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INCREASED OIL PRODUCTION AND RESERVES FROM IMPROVED COMPLETION TECHNIQUES IN THE BLUEBELL FIELD, UINTA BASIN, UTAH

Final Report
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CONTENTS

ILLUSTRATIONS

ABSTRACT

The Bluebell field is productive from the Tertiary lower Green River and Colton (Wasatch) Formations of the Uinta Basin, Utah. The productive interval consists of thousands of feet of interbedded, fractured, clastic and carbonate beds deposited in the ancestral Lake Uinta. Wells in the Bluebell field are typically completed by perforating 40 or more beds over 1000 to 3000 vertical ft (300-900 m), then stimulating the entire interval with hydrochloric acid. This technique is often referred to as the “shotgun” completion technique. Completion techniques used in the Bluebell field were discussed in detail in the Second Annual Report (Curtice, 1996). The shotgun technique is believed to leave many potentially productive beds damaged and/or untreated, while allowing water-bearing and low-pressure (thief) zones to communicate with the wellbore.

A two-year characterization study involved detailed examination of outcrop, core, well logs, surface and subsurface fractures, produced oil-field waters, engineering parameters of the two demonstration wells, and analysis of past completion techniques and effectiveness. The study was intended to improve the geologic characterization of the producing formations and thereby develop completion techniques specific to the producing beds or facies instead of a shotgun approach to stimulating all the beds. The characterization did not identify predictable-facies or predictable-fracture trends within the vertical stratigraphic column as originally hoped. Advanced logging techniques can identify productive beds in individual wells. A field-demonstration program was developed to use advanced, cased-hole logging techniques in two wells and recomplete the wells at two different scales based on the logging. The first well (Michelle Ute) was going to be recompleted at the interval scale using a multiple-stage completion technique (about 500 ft [150 m] per stage). The second well (Malnar Pike) was recompleted at the bed-scale using a bridge plug and packer to isolate four beds for stimulation. The third demonstration involved the logging and completion of a new well (Chasel 3-6A2) using the logs to reduce the number of perforated beds from more than 40 to just 19. The 19 perforated beds were stimulated in two separate treatments, greatly reducing the gross vertical interval and net perforated feet normally treated.

The first demonstration was to be a high-pressure, high-diversion, three-stage acid stimulation. Because of a leak in the tubing the operator could not treat the reservoir at as high a pressure as planned. Also, the treatment was pumped from a single packer location instead of from three intervals as planned. Dipole shear anisotropy and dual burst thermal decay time logs were run before treatment, and an isotope tracer log was run after treatment. These logs were effective tools for identifying fractures and fluid-flow communication within the reservoir. Only the first 500 ft (150 m) of the gross perforated interval received acid, the lower 1000 ft (300 m) remained untreated. The demonstration did show how difficult it is to treat large vertical intervals from a single packer seat. The second demonstration resulted in increased production. This demonstration successfully treated four beds but two were bridged off after limited testing. The operator felt the lower two treated beds might produce water. The increase in production is encouraging considering it is coming from only two beds. Cased-hole logs indicate several beds exist in the well with potential equal to or greater than the beds that were treated. During the third demonstration, completion testing of the Chasel 3-6A2 well appeared very promising. The well began flowing oil with no water but the casing collapsed. Because of the collapsed casing the well will probably not produce anywhere near its potential.

EXECUTIVE SUMMARY

The objective of the project was to increase oil production and reserves by the use of improved reservoir characterization and completion techniques in the Uinta Basin, Utah. To accomplish this objective, a two-year geologic and engineering characterization of the Bluebell field was conducted. The study evaluated surface and subsurface data, currently used completion techniques, and common production problems. It was determined that advanced cased- and open-hole logs could be effective in determining productive beds and that staged-interval (about 500 ft [150 m] per stage) and bed-scale isolation completion techniques could result in improved well performance. In the first demonstration well (Michelle Ute), dipole shear anisotropy (anisotropy) and dual-burst, thermal decay time (TDT) logs were run before treatment, and an isotope tracer log was run after treatment. The logs were very helpful in characterizing the remaining hydrocarbon potential in the well. Significant improvement in the oil production from the well was not obtained due to mechanical problems during the recompletion.

The second demonstration well (Malnar Pike) was a recompletion of four separate beds which resulted in increased hydrocarbon production. Anisotropy, TDT, and isotope tracer logs were used to identify beds for recompletion and to evaluate the effectiveness of each treatment. The third demonstration (Chasel 3-6A2) was a newly drilled well which was logged with anisotropy, TDT and isotope tracer logs. The logs were used to select 19 beds for perforating and acidizing, compared to more than 40 beds that are typically perforated in a new well. It was expected that fewer perforated beds would result in lower treatment costs, more effective treatment of each of the selected beds, and more oil production with less production of associated formation water. Initial testing was encouraging but the casing collapsed and the operator was unable to complete the well.

A portable, parallel, fractured-reservoir simulator was developed to carry out reservoir analysis of the Bluebell field. The development and performance of the simulator on a shared-memory machine (Silicon Graphics Power Challenge) was reported in earlier quarterly and annual reports. The performance of the parallel program was also studied on a distributed memory machine. The results of parallel computing on the distributed memory machine were rather disappointing. If the code was ported to a cluster of workstations, the cluster would be expected to perform as a distributed memory virtual machine. The way in which the equations are solved and the communication protocol will have to be optimized to improve the performance of the code on distributed memory platforms.

Technology transfer activities for the final year of the project included one paper in the American Association of Petroleum Geologists (AAPG) Bulletin, a poster presentation at the National AAPG meeting in Salt Lake City, and an oral presentation at the Department of Energy/ Petroleum Technology Transfer Council Symposium in Denver. Information exhibits were displayed at the Utah Geological Survey (UGS) booth during the National AAPG meeting and Vernal Petroleum Days exhibition in Vernal, Utah. Inquiries and general discussion at the poster session and exhibitor booth indicate a strong interest by oil industry personnel. Daily activity reports for the second and third demonstration were posted on the Bluebell project Internet home page. Previous technology transfer activities have been reported in earlier annual technical reports.

INTRODUCTION

Project Status

The contract with the U.S. Department of Energy ended September 30, 1999. The two-year characterization study of the Bluebell field, Duchesne and Uintah Counties, Utah, consisted of separate, yet related tasks. The characterization tasks were: (1) log analysis and petrophysical investigations, (2) outcrop studies, (3) cuttings and core analysis, (4) subsurface mapping, (5) acquisition and analyses of new logs and cores, (6) fracture analysis, (7) geologic characterization synthesis, (8) analysis of completion techniques, (9) reservoir analysis, (10) best completion technique identification, (11) best zones or areas identification, and (12) technology transfer. The study helped identify advanced logging techniques that can be effective in selecting beds for stimulation in old and new wells. A three-part field demonstration was developed using advanced logging techniques to selectively identify productive beds and test the effectiveness of treating at different scales (interval about 500 ft [150 m] and bed scale).

The first demonstration was a recompletion at the interval scale and was discussed in the previous technical report. The second demonstration was a recompletion of the Malnar Pike well at the bed scale. The recompletion resulted in an increase in the daily oil production from the well. The production is still being monitored and the long-term production increase is being evaluated. The third demonstration was the logging and completion of the Chasel 3-6A2, a newly drilled well. Reservoir characterization using the anisotropy and TDT logs resulted in perforating and acidizing of 19 beds in the new well, far fewer than the more than 40 beds that are typically perforated in new wells. Fewer perforated beds should result in lower completion cost, improved oil production, and less production of formation water. Preliminary test results were encouraging until the casing collapsed in the well. As a result, the operator was unable to complete the well as an oil producer.

Geology and Field Background

The Uinta Basin is a topographic and structural basin encompassing an area of more than 9300 square miles (24,000 km^2) (Osmond, 1964). The basin is sharply asymmetrical, with a steep north flank bounded by the east-west-trending Uinta Mountains, and a gently dipping south flank bounded by the northwest-plunging Uncompahgre and north-plunging San Rafael uplifts. In Paleocene to Eocene time, the Uinta Basin had internal drainage forming ancestral Lake Uinta. Deposition in and around Lake Uinta consisted of open- to marginal-lacustrine facies that make up the Green River Formation. Alluvial, red-bed deposits that are laterally equivalent and intertongue with the Green River lacustrine deposits make up the Colton (Wasatch) Formation. The depositional environments are described in detail by Fouch (1975, 1976, 1981), Ryder and others (1976), Pitman and others (1982), Stokes (1986), Castle (1991), Fouch and others (1990), Fouch and Pitman (1991, 1992), and Franczyk and others (1992).

