Carpinteria field offshore Santa Barbara Co., California: Slimhole horizontals reap big benefits": Pacific AAPG/ SPE Western Regional Joint Conference, Long Beach, CA, June 19-22, 2000.

Project Status: Project completed August 1999. Final report published March 2001.

Application of Advanced Reservoir Characterization, Simulation and Production Optimization Strategies to Maximize Recovery in Slope and Basin Clastic Reservoirs, West Texas (Delaware Basin) -- Class III

Bureau of Economic Geology



Bell Canyon Formation	East Ford Field
Ramsey Sandstone	Geraldine Ford Field
@ 2,700 ft.	Reeves & Culbertson Counties, TX
Permian Age	Delaware Basin

DE-FC22-95BC14936

Contract Period:
3/31/1995 to 8/31/2001

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Objective: Demonstrate that detailed reservoir characterization is a cost-effective way to recover a higher percentage of the original oil in place through strategic placement of infill wells and geologically based field development.

Technologies Used: 3-D seismic; reservoir characterization; core analysis; outcrop studies; reservoir simulation; infill drilling; CO2 flood.

Background: Slope and basin clastic reservoirs in the sandstones of the Delaware Mountain Group in the Delaware Basin (the western subbasin of the Permian Basin) of West Texas and New Mexico contained more than 1.8 billion bbl of original oil at discovery. Recovery efficiencies of these reservoirs have been considerably lower than that of the national average. Thus, a substantial amount of the original oil in place still remains in these reservoirs. The immediate target for this project is 16.9 million bbl of remaining oil in place in the East Ford field. Through technology transfer, the knowledge gained in the study of this field can then be applied to increase production from more than 100 other Delaware Play reservoirs, which together contain 1.6 billion bbl of remaining oil. In addition, the development and transfer of advanced reservoir characterization techniques provide an opportunity for increasing oil recovery from two other major slope and basin clastic plays in the Permian Basin. The volume of oil to which these techniques can be extended exceeds 10 billion bbl of mobile and residual oil.

Incremental Production: The unit has produced 180,097 bbl of oil from the start of tertiary recovery through May 2001, essentially all production can be attributed to the enhanced oil recovery project. Application of project technology to East Ford field will result in 1.7 MMbbl (estimated) of incremental oil recovery. Of the 12.2 MMbbl of remaining oil in place in the East Ford demonstration area, an estimated 1.2 to 3.7 MMbbl will be ultimately recoverable through CO2 flood.

Expected Benefits and Applications: The reservoir-architecture descriptions that are derived for this project to improve EOR recovery are expected to apply to other fields in the Delaware Basin. Use of reservoir-architecture information developed from outcrop and subsurface data to design geologically optimized injector and producer well patterns in the demonstration area. If the project is effective other operators may use the technology, which would help maintain access to the estimated 686 million bbl of mobile oil and 872 million bbl of residual (immobile) oil in Delaware Basin reservoirs. It is estimated that application of the technology to existing reservoirs in the Delaware Mountain Group could result in production of an additional 210 million bbl of oil, 123 million bbl of mobile oil from infill drilling and 87 million bbl of residual oil from improved CO2 flooding. Application in other slope and basin clastic plays in the Permian Basin has potential for another 110 million bbl of incremental oil. Reservoir characterization of East Ford field is an effective test of the transferability of concepts, methods, and the geologic reservoir model of the Ramsey sandstone that was developed earlier in the project. Use of reservoir-architecture information developed from outcrop and subsurface data to design geologically optimized injector and producer well patterns in the demonstration area.

Accomplishments: This project has demonstrated that (1) enhanced oil recovery by CO2 flood can increase production from slope and basin clastic reservoirs of the Delaware Mountain Group, and (2) reservoir characterization can improve EOR projects. CO2 injection in the East Ford unit began in July 1995. As a result of the CO2 flood, production has increased from 30 bbl/d at the end of primary production to more than 185 bbl/d in 2001. East Ford unit has produced 180,097 bbl incremental oil during the project from CO2 flooding. Technology Transfer of concepts will benefit development of other Delaware Reservoirs, which contain 1,558 MMBO of remaining oil. New website: http://www.utexas.edu/research/beg/delaware_project.
The project won the Best Paper award at the Southwest Section AAPG meeting, Midland, Texas, February 28-29, 2000.

Publications: (1) Dutton, S. P., Malik, M. A., Asquith, G. B. Barton, M.D., Cole, A.G., Gogas, J., Clift, S.J., and Guzman, J. I., 1997, "Geologic and Engineering Characterization of Geraldine Ford Field, Reeves and Culberson Counties, Texas": The University of Texas at Austin, Bureau of Economic Geology, topical report prepared for the U.S. Department of Energy, DOE/BC/14936-10, 115 p. (2) Dutton, S. P., 1999, “Application of advanced reservoir characterization, simulation, and production optimization strategies to maximize recovery in slope and basin clastic reservoirs, West Texas (Delaware Basin)”, The CLASS ACT, Vol. 5, No. 2, Summer 1999. (3) Dutton, S. P., W. A. Flanders, J. I. Guzman, and H. Zirczy, Application of advanced reservoir characterization, simulation, and production optimization strategies to maximize recovery in slope and basin clastic reservoirs, West Texas (Delaware Basin), Annual report, March

31, 1998 to March 30, 1999, DOE/BC/14936-11. (4) Dutton , S. et al. 1999. “Geological and engineering characterization of East Ford Field, Reeves County, Texas”, Topical report DOE/BC/14936-12, July 1999. (5) Dutton, S. P. et al. 1999. “Geological and engineering characterization of turbidite reservoirs, Ford Geraldine Unit, Bell Canyon Formation, West Texas: Bureau of Economic Geology, University of Texas, Austin, Report of Investigations No. 255, Austin, TX. (6) Dutton, S. P., W. A. Flanders, and H. Zirczy, “Application of advanced reservoir characterization, simulation, and production optimization strategies to maximize recovery in slope and basin clastic reservoirs, West Texas (Delaware Basin), Annual report, March 31, 1999 to March 30, 2000, DOE/BC/14936-15. (7) Dutton, S. P. and W. A. Flanders, 2001, “Application of advanced reservoir characterization, simulation, and production optimization strategies to maximize recovery in slope and basin clastic reservoirs, West Texas (Delaware Basin)”:, Final Report, DOE/BC 14936-18, November 2001, 166 pp. (8) Dutton, S. P. and W. A. Flanders, 2001, “Application of Advanced Reservoir Characterization, Simulation, and Production Optimization Strategies to Maximize Recovery in slope and Basin Clastic Reservoirs, West Texas (Delaware Basin)”: The Class ACT, Vol 8, No. 1, Winter 2002.

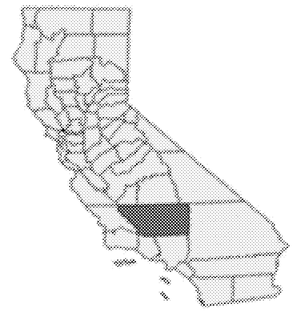
Recent/Upcoming Technology Transfer Events: (1) Shirley Dutton, "Characterization and Development of Turbidite Reservoirs in a Deep-Water Channel-Levee & Lobe System, Ford Geraldine Unit, Permian Bell Canyon Formation, Delaware Basin, USA", 3rd AAPG/EAGE joint Research Conference on Developing & Managing Turbidite Reservoirs: Case Histories & Experiences, Almeria, Spain, October 4-9, 1998. (2) Dutton, S., "Characterization of reservoir heterogeneity in slope and basin clastic reservoirs, Bell Canyon Formation, Delaware Basin, Texas", Southwest Section AAPG, Midland, Texas, February 28-29, 2000. (3) Dutton, S. P., W. A. Flanders, “Deposition and diagenesis of turbidite sandstones in East Ford Field, Bell Canyon Formation, Delaware Basin, Texas”: AAPG Southwest Section, Dallas, TXC March 10-13, 2001. (4) Dutton, S. P., W. A. Flanders, “Field Development of a Permian deep-water sandstone, East Ford Field, Bell Canyon Formation, Delware Basin, Texas”: AAPG Annual Convention, Denver, CO, June 3-6, 2001. (5) Dutton, S. P., 2001, Reservoir characterization of a Permian deep-water sandstone, East Ford field, Bell Canyon formation, Delaware Basin, Texas: South Texas Geological Society November 2001. (6) Dutton, S. P. and M. D. Barton, 2001, Diagenesis and Reservoir Quality of Deep-Water Sandstones in the Bell Canyon Formation, Delaware Basin, Texas: Geological Society of America annual meeting, “Recent Advances in Deep-Water Facies Models”, Boston, MA, November 2001.

Project Status: Budget Period I was conducted in Ford Geraldine and West Ford fields with Conoco as the operator. An extension of Budget Period I transferred the project to East Ford Field with Orla Petco as the field operator. Project completed in June 2001. Final report published November 2001.

Reactivation of an Idle Lease to Increase Heavy Oil Recovery through Application of Conventional Steam Drive Technology -- Class III

University of Utah

Monarch Sandstone	Midway-Sunset Field	
@ 1,250 ft.	Pru Lease	
Miocene Age	Kern County, CA	
	San Joaquin Basin	



DE-FC22-95BC14937

Contract Period:
6/14/1995 to 3/30/2001

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Objective: The objectives of the project are (1) to return the shut-in portion of the reservoir to commercial production; (2) to accurately describe the reservoir and recovery process; and (3) to convey the details of this activity to the domestic petroleum industry, especially to other producers in California, through an aggressive technology transfer program.

Technologies Used: 3-D seismic; reservoir characterization; core analysis; outcrop studies; reservoir simulation; infill drilling; cyclic steamflood CO2, waterflood.

