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# Increased Oil Production and Reserves from Improved Completion Techniques in the Bluebell Field, Uinta Basin, Utah

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# CONTENTS



# ILLUSTRATIONS

## TABLES

## 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. 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 shot gun 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 40 to 60 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 and an isotope tracer log was run after the treatment and these 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. 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 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 is 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 well discussed in the previous technical report), dipole shear anisotropy (anisotropy) and dual-burst thermal decay time (TDT) logs were run before and an isotope tracer log was run after the treatment. The logs were very helpful in characterizing the remaining hydrocarbon potential in the well. But, mechanical failure resulted in a poor recompletion and did not result in a significant improvement in the oil production from the well.

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) is 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 40 to 60 beds that are typically perforated in a new well. Fewer perforated beds should result in lower treatment cost, more effective treatment of each of the beds, and more oil production with less associated formation water. Initial testing was encouraging but the casing collapsed and the operator has been unable to complete the well as of September 30, 1998.

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) were 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 is to be ported to a cluster of workstations, the cluster is 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; that work is underway.

Technology transfer activities for the year 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 booth during the National AAPG 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.

# INTRODUCTION

## Project Status

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. Although portions of the characterization study are ongoing, the study has identified 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 40 to 60 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. The operator is still trying to complete the well (as of September 30, 1998), but the well will never produce at its full potential.

## 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 and fluvial 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 (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, but much of the field is still produced at one well per section. The Roosevelt unit within the Bluebell field operates under a unit agreement. 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 [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-fluvial 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 make it very difficult to identify which beds are actually potential oil producers. As a result, the operators have taken a shotgun approach to completing and recompleting the wells; they perforate 40 to 60 beds over a vertical interval of 1500 ft (460 m) or more, and acidize the entire interval. This completion technique is believed by the operators to 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). Oil productive beds can be identified using advanced open- and cased-hole logs, allowing operators to perforate and treat smaller intervals resulting in more effective completions. The demonstrations are designed to show the effectiveness of treating more selective beds at different scales.

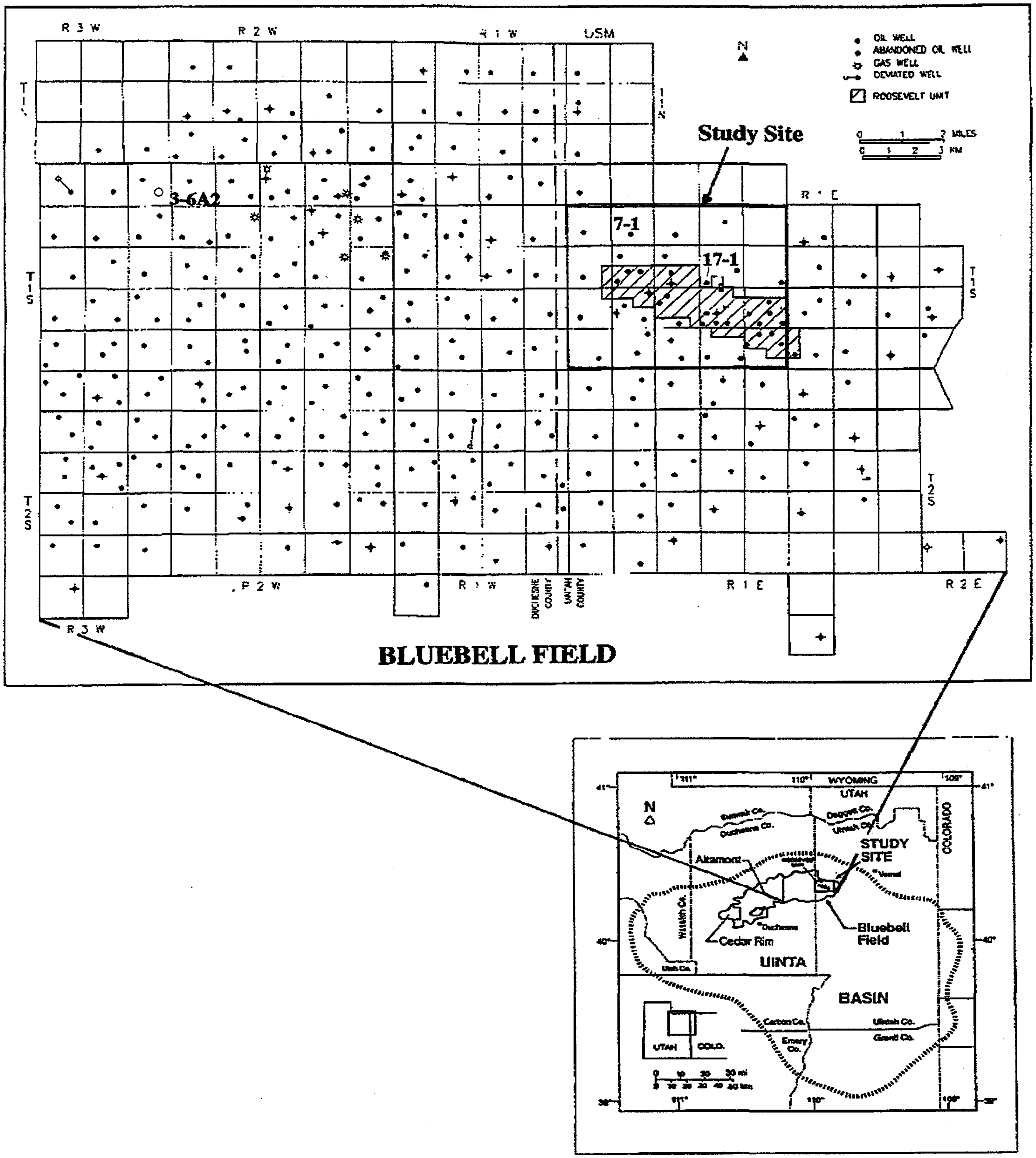


Fig.1. Location of Bluebell field, Duchesne and Uintah Counties, Utah. Demonstration wells 7-1, 17-1, and 3-6A2 are labeled. Study site is the area of detailed characterization discussed in previous reports.

## DEVELOPMENT OF A PARALLEL PROCESSING FRACTURED RESERVOIR SIMULATOR

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) were reported in earlier quarterly and annual reports.

The performance of the parallel program was also studied on a distributed memory machine, the IBM SP which has 64 nodes of which eight nodes are 66 megahertz (MHz) processors with 128 megabytes (Mbytes) of local memory and the remaining 56 nodes are 120 MHz processors. The local memory configuration for the remaining 56 nodes was as follows: 46 nodes with 128 Mbytes, four with 256 Mbytes, two with 512 Mbytes, and four with 1 gigabyte (Gbyte). Each node had 2.2 Gbytes of local hard disk space. The communications between different nodes are performed through an external ethernet connection and a high performance switch that allows communications between any two nodes. The performance of the parallel program was studied with the four, 120 MHz processor nodes with 1 Gbyte of local memory. The performance was studied for the same four data sets that were examined on the shared memory machine. These had grid configurations of 16X16X16, 32X32X16, 64X64X16, and 128X128X16, respectively. The times required for various computations are compared for one, two, and four processor configurations.

The time required to calculate the coefficient matrices are compared in Fig. 2. For the smallest data set (16X16X16) the time required does not decrease significantly as the number of processors are increased. For the 32X32X16 data set, as the number of processors are increased from one to two to four, the time required decreases though the decrease is not very significant. For the larger data sets, 64X64X16 and 128X128X16, the time required decreases significantly as the number of processors are increased from one to four (by a factor of 2.5 for the four processor configuration).

The times required to solve the fracture and matrix pressure equations are compared in Figs. 3 and 4. As can be seen from both the figures, there is no effect on the time required to solve the two equations as the number of processors is increased for the two small data sets, 16X16X16 and 32X32X16. For the 64X64X16 and 128X128X16 data sets, the time required increases as the number of processors is increased. The increase is very significant for solution of the matrix pressure equation. The total times for completion of one time step are compared in Fig. 5. Except for the largest data set (128X128X16), the time required to complete a single time step does not vary significantly with additional processors. For the largest data set, the time decreases as the number of processors is increased from one to two but increases as additional processors are used.

The results for the distributed memory machine are different than the shared memory machine. The message-passing protocols used by the two machines are different. On the shared-memory machine, each time a processor has to send a message it does so without waiting for a ready message from the processor that is supposed to receive the message. The processor performs the send and carries on to the next instruction. Conversely, on the IBM SP, each processor waits for the ready signal from the receiving processor before it sends the data. This waiting takes place only for the cases where the size of the data to be communicated is at least four kilobytes (Kbytes). For the largest model (128X128X16) the size of the data to be communicated between the processors is greater than four Kbytes. The number of communications increases when the tridiagonal system of equations is solved with an iterative method. As the number of processors is increased the time lost in waiting also goes up considerably. As can be seen from Figs. 3 and 4, the increase in time required to solve the system of equations is greater for the matrix equations compared to the fracture equations. This is because of the order in which the two equations are solved. The matrix equation is solved first, with initial guesses for fracture and matrix pressures from the previous time step. The results are then used to solve the fracture equations. Thus, more iterations are required to solve the matrix equation requiring additional computing time.

The results of parallel computing on the distributed memory machine were rather disappointing. If the code is to be ported to a cluster of workstations, the cluster is 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; that work is underway.