The Bluebell field is the largest oil producing field in the Uinta Basin. Bluebell is one of three contiguous oil fields: Bluebell, Altamont, and Cedar Rim (Fig. 1). The Bluebell field is 251 square miles (650 km^2) in area and covers all or parts of Townships 1 North, 1 and 2 South and Ranges 1 and 2 East and 1 through 3 West, Uinta Base Line and Meridian (Fig. 1). More than 139 million barrels of oil (MMBO [19.5 million MT]) and nearly 182 billion cubic feet (BCF [5.2 billion m^3]) of associated gas have been produced as of September 30, 1997 (Utah Division of Oil, Gas and Mining records). The spacing is two wells per section except within the Roosevelt unit, but much of the field is still produced at one well per section. Although some wells have produced over 3.0 MMBO (420,000 MT), most produce less than 0.5 MMBO (70,000 MT).

The majority of the production and the focus of the demonstration is the Flagstaff Member of the Green River Formation reservoir (lower Wasatch transition in operator terminology). The Flagstaff reservoir consists dominantly of carbonate and sandstone beds that were deposited in marginal- to open-lacustrine environments and is productive throughout most of the field. The Flagstaff is overlain by the alluvial sandstone, siltstone, and shale (red beds) deposits of the Colton Formation. The Colton is overlain by the lower Green River lacustrine facies.

The complex, heterogeneous lithology of the Colton and Green River Formations makes it very difficult to identify which beds are potential oil producers. As a result, the operators have taken a shotgun approach to completing and recompleting the wells; they typically perforate 40 to 60 beds over a vertical interval of 1500 ft (460 m) or more, and acidize the entire interval. Operators believe this completion technique may leave many potentially productive beds damaged and/or untreated, while allowing water-bearing and low-pressure (thief) zones to communicate with the wellbore (Allison, 1995). Our study found that oil productive beds can be identified using advanced open- and cased-hole logs, which would allow operators to perforate and treat smaller intervals and result in more effective completions. The demonstrations were designed to show the effectiveness of treating more selective beds at different scales.

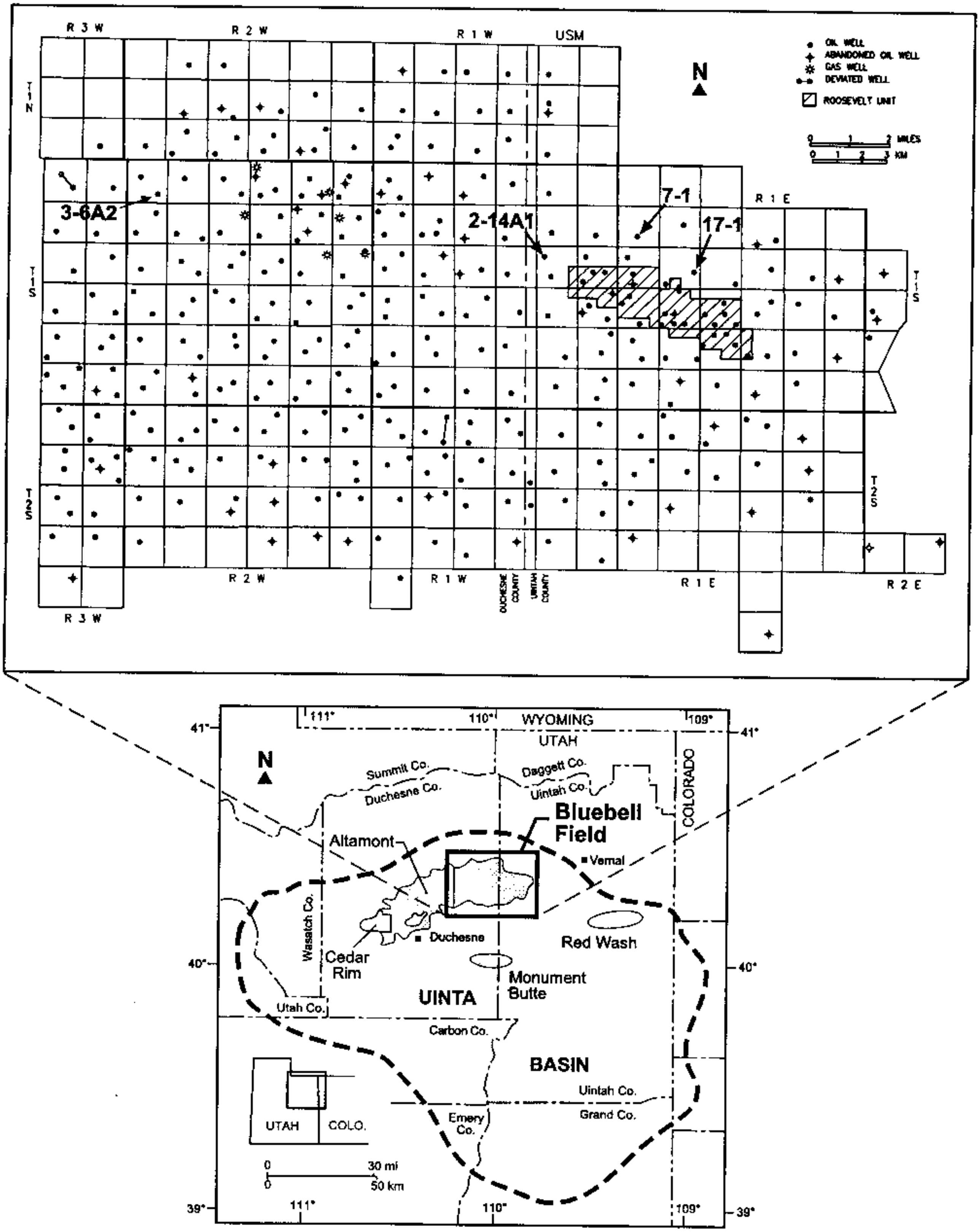

Fig. 1. Index map of the Uinta Basin showing major oil fields producing from Tertiary-aged reservoirs. Dashed line approximating the basin extent is the base of the Tertiary-aged rocks. Enlarged map is the Bluebell field with the location of the demonstration wells labeled, 7-1, 17-1, 3-6A2, and 2-14A1.

TASK 1: LOG ANALYSIS AND PETROPHYSICAL INVESTIGATIONS

Objectives

The objectives of task 1 were to: (1) develop a digital well-log database useful for correlating horizons between wells and drawing field-wide, structure maps and cross sections; (2) calculate lithology, porosity, and pore fluids from those wells with a full suite of digitized logs; and (3) evaluate the reliability of log-based estimation of these parameters.

Accomplishments

Geophysical well logs from 80 wells distributed across the Bluebell field were digitized. Logs were quality checked and only the better quality logs were digitized. Poor log quality often resulted from irregular borehole diameter. Correlation was done primarily by using the gamma-ray curve. A wide suite of logs (gamma-ray, sonic, neutron, density, resistivity, and sprectral gamma ray) was digitized and analyzed from a subset of wells. Lithology and porosity derived from core plugs and cuttings were used to calibrate the geophysical well log calculations.

Formation-water resistivities were difficult to determine. As a result, calculated water saturations were unreliable. We originally planned to calculate lithology and porosity by inversion, then do a shaley-sand hydrocarbon analysis. However, the relative proportions of quartz, dolomite, and limestone were poorly resolved, causing the inversion to give unreliable porosity values. Core-plug measurements showed that the relative proportions of quartz, dolomite, and limestone are of minor importance to calculating porosity from well logs. The best method for calculating porosity from logs was determined to be neutron-density averaging.

