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The Class Act

DOE's Field Demonstration and Best Practices Newsletter

Class II Shallow-Shelf Carbonate Reservoirs

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In 1992, the U. S. Department of Energy (DOE) announced its Reservoir Class Program, based on recognition of domestic reservoirs by depositional type. The new field demonstration initiative was in response to rapidly declining domestic production and the realization that huge volumes of oil were being abandoned in reservoirs because of uneconomic production techniques. The focus was on providing help to operators to increase production and identification of new reserves in mature U. S. oil fields. The cost-shared field demonstration projects were initiated in geologically defined reservoir classes, which were prioritized relative to the risk of abandonment and potential for incremental recovery. Shallow-Shelf carbonate reservoirs were designated as Class II, and implementation of nine projects began in 1994. In 2000 an additional six shallow-shelf carbonate projects were funded as part of the Class Revisit Program. Over 17 million barrels of incremental oil are expected to be produced from the project areas from estimated reserves of 30 million barrels.

Program Goals

- Extend the economic production of domestic fields by slowing oil well abandonment rates, and preserving industry infrastructure.
- Demonstrate improved methods of reservoir characterization, advanced oil recovery, advanced environmental compliance techniques, and improved reservoir management techniques to increase ultimate recovery in known fields.
- Broaden information exchange and technology application among stakeholders by expanding participation to both traditional and non-traditional participants and making technology transfer products user-friendly.

Class II Review

December 12, 2002 DOE sponsored a one day review of the 15 Class II shallow-shelf carbonate projects. The Review was held at the University of Texas, Permian Basin Center for Energy and Economic Diversification (CEED) Odessa, Texas in the Permian Basin of West Texas where five of the projects were conducted. The original nine projects were completed between December 1997 and September 2002. The six Class Revisit projects are ongoing, most having completed the reservoir characterization (Phase I) of all Class projects. The Map in **Figure 1** shows the distribution of the projects across the United States.

The Review provided an opportunity for all the projects to present their technologies, results, and lessons learned to a large audience of operators involved with carbonate reservoirs. Technology transfer activities such as the Class II review assist DOE is fulfilling their obligation to make the public aware of the valuable research funded through federal cost-shared projects.

Project results, as to be expected, ranged from the very successful technologies,

What's Inside

Figure 1. Distribution of shallow shelf carbonate DOE Class II and Class Revisit projects.

which spawned new discoveries to the less successful applications, and to those technologies that you want to know about in order to avoid costly investments in similar reservoirs. Three elements that are essential to success: 1) Reservoir Characterization, 2) Technology Transfer and 3) Innovative Ideas.

Highlights of the 15 Class II Shallow Shelf Carbonate Projects

Recovery of Bypassed Oil in the Dundee Formation –

Michigan Technological University

The project at Crystal Field in the central Michigan Basin addressed declining recovery from mature fields from highly karsted reservoirs, where initial high production rates have resulted in inverse coning of water. The Devonian age Dundee formation is a fractured, vuggy dolomite which averages only 12 feet thick, presenting a thin window of opportunity for drilling targets. The project drilled the first horizontal well in the Michigan Basin to demonstrate the advantages of this technology to overcome high water production rates. The TOW-1 well is shown in **Figure 2**. The project found that reservoir characterization of the Dundee reservoir was the key to production. Accurate mapping of the top of the Dundee was necessary due to the extreme topography changes resulting from karst development of the dolomite. Analysis of the diagenetic changes and their effects on porosity and permeability were crucial in determining drilling and completion strategies. The detailed reservoir characterization depended on drilling a vertical well and analyzing the core and logs in connection with the production history of the field before siting the location of the first horizontal well, TOW-1.

Lessons learned include the knowledge that when working the Dundee, operators should avoid drilling wells low on structure, and the surface of the dolomite should be carefully mapped. The focus on discovery of bypassed oil in the Dundee should be on “attic oil”. Expansion of the success of the TOW-1 should be followed by looking for similar opportunities in the Michigan Basin, by developing a dolomite map of the central Michigan Basin, and developing a model for dolomite diagenesis that is applicable over multiple carbonate fields. The project completed detailed characterization of 30 similar fields.

Benefits

Following the Crystal field demonstration, 27 Devonian age horizontal wells were drilled in the Michigan Basin with a capital investment of $10 million. The average production is 30 bbl per day with annual production of 300,000 bbl of oil. State severance taxes are paying $250,000 per year, and $630,000 per year Royalties are paid out. The Federal, state and local income taxes paid are $1,650,000 per year. State Approval of Waiver of Liability for pre-existing pollution in Crystal field led the way for hundreds of similar candidate fields. One year after the end of the project Michigan had issued 78 horizontal drilling permits, and horizontal drilling has expanded statewide into several other formations.

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Performer: Michigan Technological University, Houghton, MI.
Performance Period: 4/28/1994 to 12/31/1997.

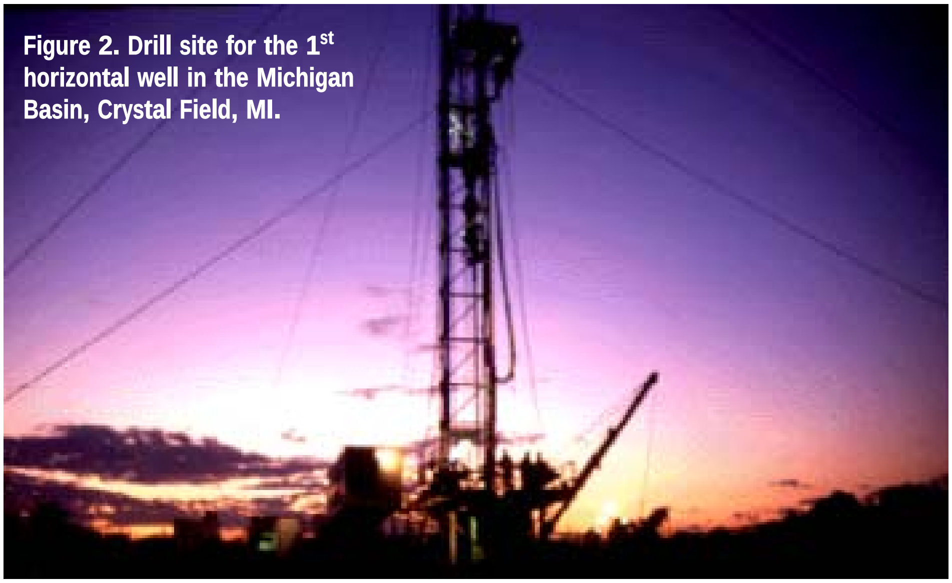

Figure 2. Drill site for the 1st horizontal well in the Michigan Basin, Crystal Field, MI.

Improved Recovery for Williston Basin Carbonates – *Luff Exploration Company*

Prospecting for drilling locations in the Red River and Ratcliffe formations of the Williston Basin in North and South Dakota and Montana is complicated by small structural features often less than a square mile is size. Reservoir depths are from 8,500 ft (Ratcliffe) to 9,500 ft (Red River) and the cost of drilling is high. Luff Exploration explored the reinterpretation of old 2D seismic surveys, and new 3D seismic techniques for structural delineation. In the early 1990s reservoir characterization from seismic attributes was in its infancy. Primary recovery drilling strategy had been based on drilling a single well per structural feature on the crest, and hydraulic fracturing. Standard completion techniques of perforation and acidization had not proved efficient. Hydraulic fracturing caused communication with the water zones resulting in low primary recovery and low water injectivity for waterflood operations.

Development of synthetic seismograms for the local area proved useful for interpretation of both the Red River and Ratcliffe formations. Two demonstration sites were identified and drilled based on detailed reservoir characterization using Forward Seismic Modeling. Amplitude attributes were used for prediction of porosity development and location of drilling zones in the Red River formation. **Figure 3** illustrates production curves from the demonstration sites. It was discovered that a single well for Red River and Ratcliffe targets did not yield optimum production, and that drilling the flanks of structural features was much more productive for Red River targets than the original crestal drilling practices.

In the completion techniques part of the project several technologies were analyzed. Lateral jet lance completion techniques using high pressure water were unsuccessful at the depths of Red River and Ratcliffe formations, and the technology available at the time appeared unable to operate in the pressure and temperature regimes below 5,000 ft. A Sidewinder lateral technology by Amoco was also unsuccessful. Using conventional drilling technology, horizontal re-entry completions were tested, and yielded a three-fold increase in productivity. Horizontal drilling from plugged and uneconomical vertical wells resulted in production rates over 150 BOPD. Waterflooding using horizontal injection wells in a third demonstration site demonstrated that reserves generated by waterflood will equal or exceed primary recovery.

