HIGH POTENTIAL RECOVERY - GAS REPRESSURIZATION

Topical Report
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By
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BDM-Oklahoma, Inc
Bartlesville, OK

**National Petroleum Technology Office
U. S. DEPARTMENT OF ENERGY
Tulsa, Oklahoma**

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Topical Report

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Management and Operating Contract for the Department of Energy's National Oil and Related Programs

Work Performed Under Contract No.
DE-AC22-94PC91008

Prepared for
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National Petroleum Technology Office

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ABSTRACT

This report presents the background and results of a program initiated by the U.S. Department of Energy to assess the feasibility of gas repressurization to improve the economic recovery of petroleum by small, independent oil production companies. The work was performed under prime contract DE-AC22-94PC91008 by BDM-Oklahoma, Inc., as part of Work Authorization A03 Extraction Research, Improved Recovery Processes, Task 8 "High Potential Recovery—Gas Repressurization."

Workshops were conducted around the United States to present the program to independent producers and to inform them of a solicitation for proposals to conduct cost-shared projects to demonstrate gas repressurization technologies. A solicitation was conducted, and four subcontracts were awarded to demonstrate the use of natural gas and flue gas to improve oil recovery by small independent producers. This report also includes the four final reports from the field demonstration projects.

Two of the demonstration projects, one using flue gas and the other involving natural gas from a deeper coal zone, were both technical and economic successes. The two major lessons learned from the projects are the importance of (1) adequate infrastructure (piping, wells, compressors, etc.) and (2) adequate planning including testing compatibility between injected gases and fluids, and reservoir gases, fluids, and rocks.

ACKNOWLEDGMENTS

This work was sponsored by the U.S. Department of Energy under contract DE-AC22-94PC91008 Work Authorization A03 Extraction Research, Improved Recovery Processes, Task 8: High Potential Recovery—Gas Repressurization. Dr. Jerry F. Casteel was the DOE Project Manager. The project was planned, initiated, and, for most of its duration, led by David K. Olsen while he was with BDM-Oklahoma, Inc. Much of the material in the body of this report is based on earlier reports written by Dr. Olsen. Finally, the project has been possible only because of the courage and ability of the owners of the four small producing companies to undertake the field demonstration projects: Don Benson, John Godwin, Joe Klaeger, and Andy Park.

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EXECUTIVE SUMMARY

The Gas Repressurization Program was initiated by the U.S. Department of Energy to assess the feasibility of gas repressurization technologies to improve the economics of oil production by small independent oil production companies. The objective of this project was to demonstrate the ability of small independent oil producers to use existing gas injection technologies, scaled to their operations, to repressurize petroleum reservoirs and increase their economic oil production. The three major activities to accomplish the project objectives were:

1. Preparing and conducting workshops to inform independent producers about the program and about a solicitation for proposals to demonstrate gas repressurization technologies
2. Conducting a competitive solicitation for proposals and awarding subcontracts for field projects to demonstrate the use of gas repressurization technologies by small independent producers
3. Monitoring field projects through the subcontracts to demonstrate the feasibility of gas repressurization as a recovery method for use by small independent production companies and transferring the lessons learned to the oil production community

Six workshops were held in Kansas, Ohio, Oklahoma, and Wyoming to describe gas repressurization technologies and associated economic factors. Also, proposals were solicited from small production companies to demonstrate gas repressurization technologies. Four subcontracts were awarded as a result of the competitive solicitation:

- A.R. & R. Limited of Chautauqua, Kansas, for using coalbed methane to repressurize a shallower oil reservoir
- Driver Production, Inc. of Okmulgee, Oklahoma, for using flue gas to repressurize and as a drive
- Hydrocarbon Generation, Inc. of Allegany, New York, for using flue gas to repressurize and in a cyclic and drive mode
- Klaeger Operating Company of Hondo, Texas, for using natural gas to repressurize

Two of the projects—A.R. & R. and Driver—claimed both economic and technical success: additional oil was produced and revenues were higher than costs. A major problem encountered by the flue gas projects was the corrosion of tubulars, such as pipes, casing, etc. This problem, also faced in earlier projects, is caused by the potentially corrosive nature of flue gas. The major problem encountered with one of the natural gas injection projects was the incompatibility of the natural gas and solvents injected with the oil in the reservoir—asphaltene precipitation near the wellbore reduced the permeability drastically and resulted in a corresponding loss in production. Neither the operator nor consultants had become aware of the high potential for severe asphaltene precipitation until it was too late.

The results of this project show that small independent oil producers can apply gas repressurization techniques in appropriate circumstances. The bottom line in almost all cases is that prior planning will prevent, or at least identify, potential problems. In the case of injecting flue gas, corrosion is to be expected as a potential problem. Therefore, including equipment to remove potentially corrosive constituents from the flue gas is a necessity, as are inspecting piping and replacing sections that may be susceptible to corrosion. Testing the compatibility between the oil in the reservoir and gases and other materials planned for injection is essential to prevent injection of materials that may irreversibly damage the formation.

1.0 INTRODUCTION

The objective of this project was to demonstrate that small independent oil producers can use existing gas injection technologies, scaled to their operations, to repressurize petroleum reservoirs and increase their economic oil production. This report gives background information for gas repressurization technologies, the results of workshops held to inform small independent producers about gas repressurization, and the results of four gas repressurization field demonstration projects. Much of the material in this report is based on annual reports (BDM-Oklahoma 1995, BDM-Oklahoma 1996, BDM-Oklahoma 1997), a report describing the results of the workshops (Olsen 1995), and the four final reports for the field demonstration projects which are reproduced in the Appendix.

Most U.S. reservoirs were drilled and developed before pressure maintenance or repressurization was considered. Because of the practice of flaring low-cost gas in an effort to accelerate production of higher value liquids, i.e., oil and condensate, ultimate recovery from such reservoirs had been reduced. As reservoirs were discovered and drilled after the 1950s, increasing emphasis was placed on pressure maintenance and longer term best usage of the resource. Pressure maintenance and repressurization are common practices among major companies and larger independent producers. As the size of producing companies decline, reservoirs are more likely to be pressure depleted.

Reservoir repressurization technologies are well known. Gas (air and natural gas) injection was widely used in the Appalachian and Mid-Continent areas during the 1930s and 1940s before waterflooding was adopted. Natural gas and enriched gas have been used for decades by larger operators with plentiful gas resources, but are not available at a low enough price for most small producers. Steam has been used for more than 30 years but principally to recover heavy oil by major oil companies in California. Nitrogen generation on-site has become economic because of advances in nitrogen separation technology during the last decade. Flue gas, which was widely promoted in the 1970s, suffers from problems associated with corrosion and the very limited solubility of the 78% nitrogen. Each of these technologies has been used economically by larger companies, but the technology is not being used by many small oil-producing companies.

This project was designed to demonstrate that repressurization of reservoirs with gas (natural gas, enriched gas, nitrogen, flue gas, or air) can be used by small independent operators in selected reservoirs to increase production and/or decrease premature abandonment of the resource. The project excluded carbon dioxide because of other DOE-sponsored projects that address carbon dioxide processes directly.

1.1 PROJECT DESCRIPTION

The use of gas for pressure maintenance or repressurization is a well known and routinely practiced technology within larger oil companies; however, small operators seldom use it. Proven economic processes implemented in large operations must be redesigned for small-scale operations. To demonstrate the feasibility of scaling the technology for use by small operators, the following tasks were undertaken:

- Prepare and conduct workshops on repressurization.
- Conduct a competitive solicitation and award subcontracts for field demonstrations of repressurization by small independent producers.
- Monitor the field demonstration subcontracts and provide limited technical assistance to the project operators.

The workshops enabled presentation of the technical feasibility and economics of using gas injection for pressure maintenance or repressurization (Olsen 1995). The workshops also were used as a forum to announce a potential competitive solicitation for proposals from small independent producers for projects using gas for repressurization. The solicitation resulted in four field demonstration projects by small independent producers who were required to provide in-kind or matching funds. The lessons learned from the field projects were documented and disseminated in presentations for use by other area operators as part of the project.

1.2 BACKGROUND

Twenty-eight earlier field projects were analyzed in an effort to develop materials for workshops, to provide background for the proposal request and evaluation criteria, and to determine the scope of field projects that could be funded under this project.

Gas repressurization of oil reservoirs was first tried in Venango County, Pennsylvania, in 1890. The operator purposely allowed communication between a partially depleted oil sand and an underlying, higher pressure natural gas sand. Operators in the area today still reinject produced gas as part of their oil recovery operations. Within a few years, "gas pumps" (early compressors) were used to pull a vacuum on wells while discharging gas to other oil wells.

By 1910, compressors were becoming common, and air was often injected either alone or mixed with produced gas. Compressors served the dual purpose of condensing casinghead gasoline and providing gas for reinjection into the reservoir. By 1925, gas and air injection for repressurizing oil reservoirs (secondary recovery) was being used by Appalachian, Mid-Continent, and Gulf Coast producers. The first large field gas injection project was in the Nowata field of northeastern Oklahoma (Sandrea and Nielsen 1974).

Guides have been published (for example, see Goodlet et al. 1986a and 1986b) for selecting appropriate recovery processes including gas injection. The screening criteria presented for gas

injection often are based on achieving partial or complete miscibility between the injected gas and the oil in the reservoir. Although miscibility is not a prerequisite for gas repressurization, some of these criteria and testing methods can be useful as guides to the potential effectiveness of gas injection as a recovery method. Publications also are available for the design of projects and selection of equipment including the *Gas Engineers Handbook* (Segeler, editor, 1965); *Petroleum Engineers Handbook* (Bradley 1987), among others (Smith 1966; Langnes et al. 1972).

1.2.1 Natural Gas for Gas Repressurization

One of the most common applications of gas repressurization is external gas injection, often referred to as crestal, attic gas, or gas cap injection—the use of gas for displacing oil that is upstructure. Figure 1–1 illustrates the three stages of this type of gas repressurization project. In Stage 1, a well perforated in the producing zone allows oil to flow. As oil is withdrawn, the oil/water contact rises, increasing volumes of water are produced, and the remaining oil is trapped in the top of the reservoir (the attic). In Stage 2, the oil/water contact rises above the perforations. If high pressure gas is injected, then the attic oil can be displaced down structure toward the producing zone, creating a gas cap at the top of the structure as shown in Stage 3, enabling the well to produce oil again. Well remediation or reduced production rates may be necessary to minimize water coning, if the oil column is not pushed below the bottom perforations.

Figure 1–1 Gas repressurization for recovery of attic oil (Olsen 1995)

A classic pressure maintenance project (McGraw et al. 1964) and test of unitization in a low-relief anticline was conducted in the Pickton field developed on 40-acre spacing with 166 producing wells. Natural gas injection was initiated in the late 1940s, when voluntary unitization was in its infancy and several operators, royalty interest owners, and the courts were wrestling with how to apportion costs, reserves, and allowable production levels.

Reservoir studies indicated primary recovery of this high shrinkage oil would yield only 6,600,000 bbl oil or 19% of the OOIP. Unitization and repressurization were estimated to increase production to 17,800,000 bbl oil or 52% of OOIP. Natural gas was collected from gas-gathering lines in the field and supplemented by gas from a nearby gas reservoir. Gas was injected into four updip wells for pressure maintenance to supplement solution gas drive. The impact of gas injection was complicated by an infill drilling program, expansion of the limits of the field, and a reduction of the allowable production limit in an attempt to obtain higher economic recovery, but the increase in pressure owing to gas injection was reflected by the increase in daily oil production.

1.2.2 Use of Flue Gas for Repressurization

Interviews were conducted with small Mid-Continent and Appalachian basin producers who have used flue gas, or flue gas and steam (in both single-well and multiple-well patterns), in both cyclic and drive modes on their leases within the last decade. They report both successes and failures. Specifics are poorly documented in their field notes. While it is difficult to analyze why some applications succeeded and others failed, failures most often can be attributed to four causes: inadequate compressors, the mechanical failure of the well, insufficient knowledge of the geology of the reservoir, and the low oil saturation near the well. Evaluating failures often is more informative than describing successes in determining the critical factors influencing oil recovery.

Flue gas often is generated by mobile burners or internal combustion engines mounted on trucks or skid units. The gas is used for cyclic gas injection on single wells, gas drive between wells, injection into the gas cap, or attic gas injection to force oil down structure or to increase the pressure within reservoirs. The composition of the flue gas depends on the fuel burned, the fuel-air ratios, and whether an efficient catalytic converter is used to assist complete oxidation. Products of combustion include CO, CO₂, and oxides of sulfur and nitrogen which form corrosive acids when they contact water. Typical flue gas composition is about 85% N₂ and 15% CO₂. Carbon dioxide is much more soluble in water or oil than N₂. A DOE-funded review of the state-of-the-art use of flue gas and nitrogen was published earlier (Anada 1980). Numerous inventors and small operators built upon the basics published in the review and successfully implemented oil production (Olsen and Johnson 1993).

One of the case studies presented in the workshops involved the operation and economics of a small producer's use of flue gas in a cyclic operation to produce 29° API gravity oil from a Mid-Continent shallow (250–300 ft) sandstone reservoir (Johnson et al. 1990). This multiyear injection

project involved 51 wells. About 11 Mcf/D of natural gas was burned in an internal combustion engine to produce 100 Mcf/D of flue gas. The exhaust gas was passed through a platinum catalytic converter to remove corrosive oxygen and nitrogen oxides from the gas. The gas was cooled from 1,100° to 135° F, moisture was removed in a liquid-gas separator, and the gas was introduced to a compressor where it reached pressures ranging from 240 to 300 psi. Compression heated the gas to about 350° F, which was again cooled to about 135°F before being injected into the formation. The flue gas was sufficient to treat six wells simultaneously at an average injection rate of 17 Mcf/D. Following injection (3 weeks), a well was allowed to "soak" for 1 day and then opened to the stock tanks, producing about half of the gas injected. Typical cycles consisted of 3 weeks of injection followed by 21 weeks of production.

The economics of a project depends on the cost of natural gas, level of oil production, oil price, net revenue interest in a lease, life of the project, etc., where each project must be analyzed individually. In the case of the project just described, the cash flow paid back the initial investment in 2.3 years (undiscounted) and yielded an internal rate of return of 42% over a 10-year project life (Johnson et al. 1990).

Essentially two modes of flue gas generation have been used: internal combustion engines and steam boilers. Some operators have omitted air dryers and catalytic converters from their flue gas generators and have suffered the consequences of corrosive gasses being injected into piping, wells, and the reservoir. Maintaining the integrity of casing is not as critical for wells approaching abandonment; however, the two field demonstrations which used flue gas in this project (Driver and Hydrocarbon Generation) encountered severe problems from corroding tubulars.

Two sources of flue gas are (1) local generation of flue gas through combustion or incineration of fuel in a boiler and (2) remote generation by large industrial sources (i.e., fertilizer plants, electric utility plants, and local steam generation facilities). The industrial sources require pipelining the gas from the source to the field. Local generation is more common for small operators, where the gas volume required and the investment are low to modest. Fuels that have been used for local, or mobile, flue gas generators include natural gas, propane, and diesel fuel. Several operators using skid-mounted units, which remain on location for months, have used produced gas from other formations that they could not sell because of low volume, lack of gas gathering and transmission systems, or off-spec gas (i.e., natural gas below the minimum Btu/scf) as the fuel for their flue gas generators.

1.2.3 Use of Nitrogen for Gas Repressurization

Gas repressurization of oil reservoirs (Clancy et al. 1985; Sandrea and Nielsen 1974) using noncorrosive N₂ has become more widely available at a much lower cost per Mcf than 20 years or even a decade ago because of advances in air separation technology. Large cryogenic plants still supply large industrial users with N₂ and O₂. Until about a decade ago, nitrogen for small volume use was supplied as liquid N₂ produced by cryogenic separation at a central facility and

trucked to the end user, where it is vaporized. Cost of this N_2 at the cryogenic plant is low, but transportation, storage, and vaporization of liquid N_2 to generate a gas add to the compression cost such that the cost is \$23–\$28/Mcf (Eson 1989). In the last decade, on-site nitrogen generation has reduced N_2 costs by more than an order of magnitude. Two separate and distinct N_2 generation (air separation) technologies are common: pressure swing adsorption (PSA) using molecular sieve technology, and membrane gas separation technology.

Molecular sieve technology separates O_2 and N_2 from the air by preferential adsorption/desorption of O_2 and other gases from the air. Adsorbers within the sieve bed, when pressurized with air, adsorb O_2 and permit N_2 to pass through as product. Before becoming saturated with O_2 , the sieve bed is regenerated by reducing the pressure which releases an O_2 enriched waste gas. This process can generate 1 ft³ of 98% N_2 (2% O_2) for every 3 ft³ of inlet feed air. Membrane gas separation technology employs the principle of selective permeation to separate gases. Each gas has a characteristic permeation rate that is a function of its ability to dissolve and diffuse through a membrane. This characteristic rate allows “fast” gases such as oxygen to be separated from “slow” gases such as nitrogen. Compressed air is injected into a bundle of several thousand small hollow membrane fibers. The driving force for the separation is the difference between the gas partial pressure of each component gas inside and outside the fiber. As the gas stream flows along the inner surface of the hollow fibers, each gas component responds to its partial pressure differential and permeates through to the outside. “Fast” gases, such as O_2 and H_2O , permeate easily so that the outside gas stream is rich in O_2 . Due to their lower solubility and diffusivity, gases such as N_2 and Ar permeate much slower through the membrane. Thus, the inner portion of the fibers carry a gas stream which is enriched in N_2 . The capacity of membrane systems is flexible; the addition of skid-mounted units in series can easily expand capacity. PSA units, on the other hand, should be sized for maximum volume anticipated in the project, and are therefore less flexible.

The cost of N_2 from both PSA and membrane systems depends on the purity of N_2 required (gas repressurization often tolerates 3–5% O_2 content in the N_2), injection pressure, volume, and demand characteristics (baseline, periodic, erratic, or combination of demand patterns) (Hvizdos et al. 1988). The cost to deliver 97% N_2 at 500 psi at the rate of 36 and 180 tons/D is \$1.41/Mcf and \$1.03/Mcf, where the price difference results from the scale of operation. Lease of this size of equipment requires multiyear contracts, usually more than 5 years, plus mobilization and demobilization fees of approximately \$55,000.

1.2.4 Air and Mixtures of Air and Natural Gas for Gas Repressurization

Air or mixtures of air and natural gas above the explosive limit have been used for repressurization of oil reservoirs since 1911 (Torrey 1950). Although air is the most readily available and least expensive gas to inject per Mcf, ever-present oxidation of the oil (low temperature oxidation or high temperature in-situ combustion that ignites either spontaneously or is intentionally initiated) and greatly accelerated corrosion of tubular goods limit economic application. The first intentional in-situ combustion was reported as a method of paraffin

removal (Mills 1923). The literature is replete with descriptions of operators injecting air, with most trying to initiate combustion for the recovery of heavy oil. In the United States, there have been more than 230 attempts at air injection, mostly by smaller producers but also by major companies with extensive engineering, research, and development capabilities (Olsen 1995). About 20 air injection projects are reported to be commercially economic. Most, however, were poorly engineered with inadequate reservoir knowledge for the process implemented; inadequate surface or subsurface installation of facilities including piping, control equipment and water injection on producing wells to prevent wells from burning up; and inadequate or undependable compression facilities. Once air injection stopped, in-situ combustion projects could not be reignited. Only a handful of in-situ combustion projects are operating in the United States at the present, and these projects have more than 20 years of operational history where many of the site specific problems have been solved (Moritis 1994). A recent air injection project, partially sponsored by DOE, is reported to be both technically and economically successful (Gillham et al. 1998). Injection of air for the purpose of oil recovery has proven to be one of the most technologically difficult and manpower-intensive oil recovery processes.