Background: A previously idle portion of the Midway-Sunset field, Aera Energy's Pru Fee property, has been brought back into commercial production through tight integration of geologic characterization, geostatistical modeling, reservoir simulation , and petroleum engineering. This property, shut-in over a decade ago as economically marginal using conventional cyclic steaming methods, has a 200-300 foot thick oil column in the Monarch Sand. However, the sand lacks effective steam barriers and has a thick water-saturation zone above the oil-water contact. These factors require an innovative approach to steam flood production design that balances optimal total oil production against economically viable steam-oil ratios and production rates. The methods used in this DOE Class III oil technology demonstration are accessible to most operators in the Midway-Sunset field and could be used to revitalize properties with declining production of heavy oils throughout the region. The 40-acre Pru Fee property is located south of Taft in the super-giant Midway-Sunset Field and produces from the late Miocene Monarch Sand, part of the Belridge Diatomite Member of the Monterey Formation. The Midway-sunset field was discovered prior to 1880. The original 13 wells drilled on the property in the early 1900's were operated on primary production by Bankline Oil company prior to 1959. Then signal Oil compnay until 1969, when infill drilling and cyclic steaming was initiated by Tenneco. During the hald century of primary production nearly 1.8 MMBO was produced from the Pru property, 114 to 151 MBO per well, but production declined steadily reaching insignificant quantities by the late 1960's. Cyclic steaming was partially successful in extracting the remaining viscous 13 degrees API oil until the Pru property was shut down in 1986 as uneconomic. Total secondary recovery from the 40 acre site peaked at about 300 BOPD in 1972, but by the time the property was shut-in had dropped to less than 10 BOPD. ARCO Western Energy (AWE) acquired the lease in 1988 along with various producing properties in the Midway-sunset field. On October 31, 1998 all of the AWE properties in the southern San Joaquin basin, including Pre Fee, were passed through Mobil with simultaneous closing and transfer to Aera Energy LLC, a Shell-Mobil joint-venture company. AWE continued to operate the property on contract to Aea Energy LLc until December 31, 1999, at which time operatorship passed to Aera Energy LLC.

Incremental Production: Total Pru Fee production following the first steam cycle was 70 BOPD and 300 BWPD in 1996. A dramatic jump in oil production rates occurred between February and March 2000. The average daily production for the 8-acre steam pilot had ben 300 BOPD in January and February increased to 444 BOPD in March. For the remaining portion of the Pru lease production rose from 430 BOPD to 760 BOPD. This represents a 54% and 76% increase in production rates injust a single month. Cumulative incremental production for the 8-acre pilot as of March 31, 2000 is 366,000 bbl since reactivation of the Pru Fee Lease in 1996. Total cumulative incremental production for the 40 acre Pru Fee Lease is pver 1.1 million barrels of oil.

Expected Benefits and Applications: If the project is successful and recovery of the potential oil reserves of the Pru Fee property are demonstrated, application of the methods used to one-half of the currently shut-in properties (totaling 2,194 acres) could add another 80 million bbl of oil to the ultimate production from the Midway-Sunset Field. Success of this demonstration project property communicated through an aggressive, effective technology transfer program is expected to have a major impact in encouraging operators in similar fields to return properties previously thought uneconomic to production. Use of reservoir-architecture information developed from outcrop and subsurface data to design geologically optimized injector and producer well patterns in the pilot area. Details of the project and methodology will be conveyed to a broad segment of the industry, especially to other producers in the filed and Californian through an aggressive technology transfer and outreach program. Use of reservoir-architecture information developed from outcrop and subsurface data to design geologically optimized injector and producer well patterns in the pilot area.

Accomplishments: Preliminary numerical simulations indicate that the site, previously considered sub-commercial, may exceed projected production by an innovatively configured conventional steamflood strategy. Under the cyclic baseline testing of the characterization phase, the 8 acre site produced at an average rate of 70 barrels of oil per day. The optimal injection interval for the Monarch Sand has been determined to be 90 to 100 feet above the oil water contact. Core and temperature analysis have revealed new oil reserves in the overlying Tulare which may equal or surpass production from the Monarch sand of the Pru lease. The production strategy adopted in the steam flood pilot is to restict steam injection to the upper one-third of the pay zone, that portion where oil saturations exceed 50%. Any steam injected below this interval would loose large quantities of heat to water and result in unfavorable steam-oil and water-oil ratios.

During the fourth year of the oil demonstration project, produciton from the 8 ac four pattern steam flood pilot continues to remain high. As of December 1999, the oil rate was averaging 308 BOPD and the cumulative oil production from the pilot alone was 335 MBO. The steam-oil and water-oil ratis, measures of steam flood effectiveness, closed the year at about 5 and 8, respectively. Also, an additional 37 new wells drilled in 1998 surrounding the pilot have been put into cyclic production. By the end of 1999 they were producing up to 458.3 BOPD, bringing the total oil rate for the Pru Fee property up to 689 BOPD. The total produciton from the property seince the beginning of the projet in late 1995 is 541 MBO. The average production rates per well are higher under steam flood than in cyclic mode. The target additional recoverable reserves from the Monarch sand in the Midway-Sunset field, 40 acre Pru Fee property are 2.9 MMBO or greater. 54 additional wells have been on the margin of the Pru Fee because of the success of the project. The project received the 1998 Hart's Award for Best Advanced Recovery Project in the Pacific Section. An additional 500,000 bbl of incremental oil is expected between March 2000 and March 2001 (end of project).

New separate metering facilities for the Pru lease established by Aera Energy were completed in February 2000. Previously the oil from the Pru Fee and several other Midway-Sunset leases were commingled. The new metering will allow more accurate evaluation of production results from the Monarch and Tulare formations. During 2000 production continued to increase significantly. Daily production rose to over 1,500 bbl per day in the second half of 2000. In the 4th quarter 2000 the 8-acre pilot produced 54,900 bbl and the surrounding 32 acres of the Pru produced 47,800 bbl. Only 11,700 barrels of steam were injected in the pilot to produce this amount. After four years of injection large amounts of steam are no longer required to maintain temperatures and production. The technologies and methodologies employed by the project have spread to three additional leases in the Midway-Sunset field. The Pru lease was idle for 10 years when reactivated by this project. In 1985 when the lease was shut-in is was averaging 10 BOPD at the end of the project production averaged 1,500 BOPD. Secretery of Energy Abraham made a Press Release on the Success of the Pru reactivation in March 2001.

Publications: (1) Schamel, S., M. Deo, C. Forster, C. Jenkins, D. Sprinkel, and R. Swain, 1999, "Reactivation of an idle lease to increase heavy oil recovery through application of conventional steam drive technology in a low dip slope and basin reservoir in the Midway-Sunset Field, San Joaquin Basin, California": Annual report June 13, 1996 to June 13, 1997, Earth & Geoscience Institute , University of Utah; February, 1999, DOE/BC/14937-8 (OSTI_ID:3258). (2) Schamel, Steven, 1999, "Optimization of heavy-oil production by steamflood from a shallow sandstone reservoir, Midway-Sunset field, southern San Joaquin Basin, California": The Class ACT, DOE Newsletter, Vol. 5, No. 1,

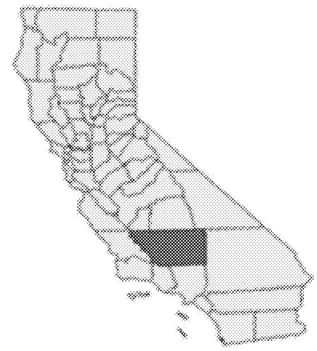
Winter 1999. (3) Schamel, S. "Reactivation of an idle lease to increase heavy oil recovery through application of conventional steam drive technology in a low dip slope and basin reservoir in the Midway-Sunset Field, San Joaquin Basin, California": Annual report June 13, 1997 to June 13, 1998, DOE/BC 14937-9 (OSTI 8524), July 1999. (4) Deo, M. 1999. "Strategies for Steamflood Optimization in a High Water Saturation Reservoir in the Midway-Sunset Field", SPE 54074, SPE International Thermal Operations and Heavy Oil Symposium; Bakersfield, CA. (5) Schamel, S. and M. Deo, 2000, "Strategies for optimal enhanced recovery of heavy oil by thermal methods, Midway-Sunset field, southern San Joaquin, California": SPE 63295, Pacific AAPG/SPE Western Regional Joint Conference, Long Beach, CA, June 19-22, 2000. (6) S. Schamel, M. Deets, and V. Rawn-Schatzinger, 2002, Innovative steamflood revives shut-in heavy oil property: World Oil, March 2002. (7) S. Schamel, M. Deo, M. Deets, 2002, "Reactivation of an idle lease to increase heavy oil recovery through application of conventional steam drive technology in a low dip slope and basin reservoir in the Midway-Sunset Field, San Joaquin Basin, California": Final report, DOE/BC 14937-13, February 2002, 146pp. Articles are being prepared for publication in the AAPG Bulletin and the Oil and Gas Journal.

Recent/Upcoming Technology Transfer Events: (1) S. Schamel, C. Forster, M. Deo, D. Sprinkel, K. Olson, M. Simmons, C. Jenkins: Optimization of Heavy-Oil Production by Steamflood from a Shallow Sandstone Reservoir, Midway-Sunset Field, Southern San Joaquin Basin, California, poster session: AAPG National Convention, May 17-20, Salt Lake City, Utah. (2) S. Schamel, M. Deo, C. Forster, D. Sprinkel, K. Olson: Strategies for Steam Flood Optimization in the Midway-Sunset Field, Southern San Joaquin Basin, California, AAPG National Convention, April 11-14, 1999, San Antonio, Texas. (3) SPE # 54074 "Strategies for Steamflood Optimization in a High Water Saturation Reservoir in the Midway-Sunset Field". Milind Deo, U. of Utah, 1999 SPE International Thermal Operations and Heavy Oil Symposium; March 17-19, 1999 Bakersfield, CA. (4) S. Schamel, M. Deo, C. Forster, D. Sprinkel, K. Olson, "Strategies for steam flood optimization in the Midway-Sunset Field, Southern San Joaquin Basin, California", poster; AAPG Annual Convention, San Antonio, TX, April 11-14, 1999. (5) One day workshop on the Pru lease, February 20, 2001, Bakersfield, CA.

Project Status: The original subcontractor and field operator of the Pru lease was ARCO Western. The property was taken over by AERA Energy in October 1998. The project was granted a 1 year extension to make the transfer of field operation from ARCO to AERA. Incremental production has continued to increase throughout 1999 and 2000. Project completed March 2001. Final report published February 2002.

Advanced Reservoir Characterization in the Antelope Shale to Establish the Viability of CO2-Enhanced Oil Recovery in California's Monterey Formation Siliceous Shales -- Class III

Chevron USA Inc.



Monterey Formation	Buena Vista Hills Field
Antelope Shale @ 4,4450 ft.	Kern County, CA
Monterey Formation	Lost Hills Field
Belridge Diatomite @ 1,300 ft.	Kern County, CA
Miocene Age	San Joaquin Basin

DE-FC22-95BC14938

Contract Period:
2/12/1996 to 2/28/2003

DOE Project Manager:
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gwalker@npto.doe.gov

Contractor:
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Principal Investigator:
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Objective: Increase oil recovery from the Monterey/Antelope Siliceous Shale through the application of an innovative reservoir management plan.