Benefits

The project demonstrated the use of and advantages of advanced seismic attribute analysis for locating drilling targets in small carbonate features in the Williston Basin. Several lateral drilling technologies on the market were rejected as unsuccessful or uneconomic in the Williston Basin or other locations below 5,000 ft. Horizontal recompletions of vertical wells in both the Red River and Ratcliffe yielded significant new reserves, and increased recovery up to 3 times production over vertical wells in the region.

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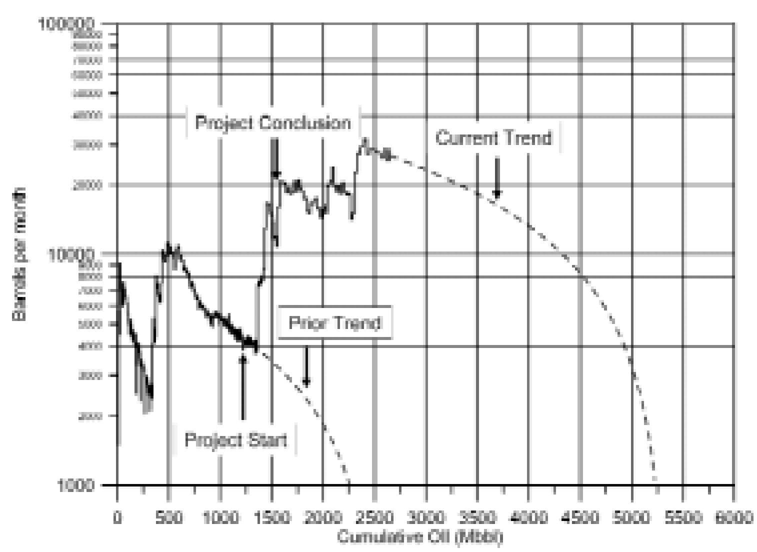

Figure 3. Production graphs from the demonstration sites in the Williston Basin.

Performer: Luff Exploration Company, Denver, CO.
Performance Period: 6/10/1994 to 12/31/1997.

Integrated Study of Foster/South Cowden Field, TX – *Laguna Petroleum Corporation*

The reservoirs in the Foster/South Cowden field lease were approaching their economic limit, and the 68 year old field was in decline, and approaching abandonment within 10 years. The low permeability reservoir was experiencing cross-flow between zones, no fracture stimulations had been performed and a significant problem was determining where the injected water went. Laguna initiated a multidisciplinary approach using 3D seismic inversion modeling to identify productive zones; and an integrated reservoir characterization study including flow modeling, history matching, chemical analysis of the water, and well monitoring tests.

The reservoir characterization study identified the major production as coming from the Grayburg formation, and that the San Andres formation acts as a thief zone in that portion of the Permian Basin. Previously work had greatly over estimated the contribution of the San Andres, and failed to identify significant barriers to vertical flow in the reservoir. Application of new inversion modeling techniques, and relating seismic velocity to neutron density enabled detailed porosity mapping of the reservoir to identify bypassed oil zones.

Well tests, particularly water chemistry analysis and bottomhole pressure tests were used to better describe the complex layering of the reservoir and identify the cross-flow patterns. A key to production and pressure testing was the discovery that low permeability reservoirs require much longer test duration (a minimum of 3 days) to obtain the necessary information to redesign completion strategies and fracture treatments. Prior to the well work the Upper Grayburg was producing at only 37 BOPD from the foster/S. Cowden lease. Initial production following redrills and workovers was 467 BOPD, and two years after the end of the project production is maintaining a rate of 280 BOPD (**Figure 4**).

Benefits

Data and analysis led to drilling three re-entries, four new wells and 12 workovers, resulting in 290,000 barrels of incremental oil. The seismic inversion study increased incremental reserves for the field by 650,000 barrels of oil. The economic life of the field was extended from nine to sixteen years. Without the impetus supplied by the DOE funding, Laguna would have abandoned the Foster/S. Cowden lease by 2003, instead the property was sold in 2002 to OXY, USA for well above the decline curve price.

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Figure 4. Graph of the incremental production from Foster/S.Cowden Field, Texas.

Performer: Laguna Petroleum Corporation, Midland, TX.
Performance Period: 8/2/12996 to 8/2/2000.

CO_2 Huff-n-Puff Process in a Light Oil Shallow Shelf Carbonate Reservoir – *Texaco Exploration & Production*

The objectives of the project were to determine whether oil could be recovered economically in a cyclic CO_2 huff-n-puff process in a reservoir undergoing waterflood drive, and to provide guidelines to the industry on huff-n-puff CO_2 recovery and site selection. The initial field location was Central Vacuum field, Lea County, New Mexico. In Phase II the Sundown-Slaughter Unit of Slaughter field, Hockley County, Texas was added to the analysis. Production targets were the Permian age Grayburg and San Andres formations at an average depth of 4,550 ft. The CO_2 huff-n-puff was designed to mitigate early negative cashflow in conventional CO_2 floods with speeder response time, and to add new reserves and maximize recovery in smaller fields.

Figure 5 illustrates the three phases and length of time involved in the

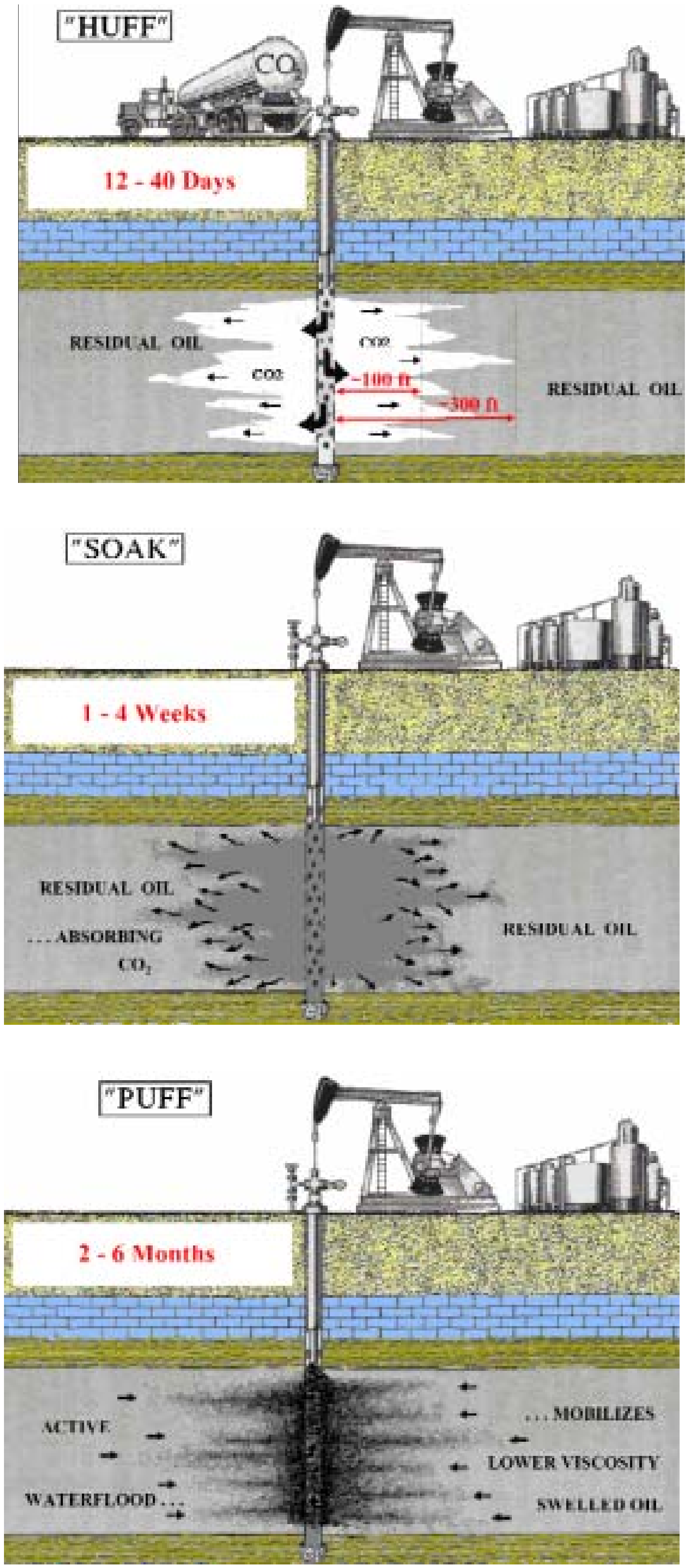

Figure 5. Illustration of the three-part process and time involved in a huff-n-puff CO_2 operation.

huff-n-puff process. The reservoir characterization and modeling phase of the project suggested that peak oil production could be 2 to 5 times higher that the base production rate. However the decline was rapid returning to the base rate in 40 to 80 days. Simulations indicated that incremental oil would increase proportional to the volume of CO_2 injected, and that trapped gas saturation was required for incremental oil production. Oil swelling, viscosity reduction and near well pressure increase caused the initial rise in oil rate; but no long term incremental oil, which only resulted from sustained trapped gas presence. Without the trapped gas, the oil production rate falls below the base rate after the initial peak. At the end of Phase I it was determined that Central Vacuum field did not have the desired trapped gas to make a huff-n-puff operation economic.

