

YEARLY TECHNICAL PROGRESS REPORT
(8th Year – 2002-2003)

**ADVANCED OIL RECOVERY TECHNOLOGIES FOR IMPROVED
RECOVERY FROM SLOPE BASIN CLASTIC RESERVOIRS,
NASH DRAW BRUSHY CANYON POOL, EDDY COUNTY, NM**

DOE Cooperative Agreement No. DE-FC-95BC14941

Strata Production Company
P.O. Box 1030
Roswell, NM 88202
(505) 622-1127

| | |
|--|--|
| Date of Report: | October 31, 2003 |
| Award Date: | September 25, 1995 |
| Anticipated Completion Date: | September 24, 1998 - Budget Period I June 30, 2004 - Budget Period II |
| Award Amount for Current Fiscal Year: | \$2,017,435 |
| Award Amount for Budget Period II: | \$5,013,760 |
| Name of Project Manager: | Mark B. Murphy |
| Contracting Officer's Representative: | Dan Ferguson |
| Reporting Period: | October 1, 2002-September 30, 2003 |

US/DOE Patent Clearance is not required prior to the publication of this document.

DISCLAIMER

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

TABLE OF CONTENTS

| | |
|------------------------------------|----|
| LIST OF FIGURES | ii |
| OBJECTIVE | 1 |
| ABSTRACT | 1 |
| EXECUTIVE SUMMARY | 2 |
| INTRODUCTION | 3 |
| RESULTS AND DISCUSSION | 3 |
| Reporting | 3 |
| Workovers | 4 |
| Nash Draw #33 | 4 |
| Nash Draw #33 Deepening | 8 |
| Nash Draw #36 | 8 |
| Nash Draw #36 Deepening | 8 |
| Nash Draw#34 | 9 |
| 3-D Seismic. | 9 |
| Dip Calibration | 11 |
| Gas Processing and Injection | 11 |
| Data and Databases | 12 |
| Other Applications | 12 |
| Internet Homepage | 13 |
| Technology Transfer | 13 |
| Experimental Results | 13 |
| CONCLUSIONS..... | 13 |
| REFERENCES | 14 |

LIST OF FIGURES

| | |
|--|----|
| Fig. 1. Nash Draw #33 seismic target. | 16 |
| Fig. 2. Nash Draw #33 well path. | 16 |
| Fig. 3. Nash Draw #33 proposed deepening. | 17 |
| Fig. 4. Nash Draw #36 proposed deepening. | 17 |
| Fig. 5. Nash draw #34 proposed wellbore path. | 18 |
| Fig. 6. Second generation 3-D seismic Bone Spring structure map. | 18 |
| Fig. 7. Dip using well control. | 19 |
| Fig. 8. Dip using first generation #-D seismic survey. | 19 |
| Fig. 9. Dip using second generation 3-D seismic survey..... | 19 |
| Fig. 10. Nash Draw D.O.E. wells cumulative production through 7-1-03. | 20 |

OBJECTIVE

The overall objective of this project is to demonstrate that a development program based on advanced reservoir management methods can significantly improve oil recovery at the Nash Draw Pool (NDP). The plan includes developing a control area using standard reservoir management techniques and comparing its performance to an area developed using advanced reservoir management methods. Specific goals are (1) to demonstrate that an advanced development drilling and pressure maintenance program can significantly improve oil recovery compared to existing technology applications and (2) to transfer these advanced methodologies to oil and gas producers in the Permian Basin and elsewhere throughout the U.S. oil and gas industry.

ABSTRACT

The Nash Draw Brushy Canyon Pool (NDP) in southeast New Mexico is one of the nine projects selected in 1995 by the U.S. Department of Energy (DOE) for participation in the Class III Reservoir Field Demonstration Program. The goals of the DOE cost-shared Class Program are to: (1) extend economic production, (2) increase ultimate recovery, and (3) broaden information exchange and technology application. Reservoirs in the Class III Program are focused on slope-basin and deep-basin clastic depositional types.

Production at the NDP is from the Brushy Canyon formation, a low-permeability turbidite reservoir in the Delaware Mountain Group of Permian, Guadalupian age. A major challenge in this marginal-quality reservoir is to distinguish oil-productive pay intervals from water-saturated non-pay intervals. Because initial reservoir pressure is only slightly above bubble-point pressure, rapid oil decline rates and high gas/oil ratios are typically observed in the first year of primary production. Limited surface access, caused by the proximity of underground potash mining and surface playa lakes, prohibits development with conventional drilling.

Reservoir characterization results obtained to date at the NDP show that a proposed pilot injection area appears to be compartmentalized. Because reservoir discontinuities will reduce effectiveness of a pressure maintenance project, the pilot area will be reconsidered in a more continuous part of the reservoir if such areas have sufficient reservoir pressure. Most importantly, the advanced characterization results are being used to design extended-reach/horizontal wells to tap into predicted "sweet spots" that are inaccessible with conventional vertical wells.

The activity at the NDP during the past year has included the completion of the NDP Well #36 deviated/horizontal well, the drilling of the NDP Well #33 and the completion of additional zones in four wells, the design of the NDP #34 directional/horizontal well, the completion of the north 3-D seismic survey extension and the interpretation and analysis of data.

EXECUTIVE SUMMARY

The use of the Advanced Log Analysis techniques developed from the NDP project has proven useful in defining additional productive zones and refining completion techniques. The Advanced Log Analysis program proved to be especially helpful in locating and evaluating potential recompletion intervals, which has resulted in low development costs with only small incremental increases in lifting costs. To develop additional reserves at lower costs, zones behind pipe in existing wells were evaluated using techniques developed for the Brushy Canyon interval. Log analysis techniques developed in Phase I have been used to complete a total of thirteen of the NDP wells in uphole zones. Four wells were recompleted in 1999, which allowed the development of economical reserves during a period of low crude oil prices. An additional four wells were recompleted during 2000, which resulted in 123,462 BO and 453,424 MCFG reserves being added at a development cost of \$1.57 per B.O.E. Two wells, #29 and #38 were recompleted in 2001 which added 7,000 BO and 18 MMCFG to the reserves at a cost of \$9.70 per BOE. NDP Wells #1, #12, #15 and #20 were completed in uphole zones during 2002-03 which added 128,000 BO and 150 MMCFG to the reserves at a cost of \$1.64 per BOE.

The NDP #36 well toe zone was completed in October 2001, then restimulated in April 2002. During the workover an additional zone in the deviated section of the well was added. Cumulative production through August 2003 is 94,036 BO, 258.2 MMCFG and 43,693 BW.

The NDP #33 well toe zone and "H" zone were completed in December 2002. Cumulative production through August 2003 is 29,996 BO, 114.5 MMCFG and 86,000 BW.

Continued interpretation of the original 3-D seismic survey using the results from drilling NDP Well #36 and #33 has resulted in a more complete characterization of the Brushy Canyon reservoir. The new 3-D seismic survey has refined the original interpretation and added at least two (2) targets for additional development.

INTRODUCTION

The Nash Draw Pool (NDP) in Eddy County, New Mexico produces oil and associated gas from the Permian (Guadalupian) Brushy Canyon Formation. The Brushy Canyon is a relatively new producer in the Delaware Basin of West Texas, with most drilling having occurred since the late 1980s and many discoveries occurring in the 1990s. Regionally, the fine-grained sandstones of the Brushy Canyon contain as much as 400–800 MMbbls of oil-in-place and thus this formation represents a significant reservoir interval in the Permian Basin. However, low permeability and petrophysical heterogeneity limit primary recovery to only 10-16%.