Technologies Used: Core/fluid analysis, borehole imaging, NMR logging, geochemical fingerprinting, well tests, reservoir modeling; CT scanning, numerical simulation, cross-well seismic, acoustic anisotropy, pilot CO2 injection.

Background: The Buena Vista Hills reservoir discovered in 1952 has produced only 9 million bbl of oil representing 6.5% of the estimated 130 million bbl of original-oil-in-place. The current status of the reservoir indicates that it is producing at 40% of its original reservoir energy. In addition, production from wells in this field, and in the Antelope Shale in general, has been declining, and the wells are in danger of being abandoned. Several methods were tried to improve the reservoir productivity. Technologies such as waterflooding, acid treatments, and induced fractures were implemented and, although some were proven successful, the overall oil recovery from the Antelope Shale still remains low at 6.5%. Based on the Reservoir Characterization of Buena Vista Hills field, the Antelope shale is unsuitable for a CO2 flood. Budget Period II has been transferred to a 8-acre site in Lost Hills field for the pilot CO2 flood demonstration. The Lost Hills Belridge diatomite is a unique reservoir and its unusual properties such as extremely small pore size, high porosity and low permeability have led to historically, low primary oil recovery (3 - 4% OOIP). Due to the low primary recovery and large amount of remaining oil in place, Lost Hills presents an attractive target for EOR. CO2 flooding has the potential for dramatically improving the recovery from the Lost Hills Belridge diatomite. Compared to Buena Vista Hills the reservoir at Lost Hills has several advantages for a CO2 flood: (1) the temperature is lower, which will improve the partial-miscibility of the oil with CO2; (2) the reservoir is shallower so operating pressure will be lower; (3) the oil is heavier, which will improve the partial Bmiscibility of the oil with CO2; (4) and the Lost Hills reservoir has overall lower permeability due to the absence of thin sandstone layers in the targeted intervals.

Incremental Production: Incremental production has not yet began. The project is preparing for the CO2 field demonstration at Lost Hills field.

Expected Benefits and Applications: Conducting this project: (1) will improve the reservoir characterization of siliceous shales and, 2) find a new way to recover the large amounts of potential reserves that could not be produced by current methods. We hope that this new innovative method will recovery 5% to 15% of the estimated reserves potential of remaining oil. The application of state-of-the-art reservoir characterization and reservoir management techniques to establish the viability of CO2 enhanced oil recovery. The application of state-of-the-art reservoir characterization and reservoir management techniques to establish the viability of CO2 enhanced oil recovery. If the process proves successful, other siliceous shale and diatomite reservoir in the San Joaquin Valley will benefit.

Accomplishments:
Reservoir characterization of Brown and Antelope shales completed. First coreflood analysis of siliceous shales. Data from 160 wells has been compiled into a database and used for high resolution and structural mapping. The first high-resolution crosswell reflection images obtained in any oil field in the San Joaquin Valley. Project demonstrated the first successful application of the TomoSeis acquisition system in siliceous shales. The study at Buena Vista Hills was the first detailed reservoir characterization of San Joaquin Valley siliceous shales. Outcrop analysis of rock fractures has been completed and shows how fractures can act as permeable pathways. Core analysis indicates that siliceous shale layers not capable of high oil saturation, but the sandstone layers have high oil saturations. A mineral model has been built to determine lithology variations and oil saturations in siliceous shales. A comprehensive 3D-earth model was completed. With regards to crosswell seismic tomography: (1) researchers at the Seismic Tomography Project at Stanford University (under Jerry M. Harris) have developed a modification of their original centroid frequency shift scheme, which now includes the rise time of the direct arrival as a way of improving the estimate of the degree of frequency shift in the waveform; (2) we are currently working on improved velocity imaging algorithms which will properly handle well deviations and will estimate small amounts of elastic anisotropy; (3) we are also developing improved reflection imaging algorithms which can handle well deviations, elastic anisotropy, and complex structure.

CO2 injectivity tests at Lost Hills field have been completed and indicate that CO2 injection will not be a problem. However, there was some concern with pre-mature CO2 breakthrough because of the small well spacing (2.50 acre patterns). The CO2 facility construction was completed for the well gauging and the liquid CO2 injection facilities. Two existing injection wells were successfully repaired. Three observation wells and two replacement injection wells were drilled and completed. The pilot construction and all associated well work were completed and CO2 injection commenced on August 31, 2000. A comprehensive CO2 monitoring program has been put in place and baseline surveys taken prior to the injection of CO2.

CO2 injection has continued into all four pilot injectors, intermittently in 2001, as we encountered re-occurring sanding problems with the producers. It appears that the CO2 injection may have played a role in the sanding problems. Through December 31, 2001, approximately 216,514 MCF of CO2 has been injected at the average rate of 239 MCF/D per injector. An initial oil response was observed in one well (11-8E) as a result of CO2 injection. However, the initial oil response in well 11-8E has been curtailed due to sanding problems with it and four other pilot producers.

CO2 injection was suspended in early May 2001 as the project continued to be hampered by excessive sanding of the producers. Five wells had to be shut-in for remedial procedures: 11-8D, 11-8E, 12-8B, 12-8C, and 12-8D. As a result of the sanding problems, we reverted back to water injection in the four pilot injectors (11-8WR, 11-8WAR, 12-7W, and 12-8W).

The 5 problem producers were remediated and returned to production. CO2 injection on was restarted on September 5, 2001 after being shut in since mid-May 2001. After several weeks, the sanding problems returned. We once again reverted back to water injection in the four pilot injectors as we contemplate what new remedial actions to take. We are also considering short WAG cycles (one week of CO2 followed by one week of water injection) to maybe also help alleviate the sanding problems.

The following accomplishments are a result of the comprehensive CO2 monitoring program to date: (1) Cased hole resistivity logging in observation wells show oil saturation changes in and above the injection interval after 1 year of CO2 injection. (2) Electromagnetic (EM) surveys run by EMI Inc. and Lawrence Livermore National Laboratory show resistivity changes in injection zone due to CO2. (3) Presence of injection tracers in seven of ten producers indicates the existence of a natural fracture system. (4) Injection profiles range from poor to excellent coverage. (5) Oil geochemistry samples collected after 1 year of CO2 injection are being analyzed. (6) Crosswell seismic survey interpreted by Lawrence Berkeley National Laboratory. (7) Baseline and follow-up gas samples are being analyzed by Oak Ridge National Laboratory. (8) Seven of ten producers have had sanding problems possibly due to CO2 injection.

Publications: (1) Morea, M. F. and T. A. Zalan, 1998, "Buena Vista Hills Field, California, Advanced Logging Tools"; Chapter 4 in Field Demonstrations of Logging Technologies for Reservoir Characterization, Eds. M. Fowler and R. Schatzinger, NIPER/BDM-0379. (2) Perri, P. R., M. A. Emanuele, W. S. Fong, M. F. Morea, 2000, "Lost Hills CO2 pilot: Evaluation, design, injectivity test results and implementaion":

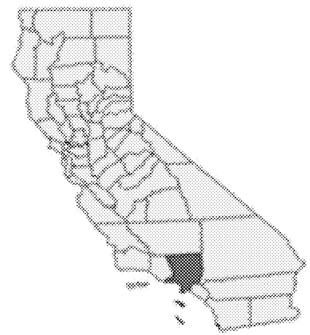
SPE 62526, Pacific AAPG /SPE Western Regional Joint Conference, Long Beach, CA, June 19-22, 2000. (3) Daley, T. M., E. L. Majer, R. Gritti, and S. M. Benson, 2000. Borehole seismic monitoring of CO2 injection in a diatomite reservoir: AGU, EOS, Vol . 81, no. 48. (4) Montgomery S. L, M. F. Morea, P. R. Perri and M. A. Emanuele, 2000. New effort to evaluate EOR possibilities in Monterey Formation, San Joaquin Basin; Oil & Gas Journal, Sept. 25, 2000. (5) Montgomery, S. L. and M. F. Morea, 2001. Antelope shale (Monterey Formation), Buena Vista Hills field: Advanced reservoir characterization to evaluate CO2 injection for enhanced oil recovery: AAPG Bulletin, Vol. 85, No. 4, April 2001 pp. 561-585. (6) Wilt, M., P. Zhang, M. Morea, D. Julander, and P. Mock. "Using Crosswell Electromagnetics to Map Water Saturation and Formation Structure At Lost Hills, SPE 68802, SPE Western Regional Meeting, June 2001. (7) Wilt, M, R. Mallan, P. Kasamyer, and B. Kirkendall, "3D Extended Logging for Geothermal Resources: Field Trials with the GEO-BUILT System", Proceedings, 27th Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, CA, SGP-TR-171.
(8) Majer, E. L., T. M. daley, R. Gritto, V. Korneev, and G. Li, 2001. "Application of Crosswell and Single Well Seismic Methods for mapping CO2 movement", GSA Cordilleran Section annual Meeting, paper #3514, Universal City, CA. (9) Wilt, M., R. Mallan, P. Kasamyer, and b. Kirkendall, 2002. "3D extended logging for geothermal resources: Field trials with the GEO-BUILT system", Proceedings, 27th Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, CA, SGP-TR-171.