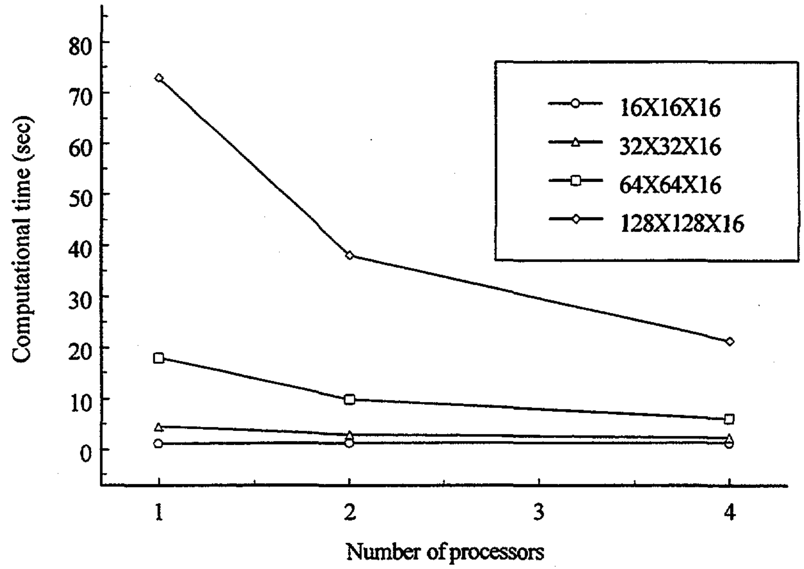


Fig. 2. Comparison of computational times for calculation of coefficient matrices for serial program (1 processor) and parallel program (2 & 4 processors) on IBM SP, a distributed memory machine (the four model grid configurations are shown in the explanation).

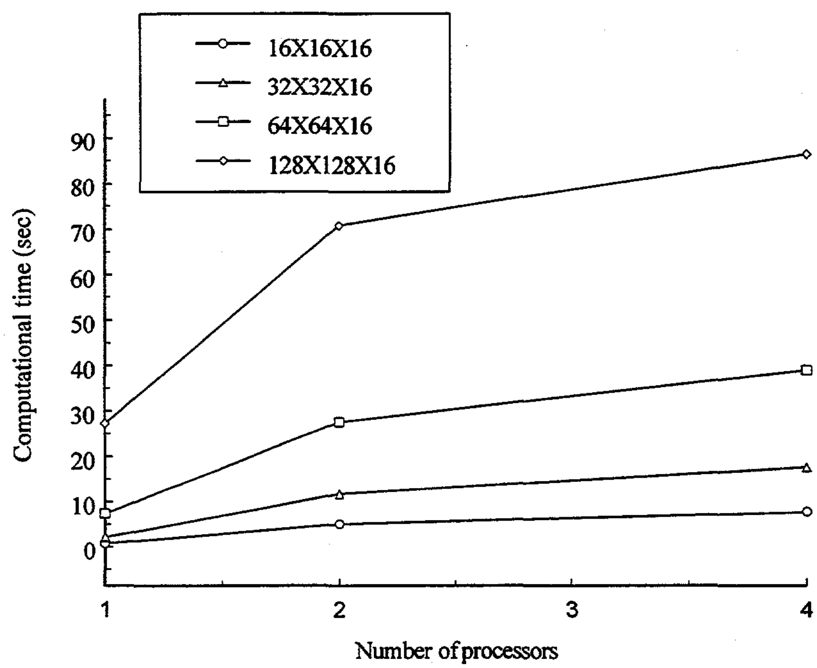


Fig. 3. Comparison of computational times for the solution of fracture pressure equations for the serial program (1 processor) and parallel program (2 & 4 processors) on IBM SP, a distributed memory machine (the four model grid configurations are shown in the explanation).

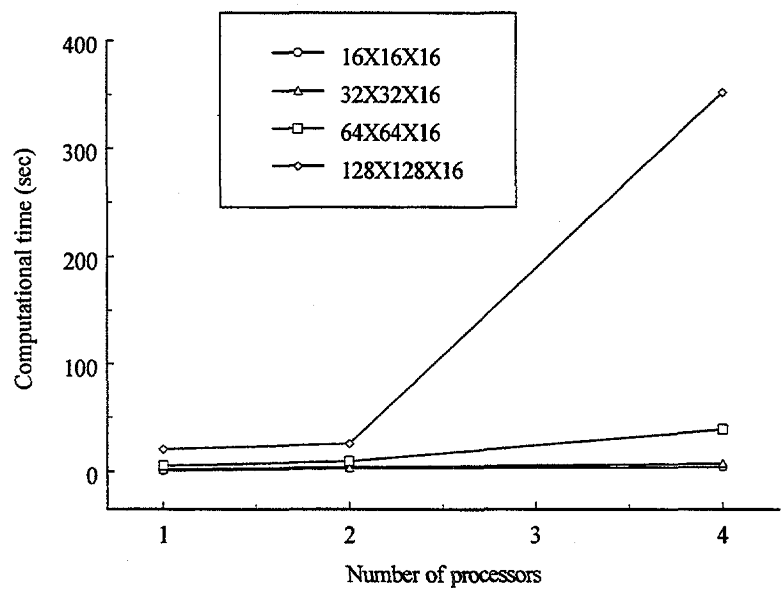


Fig. 4. Comparison of computational times for the solution of matrix pressure equations for the serial program (1 processor) and parallel program (2 & 4 processors) on IBM SP, a distributed memory machine (the four model grid configurations are shown in the explanation).

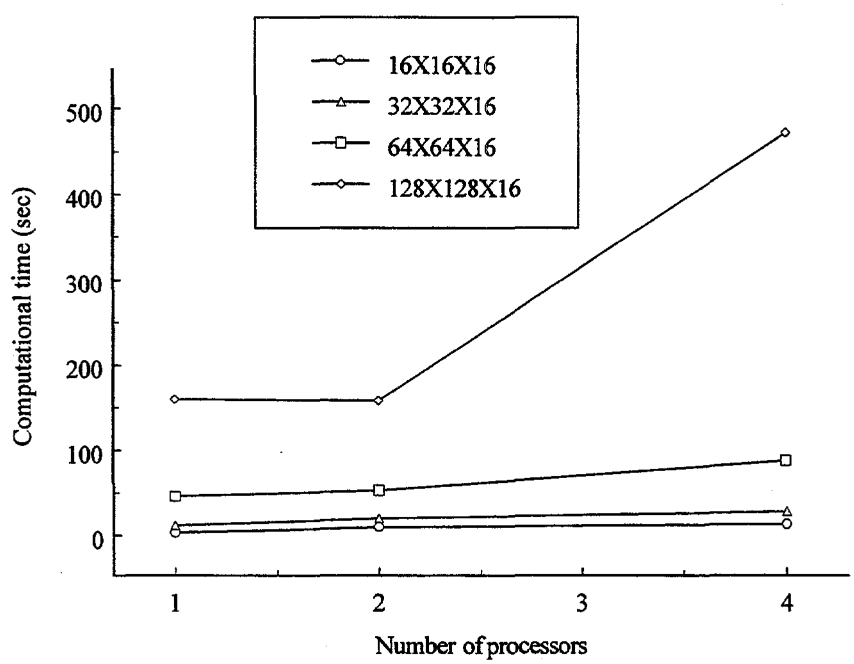


Fig. 5. Comparison of the total computational times for one time step for the serial program (1 processor) and parallel program (2 & 4 processors) on IBM SP, a distributed memory machine (the four model grid configurations are shown in the explanation).

# RECOMPLETION OF THE MALNAR PIKE 17-1 WELL

The recompletion of the Malnar Pike 17-1 well (sec. 17, T. 1 S., R. 1 E., UBM) was the second step in a three-well demonstration. The first well, Michelle Ute 7-1 (sec. 7, T. 1 S., R. 1 E.) was discussed in previous reports. The Michelle Ute was planned as a high-diversion, high-pressure, three-stage recompletion. Each stage, or interval, was intended to span about 500 vertical ft (150 m). Mechanical problems prevented a valid test of this recompletion technique. The Malnar Pike recompletion involved isolation, stimulation, and testing of much smaller intervals, treating at bed scale, or as close to bed scale as was practical. The intervals were isolated using a bridge plug at the base and a packer at the top of the test interval.

Four separate treatments and tests were applied. 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.

Dual burst thermal decay time (TDT), dipole shear anisotropy (anisotropy), and isotope tracer logs were used to identify beds for treatment and testing and for post-treatment evaluation.

## Test Number 1

The first interval stimulated and tested was from 13,366 to 13,470 ft (4073.9-4105.7 m) log depth (Fig. 6A). A temperature and spinner survey run early in the production history of the well, shows the perforated bed from 13,434 to 13,438 ft (4094.7-4095.9 m) was responsible for 17% of the oil production at that time. The TDT log shows this bed has a water saturation from 63 to 79%. The pre-treatment anisotropy log shows little to no fracturing in this bed. The perforated intervals 13,402 to 13,412 ft (4084.9-4087.9 m) and 13,486 to 13,494 ft (4110.5-4112.9 m) were identified as thief zones by the earlier temperature and spinner survey. The pre-treatment anisotropy log shows good fracture development in both thief zones. The perforated bed from 13,414 to 13,418 ft (4088.6-4089.8 m) has a water saturation of 25 to 40%. All the other perforated beds in the test interval have water saturation ranging from 62 to 79% as indicated on the TDT log.

The interval (13,366-13,470 ft [4073.9-4105.7 m]) was treated with 357 barrels (56,800 L) of hydrochloric acid (HCl) pumped at a maximum pressure of 7214 psi (49,700 kPa), an average pressure of 5500 psi (38,000 kPa), and at a maximum rate of 10 barrels per minute (bpm) (1600 Lpm). Communication occurred behind the casing (probably in the cement between the casing and the formation) above the packer and below the bridge plug. The communication can be identified on the isotope tracer (tracer number 1) and the post-treatment anisotropy logs (Fig. 6A). The communication greatly reduced the effectiveness of the treatment. Limited swab testing after the treatment recovered water. However, due to the communication it cannot be determined if the water is from the test interval or the beds above or below the test interval, or all of them.

Fig. 6A-6D. Portions of the cased-hole logs ran in the Malnar Pike 17-1demonstration well. Column A is a portion of the dipole shear anisotropy log run before acid treatment. The greater the separation of the two lines (shaded in) the greater the density of fractures. Column B is a gamma-ray curve for correlation and bed identification. Column C is the anisotropy log run after the acid treatments. Column D is from the isotope tracer log with the different tracers labeled 1, 2, and 3. The larger the curve, the more isotope left behind the casing, which helps determines where the acid went. The dual burst thermal decay time log (TDT) shows percent water saturation (Sw) in column E and column F diagrammatically shows oil (black) and water (white) in the pore volume of the rock.