The NDP is one of the project sites in the Department of Energy (DOE) Class III field demonstration program for slope-basin clastic reservoirs. The objective of the NDP Class III project is to demonstrate that an advanced development drilling and pressure maintenance program can significantly improve oil recovery compared to existing technology applications. A further goal of the project is to transfer these advanced methodologies to oil and gas producers in the Permian Basin and elsewhere throughout the U.S. oil and gas industry.

In the first phase of the NDP project, an integrated reservoir characterization study was performed to better understand the nature of Brushy Canyon production and to explore options for enhanced recovery. Results obtained in the NDP project indicate that a combination of early pressure maintenance (gas injection) and secondary carbon dioxide flooding may maximize production in these complex, laterally variable reservoirs. Because of low permeabilities involved and high water-to-oil relative permeabilities, the use of gas instead of water is suggested as preferable as an oil-mobilizing agent.

Phase II is directed toward enhancing the ultimate recovery from the project. The plan includes directional/horizontal drilling of new wells in order to develop reserves under surface-restricted areas and potash mines and evaluation of prospects of early pressure maintenance.

RESULTS AND DISCUSSION

This is the eighth annual progress report on the project. Results obtained in the first seven years of the project are discussed in previous annual reports¹⁻⁷ and in technical papers.⁷⁻¹⁵ Results obtained during this reporting period are summarized in this progress report.

Reporting

Early in the current project year, the Seventh Annual Technical Progress Report was prepared and submitted to the DOE. Four quarterly reports have been prepared and submitted for the period September 25, 2002 through September 25, 2003.

Workovers

Four workovers, to add additional pay zones, were performed on the Nash Draw #1, #12, #15 and #20 wells. The work is summarized in the following table:

| Well | Interval | Increase in Oil, BOPD | Increase in Gas, MCFD | Increase in Water, BWPD |
|-------------|--------------------------------------|------------------------------|------------------------------|--------------------------------|
| 1 | 5750–56 ft, 5477–80 ft | 10 | 17 | 25 |
| 12 | 6265–69 ft | 10 | -35 | 132 |
| 15 | 6276–79 ft | 33 | 80 | 10 |
| 20 | 6254–57 ft, 5497–5509 ft, 5319–31 ft | 0 | 0 | 0 |

Nash Draw #33

The drilling of the #33 deviated-horizontal well started on October 18, 2002. The Nash Draw #33 was drilled from a surface location located 10 ft FSL and 175 ft FWL of section 12-T23S-R29E. The BHL is located 3192.34 ft west and 2657.31 ft north, displacement is 4153.54 ft, measured depth is 9573 ft, TVD is 6736 ft. The wellbore encountered the target as shown in Fig. 1.

Drilling Rig - Key Energy Services, Inc. Rig #37, draw works EMSCO D-2, 1100 HP, derrick 134 ft L.C. Moore, 450,000#, pump #1 PZ-9, 1,000 HP, 6 in. Liners, pump #2 PZ-8, 750 HP, 6 in. liners, mud system- 3 tanks, 900 BBLS., 2 cone desander & 8 cone desilter, single screen shale shaker, drill pipe 4 ½ in.- 20#/ft grade “X”, 4.5” XH.

Surface Hole - 13 3/8 in.-48 #/FT, H-40, STC, set at 400 ft in a 17 ½ in. hole, cemented with 454 sx. class “C” W/ 5 #/sx. D-24, 2 % CaCl, 0.12 #/SX. D-130, 1.37 CU.FT/SX., did not circulate, used 1 in. tubing to T.O.C. @ 69 ft, cemented to surface with 75 SX. class “C” cement W/ 3 % CaCl.

Intermediate Hole - 8 5/8 in.-32 #/FT, J-55, LTC , set at 3,055 ft in a 11 in. hole, cemented with 813 sx. 50/50 Pozmix class “C” W/ 10 #/sx. D-44, 2 % D-20, 0.25 #/SX. D-29, 0.2 % D-46, 2.10 CU.FT/SX., tail in with 200 sx. class “C” W/ 2 % CaCl, circulated 348 sx.

Directional Drilling – The initial kickoff point was at 3200 ft with the build angle averaging 3.5 deg./100 ft, to a total of 30 degrees at 4122 ft. The 30 degree angle was maintained to 6935 ft where the angle was built at 12 degrees/100 ft until the wellbore was horizontal at 7691 ft. The horizontal section was drilled at 92.5degrees to follow the “L” zone updip to a total measured depth of 9573 ft (Fig. 2). Final well path at a T.D. of 9573 FT (MD), azimuth 305.86°, Vs 4153.54 FT, TVD 6735.65 FT, BHL 2657.31 ft N - 3192.34 ft W. A typical bottomhole assembly was:

| ANADRILL BHA | |
|------------------------------------|----------|
| 7.875 in. BIT | 0.80 ft |
| A625XP(7:8) MOTOR W/ 1.5° BENT SUB | 26.74 ft |
| FLOAT SUB | 2.05 ft |

| | |
|--|-------------------|
| 6 1/8 in. O.D. FLEX PONY | 13.85 ft |
| UBHO SUB | 1.99 ft |
| NONMETALIC COLLAR | 28.93 ft |
| FLEX JOINT | 30.60 ft |
| CROSS-OVER | 2.16 ft |
| 91 JTS. 4 in. F.H. DRILL PIPE | 2831.53 ft |
| CROSSOVER | 1.53 ft |
| 37 JTS. 4.5 in. X.H. HEAVY WEIGHT DRILL PIPE | 1111.45 ft |
| JARS | 30.97 ft |
| 5 JTS. 4.5 in. X.H. HEAVY WEIGHT DRILL PIPE | 150.20 ft |
| KEYSEAT WIPER | 3.97 ft |
| TOTAL | 4236.77 ft |

Mud System – The mud system was a semi-closed system, composed of three 300 barrel steel pits, two centrifuges, a two-cone desander and a eight-cone desilter. Well cuttings were collected in a cuttings pit. Mud properties were as follows:

| | | |
|--------------|-------------------|--|
| 0-400 ft | Fresh Water | Gel & Lime |
| 400-3055 ft | Brine Water | Lime, Paper, Maxiseal, Cedar Fiber, VIS-plus |
| 3055-5600 ft | Cut Brine 9.3 PPG | Lime, EPL-50, Caustic Soda |
| 5600-7338 ft | Cut Brine 9.3 PPG | Lime, Soda Ash, Ammonium Nitrate, XCD Polymer, Graphite, Caustic Soda, EPL-50, STC, Flozan, Defoamer |
| 7338-T.D. | Cut Brine 9.3 PPG | + Starch, 1.5% Diesel, Delta P, Mica, Magnafiber, Lubribeads |

Typical Properties - 9.3 PPG, Vis 44, PV 10, YP 24, PH 10, Filter Cake 0.03125 in., Cl 100,000, Ca 2800, Sand Trace, Solids 0.2%, Oil 1.5 %