Recent/Upcoming Technology Transfer Events: (1) Langan, R. T. , D. R. Julander, M. F. Morea, C. M. Addington, and S. K. Lazaratos, 2000. Crosswell seismic imaging in the Buena Vista Hills, San Joaquin Valley: A case history: Pacific Section Convention, AAPG, Long Beach, June 2000. (2) Perri, P. R., M. A. Emanuele, M. F. Morea, and W. S. Fong. Lost Hills CO2 pilot: Evaluation, design, implementation and early Results: Sixth Annual Permian Basin CO2 Conference, Midland, TX, December 6, 2000. (3) Wilt, M., M. F. Morea, D. Julander, and P. Mock. Using crosswell electromagnetics to map water saturation and formation sturcture at Lost Hills; SPE Bakersfield, SPE 68802, 2001. (4) Hoversten, G. M. "Crosswell Seismic and Electomagnetic Monitoring of CO2 Injection", SEG Development and Production Forum, Taos, NM, 2001. (5) Kirkendall, B. and J. Roberts, "Cross-Borehole Electromagnetic Imaging of a CO2 site: An integrated field and laboratory study", First National Conference on Carbon Sequestration, Washington DC, May 14-17, 2001. (6) Kirkendall, B. and J. Roberts, "Reservoir Management of Sequestrated CO2 using Borehole Electromagetic Tomographic Imaging", International Gas Research Conference, Amsterda, The Netherlands, November 5-8, 2001. (7) Lee, K. H. H. J. Kim, H. W. Tseng, and M. Wilt, "Electromagnetic Methods for Geothermal Exploration", Annual Meeting Geothermal Resources Council, San Diego, CA, August 26-29, 2001. (8) Hoversten, G.M., 2001, Crosswell Seismic and Electromagnetic Monitoring of CO2 Injection, SEG Development and Production Forum, Taos, N.M. (9) Lee, K.H., Kim, H.J., Tseng, H.W., and Wilt, M., 2001, Electromagnetic Methods for Geothermal Exploration, Annual Meeting Geothermal Resources Council, San Diego (August 26-29).
Public Relations: Edward R. Spaulding, Public Affairs Manager, Chevron USA Production Company, (661) 633-4500, email: ersp@chevrontexaco.com.
Chip Power, The Bakersfield Californian, Staff Writer, email: ppower@bakersfield.com.

Project Status: The project Budget Period I was conducted at Buena Vista Hills field. Results from Budget Period I indicated that Buena Vista Hills field was not a good CO2 flood candidate. Budget Period II was transferred to Lost Hills field for the field demonstration of CO2 flooding. Project is in Budget Period II, one year no-cost extension granted to allow for CO2 monitoiring.

Increasing Heavy Oil Reserves in the Wilmington Oil Field through Advanced Reservoir Characterization and Thermal Production Technologies -- Class III

City of Long Beach



Puente Formation

@ 3,000 ft.

Miocene Age

Wilmington Field

Los Angeles County, CA

Los Angeles Basin

DE-FC22-95BC14939

Contract Period:
3/30/1995 to 9/30/2006

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Principal Investigator:
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Objective: Develop and apply advanced characterization and production technologies to increase heavy oil reserves and decrease thermal recovery operating costs in slope and basin type reservoirs.

Technologies Used: (1) 3-D deterministic and stochastic thermal reservoir simulation models. (2) Study on the geochemical interactions between the steam and the formation rock and fluids. (3) Hot water alternating steam (WAS) drive pilot in the existing stream drive area to improve thermal efficiency. (4) Novel alkaline steam completion technique to control well sanding problems and fluid entry profiles. (5) Implement pilot horizontal well steamflood project.

Background: Thermal operations in the Wilmington Field have been economical with current low oil prices due to the availability of inexpensive steam. Such favorable terms for obtaining steam are not expected to be available in the future. Future expansion of thermal recovery to other parts of the Wilmington Field will depend on improving the efficiency and economics of heavy oil recovery. This project may produce 13 million barrels of additional oil, and if expanded field-wide could add 525 million barrels of production A highlight from the steamflood project is the sand consolidation well completion technology which prevents sand entry into the producing wellbore. This new technology requires lower capital costs, provides more operating flexibility, and appears to have higher productivity indexes than other sand control completions.

Incremental Production: New wells drilled and completed include two horizontal producers, two horizontal steam injectors, and five temperature observation wells (of which two were cored). The horizontal well steamflood pilot peaked at 350 BOPD and has stabilized production of 300 BOPD at an instantaneous steam/oil ratio of 12. Reasons for the poor performance are being evaluated.

Expected Benefits and Applications: Lower drilling and completion costs can benefit all operators. Many aspects of this project entail reducing operating problems unique to deep, high pressure steamfloods and improving oil recovery efficiency by applying advanced reservoir characterization techniques. Successful resolution of the problems and improvement in recovery efficiency would make steamflooding of similar reservoirs more attractive, with a potential of 1.4 billion bbl of oil in the Los Angeles area. Implement a horizontal well steamflood pilot project into a deep, high pressure heavy oil reservoir, install insulated subsurface channel crossing to transport steam, test hot alkaline/steam well completion technique for sand control, and develop 3-D deterministic and stochastic reservoir simulation models. Implement a horizontal well steamflood pilot project into a deep, high pressure heavy oil reservoir, install insulated subsurface channel crossing to transport steam, test hot alkaline/steam well completion technique for sand control, and develop 3-D deterministic and stochastic reservoir simulation models.

Accomplishments: (1) A novel alkaline steam well completion technique has been successfully developed and tested that controls well sanding problems in unconsolidated sand formations and provides improved fluid entry and injection profiles. This well completion technique works equally well on horizontal and vertical wells and costs less than the conventional completions for controlling sand. Sand free operations due to steam consolidation techniques have saved $90K per vertical well and $150K per horizontal well, resulting in 25% reduction of capital costs for drilling wells in unconsolidated sediments. (2) Compiled a computer database of production and injection data, historical reservoir engineering data, detailed core studies, and digitized and normalized log data to enable work on the basic reservoir engineering study and 3-D deterministic and stochastic geologic models. (3) Completed 3-D deterministic geologic model and computerized three-dimensional (3-D) visualizations to aid in drilling of horizontal wells in Tar II-A and Tar V. Geologic modeling technique used for drilling other horizontal wells, both thermal and non-thermal, in Fault Blocks IV and V. (4) A comprehensive rock-log model has been completed based on correlations between cores and logs which can predict basic rock types in wells with only log data. (5) Basic reservoir engineering study on Fault Block II-A Tar zone completed. (6) 3-D deterministic reservoir simulation model completed using the STARS program by the Computer Modeling Group of Calgary that history matches the primary, waterflood and steamflood phases. Utilized 3-D deterministic reservoir simulation model to control formation compaction and maximize oil production. This model was modified to plan post-steamflood operations when the steam host, Harbor Cogeneration, permanently shut down operations in mid-January 1999. The deterministic model successfully provided guidelines for injecting cold water along the flanks of the steamflood at rates sufficient to offset reservoir pressure declines due to localized steam chest collapses and fluid production

withdrawals. (7) Developed a rock compaction algorithm that can mimic the local and dynamic features of rock compaction and rebound as a function of reservoir pressure. The Computer Modeling Group incorporated the algorithm into their thermal reservoir simulator, STARS starting in 1998. (8) Completed a study of scale minerals created in the producing wellbores. Analysis of geochemical interactions between the steam and the formation rocks and fluids has significantly reduced scale-related well costs. (9) Drilled and completed four horizontal wells and five temperature observation wells. The horizontal well steamflood pilot peaked at 350 BOPD, but overall performance has been disappointing due to high fluid levels and restricted production rates in order to meet required injection to production ratios to prevent surface subsidence. Only one of the four pilot horizontal wells is active. (10) Drilled a 2100 foot subsurface harbor channel crossing beneath the Cerritos Channel and installed a 14 inch insulated line to transport steam to Terminal Island. The pipeline has worked trouble-free since installation. Two additional pipeline channel crossings have been drilled based on the steam channel crossing from this project. (11) Two tracer studies have been completed, one based on monitoring water salinities and one based on non-radioactive tracers. The water salinity tracer shows promise because of its low cost and ability to identify fresh water steam breakthrough in a reservoir with saline water. The non-radioactive tracers could not be traced and was unsuccessful. (12) Tested several core analysis procedures for measuring formation porosity, permeability and oil saturation to improve the 'routine' Dean Stark method. The most cost effective change is to perform the analysis under reservoir overburden pressures rather than under minimum 300 psi stress to get more accurate (and lower) porosities and permeabilities. (13) A neural network analyzer has been completed to analyze the similarities of various zones and sub-zones in terms of sequence stratigraphy using gamma ray, spontaneous potential, neutron and resistivity logs. This technology allows large numbers of logs to be screened quickly for formation markers or other distinctive formation characteristics rather than visual picks from individual logs.
(14) Operating costs have been reduced through application of an innovative new commercial H2S scrubber technology, called Lo~Cost SM, which can strip out H2S gases created in the steamflood at a 50% reduction in cost. Hart's Oil and Gas World Magazine honored Tidelands with the Best Field Improvement Project award in their Best of the Pacific contest in April 1999 for the design and implementation of this lower-cost H2S scrubber. Our project partners were T. J. Cross Engineers and the Sulfa Treat Company. (15) The project team designed and installed a new steam generator that can burn variable low quality waste gas created by thermal operations. (16) Performed pilot tests of cyclic steam injection and production on new horizontal wells. Initial injection rates low but increase over time as near wellbore area heats up. Initial production generally high, ranging from 223-328 BOPD in Tar V wells. (17) Performed pilot tests of hot water-alternating-steam (WAS) injection in the existing steam drive area to improve thermal efficiency and to wind down steamflood.. (18) Performed pilot steamflood with the horizontal injectors and producers in the Tar II-A using a pseudo steam-assisted gravity-drainage process. High fluid levels hurt performance. (19) Performing advanced reservoir management through computer-aided access to production and geologic data to integrate reservoir characterization, engineering, monitoring and evaluation. (20) Maintaining Tar II-A post-steamflood reservoir fill-up of steam chest using flank cold water injection. Learning how to end a steamflood safely and cost-effectively. (21) High temperature core-flood work indicates that under certain situations, shales can fail and undergo compaction. It appears this occurs when shale intervals are over seven feet thick

and temperatures exceed 400degrees F. More lab work and studies are needed to confirm these initial findings. (22) Expanded the steamflood project to include the five well horizontal steamflood pilot in the Fault Block V Tar zone. (23) The project team has published 37 original papers, poster sessions, reports, and other reference materials and activities to further technology transfer to the industry. In addition, the project is responsible for 16 other publications related to original DOE project technical work and articles of interest. Internet home page is http://www.usc.edu/dept/peteng/topko.html. A CD-ROM of the project on IBM PC format is being distributed free upon request to Scott Hara at scott.hara@tidelandsoil.com or 562-495-9351.