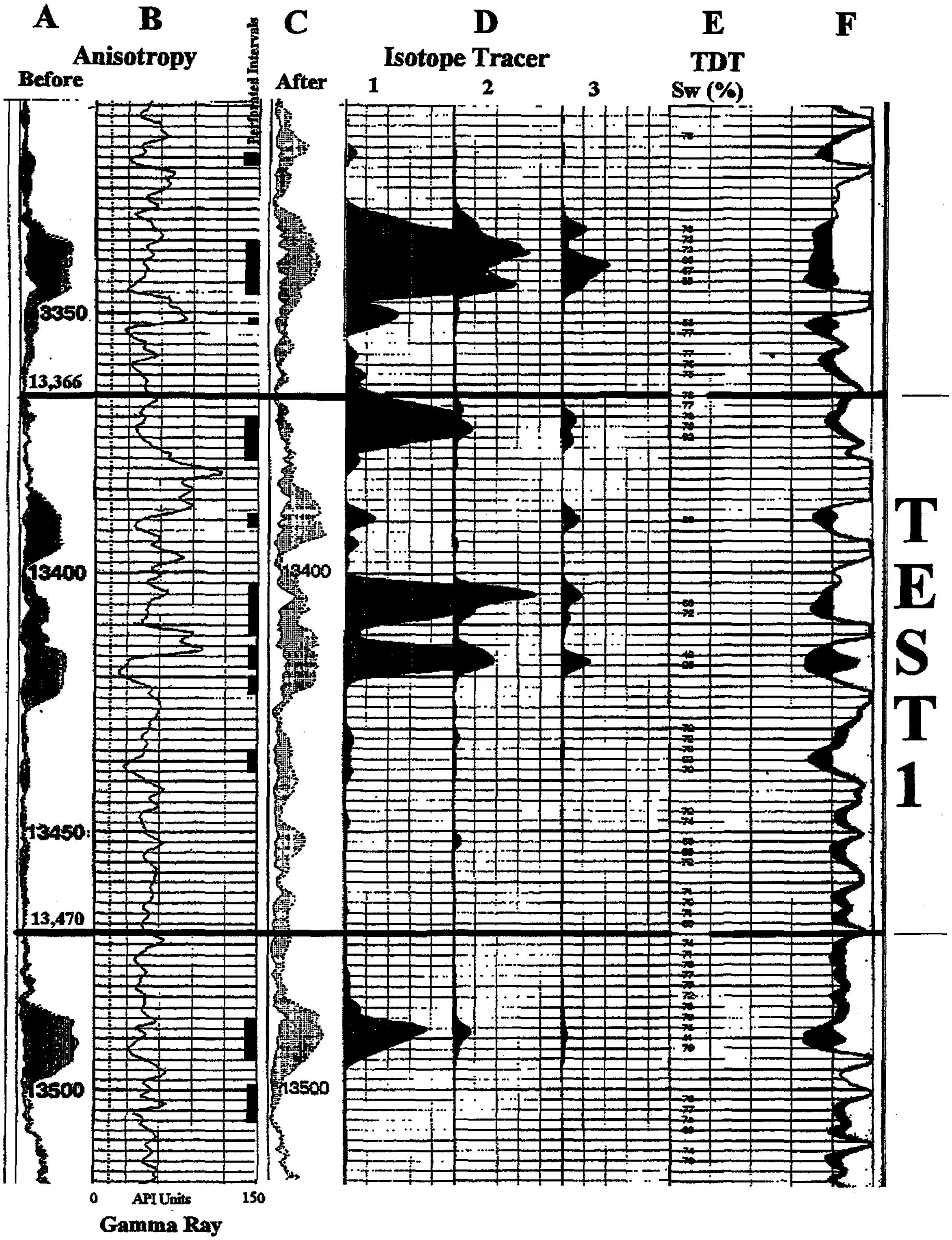
A
B
C
D
E
F
Anisotropy
Before
After
Perforated Intervals
Isotope Tracer
1
2
3
TDT
Sw (%)
13350
13,366
13400
13450
13,470
13500
0
API Units
150
Gamma Ray
TEST 1

Fig. 6A.

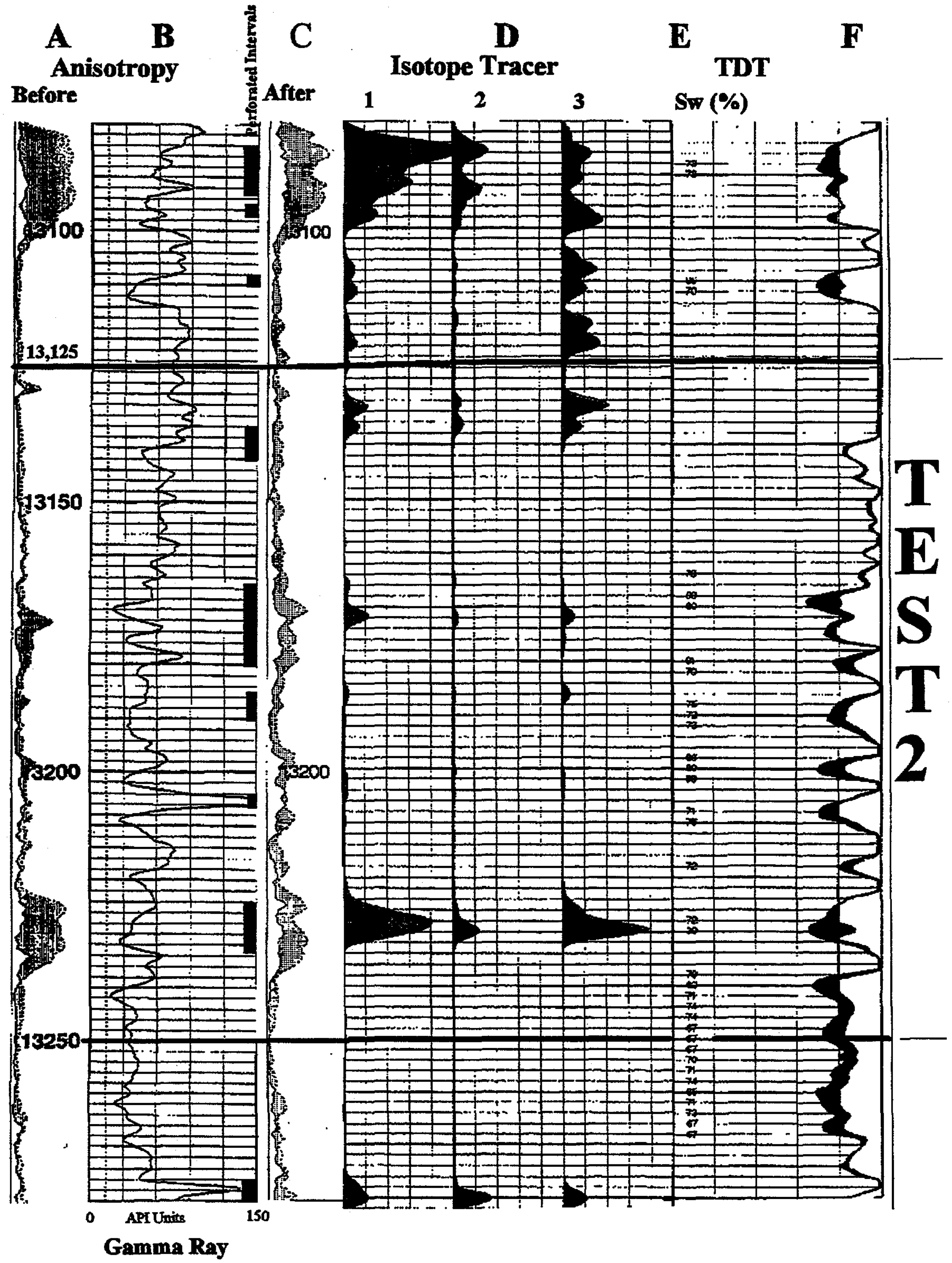
A
B
Anisotropy
Before
Perforated Intervals
C
After
D
Isotope Tracer
1
2
3
E
TDT
Sw (%)
F
13100
13,125
13150
13200
13250
TEST 2
0
API Units
150
Gamma Ray

Fig. 6B.