Several small oil producers continue to use low pressure air to repressurize reservoirs which are stripper or marginal wells, late in their productive life. Operators typically report severe corrosion problems associated with low temperature oxidation, but sacrifice wells as they are about to be plugged and abandoned.

1.2.5 Costs in Gas Repressurization

Estimates of representative costs for compression equipment for small gas repressurization projects were obtained from equipment distributors and leasing companies during the summer of 1995. Costs were averaged over quotations received. Current equipment costs for natural gas and air compressors (Tables 1-1 through 1-4) suggest that most small independent producers are likely to lease equipment or find old repairable compressors rather than purchase new compressors. A definite scale of size is apparent in compression equipment, volume of gas delivered, compressor acquisition, and rental cost. Larger volumes of gas can be injected at much lower cost per Mcf.

Table 1-1 Cost of new natural gas or air compressors (Olsen 1995)

Rate, ft ³ /D	Inlet Atmospheric Discharge, psi	Stages/total horsepower	Cost \$/horsepower
100,000	500	3 stage, 60 hp	1,100
250,000	500	3 stage, 150 hp	800
500,000	500	3 stage, 200 hp	650
1,000,000	500	3 stage, 300 hp	550

Table 1-2 Natural gas compression size and equipment lease rate: inlet pressure = 25 psig, discharge pressure as stated (Olsen 1995)

Estimated Horsepower Required					
Discharge, psi	Stage	160 Mcf/D	250 Mcf/D	500 Mcf/D	1,000 Mcf/D
100	1	7	17	34	67
300	2	14	34	68	136
500	2	17	42	84	168
1,000	3	21	54	107	214

Estimated Monthly Rental Rate (natural gas engine driven)					
Discharge, psi	Stage	\$	\$	\$	\$
100	1	800	800	900	1,200
300	2	950	1,100	1,350	1,800
500	2	950	1,100	1,400	2,100
1,000	3	1,200	1,600	2,200	2,600

Table 1-3 Air compression size and equipment lease rate: inlet pressure = 0 psig, discharge pressure as stated (Olsen 1995)

Estimated Horsepower Required							
Discharge, psi	Number of Stages	100 Mcf/D	250 Mcf/D	500 Mcf/D	1,000 Mcf/D	2,000 Mcf/D	10,000 Mcf/D
100	2	13	38	76	152	455	1,510
300	3 or 2	23	58	115	229	686	2,289
500	3 or 4	27	68	135	270	812	2,708
1,000	5 or 3	32	81	162	324	976	3,238

Estimated Monthly Rental Rate (see footnotes)							
Discharge, psi	Stage	\$	\$	\$	\$	\$	\$
100	2	^E 280	^E 650	^D 1,200	^D 1,800	^E 2,400	^E 7,500
300	2 or 3		^S 3,000	^S 3,200	^S 4,200	^S 11,000	^S 35,000
1,000	3				^B 11,000	^B 17,000	^B 51,000

S = two-stage screw D = diesel engine driven N = natural gas engine driven
B = booster required E = electric motor driven two-stage screw and single-stage piston booster

Table 1-4 Air compression costs with 100-psi discharge (Olsen 1995)

Motor Size, horsepower	40	125	500
ft ³ /min	156	700	2,610
ft ³ /D	224,640	1,008,000	3,758,400
Initial Investment:			
Equipment Cost, \$	4,371	17,107	49,177
Installation, \$	458	1,571	7,582
Monthly Upkeep/Repair, \$	95	230	535

The cost of air compressor rental is significantly higher than that for natural gas compressors for the same volume and discharge pressure. Air compressors start compression at zero psi (natural gas collection lines usually have >20 psi), and air requires greater maintenance and stricter operating tolerances, and costs more to operate per Mcf injected; however, air is readily available at no cost, whereas natural gas has an associated acquisition cost, even if it is produced in the same field as the gas injection project. The combined cost of natural gas with a compressor is higher than for an air system.

The analysis of several field projects reveals a wide range of cost for gases injected, as well as for the cost of each barrel of oil produced by gas repressurization. The representative costs (with overhead, royalties, utilities, maintenance, etc.) per barrel of oil produced is shown in Table 1-5. These do not include initial investment in equipment required for startup. Steam is included for reference purposes only because it is widely used in heavy oil recovery. Carbon dioxide was omitted because the scale of operation greatly impacts the cost of oil production with this gas. Energy costs were based on \$18/bbl oil, \$1.20/Mcf for acquisition of natural gas, and \$0.05/Kwh for electricity.

Table 1-5 Representative costs for each barrel of oil produced (Olsen 1995)

• Flue Gas—less than \$4/Mcf using propane for fuel
- 1995 Cyclic operations \$8 to \$14/bbl of oil produced
- 1990 Drive \$4 to \$9/bbl of oil produced
• Nitrogen—cost of \$0.40 to \$1.33/Mcf of N ₂ injected
• Natural Gas—up to \$1.80/Mcf
- 1995 Cyclic operation \$8 to \$10/bbl of oil produced
• Steam—cyclic \$5.50 to \$12.50/bbl, drive \$7 to \$12/bbl of oil produced
• Air/In-Situ Combustion—< \$0.40/Mcf for air injected
- Drive > \$4.50/bbl of oil produced

Many small producers are very familiar with pumping units; however, they are not as familiar with the more critical requirements of high pressure compressors which are the heart of gas repressurization. The pros and cons of centrifugal and reciprocal compressors are briefly listed in Table 1-6.

Table 1-6 Relative merits of centrifugal vs. reciprocating compressors (Olsen 1995)

Advantages		Disadvantages	
Centrifugal			
1.	Lower first cost	1.	Higher horsepower requirements
2.	Continuous operation	2.	Specialty maintenance is mandatory
3.	Low maintenance (shutdown required only every two years)	3.	If major problems arise, only factory can fix
4.	High technology (many are in use)	4.	Must make internal changes for each type of gas injected
5.	Less space required	5.	More sophisticated controls
6.	Oil free air	6.	Internal corrosion because of H ₂ S in air
Reciprocating			
1.	Lower horsepower requirements	1.	Higher initial costs
2.	Routine maintenance can be done on site	2.	High maintenance (shutdown required every 6 months)
3.	More forgiving if external maintenance is deficient	3.	Higher installation costs
4.	Major problems probably will not arise		
5.	Low maintenance if synchronous motors used		

1.2.6 NPR-3 Gas Injection Projects

The Naval Petroleum Reserve No. 3 (NPR-3), Teapot Dome field, Wyoming, has been the site of four gas injection projects which were operated on the scale of a small- to medium-sized oil producer. The Shannon reservoir at NPR-3 produces light oil (32°–34° API gravity) from a shallow, pressure-depleted, heterogeneous, faulted and highly fractured sandstone. The Shannon is the shallowest of nine producing reservoirs in the field and has been the site of three of the gas injection projects: an in-situ combustion pilot (Sarathi et al. 1993), a steamflood (Olsen et al. 1993; Doll et al. 1995), and a cyclic natural gas repressurization project. The cyclic natural gas project grew from a pilot in 1993 to a commercial-size project covering 200 wells in 1995. The project demonstrated economic oil recovery (\$8–\$10/bbl of oil produced) from an area south and west of the current steamflood with recovery of more than half of the natural gas injected. The cyclic natural gas project has been more economically favorable than the light-oil steamflood (\$10.15/bbl) and required far less capital investment than steamfloods. This innovative project

takes advantage of the solubility of natural gas in oil, the extensive fracture network in a pressure-depleted reservoir, and engineering expertise gained through experience with the previous gas injection projects and understanding of the reservoir geology's influence on oil production.

An air injection and enriched air injection pilot was conducted between 1981 and 1986 for an in-situ combustion project in the Shannon (Sarathi et al. 1994). Many attempts to ignite the reservoir failed. It was only after preheating the reservoir with steam that in-situ combustion was initiated, and then all monitoring parameters indicated a very inefficient burn. Over the 18-month life of the pilot, 72,500 bbl of oil were produced with only 17,000 bbl from the five-acre pilot area. Because the pilot was implemented at the time of rising oil prices, the project proved to be marginally economic despite a high air/oil ratio of 39.2 Mcf/bbl of oil produced.

The analysis of previous DOE-funded air injection projects highlighted the difficulties in using air to recover oil (Sarathi and Olsen 1994). Air injection has been used since the 1920s. Field projects and laboratory studies have confirmed that this technology is one of the most technically challenging and manpower-intensive oil recovery technologies (Farouq Ali 1994; Sarathi and Olsen 1994). Very few companies have been able economically and safely to handle air injection as a method of repressurization because of in-situ combustion.

The Second Wall Creek reservoir at NPR-3 has been natural gas flooded, operated as a gas storage unit where low-cost gas is purchased during the summer and produced during the winter when natural gas demand and price are higher. Enriched gas and oil are produced with oil being recovered in the separators, condensate being recovered in the gas plant, and lean gas being sold or reinjected.

1.3 WORKSHOPS

Workshops were conducted featuring case histories of pressure maintenance or repressurization through the use of natural gas, enriched gas, flue gas, air, and nitrogen (Olsen 1995). The workshops also were used as a forum to announce a solicitation for pressure maintenance or repressurization field demonstration subcontracts.

Between August and October 1995, six workshops on gas repressurization were conducted by BDM-Oklahoma. The workshops attracted 181 participants. The location and attendance at the workshops are shown in Table 1-7. The workshops covered examples of gas (air, natural gas, flue gas, and nitrogen) injection projects conducted by independent operators over the last 90 years. Because the technology is not new, many of the examples were those from projects conducted in the 1900 to 1950s era, during which time many operators were flaring gas rather than reinjecting produced gas into the reservoir to maintain pressure. The workshops briefly covered: (1) an overview of DOE's Gas Repressurization Program, (2) the economics of gas repressurization and the cost of compression, (3) a review and history of oil recovery processes by gas injection, (4) reservoir and process screening criteria, (5) a review of the impact of reservoir internal architecture on gas repressurization, (6) case studies of selected gas repressurization projects, (7) a description of the Program Research and Development Announcement (PRDA) requesting

proposals from small independent petroleum producers and the application form to conduct gas repressurization projects on a cost-sharing basis, and (8) a question and answer session following the formal presentation.

Table 1-7 Location and attendance at gas repressurization workshops

Date	Meeting	Location	Attendance	Applications Distributed
August 16-18, 1995	Wyoming Independent Producers Meeting and PTTC Problem Identification Workshop	Casper, Wyoming	28	14
August 24-25, 1995	Mid-Continent Technical Session on Increasing Profits in Marginal Oil Fields	Great Bend, Kansas	11	11
September 6, 1995	PTTC Problem Identification Workshop	North Canton, Ohio	28	15
September 15, 1995	Eastern Kansas Oil & Gas Association Annual Meeting	Chanute, Kansas	74	42
September 26, 1995	Oklahoma Independent Producers Association	Oklahoma City, Oklahoma	24	19
October 10, 1995	Oklahoma Independent Producers Association	Ardmore, Oklahoma	16	16

The best response from small independent producers was through workshops held in Kansas and Oklahoma. Focused workshops such as the PTTC Northern Mid-Continent/Tertiary Oil Recovery Project workshop on Increasing Profits in Marginal Oil Fields (Great Bend, Kansas), which brought small producers together for two days, prompted significant discussion outside the presentation time. Workshops coordinated with state oil and gas associations held in areas where small independent producers predominate (southeast Kansas, central, and southern Oklahoma) generated interest beyond the workshops as reflected in the large number of phone inquiries after the workshops.

1.4 SOLICITATION

An announcement of a solicitation for firm-fixed priced proposals for field projects, titled "High Potential Recovery by Gas Repressurization Conducted by Small, Independent Petroleum Producers," PRDA No. OKL-5204-01, was published in the *Commerce Business Daily (CBD)* on

July 28, 1995. A news release was sent to about 30 petroleum industry trade journals, newspapers on petroleum production, and weekly-subscription energy publications. The *American Oil & Gas Reporter* (principal independent producer trade journal) published the announcement in the September 1995 issue; *Improved Recovery Week* published the announcement in the August 28, 1995, issue; and announcements appeared in state independent petroleum producer association newsletters. The *American Oil & Gas Reporter* published a follow-up article on gas repressurization as part of their coverage of the Eastern Kansas Oil & Gas Association annual meeting (October 1995 issue).

Proposal applications were distributed at the workshops and also upon written, faxed, or phoned request. As of December 29, 1995, the closing date for receipt of applications, more than 350 applications had been distributed.

BDM-Oklahoma received eight completed applications in response to the PRDA. The proposed projects fell into two categories.

- Projects that are on close spacing, are in shallow reservoirs, and should show significant oil production within 12 months
- Projects that are on larger spacing, are in deeper reservoirs, and would require more than 12 months to show significant oil production

The proposed project's sites were spread across the United States:

- Kansas, 1
- New York, 1
- Oklahoma, 2
- Texas, 1
- Utah, 1
- Wyoming, 2

Respondents proposed using a number of secondary oil production technologies: three proposed natural gas injection, two proposed natural gas injection with gas derived from coal beds, one proposed cyclic natural gas, and two proposed flue gas injection. Applicants could request up to a maximum of \$150,000 per project and had to match in cash or in kind at a minimum of 50:50. Applicants proposed projects totaling \$7,376,917 and requested funding of \$1,160,417. Funding from DOE was sufficient for four field projects. An environmental site assessment, ES&H review of the projects, and an assessment of applicants' in-kind contributions were completed prior to award.

BDM-Oklahoma awarded four fixed-price, fixed-time subcontracts for gas repressurization field projects. The four projects were on close spacing, in shallow reservoirs, and significant oil production could be expected within 12 months. The four projects were distributed across the United States, as shown in Figure 1-2.

Figure 1-2 Location of the four gas repressurization field demonstration projects

In addition to the field projects themselves, transfer of lessons learned to other independent producers, giving them an opportunity to evaluate their leases and the economics of implementing gas repressurization in their holdings, also was an integral part of the program. Field project operators, with BDM-Oklahoma assistance, were to provide final reports (see the Appendix) describing the following:

- Details and logic of why a specific gas repressurization process (natural gas injection, flue gas injection, etc.) was chosen
- Reasons why the process is compatible with the reservoir architecture, and the factors that control oil recovery
- Design of the project
- Project start-up
- Description of operating problems
- Oil production response
- Detailed economics of the project

Field tours and technical presentations by the producers were part of the technology transfer to encourage economically efficient and environmentally acceptable oil production. The results of the Driver project were the subject of a paper presented at the SPE/DOE IOR Symposium in Tulsa, Oklahoma, in April 1998 (Godwin et al. 1998). The DOE-funded portion of the projects was completed by the end of 1997. As discussed later, most of the operators continued operation

beyond this date on their own. The four projects, identified by operator, are briefly described below.

A.R. & R. Limited

A.R. & R. proposed repressurization of a Weiser sandstone oil reservoir using natural gas obtained from shallower coal beds to recover 32° API gravity oil. The project was located in the Sorghum Hollow field in Chautauqua County, Kansas. The nearest town is Hale, Kansas. The project had one coalbed methane well that was producing. A water disposal well was to be drilled as part of the project, oil wells that had been shut in (since 1993) were reworked, and a gas line was installed from the existing coalbed methane well to an updip injection well.

Andy Park and his wife run a two-person operation with six coalbed methane wells and about 35 oil wells in Chautauqua and Montgomery Counties in Kansas. A.R. & R.'s production amounts to about 5–10 bbl/day of oil and 300 Mcf/day of gas. The company has been in the production business since the early 1980s. The Parks do not have a geology or engineering background, but have gained their experience and knowledge on the job.

Driver Production, Inc.

Driver proposed conducting a flue gas drive on a five-spot pattern to recover 30° API gravity oil from a Dutcher sandstone reservoir in East Edna field in Okmulgee County, Oklahoma. The nearest town is Slick, Oklahoma. The operator assembled a flue gas generating system, reworked wells, and was injecting flue gas by mid-September 1996.

John Godwin runs Driver as a one-person operation. He has about 80 wells in 7 counties of east central Oklahoma. His operations produce about 1,500 bbl/month of oil and 5 MMcf/month of gas. He is in his 20th year of oil production. He does not have a geology or engineering background—his B.S. degree is in business management.

Hydrocarbon Generation, Inc.

Hydrocarbon Generation, Inc. (HGI) proposed conducting a flue gas drive in a multiwell pattern to recover 43° API gravity oil from the Chipmonk sand in Allegany field in Cattaraugus County, New York. The nearest town is Allegany, New York. The field is on the north side of the Bradford field that straddles the Pennsylvania/New York state line. The majority of the wells in the field are pre-World War II. This field was the site of a former waterflood. The operator built a flue gas generating system, reworked wells and flow lines, and injected flue gas by mid-September 1996.

Don Benson operates HGI with between three and ten people, depending on drilling activity. HGI owns and operates about 80 wells, including 20 water injectors, in Cattaraugus and Wyoming Counties of New York. Normally, production amounts to about 30 to 40 bbl/day of oil and 450 Mcf/day of gas. Most of the gas has been used to generate electricity which is sold to the

electric utility; however, recent adverse pricing has led to shutting in most of the gas production. Benson has some civil engineering education, but otherwise, none of the HGI personnel have engineering or geological backgrounds.

Klaeger Operating Co.

Klaeger proposed operating a cyclic natural gas project to recover 18° API gravity oil from the Olmos sandstone, Taylor-Ina field in Medina County, Texas. The nearest town is Hondo, Texas. This project involved a solvent slug/natural gas injection. The Olmos sand is very fluid sensitive. Several EOR methods had been tried in the field previously, but failed because of loss of permeability because of swelling and migrating clays. Ten wells were reworked, gas lines were installed, and the first cycle of solvent slug/natural gas was injected in August 1996.

Joe Klaeger has a six-person operation with about 250 stripper wells, all in Medina County, Texas. Production is about 3,000 bbl/month of oil. The company has been in operation since 1964. Prior to starting the company, Klaeger worked for 13 years at Halliburton, where he ended in charge of the Carrizo Springs, Texas, field camp. Neither Klaeger nor any of his employees are geologists or engineers.

2.0 LESSONS LEARNED AND CONCLUSIONS

Of the four gas repressurization field demonstration projects, two involved injection of natural gas whereas the other two involved injection of flue gas generated by internal combustion engines. A complete description of the projects, their results both technical and economic, conclusions, and lessons learned can be found in their final reports, which are included in the Appendix in their entirety.

Two of the projects (A.R. & R. and Driver) claim both economic and technical success: additional oil was produced and revenues were higher than costs.

A major problem encountered with the flue gas projects was corrosion of tubulars: pipes, casing, etc. This is a problem faced by earlier flue gas projects. The major problem encountered with one of the natural gas injection projects was the incompatibility of the natural gas and solvents injected with the oil in the reservoir—asphaltene precipitation near the wellbore reduced the permeability drastically, which resulted in a corresponding loss in production. Neither the operator nor consultants became aware of the high potential for severe asphaltene precipitation until it was too late.

The bottom line in almost all cases is that prior planning will prevent, or at least identify, potential problems. In the case of flue gas, corrosion is to be expected as a potential problem. Therefore, including equipment to treat the flue gas to remove potentially corrosive constituents is a necessity as is inspecting piping and replacing sections that may be susceptible to corrosion. In all cases, testing the reaction between the oil in the reservoir and gases and other materials planned for injection is essential to prevent injection of materials that may irreversibly damage the formation. Some of the other lessons learned in the four demonstration projects are summarized as follows.