The Slaughter-Sundown Unit approximately 90 miles east of Central Vacuum field was selected for Phase II to evaluate the feasibility of the huff-n-puff process. Unfortunately the necessary volumes of trapped gas were not available in the near wellbore vicinity in the demonstration wells in Slaughter-Sundown Unit either. The project recovered only 1388 bbl of incremental oil, and was deemed uneconomic. Additional problems were encountered in the acquisition of CO_2, no pipelines were close by and trucking large volume of CO_2 is prohibitively expensive.

Conclusions from the project were that; an estimate of CO_2 injectivity can be made using simulations, oil response is related to CO_2 volume injected, and higher water-cuts provide a better huff-n-puff response. A recent development (five years after the end of the project), it has been discovered that CO_2 miscible flooding in the huff-n-puff pilot unit had an accelerated response, with production sooner than adjacent units.

Benefits

Although the huff-n-puff demonstration in the Permian Basin did not produce sufficient incremental oil to be economic, the second objective of the project was fulfilled. The final report for the project provides a detailed analysis and guide for future huff-n-puff CO_2 projects, defining the necessary field parameters, which need to be met for success. The potential for accelerated response in CO_2 miscible floods holds potential value for the huff-n-puff process.

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Improved Oil from Mississippian Age Carbonate Reservoirs of KS – *University of Kansas/Kansas Geological Survey*

The Kansas Geological Survey faces the challenge of assisting over 3,000 independent operators who produce 90% of the oil in Kansas from mature reservoirs. The over 33,000 wells in Kansas average less than 5 BOPD. This low production rate is complicated by a high water cut and many fields and reservoirs are at or near the economic limits. Inadequate reservoir characterization and drilling and completion design problems are a significant cause of low primary recovery and limited secondary recovery efforts. Part of the project objective was to sponsor an active technology transfer mechanism to provide Kansas independents with up to date data and technologies specific to their problems in Kansas. The approach for the DOE sponsored project conducted in Schaben and Ness City North fields was to develop cost-effective technologies for reservoir description and management, evaluation methods including software, and demonstration of horizontal drilling and infill drilling technologies. Mississippian carbonate reservoirs hold nearly 20% of the recoverable oil in Kansas. Detailed reservoir characterization was combined with the development of PfEFFER, a wireline logging software for petrophysical analysis, designed as an add-on to Excel spreadsheet software, specifically as a low-cost, user-friendly tool for the independent producer. PfEFFER has the capability to take log and production data and generate detailed maps at the reservoir, field or state level. The depositional model shown in **Figure 6** illustrates the use of core and log analysis and the interpretation of facies relationships, which was used to identify infill and horizontal drilling locations to contact bypassed oil.

Selection of the horizontal drilling target at Ness City North field was made using information from the reservoir characterization phase and participation of the drilling contractor, Mull Drilling. The horizontal well was completed as a kick-off from an old vertical well in the Warsaw formation. During the first two months production stabilized at 48 BOPD and 48 BWPD, significantly higher than production from vertical wells in the field. Subsequently the well developed problems with collapse of clays into the open hole horizontal leg and production was lost. The analysis of the well suggested that failure to case the horizontal section of the well resulted in the failure.

Benefits

Technology transfer of data and technologies developed by the project is available on a digital website operated and updated daily by the Kansas Geological Survey. Sales of the low-cost PfEFFER, wireline logging petrophysical analysis software, have spread to eleven states and four foreign countries with over 150 packages in use. Mull Drilling used the simulation results and learning curve provided by the project and successfully recompleted a neighboring vertical well following the DOE project. Production from the well increased from 2 BOPD (typical Kansas recovery) to 20 BOPD, demonstrating the

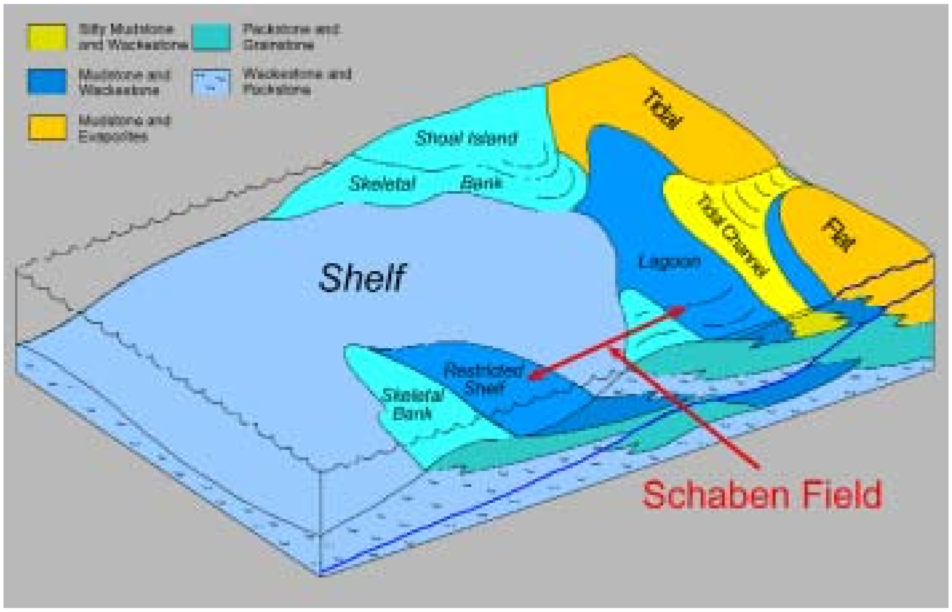

Figure 6. Depositional model of th carbonate environment t Schaben Field, KS.

value of horizontal drilling to independent operators in central Kansas.

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Performance Period: 9/16/1994 to 2/30/2001.

Secondary/Tertiary Recovery Techniques for Small Reservoirs in the Paradox Basin, UT – *Utah Geological Survey*

The Paradox Basin contains over 100 small carbonate fields consisting of algal mounds and oolitic-bank deposits in the Ismay and Desert Creek zones of the Pennsylvanian Paradox Formation. These small fields typically contain 2 to 10 million barrels of original oil-in-place, but only 15% to 20% is recovered during primary production. The objective of the project was to model the geologic and engineering parameters of five example fields to determine the best effective means to increase production and reserves through secondary recovery technologies, and to select a field to demonstrate the technology.

The project conducted extensive geological research and mapping of the Desert Creek and Ismay members including an outcrop analog study. Modeling of the facies and diagenetic analysis revealed the intricate facies relationship and heterogeneity of the reservoirs. Early in Phase I a horizontal well was drilled in Mule field with an average production rate of 149 BOPD for the first few months before declining. This portion of the project was to show the feasibility of horizontal drilling small, targeted carbonate facies.