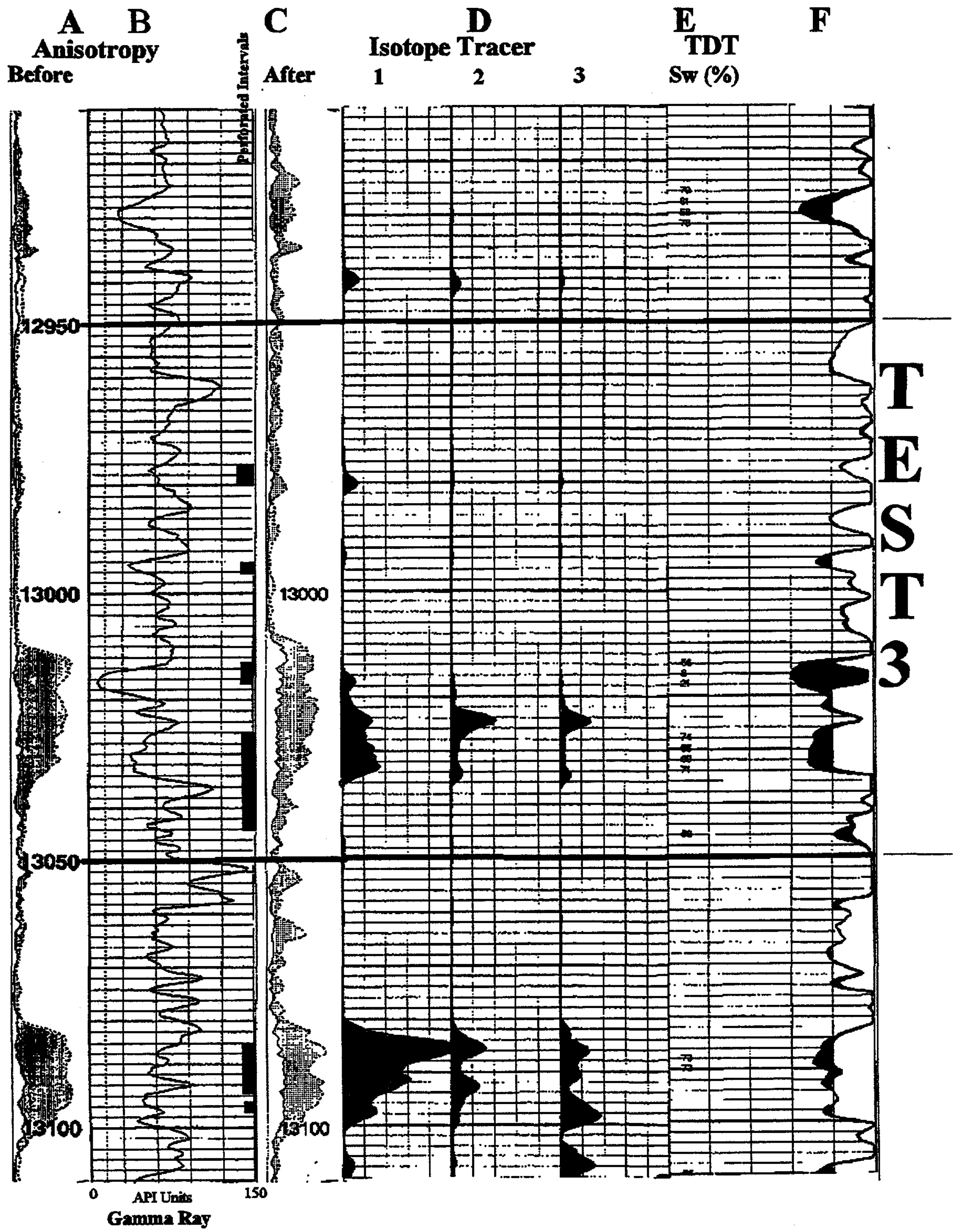
A B
Anisotropy
Before
Perforated Intervals
C
After
D
Isotope Tracer
1
2
3
E
TDT
Sw (%)
F
12950
13000
13050
13100
0
API Units
150
Gamma Ray
TEST 3

Fig. 6C.

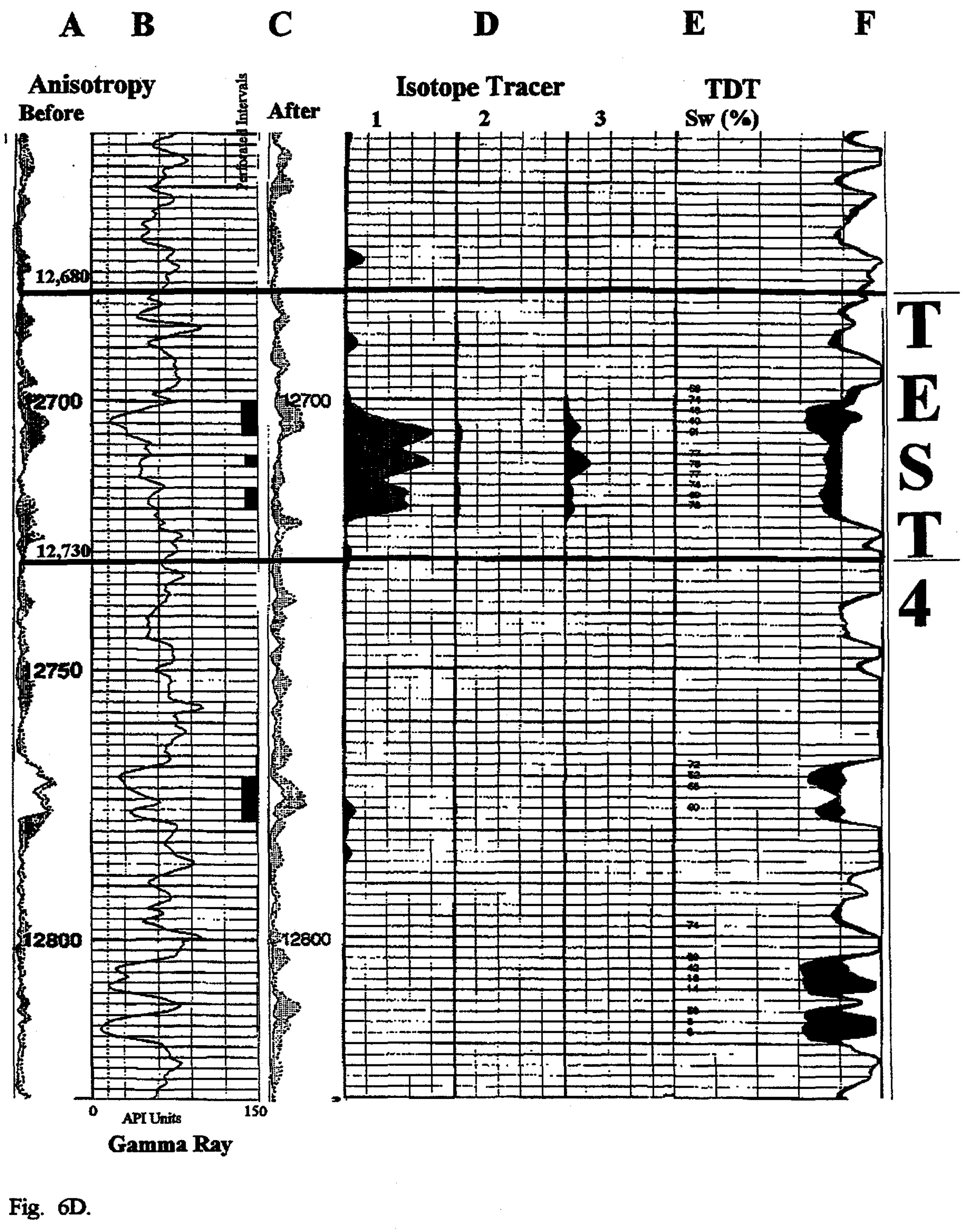
A
B
C
D
E
F
Anisotropy
Before
Perforated Intervals
After
Isotope Tracer
1
2
3
TDT
Sw (%)
12,680
12700
12,730
12750
12800
0
API Units
150
Gamma Ray
TEST 4

Fig. 6D.

## Test Number 2

The second interval stimulated and tested was from 13,125 to 13,250 ft (4000.5-4038.6 m) log depth (Fig. 6B). The pre-treatment anisotropy log shows two perforated intervals with well-developed fractures, 13,224 to 13,233 ft (4030.7-4033.4 m) and 13,165 to 13,180 ft (4012.7-4017.3 m). A 2-foot layer (13,228 to 13,230 ft [ 4031.9-4032.5 m]) has a water saturation of 39%. The other perforated intervals have water saturations ranging from 59% to more than 79% based on the TDT log.

The interval (13,125 to 13,250 ft [4000.5-4038.6 m]) was stimulated with 95 barrels (15,100 L) of HCl pumped at a maximum pressure of 6810 psi (46,900 kPa), an average pressure of 6000 psi (41,000 kPa), and at a maximum rate of 10.2 bpm (1,600 Lpm). Communication occurred behind the casing (probably in the cement between the casing and the formation) above the packer and possibly below the bridge plug. The communication can be identified on the isotope tracer (tracer number 3) and the post-treatment anisotropy logs (Fig. 6B). The communication greatly reduced the effectiveness of the treatment. Limited swab testing after the treatment recovered water, but once again because of the communication it cannot be determined if the water is from the test interval or the beds above or below the test interval, or all of them.

## Test Number 3

The third interval stimulated and tested was from 12,950 to 13,050 ft (3947.2-3977.6 m) log depth (Fig. 6C). The perforated interval 13,013 to 13,017 ft (3966.4-3967.6 m) has a water saturation ranging from 8 to 56% and the perforated interval 13,026 to 13,044 ft (3970.3-3975.8 m) has a water saturation ranging from 66 to 71% based on the TDT log. Although these two perforated intervals appear to be separate beds based on the gamma-ray log, the pre-treatment anisotropy log shows the beds communicate via fractures. Perforated intervals 12,994 to 12,996 ft (3960.6-3961.2 m) and 12,976 to 12,980 ft (3955.1-3956.3 m) have more than 80% water saturation and no fractures.

The interval (12,950 to 13,050 ft [3947.2-3977.6 m]) was stimulated with 72 barrels (11,400 L) of HCl pumped at a maximum pressure of 8203 psi (57,000 kPa), an average pressure of 6000 psi (41,000 kPa), and at a maximum rate of 10 bpm (1,600 Lpm). A minor amount of communication occurred below the bridge plug. The communication is identified on the isotope tracer (tracer number 2) and the post-treatment anisotropy logs. The upper perforated intervals do not appear to have taken any acid. The tracer log shows that the perforated intervals 13,013 to 13,017 ft (3966.4-3967.6 m) and 13,026 to 13,044 ft (3970.3-3975.8 m) are in communication as indicated on the pre-treatment anisotropy log. Limited swab testing after the treatment recovered a minor amount of oil, gas, and water.

## Test Number 4

The fourth interval stimulated and tested was from 12,680 to 12,730 ft (3864.9-3880.1 m) log depth (Fig. 6D). The perforated intervals 12,700 to 12,706 ft (3870.9-3872.8 m), 12,710 to 12,712 ft (3874.0-3874.6 m), and 12,716 to 12,720 ft (3875.8-3877.1 m), are in a coarsening-upward sequence with the best developed fracturing (pre-treatment anisotropy log) and lowest water saturation (40 to 48% on the TDT log) near the top of the sequence. The lower portion of the sequence has water saturations ranging from 69 to 78%.

The interval was stimulated with 71 barrels (11,300 L) of HCl pumped at a maximum pressure of 7200 psi (49,600 kPa), an average pressure of 6700 psi (46,200 kPa), and at a maximum rate of 9.6 bpm (1,500 Lpm). The isotope tracer (tracer number 1) and post-treatment anisotropy logs show little to no communication above or below the test interval (Fig. 6D). Limited swab testing after the treatment recovered a minor amount of oil, gas, and water.