A.R. & R.

- The reclaiming and reuse of the natural gas for the enhancement of the oil production could easily double the amount of oil produced from a field under the right circumstances. If there is not a methane reclaiming system in use, there probably should be, for this could benefit the operator very much so, economically.
- A pressure maintenance program needs to be installed immediately when new reserves are found and should be put in place in depleted reservoirs even if secondary water flooding has failed.
- A good steady volume of methane should be injected without interruption. The volume will depend on the operator's supply. Discussion continues regarding the best compression system to use: electric motors or natural gas engines.

Driver

- Recognition of time requirements is the biggest lesson to be passed on to other project operators. To review, acquire, and set up the necessary equipment for this project requires many days.
- Knowledge and proper installation of equipment to be used, and knowledge of the behavior of the equipment so it can be sized appropriately for application to a specific reservoir are very important. Many independent producers may not be familiar with fabrication, compression, gas injection, and corrosion potential.
- Control requirements are essentials to the success of a project. The operator must be able to measure pressures and production of the individual wells. Ability or access to laboratories capable of determining gas composition are invaluable.
- Patience is necessary because of the time it takes from start-up to actual results. This type of project will probably take up to six months before there are observable results.
- Anticipation of solving problems before they become larger is essential. Maintenance of equipment, coated fittings, and corrosion prevention chemicals are the three main problems that must be resolved for this type of project.
- Corrosion control is the single most important factor present. The flue gas constituents must be reviewed, and adverse or unwanted components must be controlled. Fuel mixture must be kept very rich, the catalytic converter must be functional, and gas cooling and liquid condensation must attain a maximum level at all stages of compression and before injection.

Hydrocarbon Generation

- The very first lesson learned was that the existing water injectors were not taking as much fluid as previously believed. This put immediate constraints on the project. It could be noted that this project turned out to be more of a pressure maintenance program, rather than a repressurization of the Chipmonk formation.
- It was expected that one would see some immediate effect on the injectivity of the flue gas. One now will assume that this could not take place because of the wellbore damage already caused by the waterflood.

Klaeger

- When a new project is planned, all aspects of the complete program are decided on. Stop right then and take a fresh look at each and every part of the program before any dollars are spent.
- It was common knowledge to all operators in Taylor-Ina field that the crude is asphalt based, but no one connected with the project had any idea of the severity [of the consequences] of injecting natural gas and condensate into the formation. The mix

didn't provide sufficient solubility to keep the asphaltenes from flocculating and plugging the formation around the wellbore. The more that was injected, the more production declined. The operator did not find out about this problem until late in the project. This stemmed from a lack of understanding of the reservoir fluids.

- Never fracture wells down 2-in. tubing with this type of oil without using friction reducers or higher gravity crude. After fracturing eight wells at 1,200 feet, Klaeger tried using a 1.5-in. sand pump. This would take at least an hour per trip. The operator has fractured a couple hundred wells in the Taylor-Ina area down 4-in. casing reverse circulating fracture sand through 2-in. tubing without problem. These wells had to be fractured through tubing and packer because of the age of the casing.

Conclusions

Andy Park identified two positive results from A.R. & R.'s coalbed methane injection project:

The volume of fluid increased to wells located around the gas cap well. Prior to gas injection, wells were pumped off making approximately 0.5 BOPD per well. After injection of methane as part of this project, these same wells are making 2.5 to 3.5 BOPD per well and holding 10 to 20 psig on the annulus. This is a very positive result, since prior to injection, 1 psig would hold back the fluid and only a small volume could be pumped. With 10 to 20 psig on the wellhead now, we are getting a full stroke of fluid just about as fast as we can pump.

The second result is an economic one. We have realized that we have the ability to store methane through the low price months while building pressure on the oil formation and possibly blowing down certain wells, hopefully moving oil into these wellbores, and selling the methane at a yearly peak price. This alone is worth the price of injecting methane. Even if an operator has to purchase methane, it could be bought at a low, summer price, be injected, and blown down to sell at a higher price.

Prior to this project, the lease in A.R. & R.'s project had been shut in, in terms of oil production, for the two years before 1995. Before shut-in, production had been 4 bbl/day oil and 150 bbl/day water from eight to ten wells pumping full time. At the conclusion of the project, A.R. & R. was producing 5 BOPD and 25 BWPD from two wells. As Park said in his report, "the methane injection project didn't 'take a sick horse and make it well,' it took a dead horse and resurrected it."

According to John Godwin of Driver,

...the most important benefit to other operators who are considering a similar project is that this type of project can be accomplished. The operator does not need to have firsthand knowledge of all aspects of this project. The operator

already has the basic knowledge of oil and gas production and the corresponding use of that related equipment.

There are very common similarities between choosing a field for a flood project in either water flooding or gas flooding. The engineering and geological requirements are very similar for either type of flood. The determination must be made as to the [fraction of] reservoir volume, whether gas or water, that must be injected into the producing formation to re-charge the formation and cause the oil to begin to move. Controls must be kept to determine injected and produced volumes. Downhole pressurization and formation fill up happens in both types of floods. The gas injection systems appear to be much cleaner both environmentally and downhole.

The results of Hydrocarbon Generation's project were not as favorable as those of A.R. & R. or Driver. As Don Benson said,

Very little incremental oil production was realized. Most of the incremental oil that was produced came from oil producing wells that had a huff'n' puff completed on them. This seemed to have a cleansing effect on the wellbore and tubulars.

Benson did not identify the repressurization technology as the cause for the poor results; rather, "... the age of the field and past practices inhibited the final results both economically and technically."

HGI plans to move the flue gas generator to another oil field in Allegany, New York, which has not been waterflooded and has good permeability and porosity. The operator says, "We are very confident that this technology will work given the correct location."

The major conclusion of the project conducted by Klaeger is that injection of gas and/or chemicals that are incompatible with native fluids can ruin a project. Neither Klaeger himself, his neighboring operators, nor consultants were aware of the high potential for severe asphaltene precipitation in his reservoir. Once the incompatible materials had been injected, the formation did not recover injectivity and production.

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**APPENDIX A
GAS REPRESSURIZATION PROJECT
SORGHUM HOLLOW FIELD
CHAUTAUQUA COUNTY, KANSAS**

Final Report

**by
Luther A. Park, Jr.
A.R. & R. Ltd.**

September 1997

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EXECUTIVE SUMMARY

This report summarizes the 1996–1997 field research conducted by A.R. & R. Ltd. (PRDA) No. OKL-5204-01. This project is part of Project 95-103 Extraction Research, Improved Recovery Processes Task 8 High Potential Recovery—Gas Repressurization by BDM-Oklahoma for the U.S. Department of Energy.

The project included four tasks as follows: (1) repair lease roads from county road over to the gas cap well, (2) drill and complete a salt water disposal well, (3) inject natural gas into the “gas cap,” and (4) pump several wells surrounding the gas cap.

The purpose of this project was to take an existing solution gas drive oil reservoir which has basically been depleted of its primary recovery, inject natural gas into the “gas cap” of the horizon, monitor all existing surrounding oil wells, determine which oil wells were affected in a positive or negative way, and coming to an economic and feasibility evaluation.

At the end of the project, two positive results were apparent.

- The volume of fluid increased to wells located around the gas cap well. Prior to gas injection, wells were pumped off making approximately 0.5 barrel of oil per day per well. After injection of methane as part of this project, these same wells are making 2.5 to 3.5 bbl per day of oil per well and holding 10 to 20 psig on the annulus. This is a very positive result since prior to injection, 1 psig would hold back the fluid and only a small volume could be pumped. With 10 to 20 psig on the wellhead now, we are getting a full stroke of fluid just about as fast as we can pump.
- The second result is an economic one. We have realized that we have the ability to store methane through the low price months while building pressure on the oil formation and possibly blowing down certain wells, hopefully moving oil into these wellbores, and selling the methane at a yearly peak price. This alone is worth the price of injecting methane. Even if an operator has to purchase methane, it could be bought at a low, summer price, be injected, and blown down to sell at a higher price.

The main lesson learned during the project is that a pressure maintenance program needs to be installed immediately when new reserves are found and should be put in place in depleted reservoirs even if secondary water flooding has failed.

A good steady volume of methane should be injected without interruption. The volume will depend on the operator's supply. Discussion continues regarding the best compression system to use: electric motors or natural gas engines.

ACKNOWLEDGMENTS

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A-1.0 PROJECT DESCRIPTION

A-1.1 INTRODUCTION

The intent of this paper is to review the influence of geology on repressurization performance and describe the changes made to the operations since 1996 and the results of those changes.

The overall objective of the repressurization at the Ownbey lease is to extend the economic life of the field, thus allowing for future development of other producing formations. It is hoped that lessons learned from this repressurization operation may be useful in developing other pressure-depleted, consolidated, tight, fractured, heterogeneous light-oil reservoirs.

A-1.2 BACKGROUND

A-1.2.1 Setting and History

The Sorghum Hollow field was first discovered in the early 1900s. The producing formation is the Weiser sand at a depth between 850 and 1,050 feet. The field extends approximately 5 miles in a northeast southwest direction. The Ownbey lease is the most southwest extension of the field to date with dry holes to the southwest. It was discovered in 1980 and is approximately 320 acres. The heart of the pool is considered approximately 160 acres; however, the northeast extension has not yet been defined. The lease is located 13 miles southwest of Independence, Kansas, and 13 miles northeast of Sedan, Kansas. The initial wells had a shut in pressure from 380 psig to 410 psig, 24 to 48 hours after frac. The "higher" wells were usually flowing wells from 1 up to 90 days, some with an oil cut of 80%. A photograph of a good example of initial oil flow and pressure is given in Figure A-1. The "lower" wells usually had to be pumped with an oil cut from 5% to 25%. The lease produced approximately 60,000 bbl of primary oil. Water flooding was attempted and had little effect. The "gas cap" well was drilled in 1982 and methane was vented into the air to bring the oil into the wellbore. At this time there was no gas market, and oil was \$30/bbl. This exhausted the gas drive of the oil, and production began to fall rapidly. New wells were drilled around the "gas cap" with marginal success. Natural gas was discovered on the adjoining lease in 1992 from a coal seam known as the Mulky. This gas-bearing coal is approximately 300 feet deeper than the Weiser oil sand. A new well was drilled on the Ownbey lease, and gas was found in the "Mulky coal."

Figure A-1 A good example of initial oil flow and pressure: Owbey No. 22, 24 hours after
fracturing

A-1.2.2 Weiser Repressuring Operating Strategies

The problem with existing strategies is that there were none that we could find. The Weiser sandstone has had attempts at water flooding for the past 90 years in this area, but as far as we know it has not been "gas" repressurized. The water flood attempted usually has no effect because of the fact that the Weiser sand has many laminations of Bandera shale. This apparently causes the injected water to "channel" in undesired directions. The strategy that we developed was that the injected methane would end up going the right direction (to the gas cap) causing a rejuvenation of the gas drive to a certain degree and possibly "sweeping" oil to existing wells and hopefully force the encroachment of water down dip bringing more oil into the "down dip" oil wells. We came to this strategy with cross section, structure, and isopach mapping.

A-1.2.3 Operating Costs

The operating cost basically has four major factors.

- The supply of methane
- The cost of compression
- The cost of water disposal
- Pumper and roustabout fees

For this project, the supply of methane does not have to be purchased, which has a marked influence on the feasibility of the project. The disposal of water in this case has almost no cost because of the fact of a disposal well that takes water on gravity instead of having to pump water with electricity and high pressure pumps. The cost of man and machine hire is minimal in this case also. The biggest expense is the cost of compression. This can be hired out, or the operator can attempt to compress the gas by buying the equipment himself. Either way, it is the biggest expense of the project.

A-1.2.4 Project Review

To determine if we should attempt this project as far as having enough methane and to the feasibility of secondary recoverable oil, a consultant was hired to give his opinion and calculations (see Section A-5.0). With this information and the help of the National Institute for Petroleum and Energy Research, we elected to go forward.

A-1.3 GEOLOGIC CHARACTERIZATION

A-1.3.1 Geologic Setting

The Weiser sandstone formation is found in the Bandera Shale as part of the Marmaton group of the Pennsylvania System. The Weiser sand in the Sorghum Hollow field is described as being located below the Altamont limestone and above the Pawnee limestone. In the Sorghum Hollow field, the Weiser sand is found at a depth between 850 and 1,050 feet. Typically, the sand is grayish-brown, fine to medium grained shaley sandstone ranging in thickness from 10 to 100 feet in completed wells. Location, isopach, and structure maps are presented in Figures A-2 and A-3.

Figure A-2 Field location and oil sand isopach map of Ownbey and neighboring leases

Figure A-3 Geological structure map, top of the Altamont limestone, of Ownbey lease

Analysis of core samples (see Section A-5.0) shows porosity of 16%, saturation of oil 20%, saturation of water 5%, total saturation volume 25%, permeability 10 to 90 md.

A-1.4 FACILITY DESIGN, OPERATIONS AND PROBLEMS

A-1.4.1 Water Disposal

The water disposal system for the project is a well drilled approximately 200 feet into the Arbuckle formation. Porosity was found, the well was perforated, and an acid breakdown job was performed. A series of filters was put inline to filter impurities before disposal. This well should take a large amount of water under "gravity" injection.

A-1.4.2 Methane Supply

The methane supply for the project is from a new well (well No. 2-M) drilled on the Ownbey lease in 1995. The Weiser oil sand had thinned to 7 feet in this well. The well was structurally high (see Fig. A-3), thinning the sand on the high. The "Mulky coal zone" was perforated and sand fractured, then put on pump. A photograph of a typical shallow well workover is shown in Figure A-4. The well pumped approximately 1 hour, started flowing through the tubing, and has been flowing around 70 to 90 Mcf per day with approximately 5 bbl of water since day one. The shut-in pressure of the Mulky well is 340 to 360 psig. When the well is flowing through the tubing, the annulus pressure is 210 to 260 psig depending on the volume of gas allowed to flow. This gas would go to market, and a supply line to the injection "gas cap" well would supply methane for injection. The Btu rating of the coal gas was 890, while the Weiser gas was 1,341 (see Table A-1).

Table A-1 Gas sample analysis: analysis of gas sample from Troyer lease, A.R. & R. Ltd., performed by Treat-Rite Water Labs, Inc., of Nowata, Oklahoma

Component	Mol %	Sp. Gr.	Btu	GPM
Hexanes Plus	1.2672	0.0377	60.2705	0.5313
Nitrogen	10.3864	0.1005	0.0000	0.0000
Methane	62.5812	0.3466	631.8820	10.8453
Carbon Dioxide	1.0688	0.0162	0.0000	0.0000
Ethane	6.4638	0.0671	114.3320	1.7633
Propane	10.0447	0.1529	252.8750	2.8195
Iso-Butane	1.9428	0.0390	63.1935	0.6481
N-Butane	4.1728	0.0837	136.1210	1.3411
Iso-Pentane	1.0362	0.0258	41.3189	0.3809
N-Pentane	1.0305	0.0257	41.3189	0.3809
Total		0.8953	1,341.4400	18.9001

Compressibility Factor 0.9953

Figure A-4 Typical shallow well workover: Ownbey No. 2M

A-1.4.3 Natural Gas Injection

The sales line from the supply well would be shut, and all the methane would be delivered to the "gas cap" injection well (Ownbey well No. 13, see Fig. A-5), hoping that the pressure of the "Mulky zone" would allow methane to start repressuring the Weiser sandstone. Then when gas flow into the gas cap slowed, a compressor system would be put in place to compress gas into the oil sand. This would allow, hopefully, the first "fillup" of natural gas to be done cost free—free from compression expenses.

A-1.4.4 Oil and Water Gathering System

The water and oil separation for the project is a typical oil field separator with the water being allowed to "gravity feed" to the saltwater disposal well (well No. 1A) and oil being sent to the oil tanks. The possibility of reclaiming the small amount of natural gas that is produced with the oil and water is under consideration, however, it is most likely not cost feasible.

Figure A-5 Injection well: Ownbey No. 13 wellhead

A-1.4.5 Production Problems

Water Disposal Problems

The only problem with the saltwater disposal system to date has been filtering the sediments and particles out of the water before injection. Even with filter screens of very small mesh, they still allow undetectable particles to eventually "plug off" the perforations, stopping the water from moving into the disposal formation. This has been corrected with the "spot acid" job and a "Nowata" filter installed at the wellhead. Also a program of cleaning chemicals and soap will be put in place in the near future.

Methane Supply Problems

The methane supply for the project has had virtually had no problems except for the extreme cold weather we experienced this past January and February. The problem is that the "back pressure regulator" which we have installed just after the supply wells gas and water separator collects condensation and sometimes freezes shut and "kills" the flowing well. This holds back too much pressure against the tubing, causing the gas well to water out and stop producing. However, we are very fortunate that all we have to do, when the regulator is thawed, is to open the tubing valve, regulate the volume with the tubing valve, and the well is back in production.

Natural Gas Injection Problems

The compression of the methane was by far the most troublesome part of the project. The first stage of the compression was to let the Mulky supply well start "fill up" of the oil zone under its own pressure. The sales line will shut and the methane was directed to the "gas cap" well. The injection well started with the wellhead pressure of 14 psig. The volume of methane for injection was held at 40 to 50 Mcf per day at first, with a decrease of 20 to 25 Mcf towards the end of the "natural" stage (see Fig. A-6). The wellhead of the supply well was fitted with the "Little Joe" downstream pressure regulator which controlled the pressure against the injection well. This pressure was increased on a regular basis up to 120 psig, almost to the maximum working pressure of the water and gas separation equipment.

The problems began because of the fact that the operator chose to compress the methane himself with his own equipment and, I might add, with limited experience. An electrical compressor was put in place first with minor success (a photograph is given in Fig. A-7). This compression was started on 1/26/97, moving approximately 45 Mcf per day. A 5 hp electric motor powering a 4 inch by 6 inch piston compressor was the tool on hand. As the pressure in the injection well increased, so did the problems of the electric motor getting hot and turning off or sometimes burning up. Consideration was given as to raise the horsepower for the compressor. This may have helped the problem, but the operator elected to call a company that rents and maintains compressors. Global Compression Services in Tulsa, Oklahoma, was called, and with their experience and knowledge, a compressor was set and compression was started on 5/5/97. A Gemini G 26/MOC-2 natural gas compressor with a 26 horsepower natural gas engine was the tool used (a photograph is given in Fig. A-8). Injection volume was approximately 70 to 80 Mcf per day. Since the installation of the more efficient compressor system, there have been no problems as far as volume movement is concerned (see Fig. A-9).

Oil and Water Gathering Problems

The problem with the oil and water gathering system was a basic and common one. The fluid lines have had many barrels of brine and oil through them over the past 17 years. Inside the lines, scale buildup becomes common. With the influx of new oil and water, in some places the scale was sluffed loose and "bridging" occurred. This caused a problem of not being able to get the fluid to the oil and water separator. Plug-offs were plentiful but repaired and bypassed quickly.

Figure A-6 Pressure effect on gas injection well, Ownbey No. 13, September 1996–June 1997

Figure A-7 Photograph of electric 2-stage compressor—first compression system installed January 1997

Figure A-8 Photograph of more efficient 26 hp natural gas compression system installed May 1997

Figure A-9 Pressure effect on gas injection well, Ownbey No. 13, detail for May 1997

A-1.5 ANALYSIS OF REPRESSURING PERFORMANCE

A-1.5.1 Pressure Enhancement of Surrounding Oil Wells

The pressure effect of gas injection of oil production wells Nos. 1, 2, 9, 10, 12, and 15-23 is shown in Figures A-10 through A-23. Wells Nos. 4, 5, 6, 7, 8, and 11 showed zero annulus pressure during the entire project period.