Results

The results of this task are discussed in detail by Jarrard (1996). Geophysical log analyses and petrophysics were used to better evaluate potentially productive beds. Natural fracture permeability is believed to play an important role in hydrocarbon production, but for long-term production, intergranular permeability (>0.1 milliDarcy [mD]) and intergranular porosity are also important. Core studies determined that fractures exist in carbonate and sandstone, but are rare in shale. Based on core-plug analyses, intergranular permeability of >0.1 mD exists only when clay content is 4% or less and intergranular porosity is >4%.

Log analysis of wells in the Bluebell field has shown that clay content can be accurately estimated from a computed gamma-ray (CGR) log using the potassium (K) and thorium (Th) contributions to total gamma radiation. Uranium is not present uniformly in the clays and is therefore not correlated with K or Th. As a result, total gamma ray is a less reliable indicator of clay content than is CGR from spectral gamma-ray logs.

Analyses of core plugs shows that grain densities are generally lower than had been expected, averaging 2.66 g/cc, in contrast to the normally-assumed matrix value of 2.68 g/cc in the eastern part of the field and 2.71 g/cc in the western part of the field. As a result, the density porosity is often overestimated. The presence of feldspar may account for the lower than expected grain density.

The biases found in both the neutron-porosity and density-porosity measurements are opposite in sign and roughly the same magnitude (within about one porosity unit). Therefore, the best log-based estimate of porosity for shale-free rocks is the average of density-porosity and neutron-porosity, both calculated using a limestone matrix. Wash out zones in well logs must be avoided because they give unreliably high porosity readings, but fortunately washouts are less common in shale-free rocks than in shaley rocks. For wells in which a sonic log was run without a density/neutron log, porosity cannot be accurately determined even when the analysis is confined to shale-free rocks, because of lithology-dependent variations in matrix travel-time.

Without quantifying the role of fractures, the best reservoirs were predicted to be beds with, CGR of < 20 API units (or less reliably GR < 45 API units), neutron/density porosities of >6% (4% intergranular plus 2% fracture), and high resistivities. This was based on the assumption that fractures are important in the permeability of the rock but that intergranular porosity is necessary for sufficient storage capacity. Detailed mapping of beds that meet the above criteria (Morgan, 1997) failed to established a correlation between net reservoir thickness and cumulative production. Also, wells in which a fluid entry log was run showed that the majority of the production was often coming from beds that did not meet the minimum criteria. There are several reasons why the predictive criteria failed: (1) the storage capacity of the fracture network is much larger than expected, (2) the storage capacity of some beds with high GR values is much larger than expected, and (3) ineffective completion techniques has resulted in poor reservoir rocks producing and the better quality reservoir rocks being damaged or untreated and not contributing to the production. The third possibly is considered the least likely since some of the wells where fluid entry logs show the production coming from very poor quality beds are high-volume producers. If the reservoir beds were as poor as the geophysical well logs indicate, then the well should have been a very poor producer. The most likely explanation of the well’s performance is that fractures play a much larger role in both permeability and storage capacity than originally anticipated.

TASK 2: OUTCROP STUDIES

Objective

The objective of task 2 was to delineate the general stratigraphic framework and broad facies of the Green River and Colton (Wasatch) Formations in order to understand facies heterogeneity and reservoir capacity within each facies.

Accomplishments

About 2790 ft (850 m) of vertical section in the lower Green River Formation was measured and described from outcrop in Willow Creek Canyon. Samples representing the volumetric majority of rock types present in the outcrop were petrographically analyzed. Core plugs from the lithologic samples were analyzed for porosity, vertical and horizontal permeability, and grain density. Thin sections were made from 33 of these samples, and each thin section was petrographically classified. The sand-dominated clastic rocks (16 in all) were each subjected to a 300-grain point-count. All samples were analyzed for clay type by x-ray diffraction (XRD).

Lithologic units in the outcrop were so discontinuous and varied that we were unable to draw distinct boundaries that delineate the open lacustrine facies from the marginal lacustrine facies, or from the lower delta plain or fluvial facies. Throughout most of the stratigraphic section, the facies commonly intertongue with each other within a few feet, both vertically and laterally.

Results

The results of this task are discussed in detail in Garner (1996), and Garner and Morris (1996a and 1996b). The upper 600 ft (183 m) of the Willow Creek Canyon outcrop is mostly marginal to open lacustrine facies with abundant silty limy mudstone and crystalline limestone. The lower portion of the outcrop is a mix of marginal and open lacustrine as well as fluvial facies. There are abundant channel and overbank sandstone deposits intermixed with red to green siltstone and silty limy mudstone. About 360 ft (110 m) above the base of the measured section is an 82-ft (25-m) thick unit of limestone/dolomite which clearly represents an open lacustrine environment.

The Flagstaff Member of the Green River Formation, which underlies the Colton Formation, was also measured and described. The predominant rock types were shale/mudstone, limy mudstone, and limestone which represents a marginal to open lacustrine environment.

The arenites in the Green River Formation outcrop tend to have the best porosity and permeability and therefore the best storage capacity. The most porous arenites were found in the bottom half of the section just above the Colton Formation. These arenites are extensively interbedded with shale and mudstone which are potential source rocks. There are clays and relatively abundant swelling mixed-layer clays present in the outcrop. The amount of swelling clays decreases towards the base of the section.

Comparison of the outcrop study with the limited data from subsurface core analyses of the Green River Formation shows that there is more smectite present in the outcrop than in core and that the arenites at the outcrop contain more feldspars and lithics than those in the core. This may be due to different provenances and transportation distances. The outcrop represents the south shore of Lake Uinta with streams transporting sediment hundreds of miles from the south. The core samples from Bluebell field represent the north shore of Lake Uinta with sediment transported miles to a few tens of miles from the Uinta Mountains to the north.

The arenites have the best reservoir characteristics of the rocks studied in outcrop. The majority of the oil production at Bluebell field is from the Flagstaff Member of the Green River Formation. Where the Flagstaff outcrops it is relatively thin and consists mostly of marginal lacustrine carbonates. In the subsurface at Bluebell the Flagstaff is much thicker and much more varied in lithology and environment of deposition. Therefore, the lower Green River strata in Willow Creek may be more representative of the types of facies found in the subsurface at Bluebell, even though they come from a different part of the stratigraphic section and had a different source. There are no truly representative outcrops for the Flagstaff Member as found in the deep Bluebell area.

Studies of the reservoir at Bluebell field failed to correlate oil production to specific facies or lithology. Therefore, understanding the facies relationships and distributions of the Green River Formation on outcrop did not directly improve our understanding of the reservoir in the Bluebell field.

TASK 3: CORE ANALYSIS

Objective

The objective of task 3 was to identify the facies and rock types in the subsurface with the best potential for oil production in the Bluebell field. If specific facies could be identified as the primary pay in the Bluebell field then identification and mapping of those facies could result in better selection of well sites and improved completion techniques by limiting the number of beds being perforated and treated.

Accomplishments

A total of 1613 ft (492 m) of core from the Bluebell field was described. The cores are from the lower Green River and Colton Formations, and Flagstaff Member of the Green River Formation. Seventy-two thin sections were made from a broad sampling of rock types throughout the cores and were petrographically examined. The sandstone samples were subjected to a 300-grain point-count. Thirty-five samples were analyzed for clay type using XRD. Fracture data were analyzed to determine how lithology, bed thickness, and/or depth control fracture density. Porosity and permeability data were determined from plug analysis.

Results

The results of this task are discussed in detail in Wegner (1996) and Wegner and Morris (1996). Natural fractures identified in the core were carefully described because of the importance of fractures in the reservoir quality. Fractures in sandstone beds are commonly perpendicular, to near-perpendicular, to bedding, with a measured length greater than 3.3 ft (1 m) (many fractures extend out of the sample). The width of the fractures ranges from 0.03 to 0.13 inches (0.5-3.0 mm) wide, and the fractures are only partially calcite-filled. Fractures in mudstone beds have multiple orientations and have a higher fracture density than is found in the sandstone beds. However, fractures in mudstone beds are very short (commonly less than 4 inches [10.2 cm]), generally less than 0.03 inches (0.5 mm) wide, and almost completely calcite-filled.

Dominant rock types in the core are sandstone of varying composition (39 %), and limy mudstone (15 %). In general, feldspar and lithic fragments seem to be present in nearly equal amounts in most thin sections counted.