Bits – Standard bits were used to drill the vertical and horizontal sections. Diamond enhancement for gauge protection was used on bits number 8 and 9. The diamond enhancement aided in maintaining gauge hole. The two diamond enhanced bits performed well and were pulled due to other problems other than bit condition. Bits used are presented as follows:

| No.: | SIZE | MAKE | MODEL | SER. # | DEPTH | FEET | HOURS | FT/HR. |
|------|-----------|-------|--------|---------|--------------|-------------------|--------|--------|
| #1 | 17.5 in. | HUGES | GTX | P96JW | 0-400 ft | 380 ft | 9.75 | 38.97 |
| #2 | 11 in. | REED | HP-53 | NL-5609 | 400-3055 ft | 2655 ft | 68.25 | 38.90 |
| #3 | 7.875 in. | REED | HP-53B | M25260 | 3055-3963 ft | 908 ft | 30.50 | 29.77 |
| #4 | 7.875 in. | REED | HP-53B | M25515 | 3963-6935 ft | 2972 ft | 109.00 | 27.27 |
| #5 | 7.875 in. | REED | HP-53B | T96054 | 6935-7338 ft | 403 ft | 33.50 | 12.03 |
| #6 | 7.875 in. | RR #3 | REED | HP-53B | M25260 | REAM 2995-6935 ft | | |
| #7 | 7.875 in. | REED | HP-53H | R22694 | 7338-8002 ft | 646 ft | 92.25 | 7.00 |
| #8 | 7.875 in. | REED | HP-53H | R22695 | 8002-8562 ft | 578 ft | 59.00 | 9.80 |
| #9 | 7.875 in. | REED | HP-53B | T96096 | 8562-9573 ft | 1010 ft | 78.75 | 12.83 |

| BIT CONDITION | TEETH | BEARINGS | Gauge | COMMENTS |
|---------------|----------------------|----------|-------------|------------------------|
| #3 | 4 | 4 | IN | |
| #4 | 5 | 5 | -0.0625 in. | |
| #5 | 6 | 4 | -0.0625 in. | |
| #6 | RERUN BIT #3 TO REAM | | | |
| #7 | 4 | 3 | IN | DIAMOND ENHANCED |
| #8 | 3 | 3 | IN | DIAMOND ENHANCED |
| #9 | 2 | 2 | -0.25 in. | EROSION AROUND INSERTS |

Logging – A gamma ray log and rate-of-penetration log were obtained while drilling. At T.D. a gamma ray, density, compensated neutron, dual laterolog, micro-laterolog and caliper were run to 6900 ft.

Mud Log – The conventional mud log showed good correlation to the 3-D seismic for the “L” interval. Gas shows increased with increasing amplitude and gas shows decreased with decreasing seismic amplitude.

Long String 2963 ft of 5.5 in.-17 #/FT P-110, HYDRIL 513, & 6587 ft of 5.5 in.-17#/FT, N-80, LTC, D.V. Tool at 6448 ft, first-stage cement 633 sacks 50/50 Pozmix “C” w/ 3% D-44, 3% D-174, 1.5 gals/sx. D-600, 0.2% D-65, 0.05 gals./sx. D-47, 0.05 gals./sx. D-177, Circulated 25 sacks, second-stage cement 100 sacks Lite, 750 sacks Litecrete w/ 0.2% D-46, 0.2% D-65, 1% D-112, 2% D-79, 10% D-20, Circulated 100 sacks.

Problems

The #33 well was drilled with much fewer problems than the #36 well. The two main problems that were encountered were differential sticking and slow rates of penetration.

Zones that have been produced in the field are showing low BHP that caused differential sticking problems at 5000 ft and 7300-7450 ft. The worst sticking was in the interval 7300-7450 ft, which correlates to the “K-2” zone. The “K-2” is predominately water productive throughout the field, but a large volume of water has been produced from this zone.

With the sands only +/- 1 ft thick, horizontal drilling is continuously encountering shales and siltstones. The shales and siltstones are “gummy” and impede drilling. ROP in clean sands is 30-60+ft/hour, in the shales/siltstone ROP is >10 ft/hour.

Drilling Time

The anticipated drilling time without any delays was projected at 24 days. With time lost dealing with the differential sticking and slow drilling in the siltstone the well took 36 days (Fig. 4). The #36 well took 47 days to drill due to hole problems, equipment problems and slow drilling rates.

Completion

The initial completion is in the toe of the well through 32 ft of open hole. After setting and cementing the 5.5 in. casing the shoe joint and 32 ft of formation were drilled with a mud motor and 4.75 in. bit. The openhole section is from 9573 ft to 9605 ft.

To aid in formation breakdown and an attempt to control fracture initiation, a hydraulic jetting tool was run into the open hole and a groove was cut into the formation approximately 10 ft from

the end of the well. Jetting was accomplished with a four jet head, rotated at 6 rpm while pumping slick water at 5 BPM at 2300 psi for 45 minutes. The breakdown pressure on the #33 well was 2700 psi at 22 BPM compared to 4093 psi at 2 BPM on the #36 well. It is apparent that the jetting aided in the initial breakdown and aided in fracture initiation.

The fracture stimulation treatment was designed to create 475 ft of fracture half-length with 241 ft of fracture height, with 0.96 #/ft² proppant concentration, yielding +/- 8,000 md-ft flow capacity. The design resulted in pumping 70,000 gallons of 35 #/1000 gals. complexed borate gelled 2% KCL water carrying 200,000 pounds of C-Lite (ceramic proppant) at 30 BPM.

The initial breakdown was lower than experienced on the #36 well, but fracture propagation was hampered by the maximum pressure limitation of 5000 psi. The rate decreased and pressure increased throughout the pad. The fracture friction-tortuosity pressure increased to the point that the job gelled out and was shut down. To enable the treating pressure maximum pressure to increase a wellhead isolation tool was used to isolate the 5000 psi W.P. wellhead and allow the maximum treating pressure to increase to 6300 psi.

After pressuring up to 6200 psi to initiate fracture propagation, the treatment was able to be pumped at 30 BPM at 3200 psi. Just as the displacement was completed the treatment sanded-out, without leaving any excess proppant in the casing.

After being shut-in for three hours the well was opened on an 1/8 in. choke and allowed to flow back the load.

The "H" zone in the Nash Draw #33 was tested in two intervals: 6691–99 ft and 6562–6682 ft. The two zones were tested separately to determine if the lower interval was water-productive. The Advanced Log Analysis Program showed the interval 6691–99 ft was water-productive and the interval 6562–6682 ft was oil-productive. Testing the lower zone was necessary because, while this zone is correlative to zones in other wells that are productive, it is lower structurally.

Testing showed the lower zone was water-productive with a 10% oil cut and the upper zone was oil-productive. The upper zone was then isolated and fracture stimulated with 40,000 gallons of 30 lb /1000 g crosslinked KCL water carrying 61,000 lb of 20–40 sand. The average treating rate was 20 BPM and the average treating pressure was 3800 psi. The treating pressure indicates there is some tortuosity effect in the deviated hole similar to that observed in treatments in the horizontal hole.

The Nash #33 was completed on December 11, 2002. Through April 21, 2003, it has produced 15,728 BO, 37,962 MCFG, averaging 121 BOPD and 285 MCFGD.

The "H" zone and the toe zone are commingled with a nine-valve gas lift system designed to lift 1500 barrels of fluid per day. Some initial problems were experienced in March due to compressor suction pressure, high line pressure and one leaking valve. Most of these problems were resolved by April 1, 2003 and lift efficiency is being maximized by monitoring the bottom-hole producing pressure.

Nash Draw #33 Deepening

The analysis of the second seismic survey has shown that the toe zone lies at the top of the “L” zone and the stimulation treatment did not extend down into the “L” zone. This has resulted in a “K” and “K-2” zone completion with characteristically high water cuts and low oil cuts. To correct this situation a deepening operation has been designed to extend the openhole section 367 ft while dropping the TVD 50 ft deeper. This should place the BHL at the bottom of the “L” zone porosity interval and allow fracture stimulation of the “L” zone.

A openhole packer assembly will be used to isolate the new openhole section from the previously completed toe zone. A packer seat will be attempted in the tighter upper “L” section, generally in the upper 7 ft of the “L” interval. A groove will be hydrojetted into the lower “L” interval to create a stress point to control fracture initiation.

This workover is scheduled for early November 2003 and should be completed in approximately two weeks. A representation of the proposed wellbore configuration is presented in Fig. 3. The new openhole section is shown as the black portion at the tip of the wellbore.