Ownbey No. 12—First "Gas Out" Found

On 3-23-97 Ownbey No. 12 was put on pump. The well started pumping a full stroke of oil at 12 strokes per minute. Annulus pressure was 10 psig when started. The well's fluid output fell quickly and by 5-23-97, the well was getting a 40% stroke of fluid with a very small oil cut. Wellhead pressure was 55 psig. On 5-25-97 natural gas was noticed bubbling out in the oil and water separator. The conclusion about where the gas was coming from was that natural gas was entering the fluid system of Ownbey No. 12 through the tubing. The well was shut down and the "gas out" was stopped. As you can tell (see Fig. A-14), the well definitely had communication over to the injection well. After the shut-in of the well annulus, the pressure climbed immediately.

Figure A-10 Pressure effect on oil production well, Ownbey No. 1, September 1996–June 1997

Figure A-11 Pressure effect on oil production well, Ownbey No. 2, September 1996–June 1997

Figure A-12 Pressure effect on oil production well, Ownbey No. 9, September 1996–June 1997

Figure A-13 Pressure effect on oil production well, Ownbey No. 10, September 1996–June 1997

Figure A-14 Pressure effect on oil production well, Ownbey No. 12, September 1996–June 1997

Figure A-15 Pressure effect on oil production well, Ownbey No. 15, September 1996–June 1997

Figure A-16 Pressure effect on oil production well, Ownbey No. 16, September 1996–June 1997

Figure A-17 Pressure effect on oil production well, Ownbey No. 17, September 1996–June 1997

Figure A-18 Pressure effect on oil production well, Ownbey No. 18, September 1996–June 1997

Figure A-19 Pressure effect on oil production well, Ownbey No. 19, September 1996–June 1997

Figure A-20 Pressure effect on oil production well, Ownbey No. 20, September 1996–June 1997

Figure A-21 Pressure effect on oil production well, Ownbey No. 21, September 1996–June 1997

Figure A-22 Pressure effect on oil production well, Ownbey No. 22, September 1996–June 1997

Figure A-23 Pressure effect on oil production well, Ownbey No. 23, September 1996–June 1997

Down Dip Wells

The oil wells that are down dip structurally and regionally have had water encroachment slowly and steadily ever since the gas cap was blown down. Our hope is to eventually put enough methane back in and build the proper pressure in the gas cap to force the water back down dip where it belongs. Some wells (Ownbey Nos. 4, 5, 6, 7, 8, and 11) have and always have had zero pressure on their annuluses. We are assuming that these wells are in the encroachment of water. However, in several of the down dip wells (well Nos. 2, 10, and 17) there is a show of pressure. This may be due to the internal structure of the sand or some unknown reason (see Figs. A-2 and A-3).

Ownbey No. 19 and No. 20

While taking readings on the project, we noticed that No. 19's pressure rose and then fell and then rose again (Fig. A-19). Also, well No. 20 had zero pressure for a while and then suddenly rose in pressure to almost the highest pressure effect in the project (Fig. A-20). After comparing charts, we realized that these fluctuations occurred at approximately the same time. Whether this effect is from communication or standard repressuring movement, we do not know at this time. Note that on 1-26-97, we started injection with the first compressor. If this was the cause, or the nearby wells pumping fluid were the cause, we do not know. But it is certain that we are getting a "pressure effect" from the project.

On further evaluation, it is noticed that on 6-25-97 the pressure in No. 20 had climbed to the second highest pressure of the surrounding oil wells in the project. This is probably a "gas out" well due to communication. Number 19's wellhead pressure, however, seems to be comparable to the "up dip" wells and may have a good positive effect on the oil drive. Time will answer this question when No. 19 is put on pump in the near future.

Owney No. 22

Number 22 is regionally up dip to the "gas cap" injection well. This well had a good, steady increase in pressure through the entire project (see Fig. A-22). On 6/11/97, number 22's annulus was "blown down" into a "reclaiming line" that was put in place from the wellheads of the up dip wells to the supply line for the compressor. The wellhead pressure was 47 psig and fell to approximately 17 psig in just a few hours. The well was getting a full stroke of fluid at 12 strokes per minute. The oil cut was 25%. The well will make around 3 bbl of 32 gravity oil and 9 bbl of water per day. This may not sound like much; however, this well always from day one, hit about a 1/4 stroke of fluid with no pressure against the wellhead. This well was drilled several years after the gas cap was blown down. If 1 pound of pressure was put on the annulus, the well would pump zero fluid. Oil production before repressurization was 1/4 to 1/2 barrel per day. This is a very nice increase in production. This is obviously a result of the repressuring project. When the supply line pressure fluctuates, so does the production: from zero fluid at 22 psig to 3 bbl of oil and 9 bbl of water at 17 psig. We look for this to improve as long as the gas cap is repressured.

The "Gas Cap" Injection Well

The injection well (Owney No. 13) was selected because of the fact that its oil sand formation was the highest in the pool and because of the way it acted when it was "brought in." It was drilled in 1982, perforated, and sand fractured. Twenty-four hours after the frac job, the well was flowing at a rate of 240 bbl of fluid per day through the production casing. The oil cut was between 30% and 35%. This by far was the best well on the lease—most likely because the gas drive was almost "virgin" and it had the highest oil sand, structurally. The well produced very well for approximately 6 to 8 months, then started to fall in pressure and fluid production. The volume of gas injected over the project is given in Figure A-24.

Up Dip Wells

The up dip wells regionally are Nos. 20, 21 (see Fig. A-25), 22, and 23. Numbers 15 (see Fig. A-26) and 16 appear to be higher structurally. It appears at this point in the project that these wells hold the best chance of oil enhancement; however, we feel that the down dip wells also have a good possibility of oil enhancement, if we can continue to repressure the oil formation with methane and lower the level of the water encroachment.

Figure A-25 Ownbey No. 21, 72 hours after frac job

Figure A-24 Volume of gas injection into Ownbey No. 13 during the project

Figure A-26 Ownbey No. 15, 48 hours after frac job

A-1.5.2 Production Results

Production Operations

We feel at this point that operations should continue as before. Lower maintenance may be a possibility, especially in well pulling, due to the fact that more fluid is coming into the wellbore allowing the downhole pumps to pump more efficiently and cleaner. A cleaning "pot" will be established at each oil well for the circulation of cleaners.

The lease prior to the project had been all but shut down. No oil had been produced for about 2 years. The discovery of coal gas on the lease kept the lease valid. The methane injection project didn't "take a sick horse and make it well," it took a dead horse and resurrected it. Prior to the 2 years of "slowdown," the lease was making about 4 BOPD and 150 BWPD. This production was coming out of eight to ten wells pumping full time. We had high electric bills, lots of pulling bills, bills for getting rid of water, etc. Thus, the lease was marginal at best. At the present, we are making 5 BOPD and 25 BWPD (8/15/97) from only two wells.

All the oil wells are tied into one oil and water line system then into one separator. It is difficult to get an accurate gauge on a well by well basis, but not impossible. The oil and water production shown in Figures A-27 and A-28 are basically three wells through 5/29/97: Nos. 9, 11, and 12. All three wells were stopped and No. 22 (up dip well) was put on production by itself on the first of June. This partially explains the drop in water and the increase in oil. We sold about 100 bbl of crude before the project closed. We did have salt water disposal problems toward the end of the project, slowing oil production.

A-1.6 FUTURE DIRECTION OF PROGRAM

A-1.6.1 The Reclaiming of "Used Methane"

A reclaiming gas line should be put in place at every producing wellhead, then turned into the methane supply line going to the compressor for "reuse" of the natural gas. This is important for the fact of conservation of the natural gas, conservation of the formation pressure, and the conservation of the crude oil that has been left in the ground.

Figure A-27 Ownbey oil and water production from 12/12/96 to 6/25/97

Figure A-28 Ownbey oil-water ratio

A-1.6.2 The Continuing Production of Oil

The lease will continue to be produced. Each oil well will be monitored closer than it was prior to the project, as far as economic feasibility is concerned.

A-1.6.3 Compression Cost

The compression costs are indeed the most expensive part of the project. These costs should be examined in the near future for reductions. This could be possibly by buying and maintaining the project's own compression system instead of renting compression systems.

A-1.6.4 Water Disposal Cost

The future of water disposal costs looks very good for this project. With a salt water disposal well drilled deep into the Arbuckle formation with good porosity, the cost should be at a minimum. There are no electric motors or expensive pumps to maintain. With water being disposed of under "gravity," the costs should be almost zero.

A-1.6.5 The Ownbey "Natural Gas Storage Field"

An exciting future direction of the project is to have the possibility to put natural gas into the oil sand during the time that the price of natural gas is at a low, which gives us the opportunity to

take the gas out of the oil sand at a much higher price. This alone could make the project economically feasible, not to mention the economic benefit of the oil which is moved into the wellbores. The Btu of the methane should be enhanced, also increasing the economical benefits.

A-1.7 SUMMARY

In summarizing the project's data, we can conclude that methane repressurization is an important and essential part of extending the production life of an oil formation. If reclaiming lines and compression systems can be put into place from the discovery of the oil, it can and more than likely will, extend the recoverable amount of oil.

It is also concluded that repressurization can be installed at a later date even after primary production has stopped, and still get a promising secondary production outlook.

A-2.0 ECONOMICS OF THE PROJECT

A-2.1 THE ECONOMIC BENEFITS

The benefit of being able to “store” natural gas at a low price and sell at a higher price probably makes the whole project feasible in itself. A possible Btu increase also should be included in this benefit.

When the wellhead pressure of certain oil wells is decreased either for the sales market or for more compression, most certainly fluid will come into the wellbore at a much faster rate than before repressurization. A 25% oil cut as seen in well number 22, certainly will be a benefit that, by itself, can make the project economically feasible. Coupled with the “storage” of methane at a low price and sales at a higher price, we are very optimistic about the future of the program and its economic benefits.

A-2.2 THE ECONOMIC PROBLEMS

The supply of natural gas would probably be the biggest expenditure for a project like this. If on-lease gas was not available, having to purchase methane to inject would be somewhat different from this project's experience. The gas could and should be reclaimed if everything goes as planned; however, an unidentified gas out or many other unexpected problems could be economically devastating. Availability of on-lease gas is most certainly a big plus for this type of project.

Having to rent compression has its pluses and minuses as far as economics is concerned. The main minus is that it usually is very expensive. A plus is that it is usually maintained and serviced properly, and when the system needs overhauled, the lessor pays the bill. If the operator purchases a system, then overhaul and maintenance must be figured in. This would depend on the operator's personnel and, of course, financial situation.

Of course, the main economic concern for the oil and gas business is the price of our commodities. With oil prices as low as they are, it is very hard to show profits on stripper wells. Corners have to be cut and production has to be increased in order to sometimes just break even. However, it is possible to make a huge profit in the oil business at \$5.00 per barrel if you have enough oil to sell. This may explain why small independent domestic oil producers such as A.R. & R. Ltd. keep trying to increase their production and cut their costs.

It is sad, however, that a strategic commodity that America does not have enough of and has to import well over 60% of what it uses from foreign countries, cannot have a price stable enough to maintain the production costs of stripper wells. America needs America's oil, and hopefully this project will help A.R. & R. Ltd. and other small independent oil producers to get more of it.

A-2.3 METHANE INJECTION

To purchase a new or fairly new natural gas injection compressor like the one we are using now apparently would cost around \$25,000 to \$35,000. This is for the 25-hp natural gas engine and a compressor that would move enough volume under the pressure we have. If we owned the compressor, we of course would have to maintain and repair it. This is why we decided to rent the compressor. At a cost of \$1,010/month, it would be best for us to do it this way because of our lack of mechanical experience and the time factor of repairing the unit, not to mention the time that would be lost injecting methane. This is a decision that will vary from operator to operator. This monthly rental fee included maintenance by certified mechanics—all we do is supply the fluids (oil and water).

The electrically powered compressor should be considered in comparison with the economics of one powered by natural gas. The first system in place on the project was a two-stage, 5-hp compressor. This unit could have moved the right amount of gas at the injection pressure we had. This used compressor was purchased at a price of \$5,000. Assorted valves, connections, regulators, and dryer vessels had to be purchased at an additional cost of between \$1,000 and \$2,000. Shortly after injection began, the compressor valves had to be repaired and then, as the pressure in the injection well increased, we needed to increase the horsepower to the compressor. Electric power in our area is about \$0.12/kilowatt. So, before we knew it, we were reaching a monthly rental price of the fully maintained compressor on just the cost of electricity alone.

If we were to purchase a natural gas engine and compressor system, we would have to replace or overhaul the engine and the compressor. To certain operators, this may not be a problem; however, with us at this time, rental made economic sense. It comes down to which way is the cheapest and most practical for each individual operator.

A-3.0 TECHNOLOGY TRANSFER

The technology transfer of the information gathered for this project will be as follows:

- Approximately 50 copies of the final report will be mailed to geologists, petroleum engineers, land men, operators, etc. all over the United States. These people are contacts that A.R. & R. Ltd. has accumulated over 18 years in the oil and gas business.
- The final report will be available on the Internet.
- Local newspapers will be notified of the project for possible local reporting.
- A lecture will possibly be held for the Southeast Kansas Independent Oil Producers Association.
- Any possibility of publication will be sought, and hopefully this project can be reported.
- This will be an ongoing study, and future information will be available on request.
- Other operators will be welcome to visit the site and discuss the project by appointment.

A-4.0 LESSONS LEARNED THAT CAN BE OF BENEFIT TO OTHER OPERATORS

The main lessons that A.R. & R. Ltd. has learned during the course of this project include the following:

- The reclamation and reuse of natural gas to enhance oil production could easily double the amount of oil produced from a field under the right circumstances. If there is not a methane reclaiming system in use, there probably should be, for this could benefit the operator very much so, economically.
- A pressure maintenance program needs to be installed immediately when new reserves are found and should be put in place in depleted reservoirs, even if secondary water flooding has failed.
- A good steady volume of methane should be injected without interruption. The volume will depend on the operator's supply. Discussion continues regarding the best compression system to use: electric motors or natural gas engines.

A-5.0 WILLIAM T. STOECKINGER REPORT

WILLIAM T. STOECKINGER

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A.R.R. Ltd
RR 2
Elk City, Ok 67344

February 23, 1996

OWENBY LEASE

Dear Andy:

You have asked me to address several of the queries made by NIPER in their letter dated February 14, 1996, as follows:

ITEM 1, d: What is the estimated gas reserves for your coal seam well, Owenby # 2M ?

Non- conventional (coal/shale) gas wells are now the largest single gas source in Southeastern Kansas with particular success being realized in your part of the county in the so-called Mulky coal zone, which is composed of about one foot of coal and 5 feet of fractured shale.

Gas reserve estimates based on volumetrics using actual measured gas contents of both the shale and coal are usually lower than the volume of gas ultimately recovered. This observation is made after several years of production history in leases to the west and south of your holdings. For example: recoverable gas is estimated to be 300 Mcf per acre foot of coal and 40 Mcf per acre foot of shale. Add to this the fracture porosity which creates the zone's exceptional permeability, and we arrive at about 40,000 Mcf per each 80 acres drained. A typical Mulky coal gas well comes in at about 60 Mcfgpd, displays a negative decline over the first few years, and then drops off at about 15 % per annum. Cumulative numbers prove beyond any doubt that wellbores are in contact with 100's of acres which explains why these little wells last so long and produce so much gas.

To conclude, when the Mulky zone displays good permeability (which can be determined during treatment and early production), each well should drain a vast area (several hundred acres) and as a result cumulative production will exceed your expectations. The conclusion is: estimated gas reserves of 120,000 to 200,000 Mcf might be realized per well, assuming a wide spacing. Don't under-estimate these wells based on volumetrics alone. Rely more on production history.

POINT # 5 OF THE NIPER LETTER:

Oil Saturation:

a) Analyses of cores from the # 5 and #6 wells are attached for easy reference. These cores were taken from the oil interval (operator). The cores were bleeding oil profusely, were not bagged, and reached the lab many hours later (they were probably analyzed the next morning). Average results are :

Porosity of 16 %
Saturation Oil of 20% (this is residual, ROS)
Saturation water of 5% (this is unusually low)
Total saturated volume is 25%
Total void space is, therefore, 75% (moveable oil/gas)
Permeability of 10-90 md. This is unusually high for such low porosity and streakiness. I suspect secondary perms due to pin-point vugginess

To covert the above to barrels of oil per acre foot:

ROS of 20% X 16% porosity X 7758 = 248 bo/acre foot
Moveable Oil of 75% X 16 % porosity X 7758 = 930 bo/acft.

b) Hydrocarbon saturation based on the open hole logs from the Owenby Mississippi test. See attached log.

Interval 910-960 feet
Average Density is 2.41 for a porosity of 17 % which is a little lower than written on the log itself.
Average Resistivity: 4 ohms from the log.
SW = 65% using R_w of .07, which is normal.

Remarks on the log:

Possible Oil/Water contact at 940 feet.
Good permeability is indicated by mud cake build-up over the interval 920-954'.
Gamma Ray curve indicates streakiness, but the tool is also very noisy and of poor quality.
Shaliness is confirmed by the Neutron response.
SW values based on porosity derived from the Density tool over a shaley sand are notoriously pessimistic (SW values reached are too high).

c) Using the above parameters:

OOIP based on the cores is 1178 bo/acre foot, 248 bo/acre foot is residual and not moveable, therefore, 930 bo/acre foot is potentially recoverable.

OOIP based on the open hole logs is 461 bo/acre foot.
Reached as follows: $SO (1 - SW) = 35\% \times 17\% \text{ porosity} \times 7758 = 461 \text{ bo/acft}$

d) Field size based on thickness map supplied by the operator shows an average of 20 feet of oil saturated sand covering at least 160 acres, for a total of 3200 acre feet.

e) 60,000 barrels of oil have been produced (operator), for a recovery of $60,000 / 3200 = 19 \text{ bo/ac ft.}$

f) If we accept OOIP as that derived from the open hole logs (that is 461 bo/acft), then about 4% of the OOIP has been recovered so far. This figure conforms to much of my work in southeastern Kansas, where my rule of thumb is 30 bo/acft by primary means.

g) INCREMENTAL SECONDARY RECOVERY usually doubles and even trebles that recovered by primary means, therefore, we might anticipate another 60,000 to 120,000 bo from the 160 acres under the lease. However, this is purely conjectural as I have no experience with Tertiary oil recovered using methane gas injection.

If you should have any questions, please give me a call.

W.T. Stoeckinger

Certified Petroleum Geologist
by the AAPG # 1237

**APPENDIX B
GAS REPRESSURIZATION PROJECT
EAST EDNA FIELD,
OKMULGEE COUNTY, OKLAHOMA**

Final Report

**by
John Godwin
Driver Production, Inc.**

August 18, 1997

Work performed for
BDM-Oklahoma, Inc.
Under Subcontract No. G4560334
U.S. Department of Energy
Prime Contract No. DE-AC22-94PC91008

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EXECUTIVE SUMMARY

This report summarizes the 1996–1997 field research conducted by Driver Production Inc. in response to Program Research and Development Announcement (PRDA) No. OKL-5204-01. This project is part of Project 95-A03 Extraction Research, Improved Recovery Processes, Task 8 High Potential Recovery-Gas Repressurization by BDM-Oklahoma for the U.S. Department of Energy.

