QUARTERLY TECHNICAL PROGRESS REPORT
(29th Quarter)

**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

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Date of Report:	December 31, 2002
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-December 31, 2002

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

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.

SUMMARY OF TECHNICAL PROGRESS

This is the twenty-ninth quarterly progress report on the project. Results obtained to date are summarized.

Geology and Engineering

The production database was updated through November 2002. This data was 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.

Nash Draw #36 Completion

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 6333–6349 ft continues to flow. As of December 31, 2002 the zone has cumulative production of 55,407 BO, 130 MMCFG, and 11,082 BW and production rates are 130 BOPD, 596 MCFGD and 12 BWPD.

The reservoir simulation model is proving to be a good match to the actual production, as shown in Fig. 1. The actual produced gas volume appears higher than predicted, but after comparing the field volumes to the actual purchased volumes the field volumes are 20% to 30% too high. Purchased volumes plus fuel usage are much closer to the predicted gas volumes.

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.

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) 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 Duke 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 had been installed near the beginning of the Nash Unit project, some 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.

Workovers

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

<u>Well</u>	<u>Interval</u>	<u>Increase in Oil, BOPD</u>	<u>Increase in Gas, MCFD</u>	<u>Increase in Water, BWPD</u>
1	5750–56 ft, 5477–80 ft	10	17	25
15	6276–79 ft	33	80	10
20	6254–57 ft, 5497–5509 ft, 5319–31 ft	0	0	0

3-D Seismic

The permitting of the 3-D seismic survey for the north end of the Nash Draw Unit is 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 square miles was shot, with 4371 receivers and 1191 source points. Preliminary quality control indicates that the data are good and the lower Delaware was successfully imaged. The data are now being processed and preliminary interpretation are expected in February 2003.

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 is hoped that data can be extracted from the data set that will aid in mapping fracture area and orientation. Processing of this data is in progress and preliminary information will be available after the initial 3-D interpretation is prepared.

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. 2.

Drilling Rig–Key Energy Services, Inc. Rig #37, draw works EMSCO D-2, 1100 HP, derrick 134' 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 and 8 cone desilter, single screen shale shaker, drill pipe 4.5 in.–20 lbf grade “X”, 4.5 in. XH.

Surface Hole–13 3/8 in.–48 lbf, H-40, STC, set at 400 ft in a 17.5 in. hole, cemented with 454 sx. class “C” W/ 5 lb/sx. D-24, 2% CaCl, 0.12 lb/sx. D-130, 1.37 CU.FT./SX., did not circulate, used 1 in. tubing to T.O.C. at 69 ft, cemented to surface with 75 sx. class “C” cement with 3 % CaCl.

Intermediate Hole–8.375 in.–32 lbf, J-55, LTC , set at 3,055 ft in an 11-in. hole, cemented with 813 sx. 50/50 Pozmix class “C” W/ 10 lb/sx. D-44, 2% D-20, 0.25 lb/sx. D-29, 0.2% D-46, 2.10 CU.FT./SX., tail in with 200 sx. class “C” with 2 % CaCl, circulated 348 sx.

Directional Drilling–The initial kickoff point was at 3200 ft with the build angle averaging 3.5°/100 ft, to a total of 30° at 4122'. The 30° angle was maintained to 6935 ft where the angle was built at 12°/100 ft until the wellbore was horizontal at 7691 ft. The horizontal section was drilled at 92.5° to follow the “L” zone updip to a total measured depth of 9573 ft (Fig. 3). 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 7/8" BIT	0.80 ft
A625XP(7:8) MOTOR W/ 1.5° BENT SUB	26.74 ft
FLOAT SUB	2.05 ft
6 1/8" O.D. FLEX PONY	13.85 ft
UBHO SUB	1.99'
NONMETALIC COLLAR	28.93 ft
FLEX JOINT	30.60 ft
CROSS-OVER	2.16 ft
91 JTS. 4" F.H. DRILL PIPE	2831.53 ft
CROSSOVER	1.53 ft
37 JTS. 4 1/2" X.H. HEAVY WEIGHT DRILL PIPE	1111.45 ft
JARS	30.97 ft
5 JTS. 4 1/2" 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 .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	9.75	38.97
2	11.0 in	REED	HP-53	NL-5609	400-3055 ft	2655	68.25	38.90
3	7.0875 in	REED	HP-53B	M25260	3055-3963 ft	908	30.50	29.77
4	7.0875 in	REED	HP-53B	M25515	3963-6935 ft	2972	109.00	27.27
5	7.0875 in	REED	HP-53B	T96054	6935-7338 ft	403	33.50	12.03
6	7.0875 in	REED	HP-53B	M25260	REAM 2995-6935 ft			
7	7.0875 in	REED	HP-53H	R22694	7338-8002 ft	646	92.25	7.00
8	7.0875 in	REED	HP-53H	R22695	8002-8562 ft	578	59.00	9.80
9	7.0875 in	REED	HP-53B	T96096	8562-9573 ft	1010	78.75	12.83

BIT CONDITION	TEETH	BEARINGS	GAUGE	COMMENTS
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#3	4	4	in.	
#4	5	5	-1.0625 in	
#5	6	4	-1.0625 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 lbf P-110, HYDRIL 513, and 6587 ft of 5 ½”-17 lbf N-80, LTC, D.V. Tool at 6448 ft, first stage cement 633 sacks 50/50 Pozmix “C” with 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 with 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 are 30–60+ft/hr, in the shales/siltstone ROP is >10 ft/hr.

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 feet of open hole. After setting and

cementing the 5.5 in. casing the shoe joint and 32 feet 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 lbf² proppant concentration, yielding $\pm 8,000$ md-ft. flow capacity. The design resulted in pumping 70,000 gallons of 35 lb/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 a 0.125-in. choke and allowed to flow back the load. The daily production rates through December 31, 2002 are shown in Exhibit 5. Continued testing and analysis will be provided in the next quarterly report.

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.

Internet Homepage: Preparing to be redesigned and updated.

Fig. 1. Nash Draw #36 actual production versus simulator production.

Fig. 2. 3-D seismic "L" Zone amplitude map showing #33 target area.

Fig. 3. Nash Draw #33 wellbore path.

Fig. 4. Predicted drilling time versus actual drilling time.

Fig. 5. Daily production tests.