Runway and Anasazi fields were selected as the best potential candidates for secondary recovery. Initial core and log analysis determined that waterflooding would be uneconomic for these carbonate mounds and that CO_2 flooding offered the best potential for improved oil recovery. Detailed environmental modeling of the lagoon and carbonate settings are illustrated in **Figures 7** and **8**. The productive units at Runway field were identified as the phylloid algal, coralline algal and bryozoan facies. Diagenetic processes during the post-depositional period including; anhydrite cement formation and replacement, pore plugging by bitumen, formation of saddle dolomite, styolitization and finally silica replacement have produced a complex vuggy reservoir. Anasazi and Runway fields have produced, respectively, over 2 million and nearly 1 million barrels of oil under primary since their discovery in 1990. Reservoir simulation of the fields indicated that CO_2 recovery could increase ultimate recovery to 78% for Anasazi and 71% for Runway, and that similar small carbonate fields in the Paradox Basin could also substantially benefit from CO_2 recovery technology. The nearby, giant Greater Aneth field is producing under CO_2 flood, but during the time frame of the project a cost-effective CO_2 source could not be arranged to accomplish the Phase II demonstration. The CO_2 pipeline to Greater Aneth had no spare capacity and other planned

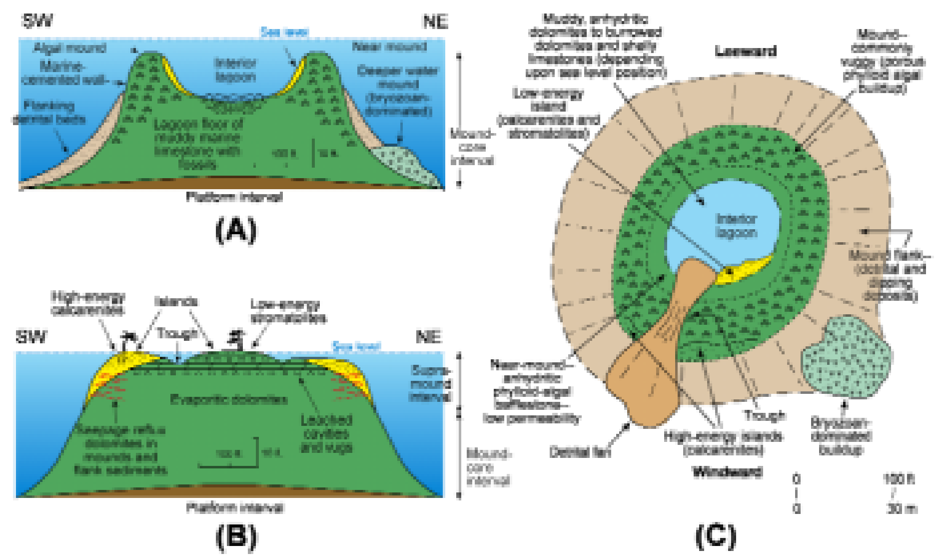

Figure 7. Schematic illustration of the environment of the Desert Creek member of the Paradox Formation, UT.

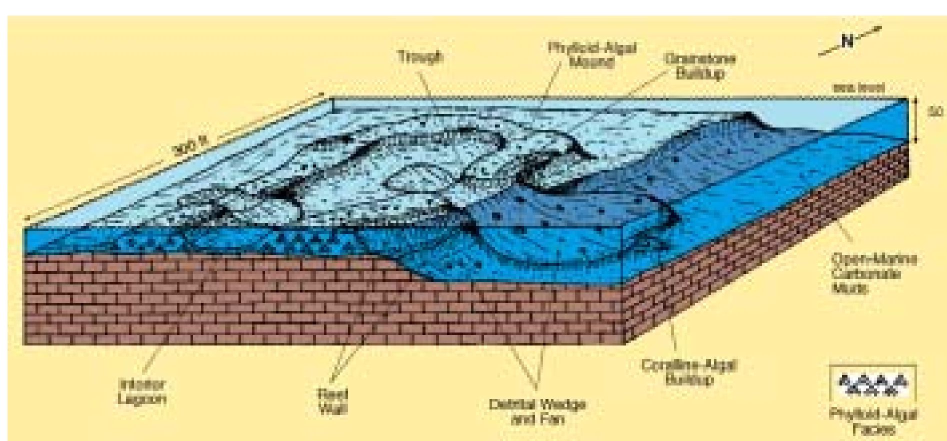

Figure 8. Schematic interpretation of the deposition at Wild Horse Canyon, Paradox Basin, UT.

pipelines have been delayed.

Benefits

The project made the first extensive maps and depositional models of the carbonate reservoirs in the Ismay and Desert Creek members of the Paradox formation and this data is available to independent operators to assist in their exploitation of hydrocarbons in the Paradox Basin. The first demonstration of a horizontal well targeted to a small algal mound was completed. The analysis and reservoir simulation of two fields in the Paradox Basin provides a guide for potential CO_2 flood recovery from the over 100 small fields in the region.

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Performance Period: 2/9/1995 to 8/31/2002.

Integrated Reservoir Management and Reservoir Characterization to Optimize Infill Drilling – *FINA USA*

The objective of the project was to apply advanced secondary recovery technologies to remedy producibility problems in a shallow-shelf carbonate reservoir in the Permian Basin, Texas. North Robertson field (**Figure 9**) was the single largest waterflood in the Continental US in the 1980s; but after several decades in waterflood the field was in decline with poor sweep efficiency, and poor injection and production rates. The Clearfork dolomite, the main reservoir at the field was producing 3,000 BOPD in 1993, but was expected to be at abandonment stage within ten years. The 1,200 ft gross pay interval and the low primary recovery of 15% to 22% indicated that a significant resource remained to be captured with application of improved drilling and completion technologies.

Figure 9. View of North Robertson Unit, Permian Basin, TX.

The Clearfork reservoir has a high degree of heterogeneity and complexity related to original facies development and diagenesis. The key to increased recovery was the development of a Rock-Log Model to identify the highest quality pay intervals using open-hole well log data for extrapolation of core properties. Core data was available from only a limited number of wells, but extensive logs data from the field were used in conjunction with the cores in the Rock-Log model to map spatial relationships for porosity and permeability. 3D reservoir simulation of the data including fluid volumes and flow characteristics from decline curve analysis and history matching was used to plan the infill drilling program.

Correlation of depositional facies, diagenetic history and reservoir quality indicated that the previously used blanket drilling approach was not optimal, and that line drive geologically targeted drilling at North Robertson could capture reserves for half the cost. The North Robertson Unit has been reconfigured to an east-west line drive and well spacing was reduced from 20 acres to 10 acres. The majority of the old producers were incorporated into the pattern along with 18 new infill wells (4 injectors and 14 producers). By the end of Budget Phase I, the eleven new wells completed had added 700 BOPD to the unit production.

Completion technologies studied in Budget Phase II included tiltmeter and tracer studies of the hydraulic fracture stimulations and installation of magnetic flow conditioners to reduce scale and paraffin buildup in production lines. The tiltmeter study suggested that two, rather than the three hydraulic fracture treatments previously used at North Robertson, might provide the optimal well stimulation. Magnetic flow conditioners work by lowering the "cloud point" or point of precipitation of paraffin crystals as the crude reacts to lower temperatures and pressure in flow lines. The conditioners were tested in three wells with scale problems and significantly reduced paraffin buildup in two of the wells.

Benefits

Detailed reservoir characterization is credited with the development of a geologically targeted infill drilling program at North Robertson Unit that can be implemented for half the cost of blanket drilling. Development costs for a direct line drive pattern are 25% less than 5-spot patterns. By the end of the project North Robertson Unit had been saved from abandonment, reservoir life extended and the production of 2,700 BOPD represented a

26% increase in production for the Unit over the decline curve.

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Performance Period: 6/13/1994 to 6/12/1999.

Improved Recovery and Economics in a Lower Quality Shallow Shelf Carbonate Reservoir – *OXY USA*

Declining production from the 30 year-old waterflood of West Welch field in the Permian Basin of West Texas prompted implementation of a CO_2 flood to increase production of over 17 million barrels of recoverable oil. West Welch field suffered from both low productivity and a low reservoir processing rate. The approach was to use advanced 3D seismic interpretation and cross-well tomography to identify optimal infill drilling locations and to monitor the CO_2 injection and flow paths between wells. Core and log descriptions were used to develop a petrophysical flow description for use in the reservoir simulation models. Cyclic CO_2 stimulation of the San Andres formation at West Welch field was combined with hydraulic fracture stimulation treatments to improve oil recovery.

The redesign of the CO_2 flood based on the Phase I reservoir characterization included drilling five new wells, recompletion of 10 wells and drilling a horizontal CO_2 well. The response from the CO_2 injection program was a reduction in water production, an increase in gas production, and a flattening of the oil decline followed by a moderate increase in oil production. Monitoring efforts were able to trace the CO_2 migration within the reservoir indicating that while some of the CO_2 passed through the main pay intervals, some was lost to zones below the pay interval. Following the reservoir characterization phase the project area was expanded, and five new wells were drilled, which increased incremental production by 100 BOPD.

The horizontal well was successfully drilled in phase II, but did not improve the reservoir processing rate. Application of the SURGI tool used for hydraulic fracture stimulation did not correct the problem of fluid loss occurring in the previous open fracture methods. The horizontal well produced 30 BOPD of incremental oil. Economic analysis of the project revealed that although CO_2 injection did increase oil production and the rate of return on investment, it was not sufficient to overcome the natural decline in the reservoir. Capital investment costs and the high cost of CO_2 injection would not make this strategy economic in other OXY properties in the Permian Basin.