The East Edna Field Flue Gas Repressurization Project was a combined attempt by Driver Production and BDM-Oklahoma/DOE to increase reservoir pressure on an 80-acre six-well tract which had no reservoir energy to drive oil.

The production wells were reworked, a flue gas generator was constructed, lease natural gas was used for power, operation and injection began in September of 1996 into one of the converted production wells. At that point of the project, the oil production was 4.5 BOP/D and gas production was 10 Mcf/D.

The economic results show a threefold increase in both oil and gas production from project start-up to 14 BOP/D oil and 33 Mcf/D gas. The project is following predictions, and as of July 1997, is stabilizing injection rates at 350–400 Mcf/week until a gas channeling problem is addressed.

If currently forecast production is achieved, payout for this project is expected to be 26 months after the project ending date of June 1997.

ACKNOWLEDGMENTS

This work is sponsored by the U.S. Department of Energy (DOE) in response to Program Research and Development Announcement (PRDA) No. OKL-5204-01. This project is part of Project 95-A03 Extraction Research, Improved Recovery Processes, Task 8 High Potential Recovery—Gas Repressurization by BDM-Oklahoma for the U.S. Department of Energy. The author wishes to thank Dr. David Olsen of BDM-Oklahoma for his support and encouragement; Trevor Lyons (geologist and independent producer), and Nancy Richardson (oil technology coordinator) with the Oklahoma Independent Petroleum Association for their critical review.

B-1.0 INTRODUCTION

B-1.1 GAS REPRESSURIZATION PROJECT: STATEMENT OF WORK

This section is based on the original proposal to conduct this project. Changes in actual practice from the work initially proposed will be identified.

Proposed Gas Injection Technology

The injection process to be used is the Flue Gas Method of injection. The process to be implemented uses an internal combustion four-cycle engine burning natural gas and a compressor developing 900-psi injection pressure.

The air and fuel gas are burned and changed into flue gas consisting of nitrogen and carbon dioxide. The flue gas from the exhaust systems is cleaned through catalytic converter systems with water and corrosion elements removed by cooling and scrubbers before each state of compression. The gas is then compressed into the formation through the casing of a converted production well. The flue gas to be injected will be 87% nitrogen and 13% carbon dioxide. The carbon dioxide will be partially absorbed into the reservoir oil surrounding the wellbore, thereby decreasing the viscosity of the oil. The nitrogen is not absorbed, but fills the available reservoir space, increasing the reservoir pressure. With increased reservoir pressure, the lower viscosity oil will move easier to the wellbores of the producing wells.

Project Wells

There are six wells involved in the project. All of the wells are presently producing. The structurally lowest well, which was the Nash 3, will be the injection well injecting into the casing annulus while leaving the pumping equipment in the tubing. With the pumping equipment in place, the fluid will be removed from the formation around the wellbore, lowering the fluid restriction to a minimum. Four of the producing wells, which are the Nash 1, Nash 2, Nash 4, and Thomas 2, are situated on ten acre tracts around the injection well and one well, the Thomas 1, has a 10-acre tract between the well pattern and the injection well. The average daily production from the six project wells for six-month period prior to the start of injection from December 1995 to May 1996 is shown in Table B-1.

Targeted Pressure Increase

Available records indicate initial pressure of the Lower Dutcher was 850 psi. The selected compressor for this project is rated at a maximum pressure of 900 psi. This pressure will provide a potential reservoir pressure of 750-800 psi. At the project start up, the shut-in reservoir pressure was less than 100 psi.

Table B-1 **Average daily production from the six project wells for the six-month period prior to the start of injection from December 1995 to May 1996**

Well	Oil Production bbl/day	Gas Production Mcf/day	Water Production bbl/day
Thomas 1	0.5	0	Trace
Thomas 2	0.3	0	Trace
Nash 1,2,3,4	1.75	11.6	Trace
	2.55	11.6	Trace

Anticipated Technical and Economic Problems

Minimal technical problems are anticipated with nothing to cause a slowdown or stoppage of the project. The operator is very familiar with production techniques, downhole production enhancing work, compressors, power drives, and chemical treatments required to minimize corrosion. In this project, a xylene-diesel oil-acid downhole treatment will be utilized in all six wells to clean the production tubulars and the wellbore formation. This treatment has been proved to increase production. Due to increased pressures to be encountered from the flue gas injection, the downhole pumps will have to be changed to eliminate pump failure. Once flue gas injection is started, a chemical injection program must be implemented to eliminate the potential normal corrosion problems associated with flue gas. Other chemicals may be necessary as the projects are implemented. Treatment will be based upon analysis of produced fluids and gas.

Initial fuel supply will be available from the existing wells. As the flue gas begins contaminating the produced gas, a secondary gas source is available from an existing gas gathering system into which the produced gas is currently being sold.

The wells in this project are not encumbered with any mortgage or financing agreement. There are no liens, judgments, or other debts on the properties. Driver Production, Inc. owns 100% of four of the wells and 50% of the other two wells. The current ownership will have the ability to comply with the length of the project and all of the project requirements. The current ownership produces oil and gas properties to reservoir depletion. Driver Production, Inc.'s business is to acquire oil and gas properties and produce them. Driver Production, Inc. has never sold a producing property. There are no Oklahoma Corporation Commission or Oklahoma Tax Commission actions pending on the project properties.

The biggest problem with flue gas injection is not the cost of treatment or availability of equipment. It appears to the applicant that the lack of understanding and knowledge at the producer level is the biggest single problem concerning flue gas injection. This problem can be overcome through education and experience and could be the answer to economically feasible increased oil production.

Anticipated Project Schedule

1. Project paperwork completion—one month.
2. Oklahoma Corporation Commission paperwork for disposal well—one month, concurrent with project paperwork.
3. Purchase of compressor and related equipment—1/2 month.
4. Perform individual well cleanup workover—1/2 month, concurrent with equipment purchase.
5. Site preparation, injection line and gas line construction—one month concurrent with equipment purchase.
6. Setup of compressor and related equipment—1/2 month.
7. Start of project—three months from beginning of paperwork.

Note: Actual schedule for project was modified in concurrence with the technical project manager (Dr. David Olsen of BDM-Oklahoma) to accommodate problems encountered in operation, weather, and project response.

The following delays occurred which caused the schedule to be altered:

1. Weather—rain and cold weather. During the construction process, numerous rains occurred. Since this project was constructed on site, access to the project and actual construction time was delayed due to the rain and the muddy conditions. Weather did not affect construction time, but during periods of extended cold weather, the project was forced to shut down due to freeze-ups of the air exchangers.
2. Equipment procurement and delivery. The locating and corresponding delivery of the equipment for this project required much more time than anticipated. There were not enough hours in the day to find equipment, travel to its location and look at the equipment to see if it would work in the project. After a determination was made that the equipment would be acceptable and was purchased, then the delivery schedule had to be set and delivery made.

Gas Injection in the Area

Flue gas injection in both Oklahoma and Kansas has been tried in both permanent and short-term applications by several injection companies and oil producers with varying results. In the immediate area, one producer has a permanent installation, but the equipment, production techniques, and results have been kept confidential.

The most numerous applications of flue gas injection technology have been on a 2–4 day schedule, where a producing well has flue gas injected into the casing annulus to increase formation pressure in that well and offsetting wells. The degree of success has ranged from highly successful to no success. The downhole conditions of some wells are not known, but

factors such as formation treatment, number of producing zones, water production, structural position, and drainage details will have to be known and considered for proper analysis. The successful wells normally are shut-in for a short period of time to allow formation pressure equalization. The wells are then flowed or pumped through the tubing. The results have been quite prolific in some wells, and increased production has lasted for up to 90 days. Needless to say, these particular wells are usually treated again.

B-1.2 FIELD HISTORY

The Project wells are located in the East Edna field in Okmulgee County, Oklahoma (see Fig. B-1). The first discovery wells were drilled in the 1930s, and both oil and gas were discovered in the Dutcher formation.

Typical Dutcher wells in this area, when drilled, had a high gas-to-oil ratio. As the gas drive decreased, oil production decreased to the one-to-four-bbl-per-day level.

The gas history of the area is sketchy. Obviously, much of the original gas was vented since there were no pipeline gathering systems. There are no major gathering systems in this area presently. There were several small unreliable gathering systems that were established in the mid to late 1970s, but the records do not reflect any cumulative production figures. The first records available on the Nash lease date from 1992.

Cumulative records do not reflect per well production, but lease accumulation records show cumulative production records which range from 1,200 to 107,000 bbl of oil. Gas records are similar, showing traces of gas per lease to a high of approximately 150 MMcf of gas. Because of the sketchy gas history records, there are no known records available on the Mcf/bbl of oil produced or gas-oil ratios.

B-1.3 PROJECT HISTORY

The project wells consist of three separate leases containing six producing oil and gas wells (see Fig. B-2). These wells were drilled between 1982 and 1984, and initial production was reported in the range from 5 to 240 BOPD. Gas production ranged between a trace showing to 200 Mcf/D.

During 1996 prior to project start-up, the wells were averaging 1.17 BOPD of 30° API gravity oil and 3.0 Mcf/D with a minute trace of water. After the Nash No. 3 was converted to an injection well, the oil production was 4.5 BOPD and gas production was 8 Mcf/D for the five wells.

The accumulated production for the project wells at the start of the project totaled 41,000+ bbl of oil and 13 Mcf of gas. Water production and vented gas records were unavailable.

Figure B-2 Well location map

B-1.4 GEOLOGIC CHARACTERIZATION

The Dutcher formation is a consolidated sandstone formation. In the project field, the gross thickness is 22 feet with a net pay thickness of 12 feet (see Fig. B-3).

Figure B-3 Cross section of wells

The average porosity is 12% with an average permeability of 5-20 md as calculated from electric logs. The initial reservoir pressure was reported at 840 psi from a driller's log from the original well drilled on the Nash lease in 1958 with a shut-in reservoir pressure of less than 100 psi at the start of this project. Current oil saturation was calculated at 35% pore volume or 575 bbl/acre-ft. Total original oil with the pattern was calculated at 612,608 bbl. With a total of 58,495 bbl of oil removed for a current calculated target oil in place of 554,000 bbl.

Historically, most of the wells in the East Edna field require fracture stimulation to be economically productive. All project wells were originally sand-fractured with the exception of the Thomas 2-18. This well was sand-fractured with 10,000 pounds of sand before the injection project began using a water gel system. Formation parting pressure on this particular job was

2,300 psi with an instantaneous shut-in pressure of 925 psi. No frac records for the other wells are available.

An electric log of the Nash 2 which is representative of all project wells is given in Fig. B-4.

Figure B-4 Electric log of Nash No. 4

B-2.0 DESIGN AND CONSTRUCTION OF INJECTION SYSTEM AND GENERATOR

B-2.1 INTRODUCTION TO FLUE GAS SYSTEM

The lease records show that 58,495 bbl of oil or oil equivalent, or 9% of the oil in this project reservoir of the calculated primary oil (612,608 bbl), had been produced. The amount of oil to be recovered from this reservoir is therefore very significant.

Water flooding as a secondary recovery method was dismissed as viable for the following reasons: small size of the reservoir, lack of produced reservoir water, risk to interstitial clays in the reservoir rock and risk to environment of leaked produced and injection waters. Carbon dioxide and nitrogen flooding were eliminated due to the cost of the systems to separate air and economically deliver these gases to the wells. Two of these systems, carbon dioxide and nitrogen, usually are not economical for the small independent producer to attempt, and water flooding was considered very undesirable.

The most economically viable injection system available to the small producer is the flue gas injection system, whereby treated exhaust gas from an internal combustion engine powering a compressor is dehydrated and injected into the producing formation utilizing the compressor to pump the gas.

Ideally, the treated exhaust gas consists of 87% nitrogen and 13% carbon dioxide. The carbon dioxide is readily absorbed into the reservoir oil and results in a decrease in viscosity permitting the oil to flow freely. Nitrogen is not absorbed but fills the depleted reservoir void space and provides pressure to push oil from the injector well to the producing wells.

B-2.2 DESIGN OF FLUE GAS GENERATOR

Design of the flue gas generator for the depleted reservoir (9% of oil in place produced) eliminated a huff 'n' puff or cyclic type system from being employed. The reservoir void was large enough, and the time frame for the project was short enough to require a flue gas generator installation that could cause results in a short time frame (less than 9 months). Injection volumes ranged up to 375 Mcf/D of gas initially after 24 hour per day continuous operation began in October 1996. After the injection pressure began increasing, the flue gas generator delivered 250 Mcf/D of gas at 400 psi which was the normal injection pressure at the end of the project period.

The target pressure of 900 psi that was proposed was never met, since the injection pressure never exceeded 400 psi.

The generator selected was a Waukasha 817 engine powering a Chicago Pneumatic two-stage compressor. This horizontal compressor has the capability of developing pressures of over 900 psi, which exceeded the initial reported reservoir pressure of the wells. The compressor has an 11 inch first-stage cylinder and a 5 inch second-stage cylinder with a 13 inch rod stroke.

B-2.3 DESIGN OF POWER FOR GENERATOR

The generator originally selected to power the compressor was an 817 Waukasha (see Fig. B-5), but a combination of problems caused this engine to be unacceptable to perform as anticipated.

Figure B-5 Photographs of compressor with Waukasha 817 engine

The 817 Waukasha was calculated to be able to provide the projected volume of 250–275 Mcf/D of gas, but as pressures increased, the engine could not deliver the necessary volumes at the increased pressures due to insufficient power causing the engine to overheat. The engine was shut down and rebuilt, but after a total expense of approximately \$8,500, which included purchase price and labor, the decision was made to replace the engine.

The 817 Waukasha was replaced with an 1197 Waukasha (see Fig. B–6), which proved to be adequate for providing the necessary power and exhaust gas. The 1197 can produce approximately 50 horsepower more than the 817, and the 1197's 149–155 HP was more than sufficient to power the compressor and provide more than enough exhaust gas for the projected injection volumes that were sought.

Figure B–6 Photographs of compressor with Waukasha 1197 engine

The cost of this 1197 Waukasha was much higher (approximately \$18,000) and caused additional fabrication work to be done to the piping, but this engine eliminated any power problem. At the end of the project, the injection pressure was 400 psi and the volumes were 250–260 Mcf/D of gas.

B-2.4 DESIGN OF PIPING, COOLERS, AND SCRUBBERS

Piping, coolers, and scrubbers were designed to allow the exhaust gas to pass through a catalytic converter system, fan cooling system, scrubber, first stage cylinder, and then through a cooling system, scrubber, second stage cylinder, scrubber before metering, and scrubber before injection into the well (see Figs. B-7 and B-8).

The Pancake catalytic converter system used was a large truck type catalytic converter which is available from most major truck muffler and converter companies.

The air exchangers to cool the exhaust gas were acquired in the local operating area and were a standard type designed to cool the gas and handle the appropriate compression pressures.

Figure B-7 Flue gas generator flow chart

Figure B-8 Photographs of components and piping

The scrubbers (gas separators) are of standard design and are readily available throughout the gas industry. The standard low-pressure separator, preferable with 3-inch diameter fittings, is acceptable for the exhaust-gas scrubber and first-stage scrubber. Horizontal or vertical high-pressure scrubbers should be used on the second-stage discharge portion of the injection system where higher pressures are encountered.

Piping for the injection systems can use standard pipe and fittings if corrosion control chemical is used at the beginning. More expensive piping and coated fittings last longer without corrosion control chemical, but the cost is greatly increased. The life of either method of piping and fittings is greatly increased when corrosion chemical control is introduced at the start up of injection. The cost of the piping and fitting products can vary depending on market availability and quality.

B-2.5 FUEL SUPPLY

Natural gas as a fuel supply for the generator was predetermined from the start of the project. To determine whether the project could be successful for use by the small producer, natural gas (lease gas) supply had to be available. Propane fuel has a much higher Btu content as a fuel which most huff 'n' puff systems use, but the prolonged use and corresponding higher cost of propane would be a significant factor in the economic success over a period of time.

B-3.0 OPERATION OF INERT GAS GENERATOR

B-3.1 PROJECT DELAYS

Several start-up delays occurred at the onset of the project. Due to the project's location which is in a low area of high clay content soil, large rainstorms rendered the roads to the wells impassable until periods of "drying out" happened, causing the most common delay.

Fabrication of the injection systems was performed at the project site. Piping changes were numerous because scrubber and air exchanger location changes had to be determined to create the most efficient flow rates of flue gas and liquid dropouts.

As mentioned earlier, one of the longest delays was the exchange of compressor engines. When the smaller engine proved to be of insufficient power as the injection pressures started to increase, it was exchanged for the larger one.

B-3.2 CORROSION

The most constant flue gas injection interruption was due to corrosion problems. These problems existed from a highly acidic residue of the flue gas. The catalytic converter was the first effort in corrosion control. The optimum operating temperature for maximum effectiveness of the catalytic converter is 600–650°F. The corrosion problem began after the first stage discharge and affected piping, gas coolers and the second stage of compression. After the second stage of compression, corrosion occurred again in the piping system for approximately 60–70 feet. The corrosion occurred at two points in the system, i.e., the highest heat and pressure points. The corrosion points were not numerous after the first stage of compression due to the lower pressures (maximum 60 psi) and the lower temperatures (maximum 140°F). The piping after the second stage of compression was the location of numerous corrosion problems, more so after the injection pressures started to increase (over 300 psi). The heat due to compression would continue to increase up to 240–260°F. As the injection pressure increased, numerous material failures occurred in the pipe threading and noncoated fittings.

Both liquid and gas analysis were performed at different periods during the project to analyze the flue gas and the liquid residue. The liquid which was a fall-out from the flue gas residue contained an acidic residue which was analyzed by a local chemical treatment company. This acidic residue is common in gas processing and compression and results from both nitrogen and CO₂.

An anti-corrosion chemical was blended to treat this corrosion residue. The chemical is a common neutralizing amine that neutralizes the acidic corrosive elements and is injected into the

gas flow by a chemical pump using gas pressure. This chemical injection corrected the problem through the first stage of compression up to the second stage.

Corrosion problems were severe in the piping after the second stage, and the chemical injection system was moved to this point after the flue gas passed through the second stage of compression. This change brought the corrosiveness of the flue gas to an acceptable level. The piping used at the beginning of this project was standard oil field pipe and fittings using high-pressure fittings where necessary. As discussed in Section B-2.4, changes could be made at the onset which would lower the corrosion damage.

B-3.3 INJECTED GAS FLOW

Flue gas was injected into the Nash No. 3 well. The determination was made after reviewing huff 'n' puff injection systems which indicated that even with gas entering the well-bore, the gas would not push oil away from the wellbore, but would pass through the oil and into the formation. The corresponding formation pressure buildup would cause well-bore oil to always be at or near the wellbore and cause an additional injection pressure increase. During periods of compressor shut down, the attempt was made to produce the injection well by pumping the well through the tubing string.

Special permission was granted by the Oklahoma Corporation Commission to inject the flue gas down the casing annulus after a mechanical integrity test was performed to determine casing structural soundness. Normally, the Corporation Commission requires the tubing string to be set on a packer and fluid or gas is then injected through the tubing. A special "no gas lock" downhole pump was installed in the tubing and rod string which was left intact to attempt to pump any wellbore fluids to surface, thus eliminating wellbore fluid back pressure. This type of downhole pump is common to the oil field and is used where downhole gas pressure is significant and the attempt is being made to pump fluid from the formation. The cost is greater than a standard downhole pump, but is not significant. This technique was successfully used on four separate occasions, and the amount of produced oil was significant. This technique is similar to the huff 'n' puff method performed on individual producing wells, except for the higher volumes injected and higher reservoir pressures utilized. After the downhole pump became stuck, the pump was not changed because depressurization of the reservoir would occur. It is speculated that the pump became stuck due to some wellbore corrosion flaking into the oil and jamming the pump. After pulling the pump, consideration is being given to injecting some additional chemical corrosion inhibitor at the wellhead.