Publications: (1) Montgomery, S.L."Increasing Reserves in a Mature Giant: Wilmington Field, Los Angeles Basin, Part 1; Reservoir Characterization to Identify Bypassed Oil", AAPG Bulletin, V. 82, No. 3 (March 1998), p. 367-385. (2) Montgomery, S.L., 1998. "Increasing Reserves in a Mature Giant: Wilmington Field, Los Angeles Basin, Part II: Improving Heavy Oil Production Through Advanced Reservoir Characterization and Innovative Thermal Technologies", AAPG Bulletin, V. 82, No. 4, p. 531-544. (3) Davies, David, David K. Davies and Assoc. Inc., Mondragon, Julius III and Hara, Scott, Tidelands Oil Production Co., SPE Paper # 38793, "Well-Completion Technique Using Steam For Formations With Unconsolidated Sands", SPE Journal of Petroleum Technology, September 1998, pages 46-52; (4) Phillips, Chris, Tidelands Oil Production Co, Clarke, Don, City of Long Beach, "3-D Modeling/Visualization Guides Horizontal Well Program in Wilmington Field", Journal of Canadian Petroleum Technology, October 1998, pages 7-15; (5) Davies, D. K., R. Vessel, J. Aumon, 1999, "Improved prediction of reservoir behavior through integration of quantitative geological and petrophysical data": SPE 55881, *SPE Reservoir Evaluation and Engineering* Magazine, April, 1999. (6) Davies, D., P. S. Hara, J. Mondragon, 1999, "Geometry, internal heterogeneity and permeability distribution in turvidite reservoirs, Pliocene California": SPE 56819, SPE Ann Techn Conf. ACTE, Houston, TX, Oct 3-6, 1999. (7) Ershaghi, I., and M. Hassibi, 1999, "Reservoir heterogeneity mapping using an artificial intelligence approach": SPE 56818, SPE Ann Techn Conf. ACTE, Houston, TX, Oct 3-6, 1999. (8) Davies, D., 2000, "Stress-dependent permeability in unconsolidated sand reservoirs": *Offshore Magazine*, February, 2000, pp. 82-84. (9) Mondragon, J., Z. Yang, I. Ershaghi, P. Hara, S. Baily, R. Koerner, "Post steamflood reservoir management using a full-scale three-dimensional deterministic thermal reservoir simulation model, Wilmington field, California": SPE 62571, Pacific AAPG/ SPE Western Regional Joint Conference, Long Beach, CA, June 19-22, 2000. (10) Changan Du, Iraj ershaghi, (USC), "Reservoir Characterization and Stochastic Modeling of Fault Block II-A Turbidite Sand Formation of Wilmington Oil Field, Long Beach, Californian", technical report, USC Department of Chemical Engineering –Petroleum Engineering Program, December 1998, Revided by Julius Mondragon III, (City of Long Beach), May 2001. (11) F. E. Moreno, D. D. Mamora, (Texas A & M University), "Sand Consolidation Using High Temperature alkaline Solution – Analysis of Reaction Parameters", SPE 68847, 2001 SPE Western Regional Meeting, Bakersfield, CA. March 26-30, 2001.

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Blocak V Tar Zone": West Coast PTTC Annual Forum, USC, Los Angeles, CA, Dec. 10, 1999. (3) Clarke, D., "At 68 Wilmington still has life: New technology revitalizes the old field": Pacific AAPG/ SPE Western Regional Joint Conference, Long Beach, CA, June 19-22, 2000. (4) Scott Hara, "Applying New Technology to an Old Field"; California ConservationCommittee of Oil and Gas Producers, Long Beach, CA, September 25, 2001. (6) Scott Hara, "Applying New Technology to an Old Field"; Petroleum Engineering Department, Standord University, November 2, 2001. Internet home page is http://www.usc.edu/peteng/doe.html.

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Long Beach Press Telegram: Mr. Will Shuck 916-492-8749
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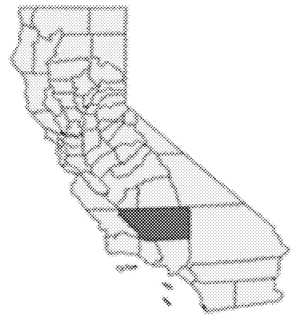
Project Status: Project Budget Period I extended to September 30, 2003.

Economic Recovery of Oil Trapped at Fan Margins Using High Angle Wells and Multiple Hydraulic Fractures -- Class III

AERA Energy LLC



Yowlumne Sandstone	Yowlumne Field
@ 12,000 ft.	Kern County, CA
Miocene Age	San Joaquin Basin

DE-FC22-95BC14940

Contract Period:
9/29/1995 to 9/28/2001

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Objective: Apply several advanced technologies, such as high angle wells and hydraulic fracturing, to economically develop potential reserves of bypassed oil trapped within thinly bedded, heterogeneous fan margin portions of a slope-basin clastic reservoir.

Technologies Used: Hydraulic fracturing in a high-angle well, microseismic logging, reservoir characterization, core and fluid analysis, reservoir modeling and numerical simulation, measurement-while-drilling tool strings and bottomhole assemblies, polycrystalline diamond compact (PDC) drill bits, advanced logging (formation micro scanner [FMS]), array induction tool (AIT), well tests (repeat formation tester [RFT]), electrical submersible pumps (ESP).

Background: In more than 20 years, the Yowlumne Field has experienced primary depletion, a secondary recovery program, and significant decline as the waterflood programs mature. The present project seeks to economically develop potential reserves and under-recovered portions of the waterflooded submarine Yowlumne Field reservoir by coupling several advanced technologies. Using demonstrated cost effective technology the project is expected to produce about 750,000 bbls of incremental oil effectively improving recovery by 25% to 45%. The project will attempt to demonstrate the use of hydraulically fractured horizontal or high angle wells to expose greater extent of pay zone while maintaining vertical communication between thin inter-bedded layers and the well bore. Through transferring project findings from applied technology to operators of similar reservoirs, an additional 80 million bbls of new oil production is anticipated.

Incremental Production: Incremental production in this single horizontal, which replaces three conventional vertical wells, is expected to reach 745,000 bbl of oil. Non-acid system and treatment via coiled tubing increased production in new well to 250 BOPD.

Expected Benefits and Applications: If successful, this project provides a practical demonstration of several leveraged technologies that can be applied to a huge volume of remaining oil-in-place in other fields. Successful demonstration of this approach could increase field reserves by as much as 8.3 million bbl of oil, and could increase reserves in analogous slope-basin and basin clastic reservoirs in California by 330 million bbl of oil, or 52.5% of remaining reserves not economically recoverable using conventional technologies. This project plans to demonstrate that hydraulically fracturing deviated wells is a cost-effective approach to develop thinly stratified systems that comprise a volumetrically significant portion of slope-basin and basin clastic reservoirs.

Accomplishments: A fine-grid partial-field reservoir simulation model of the northeast fan-margin region was built and used to test a variety of development alternatives. Model forecasts compared slant well performance to more conventional development options and quantified rate impacts due to changes in well location, orientation, and completion technique. The model was used to site the location and orientation of the slant well. The slant well was drilled to a total depth of 14,300 ft with a 1,100 ft lateral across the thin bedded fracture zone. After logging, production liners were run and cemented across the target formation. However, well conditions prevented the 7 inch liner from reaching bottom. The final 1000 ft were cased with a 5 inch liner. Much of the target formation, primarily behind the 5 inch liner, proved to be swept by waterflood operations. Consequently, the three hydraulic fracture treatments originally planned for the well were reduced to one. In addition, cement bond logs revealed a poor bond between the 5 inch liner and formation leaving only one viable hydraulic fracture treatment candidate. After pumping a remedial cement squeeze, the well was perforated and stimulated with a non-acid reactive KCl fluid. The well was completed (fractured) in sand intervals A,B, and C. Sands D&E were not completed as they contain a high water saturation, which would flow vertically if they had been fractured. Recommendation for drilling another well in the area include less of an inclination in the drilling curve to reduce frac gradient, more powerful mud-motors and a stronger bit because the abrasive nature of the turbidite sediments. Pay intervals were perforated during 4th quarter 1998 and treated with KCI water. A half day workshop in August 1998 addressed the reservoir characterization, and engineering problems encountered in drilling and completing the horizontal well and fracture treatments.

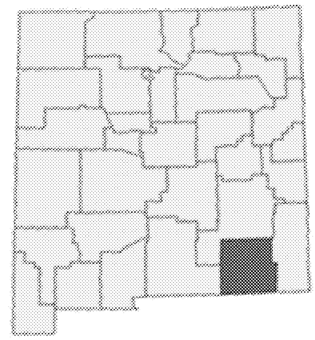
Publications: (1) M. Clark, J.D. Melvin, R.K. Prather, A.W. Marino, J.R. Boles and D.P. Imperato, 1997. "Characterization of the Distal Fan Margin of a Slope-Basin (Class III) Reservoir, ARCO-DOE Slant Well Project, Yowlumne Field, California", 4th International Reservoir Characterization Technical Conference, Workshop on Reservoir Characterization, Houston, TX, pp. 49-64. (2) Clark, M., et al. 1999. "Characterization of the Distal Fan Margin of a Slope-Basin (Class III) Reservoir, ARCO-DOE Slant Well Project, Yowlumme Field, California", in R. Schatzinger and J.F. Jordan, editors, Reservoir Characterization - Recent Advances, AAPG Memoir 71, AAPG, Tulsa, OK, p. 21-28.

Recent/Upcoming Technology Transfer Events: : (1) August 20, 1998, "Economic Recovery of Oil Trapped at Fan Margins Using High-Angle Wells & Multiple Hydraulic Fractures Workshop: Yowlumne Field, California", ARCO workshop on Yowlumne DOE project, Mike Laue, Mike Clark, Tim Speirs, and Thomas Riggs, Bakersfield, CA. (2) M. Clark, "Reservoir Characterization of a Fan-Shaped Turbidite Complex in an Active-Margin Basin, Miocene Stevens Sandstone, Yowlumne Field, San Joaquin Basin, California" October 4-9, 1998 3rd AAPG/EAGE Joint Research Conference on Developing & Managing Turbidite Reservoirs: Case Histories & Experiences, Almeria, Spain. (3) Clark, M., "Characterization and Exploitation of the distal Margin of a Fan-shaped turbidite reservoir – Yowlumne Field", Poster, AAPG/SPWLA Hedberg Research Symposium, The Woodlands, TX, October 10-13, 1999.

Project Status: The project was initiated and run by ARCO. The property was transferred to AERA Energy at the end on 1998. No work has been done since 1998.
Project closed out at completion date September 2001. No final report.