Nash Draw #36

Evaluation of the completion, stimulation, and production testing and analysis of the Nash Draw #36 horizontal well is continuing. The “H-2” zone completed from 6333-49 ft continues to flow. As of August 31, 2003 the zone has cumulative production of 94,036 BO, 258 MMCFG, and 43,693 BW and production rates are 70 BOPD, 451 MCFGD and 25 BWPD.

When the “H-2” zone stops flowing the retrievable bridge plug will be removed and production from the toe zone and the “H-2” zone will be commingled and tested.

Nash Draw #36 Deepening

The second generation seismic shows the #36 well toe zone is completed at the top of the “L” zone and probably did not achieve penetration through all of the “L” zone pay. Initial testing showed good oil cuts, but final testing showed high water cuts consistent with “K” and “K-2” characterization.

A deepening operation has been designed to extend the openhole section 2014 ft while dropping the TVD 50 ft deeper. This should place the BHL at the bottom of the “L” zone porosity interval and allow fracture stimulation of the “L” zone.

A openhole packer assembly will be used to isolate the new openhole section from the previously completed toe zone. A packer seat will be attempted in the tighter upper “L” section, generally in the upper 7 ft of the “L” interval. A groove will be hydrojetted into the lower “L” interval to create a stress point to control fracture initiation.

This workover is scheduled after the #33 deepening is completed and tested. A representation of

the proposed wellbore configuration is presented in Fig. 4. The new openhole section is shown as the black portion at the tip of the wellbore.

Nash Draw #34

The preliminary interpretation of the second generation 3-D seismic survey has yielded a drilling target in the NE/4 of section 12. A well is being planned from the #19 location to the NE/4 of section 12 as shown in Fig. 5.

Upon the successful completion of the #33 and #36 deepenings and confirmation that the “L” zone is as productive as the seismic predicts, the #34 well will be drilled through the NE/4 of section 12-T23S-R29E. The well is designed to be a directional/horizontal well with the directional section intersecting the “L” zone approximately 1400 ft northeast of the surface location at an azimuth of 51.98°. After intersecting the “L” zone the wellbore will continue horizontally to a BHL 400 FSL and 400 FEL of section 1. The bottom hole location is projected to be 1800 ft east and 3181.74 ft north of the surface location, A total of 3655 ft from the surface location at an azimuth of 25.50°.

3-D Seismic

The permitting of the 3-D seismic survey for the north end of the Nash Draw Unit was completed, laying of the lines started November 22, 2002 and was completed on December 8, 2002. The acquisition of data started December 8, 2002 and was completed December 16, 2002. A total of 9.48 mi² was shot, with 4371 receivers and 1191 source points.

The recording of the seismic data was suspended during the frac treatment on the #33 well. An experiment was performed using the full 3-D receiver array to attempt to record micro-seismic events during the frac treatment. The 3-D Seismic array was cycled to be turned on to record for 1.5 minutes–off 5 minutes, for a total of 90 minutes. It was hoped that data can be extracted from the data set that will aid in mapping fracture area and orientation. Preliminary information indicates that any induced fracture “noise” is hidden in the data and extraction of any useful information is not possible at this time.

Initial processing of the data and the preliminary interpretation yielded some issues that had to be resolved 1) matching new amplitude maps to the original survey maps, 2) calibration of new data to existing well performance data, and 3) integration of existing data, new data and geological modeling to achieve a comprehensive “Geological Model”. The new seismic interpretation is completed and has created some corrections in the original interpretation as to dip across section 11 and new drilling targets.

The second generation seismic structure map (Fig. 6) indicates that there is only 55 ft of west to east dip across section 11. The first generation seismic structure map showed 125 ft of west to east dip. This reinterpretation causes a problem with targeting the BHL of the horizontal wells drilled in section 11. The #33 and #36 wells were drilled using the dip exhibited by the first generation seismic survey and followed the “L” zone updip 75 ft to 50 ft. The second generation seismic structure map indicates that these wells only need to go updip +/- 25 ft. Therefore, if the

second generation structure map is correct, the #33 and #36 BHL are at the top of the “L” zone or in the bottom of the “K-2”. This may explain why the water cut is higher than expected from the #33 well.

Dr. Bob Hardage at the University of Texas Bureau of Economic Geology offers this explanation for the varying structural interpretation. “When depth maps are made from seismic-derived velocities without the benefit of well control to constrain the depth estimates, the maps are usually correct in a relative sense, but rarely yield precise depths. In other words, structural highs are generally structural highs when drilled; structural lows are indeed structural lows, and positive and negative dips are usually correct indications of actual subsurface dips. Thus the depth picture is correct in a relative sense. However, the seismic estimate of the depth of a target can be in error by several tens of ft even though the relative subsurface geometry is correct. This depth error results because of the error bar associated with the estimate of seismic velocity, because the stacking velocity determined early in the seismic data-processing process was not optimal, or because anisotropy results in large differences between horizontal and vertical velocities. As an example, if the selected stacking velocity at image time of 1 second is 10,000 ft/sec, a 2-percent error in velocity estimation will result in a depth error of (+/-) 200 ft.

To improve the depth accuracy of seismic maps, it is essential to incorporate well control into the depth conversion process so that wireline-measured depths of key formation tops can be tagged to seismic image times of those units. With a reasonable amount of well control as constraints, seismic depth maps can often be amazingly accurate, with depth predictions differing from actual depths by less than 10 ft at depths of 8,000 to 12,000 ft.

With this background, the Nash Draw depth maps can now be discussed. The original depth maps that led to the drilling of the 33 and 36 wells into Section 11 were made without any calibration wells in Section 11 to constrain the depth predictions. These first-generation maps were made using seismic-derived velocities across the total image space and control wells that existed only to the east of Section 11. The maps were affected by velocity error bars as the depth predictions moved farther away from each control well. These maps indicated that the depth of the Bone Spring, and units immediately above Bone Spring, decreased toward the west at a rate of about 100 ft per mile. The bottomhole depths of wells 33 and 36 were targeted based on this implied dip rate.

My opinion is that the original depth maps are correct across Section 11 in a relative sense. The Bone Spring does become shallower to the west, but it is risky to assume that the dip is exactly 100 ft per mile. The error bars associated with the seismic velocities would allow this dip to vary by a few tens of ft over a distance of a mile.

There is now a new seismic survey and new depth maps have been made. The important difference in the depth mapping process with these new data, compared to the original depth mapping, is that there are now two control wells (33 and 36) in Section 11. A Bone Spring depth was provided to the Bureau for each well, and these depth values were used to constrain the new seismic depth predictions. These latter maps indicate the dips of the Bone Spring and the K and L reservoir targets are now about 50 ft per mile across Section 11, not 100 ft per mile as estimated by the first-generation maps.

By definition, these new maps are more reliable depth maps than the first maps IF (and a most important “if”) the Bone Spring depths provided for wells 33 and 36 are correct. If these well depths are incorrect, then the seismic maps are incorrect, again by definition.”

Dip Calibration

To calibrate the dip across section 11, three models were created using actual well data and seismic derived data. Case I uses the actual formation tops from the Nash Draw #13 and #15 wells and two wells located approximately 2.5 miles to the west. The indicated dip is 70 to 78 ft/mile (Fig. 7). There is good agreement with the “L” zone top observed in the #33 and #36 wells and the projected Bone Spring top for each well. In this case the BHL for the #33 and #36 wells are at the top of the “L” zone.