Of the total core described, 78 % was siliciclastic, while only 22 % was carbonate. This is probably not an accurate reflection of the true ratio of siliciclastic to carbonate rocks in the subsurface, because it probably reflects operator bias to core siliciclastic intervals since sandstone beds are considered the best reservoirs in the Bluebell field.

Based on the semi-quantitative analyses, core samples show very low concentrations of smectitic mixed-layer clays throughout. Where they do exist, they are primarily illite-smectite or chlorite-smectite mixed layers, with only minor kaolinite-smectite mixed layers present. Nearly pure illite dominates the core samples, but chlorite is also found, in smaller amounts, in many of the samples. Kaolinite is less prevalent.

Of the 219 samples tested, 85 % have less than 4 % porosity and less than 0.05 mD permeability. In general, porosity and permeability tend to be slightly higher in the arenite beds that contain significantly more quartz than lithic fragments and feldspar. Overall, most rock types sampled have very low intergranular porosity and permeability

Limited core studies, such as this, do not result in a very large database, and therefore, the results may be biased. The study may also be biased because companies typically target the clastic beds for coring. These facts must be kept in mind when interpreting the core results and making recommendations.

Analyses of core from the Bluebell field indicate that the most promising hydrocarbon reservoirs are arenitic with high quartz content, low concentrations of swelling clays, relatively high porosity and permeability, large, open fractures, and that overlie fractured mudstone.

Limited core data makes an accurate description of the depositional processes in the Green River Formation in the Bluebell field inconclusive. The fluvial-dominated deltaic depositional environment often applied to the Green River Formation cannot be proven or disproven from the few available cores. Another possible interpretation is deposition of sand by wave-dominated transport derived from fan deltas developed along the slopes of the ancestral Uinta Mountains.

TASK 4: SUBSURFACE MAPPING

Objective

The objective of task 4 was to use geophysical well logs to correlate and map important oil producing beds or facies from well to well. Thickness mapping of individual units helps establish reservoir distribution and depositional patterns. Thickness mapping of thicker intervals helps to delineate depositional trends and regional thinning. Contour mapping shows the structural setting and potential migration direction of hydrocarbons and, in combination with thickness mapping, can show stratigraphic traps and identify potentially productive beds in old wells and new well locations.

Accomplishments

Field-wide structure contour, production, and gas-to-oil ratio maps were published (Morgan, 1994). Fourthy-nine sandstone isochore maps covering a 20-square-mile (51.8 km^2) area in the eastern portion of the Bluebell field were published by Morgan (1997). Isochore mapping of large stratigraphic intervals within the lower Green River and Colton Formations showed a general east-west strike with north to south thinning (Morgan and Tripp, 1996). The sandstone beds selected for mapping were based on critical parameters determined by the characterization study. The minimum standard in selecting a sandstone unit was that the bed must have a gamma-ray count of 60 API units or less, be at least 6 ft (1.8 m) thick, and have 6 percent or more porosity (density/neutron averaging) in at least one well. Average porosity and water saturation were determined for every sandstone bed in every well that was mapped.

Results

The thickness, porosity, and water saturation data were used to develop a reservoir simulation model. The sandstone isochore maps were compared to cumulative oil production from each of the wells. Neither the thickness, porosity development of individual beds nor the summation of beds could be correlated with well productivity. In wells where fluid-entry log data were available there was very little correlation between actual versus predicted production. Many of the producing beds did not meet the minimum criteria while many of the beds with the best parameters did not produce at all. The role of natural fractures, which we were unable to quantify due to a lack of core and bore-hole imaging, appears to have a dominant effect on the reservoir productivity.

Correlation of many of the beds and depositional cycles defined by log character, showed good lateral continuity with generally minor thickness variations over several miles. Fining-upward log character, typical of fluvial channels, and anomalous thick sandstone buildups, typical of distributary mouth bars, were not found. The Flagstaff Member and lower Green River Formation may best be described as wave-dominated shoreface deposits, not fluvial-dominated deltaic deposits. The dominant factor controlling hydrocarbon entrapment is fracturing, not stratigraphy or structure. The hydrocarbons in the Flagstaff reservoir are believed to have been generated in-situ. The expansion caused by the conversion of kerogen to hydrocarbon is responsible for most of the fracturing in the reservoir. The greatest volume of hydrocarbons is found where the largest volume of source rocks in the Flagstaff has reached maturity, generally at the greatest depth. Near the northern limits of the field the Flagstaff thins. As a result, that area is thermally mature, but has less source rock to generate hydrocarbons. Near the southern limits of the field the Flagstaff has abundant source rock, but was not buried as deep. As a result, in the southern part of the field there is an abundance of source rock, but it is less thermally mature.

TASK 5: ACQUISITION AND ANALYSES OF NEW LOGS AND CORE

Objective

The objective of task 5 was to gather borehole imaging logs and cores from new wells drilled in the Bluebell field. There was no core taken during the project period. The new logs were used to better understand the sedimentary structure, bedding, and natural fractures. At the beginning of budget period two, the definition of new logs was expanded to included cased hole logs that can determine fracturing and oil saturation.

Accomplishments

The level of drilling activity in the Bluebell field dropped dramatically from the time the proposal was written till the project began. It was initially estimated that we would gather borehole imaging logs and core from at least five wells per year. However, during budget period one only three wells were drilled. All three wells were logged with borehole imaging tools, but none were cored. The fracture analysis of these logs, and a very limited number of older directional cores, is discussed by Allison and Morgan (1996). New cased hole logs were run in each of the demonstration wells, but other operators did not take advantage of the funding for logging before recompleting any of their wells.

Results

Borehole imaging logs are an effective tool to identify fractures in the well even though rugose hole conditions resulted in portions of the section without data. Unfortunately, the operators ran the logs but didn't use them. The wells were completed in the usual fashion of perforating every bed that had a drilling show. If fracturing is the most important reservoir property it would have been logical to perforate only the beds that have fractures. If the well was drilled in a partially drained portion of the field, then an operator should perforate and acid-stimulate the beds with shows but no fractures, and then perforate the fractured beds, thus avoiding sending all the acid down a few drained fractured beds.

Dipole shear anisotropy (anisotropy) logs for fracture data, and thermal decay neutron (TDT) logs for oil saturation, were run in the three demonstration wells. Both logs can be run in a cased hole or open hole environment. The logs were used selectively by the operator. Fracturing identified on the anisotropy log was considered when selecting beds to be perforated and acid stimulated, but it was never a deciding criterion: both fractured and nonfractured beds were selected. Good oil saturation indicated on the TDT log was used as a criterion for selecting beds for perforating and acid-stimulating, but low oil saturation indicated on the TDT log was not used as a criterion to eliminate a bed from consideration. The role of fracturing cannot be quantified in the demonstration wells because both fractured and nonfractured beds were perforated and fluid entry logs were not run after the stimulations.

The TDT log was the primary tool used to select beds to be perforated in the third demonstration which was a new well. Only 19 beds were selected, far fewer than the 40 or more that are normally perforated in Bluebell wells. During swab testing the casing collapsed and the lower portion of the hole (covering all 19 perforated beds) had to be abandoned before the effectiveness of the selection could be evaluated.

TASK 6: FRACTURE ANALYSIS

Objective

The objective of task 6 was to determine the nature and characteristics of fracturing in the Bluebell reservoir. It was intended to use the fracture information to determine if there is a preferred orientation of productive fractures, what fracture characteristics affect production, and recognize stratigraphic intervals and areas or conditions where an operator might take advantage of natural fractures. New fracture data were gathered from both the surface and subsurface.

Accomplishments

Surface fracture data were gathered and analyzed by B.J. Kowallis and are discussed in Allison (1995). Analysis of the subsurface fracture data is discussed in Allison and Morgan (1996). Fewer imaging logs were obtained from the Bluebell field during the new logs task than anticipated due to a sharp decrease in the number of wells drilled during the project. As a result, we were only able to collect five sets of subsurface data during the characterization phase: three modern imaging logs and two oriented cores.