Advanced Oil Recovery Technologies for Improved Recovery from Slope Basin Clastic Reservoirs, Nash Draw Brushy Canyon Pool, Eddy County, New Mexico -- Class III

Strata Production Co



Delaware Formation	Nash Draw Field
@ 6,700 ft.	Brushy Canyon Unit
Permian Age	Eddy County, NM
	Delaware Basin

DE-FC22-95BC14941

Contract Period:
9/25/1995 to 9/23/2004

DOE Project Manager:
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Objective: Demonstrate that a development program based on advanced reservoir management methods can significantly improve oil recovery and transfer this technology to oil and gas producers in the Permian Basin.

Technologies Used: Core/fluid analysis, whole core calibrated log analysis, analog area characterization, vertical seismic profiling, 3-D seismic, thin-bed enhancement, MRI logging, well tests, geological modeling, geostatistics, numerical simulation, and targeted drilling.

Background: Low recovery in the Nash Draw Reservoir (NDU) is caused by low reservoir energy, less-than-optimum permeabilities and porosities, inadequate reservoir characterization, and poor past reservoir management strategies. Based on the production constraints due to high gas-oil ratios that have been observed in other similar Delaware fields, pressure maintenance, in continuous parts of the reservoir, is a likely requirement at the NDU. Three basic constraints to producing the NDU Brushy Canyon Reservoir are: (1) limited areal and interwell geologic knowledge, (2) lack of an engineering tool to evaluate the various producing strategies, and (3) limited surface access that will prohibit development with conventional drilling. The limited surface access at NDU is caused by the proximity of underground potash mining and surface playa lakes.

Incremental Production: Six new wells with discovery of 583,206 BO of new reserves, and 274,206 BO of incremental production and 1,854 MMCFG.

Expected Benefits and Applications: Quantifiable results will include: (1) the data and results will be public, (2) other producers with similar problems can consider the advanced technologies for their projects, (3) increased recovery will contribute to the availability of a stable and low-cost source of domestic oil, and (4) increased tax revenues. Approximately one MMBB of oil not currently recoverable remains in reservoirs similar to the Nash Draw Brushy Canyon Pool. Recovery efficiency is poor, estimated at only 10% of OOIP. Success could improve production from the Nash Draw Brushy Canyon Pool by over 2,500 BOPD or a total of 18.5 million bbl of oil, an incremental increase of 35% of OOIP. Analogous reservoirs in New Mexico and Texas, could recover one billion additional barrels of oil. Advanced reservoir management methods will be employed to maximize production in the recently discovered Nash Draw Brushy Canyon Pool. Demonstrate the success of a "virtual" company. Producing companies and consultants working in the area can extend the data and interpretation to other Delaware reservoirs. The methodology for identifying net pay can be applied in other sandstone formations.

Accomplishments: Six new wells were drilled for data acquisition. Multiple sidewall cores were obtained for analysis. Approximately 203 ft of full core was cut from 6641 to 6844 ft from NDU #23. The routine core analysis included porosity, permeability, and saturation for each foot of core. Special core analysis to determine wettability, relative permeabilities, mineralogy, pore structure, and clay content are being utilized for characterization. Normal suites of logs were obtained in all wells, and a magnetic resonance tool was run in NDU #23 for comparison to the cores taken. Well data, including logs, cores, fluid properties, production history and analysis, are distributed to the multidisciplinary geoscience team using the interactive data base. A VSP survey was performed on NDU #25 and the data obtained was used to calibrate the 3-D seismic which was finished in 6/96. The 3-D data set has been used to create the geologic model. Reservoir modeling used the Advanced Log Analysis data to develop the second generation model. Seismic amplitudes will be used to distribute reservoir attributes in the third generation reservoir model. The 3-D seismic data has yielded drilling targets, has indicated that the proposed pilot area may be compartmentalized, and identified more continuous area of the reservoir. Two wells have been drilled into seismic anomalies and a directional/horizontal well has been drilled to reach a seismic anomaly located beneath a playa lake and potash reserves. Analysis of production rates versus cumulative production, BHP versus GOR and seismic data using geostatistics has helped identify drainage areas and boundaries. Incremental oil production since beginning of project is 274,206 barrels of oil and if successful, this project will recover an additional 18.5 million barrels of oil, raising the field recovery from 10% to 45% of oil in place. Have identified two potential products. The first is an Advanced Log Analysis Program and the second is a data base management system.

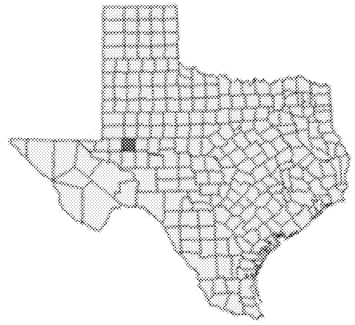
Publications: (1) Hardage, B.A., J.L. Simmons, Jr., V.M. Pendleton, B.A. Stubbs, and B.J. Uszynski, 1998. "3-D Seismic Imaging and Interpretation of Brushy Canyon Slope and Basin Thin-Bed Reservoirs, Northwest Delaware Basin": Geophysics, V. 63, No. 5, Sept-Oct 1998, P. 1507-1519. (2) Hardage, B.A., J.L. Simmons, Jr., V.M. Pendleton, B.A. Stubbs, and B.J. Uszynski, 1998. "3-D Instaneous Frequency Used as a Coherency/Continuity Parameter to Interpret Reservoir Compartment Boundaries Across an Area of Complex Turbidite Deposition": Geophysics, V. 63, No. 5, Sept-Oct 1998, P. 1520-1531. (3) Murphy, M. B., 1999, "Advanced oil recovery technologies for improved recovery from slope basin clastic reservoirs, Nash Draw Brushy Canyon Pool, Eddy County, NM": Annual report October 1, 1997 to September 30, 1998, Strata Production Company; February 1999, DOE/BC/14941-13. (4) Murphy, M. B., 1999, "Advanced oil recovery technologies for improved recovery from slope basin clastic reservoirs, Nash Draw Brushy Canyon Pool, Eddy County, NM": Budget Period I report, September 25, 1995 to September 24, 1998, Strata Production Company; February 1999, DOE/BC/14941-14. (5) "Using Reservoir Characterization Results at the Nash Draw Pool to Improve Completion Design and Stimulation Treatments", SPE # 38916 revised as #58007 in the SPE Reservoir Evaluation and Engineering, Vol. 2, No. 2, April 1999. (6) Martin, D. et al. 1999. "Advanced Reservoir characterization for improved oil recovery in a New Mexico Delaware Basin project", *in* R. Schatzinger and J. F. Jordan, editors, Reservoir Characterization - Recent Advances, AAPG Memoir 71, AAPG, Tulsa, OK, p. 93-108. (7) Weiss, W. W. et al. 2001. "Estimating bulk volume oil in thin – bedded turbidites", SPE 70041. Permian Basin Oil and Gas Recovery Conference, Midland, TX, May 15-16, 2001. (8) The completion of the Nash Draw #36 was presented at the Schlumberger Coiled Tubing Completion Seminar, Midland, TX, December 12, 2001.

Recent/Upcoming Technology Transfer Events: (1) The Nash Draw core and associated material was exhibited at a core workshop on February 26, 1998 in Midland, Texas. (2) Two SPE papers were presented at the Permian Basin Oil and Gas Recovery Conference in Midland, Texas on March 23-26, 1998. The titles of the papers are (SPE 38916) "Reservoir Characterization as a Risk Reduction Tool at the Nash Draw Pool", and SPE 39775 "Using Reservoir characterization results at the Nash Draw Pool to improve completion design and stimulation treatments". (3) R. S. Balch, W. W, Weiss and S. Wo. , "Correlating seismic Attributes to Reservoir Properties Using Multi-variate Non-linear regression": Texas West Texas Geological Society Fall Symposium, October 29-30, 1998, Midland, Texas. Published in, The Search Continues into the 21st Century, WTGS Publication 98-105, eds., W. D. DeMis and M. K. Nelis. (4) B. A. Hardage, V. M. Pendleton, R. P. Major, G. B. Asquith, D. Schultz-Ela, and D. Lancaster, "Using Petrophysics and Cross-section Balancing to Interpret Complex Structure in a Limited-Quality 3-d Seismic Image": Texas West Texas Geological Society Fall Symposium, October 29-30, 1998, Midland, Texas. Published in, The Search Continues into the 21st Century, WTGS Publication 98-105, eds., W. D. DeMis and M. K. Nelis. (5) B.A. Hardage, R.L. Remington: 3-D Seismic Stratal-Surface Concepts Applied to the Interpretation of a Fluvial Channel System Deposited in a High-Accommodation Environment, AAPG National Convention, April 11-14, 1999, San Antonio, Texas. (6) Murphy, M. 1999, "Advanced oil recovery technologies for improved recovery from slope basin clastic reservoirs, Nash Draw Brushy Canyon Pool, Eddy County New Mexico", DOE Oil and Gas Conference, Dallas, TX, June 28-30, 1999. (7) The Nash Draw Website can be accessed at
http://baervan.nmt.edu/REACT/LINKS/nash/strata.html. The current site includes the previous reports and the most recent annual report.

Project Status: Project is in Budget Period II, two year no-cost extension granted.

Advanced Reservoir Characterization and Evaluation of CO2-Gravity Drainage in the Naturally Fractured Spraberry Reservoir -- Class III

Pioneer Natural Resources



Spraberry Formation	Spraberry Trend
@ 6,800 Ft.	E. T. O'Daniel Field
Permian Age	Midland County, TX
	Permian Basin

DE-FC22-95BC14942

Contract Period:
7/24/1995 to 7/23/2002

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Objective: Determine the technical and economic feasibility of continuous CO_2 injection in the naturally fractured reservoirs of the Spraberry Trend.

Technologies Used: Core/fluid analysis, outcrop analysis, fracture analysis, borehole imaging logging, well tests, reservoir modeling, numerical simulation, horizontal drilling, infill drilling, CO_2 injection.

Background: At least 15% of all oil remaining in Class 3 (slope-basin and basin clastic) reservoirs may be in the Spraberry Trend. Project participants estimate that currently no less than 6 billion bbl remain in Spraberry reservoirs. The presence of fractures is the dominant influence on performance. Waterflooding was initiated in the Spraberry in the 1950s, but recovery of oil from this process has been relatively poor and only marginally economic. Ultimate recovery under current operations for the Spraberry is extremely low, no greater than 12% of the original oil in place. Prior to this project, no project has evaluated CO_2 injection for enhanced oil recovery in the Spraberry. Because the Spraberry is a fractured reservoir, "conventional wisdom" would imply that recoveries will not be substantially improved. The current project will test the hypotheses that when CO_2 is injected under near-miscible conditions, significant amounts of oil previously unaffected by water injection will be drained by a gravity mechanism from the rock pores into the fractures and moved to producing wells.