## Preliminary Production Results

A bridge plug was placed at a depth of 13,060 ft (3980.7 m), above the first and second intervals that tested water. The daily oil-production rate has increased (Fig. 7) as a result of the treatment of the third and fourth intervals, but the well has not produced long enough to develop a stabilized production rate.

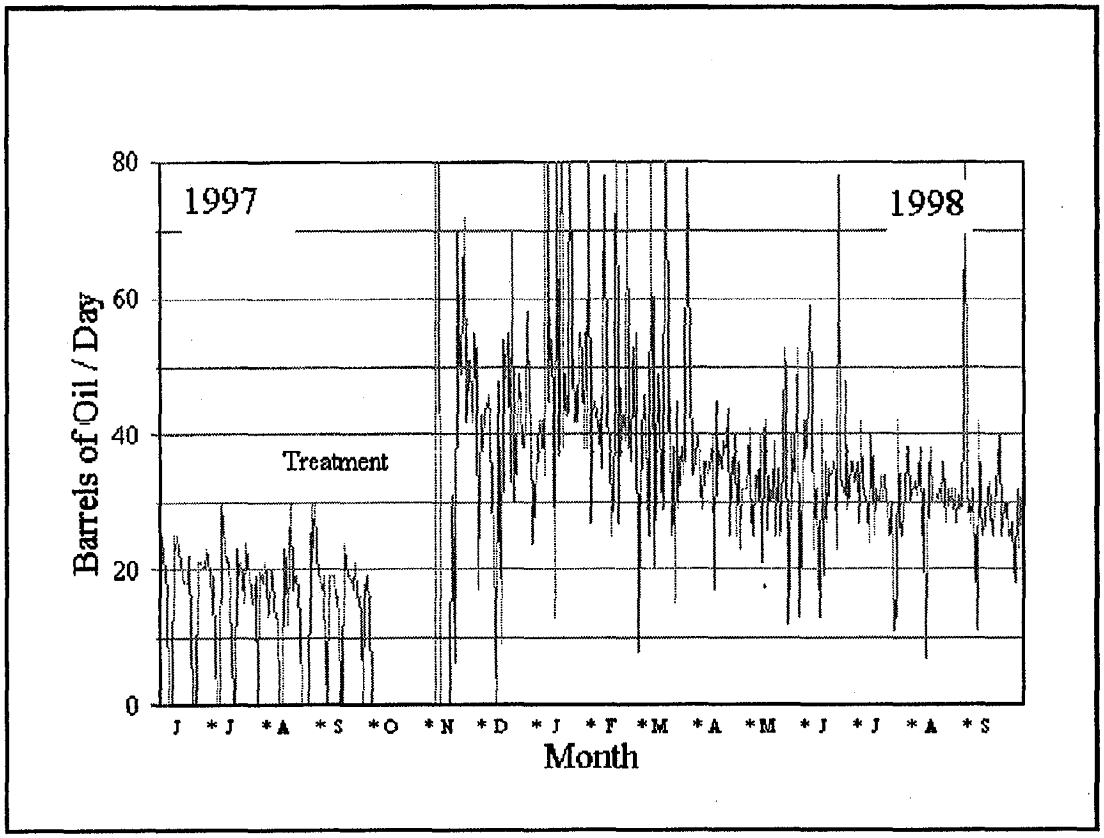


Fig. 7. Daily oil production from the Malnar Pike 17-1 demonstration well four months before and 11 months after the acid stimulation.

## Conclusions and Recommendations

Communication above and below the test intervals was a major problem. The Malnar Pike well has numerous perforations that have been acidized several times, increasing 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.

Test results generally confirmed the interpretation of the anisotropy and TDT logs. Beds with fractures indicated in the anisotropy log generally took most of the acid while beds without fractures took little to no acid. The low treating pressure (about 7000 psi [48,000 kPa] versus the normal treating pressure of 10,000 psi [69,000 kPa]) was not high enough to hydraulically induce new fractures.

To effectively use this completion technique on wells in the Bluebell field, based on the experience of the Malnar Pike demonstration, we recommend the following:

1. set both the packer and bridge plug between perforated intervals that are at least 50 ft (15 m) apart to reduce the risk of communication,
2. use the anisotropy and TDT logs to select beds that are fractured and have relatively low water saturation, and
3. use a treating pressure high enough to fracture the formation, especially if the anisotropy log indicates that some of the beds being treated do not have fractures.

## POST-TREATMENT ENGINEERING ANALYSIS OF THE MICHELLE UTE AND MALNAR PIKE WELLS

Two test intervals were evaluated in the Malnar Pike well: test interval 3, from 12,950 to 13,050 ft (3947.2-3977.6 m) and test interval 4 from 12,680 to 12,730 ft (3864.9-3880.1 m). A bridge plug was set at 13,060 ft (3980.7 m) so that the perforations below this depth are not contributing to production. After the treatment the oil production increased from about 20 barrels of oil per day (BOPD (2.8 MTPD)) to about 35 to 40 BOPD (4.9-5.6 MTPD).

The dual-porosity, dual-permeability model employed previously to match oil and gas production from Malnar Pike was modified to assess the treatment. Relevant matrix and fracture properties used in the model are presented in Table 1. The model aerial extent was 40 acres (16.2 ha). The well intersected 109 layers: 55 oil-bearing layers separated by 54 non-oil-bearing layers. Each of the layers was assigned an appropriate depth. A schematic of the model is shown in Fig. 8.

When measured water saturations were used in the model, water produced from the model was two times the actual water produced in the field. In order to match the field water production, water relative permeabilities were altered. The new set of relative permeabilities are shown in Table 2.

The cumulative oil, gas, and water production by October 1997 as predicted by the model are compared with the actual field totals in Table 3. As can be seen from the table, the agreement between the model predictions and field data is excellent. Even though this end-point history matches reasonably well, the oil, gas, and water production results from the model differ by varying degrees from the field results (Fig. 9, 10, and 11). The oil production from the field is still reasonably well matched; however, water and gas data could be improved. The history match is reasonable considering the complexity of the data set and the interdependency of data types.

The model predicted a total oil rate of 16 BOPD (2.2 MTPD) in October 1997. Several different strategies were attempted to match the post-treatment rate of about 40 BOPD (5.6 MTPD). Only the properties in the affected zones were changed at the treatment time. All of the strategies and corresponding rates after treatment are listed in Table 4. The treatment should have increased fracture permeabilities, extent of fracturing, and/or frequency of fracturing. Each of these options was examined either in isolation or in combination with other options. One final option of adding a new zone was also examined.

Table 4 demonstrates that it is possible to realize the gains in production by a variety of methods. Increasing the fracture permeability to 22 mD appears to provide the most realistic increase in production. However, in most of the strategies examined, the production rate decreases to about 25 BOPD (3.5 MTPD) after about six months. Only in the scenario where an equivalent new zone is added to the reservoir does the production remain steady at around 31 BOPD (4.3 MTPD) long after the zone is opened. The zone added to the model is 30 ft (9.1 m) thick with a porosity of 14% and an initial oil saturation of 70%. The zone has a matrix permeability of 1.5 mD and fracture permeability of 2.2 mD (properties of the older zones). Assuming only 3% recoverable oil from the zone (based on the performance of the well), about 27,000 BO (3780 MT) of net reserves were added the well.

The Michelle Ute model was also revised. Field water production from Michelle Ute is shown in Fig. 12. There are apparently two distinct regimes in the water production behavior. The water production rate was very low for about 2700 days of production (ending December 1992). Only about 5300 barrels of water (BW [742 MT]) were produced to this point. The rate drastically increased at this time and the total production reached about 25,000 BW (3500 MT) at 4600 days of production (June 1998). In order to match this behavior, two sets of water relative permeabilities were employed; a set for the first 2700 days and a different set after 2700 days. These relative permeabilities are shown in Table 5. Treatment of the Michelle Ute did not change the oil production rates over the long term. The effect of the treatment from a modeling point of view is currently being examined.

Table 1. Parameters for the Malnar Pike model.

| Parameter | Value |
|---|---|
| Modeled depth (ft) | 9582 - 14,360 |
| Grid description (blocks) | 8 x 8 x 109 |
| Grid block size in the x and y dimensions (ft) | 165 |
| Grid size in the z-dimension (ft) | Variable |
| Porosity % | 0 - 22 |
| Matrix permeability (mD) | 0.1 - 2.5 |
| Fracture porosity % | 0.0002 |
| Fracture permeability (mD) | 0.02 - 22 |
| Fracture frequency - one fracture every (ft) | 10 |
| Pressure (depth dependent)(psi/ft) | 0.5 |
| Initial oil saturation | 0.1 - 0.8 |
| Initial gas/oil ratio (scf/stb) | 1100 |
| Initial bubble point pressure (psi) | 4795 |

*psi = pounds per square foot*
*scf = standard cubic feet*
*stb = stock tank barrels*

Table 2. Relative permeabilities (mD) used to obtain the history match for the Malnar Pike well.

| Water Saturation (%) | Relative permeability to water | Relative permeability to oil |
|---|---|---|
| 22 | 0.0 | 1.0 |
| 30 | 0.05 | 0.1 |
| 35 | 0.1 | 0.05 |
| 40 | 0.15 | 0.0175 |
| 50 | 0.5 | 0.0073 |
| 60 | 0.7 | 0.005 |
| 80 | 0.9 | 0.003 |
| 90 | 0.96 | 0.001 |
| 100 | 1.0 | 0.0 |

Table 3. Production match between the model and field data for the Malnar Pike well.

| | Production as of December 1993 | | Production as of October 1997 | |
|---|---|---|---|---|
| | Field Data | Model Predictions | Field Data | Model Predictions |
| Oil (Mstb) | 93 | 100 | 113 | 125 |
| Gas (MMscf) | 79 | 87 | 96* | 119 |
| Water (Mstb) | 100 | 102 | 122* | 110 |

* -extrapolated from available data

Table 4. Different strategies used in emulating the treatment in the Malnar Pike well.