Results

Variations in the fracture orientation were determined from the limited data set both areally across the field, and vertically through the stratigraphic section. The data set was spread out over several tens of miles so continuity of fracturing between wells could not be determined. Fracture data gathered in cased holes using dipole shear anisotropy logs were used to determine statistical fracture information used in the reservoir simulation model. Cased hole anisotropy logs can detect fractures but cannot determine an orientation. Since the operators did not limit the perforations to fractured beds, and fluid entry logs were not run after perforating and acid stimulation, the importance of naturally occurring fractures in the reservoir performance cannot be quantified.

TASK 7: GEOLOGIC CHARACTERIZATION SYNTHESIS

Objective

The objective of task 7 was to coordinate and compile the other characterization tasks (1 through 5) into a single geologic evaluation.

Accomplishments

Regularly scheduled meetings resulted in good communication and cooperation among all of the task leaders of the project.

Results

The primary result was the production and submission of the Project Evaluation Report (unpublished report), and the recommended field demonstrations. The final product will be two reports, currently in review, that will hopefully be published by the UGS. The first report is the geological characterization of the Bluebell field, and the second report contains the details and evaluation of the field demonstration program.

TASK 8: ANALYSIS OF COMPLETION TECHNIQUES

Objectives

The objectives of task 8 were to compile and analyze existing completion data from wells which had been previously treated, and determine what specific type of previous treatment was the most effective. Based on past successes and failures, recommendations were whether to change the current completion technique or to develop an entirely new technique.

Accomplishments

Completion data were gathered from the Utah Division of Oil, Gas and Mining, and from companies currently operating wells in the Bluebell field. Treatment data were compiled on a spreadsheet containing 108 different categories, on 67 wells with a total of 246 stimulation treatments (original and recompletions). The database was sent to Halliburton Energy Services Tech Team in Denver, Colorado, and Reservoir Department in Houston, Texas, for analyses.

Results

The results of the analyses of completion techniques are reported by Curtice (1996). The treatment methods used by operators in the Bluebell field have not changed significantly over the years except for treating larger intervals and more perforations. As a result, no treatment method appears better than another because there is such little difference between them. As treatment intervals get larger, it is apparent that many of the beds are not getting treated because of the difficulty of diverting the acid into so many different beds. Some operators have begun staging the acid treatments and greatly increasing the amount of diversion material used. Typically, an operator treating a 1500-ft (457-m) interval will treat the lower 500 ft (152 m), move the packer up and treat the middle 500 ft (152 m), and then do the upper 500-ft (152-m) interval. Ideally, the diversion material plugs the perforations of a stage before moving uphole so only 500-ft (152-m) sections are being treated at a time.

Older wells that have been recompleted many times eventually become uneconomical to retreat. In the older wells only a minor incremental increase in the oil production rate occurs after treatment because so much of the acid is going into beds that are depleted of oil. In these older wells it is recommended that treatment of a few individual beds be attempted using a dual packer tool. This way, only the few beds with remaining oil potential are acidized, reducing the size of the treatment needed, and providing more effective stimulation of the beds with remaining potential.

TASK 9: RESERVOIR ANALYSIS

Objectives

The objectives of task 9 were to develop a reservoir model, and use that model to understand the performance of the reservoir based on model properties. If reservoir production history could be matched, based on a predefined reservoir description, then ultimate oil-producing potential could be projected with some level of confidence. Both reservoir characterization and simulation were studied. The objectives of reservoir characterization were to generate accurate petrophysical models of various portions of the reservoir using the available data, and to evaluate the possibility of projecting available fracture information field wide. The goals of reservoir simulation were to model the reservoir at various scales to see if reservoir simulation could be used as a production history matching tool and ultimately as a planning and forecasting tool. Since one of the objectives was to develop a detailed reservoir model which consists of hundreds of thousands of grid cells, it was necessary to create a computational infrastructure to accommodate such a model. Hence, a parallel, (multiprocessor) fractured reservoir simulator was developed.

Accomplishments

Reservoir data such as fluid property, production, fracture data, log-derived pay-zone thicknesses, porosities, water saturations, as well as core-derived permeabilities and porosities were compiled for the modeling effort. Single-well homogeneous and dual-porosity, dual-permeability, fractured-reservoir simulation models were constructed for the Michelle Ute and Malnar Pike demonstration wells. Homogeneous and fractured simulation models were constructed covering a 4-square-mile (10.4 km^2) area encompassing two of the demonstration wells in the eastern portion of the Bluebell field, and a 4-square-mile (10.4 km^2) area in the western portion of the field. Each of the reservoir simulation models were subjected to internal analysis and the following reservoir properties were examined: (1) original-oil-in-place in each of the perforated zones, (2) original reservoir pressure, (3) oil produced and oil remaining in each of the modeled layers, and (4) current reservoir pressure.

A significant problem in this task was the uncertainty in the reservoir data. Data at well locations, such as porosities, thicknesses, fracture permeability, and other reservoir parameters had to be interpolated between well locations. Since oil originates from tens of producing layers, establishing realistic correlations of these layers between wells is difficult. Fracture information is also limited; it was derived from a few cores and a few imaging logs. To extrapolate a fracture pattern for the field from this limited data set is problematic. The confidence level for the reservoir fluid and rock properties data is higher than the confidence level in the fracture data since the rock and fluid properties data were defined in laboratories.

Reservoir models were constructed for: (1) the Michelle Ute and Malnar Pike wells representing all of the perforated beds, (2) a 4-square-mile area in the eastern portion of the field area consisting of five correlated beds, and (3) a 4-square-mile area in the western portion of the field. Internal analyses of the reservoir models were performed and beds with the most potential for additional oil production were identified.

Various methods used for generation of fracture networks and fracture property distributions have had limited success in past petroleum reservoir characterization efforts. Most of the methods generate fracture property distributions that are not suitable for conventional methods of reservoir model development and flow simulations, like the dual-porosity, dual-permeability approach. A new method for fracture property distribution is suggested in this study. This new method uses principles of stochastic simulations. Analysis of sample data from Bluebell field shows that the fracture frequency distributions are functions of rock types. This information was used as an additional constraint while generating fracture frequency distributions, using Markov-Bayes principles. Two types of conditioning were used during the stochastic simulation procedure. The observed values of fracture frequency were fully honored (hard conditioning), while the rock type information was used for soft conditioning. The fracture frequency distributions generated through this approach were compared with the distributions generated using principles of sequential Gaussian simulations and sequential indicator simulations.

A parallel (multiprocessor) fractured reservoir program, based on the dual-porosity principles, was developed using a portable parallel library (Message Passing Interface). The parallel program was compiled and run on two types of parallel environments: shared memory, and distributed memory. In each case, the performance of the parallel program was compared against the serial version of the program. The comparison was made in terms of the time required to perform different computations in the program. These computations included calculation of coefficients and formulation of coefficient matrices, solution of fracture flow equations, solution of matrix flow equations, and all the calculations involved in an entire time step.

Results

The results of the reservoir analyses are reported in Allison (1995), Deo and Pawar (1996, 1997a, 1997b), Deo and Morgan (1998), Morgan and Deo (1998), and Pawar (1998). The modeling indicates that there is a great deal of oil remaining to be recovered from the Bluebell field and that some form of stimulation is necessary in order to recover this oil. In some wells, certain thick beds contain significant quantities of oil that might be possible to target for individual bed treatment.

Incorporating water saturations calculated from geophysical well logs into the reservoir simulators results in much larger volumes of water in the model than is actually produced from the wells. This problem could be caused by: (1) calculating water saturations lower than actually exist in the reservoir, (2) water saturations averaged over the entire bed while only a small portion actually produces, (3) the percentage of bound water is much higher than anticipated, or (4) many of the beds perforated have high water saturations but don’t actually produce.