Benefits

The 3D seismic integration in Phase I discovered an additional 300,000 barrels of oil reserves in the West Welch Unit where the DOE sponsored pilot was conducted. The cross-well tomography study indicated the potential for monitoring the CO_2 migration in the interwell areas of oil fields. Lessons learned are that well hydraulic well stimulation work needs to be completed prior to implementation of the CO_2 flood, and that more attention should be paid to out of zone injection.

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Reservoir Characterization and Horizontal CO_2 Injection Wells in a Shallow Shelf Carbonate Approaching Waterflood Depletion – *Phillips Petroleum Company*

The purpose of the project was to design an optimum CO_2 flood for a mature waterflood nearing economic abandonment using advanced reservoir characterization and horizontal CO_2 injection wells to redevelop South Cowden Unit, Ector County, Texas. The high water cut of 95% and the small size of the unit made it difficult to benefit from the economies of large scale projects using miscible or near-miscible CO_2 recovery methods. The goal of the reservoir characterization phase was to identify, and then design and restrict the CO_2 flood to the higher quality rock zones in the unit. Horizontal CO_2 injection wells were planned as a means of cutting investment and operating costs. At the time the project began the economic limit and abandonment of the unit was predicted for 1999, unless successful tertiary recovery technologies could be developed.

The South Cowden Unit produces from a typical low permeability carbonate San Andres formation reservoir. The first two horizontal CO_2 injectors were drilled in the thickest portion of the reservoir, but oil production response was less than predicted. Challenges of the second phase were to inject CO_2 at higher rates to improve flood economics, to keep CO_2 injection within the target reservoir zones, and to increase the total production rate without fracturing out of zone. Reservoir characterization efforts were partially successful in identification of the highest quality zones, and used to design the CO_2 flood to restrict injection to these zones. Overall the simulation forecast based on the reservoir characterization was optimistic and by the end of the project the prediction for ultimate tertiary oil recovery was reduced by 40%. The inability to maintain CO_2 injection rate in the desired zones was the main cause of poor oil response. Oil response rates were good in the wells where CO_2 injection rates could be maintained at the targeted injection intervals. **Figure 10** shows the oil production rates from the inception of the project in 1992 through completion in 2002.

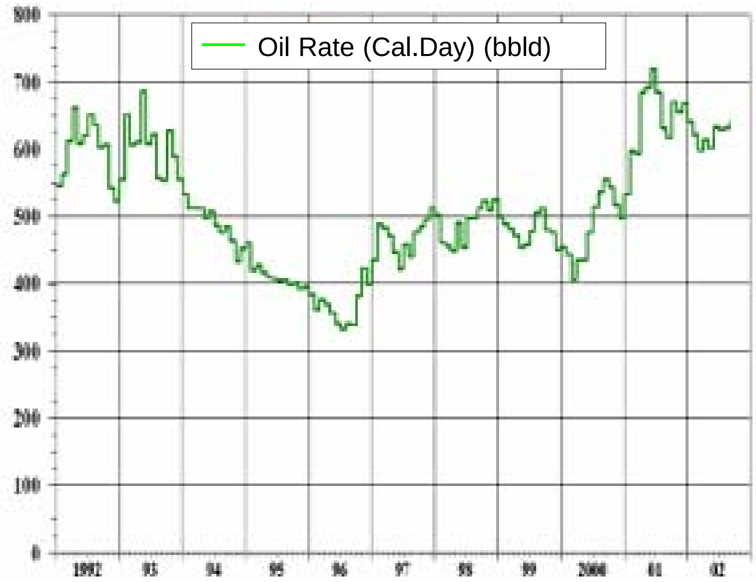

Figure 10. Graph of oil production from inception to completion at South Cowden Field, TX.

Benefits

Oil production rates have risen since implementation of the horizontal CO_2injection wells. Production by December 2002 was at 680 BOPD and has been rising steadily since April 2002 (600 BOPD). Predications for ultimate recovery suggest a recovery of 39.5 MMSTBO, representing 34% recovery of OOIP. Reservoir life of the unit was extended significantly past the original abandonment date of 1999.

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Performer: Phillips Petroleum Company (ConocoPhillips).
Performance Period: 6/30/1994 to 9/2/2001.

Optimization of Reservoir Performance in the Hunton Formation, OK – *University of Tulsa*

Objectives of the project conducted in West Carney field, Oklahoma are to understand the primary production mechanism by which oil is produced in this unique retrograde reservoir, to develop procedures for extrapolating the production methods to other wells and reservoirs, and to extend the life of the field beyond primary production. Production of oil from the Hunton formation is accompanied by a very high water cut, however as oil is produced the water cut decreases, a function termed retrograde oil cut. As the water/oil ratio decreases over time, the gas/oil ratio first increases and then decreases with time. After several years of primary production (field development began in 1995) gas production becomes the primary economic factor. When wells are restarted following workovers there is an increase in the gas/oil ratio. The high water rates are related to the high permeability and fracture system, which allows communication between wells. Because of the high water cut, West Carney is not a candidate for waterflood as a secondary recovery mechanism.

The reservoir characterization phase of the project has involved detailed geologic description, log analysis, flow simulation and rate-time analysis of the production data. Because of high initial primary production and the unique characteristics of the field, the operator was willing to take cores for 27 wells drilled during Phase I. The cores are being described and fourteen facies have been described. The main lithofacies in the Cochrane and Clarita formations are limestone and dolomite, associated with four pore types; vugs, coarse matrix, fine matrix, and the fracture system. Production is associated with the highly heterogeneous, fractured, fossiliferous limestone facies. Statistical analysis using Buckles plots and principal component analysis has been used to study the retrograde water cut mechanism.

Findings are that the aquifer is limited, and the water rate and reservoir pressure are declining as the field is produced. However, the bulk of hydrocarbon production is through the water zone and dependent on it, such that wells that produce less water also produce less oil (**Figure 11**). Production from wells drilled in the late 1990s is declining at a rate of 50% per year. Results of the rate-time analysis reveal that wells drain more than 160 acres due to the fracture system. A duel permeability system seems to exist, and the oil and gas layers have much lower permeability than the water layer of the reservoir. The fine matrix rock containing the oil is better connected to the high permeability component of the rock, and low recovery from the coarse matrix and vuggy rock suggests that this is from isolated pores. As Phase II continues, the emphasis will be on search for a viable tertiary recovery method to improve ultimate recovery.

Benefits

The discovery of how the retrograde

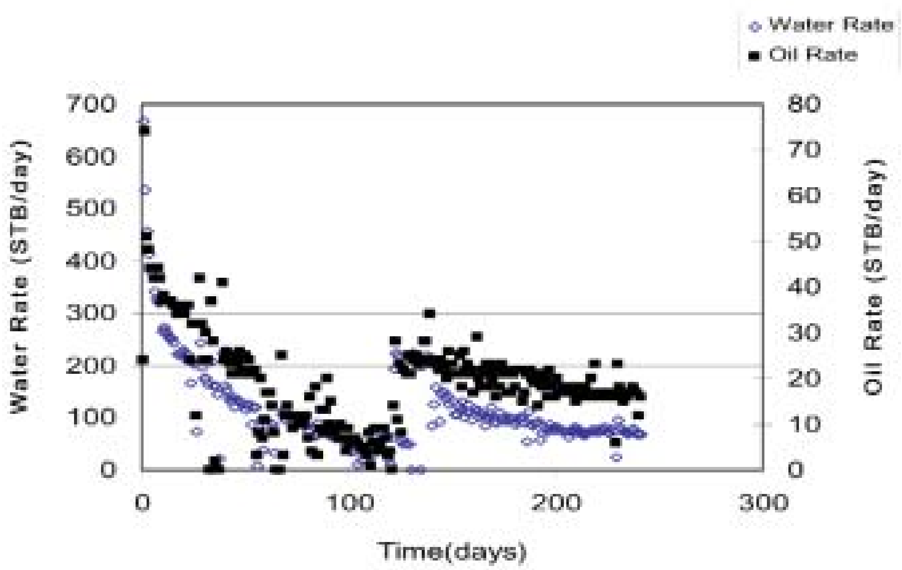

Figure 11. Representation of water and oil production from the Hunton Formation, OK.

oil system functions will aid researchers and operators who encounter similar reservoirs in both the extensive Hunton formation and in other similar reservoirs. The detailed geological and reservoir properties descriptions provided in technology transfer presentations will help others identify the characteristics of the highly heterogeneous nature of this system and plan development of their fields to maximize primary production.

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Performance Period: 3/7/2000 to 3/6/2005.