| Strategy | Production rate immediately after treatment (stb/day) | Production rate 4 months after treatment (stb/day) |
|---|---|---|
| 1. Increase fracture permeability in affected zones from 2.2 to 22 mD | 39 | 25 |
| 2. Increase extent of fracturing in the affected zones from 495 ft to 660 ft | 29 | 22 |
| 3. Combine strategies 1 and 2 | 35 | 23 |
| 4. Increase fracture frequency to one every 5 ft | 41 | 24 |
| 5. Add a new zone 12 ft thick of porosity 10% and oil saturation 70% | 39 | 31 |

Table 5. Relative permeabilities (mD) used in matching water production from the Michelle Ute well over the entire time interval.

| Water Saturation (%) | Water relative permeability for the first 2700 days | Water relative permeability after 2700 days | Oil relative permeability |
|---|---|---|---|
| 22 | 0.0 | 0.0 | 1.0 |
| 30 | 0.0 | 0.0 | 0.7 |
| 40 | 0.0 | 0.0 | 0.4 |
| 50 | 0.003 | 0.02 | 0.3 |
| 60 | 0.009 | 0.06 | 0.05 |
| 80 | 0.015 | 0.1 | 0.03 |
| 90 | 0.021 | 0.14 | 0.0 |
| 100 | 0.03 | 0.2 | 0.0 |

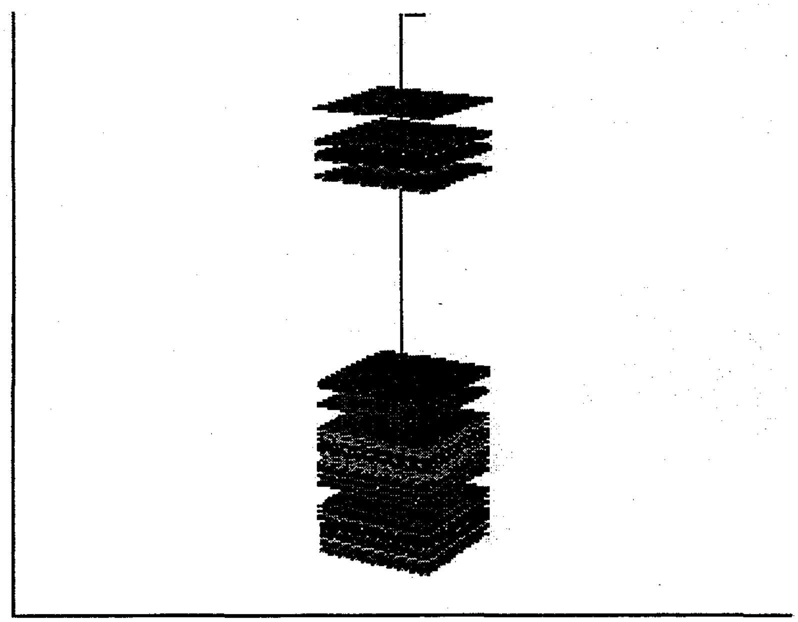

Fig. 8. Schematic of the 109-layer Malnar Pike model. Plot covers drill depth from 9582 to 14,350 ft.