The production performance of parts of the naturally fractured reservoirs in the Bluebell field was studied through flow simulations performed on numerical models. Models were developed for two four-section areas on the east and the west portions of the field. The east-side model was a preliminary model that only took into account some of the beds responsible for the oil production. The west-side model incorporated each bed into the model, as it was perforated during the life of the well. Two comprehensive models were developed for two wells on the east portion of the field. These models took into account all the perforated beds. Lack of data on some of the required parameters made model development a challenging task. The numerical values of these parameters were calculated through production history match. Extremely low values of matrix rock permeability and fracture properties were needed to match the production history. Such low rock permeability values are in agreement with the core values. On the other hand, low values of fracture properties suggest that either the fractures are not contributing to the flow, or the field operations have resulted in extensive formation damage near the well bore rendering the fractures noncontributing. The amount of formation damage was quantified through time dependent permeabilities of well bore blocks. A 20-section area on the east side of the Bluebell field was used to study the effect of fractures on production variability from stochastically generated data. Geophysical logs were used to identify and characterize all the oil-bearing beds in the entire 20-section area. Reservoir rock properties were calculated for all the beds based on properties calculated from log analyses. Stochastic simulations were performed to generate distributions of rock properties. These simulations were then used to study the variability in fluids in place. A number of beds in the 20-section area were estimated to contain significant amounts of fluids in place. Most of the beds in the 20-section area were not continuous over the entire area. Inclusion of fractures reduced the variability in the production from the 20-section area. In the dual-porosity, dual-permeability approach, the fractures are the main pathways for the flow while the rock matrix is the main storage area for the fluids. Only the rock matrix properties were generated through stochastic simulations while the fracture properties were assumed to be continuous over the study area. Since the fractures dominated the flow, the variability in production due to matrix properties was reduced. The effect of various fracture properties on the production behavior of the fractured reservoir was also studied. As fracture porosity increased, oil and gas production also increased due to increased oil contained in the fractures. Increasing the fracture permeability increased the oil production up to a certain value of permeability, but beyond that the production was limited by the rate of fluid transfer between matrix and fractures. Increase in fracture frequency also increased the oil and gas production only up to a certain fracture frequency. Beyond that particular frequency, the increase in fracture frequency had only a marginal effect on production. The effect of variations in fluid thermodynamic properties on production was also studied. Increasing the oil API gravity resulted in increased oil production and reduced gas production. Increasing the reservoir temperature did not have any effect on the production performance.

The effect of scale was studied on the production for two wells in the reservoir. The study was performed only for one layer. The results showed that the production performance of Michelle Ute well was affected by scale of study. The production for single well model, where only a 40-acre area around the well was studied, was lower than the production for 20-section area. The continuity of the sand around the well did increase the production significantly even with low values of fracture and matrix flow properties.

Wells in the fractured reservoir models exhibit radii of influence (up to about 1000 ft [304.8 m]) that are larger than those in the homogeneous models. Most wells in the field are more than 1000 ft

(304.8 m) apart, but generally the second well drilled in a section is partially depleted. The difference between the modeled and actual production data could result fromeither of the following conditions: (1) the fractures are closed and not a significant part of the reservoir property, or (2) the production is from fractures, but from only a few of the perforated beds, and most of the other beds are not contributing to the production.

When the model included soft conditioning, the relationship of fracture frequency distribution on the rock type could be duplicated. The frequency distributions generated through the other two approaches did not reproduce this important trend. Reservoir models were developed with the fracture frequency distributions generated through these three approaches. The production performances of these three reservoir models, as expected, were different.

The parallel program was compiled and run on Silicon Graphics Power Challenge. The Power Challenge was a shared memory computer with 12 processors. The machine had 2 gigabytes of random access memory (RAM) and 12 gigabytes of hard disk space. The processors were MIPS R8000 chips with clock speed of 75 megahertz each. The parallel program was run with two and four processors. Four different input models were used. The grid configurations for the four models were 16X16X16, 32X32X16, 64X64X16 and 128X128X16.

Considerable speed up was observed with the parallel codes on the SGI Inca. The addition of processors was beneficial only for larger size problems, where even with the additional time required for communications, the total time required to complete one computational time step decreased. Performance degradation of the parallel program on IBM SP may be due to the waiting during the communications. A simple parallel solution technique was successfully implemented to achieve faster computational performance.

TASK 10: BEST COMPLETION TECHNIQUE IDENTIFICATION

Objective

The objective of task 10 was to recommend completion techniques for recompletion of older wells and completion of new wells based on the results of task 8 (Analysis of Completion Techniques) and Task 9 (Reservoir Analysis).

Accomplishments

A detailed analysis of prior completion techniques (task 8) identified many ways current completion practices could be improved. It is evident that many of the beds are not getting treated, and that smaller treatment intervals, and more effective diversion of treatment fluids is needed.

A detailed study was conducted by Gwynn (1996) of the produced water compositions from wells in the Bluebell field, including computer simulations to restore in-situ conditions. Production of water with varying composition was computer simulated. Production at varying reservoir conditions, with changes in pressure, temperature, and gas content, was simulated to identify the amount and composition of potential scaling materials precipitated. Changes in simulation parameters were used to determine ways to reduce scaling problems during production. The study did not find any unique or unusual water chemistries in any particular facies or area of the field that might affect completion techniques.

Reservoir analysis indicates that there is a significant amount of oil left to be produced in the Bluebell field wells. Accurately identifying which beds actually contribute to the production and the role that naturally occurring fractures play in the reservoir remains a major problem.

Results

Almost all the completions in the Bluebell field follow the same procedures, generally varying only slightly in the volume of acid and the types of additives used. As a result, analyses of past completion techniques did not identify one technique that was more effective than another. In newer wells, perforating fewer beds and treating shorter gross intervals can result in more effective completions. In recompleting wells, staging the treatments over shorter intervals and more effective diversion of the treatment fluid to the desired interval, will result in better completions. In older wells, where expensive staged completions are no longer economical, identifying remaining oil with cased holes and then acid treating individual beds with a dual packer tool may help extend the life of the well.

TASK 11: BEST ZONES OR AREAS IDENTIFICATION

Objectives

The objectives of task 11 were to identify the most productive facies, and the areas within the Bluebell field with the most remaining oil potential. A better definition of what beds are the oil pay and prediction of where these beds can be found in undrilled portions of the field would identify new drill locations and help reduce the number of perforations needed in a well.

Accomplishments

Detailed correlation and log analyses of thousands of feet of section from all the wells in a 20-square-mile area allowed stratigraphic cross sections, isochore maps of individual beds, evaluation of production histories, and reservoir simulation modeling to be completed as part of the Bluebell geologic characterization and reservoir analysis. A lack of detailed information on which beds actually contribute to the oil production in a well, and very limited amount of core, made it impossible to identify (if it exists) any specific facies or fracture trend that is responsible for the production at Bluebell field.

Results

It is recommended that operators in the Bluebell field use geophysical and imaging logs as the primary tool for selecting perforations in new wells, not drilling shows as is commonly done. This should result in a reduction of the number of beds perforated, and more effective treatment. In recompletion of existing wells, cased hole logs can help identify additional beds to be perforated, and if necessary, identify beds that can be treated individually.

OIL WELL DEMONSTRATION PROGRAM

The oil well demonstration program carried out by Quinex Energy Corporation, Bountiful, Utah, involved three parts. The first demonstration well was a recompletion of the Michelle Ute 7-1 well using a three-stage, high-diversion, high-pressure, acid treatment. Each stage was about 500-ft (150-m) vertical interval with over 10 beds perforated in each interval. The second well demonstration was a recompletion of the Malnar Pike 1-17 well using an acid treatment of four separate beds using a bridge plug and packer to isolate individual beds in a well with over 60 beds previously perforated. The third well demonstration was the logging and completion of a new well, the Chasel 3-6A2. The Michelle Ute and Chasel 3-6A2 wells were both severely hampered by mechanical problems. The Malnar Pike recompletion was mechanically successful but the incremental increase in oil production was less than most recompletions in the Bluebell field.

The Wade Cook 2-14A1 well was not originally part of the demonstration program. The well was drilled by Quinex Energy Corporation about 2 miles from the Michelle Ute well. Financial support from the project was provided for running dipole shear anisotropy and TDT logs in the well which were run in each of the three demonstration wells.