Surface Geochemistry to Redevelop a Shallow Shelf Carbonate Reservoir, Vernon Field, MI – *Michigan Technological University*

The goals of the project are to increase production from mature Michigan oil fields, and through an investigation of recent advances in surface geochemistry analysis to identify drilling targets. Most of the Devonian age oil fields in central Michigan were discovered in the 1930s and are now in decline with numerous bypassed zones thought to contain significant quantities of oil. Estimated recovery from Vernon field is 1.5 million barrels of oil with a 50% recovery factor. During the reservoir characterization phase efforts were made to obtain more accurate maps of the structure of the Dundee dolomite using advanced techniques for reinterpreting 2D seismic data. The surface topography of the Dundee, showing the irregular karsted surface is seen in **Figure 12**. Mapping 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.

Surface geochemical analysis includes; surface iodine, microbial, enzyme leaching, soil gas and subsurface iodine surveys. The emphasis has been on correlation of geochemical survey analysis results with mapped reservoir facies to predict drilling targets for bypassed oil. Results from the microbial, soil gas, iodine and trace element surveys have shown the most positive correlation and were used to select the first drilling site. The geochemical survey was able to predict marginal areas of unswept oil at Vernon field, but results indicate that a much larger grid should be surveyed for better prediction. In Phase II the surface geochemical sampling technologies will be applied in a larger area in the central Michigan Basin (two test wells in pinnacle reefs), and in a similar carbonate area in the Williston Basin (one test well planned).

Lessons Learned: 1) The Vernon and Crystal types of water-drive fields appear to be poor candidates for recovery of bypassed oil due to efficient primary recovery. 2) Mapping the surface of the dolomite (for porosity) was crucial to identification of plays. 3) A vertical test well should be drilled prior to the first horizontal well since surface geochemical results were not encouraging.

Benefits

Surface geochemistry appears to work for prediction of subsurface hydrocarbon. For successful surface geochemical analysis the survey should cover a

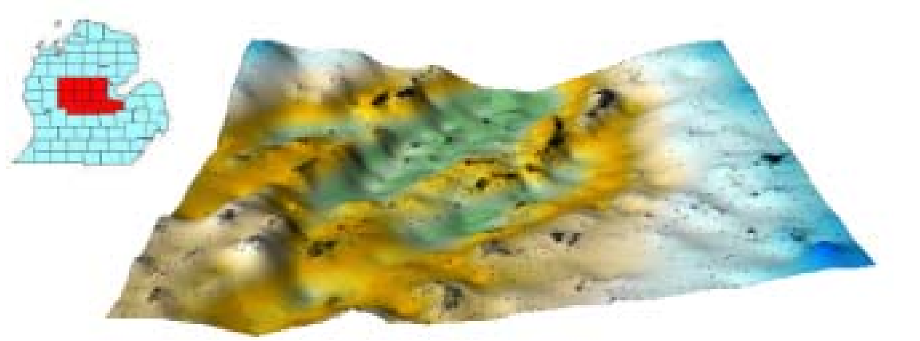

Figure 12. Computer image of the 3D "top" surface of the Dundee Formation central Michigan.

wide area. Drilling in the highly karsted Dundee formation has shown that horizontal wells may not be economic or necessary and that vertical test wells are worth the money prior to horizontal drilling.

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Intelligent Computing System for Anlysis of the Red River Formation in the Williston Basin – *Luff Exploration Company*

The Intelligent Computing System (ICS) has been developed by Luff using neural networks and fuzzy logic for reservoir analysis and risk assessment. Core and log data from the Red River formation has been processed in the system and a demonstration site selected in Amor Field, Bowman Co. North Dakota. Phase I involved integrating seismic, geologic and engineering data and transforming seismic attributes to reservoir attributes in the model, and using it to predict the reservoir limits on small structural features, which had limited well control. The ICS tool kit is designed to use 3D seismic data, but can interpret high-density 2D seismic, and is effective for predicting reservoir limits at resolutions down to the 6-ft dolomite beds present in the Red River formation. ICS can also be used for simulation studies and determining the parameters for waterfloods.

The ICS tool depends on forward seismic modeling for analysis of the carbonate beds in the Red River. Traditional seismic mapping did not adequately define the reservoir limits of the small features.

Predictions from the seismic attributes are being used to transform the oil cut from Amor field (**Figure 13**). The ICS tool kit has been used to select sites for horizontal wells in small structural features in fields discovered in the 1970s and 1980s. The project re-entered plugged or uneconomic vertical wells and drilled horizontally, resulting in 200-250 BOPD per well. Incremental primary plus secondary recovery for Amor field is projected at 1,100,000 bbl.

Benefits

The Intelligent Computing System has been successfully used to characterize thin beds in the Red River formation using seismic attributes. Training the normalized seismic data from multiple 3D surveys allows for an increase in the control population. Five similar projects are planned for horizontal drilling in 2003 and 2004 using the ICS tool. The ICS tool kit and instructions can be downloaded from the project website, **http://www.luffdoe-project.com**.

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Field Demostration of CO_2 Miscible Flooding in the Lansing/Kansas City Formation – *University of Kansas/Kansas Geological Survey*

The objective of the project is to demonstrate the viability of carbon dioxide miscible flooding in the Lansing-Kansas City formation on the Central Kansas Uplift and to provide data on reservoir properties, operating costs to aid Kansas independents in

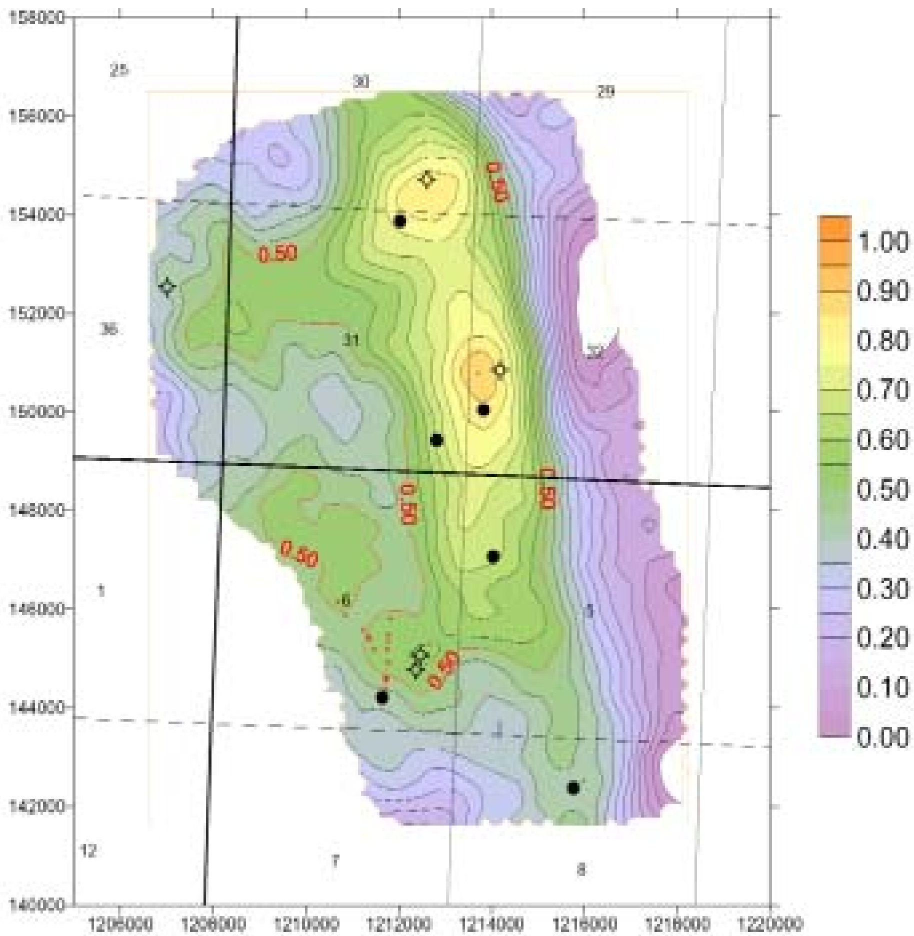

Figure 13. Computer image of seismic attributes related to structure and oil production in the Red River Formation, ND.

future CO_2 flooding. A secondary objective is to show that a reliable CO_2 source can be made available in Central Kansas. The project addresses the producibility problems inherent in shallow shelf carbonate reservoirs that have been depleted by effective waterflooding leaving significant trapped oil reserves. Currently over 6,000 fields in Kansas are in danger of abandonment unless an economically feasible tertiary recovery technology can be demonstrated.