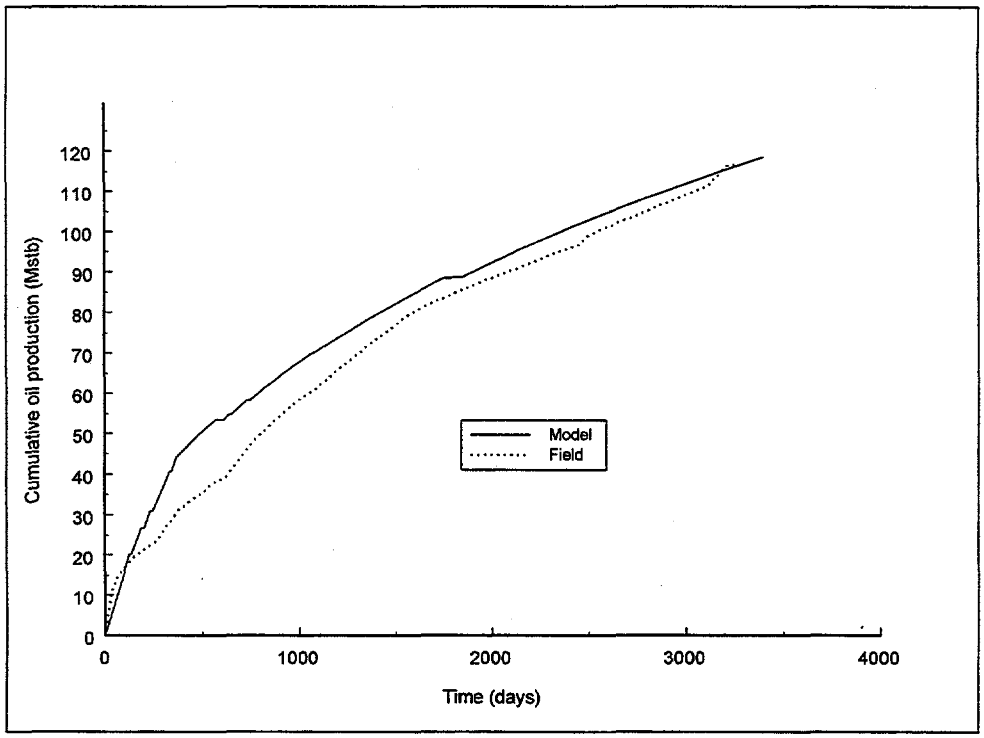


**Fig. 9. Comparison of cumulative oil production from Malnar Pike well with the model**

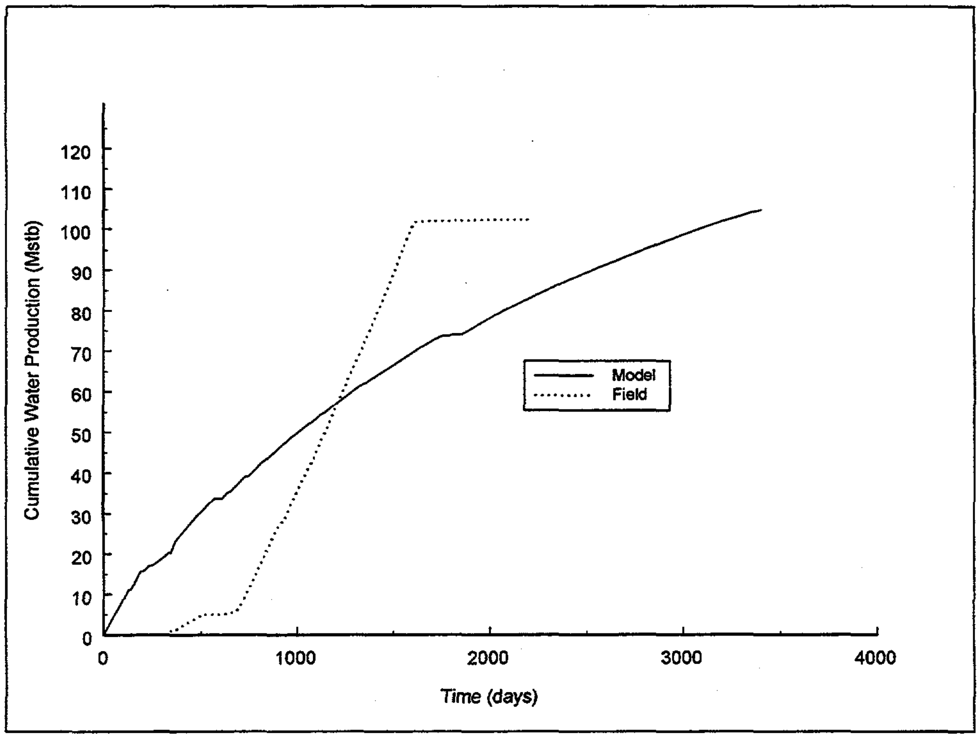


**Fig. 10. Comparison of cumulative water production from Malnar Pike well with the model**

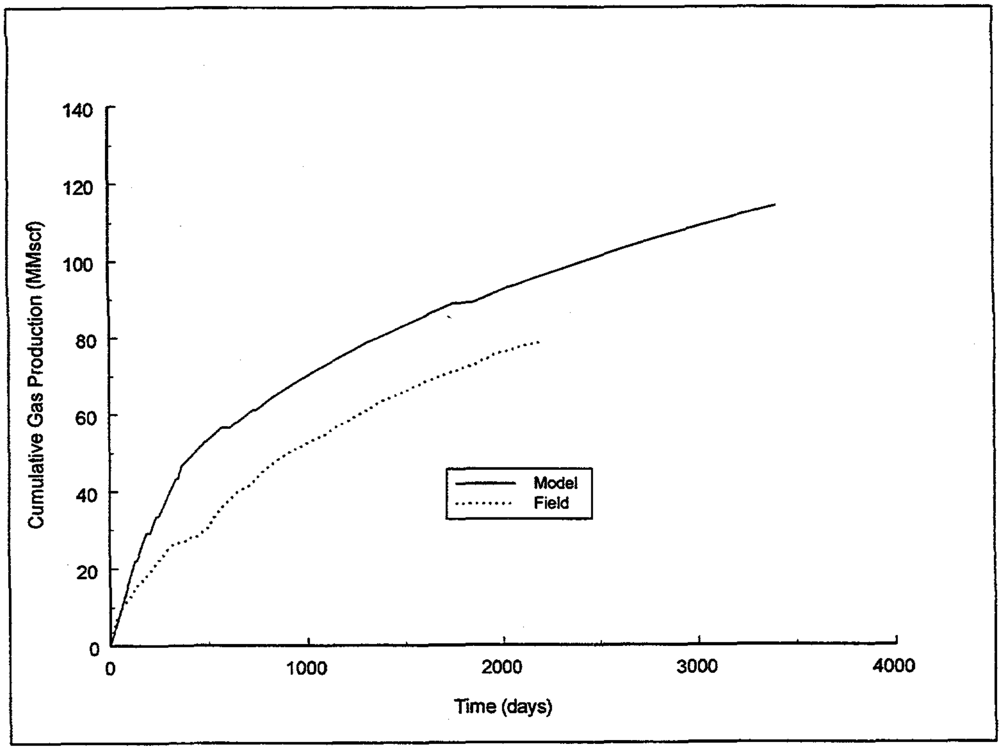


**Fig. 11. Comparison of cumulative gas production from Malnar Pike well with the model**

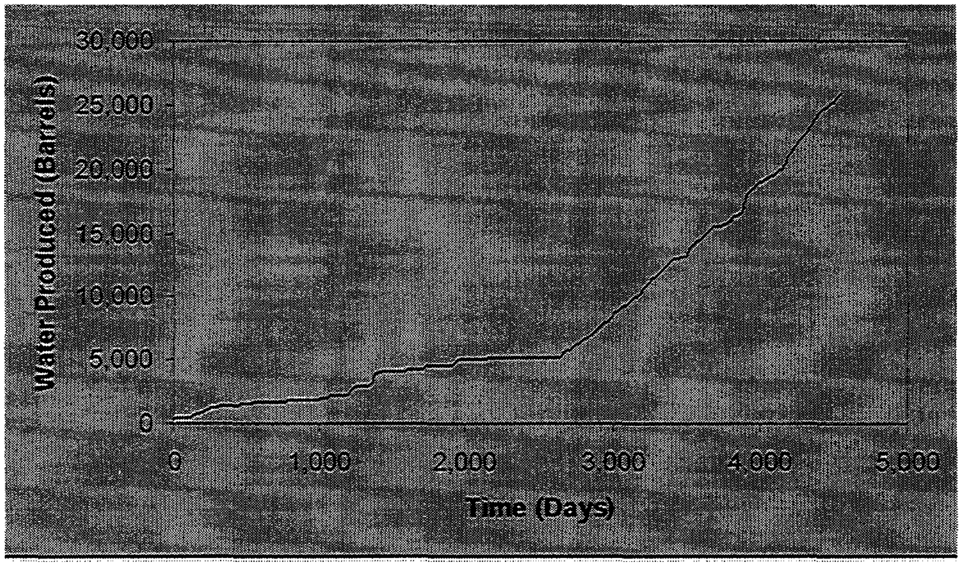


**Fig. 12. Water produced from the Michele Ute well; observe the sharp transition at around 2700 days.**

## DRILLING AND COMPLETION OF THE JOHN CHASEL 3-6A2 WELL

The completion of the John Chasel 3-6A2 well (section 6, T. 1 S., R. 2 W., UBM) is the third, and final, demonstration. The well was stimulated with two separate acid treatments but poor cement followed by partial collapse of the casing has delayed the completion of the well.

Most wells in the Bluebell field are completed by perforating 40 to 60 or more beds. Perforations are usually selected based on drilling shows with minor reliance on geophysical well logs. The objective of completing the 3-6A2 well was to use geophysical well logs to select far fewer beds for completion, hopefully reducing completion costs, increasing the production rate, and greatly reducing the volume of water produced. Nineteen beds between 14,574 to 15,746 ft (4445.1- 4802.5 m) gross vertical interval were selected for perforating (Table 6), 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.

Table 6. Evaluation of proposed perforations for the John Chasel 3-6A2 well. Bed numbers shown on the cross section (Fig. 15).

| ***Stage*** | ***Bed*** | ***Drill Depth (ft)*** | ***Drilling Show*** | ***Resistivity (ohm-m)*** | ***Percent Porosity (D+N/2)*** | ***Fractures (Shear anisotropy)*** | ***Oil Saturation (TDT)*** |
|---|---|---|---|---|---|---|---|
| One | 1 | 15,788-91 | gas | 50 | 4 | poor | poor-fair |
| | 2 | 15,746-49 | oil | 30 | 5 | poor | poor |
| | 3 | 15,732-34 | oil | 50 | 4.5 | poor | fair |
| | 4 | 15,660-62 | gas | 25 | 3 | poor | poor |
| | 5 | 15,620-25 | gas | 22 | 7.5 | none | wet |
| | 6 | 15,519-21 | gas | 17 | 10 | poor | excellent |
| | 7 | 15,384-87 | none | 28 | 6.5 | base of fracture | good |
| | 8 | 15,334-41 | gas | 65 | 7.5 | poor | excellent |
| | 9 | 15,306-14 | oil | 28 | 6 | poor | good |
| | 10 | 15,226-30 | gas | 15 | 8 | fair | excellent |
| | 11 | 15,191-95 | oil | 25 | 10 | fair | poor-fair |
| | 12 | 15,130-36 | oil | 25 | 7 | very good | wet-trace of oil |

| *Stage* | *Bed* | *Drill Depth (ft)* | *Drilling Show* | *Resistivity (ohm-m)* | *Percent Porosity (D+N/2)* | *Fractures (Shear anisotropy)* | *Oil Saturation (TDT)* |
|---|---|---|---|---|---|---|---|
| Two | 13 | 15,035-45 | gas | 40 | 12 | good | very good |
| | 14 | 14,925-29 | gas | 45 | 10.5 | poor | excellent (highest oil saturation) |
| | 15 | 14,814-16 | gas | 20 | 7.5 | good | fair |
| | 16 | 14,752-58 | gas | 25 | 5 | poor-fair | poor-fair |
| | 17 | 14,710-14 | oil (best show) | 25 | 5 | poor | poor-fair |
| | 18 | 14,608-12 | gas | 35 | 8 | good | poor |
| | 19 | 14,574-77 | oil (start of strong oil shows) | 20 | 8 | fair-good | excellent |

## Drilling and Logging

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) (Fig. 13). The well appears to have penetrated a small overturned, repeated section within the Flagstaff (Fig. 14) resulting in a slightly higher than expected structural elevation at the top of the Flagstaff (Fig. 15). The 3-6A2 well is the second deep well in the section and like most second wells it appears to have been partially depleted. 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). In this part of the Bluebell field the first wells typically required 14 lbs/gal (1.7 kg/L) drilling mud.

Open-hole geophysical well logging consisted of dual induction, compensated neutron lithodensity, dipole shear anisotropy, gamma ray, and spontaneous potential. The TDT log was run after the hole was cased.

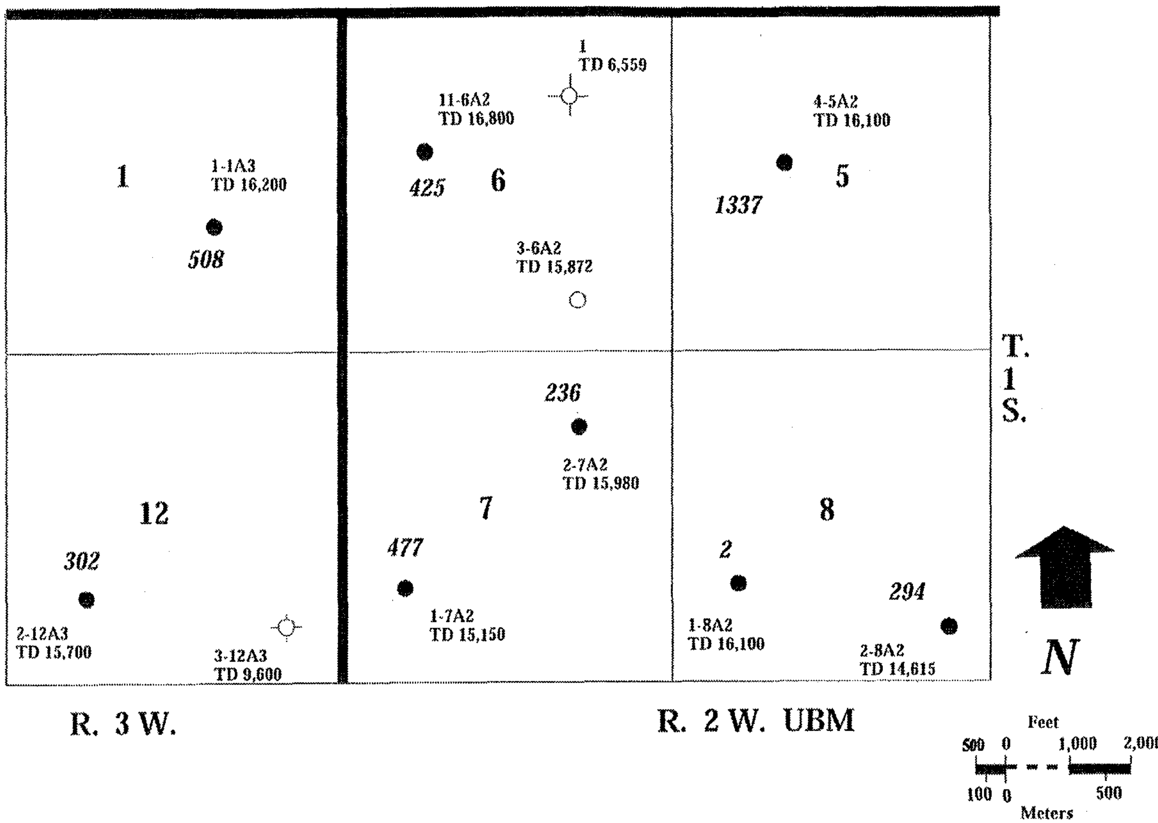


Fig. 13. Cumulative oil production from wells near the Chasel 3-6A2 demonstration well. Total depth (TD) is reported in ft. Production is shown in thousands of barrels of oil as of June 30, 1998. Data source: Utah Division of Oil, Gas and Mining.