Recompletion of the Michelle Ute 7-1 Well

Objective

The recompletion of the Michelle Ute well is discussed by Deo and Morgan (1998). Most wells in the Bluebell field have 40 or more beds perforated over a 1500-ft (460-m) or more, vertical interval. Some operators have improved their recompletions by acidizing the large intervals in stages, but it remained unclear if they were opening up more of the perforated beds to production or if they were more effectively treating a few beds that account for most of the production. The objective in the recompletion of the Michelle Ute well was to use cased-hole logs to better understand what was being accomplished with a staged treatment. Prior to the treatment, cased-hole logs would be used to determine which beds have fractures (dipole shear anisotropy), and which beds show evidence of depletion (TDT). After the treatment, dipole shear anisotropy and isotope tracer logs would be run to determine the effectiveness in diverting the acid to each of the beds, and if most of the acid went into the beds with fractures or if the treatment opened up new fractures. Fluid-entry logs would be used to determine if production was coming from significantly more beds than in the typical Bluebell well, and if production was coming from only beds with fractures.

Accomplishments

Cased-hole logs were run before the treatment and showed fracturing in many of the beds that was confined by the bed boundary. This had been seen in other wells, in both core and open-hole imaging logs. The TDT log identified several beds with oil potential that had not been previously perforated. A leak was detected when the tubing was pressure tested prior to pumping the acid. Rather than come out of the hole and delay the treatment, the operator decided to pump the acid from a single packer location over the entire 1500-ft (460-m) interval. The tubing parted after the acid was pumped as the operator was attempting to come out of the hole. As a result, the spent acid was left in the hole for several days until the tubing could be fished out of the hole.

Results

The isotope tracer log was run after the treatment and showed a pattern of dispersal of the acid similar to the fractures, providing some confidence in the interpretation of the fracture log. A qualitative analysis of the TDT log indicates an equal oil saturation in both perforated and non-perforated beds which suggests vertical communication in the reservoir. Some of the beds shown to have good oil potential on the TDT log are correlatable to neighboring wells where fluid-entry logs indicate that the beds are oil productive. The isotope tracer log showed that only beds in the upper 500 ft (150 m) of the 1500 ft (460 m) tested interval received any significant amount of acid; the lower 1000 ft (300 m) were not treated. The dipole shear anisotropy log was not run after the treatment as planned, but since the acid was pumped at lower than normal pressures, and only a third of the interval received any acid, it is unlikely that any fractures were induced.

The demonstration was not a valid test of the staged completion because of the mechanical problems encountered. A minor incremental increase in the daily oil production did occur for a few months, which was encouraging considering how few beds were actually treated. Although the interpretation of the cased-hole logs was not proven by the demonstration, the limited results did increase our confidence in the data.

Recompletion of the Malnar Pike 17-1 Well

Objectives

The recompletion of the Malnar Pike well is discussed in Morgan and Deo (1998). Wells in the Bluebell field are initially completed, and periodically recompleted, by treating tens of beds at a time. The objective of the Malnar Pike recompletion was to use cased-hole logs that were shown to be of value in the Michelle Ute demonstration, to select individual beds for treatment and determine the effectiveness of treating Bluebell wells at the bed scale.

Accomplishments

Dual-burst thermal-decay-time (TDT), dipole shear anisotropy, and isotope tracer logs were used to identify beds for treatment and testing, and for post-treatment evaluation. Four separate treatments and tests were applied. The intervals were isolated using a bridge plug at the base and a packer at the top of the test interval. The first two treatments resulted in communication above and below the test interval. Swab tests recovered water from both intervals after the treatment. The third and fourth treatments were mechanically sound, and resulted in an increase in the daily oil production.

Results

A bridge plug was placed above the first and second intervals because the operator felt these intervals would produce water. The daily oil-production rate did increase as a result of the treatment of the third and fourth intervals. The incremental increase in the oil production was less than most recompletions in the Bluebell field.

Initially we planned to do the treatments with a dual-packer tool so that all four treatments could be done in a day. The operator decided to use the bridge plug and packer method which is mechanically safer but took about two weeks, greatly increasing the cost. As a result, the incremental increase will probably not pay for the cost of the treatment.

Communication above and below the test intervals was a major problem. The Malnar Pike well has numerous perforations that have been acidized several times, and this increases the potential for communication behind the casing. It is very likely that conventional acid treatments (typically a 500 to 1500 ft [150-460 m] interval) of older wells in the Bluebell field cause a similar problem. Much of the acid may be moving vertically through the cement and not into the formation.

The bed-scale completion technique can be an effective treatment, especially in older wells where the incremental increase in oil no longer justifies the expense of a larger single or multi-staged recompletion. The bed-scale completion should be conducted using a dual packer tool to reduce cost, and the anisotropy and TDT logs should be used to select beds that are fractured and have relatively low water saturation. Both the upper and lower packer should be placed between perforated beds that are at least 50 ft (15 m) apart to reduce the risk of communication behind the pipe.

Completion of the Chasel 3-6A2 Well

Objectives

The objective of completing the 3-6A2 well was to use geophysical well logs that were shown to be effective in the first two demonstrations. This would hopefully reduce completion costs, increase the production rate, and greatly reduce the volume of water produced. The completion of the John Chasel 3-6A2 well is discussed in Morgan and Deo (1998). Most wells in the Bluebell field are completed by perforating 40 or more beds. Perforations are usually selected based on drilling shows with minor reliance on geophysical well logs.

Accomplishments

Quinex Energy Corporation drilled the John Chasel 3-6A2 well to a total depth (TD) of 15,872 ft (4837.8 m) in the Flagstaff Member of the Green River Formation. Neighboring wells have produced as little as 2000 bbl to over a million bbl of oil (280-140,000 MT). The 3-6A2 well is the second deep well in the section and, like most second wells, it appears to have been partially depleted. In this part of the Bluebell field, the first wells typically required 14 lbs/gal (1.7 kg/L) drilling mud. The 3-6A2 well encountered numerous oil and gas shows in the Green River and Colton Formations, but was drilled to TD with a maximum mud weight of 11 lbs/gal (1.3 kg/L).

Open-hole geophysical well logging consisted of a suite of logs including the dual induction, compensated neutron lithodensity, dipole shear anisotropy, gamma ray, and spontaneous potential. The TDT log was run after the hole was cased. Nineteen beds were selected for perforating, far fewer than in most other wells in the Bluebell field. The TDT log was the primary tool used for selecting perforations, along with consideration given to fracturing identified on the dipole shear anisotropy log and exceptional drilling shows. The density-neutron porosity log was evaluated but log porosity was not a deciding factor.

The 3-6A2 well was stimulated by acidizing the perforations in two separate treatments. The first treatment was of the lower 12 perforated beds, and the second treatment was of all 19 perforated beds.

Results

The isotope tracer log indicated that most of the acid went into perforated and nonperforated beds in the interval from 15,130 to 15,340 ft (4611.6-4675.6 m). The log showed extensive communication behind the casing in this interval. The interval was cement squeezed, and many of the beds were reperforated, and the entire perforated interval was acidized. Swab testing began recovering drilling mud, and then the tubing had to be pulled because it was plugged with cement chips.

While the tubing was out of the hole the well began to flow. The shut-in pressure at the well head was 2500 psi (17,160 kPa). The operator flowed the well in an attempt to reduce the pressure so they could run the tubing back in the hole. One day the well flowed 124 BO (17.4 MT), 255 MCFG (7220 m^3), and no water. The next day it flowed 133 BO (18.6 MT), 125 MCFG (3550 m^3), and no water. The operator eventually stopped the flow and ran the tubing back into the hole. It was discovered that the casing had partially collapsed at 15,354 ft (4682.9 m) and 15,573 ft (4749.8 m) with a tight spot at 14,700 ft (4480.6 m).   The swedge became stuck while trying to open the tight spot resulting in the swedge and some of the tubing being left in the hole. The well is shut in and was completed based on the earlier flow rate up the casing. The effectiveness of the selection of perforations and the completion technique cannot be evaluated in this well because of the mechanical problems that developed.

Completion of the Wade Cook Well

Objectives

The Wade Cook 2-14A1 (NW1/4NW1/4, section 14, T. 1 S., R. 1 W.) well was not originally scheduled as part of the demonstration program. However, the Wade Cook well is about 2 miles from the first demonstration well, the Michelle Ute, and we felt the data from the Wade Cook could help the study. Therefore, we supported the logging of the well to ensure that dipole shear anisotropy and TDT data were gathered.