B-3.4 RECAP OF INJECTED GAS INTO THE RESERVOIR

During the project period, approximately 25 MMcf of flue gas were injected into the reservoir. This amount of flue gas represented about 40% of reservoir pore volume occupied by the oil and

gas originally produced. The project engineer, Harvey "Dale" Walker and the project geologist, Trevor Lyons, both of Tulsa, Oklahoma, estimated that the reservoir pressurization would show some corresponding results when the 15-18 MMcf level of injection was reached. These results were observed in the Nash No. 1, Nash No. 2, Nash No. 4, and Thomas No. 2 in that order, first by an increase in gas flow and pressure and then by an increase in oil production. This is discussed further in B-4.1

Initially an increase of gas was the first indication of repressurization results. To operate the fuel supply system using formation gas, back pressure of 10-12 psi had to be maintained on the formation to fuel the engine. The produced gas originally had 1400+ Btu content. As flue gas was injected the Btu content of the produced gas decreased to 1000+ Btu. The cause of the decrease in the Btu content of the produced gas was an increase in the percentage of nitrogen. Table B-2 shows the different gas analyses during the project.

Table B-2 Gas analysis: Nash lease molecular percentage

Component	Pre-injection			
	Original	1/20/97	3/31/97	5/15/97
CO ₂	0.425	2.971	6.420	6.678
N ₂	4.531	56.182	72.751	66.090
O ₂	0.000	0.920	0.000	0.000
C ₁	62.300	20.987	9.096	13.563
C ₂	12.654	7.903	3.565	4.371
C ₃	10.296	6.255	4.638	5.015
i-C ₄	1.241	0.740	0.559	0.659
n-C ₄	3.173	1.881	1.417	1.679
i-C ₅	0.786	0.446	0.335	0.368
n-C ₅	0.929	0.538	0.388	0.377
C ₆	3.665	1.177	0.831	1.200
	100.000	100.000	100.000	100.000
Z Factor	0.993	0.9978	0.9986	0.9983
Btu -Wet	Unavailable	681.34	399.60	498.19

In retrospect, the decrease in the Btu content of the produced gas also was a contributing factor requiring the changeover installation of a larger engine. The lower Btu gas was not producing enough horsepower to efficiently run the flue gas generator.

Well by well attempts were made to increase the gas back pressure of the wells. This pressure increase proved to be successful at the onset, but as the volumes increased, the back pressure increase had a negative affect on oil production. At one point, all the wells were shut down for pumping, and formation pressure on the entire field was increased to 250 psi. After pumping

operations were resumed, gas locking of the downhole pumps occurred and gas pressure was relieved from the wells so they would work.

As the Btu content of the produced gas continued to decrease, it became apparent that the Nash No. 1 was receiving a larger volume of gas than the other wells. This well had a faster and higher shut-in pressure increase than the other wells. Because reservoir pressure increases were not happening at the other wells, it was determined that a channeling effect had begun. This well also was in the closest proximity to the injection well. At this point, the Nash No. 1 was choked back to slow the channeling effect. Injection is continuing, but until a surfactant or polymer gel treatment is performed, the channeling effect will exist.

B-4.0 ECONOMICS OF THE PROJECT

B-4.1 OIL AND GAS PRODUCTION

At the injection start-up, the wells were averaging about 7 BOPD and 12 Mcf/D of gas.

The Nash No. 3 was converted to the injection well which lowered the current production to 4.5 BOPD and 8 Mcf/D of gas. After the gas flow increased, the oil flow was expected to increase. This result did occur, and the Nash No. 1 was the first well to show signs of increased oil production, and the Nash No. 4 well was the second well to show an increase. The Thomas No. 2 was the third well to have increased oil production and then the Nash No. 2. There has been a decrease in the production on the Thomas No. 1, but this was due to a partial pump failure. This well is presently inaccessible due to weather conditions which made the lease road impassable. The oil production has shown an increase monthly since the 15-18 MMcf injection volume was reached. The production rate as of June 1997 is currently at 12-14 BOPD, and no substantial increase is expected until the channeling problem is solved in the Nash No. 1.

The gas sales showed an initial decrease due to the fuel gas usage to 6 Mcf/D of gas. Once the reservoir pressurization started, the gas sales increased on a monthly basis except during pipeline shutdowns, which occurred in October and December 1996. The last month of record was May 1997 which had a 33 Mcf/D of gas sales rate after fuel usage. Again, no significant gas production increase is anticipated until the channeling problems are addressed. Average oil and gas production are shown in Figures B-9 and B-10.

Due to the delay in start-up and the June 1997 project contract deadline, much of the progress the project experienced just started beginning April 1997 until June 1997. The project is continuing as a private domain venture with updates being made available to BDM-Oklahoma and DOE. Presently, the channeling effect is being addressed, which will give valuable feedback to future endeavors which experience similar problems.

B-4.2 COST-REVENUE RECAP

The relatively low cost of operation is the key to continued production from these types of marginal wells. Electrical lifting cost, pumper charges, and downhole pump changes are kept to a minimum due to the low fluid production. These wells pump an average of 30 minutes to 2 hours per day, which limits the wear on equipment and the required pumper time to maintain them.

The cost of operations and revenue at different times before, during, and at the end of the project, as well as forecast for October 1997, are reflected in Table B-3. Before the project was initiated, the revenue less cost of operation was less than \$600/month. At the start of the project, the costs

Figure B-9 Average monthly oil production for the six wells in the gas repressurization project. The value for 1997 is based on production from January through June. The values are "as sold" quantities as reported in Dwights.

Figure B-10 Average monthly gas production for the Nash 1, 2, 3, and 4 wells. Production data prior to 1992 are not available. The value for 1997 is based on production from January through June. The values are "as sold" quantities as reported in Dwights.

increased without a corresponding increase in revenue, but at the end of the project, the revenues were exceeding the expenses by \$1,300/month. The October projection reflects an increase in both revenue and expenses due to the increased cost of surfactant to be used in overcoming the gas channeling problem, but this should be overcome by the increased revenues caused by the more efficient injection of gas into the formation.

Table B-3 Production expenses and income

Monthly Production Expenses				
	Jan.-June Prior to Project, \$	July 1996 Start, \$	July 1997, \$	Oct. 1997 (Projected), \$
Pumper	500	2,000	1,050	1,100
Electricity	85	130	230	230
Chemicals	30	30	80	165
Miscellaneous	25	40	60	15
Avg. Pump Change	140	300	140	150
Total	780	2,500	1,560	1,660
Production Income				
Oil Sales	1,000	1,000	1,820	2,080
Gas Sales	350	350	1,100	1,320
Total	1,350	1,350	2,930	3,400

After reviewing the original projections, this operator feels that the production has the potential to increase much higher than the current levels. It would appear that the production is at the 150-day level of injection projection, which was near the time that the channeling became noticeable.

B-4.3 ECONOMIC PROJECTION

Several basic concepts have been considered in the economic projection.

1. The cost of the project properties were not considered in the evaluation and projection based on their having already been acquired.
2. The project costs of \$117,000 were adjusted due to some duplication costs which were deducted due to the construction of two power units during this project. The original power unit was replaced during the project due to its inability to handle the increased pressures and needed volumes of injection with a cost value of \$8,500. After revenues in the amount of \$28,500 were deducted from the project during the project period, the project investment at the end of the project amounted to approximately \$80,000.

It was at this point that the economics projection was made using the \$80,000 figure as of June 30, 1997. As Table B-4 shows, the payout period will be approximately 26 months after project end, based on the current oil production of 14 bbl/oil per day and current gas production of 33,000 Mcf/D. A 5% price escalation and a 5% decline curve are figured into this projection.

With the channeling problem under control and additional gas injection started, it is anticipated that the payout period will be shortened further, even after the cost of the channeling treatment is included.

Table B-4a Economic projection showing net revenue interest of 81.25%, 14 BOPD, and 33 Mcf/D gas with 5% production decline and 5% price escalation using \$17.25/bbl oil and \$1.40/Mcf gas

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7-14-1997      5:33 PM      SOFTSEARCH FASTPAK ECONOMICS      NOVICE      FASTPAK-0
PROJ NAME:      EDNA.FPK      EVALUATION DATE: 7/97      COMPANY: DRIVER PRODUCTION
INVESTMENT      80 M$      PAYOUT DATE: MM/YY      USER: TML
DIVISION OF INTEREST
BPO WORKING INT: 100.000000% NET REV INT: 81.250000% 8/8 ROY: 18.750000%
APO WORKING INT: _____% NET REV INT: _____% 8/8 ROY: _____%
PROD TYPE BEGIN RATE HYP EXP DECLINE% GOR SEG CUM DATE
OIL 1. SL 420 BBL/M _____ 5.000 _____ BBL/MCF _____ MBBL MM/YY
2. _____ BBL/M _____ BBL/MCF _____ MBBL MM/YY
GAS 1. SL 33 MCF/D _____ 5.000 _____ SCF/BBL _____ MMCF MM/YY
2. _____ MCF/M _____ SCF/BBL _____ MMCF MM/YY
PRICE OIL 17.25 $/BBL ESC 5.00% TO _____ $/BBL SEV TAX 7.000% _____ $/BBL
GAS 1.40 $/MCF ESC 5.00% TO _____ $/MCF SEV TAX 7.000% _____ $/MCF
EXPENSE 3200 $/MO ESC _____% TO _____ $/MO SEV TAX STATE CODE _____
WP TAX: TIER _____ RATE _____% ABP _____ $/BBL ESC _____% TO _____ $/BBL
ADVAL TAX: ADJ REVENUE _____% _____ $/MO

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Table B-4b Economic projection chart showing payout period based on \$80,000 investment

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7-14-1997      5:36 PM      SOFTSEARCH FASTPAK ECONOMICS      EXPERT      FASTPAK-04
PROJ NAME:      EDNA.FPK      EVALUATION DATE: 7/97      COMPANY: DRIVER PRODUCTION
COMPANY NAME:
LEASE:
COUNTY:
STATE:
WELL NO:
15 YR 4 MO 23.13 $/B 1.88 $/M
GROSS GROSS NET NET REV EXP TAXES COI INVEST NOI DISC
YR MBBL MMCf BBL MCF $ $ $ $ $ $
97 2 6 2022 4835 41647 19200 2915 19532 80000 -60468 -60483
98 5 11 3890 9304 82109 38400 5748 37961 0 37961 37582
99 5 11 3685 8814 81675 38400 5717 37558 0 37558 36814
0 4 10 3481 8324 80993 38400 5670 36923 0 36923 35832
1 4 10 3276 7835 80038 38400 5603 36035 0 36036 34623
2 4 9 3071 7345 78786 38400 5515 34871 0 34871 33170
3 4 8 2866 6855 77208 38400 5405 33403 0 33403 31459
4 3 8 2662 6366 75275 38400 5269 31606 0 31606 29470
5 3 7 2457 5876 72956 38400 5107 29449 0 29449 27186
6 3 7 2252 5386 70217 38400 4915 26902 0 26902 24588
ST 37 87 29663 70940 740904 364800 51863 324241 80000 244241 230242
RM 11 27 9057 21661 328657 224000 23006 81651 0 81651 72776
TL 48 114 38720 92601 1069561 588800 74869 405892 80000 325892 303018

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B-5.0 TECHNOLOGY TRANSFER

Initial project results are being transferred to BDM-Oklahoma and DOE for review and distribution. Technology results will be transferred on request and made available in reports and mail-outs.

Numerous individual tours of the project have been conducted to date to interested oil and gas industry personnel. Group discussions have already occurred additionally. Discussions with groups will continued as requested.

The following groups are presently being offered conducted tours, seminars, and publication of the project results:

- Oklahoma Independent Petroleum Association—A fall workshop is being planned where a seminar will be held on the project. Technology transfer by mail will be distributed to appropriate interested oil and gas producers.
- Marginal Well Commission—Discussions are occurring which will allow dissemination of the technology of this project to their members by mail and/or seminar.
- National Stripper Well Association—Discussions have been held and are continuing concerning technology transfer in one of their quarterly mail-outs. If this occurs, follow-up will be handled on an individual basis or in a workshop at one of their conventions.
- Society of Petroleum Engineers—The theme of the 1998 SPE convention is Enhanced Oil Recovery. If accepted, the project presentations will be part of the convention. The SPE 1998 convention will be held in Tulsa, and the project results will be submitted to the SPE overview committee for review.

B-6.0 LESSONS LEARNED THAT CAN BE OF BENEFIT TO OTHER OPERATORS

B-6.1 ALLOCATION OF TIME

Recognition of time requirements is the biggest lesson to be passed on to other project operators. To review, acquire and set up the necessary equipment for this project requires many days. If the project operator has unlimited resources, inventory, and manpower available, then the operator's time spent on the project can be very limited. This is normally not the case, so time has to be spent determining what the needed equipment will be, locating and purchasing that equipment, arranging for transportation and delivery and then fabrication of the equipment and piping for injection start-up. For this particular operation, the time requirement was an average of 50-75% of each working week for a period of approximately three months.

B-6.2 KNOWLEDGE AND USE OF EQUIPMENT

Knowledge of equipment to be used, proper installation of equipment, and results prediction from the use of the equipment are very important. Many independent producers may not have familiarity of fabrication, compression, gas injection, and corrosion potential.

B-6.3 CONTROL AND MEASUREMENT REQUIREMENTS

Control requirements are essentials to the success of a project. The operator must be able to measure pressures and production of the individual wells. Ability or access to laboratories capable of determining gas composition are invaluable.

B-6.4 PATIENCE

Patience is necessary because of the time it takes from start-up to actual results. This type of project will probably take up to six months before there are observable results.

B-6.5 ANTICIPATION OF PROBLEMS

Anticipation of problems and solving the problems before they become larger is essential. Maintenance of equipment, coated fittings, and corrosion prevention chemicals are the three main problems that must be resolved for this type of project.

B-6.6 CORROSION CONTROL

Corrosion control is the single most important factor present. The flue gas constituents must be reviewed, and adverse or unwanted components controlled to a minimum. Fuel mixture must be kept very rich, the catalytic converter must be functional, gas cooling and liquid condensation must attain a maximum level at all stages of compression and before injection.

B-6.7 CONCLUSION

The most important benefit to other operators who are considering a similar project is that this type of project can be accomplished. The operator does not need to have firsthand knowledge of all aspects of this project. The operator already has the basic knowledge of oil and gas production and the corresponding use of that related equipment.

There are very common similarities between choosing a field for a flood project in either water flooding or gas flooding. The engineering and geological requirements are very similar for either type of flood. The determination must be made as to the reservoir volume, and whether gas or water must be injected into the producing formation to re-charge the formation and cause the oil to begin to move. Controls must be kept to determine injected and produced volumes. Downhole pressurization and formation fill up happen in both types of floods. The gas injection systems appear to be much cleaner both environmentally and downhole.

In closing, this project has been very enlightening. Having had no previous experience in gas injection, the knowledge and insight gained have been tremendous and the experience memorable. Obviously, with the success already experienced, this project will continue and others are in the planning stage.

B-7.0 PRODUCTION REPORTS

Appendix

Dwight's Energydata, Inc. DLOOK 4.20 Record # 3 Run date: 07/12/97
 Production data from file: C:\VISION\DUMPFIL\ Retrieval code: 110,111,771930
 Lease: NASH #1,2,3,4 NWSE Well #:

Month	Oil bbls	Cum Oil bbls	Gas mcf	Cum Gas mcf	Water bbls	No.of Wells
Total 1982	2150	2150	0	0	0	1
Total 1983	6700	8850	0	0	0	1
Total 1984	8536	17386	0	0	0	1
Total 1985	3223	20609	0	0	0	1
Total 1986	1922	22531	0	0	0	1
Total 1987	1472	24003	0	0	0	1
Total 1988	1123	25126	0	0	0	1
Total 1989	1142	26268	0	0	0	1
Total 1990	982	27250	0	0	0	1
Total 1991	253	27503	0	0	0	1
Total 1992	1014	28517	4665	4665	0	1
Total 1993	561	29078	2567	7232	0	1
January	0	29078	181	7413	0	1
February	0	29078	187	7600	0	1
March	159	29237	385	7985	0	1
April	141	29378	252	8237	0	1
May	131	29509	0	8237	0	1
June	238	29747	0	8237	0	1
July	116	29863	0	8237	0	1
August	150	30013	0	8237	0	1
September	143	30156	0	8237	0	1
October	0	30156	0	8237	0	1
November	129	30285	356	8593	0	1
December	119	30404	192	8785	0	1
Total 1994	1326	30404	1553	8785	0	1
January	0	30404	91	8876	0	1
February	141	30545	188	9064	0	1
March	151	30696	241	9305	0	1
April	0	30696	281	9586	0	1
May	0	30696	242	9828	0	1
June	133	30829	222	10050	0	1
July	0	30829	270	10320	0	1
August	78	30907	98	10418	0	1
September	0	30907	230	10648	0	1
October	160	31067	242	10890	0	1
November	125	31192	177	11067	0	1

Production on Nash 1, 2, 3, and 4 from 1982 through June 1997

Appendix

Dwight's Energydata, Inc. DLOOK 4.20 Record # 3 Run date: 07/12/97
 Production data from file: C:\VISION\DUMPFIL\ Retrieval code: 110,111,771930
 Lease: NASH #1,2,3,4 NWSE Well #:

Month	Oil bbls	Cum Oil bbls	Gas mcf	Cum Gas mcf	Water bbls	No.of Wells
December	0	31192	178	11245	0	1
Total 1995	788	31192	2460	11245	0	1
January	51	31243	157	11402	0	1
February	0	31243	344	11746	0	1
March	136	31379	494	12240	0	1
April	0	31379	274	12514	0	1
May	127	31506	407	12921	0	1
June	0	31506	467	13388	0	1
July	0	31506	232	13620	0	1
August	141	31647	195	13815	0	1
September	0	31647	300	14115	0	1
October	65	31712	191	14306	0	1
November	67	31779	476	14782	0	1
December	149	31928	146	14928	0	1
Total 1996	736	31928	3683	14928	0	1
January	61	31989	522	15450	0	1
February	0	31989	790	16240	0	1
March	93	32082	831	17071	0	1
April	87	32169	990	18061	0	1
May	104	32273	1104	19165	0	1
June	119	32392	0	19165	0	1
Total 1997	464	32392	4237	19165	0	1

The number of wells column reflects 1 well, but there are actually 3 producing wells on the Nash Lease and the converted gas injection well.