Detailed reservoir characterization of the Hall-Gurney field (drilling site shown on the back cover) has been conducted prior to implementation of the CO_2 flood to plan drilling locations, completion techniques and to simulate the success of CO_2 flooding. The Colliver lease, site of the pilot, has produced 23% of OOIP on primary, 27% of OOIP on waterflood, and holds the potential to produce an additional 23,000 to 36,000 bbl of oil with miscible CO_2. Production is from an oomoldic limestone in the Lansing-Kansas City, widespread in central Kansas, and similar to other shallow shelf carbonate deposits worldwide.

Much of Budget Phase I has been focused on obtaining a CO_2 source for the pilot demonstration in Hall-Gurney field. The original plan called for trucking CO_2 200 miles from Guymon, Oklahoma; when this option became infeasible, a new CO_2 source was found in a ethanol plant operated by USEP only 7 miles from the pilot site (10 acres) in Russell, KS. The ethanol plant produces CO_2 as a byproduct, and normally flares the majority of CO_2 produced. The oil field demonstration joins the ethanol plant, a new electric co-generation plant, and several agricultural industries in an energy cycle which provides economic and environmental benefits to five industries in Kansas (**Figure 14**).

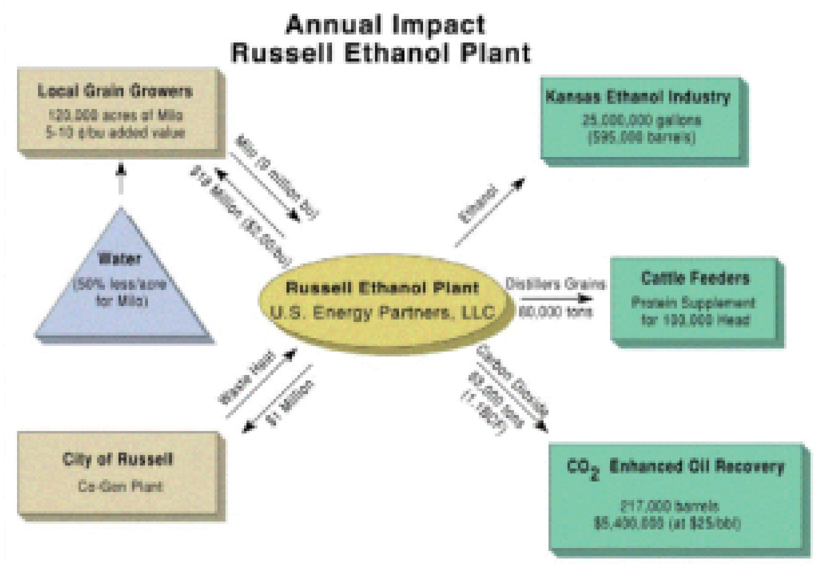

Figure 14. CO_2 supply and sequestration links industries in central Kansas.

Benefits

The EOR potential using CO_2 flooding for the Lansing-Kansas City and Arbuckle formations in Central Kansas may exceed 200-500 MMBO. The project will demonstrate sufficient interest in CO_2 flooding in Kansas to build a CO_2 pipeline or to further investigate the cyclic relationship of CO_2 from electric go-generation and ethanol plants. Use of CO_2 for flooding from the ethanol plant qualifies as CO_2 sequestration, an environmental benefit under EPA Clean Air regulations.

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Improved Oil Recovery from Jurassic Smackover Carbontes at Womack Hill Field Alabama – *University of Alabama*

The project goal is to increase the productivity and profitability of Womack Hill field, extend the economic life of the reservoir and demonstrate effective technologies for recovery of oil from the Smackover formation of the Eastern Gulf Coastal Plain. The objectives of the project are to: 1) demonstrate the importance of developing a field-wide reservoir management strategy, 2) characterize and model the reservoirs for determination of the potential for strategic infill drilling and lateral completions, 3) evaluate the existing pressure maintenance and waterflood program for modification of the injection pattern, and 4) assess the feasibility of initiating an immobilized enzyme technology for potential enhanced oil recovery. The Upper Jurassic Smackover in Mississippi, Alabama and Florida contains over 150 fields, which have produced over 900 million barrels of oil with 10% to 20% estimated recoverable oil remaining in the ground. Womack Hill field, discovered in 1970, has produced 30 MMbbl and had the potential to produce an additional 12 to 24 MMbbl using advanced technologies to optimize field management and production. Womack Hill field is one of 57 similar fields in the Interior Salt Basin fault play (**Figure 15**).

The reservoir at Womack Hill is a faulted, salt anticline producing from a basinal lime-mudstone. Reservoir

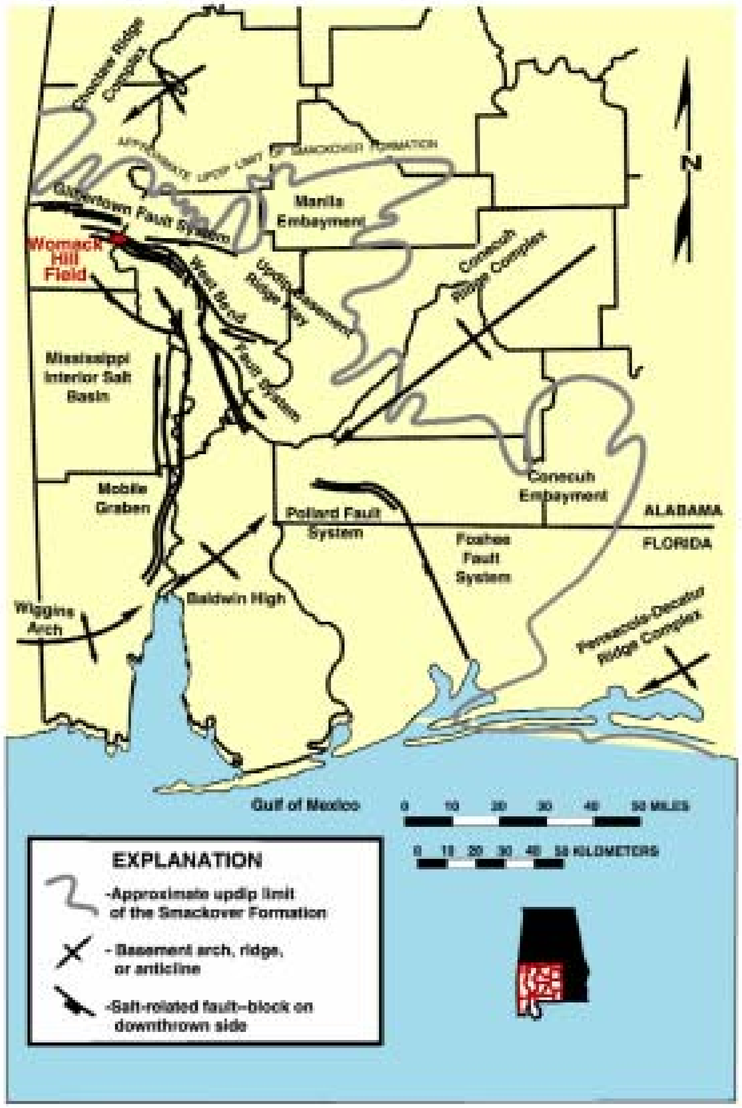

Figure 15. Location map of the Mississippian Interior Salt Basin, AL showing the fault system affecting oil production form th Smackover Formation.

characterization of the highly heterogeneous Smackover reservoir has revealed that the keys to reservoir management are pressure maintenance in the waterflood and optimizing infill drilling. 3D stratigraphic modeling has identified a W-E barrier to flow based on faulting and changes in reservoir quality. This has provided valuable information in the design of an improved field-wide management strategy and infill drilling program.

Benefits

Technologies demonstrated at Womack Hill field for improved reservoir management and optimal design of infill drilling will be directly applicable in 57 other fields in the Interior Salt fault play, and over 150 Smackover fields in a tri-state area of the Eastern Gulf Coast, and additional Smackover fields in Louisiana, Arkansas and Texas. An estimated 300 to 600 million barrels of recoverable oil is targeted in the tri-state region of the Smackover formation

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Heterogeneous Shallow Shelf Carbonate Buildups in the Blanding Sub-Basin of the Paradox Basin, UT – *Utah Geological Survey*

The objectives are to increase production and reserves from the carbonate reservoirs of the Ismay and Desert Creek zones of the Paradox Basin, and to demonstrate horizontal drilling in small carbonate mounds. The 100 small fields of the Paradox contain 2 to 10 million barrels of oil per fields. Only 15 to 25% of OOIP is recovered by primary production, leaving over 200 million barrels of oil at risk of being left behind in these small fields because of inefficient development practices and undrained heterogeneous reservoirs. Proper geological evaluation of the reservoir and successful demonstration of horizontal drilling may increase production by 20 to 50%.