Case II uses the actual data from the #13 and #15 wells and the first generation seismic data. The indicated dip ranges from 81 ft/mile to 124 ft/mile (Fig. 8). The observed formation tops in the #33 and #36 wells do not fit this dip model, indicating the dip is too steep. The BHL of the #33 and #36 wells is in the middle of the “L” section.

Case III uses the actual data from the #13 and #15 wells and the second generation seismic data. The indicated dip ranges from 43 ft/mile to 51 ft/mile (Fig. 9). The observed formation tops in the #33 and #36 wells appear to be above the projected formation tops, indicating the dip is too flat. The BHL of the #33 well is above the “L” zone and the BHL of the #36 well is just below the top of the “L” zone.

The true dip across section 11 appears to be 50 ft/mile to 70 ft/mile with the BHL of the #33 and #36 wells lying at the top of the “L” zone. Assuming the fracture stimulation treatments did not grow down into the “L” zone and only the “K” and “K-2” are contributing, a high water cut would be expected from these completions. This is confirmed by using the characterization model prepared on the #15 using only the “K” and “K-2” zones. Initial production rates are calculated to be 122 BOPD and 511 BWPD, 80% water cut. The #33 well is producing an 80% water cut, confirming the production is coming primarily from the “K” and “K-2” zones. The #33 and #36 wells may need to be drilled deeper into the “L” zone and recompleted.

Gas Processing and Injection

An analysis of the economic impact of gas processing and reinjection for pressure maintenance versus gas sales using the existing gas contract has been completed. The future estimated Gross Oil and Gross Gas and Undiscounted and Discounted Net Cash Flow (NCF) is presented for Case 1-conventional sales and Case 2-processing and reinjection are presented as follows:

| | <u>Case 1</u> | <u>Case 2</u> | <u>Case 1 vs Case 2</u> |
|-----------------|----------------------|----------------------|--------------------------------|
| Gross Oil (BO) | 2,031,830 | 2,491,679 | (459,849) |
| Gross Gas (MCF) | 10,644,603 | 9,635,326 | 1,009,277 |
| Net Cash Flow | \$49,993,023 | \$55,263,178 | (5,270,155) |
| Discounted NCF | \$37,360,661 | \$37,323,095 | 37,566 |

Note that Case 1 results in 459,849 BO less oil production but 1,009,277 MCF more gas production than Case 2. The reinjection of gas assumed in Case 2 results in higher oil recoveries but less gas recovery. This is due to the inability to economically recover all of the gas that is injected, we estimate that approximately 25% of the injected gas will be unrecoverable or lost.

Case 1 results in \$5,270,155 less NCF than does Case 2. Despite the lower gas production in Case 2 the higher oil production produces more profit. However, when the Case 1 and Case 2 NCF is discounted the difference is only \$37,566. This difference is somewhat due to the delay of increased oil production as a result of Case 2 gas injection. Primarily, however, most of the difference is due to the delay of recovery and selling the reinjected gas volumes. As noted, these gas revenues are not received until 2020 to 2022, very near the economic end of the project.

Based upon this analysis, the best economic course is to continue to sell the gas outright to the purchaser as evidenced by the results of Case 1. The additional Capital Cost required to install the Case 2 processing and injection facility is not justified given the estimated future profit. However, if a processing and reinjection system was installed near the beginning of the Nash Unit project, some ten (10) years ago, the increased oil and gas production volumes would have made better economic sense. To date the Nash Unit has produced in excess of 1.25 million BO and 7.2 BCFG. These volumes, together with increased oil recoveries from pressure maintenance, may have allowed a more rapid return and an ultimately higher multiple on the gas processing and injection facilities.

Data and Databases

The NDP production database was updated through August 1, 2003. These data were added to the history of each well to update the decline curves and to project ultimate recoveries as well as to assess the effects of interference and production strategies.

The eight wells that are part of the Class III project (#12, 23, 24, 25, 29, 33, 36 and 38) have produced 365,410 BO, 2.28 BCFG and 1,610,403 BW as of July 1, 2003, Fig. 10. Reserves associated with this project are summarized in the following table:

| Table 1. | Oil, BBLS. | Gas, MCF | Water, BBLS. |
|---|-------------------|-------------------|---------------------|
| Cumulative Production as of 7-1-03 | 365,410 | 2,279,190 | 1,610,403 |
| Remaining Proved Developed Producing | 271,026 | 1,771,407 | |
| Proved Developed Nonproducing | 170,200 | 389,523 | |
| Proved Undeveloped (#34 Drilling+Workovers) | 821,882 | 4,490,473 | |
| Probable (#33 & #36 Deepening) | 400,000 | 2,000,000 | |
| Total | 2,028,518 | 10,930,593 | 1,610,403 |

Other Applications

Strata has applied the characterization and 3-D seismic technology developed from the Nash

Draw Project to two other fields in Eddy County and a new prospect west of the Nash Draw Unit. Another application is being modeled for a Bone Spring prospect in Lea County.

Internet Homepage

The web site for the Nash Draw Project can be accessed at <http://baervan.nmt.edu/nashdraw/>. The site includes a project summary, list of participants, summary of the technical team, technical transfer including quarterly and annual reports, and future plans and current activities.

Technology Transfer

Disseminating technical information generated during the course of this project is a prime objective of the project. A summary of technology transfer activities during this quarter is outlined below.

Web Site: <http://baervan.nmt.edu/nashdraw/>

EXPERIMENTAL RESULTS

No experiments are associated with this project.

CONCLUSION

The production database was updated through August 2003. The use of the Advanced Log Analysis techniques developed from the NDP project have proven useful in defining additional productive zones and refining completion techniques. The 3-D seismic survey has proven to be a useful tool to define areas for potential development. Drilling a deviated/horizontal well to develop reserves in an area not accessible by vertical drilling is possible and becomes easier as more wells are drilled. Evaluation of the completion, stimulation, and production testing and analysis of the Nash Draw #33 horizontal well is continuing. The Nash Draw #33 production matches the model from the #15 “K” and “K-2” indicating production is coming from zones above the “L” zone. Analysis of the seismic data has identified a target in the NE/4 of section 12 for the drilling of the next deviated/horizontal well.