Incremental Production: The ten-acre pilot is expected to recover 31,000 barrels of incremental oil. Oil recovery has reached 18% of OOIP arresting the decline in production.

Expected Benefits and Applications: Success of the proposed technique could improve production in the proposed pilot study area by as much as 85 barrels of oil per day, resulting in an incremental recovery of as much as 31 thousand bbl of oil. Extrapolated to the Spraberry Trend as a whole, incremental recoveries could reach over 125 million bbl of oil, and access to additional potentially recoverable oil could be preserved. The techniques being used in this project are specifically related to CO2 flooding of fractured reservoirs. The results of the project should therefore translate to similarly fractured reservoirs of other geological classes. Applying such techniques on a widespread scale could result in incremental oil recoveries in the 2-3 billion bbl range. Management was pleased with the core analysis (1st core from 3,400 wells in Spraberry Trend) and recommended using the same core and sampling technology in additional projects in Texas. Prior to this project, no project has evaluated CO2 injection for enhanced oil recovery in the Spraberry.

Accomplishments:
(1) Reservoir characterizations have been completed. These include matrix description, and pay zone detection (from core integration), fracture characterization and detailed analysis of petrography and diagnosis of the varying rock types of the Spraberry formation. (2) Facilities for the water injection side of the 10-ac. Demonstration pilot project have been constructed. Water injection has been initiated and injection well testing has commenced. (3) All six proposed water injection and three production wells have been drilled. (4) Extensive imbibition experiments clearly indicate that the weakly water-wet behavior of the reservoir rock is responsible for poor waterflood response observed in many Spraberry fields. (5) Wettability index of the Spraberry was found to be approximately 0.2 at reservoir conditions clearly indicating weakly water wet reservoir. (6) Modeling of static and dynamic imbibition experiments show that static imbibition tests do not reproduce the behavior characteristics of dynamic conditions that prevail in the reservoir. (7) CO2 gravity drainage experiments in Spraberry and Berea whole cores at reservoir conditions continue to validate the premise that CO2 will recover oil from tight, unconfined Spraberry matrix. (8) In 1999 extensive field testing was conducted using pilot wells. Tests conducted include: step rate injection test, injection profile logging, interference (pulse) test, pressure buildup/falloff. These tests are being used to enhance the reservoir characterization process. (9) Four water injection wells and three producing wells have been drilled. Two production wells have been converted into water injection wells. Water injection began in March 1999. (10) Four gas injection wells were drilled and completed in the 1st quarter 2000. (11) Two logging observation wells were drilled in the second quarter 2000. Remedial cement jobs were performed on these wells 3rd quarter 2000 to ensure good bonding behind pipe in the Upper Spraberry. (12) Chemical tracer was injected into the six water injectors in August 2000. Samples from 29 surrounding wells were gathered and analyzed during 3rd and 4th quarter 2000 to identify well to well interconnectivities. (13) Carbon Dioxide injection into the Pilot area began in 1st Quarter of 2001. (14) Implemented Water Alternating Gas Injection process in 3rd Quarter 2001.

Publications: (1) Three papers were presented at the Permian Basin Oil & Gas Recovery Conference, Midland, TX, March 23-26, 1998, they were: "Fracture Characterization Based on Oriented Horizontal Core from the Spraberry Trend Reservoir: A Case Study", SPE 38664. (2) "Integrated Study of Imbibition Waterflooding in the Naturally Fractured Spraberry Trend Reservoirs", SPE 39801. (3) "Use of Single Well Test Data for Estimating Permeability & Anisotrophy of Naturally Fractured Spraberry Trend Reservoirs", SPE 39807. (4) SEPM Monthly Meeting, Midland, TX, January 20, 1998, "Characterization of Spraberry Fractures from the O'Daniel #28 Horizontal Core". (5) Southwestern Petroleum Short Course, Lubbock, TX, April 8-9, 1998, "Fracture Characterization Based on Oriented Horizontal Core from the Spraberry Trend Reservoir: A Case Study", SPE 38664. (5) SPE 48948 "Wellman Unit CO2 Flood: reservoir Pressure Reduction and Flooding the Water/Oil Transition Zone", D.S. Schechter, B. Guo and R. Grigg. (6) SPE 39881, "An Integrated Investigation for Design of a CO2 Pilot in the Naturally Fractured Spraberry Trend Area West Texas", David S. Schechter and Boyun Guo. (7) SPE 38913, "Integration of Petrophysical and Geological Data with Open-Hole Logs for Identification of the Naturally Fractured Spraberry Pay Zones", David S. Schechter, Ashish K. Banik. (8) Schechter, D. S. and P. McDonald, 1999, "Advanced reservoir characterization and evaluation of CO2 gravity drainage in the naturally fractured Spraberry Trend area": Annual report September 1, 1997 to August 31, 1998, Pioneer Natural Resources/ New Mexico Institute of Mining & Technology; February 1999, DOE/BC/14942-7 . (9) Heckman, T., and D. S. Schechter. 2000. "Advanced reservoir characterization and evaluation of CO2 gravity drainage in the naturally fractured Spraberry Trend area": Annual report September 1, 1998 to August 31, 1999, April 2000, DOE/BC/14942-9.

Recent/Upcoming Technology Transfer Events: PRRC hosted the 4th Naturally Fractured Reservoir Symposium on October 27, 1998, Macey Center New Mexico Tech Socorro, NM. Forty-five industry personnel were in attendance. (1) Chris Whigham, "Overview of the CO2 Pilot in the Spraberry Trend Area", The 4th Naturally Fractured Reservoir Symposium, October 27, 1998, Socorro, New Mexico. (2) Claudio Saleta, "Fracture and Matrix Diagenesis in the Spraberry Trend Area", The 4th Naturally Fractured Reservoir Symposium, October 27, 1998, Socorro, New Mexico. (3) Yanfida, PTTC "Wettability Investigation in the Spraberry Trend Area", The 4th Naturally Fractured Reservoir Symposium, October 27, 1998, Socorro, New Mexico. (4) Jenny Cherney, New Mexico Tech, "Investigation of anisotropy from Spraberry Horizontal core at In-Situ Stress Conditions", The 4th Naturally Fractured Reservoir Symposium, October 27, 1998, Socorro, New Mexico. (5) Erwin Puta, PRRC , "Reservoir Simulation Issues in the Spraberry Trend Area", The 4th Naturally Fractured Reservoir Symposium, October 27, 1998, Socorro, New Mexico. (6) PRRC hosted the 3rd CO2 Oil Recovery Forum October 28, 1998 Symposium on October 28, 1998, Macey Center New Mexico Tech Socorro, NM. Eighty-five industry personnel were in attendance. (7) Todd Yochum, "Overview of the CO2 Pilot in the Spraberry Trend Area", Pioneer Natural Resources, DOE Oil and Gas Conference, June 28-30, 1999, Dallas, TX. (8) SPE Paper 7160a, “CO2 Pilot Design and Water Injection, Performance in the Naturally Fractured Spraberry Trend Area, West Texas”: 2001 Annual Technical Conference and Exhibit in New Orleans, Louisiana, September 30 -October 3, 2001. (9) SPE Paper 71635, “Development of a Fracture Model for Spraberry Field, Texas USA”: 2001 Annual

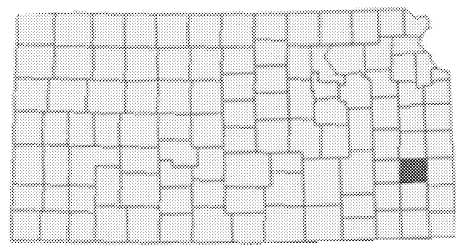
Technical Conference and Exhibit, New Orleans, Louisiana, September 30 through October 3, 2001.

Project Status: Project initiated by Parker and Parsley, who merged with Mesa Petroleum in 1997 to become Pioneer Natural Resources. Pioneer Natural Resources office moved from Midland to Irving, Texas in 2000. Project is in Budget Period II, and was completed in July 2002. Final Report in press.

ADVANCED CLASS
WORK

Optimizing the Air Flotation Water Treatment Process

Russell Petroleum, Inc.



Cherokee Sandstone	Savonburg Field
@>1,000 ft	Allen County, KS
Pennsylvanian Age	Kansas Uplift

G4S50904

Contract Period:
10/15/1995to 4/14/1997

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Objective: The objective of this project is to increase the cost effectiveness and enhance the applicability of the air flotation water treatment process demonstrated in the Class II Field Demonstration Program project 'Improved Oil Recovery in Fluvial Dominated Deltaic Reservoirs of Kansas' by (1) optimizing process design factors, (2) developing preliminary screening criteria for the application of the technology, and (3) communicating the appropriate application and benefits of the technology to other operators.

Technologies Used: Air flotation water treatment process.

Background: The use of air flotation to clean produced water for reinjection into the reservoir is new to the operations in eastern Kansas. The air flotation unit (AFU) installed at the Nelson Lease in the Class I` Field Demonstration Program project was designed primarily for the removal of oil in produced water for off shore operations. The AFU is very effective in the removal of oil. However, the removal of solids from the water has proven to be more difficult than anticipated. This is due to (1) the solids load in the water, (2) the changing composition of the solids as the ratio of produced to make up water changes, and (3) the need to change the design on the weir for removal of the froth at the surface of the AFU. The current tank design has limited the physical changes in the froth weir shape and location. This project will address improving the efficiency of the air flotation unit and reducing the man-hours required to operate the unit.

Incremental Production: Not applicable.

Expected Benefits and Applications: To increase the applicability and effectiveness of the air flotation process to water treatment and thereby reduce operating costs. New application of technology to produced-water treatment in Kansas oil fields.

Accomplishments: 1) Well cleanout frequencies were reduced from 47 per year in 1995 to 21 per year in 1996; 2) chemical costs have been lowered 34% per day, from an average of $38 per day to $25 per day, although this may increase to solve solids problems; 3) improved water filterability -5-micron and 2-micron filters are being used instead of 10 and 75 micron filters, with no significant increases in filter change frequency; and 4) improved water quality measurement techniques by using a calorimeter. The optimized system has not yet been used by other producers. An effective design for the froth weir and froth removal system.