Appendix

Dwight's Energydata, Inc. DLOOK 4.20 Record # 1 Run date: 07/12/97
 Production data from file: C:\VISION\DUMPFIL\ Retrieval code: 110,111,358671
 Lease: THOMAS 18-1 SENW Well #:

Month	Oil bbls	Cum Oil bbls	Gas mcf	Cum Gas mcf	Water bbls	No.of Wells
Total 1983	1175	1175	0	0	0	1
Total 1984	1566	2741	0	0	0	1
Total 1985	887	3628	0	0	0	1
Total 1986	584	4212	0	0	0	1
Total 1987	115	4327	0	0	0	1
Total 1988	344	4671	0	0	0	1
Total 1989	240	4911	0	0	0	1
Total 1990	0	4911	0	0	0	0
Total 1991	0	4911	0	0	0	0
Total 1992	0	4911	0	0	0	0
Total 1993	0	4911	0	0	0	0
January	0	4911	0	0	0	1
February	0	4911	0	0	0	1
March	0	4911	0	0	0	1
April	0	4911	0	0	0	1
May	0	4911	0	0	0	1
June	0	4911	0	0	0	1
July	0	4911	0	0	0	1
August	0	4911	0	0	0	1
September	0	4911	0	0	0	1
October	0	4911	0	0	0	1
November	0	4911	0	0	0	1
December	65	4976	0	0	0	1
Total 1994	65	4976	0	0	0	1
January	0	4976	0	0	0	1
February	0	4976	0	0	0	1
March	72	5048	0	0	0	1
April	0	5048	0	0	0	1
May	0	5048	0	0	0	1
June	38	5086	0	0	0	1
July	0	5086	0	0	0	1
August	0	5086	0	0	0	1
September	0	5086	0	0	0	1
October	46	5132	0	0	0	1
November	0	5132	0	0	0	1
December	0	5132	0	0	0	1
Total 1995	156	5132	0	0	0	1

Production on Thomas 18-1 from 1982 through June 1997

Appendix

Dwight's Energydata, Inc. DLOOK 4.20 Record # 1 Run date: 07/12/97
 Production data from file: C:\VISION\DUMPFIL\ Retrieval code: 110,111,358671
 Lease: THOMAS 18-1 SENW Well #:

Month	Oil bbls	Cum Oil bbls	Gas mcf	Cum Gas mcf	Water bbls	No.of Wells
January	0	5132	0	0	0	1
February	0	5132	0	0	0	1
March	0	5132	0	0	0	1
April	0	5132	0	0	0	1
May	0	5132	0	0	0	1
June	0	5132	0	0	0	1
July	0	5132	0	0	0	1
August	0	5132	0	0	0	1
September	0	5132	0	0	0	1
October	0	5132	0	0	0	1
November	0	5132	0	0	0	1
December	37	5169	0	0	0	1
Total 1996	37	5169	0	0	0	1
January	0	5169	0	0	0	1
February	0	5169	0	0	0	1
March	0	5169	0	0	0	1
April	52	5221	0	0	0	1
May	0	5221	0	0	0	1
June	32	5253	0	0	0	1
Total 1997	84	5253	0	0	0	1

The Thomas 18-1 has not produced gas in paying quantities and has never been connected to a gas gathering system.

Appendix

Dwight's Energydata, Inc. DLOOK 4.20 Record # 2 Run date: 07/12/97
 Production data from file: C:\VISION\DUMPFIL\ Retrieval code: 110,111,358681
 Lease: THOMAS 18-2 SWNE Well #:

Month	Oil bbls	Cum Oil bbls	Gas mcf	Cum Gas mcf	Water bbls	No.of Wells
Total 1983	654	654	0	0	0	1
Total 1984	1285	1939	0	0	0	1
Total 1985	524	2463	0	0	0	1
Total 1986	399	2862	0	0	0	1
Total 1987	59	2921	0	0	0	1
Total 1988	811	3732	0	0	0	1
Total 1989	576	4308	0	0	0	1
Total 1990	0	4308	0	0	0	0
Total 1991	0	4308	0	0	0	0
Total 1992	0	4308	0	0	0	0
Total 1993	0	4308	0	0	0	0
January	0	4308	0	0	0	1
February	0	4308	0	0	0	1
March	0	4308	0	0	0	1
April	0	4308	0	0	0	1
May	0	4308	0	0	0	1
June	0	4308	0	0	0	1
July	0	4308	0	0	0	1
August	0	4308	0	0	0	1
September	0	4308	0	0	0	1
October	0	4308	0	0	0	1
November	0	4308	0	0	0	1
December	63	4371	0	0	0	1
Total 1994	63	4371	0	0	0	1
January	0	4371	0	0	0	1
February	0	4371	0	0	0	1
March	68	4439	0	0	0	1
April	0	4439	0	0	0	1
May	0	4439	0	0	0	1
June	76	4515	0	0	0	1
July	0	4515	0	0	0	1
August	0	4515	0	0	0	1
September	0	4515	0	0	0	1
October	87	4602	0	0	0	1
November	0	4602	0	0	0	1
December	0	4602	0	0	0	1
Total 1995	231	4602	0	0	0	1

Production on Thomas 18-2 from 1982 through June 1997

Appendix

Dwight's Energydata, Inc. DLOOK 4.20 Record # 2 Run date: 07/12/97
 Production data from file: C:\VISION\DUMPFIL\ Retrieval code: 110,111,358681
 Lease: THOMAS 18-2 SWNE Well #:

Month	Oil bbls	Cum Oil bbls	Gas mcf	Cum Gas mcf	Water bbls	No.of Wells
January	58	4660	0	0	0	1
February	0	4660	0	0	0	1
March	0	4660	0	0	0	1
April	0	4660	0	0	0	1
May	0	4660	0	0	0	1
June	0	4660	0	0	0	1
July	104	4764	0	0	0	1
August	0	4764	0	0	0	1
September	127	4891	0	0	0	1
October	86	4977	0	0	0	1
November	70	5047	0	0	0	1
December	80	5127	0	0	0	1
Total 1996	525	5127	0	0	0	1
January	64	5191	0	0	0	1
February	0	5191	0	0	0	1
March	79	5270	0	0	0	1
April	0	5270	0	0	0	1
May	104	5374	0	0	0	1
Total 1997	247	5374	0	0	0	1

The Thomas 18-2 has not produced gas in paying quantities and has never been connected to a gas gathering system.

APPENDIX C

REPRESSURIZATION WITH FLUE GAS CHIPMONK FORMATION ALLEGANY FIELD CATTARAUGUS COUNTY, NEW YORK

Final Report

by
Don Benson
Hydrocarbon Generation, Inc.

February 1998

Work performed for
BDM-Oklahoma, Inc.
Under Subcontract G4S60335
U.S. Department of Energy
Prime Contract No. DE-AC22-94PC91008

Hydrocarbon Generation, Inc.
4683 Birch Run Road
Allegany, New York 14706

EXECUTIVE SUMMARY

This report summarizes the 1996–1997 field research conducted by Hydrocarbon Generation, Inc. in response to Program Research and Development Announcement (PRDA) No. OKL-5204-01. This project is part of Project 95-A03 Extraction Research, Improved Recovery Processes, Task 8 High Potential Recovery—Gas Repressurization by BDM-Oklahoma for the U.S. Department of Energy.

The project was designed to address four tasks: (1) determine the efficiency of the flue gas injected as an Enhanced Oil Recovery method in the Allegany field, Cattaraugus County, New York; (2) help develop screening criteria for future projects from shallow upper Devonian reservoirs; (3) test the flue gas as a solvent to remove near wellbore damage; (4) technology transfer through presentation of technical papers with workshops sponsored by the Independent Oil and Gas Association of New York and the New York State Energy Research and Development Authority.

The Allegany field was drilled and subsequently produced as primary production in the "Chipmonk" sand. The wells produced natural (no secondary recovery), and most were shot with nitroglycerin for stimulation. The produced natural gas was then used to fuel the central powers, heat oil tanks, and keep a few work sheds and company houses warm. The balance was vented to the atmosphere to enhance the oil production. In the 1960s Pennzoil developed the Chipmonk sand in the Rumsey Devonian field. The entire field had a five-spot waterflood on it. Portions of the Rumsey Devonian bordered the Hydrocarbon Generation property.

Hydrocarbon Generation, Inc. (HGI) has operated an EPA permitted waterflood from 1981 to present in the Allegany field. A triplex pump driven by an electric motor furnishes 18 injection wells with 900 psi water at the wellheads. The wells that are now used for injection were previously producers. The "pattern" for the injection wells was established by the mechanical integrity of the existing wells, then choosing a "best fit" from the givens. There are 23 producers, of which 19 have pump jacks and 4 are flowing wells.

Results in this program were limited. Very little incremental oil production was realized. Most of the incremental oil that was produced came from oil producing wells that had a huff 'n' puff completed on them. The huff 'n' puff was done by injecting up to 250 psig into the annulus, letting it soak for a day, then producing the well. This seemed to have a cleansing effect on the wellbore and tubulars. Initial gas injection occurred from September 1 through December 31, 1996. Water was injected from January 1 through March 30, 1997, then gas again was injected from April 1, 1997, to June 31, 1997.

There was little economic gain as the direct result of the exhaust gas injection. The technology of repressurizing with exhaust gas should not be blamed for limited results. It is the author's view

that the age of the field and past practices inhibited the final results both economically and technically.

HGI is in fact considering moving the exhaust gas compressor to another oil field in Allegany, New York. This new field has seen only primary production, with no secondary means of oil recovery attempted. Well logs indicate good porosity and permeability. We are very confident that this technology will work given the correct location.

ACKNOWLEDGMENTS

This work is sponsored by the U.S. Department of Energy (DOE) through BDM-Oklahoma, Inc., in response to Program Research and Development Announcement (PRDA) No. OKL-5204-01. This project is part of Project 95-A03 Extraction Research, Improved Recovery Processes, Task 8 High Potential Recovery-Gas Repressurization by BDM-Oklahoma, Inc., for the U.S. Department of Energy under prime contract DE-AC22-94PC91008. The author wishes to thank Mr. George Stoepleworth for his support and Dave Olsen, Brian Rieper, Mike Madden, and Mike Hefner of BDM-Oklahoma their critical review and encouragement.

C-1.0 PROJECT DESCRIPTION

C-1.1 INTRODUCTION

This project was conducted to determine the efficiency of the flue, or exhaust, gas injected as an enhanced oil recovery method and to help develop screening criteria that can be evaluated using information which is usually available in independent operators' files. It also tested the use of flue gas as a solvent to remove near wellbore damage.

These objectives will be approached by:

1. Performing huff 'n' puff on all wells for clean up
2. Conducting immiscible flue gas flooding and water after gas flooding
3. Comparing to results to data from geophysical logs and geological data to determine if criteria can be developed for future project selection and operation

C-1.2 BACKGROUND

C-1.2.1 Setting and History

The first oil discovered in New York State was the "Seneca Oil Spring" near Cuba, Allegany County. The first oil test well in New York was drilled in Rushford Township, Allegany County, in 1860. The first commercial oil production in New York came from a well drilled near Limestone in Carrollton Township, Cattaraugus County, in 1865. In 1877 the first commercial oil well was drilled in Allegany, New York. The first "Chipmonk Pool" producer was drilled and completed in 1896. In 1881 Cattaraugus County produced 1,159,000 bbl. Production continued to decline until "waterflooding" was discovered as a means of secondary recovery in 1919. In the year 1937, Cattaraugus County saw another peak in oil production that reached 1,661,000 bbl. Production has steadily declined in Cattaraugus County to 139,376 bbl produced in 1996.

Figure C-1 outlines Cattaraugus County in New York State. The Knapp Creek quadrangle topographic map in Figure C-2 shows that there is 900 ft of vertical relief on the Hydrocarbon lease.

Hydrocarbon Generation, Inc. has operated a waterflood from 1981 to present on this project. Eighteen (18) producing wells were converted to injectors by running packers and cement to isolate the Chipmonk sand. The other (23) wells were left as producers. Figure C-3 shows lease boundaries and well locations

Figure C-1 Project location

C-1.2.2 Original Project Objectives

This project was designed to determine the efficiency of flue gas injected as an enhanced oil recovery method and to help develop screening criteria. Another objective was to test the use of flue gas as a solvent to remove near wellbore damage.

These objectives were approached by:

- Huff 'n' puff into wells for clean up
- Immiscible flue gas flooding and water after gas flooding
- Recording of available data
- Geologic characterization.

C-1.3 GEOLOGIC SETTING

Upper Devonian sandstones in Cattaraugus County are part of a series of interfingering and lensing rocks that were deposited in shallow water at the distributary front of a large ancient delta which was built out from the east across a large part of the eastern United States during the Devonian period. These sandstones have generally low porosity and permeability that do not appear to be related to regional trends or structures. Fracturing and structural uplift associated with later Appalachian folding and faulting had a localized influence on oil migration in limited areas where favorable sandstones previously had been deposited. This also had an influence on shallow gas production.

Figure C-2 Topographic map (not to scale) of project area. Benson Oil (Hydrocarbon Generation) lot is approximately 400 acres.

Pennzoil Company had a waterflood that bordered this project on the southeast flank. A core analysis of Pennzoil well No. 291, which is 1,200 ft south of well W-38, is shown in Figure C-4.

A log of Hydrocarbon Generation well No. P-53 is shown in Figures C-5a, C-5b, and C-5c. This is a typical well on this lease. It shows the cleanest sand in the lower section (780-795 ft). The upper sand body has many sand stringers with interbedded shale. This upper sand does give up oil when fraced. Most of the injection wells on this project have the packers set just above the clean lower section; therefore, only this was flooded.

Figure C-3 Lease boundary map (not to scale). For reference, wells are approximately 300 ft apart.

JOHN DEPETRO PETROLEUM ENGINEER BRADFORD, PA.								
1962 CORE ANALYSIS SUMMARY								
ANALYSIS 7/5-6-7-9-10-11-12	OWNER	South Penn Oil Co.	FORMATION	Chipmunk				
ANALYSIS BY John De Petro	WELL NO.	229	FIELD	Chipmunk				
CORED 7/3-5-6-7-9/62	FARM	Rumsey-Devonian	TOWNSHIP	Allegany				
CORED BY Carl Starr	ELECTROLOGGED BY	Birdwell	COUNTY	Cattaraugus				
TYPE CORE Baker	ELEVATION	1975.9' R.F.	STATE	New York				
SECTION CORED	DEPTH	Section 1	Section 2	Section 3	Section 4	Section 5	Section 6	Total
	- FEET							1057.5
FORMATION	- FEET							950.0
	- FEET							107.5
	- FEET	965.4	984.3	996.6	1008.1	1018.4	1032.4	1032.4
	- FEET	957.2	965.4	984.3	996.6	1008.1	1018.4	957.2
SANDSTONE	- FEET	8.2	18.9	12.3	11.5	10.3	14.0	75.2
	- PERCENT	2.5	2.5	10.4	11.1	7.0	7.1	40.6
	- PERCENT	30.4	13.2	84.5	96.5	67.9	50.7	53.9
PERMEABLE SAND	- FEET	0	0	8.3	11.1	7.0	1.0	27.4
SHALE	- FEET	5.7	16.4	1.9	.4	3.3	6.9	34.6
	- PERCENT	69.6	86.8	15.5	3.5	32.1	49.3	46.1
AVG. POROSITY	- PERCENT	9.41	9.90	12.98	22.48	13.21	10.94	14.54
	- BBL/ACFT.	730	768	1006	1743	1024	848	1128
AVG. OIL SATURATION	- BBL/ACFT.	221	273	357	500	388	316	385
	- PERCENT	30.3	35.3	35.5	28.7	37.9	37.3	34.2
AVG. WATER SATURATION - TOTAL		20.7	16.3	29.8	52.1	24.1	19.7	30.9
	- DRILLING	2.3	3.1	11.9	45.9	4.1	1.6	15.8
75,000 PP/INCH	- COMBINE	17.8	12.8	13.5	6.7	18.2	14.2	13.0
	- FLOOD	1.7	2.4	5.3	3.0	2.9	4.8	4.0
AVG. AIR PERMEABILITY	- MILLIDARCT	.29	.32	.98	66.52	.86	.38	17.13
TOTAL OIL CONTENT	- BBL/ACRE	0	0	2963	5550	2716	316	10,549
ESTIMATED RECOVERY	- BBL/ACRE	0	0	400	500	300	0	1,200
*EST. INTAKE 700#	- BBL/DAY	0	0	1.3	122	1.0	0	124.3
EST. INITIAL INTAKE 700#	- BBL/DAY	0	0	2.0	175	1.4	0	178.4
SHOT USED FROM ELECTRIC LOG								
	FROM	TO	FEET	SHELL	QUARTS			
*All sand above .50 md.								
**Providing all sand is shot.								

Figure C-4 Core report on Pennzoil well No. 291

Figure C-5a Well log of Hydrocarbon No. P-53: upper section

Figure C-5b Well log of Hydrocarbon No. P-53: middle section

Figure C-5c Well log of Hydrocarbon No. P-53: lower section

The evaluation of the Baker Core from well No. 291 for this Chipmonk horizon, dated November 27, 1963, by W. T. Paynter, P.E. with Pennzoil, reads as follows:

The Chipmonk formation was 80 feet thick at this location and contains 38.5 feet of sandstone.

Section 1, which contains 6.7 feet of sand, is a very lenticular and tight zone. Section 2 is composed of several tight sand lenses which have a total count of 8.5 feet. Section 3 contains 8 feet of pay sand with the following core analysis characteristics: 21.3% porosity; 38% oil saturation; 7% calculated connate water saturation; 33 md permeability.

Section 4 contains an additional 5.2 feet of pay sand, which has core analysis values of 19.5% porosity; 39% oil saturation; 8% calculated connate water saturation; and 8 md permeability.

Section 5 and 6 contain the remaining 10.1 feet of sand lenses tested by this core. These lenses are tight and low porosity sand.

Only the 13.2 feet sand found in Sections 3 and 4 are pay, and the estimated recoverable oil content is 2,960 bbl/acre.

Additional five-spot development is recommended for the northern portion of the Rumsey.

It has been recorded that Pennzoil actually recovered more than 3,500 bbl/acre from this waterflood.

C-2.0 FACILITY DESIGN, OPERATIONS, AND PROBLEMS

C-2.1 COMPRESSOR SIZING AND FABRICATION

A Gardner-Denver two-stage compressor with operating capacities of 90 Mcf/D at 800 psi was powered by a Minneapolis-Moline, Model HD425-6A, 100 HP, natural gas engine to provide exhaust to the injectors. The engine worked very well in this application. The compressor was operating at its limits from the get-go. This unit was purchased as used. After the unit arrived on site many piping changes took place, along with the re-tubing of the first-stage gas cooler. This was probably due to the age of the unit, time out of service and the service it saw before our ownership. Drip pots needed replacing. Liquid knock-out bottles also were added. The ignition system on the engine was converted to an "Altronic" system. A catalytic converter also was added/replaced. The unit was purchased for \$10,000 as is. After rebuilding the complete unit, adding in the trucking, labor, etc., we had about a \$28,000 investment. Pictures of the actual unit are shown in Figure C-6.

The natural gas fuel for the engine was furnished from the Lower Devonian "Oriskany" producing horizon on the lease. We did not put a value on the gas consumed for this project. We do consume this natural gas (on the same site) in internal combustion engines that drive electric generators. The excess electricity is then transported and sold to a local public electric utility company. The average price we receive is \$.07/kilowatt-hour. Converting this to \$/Mcf for natural gas would be close to \$6.50/Mcf.

The gas flow of the exhaust gas unit is shown in the single line diagram on Figure C-7. Describing the flow, we start with the natural gas fuel entering the engine. From internal combustion the exhaust gas is now converted to approximately 15% nitrogen and 85% carbon dioxide. The exhaust gas travels through a catalytic converter, into a gas cooler where it is cooled before entering the first stage on the compressor. Arriving at the first stage at ambient pressure, it is now compressed and passed through an internal heat exchanger that is integral to the Gardner-Denver unit. After the gas is cooled, it then passes into the second-stage compressor, where it is compressed to final discharge pressure. It then travels into a gas cooler for final cooling and into a liquid knock-out vessel that catches condensate before entering the distribution lines that connect the injection wells.

Figure C-6 Flue gas generating system photographs: top shows controls and coolers, bottom shows compressor and knock-outs.