REFERENCES

1. Murphy M.B., et al: "Advanced Oil Recovery Technologies for Improved Recovery from Slope Basin Clastic Reservoirs, Nash Draw Brushy Canyon Pool, Eddy County, New Mexico," Report, Cooperative Agreement DE-FC-95BC14941, submitted to the U.S. Department of Energy (October 1996).
2. Murphy M.B., et al: "Advanced Oil Recovery Technologies for Improved Recovery from Slope Basin Clastic Reservoirs, Nash Draw Brushy Canyon Pool, Eddy County, New Mexico," Second Annual Report, Cooperative Agreement DE-FC-95BC14941, submitted to the U.S. Department of Energy (October 1997).
3. Murphy M.B., et al: "Advanced Oil Recovery Technologies for Improved Recovery from Slope Basin Clastic Reservoirs, Nash Draw Brushy Canyon Pool, Eddy County, New Mexico," Third Annual Report, Cooperative Agreement DE-FC-95BC14941, submitted to the U.S. Department of Energy (October 1998).
4. Murphy M.B., et al: "Advanced Oil Recovery Technologies for Improved Recovery from Slope Basin Clastic Reservoirs, Nash Draw Brushy Canyon Pool, Eddy County, New Mexico," Fourth Annual Report, Cooperative Agreement DE-FC-95BC14941, submitted to the U.S. Department of Energy (October 1999).
5. Murphy M.B., et al: "Advanced Oil Recovery Technologies for Improved Recovery from Slope Basin Clastic Reservoirs, Nash Draw Brushy Canyon Pool, Eddy County, New Mexico," Fifth Annual Report, Cooperative Agreement DE-FC-95BC14941, submitted to the U.S. Department of Energy (October 2000).
6. Murphy M.B., et al: "Advanced Oil Recovery Technologies for Improved Recovery from Slope Basin Clastic Reservoirs, Nash Draw Brushy Canyon Pool, Eddy County, New Mexico," Sixth Annual Report, Cooperative Agreement DE-FC-95BC14941, submitted to the U.S. Department of Energy (October 2001).
7. Murphy M.B., et al: "Advanced Oil Recovery Technologies for Improved Recovery from Slope Basin Clastic Reservoirs, Nash Draw Brushy Canyon Pool, Eddy County, New Mexico," Seventh Annual Report, Cooperative Agreement DE-FC-95BC14941, submitted to the U.S. Department of Energy (October 2002).
8. Martin F.D., et al: "Advanced Reservoir Characterization for Improved Oil Recovery in a New Mexico Delaware Basin Project," *Proc. Fourth International Reservoir Characterization Technical Conference*, Houston, (1997) March 2•4, 703-26, and revised in *Reservoir Characterization—Recent Advances*, AAPG Memoir 71, R.A. Schatzinger and J.F. Jordan (eds.), AAPG, Tulsa, (1999) 93-107.
9. Martin, F.D., et al: "Reservoir Characterization as a Risk Reduction Tool at the Nash Draw Pool," paper SPE 38916 presented at the 1997 SPE Annual Technical Conference & Exhibition, San Antonio, Oct. 5-8, *Proc. SPE Reservoir Engineering*, 751-66, and revised in *SPE Reservoir Eval. & Eng.*, 2 (2), (April 1999) 169-79.

10. Stubbs, B.A., et al: "Using Reservoir Characterization Results at the Nash Draw Pool to Improve Completion Design and Stimulation Treatments," paper SPE 39775 presented at the 1998 SPE Permian Basin Oil and Gas Recovery Conference, Midland, March 23-26.
11. Martin, F.D., et al: "Implementation of a Virtual Enterprise for Reservoir Management Applications," paper SPE 38868 presented at the 1997 SPE Annual Technical Conference & Exhibition, San Antonio, Oct. 5-8.
12. Hardage, B.A., et al: "3-D Seismic Imaging and Interpretation of Brushy Canyon Slope and Basin Thin-Bed Reservoirs, Northwest Delaware Basin," *GEOPHYSICS*, Vol. 63 No. 5 (September-October 1998) 1507-19.
13. Hardage, B.A., et al: "3-D Instantaneous Frequency Used as a Coherency/Continuity Parameter to Interpret Reservoir Compartment Boundaries Across an Area of Complex Turbidite Deposition," *GEOPHYSICS*, Vol. 63 No. 5 (September-October 1998) 1520-31.
14. Hart, D.M., Balch, R.S., Tobin, H.J., and Weiss, W.W.: "Time-to-Depth Conversion of Nash Draw "L" Seismic Horizon Using Seismic Attributes and Neural Networks," SPE 59555 presented at the 2000 SPE Permian Basin Oil & Gas Recovery Conference, Midland, Texas, 21-23 March.
14. Weiss, W.W., et al: "Estimating Bulk Volume Oil in Thin-Bedded Turbidites", SPE 70041, presented at the Permian Basin Oil and Gas Recovery Conference in Midland, Texas on May 15-16, 2001.

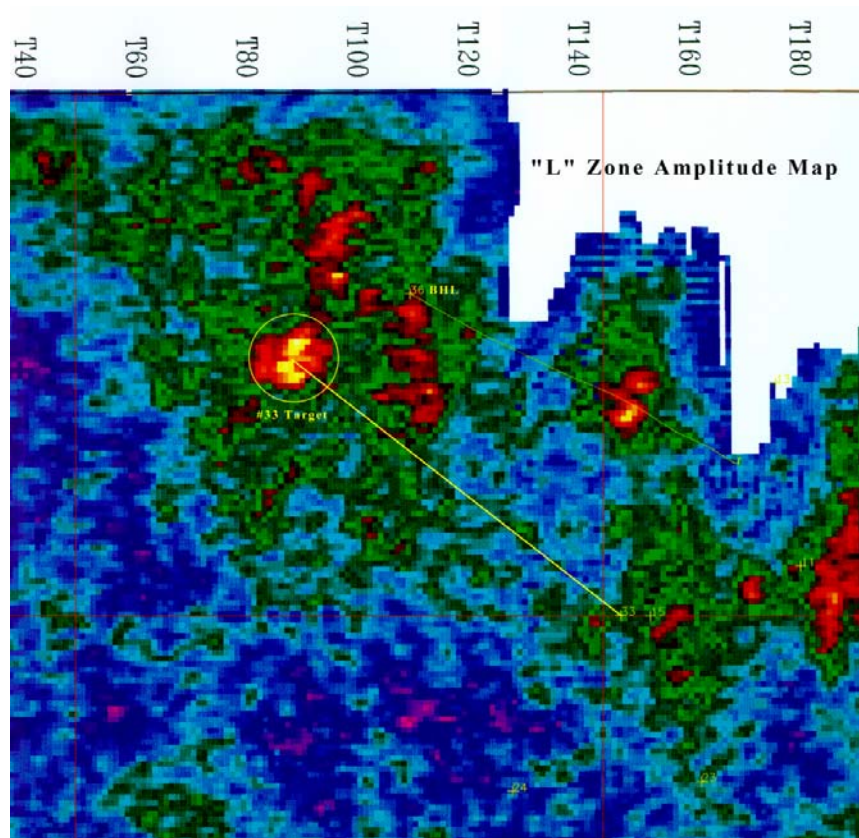


Fig. 1. Nash Draw #33 seismic target.

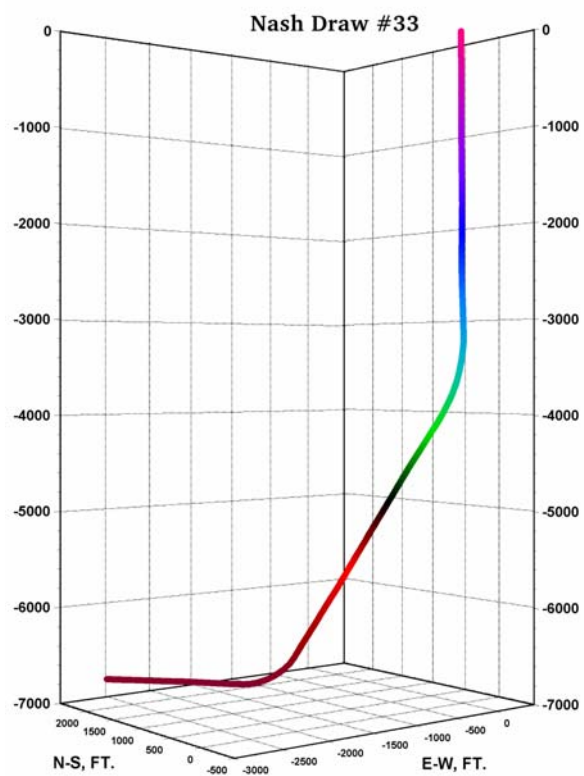


Fig. 2. Nash Draw #33 well path.