Detailed analysis of cores and logs from the four fields, (Cherokee, Bug, Sleeping Ute and Little Ute) has provided information on the limestone and dolomite facies and the complex diagenetic history of the Ismay and Desert Creek reservoirs. Ismay and Desert Creek reservoirs are predominantly phylloid-algal mounds and shoreline carbonate island facies. Pore structure and cementation are a major influence on porosity, permeability and water/oil saturation, and thus on production rates from these carbonate reservoirs.

The digenetic stages identified from cores include; moldic porosity and meteoric cementation, early micro-box-work porosity, early dolomitization, post-burial stylolitization, late dissolution/microporosity, anhydrite replacement and plugging, and bitumen plugging. The extensive dissolution (early micro-box-work porosity and late hydrothermal microporosity) are the major contributors to effective porosity in the oil zones. Two horizontal drilling strategies are being

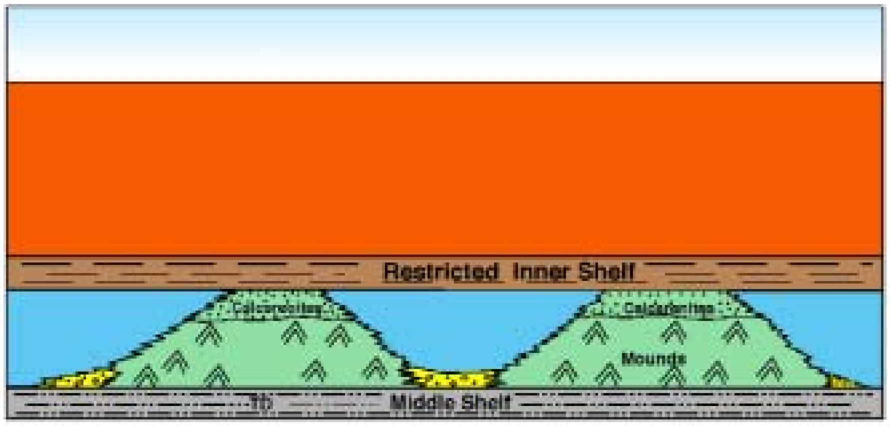

Figure 16. Design of horizontal wells for production from carbonate mounds producing from the Ismay member of the Paradox Formation, UT and CO.

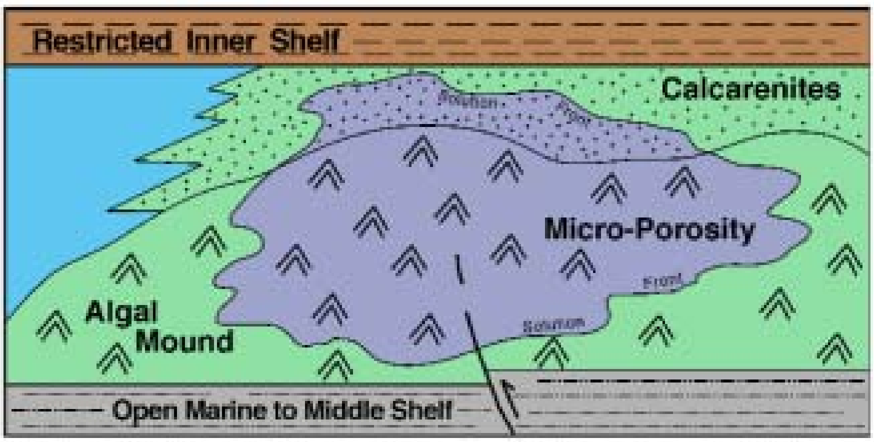

Figure 17. Strateg for horizontal drilling in the micro-box-work porosity of the Desert Creek member of the Paradox Formation, UT and CO.

developed based on stacked, parallel, horizontal laterals specific to the two different types of porosity found in the Ismay and Desert Creek (**Figure 16** and **17**).

Benefits

The horizontal drilling strategies being developed will be applicable to over 100 other Ismay and Desert Creek fields in the Paradox Basin. The Utah Geological Survey is working with the Colorado Geological Survey to provide independent producers in both states valuable data; and comprehensive, objective analysis and technologies that many small independents can not provide. The state surveys have the advantage that they are not restricted by individual leases or constrained by time as are independents operating in the Paradox Basin.

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Performance Period: 4/6/2000 to 4/5/2005. **TCA**

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The Department of Energy's National Energy Technology Laboratory's National Petroleum Technology Office is proud to bring you information on field demonstrations that benefit domestic oil producers.

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Project Fact Sheets
www.fe.doe.gov

Funding Opportunities
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C A L E N D A R

Meetings and Announcements

February 27-28, 2003 DOE Alaska Conference, *"Reducing the Effects of Oil and Gas Exploration and Production on Alaska's North Slope:Issues, Practices, and Technologies"*, Egan Center, Anchorage, AK. **www.npto.doe.gov**

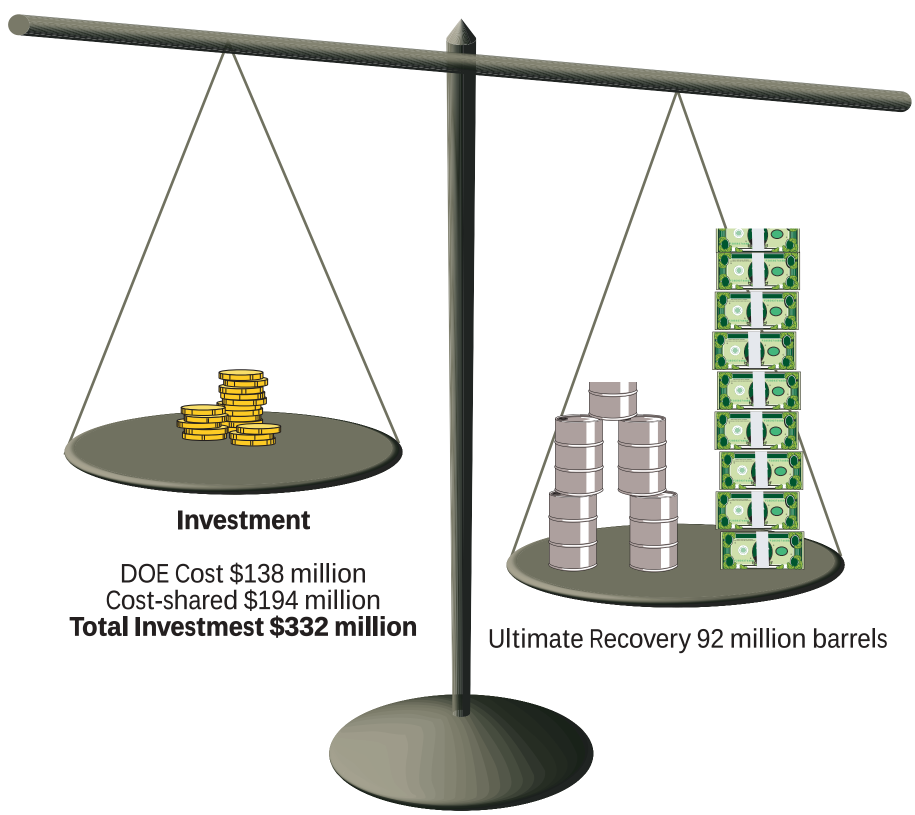
May 5-8, 2003 Offshore Technology Conference (OTC), Reliant Center, Houston, TX. Visit the DOE/NETL booth # 40-46. **www.otcnet.org**

March 10-12, 2003 SPE/EPA/DOE Exploration and Production Environmental Conference, San Antonio, TX. **www.spe.org**

March 22-25, 2003 Society of Petroleum Engineers (SPE) Production Operations Symposium, Oklahoma City, OK. **www.spe.org**

May 11-14, 2003 American Association of Petroleum Geologists (AAPG) Annual Technical Conference, Salt Palace Convention Center, Salt Lake City, UT. DOE Poster session and Core poster sessions: *"Developments of DOE- Funded Projects"*, Chairperson: Rhonda Lindsey, NETL, Tulsa, OK; Co-Chair: William Gwilliam, NETL, Morgantown, WV. *"Reservoirs in Core, Words and Pictures"*, Chairperson Edie Allison, DOE Headquarters, Washington DC. Visit the DOE/NETL booth #1508. **www.aapg.org**

Reservoir Class Program Benefits



39 Projects in 15 Oil Producing States