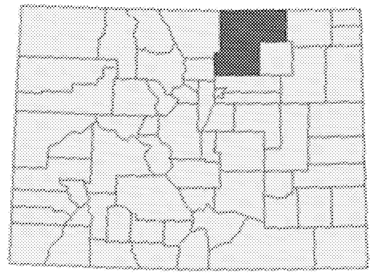
Publications: Barnett, B., 1998, "Optimizing the Air Flotation Water Treatment Process": Final Report - Advanced Class Project, James E. Russell Petroleum, Inc., September 1998, DOE/PC/91008-10 (DE98000539).

Recent/Upcoming Technology Transfer Events: Project technology transfer activities include 25 field tours conducted for various industry representatives; 2 workshop presentations; and 8 publications. Field Experience in Obtaining High Quality Injection Water Using Air Flotation in the Savonburg Field; 13th Tertiary Oil Recovery Conference, Mary 17-18, 1999, Wichita, Kansas.

Project Status: Project has been completed. Final report published September 1998. Request 91008-10.

Polymer Treatments for 'D' Sand Water Injection Wells

Diversified Operating Corp



Muddy (D) Formation	Sooner Unit
@ 6,300 ft	Weld, County, CO
Cretaceous Age	Denver-Julesburg Basin

G4S60323

Contract Period:
1/22/1996to 4/21/1997

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303-384-9611
303-384-9612

Objective: The objectives of this project are to (1) implement gel-polymer treatments in the Sooner Unit, (2) develop methodologies that increase the effectiveness of gel-polymer treatment applications, and (3) transfer the results of this project to other operators.

Technologies Used: Well testing, polymer gel treatment, production monitoring, engineering analysis.

Background: The reservoir characterization work conducted in the Class I project 'Advanced Secondary Recovery Demonstration for the Sooner Unit' resulted in the identification of reservoir heterogeneities that included compartmentalization and permeability anisotropy parallel to the depositional axis of the reservoir sand. Thief zones and strong flow barriers prevented significant increases in production from waterflooding in the Sooner Unit project. Channeling of injected water in a north-south direction resulted in increases in water production at offset production wells without an attendant increase in oil production. Where well pairs were oriented east-west, increased injection rates did not produce a measurable rise in fluid level or production response. Gelled-polymer treatments were identified as a potential remedy for the channeling problems encountered in the Sooner Unit. Documentation of the methods used to design, implement, and monitor the gel-polymer treatments would provide information on the applicability of the technology for other Class I reservoirs where channeling is a problem.

Incremental Production: None to date.

Expected Benefits and Applications: Provide information on the applicability of gel-polymer treatments to reservoirs where channeling is a problem. Polymer treatments of injection wells at the Sooner Unit are expected to improve ultimate recovery by 0.5 to 1.0 percent of OOIP. This translates to 35,000 to 70,000 bbl of oil. Incremental revenues to the working interest owners is calculated to be $453,000 over 10 years, using $17.00 per bbl, for recovery of an additional 35,000 bbl. The present value of this incremental revenue is $344,000 using a discount factor of 10 percent per year. Documentation of methods to design, implement, and monitor gel-polymer treatments.

Accomplishments: Diversified Operating Corporation has completed three water injection well polymer treatments. Pre- and post-treatment tests consisted of temperature surveys and pressure falloff tests. The temperature surveys indicated no noticeable changes to the injection profile or the ability of the zone to take fluids after the polymer treatment, however, analysis of the pressure falloff tests indicated that the polymer treatment reduced the permeability thickness by almost one-half without changing the apparent skin. It has been demonstrated, from the treatments that the gels used do link and remain stable at the high temperature (230 degrees F) found at the Sooner Unit.

Publications: Cammon, T.J., 1998, "Polymer Treatments for D Sand Water Injection Wells Sooner D Sand Unit Weld County, Colorado": Final Report - Advanced Class Project, Diversified Operating Corporation; October 1998, DOE/PC/91008-11.

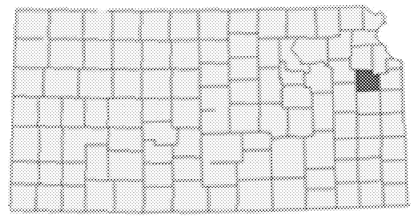
Recent/Upcoming Technology Transfer Events: Mark Sippel presented project results to a SPE/EOR study group on December 12, 1997, in Denver, CO.

Project Status: Project is complete. Final Report published October 1998. Request 91008-11.

Development and Demonstration of an Enhanced, Integrated Spreadsheet-based Well Log Analysis Software - Advanced Class Work

Kansas Geological Survey

Lawrence, Kansas



G4S60821

Contract Period:
6/13/1996to 3/4/1998

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Objective: The objectives of this project are to: (1) enhance the previously developed PfEFFER (Petrofacies Evaluation of Formations For Engineering Reservoirs) well log analysis computer package program and add major new modules to the software package; (2) demonstrate the software by conducting analysis of data from industrial participant's fields; and (3) transfer the technology to operators.

Technologies Used: Geological Information Systems (GIS), numerical simulation, computer software technology.

Background: PfEFFER is a well log analysis computer package that grew out of the 'Super-Pickett' crossplot that was initially developed as part of the DOE funding (DOE/BC/144313) 'Depositional Sequence Analysis and Sedimentological Modeling for Improved Prediction of Pennsylvanian Reservoirs' conducted between 1990-1993 by the Kansas Geological Survey. The software was tested and successfully applied in Schaben Field, a DOE Class II Field Demonstration Project (DE-FE22-93BC14987) to assist in improving reservoir characterization and assessing reservoir performance. PfEFFER v. 1 was released in January, 1996 as a commercial spreadsheet-based well-log analysis program developed and distributed through the Kansas Geological Survey.

Incremental Production: Not Applicable

Expected Benefits and Applications: The project will enhance PfEFFER's abilities to integrate engineering and geological data from petroleum reservoirs for practical applications. PfEFFER makes use of existing resistivity and porosity data from old well logs so that the costly expense of new measurements can be avoided.

Accomplishments: PfEFFER 1.1 is currently available for real-time, interactive log analysis. The spreadsheet and graphic features allow interaction and comparative evaluation of petroleum reservoirs. The enhancements added during this project have increased the ease of use and expanded the applicability of the software. The Home Area of the spreadsheet has been redesigned to include new columns for Vsh (estimated shale fraction), PAY (reservoir that meets cutoff criteria), and FLOW (flow unit designation). The upgraded PfEFFER 2.0 will include shaly sand analysis, Hough transforms, secondary porosity and forward modeling. Two new modules linking PfEFFER with other software were added to form PfEFFER-Pro - a bridge to the GIS WHEAT, and a bridge to BOAST. (1) wrote the Visual Basic code in the simulation module to automate the procedures to build input and output files; (2) tested the simulation code using field data; and (3) updated PfEFFER 2.0 and PfEFFER-Pro to run on Excel 97. None to date. Well log analysis software.

Publications: (1) Bohling, G.C., Doveton, J.H., and Watney, W.L., 1996, Systematic identification of sequence stratigraphic units from wireline logs: Stratigraphic Analysis - Utilizing Advanced Geophysical, Wireline and Borehole Technology for Petroleum Exploration and Production, Gulf Coast Section Society of Economic Paleontologists and Mineralogist Foundation, 17th Annual Research Conference, Houston, TX, p. 29-37. (2) Bohling, G.C., Doveton, J.H., and Hoth, P., 1997, Probabilistic classification and prediction of facies types in a mid-continent Cretaceous deltaic-marine sequence from petrophysical log descriptors using a CMAC procedure (Abs.): Proc. IAMG Conference, Barcelona, Spain. (3) Doveton, John H., Guy, W.J., and Watney, W.L., 1997, The Integration of Pore Measurements into Log Analysis Pattern Recognition Procedures: Methods and Examples: AAPG Convention Abstracts, Dallas, TX, p. A29. (4) Guy, W. J., Carr, T.R., Franseen, E.K., Bhattacharya, S., and Beaty, S., 1997, Combination ofMagnetic Resonance and Classic Petrophysical Techniques to Determine Pore Geometry and Characterization of Complex Heterogeneous Carbonate Reservoir: AAPG Convention Abstracts, Dallas, TX. (5) Young, D., Grauer, J., and Whittemore, D., 1997, Upper Arkansas River corridor study: Progress on Lithologic characterization of unconsolidated deposits in the study area with emphasis on Kearny and Finney Counties: Kansas Geological Survey Open-File Report 97-43, 20 p.(application of PfEFFER). (6) Watney, W.L., Guy, W.J., Doveton, J.H., Bhattacharya, S., Gerlach, P.M., Bohling, G.C., and Carr, T.R., in press, Petrofacies Analysis - A petrophysical tool for geological/engineering reservoir characterization: Proceedings of the Fourth International Reservoir Characterization Conference, Houston, March 2-4, 1997. (7) Watney, W.L., J.H. Doveton, W.J. Guy, 1998, "Development and Demonstration of an Enhanced Spreadsheet-based Well Log Analysis Software": Final Report - Advanced Class Project, Kansas Geological Survey; October 1998, DOE/PC/91008-12 (DE98000541).

Recent/Upcoming Technology Transfer Events: 1. KIPLING paper presented at Gulf Coast Section - SEPM, Houston, TX (December, 1997). 2. Demonstration of PfEFFER at PTTC Workshop, Golden, CO (February, 1997). 3. Paper presented at the Fourth International Reservoir Characterization Technical Conference, Houston (March, 1997). 4. 'PfEFFER - Log Analysis Spreadsheet Solutions for Reservoir Engineering and Petroleum Geology' presented at the Twelfth Oil Recovery conference, Wichita, KS, (March, 1997. 5. Two papers at the Annual AAPG/SEPM Meeting in Dallas (April, 1997). 6. Demonstration of PfEFFER at Phillips Petroleum Company Workshop, (April, 1997). 7. Day-Long workshop on PfEFFER at Computer Applications for the Petroleum Industry sponsored by the KU Energy Research Center, Kansas Geological Survey and the PTTC (June, 1997). 8. Software Demonstration of PfEFFER at DOE workshop in Tulsa, OK on February 24, 1998. Websites:(1)
http://www.kgs.ukans.edu/software/wheat/whtmain.htm;
(2)http://www.kgs.ukans.edu/DPA/Terry/terryMain.htm;
(3)http://www.kgs.ukans.edu/DPA/Schaben/schabenMain.htm

Project Status: Project completed December 1997. Final report published October 1998. Request 91008-12.

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