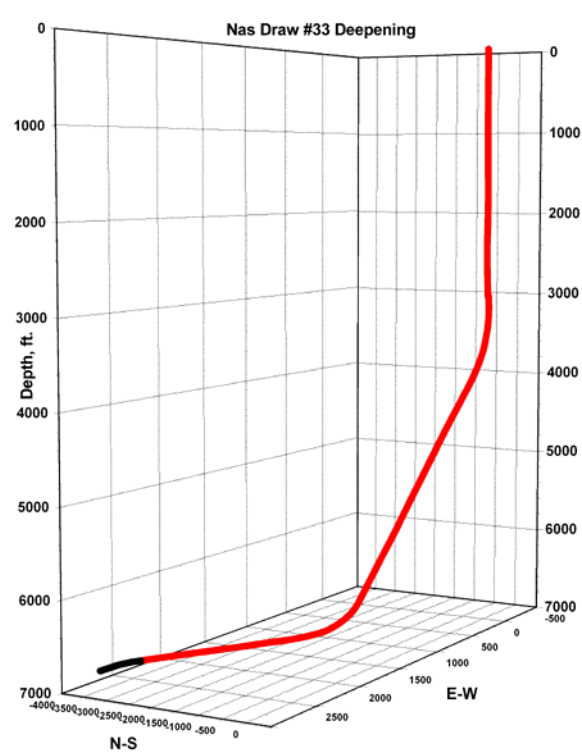


Fig. 3. Nash Draw #33 proposed deepening.

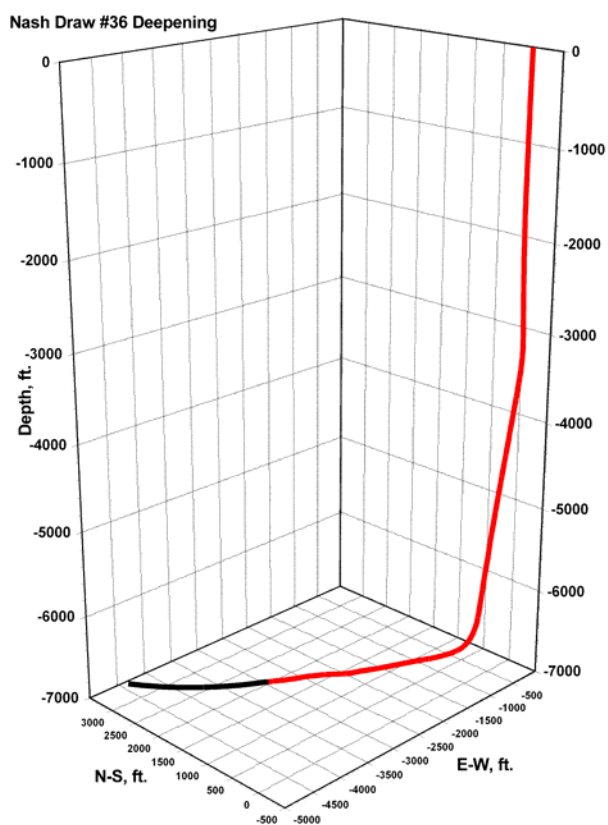


Fig. 4. Nash Draw #36 proposed deepening.

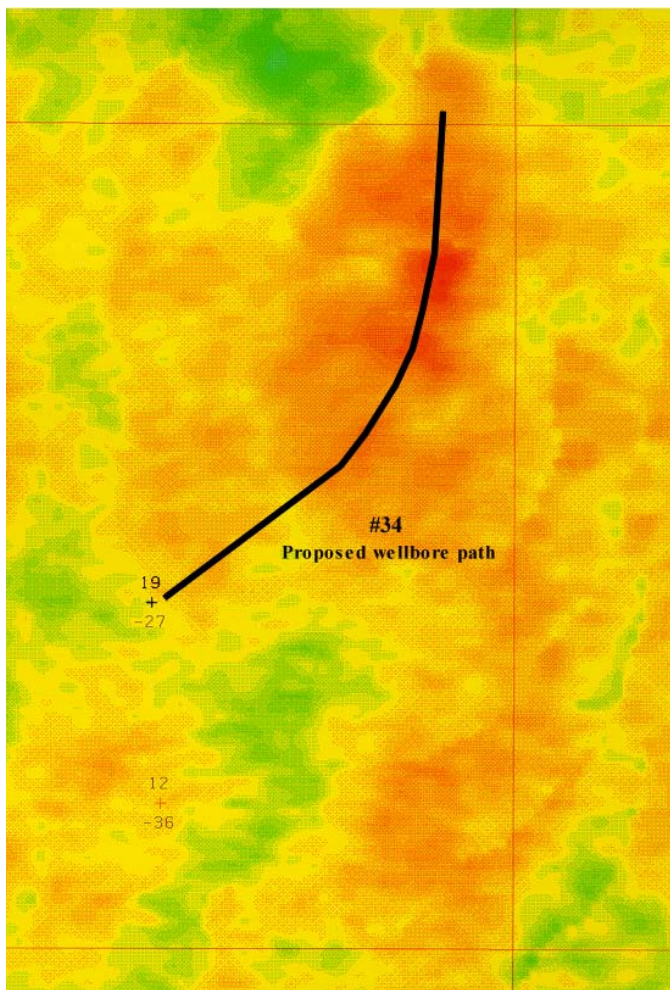


Fig. 5. Nash Draw #34 proposed wellbore path.

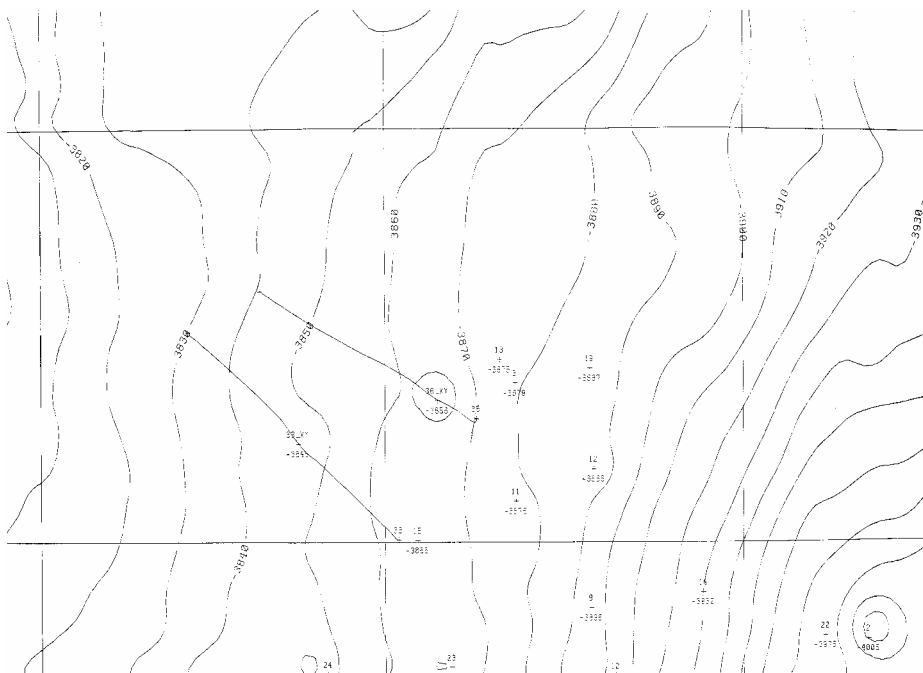


Fig. 6. Second generation 3-D seismic Bone Spring structure map.