Accomplishments

Quinex Energy Corporation drilled the Wade Cook well to a total depth of 14,212 ft (4331.8 m) in the Flagstaff Member of the Green River Formation. The well was logged with a suite of logs including the spontaneous potential, gamma ray, compensated neutron and formation density, dual induction, dipole shear anisotropy, and dual burst thermal decay time (TDT). Twenty-eight beds between 12,001 and 14,104 ft (3657.9-4298.9 m) were perforated and acidized. After swab testing another eight beds between 10,536 and 10,938 ft (3211.4-3333.9 m) were perforated and acidized. The well was completed flowing 285 BOPD (39.9 MTPD), 148 MCFGPD (4000 m^3/d) and no water.

Results

The Wade Cook well provided only limited data. The operator selected 28 beds for perforating based primarily on the TDT and drilling shows. Both fractured and nonfractured beds, as well as some beds that appeared tight or wet on the TDT log, were selected for perforating. As a result, the role of naturally occurring fractures in production of the well cannot be determined. The 2000-ft (610 m) gross interval was acidized from a single packer location instead of staging it in smaller intervals, as recommended by our study. Isotopes were not used in the acid so the effectiveness of diverting acid into the desired beds is unknown. The operator believes most of the acid went into the lowermost perforations. The well would flow oil for a few days and then stop; swabbing would start the well flowing again. The operator believes the stoppage of production occurred when the wellbore filled with oil and load water to the top of the perforated interval and blocked the set of perforations that were producing gas. When the gas-producing perforations became blocked, there wasn't enough gas in the wellbore to lift the fluids. To increase the gas to the wellbore, another eight beds (10,536-10,938 ft gross) were perforated and acidized.

The well is currently producing from 36 beds in a gross vertical interval of 3568 ft (1087.5 m). It is believed that only a few of the beds are actually contributing to the production. It is unknown if the nonproductive beds are incapable of producing, or if the inefficient completion technique failed to adequately divert acid into those beds.

TASK 12: TECHNOLOGY TRANSFER

Objective

The objective of technology transfer was to get the data and results of the study to explorationists and operators of wells in the Uinta Basin and other fluvial-dominated deltaic reservoirs, as well as to people involved in regulatory and land use planning, and anyone with a general interest in the geology and hydrocarbons of the Uinta Basin.

Accomplishments

Information was provided through:

1. Cooperation between team members from academia, state agencies, oil field service companies, and oil well operators;
2. the Utah Geological Survey Industry Outreach Program;
3. visits to the demonstration sites;
4. posting of technical reports on the UGS web site;
5. publications of technical papers and graduate theses; and
6. presentation of papers at professional meetings and industry trade shows.

Results

Team cooperation: The mutidisciplinary team met quarterly during the characterization phase to coordinate our efforts and share findings and new ideas. Service companies and operators carried the ideas back to offices and shared the information with other industry personnel and companies.

Industry outreach: The UGS Industry Outreach Program compiled and maintained a contacts list of all people and companies that expressed interest in the project. These people received copies of the quarterly and annual technical reports as well as the UGS Petroleum News and Survey Notes. The Outreach Program set up an exhibitor booth displaying information about the project at the following industry conventions and programs:

1. AAPG National Conventions from 1993 through 1999,
2. AAPG Regional Meetings from 1993 through 1999,
3. Society of Petroleum Engineers National Convention 1994,
4. Vernal (Utah) Petroleum Days 1994, 1996, and 1998;
5. Utah Geological Association and Four Corners Geological Society Symposium 1996,
6. Petroleum Technology Transfer Council 1998,
7. Interstate Oil and Gas Council National Meeting 1998.

Site visits: Site visits to each of the demonstration well locations were coordinated with the Quinex Energy Corporation. There was little interest in visiting the sites except by people directly involved in the project.

Internet web page: The UGS maintains a Bluebell home page on its web site containing the following information: (1) a description of the project, (2) a list of project participants, (3) each of the Quarterly Technical Progress Reports, (4) a description of planned field demonstration work, (5) portions of the First and Second Annual Technical Reports with information on where to obtain complete reports, (6) a reference list of all publications that were a direct result of the project, (7) an extensive, selected reference list for the Uinta Basin and lacustrine deposits worldwide, and (8) daily activity reports of the Michelle Ute 7-1, Malnar Pike 17-1, and Chasel 3-6A2 demonstration wells. Numerous inquiries resulted from the web page.

Publications: The following publications resulted from the Bluebell study:

Garner, Ann, 1996, *Outcrop study of the lower Green River Formation for the purpose of reservoir characterization and hydrocarbon production enhancement in the Altamont-Bluebell field, Uinta Basin, Utah:* Provo, Brigham Young University M.S. thesis, 192 p.

Garner, Ann, and Morris, T.H., 1996, *Outcrop study of the lower Green River Formation for the purpose of reservoir characterization and hydrocarbon production enhancement in the Altamont-Bluebell field, Uinta Basin, Utah:* Utah Geological Survey Miscellaneous Publication 96-2, 61 p.

Montgomery, S.L., and Morgan, C.D., 1998, *Bluebell field, Uinta Basin: reservoir characterization for improving well completion and oil recovery:* American Association of Petroleum Geologists Bulletin, v. 82, no. 6, p. 1113-1132.

Morgan, C.D., 1994, *Oil and gas production maps of the Bluebell field, Duchesne and Uintah Counties, Utah:* Utah Geological Survey Oil and Gas Field Study 15, 4 p., 7 plates, scale 1 inch = 0.8 miles.

Morgan, C.D., compiler, 1995, *Increased oil production and reserves from improved completion techniques in the Bluebell field, Uinta Basin, Utah - second annual report:* Utah Geological Survey Open-File Report 330, 115 p.

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Petroleum News is a newsletter published by the UGS that keeps petroleum companies, researchers, and other parties who are interested in Utah's energy resources, informed on the progress of various energy-related projects of the UGS. The following articles were published in *Petroleum News.*

January 1994, *DOE Class I Oil Program.*
June 1994, *DOE Class I Program.*
July 1995, *Bluebell project begins second successful year.*
May 1996, *Bluebell project readies for demonstration program.*
April 1997, *Bluebell field demonstration: new logs show fractures, oil.*
January 1998, *Bluebell field: second demonstration completed.*
April 1999, *Demonstration nearly completed in Bluebell field.*

The UGS *Survey Notes* is a newsletter that reaches a wide audience including industry, teachers, government, and the general public. The following articles were published in *Survey Notes.*

1995, *Bluebell project to test well-completion techniques:* v. 28, no. 1, p. 12-13.
1997, *Energy News:* v. 29, no. 2, p. 9.
1997, *Oil recovery demonstration program begins with acid treatment in the Bluebell field:* v. 29, no. 3, p. 10.
1997, *Energy News: Oil demonstration programs move into advanced phases:* v. 30, no. 1, p. 10-11.

<u>Presentations:</u> The following talks or poster presentations often with an associated published abstract, have discussed the Bluebell study:

Deo, M.D., 1998, *Fractured reservoir modeling in the Bluebell filed, Uinta Basin, Utah:* Petroleum Technology Transfer Council Symposium, Salt Lake City, UT.

Garner, Ann, 1995, *Reservoir characterization through facies analysis of the lower Green River Formation for hydrocarbon production enhancement in the Altamont-Bluebell field, Uinta Basin, Utah:* American Association of Petroleum Geologist Annual Convention Program with Abstracts p. 32A.

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Morgan, C.D., 1997, *Improving primary oil recovery from a (DOE Class I) fluvial-dominated deltaic lacustrine reservoir Uinta Basin, Utah:* American Association of Petroleum Geologists Annual Convention Program with Abstracts, p. A85.

Morgan, C.D., 1998, *Use of dipole shear anisotropy, dual burst thermal decay time, and isotope tracer logs for recompletion design and post-recompletion evaluation in complex reservoirs:* Petroleum Technology Transfer Council Symposium, Denver, CO.

Morgan, C.D., 1998, *Increased oil production and reserves from improved completion techniques in the Bluebell field, Uinta Basin, Utah:* Petroleum Technology Transfer Council Symposium, Salt Lake City, UT.

Morgan, C.D., 1998, *Second field demonstration of completion techniques in a (DOE Class I) fluvial-dominated deltaic lacustrine reservoir, Uinta Basin, Utah:* American Association of Petroleum Geologists Annual Convention Abstracts CD ROM.

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