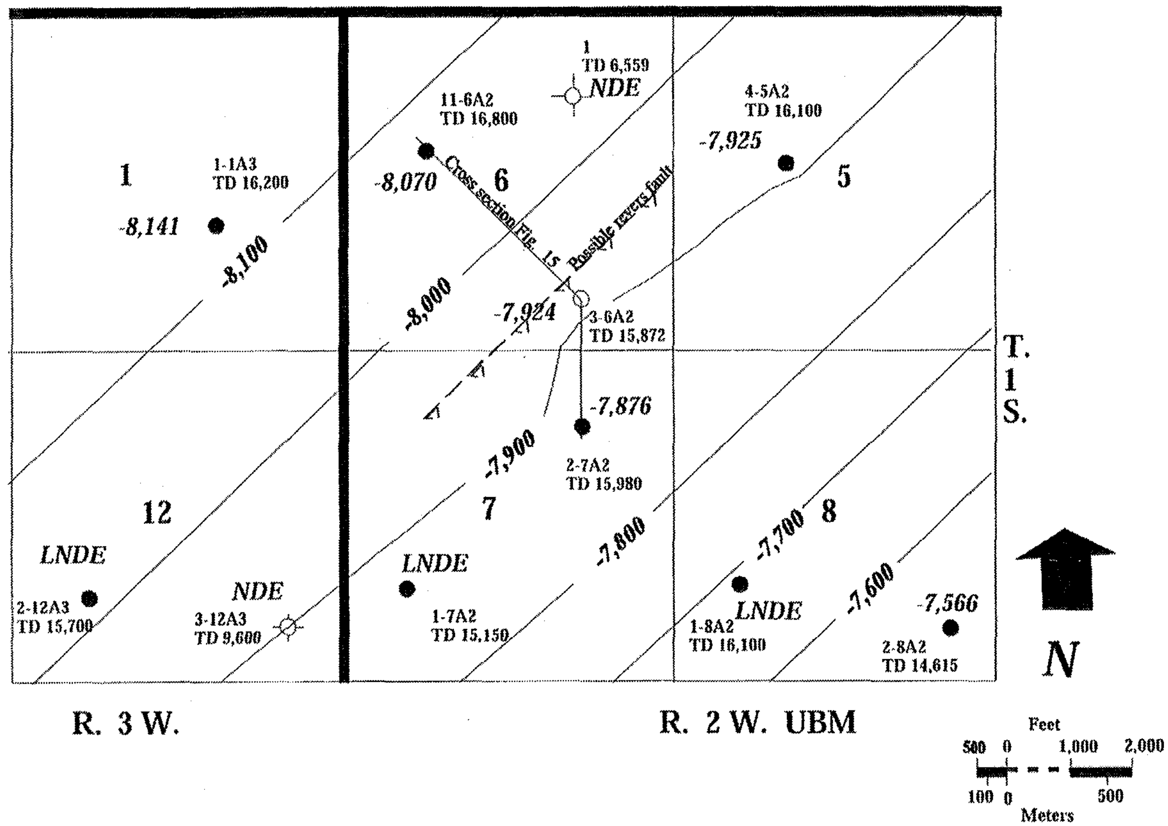


Fig. 14. Structure contours top of the Flagstaff Member of the Green River Formation (sea level datum, contour interval 100 ft.) NDE = not deep enough, LNDE = logs not deep enough. The cross section is shown in Fig. 15.

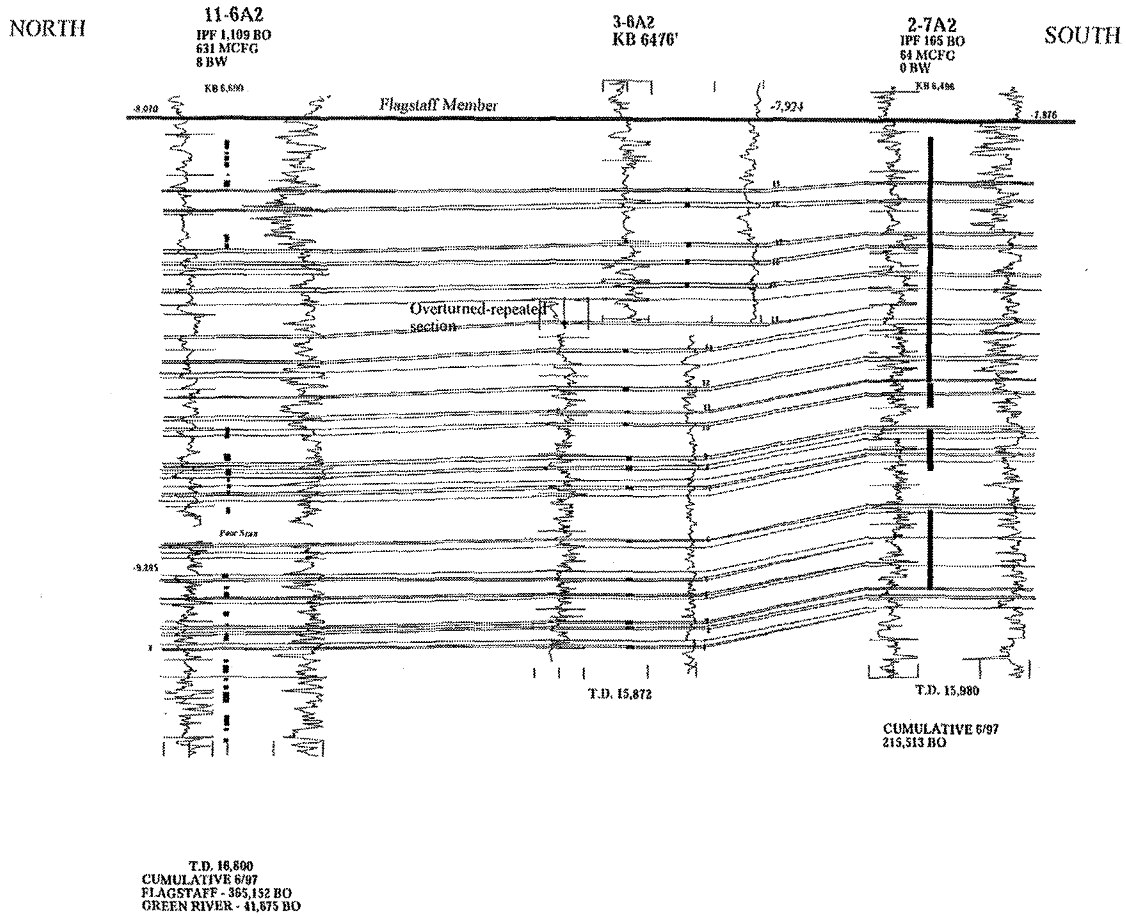


Fig. 15. North to south cross section through the Chasel 3-6A2 demonstration well using gamma-ray and resistivity curves. The cross section covers the portion of the Flagstaff Member of the Green River Formation that is perforated in the 3-6A2 well. Correlation lines show the original 19 beds perforated (see Table 6 for details) in the 3-6A2 well. Horizontal lines on the gamma-ray curve are 100-ft depth marks, horizontal distance not to scale.

## Treatment and Testing

The 3-6A2 well was completed 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. The first treatment consisted of 5500 gal (20,815 L) of 15% HCL at a maximum pressure of 10,000 psi (68,950 kPa), an average pressure of 6750 psi (46,550 kPa), a maximum rate of 15 bbl/min (2350 L/min) and an average rate 12.3 bbl/min (1950 L/min). Communication occurred behind the casing around the packer with 85 bbl (13,500 L) pumped. The well was swabbed for a day, recovering acid water estimated to be 5 to 6% oil cut. The second treatment consisted of 6500 gal (24,600 L) of 15% HCL at a maximum pressure of 10,007 psi (68,990 kPa), an average pressure of 8000 psi (55,160 kPa), a maximum rate of 19.7 bbl/min (3100 L/min), and an average rate of 14.5 bbl/min (2300 L/min).

The isotope tracer log indicated that most of the acid went into perforated and nonperforated beds from 15,130 to 15,340 ft (4611.6-4675.6 m). The log showed extensive communication behind the casing in this interval. Limited swab testing recovered acid water and no oil. Based on this test the operator believed the well was producing water. A fluid entry log was run which showed fluid entry at 15,191 to 15,195 ft (4633.3-4628.9 m) and 15,224 to 15,227 ft (4643.3-4648.2 m), and 18 bbl/day (2,850 L/day) being taken from 15,305 to 15,313 ft (4668.0-4663.9 m). A bridge plug was set at 15,320 ft (4672.6 m) and a retainer at 15,000 ft (4575.0 m). The interval that included perforated beds 9 through 19 (table 6) was cement squeezed. The cement, which was tagged at 14,172 ft (4322.5 m), was drilled out. Beds 13 through 17 and bed 19 were reperforated and beds 1 through 8 were below the cement, leaving a total of 14 beds open to the wellbore.

The well was swabbed recovering mostly oil. The entire perforated interval was acidized with 12,000 gal (45,420 L) of 15% HCL at a maximum pressure of 10,000 psi (68,950 kPa), an average pressure of 8,700 psi (59,950 kPa), at a maximum rate of 6.7 bbl/min (1050 L/min), and an average rate of 5.4 bbl/min (850 L/min). Post-treatment 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. They discovered that the casing was partially collapsed at 15,354 ft (4682.9 m) and 15,573 ft (4749.8 m) with a tight spot that had to be swedged at 14,700 ft (4480.6 m).

A retainer was set at 15,400 ft (4693.9 m) and cement was dumped on top of the retainer to a depth of 15,355 ft (4680.2 m), cutting off the lower seven perforated beds. Swab testing of the remaining seven perforated beds is continuing.

## TECHNOLOGY TRANSFER

A presentation highlighting the cased-hole logging techniques used in the first two demonstrations was made at the Department of Energy/Petroleum Technology Transfer Council-sponsored workshop in Denver, Colorado., in January 1998.

Exhibits from the Bluebell project were displayed at the UGS booth at Vernal Petroleum Days in Vernal, Utah, April 12-14, and the AAPG National Convention in Salt Lake City, Utah, April 17-20.

A poster display entitled *Second field demonstration of completion techniques in a (DOE Class I) fluvial-dominated deltaic lacustrine reservoir, Uinta Basin, Utah,* by Craig D. Morgan was presented at the AAPG Annual Convention in Salt Lake City, Utah, April 19.

A paper entitled *Bluebell field, Uinta Basin: Reservoir characterization for improving well completion and oil recovery,* by Scott L. Montgomery (AAPG) and Craig D. Morgan (UGS) was published in the AAPG Bulletin, June 1998, v. 82, no. 6, p. 1113-1132.

The Utah Geological Survey 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 are 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. The home page address is ***http://www.ugs.state.ut.us/bluebell.htm***

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