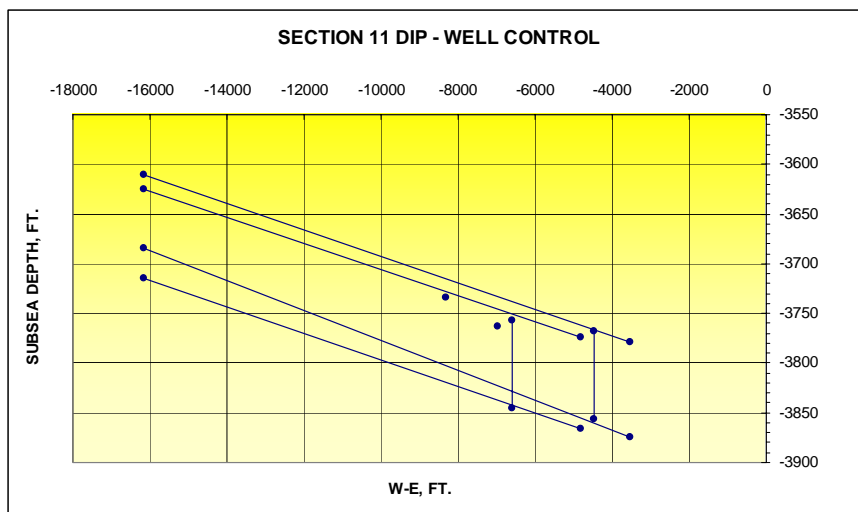


Fig. 7. Dip using well control.

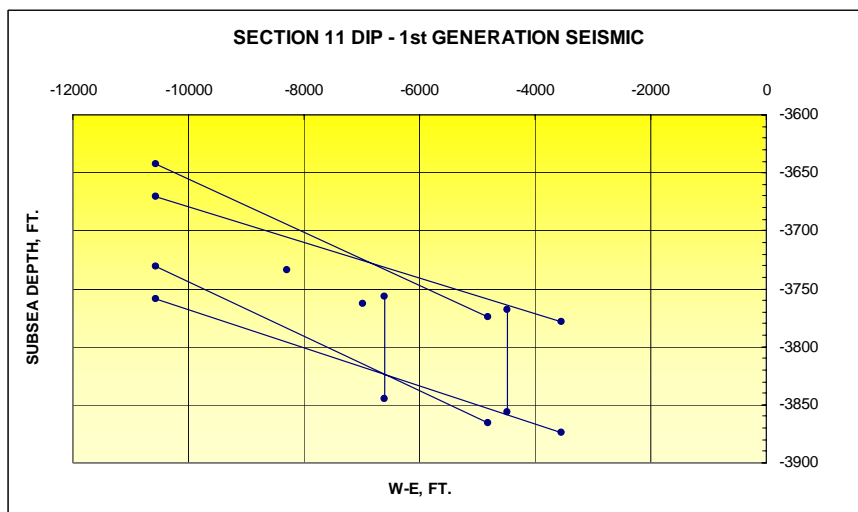


Fig. 8. Dip using first generation 3-D seismic survey.

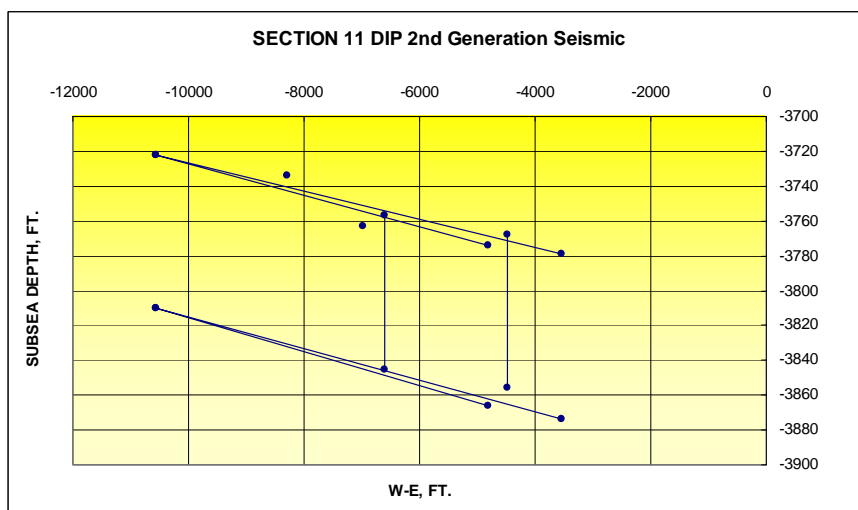


Fig. 9. Dip using 2nd generation 3-D seismic survey.

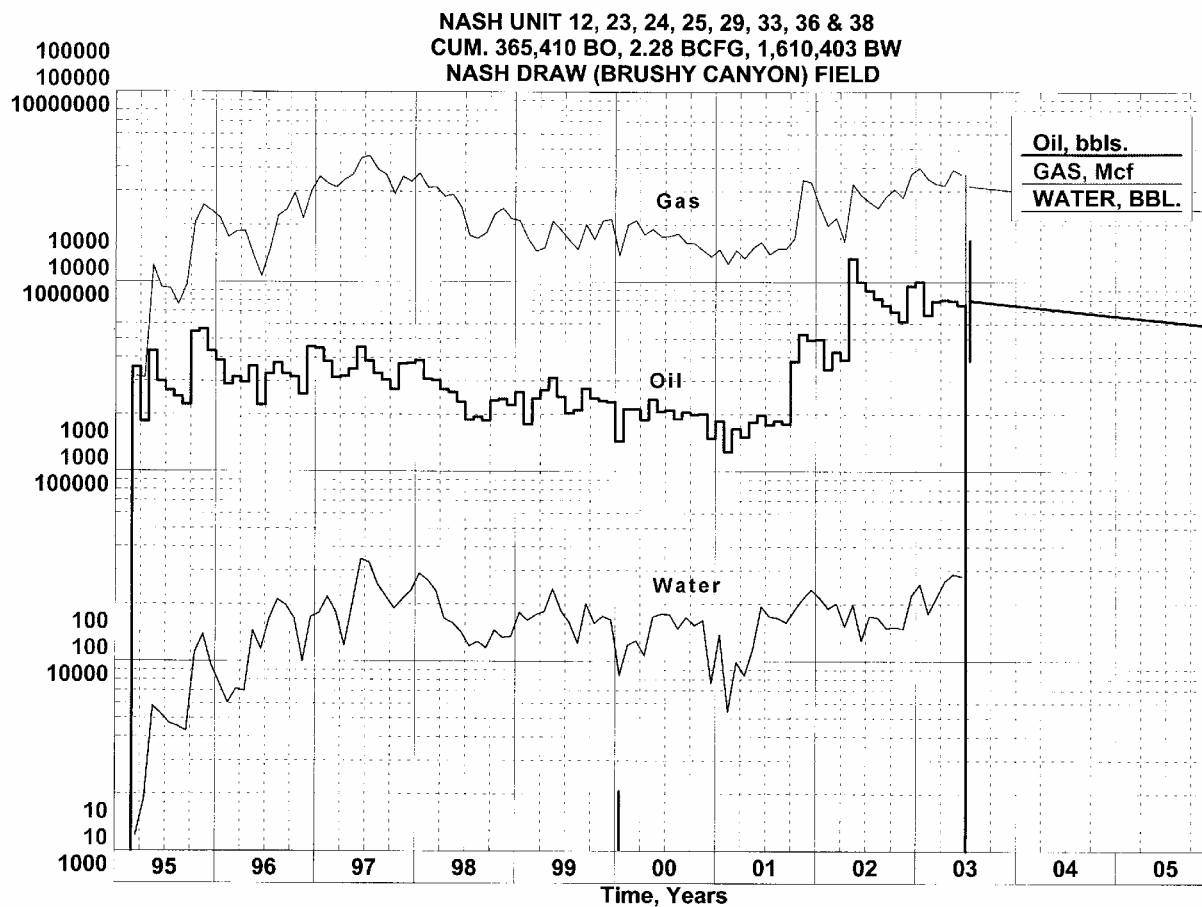


Fig. 10. Nash Draw D.O.E. wells cumulative production through 7-1-03.