Figure C-7 Flue gas generating system flow chart

C-2.2 OPERATIONS OF COMPRESSOR AND WELLS IN THE FIELD

The compressor was operated at first on a 24-hour-a-day schedule. Injection rate was approximately 80 Mcf/D. This seemed to work fine until the pressure on the injection wells got up to around 800 psig. Then the compressor could not run cool enough. This then brought on running the compressor on a more limited basis. The operating practice was to run the compressor until the intake wells had approximately 750–800 psi on them, then shut down. This would take about 14 hours. The wells would then soak until the pressure was down to around 600 psi, or until the compressor was started in the morning. If the intake wells would not take much gas, then a quick backflow was allowed.

Before any gas injection took place, each intake well was individually pumped into with a portable high pressure (3,000 psi) pump with the injection rates monitored. If the well would not take sufficient quantities, then a small amount of acid was injected to help clean up the formation.

C-2.3 PROBLEMS

During the months of January, February, and March of 1997, the intake wells were converted back over to water. This was done for two reasons. The first was that winter set in and made it uneconomical to operate the flue gas compressor. The second was that water injection rates could be monitored. No incremental change could be seen in the injection rates and volumes.

The most outstanding problem was the discouraging injection rates achieved. This, we believe, was due mainly to the damage already done to the "Chipmonk" formation. The formation had seen 15 years of waterflood activity before the flue gas was attempted. Injection water was not always filtered, and recycled water was used the majority of the time. Wellhead water pressure and injection rates should have been monitored and analyzed in more detail prior to the flue gas injection attempt. The assumed poor water quality must have contributed to the low permeability. (No water samples were taken prior to gas injection or after.) And if the water had carried dissolved solids, then pore spaces also were plugged.

C-3.0 ANALYSIS OF GAS REPRESSURIZATION PERFORMANCE

C-3.1 INITIAL START-UP

Permitting the flue gas repressurization took longer than expected. The Environmental Protection Agency (EPA) required that we add an injection fluid (flue gas) to our original permit. Initial discussion with EPA personnel led us to believe that this permit change was something minor (which in fact it was). It is very hard to put a monetary value on these delays, but they add up in the hidden cost, i.e., administration and delays on start up.

Compressor start-up was uneventful. Our personnel had run similar units in the past for natural gas compression.

Safety had to be readdressed because some of the well-to-well lines were run on top of the ground. Also, when blowing down a well that had compressed gas, field personnel would see extreme changes compared to water intake wells.

C-3.2 USING THE FLUE GAS FOR PRODUCTION WELLS

While waiting on the EPA revised permit, we were able to familiarize ourselves with the compressor by injecting small amounts (50–100 Mcf) into oil production wells. At first, gas was put into the annulus while the well was pumping. This did have a cleaning effect on the downhole tubulars. Then the annulus would be pressured up to 100–300 psi and relieved by producing the well. The third attempt was to build annulus pressure to 100–300 psi and let it “soak for a few days and then relieve it. In wells No. P-44, No. P-51, No. P-52 that this was tried in, a noticeable increase (0.5–5 bbl) flush could be seen in these individual wells.

C-3.3 FLUE GAS INTO OLD WATER INTAKE WELLS

The first things that had to be done on these intake wells was to repipe the surface fixtures. New valves were installed along with backflow devices (check valves). Flue gas was then introduced into the wells. If a particular well would not take a reasonable amount of flue gas from the start, we would backflow or bleed off. This would be done enough times until a reasonable amount could be injected until the injection pressure reached 800 psi.

The injection volumes were then monitored and if particular wells would not take flue gas then the huff ‘n’ puff was repeated. Gas volumes were not measured by recording devices on individual wells. If personnel were to close the valve at the well, then reopen it in a couple of minutes, we could estimate the flow as good or poor.

C-3.4 COST OF OPERATIONS

Having the exhaust gas injection unit operating at this particular site was very beneficial. This location is a primary operations center. If it would have been necessary to travel any length of time, operational expenses would have increased considerably.

The U.S. Department of Energy provided funds in the amount of \$133,000 for this project. As per the contract, Hydrocarbon Generation, Inc. provided a 50% contribution also. Tangible goods such as the compressor, pipe, pipe fittings, chemicals, oil, natural gas, etc., were covered pretty much by the Department of Energy hard money. Field labor, clerical, office supplies, oil field equipment such as bulldozers, backhoes, rubber tired tractors, pickup truck usage, service rigs, etc., were paid-in-kind by Hydrocarbon Generation, Inc.

C-3.5 OBJECTIVES ACHIEVED

The objectives that were outlined in the proposal were achieved.

A determination of the efficiency of the flue gas injected as an enhanced oil recovery operation was made and outlined in Section C-3.6. The measurement of the efficiency or value is the amount of incremental barrels of oil produced.

Although we determine that flue gas injection is not an economic way to recover additional oil from the Chipmonk sand on our site, we do believe this process will work at another field. Ideal conditions, or screening criteria, would be to have a field without previous waterflooding that has good permeability with good porosity, a clean wellbore, and sand face. This is discussed in Section C-4 in more detail.

The other objective to test the use of flue gas as a solvent to remove near-wellbore damage was also completed. This is discussed in more detail in Section C-3.6.

C-3.6 ECONOMIC VIABILITY OF THE TECHNOLOGY

The Flue Gas injection technology that was tried at this location was not economic. Very little incremental oil production was realized. Oil production was not tallied every day, only on a monthly basis. When flue gas was put into oil wells, we would monitor production for a few days and see a small incremental (0.5 -5 bbl/d) production increase. We need to remember that oil wells are not permitted to use as injection wells. In that, we could actually only flush (wash) the wellbore and tubulars.

Table C-1 and Figure C-8 show the details of oil production from this property. Injection of flue gas started in September 1996 and ceased in July 1997.

Table C-1 Oil production spreadsheet

	1995	1996	1997
January ¹	314	398	278
February ¹	309	396	293
March ¹	314	317	203
April	314	314	300
May	236	318	305
June	315	235	161
July	233	313	312
August	156	235	160
September ²	230	241	173
October	462	408	169
November ³	548	206	
December ³	318	308	
TOTALS	3,749	3,688	2,355

- Notes:
1. No injection for January, February, and March of 1997.
 2. Injection started September 1996
 3. November and December 1997 data were not available at time of report.

Figure C-8 Oil production chart

Oil production from September 1995 to August 1996 was 4,084 barrels (see Fig. C-8). Oil production from September 1996 to August 1997 was 3,175 barrels.

The explanation for this is that we re-fraced two old oil wells in that time period. We were able to get our investment back from a production increase, then production decreased to normal in trying this re-completion method.

If we compare 9 months production from January through September 1995 to January through September 1997, we see that oil production actually fell from 2,421 bbl to 2,185 bbl, or 236 bbl. We do not believe that the flue gas injection accounted for this. It is assumed that this is the normal production decline.

If more of our time and effort had been spent on using the flue gas unit as a wellbore cleansing application, we believe more incremental oil would have been recorded. This is not saying that money would have been made, only that more oil may have been produced.

The small amount of flue gas that could be injected on a daily basis raised the cost of daily operations. Multiple trips to the compressor for monitoring cost an estimated \$75/day extra.

C-3.7 SUCCESSES

Short terms successes were seen in the huff 'n' puff into oil production wells.

The willingness of all field personnel to keep records and adjust the program as results warranted had value.

And for all of us to keep the faith that this was going to work had a measure of success.

If we were to try and answer the typical, "was this an engineering and technical success?" my answer would be: This was an engineering success, since the flue gas compressor was built and operated as expected. Technically, this project was a success, in that it proved that flue gas can help oil well production and that the Chipmonk formation would accept flue gas.

C-3.8 FAILURES

Although a catalytic converter was used on the engine, the flue gas was still very corrosive. The flue gas leaving the engine to the compressor was not bad. From the first-stage discharge through the first-stage cooler was not that bad either. The most corrosive gas was seen in the condensation formed downstream of the second-stage cooler. The flue gas was piped from the second-stage cooler into a manifold that fed individual wells. It was here that most of the corrosive action took place.

After the flue gas had been injected for a few months, pipeline leaks started occurring. We all need to keep in mind that this project was overlapping a waterflood that had been in place for over 15 years. The steel pipelines were old at the start of the flue gas injection, along with all downhole steel tubulars. Many fittings and valves had to be replaced at this location. Towards the end of the injection period, we realized too many leaks to continue injecting. This cannot be blamed solely on the flue gas.

A few mechanical breakdowns occurred with the compressor. This unit was purchased used, then rebuilt before using. The vintage of the unit caused a few delays on getting replacement parts for breakdowns.

C-3.9 LESSONS LEARNED

The very first lesson learned was that our existing water intakes were not taking as much fluid as previously believed. This put immediate constraints on the project. It could be noted that this project turned out to be more of a pressure maintenance program, rather than a repressurization of the Chipmonk formation.

It was assumed that we would see some immediate effect on the injectivity of the flue gas. We now will assume this could not take place because of the wellbore damage already caused by the waterflood.

This project has let us see reality that the intake wells should be plugged out in the very near future.

C-4.0 FUTURE USE OF THE FLUE GAS UNIT

We plan to use the flue gas unit in continuing to flush oil wells. Another application that will be tried is artificially pressurizing shallow gas wells in our area that have siphon strings in them. Pressuring up the annulus enough to flow the produced liquids out the siphon strings will save moving in a swabbing unit. This is not new technology, but it is much safer using an inert gas (flue gas) than using air. Many wells in a gas field could be done in one day, saving considerable dollars for the industry.

Hydrocarbon Generation has a primary production oil field nearby producing from the "Kane" sandstone, which is a deeper horizon than the Chipmonk. Preliminary research shows that this formation may be a candidate for gas repressurization. This being a formation that has not seen any waterflood activity and that has good permeability and porosity, should show some interesting results. We are in discussions with the regulating authorities on this possibility.

C-5.0 SUMMARY

The project had very beneficial results. The information gathered can be used to analyze future potential candidates for a flue gas repressurization program for this area in New York State and bordering Pennsylvania.

This having been our very first time being involved with a sponsoring governmental agency, we were a little apprehensive. All of the personnel at the BDM-Oklahoma office were very helpful in overcoming this.

I sincerely thank everyone for all the sharing of their individual knowledge on all subjects.

APPENDIX D

HIGH POTENTIAL RECOVERY BY GAS REPRES- SURIZATION TAYLOR-INA FIELD MEDINA COUNTY, TEXAS

Final Report

**by
J. H. Klaeger
Klaeger Operating Company**

September 1997

Work performed for
BDM-Oklahoma, Inc.
Under Subcontract G4S60333
U.S. Department of Energy
Prime Contract No. DE-AC22-94PC91008

**Klaeger Operating Company
1209 Lake Shore Drive
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EXECUTIVE SUMMARY

This report summarizes the 1996–1997 field research conducted by J. H. Klaeger in response to Program Research and Development Announcement (PRDA OKL-5204-01 titled "High Potential Recovery—Gas Repressurization" by BDM-Oklahoma, Inc., for the U.S. Department of Energy.

We started a natural gas condensate injection pilot project on the Hutzler "A" Lease in 1995. Six wells were chosen and equipped with all related equipment: 6,000 ft of natural gas line to the purchase line, condensate, chemicals, and project startup.

Of the six wells, four had been fractured and had a good response to injections, the other two wells had not been fractured, were very tight, and had little response. We had hoped to gain information and increase production enough so we could expand the pilot over the field. As with other previous projects in the field, we were underfinanced and forced to stop the project.

In May 1996, received the \$133,000 DOE, BDM-Oklahoma subcontract for this Gas Repressurization project. Ten wells were equipped, and the project was started in July 1996 with the Injection of natural gas with condensate and chemicals. Problems were very bad with trying to pump gaseous, sandy fluid. Then we removed all bottomhole pumps and started jetting wells, which helped production some.

After each injection cycle, production would decline instead of increasing. We tried various volumes of gas condensate and chemicals, but they did not help. Then we started having problems treating the oil before it could be sold. We used treating chemicals but finally had to call Hot Oil Service Company to treat the oil before it could be shipped. At the oil-water interface, a slick black layer was noted. We discussed the problems with the owner of the Hot Oil Service Company. He informed us of a similar project that was done in Oklahoma injecting natural gas condensate into the same type formation as we have. Those wells were completely plugged, by precipitation and flocculation of asphaltenes in the wellbore region, and the project had to be abandoned.

During this interval our purchase price of natural gas increased from \$2.40/MMBtu to \$4.568/MMBtu. Injection was halted. Testing of the oil was done in February 1997. The oil contains 5.5% asphaltenes, which was a complete surprise to us and other operators in the field. We knew the oil was asphaltene based, but had not encountered any problems that we knew about.

We discussed the report with Dr. Olsen of BDM-Oklahoma and what could be done at this late date. Dr. Olsen said he would help find a solvent that might help. On March 10, 1997, we received a call from Kyle Byron, AGE Refining in San Antonio, Texas. Dr. Olsen had contacted him about our problem. Samples of oil were sent on March 14, 1997. On April 11, 1997, we received a call from AGE Refining concerning samples of our crude. They recommended using a blend of 350 gal LVN, a mixture of C₃–C₇ aliphatic, olefinic, and aromatic hydrocarbons, with 150 gal heavy aromatic naphtha (HAN) and 500 gal were purchased. At this time we decided to

inject 125 gal into four wells. We injected down 3/4-inch tubing: 180 cfm with 5 gpm LVN. We also injected nine 2-lb. batches of moth ice crystals (paradichlorobenzene) during the cycle hoping to get some temporary diversion and expose more of the formation to LVN. Wells were allowed to soak for 24 hours, then put on production. Four wells prior to LVN treatment averaged about 1 BOPD. After treatment, they averaged about 2.75 BOPD. The results were discussed with Dr. Olsen, and we decided to purchase 4,200 gal of 100% HAN, which was delivered to lease May 6, 1997. The price of natural gas was then \$3.21/MMBtu. We resumed injection on all wells. Prior to continuous injection, each well was washed—displaced with 150 gal HAN and allowed to soak, then produced back. All 10 wells were then put on a regular injection schedule.

Injections continued until all the HAN was used. Production increased some, but not enough to offset the cost of the project. The subcontract funds were exhausted, and the project was terminated May 22, 1997. Prior damage done by asphaltenes could not be overcome.

ACKNOWLEDGMENTS

This work is sponsored by the U.S. Department of Energy (DOE) through a subcontract with BDM-Oklahoma, Inc., Management and Operating contractor for the National Oil and Related Programs, in response to Program Research and Development Announcement (PRDA) No. OKL-5204-01. This project is part of Project 95-A03 Extraction Research, Improved Recovery Processes, Task 8 High Potential Recovery—Gas Repressurization being conducted by BDM-Oklahoma for the DOE. The author wishes to thank the following from BDM-Oklahoma: Brian P. Rieper and Mike Hefner for their support and encouragement, David Olsen and Mike Madden for their technical advice and critical review, and Susan Hayden for typing the manuscript.

D-1.0 PROJECT DESCRIPTION

D-1.1 INTRODUCTION

The intent of this paper is to review the influence of injecting natural gas with various amounts of condensate huff 'n' puff. The overall objective of the Taylor Ina gas repressurization is to increase the life of the field and recover more of the vast amount of oil still in the reservoir.

D-1.2 BACKGROUND

D-1.2.1 Geologic Characterization Setting and History

Production in the Olmos horizon at 1,100 feet was established in 1961 on the Hutzler-A lease with ten wells. The potentials ranged from 0.8 to 60.7 BOPD and an average of 17.2 BOPD with water cuts varying from nil to 12% and averaging 6%.

Because of the large oil-in-place found in the Olmos sand, offset wells have been tested between 1962 through 1966 to prove various secondary recovery mechanisms. The tests included carbon dioxide as well as huff-and-puff with steam, hot water, combustion products, and kerosene. To date, none of the projects have achieved engineering or economic success. A cursory review of the projects indicates that they were terminated before conclusive results were obtained; and in most cases, poor technical planning, supervision, and operating techniques rendered little probability of success.

The Taylor-Ina field is one of several fields with multiple productive horizons along what is known as the Taylor-Ina area in Southwest Texas. The area is approximately 12 miles southeast of the town of Hondo. These fields are located along the Balcones fault system, which is a major geological feature. The Olmos sandstone in the Taylor-Ina field correlates into adjacent West Fairfield and Adams fields, all of which are contained in a producing trend of about 15 miles long and 4 miles wide.

The Olmos zone is found at an average depth of 1,175 feet, or 315 feet subsea. Under the Hutzler-C lease, the highest known oil (HKO) is 285 feet subsea and the lowest known oil (LKO) is 364 feet subsea. In the study area, no oil-water contact(s) have been identified. The fault system did not control sand development or oil accumulation. All indications are that oil accumulation existed at the time faulting occurred. The faults consist of tension breaks with relief faulting occurring between the major displacements. This is consistent with the Balcones fault trend. The fault diversity provides certain fault blocks with sealing boundaries and limits the size of a given reservoir, e.g., 30 to 100 acres. The faults will be trapping where fault throws are greater than 20 feet and sealing. The nonsealing faults are interior to a reservoir and tend to restrict flow between compartments. Olmos formation pressure is a subnormal gradient, 0.273 psi/ft,

inferring that the traps may have been breached allowing the most mobile fluids and gases to escape into other horizons along fault planes leaving the 18 °API oil gravity found in-place.

The Olmos sand section in the Taylor-Ina field is better developed and cleaner than in the majority of the productive Olmos fields in the area. In general, cores were relatively soft, poorly consolidated sandstone with about 15–20% clays and a trace of dolomite (<0.3%). Small lenses of harder shale were found in some of the cores. Core analysis indicates that the sand does carry some dispersed clays. The clays are principally montmorillonite with some kaolinite. The net-to-gross ratio is in excess of 90%. Because of the high ratio of sand, the gross interval was mapped as net pay isopach. Net oil pay averages 18 feet in thickness. The zone varies in thickness from 12 to 22 feet of pay with a consistent 18 feet across most of the leases. The thickest pay lies downdip on the southern portion of the Hutzler and Schautteet leases. The thinnest pay occurs in a local area.

D-1.2.2 Reservoir Rock and Fluid Characteristics

The rock porosity and permeability for the Olmos sand are good. A cross plot of the properties from core analysis is enclosed. Porosities range from 24 to 40% and have a median of 32 percent. Air (absolute) permeabilities range from 30 to a (suspect) 1,500 md and a median of 150 md (see Fig. D-1 for a cross plot of permeability and porosity). As anticipated for the highly viscous oil, analysis of the decline rate indicated an effective oil permeability of 20 md for an average thickness of 18 feet of net oil pay. This compares to the measured oil permeabilities of 18 to 33 md in a special core analysis conducted on the Hutzler-A No. 9 well (see Fig. D-2 for a map of the Taylor-Ina field showing well locations).

Water saturations for the Olmos, estimated from core analysis and log evaluations, increase slightly with depth. Water saturation ranges from 46 to 62% as determined by summation of fluids method from cores. This method has the inherent empirical correction factor for clay-water content and flushing of rock by drilling fluid. Log calculations estimated a 30 to 32% saturation. Based on this information, we estimated a 40% water saturation. Initial well completions have tested at 5 to 10% water cut. This amount of initial water flow is expected for sandstone containing mobile and immobile connate water, e.g., 40% being greater than an estimated 30% irreducible saturation.

Rate-time analysis has estimated 20 md of oil permeability, which compares favorably to core analysis. Produced water cut on the Hutzler lease has been 50 to 60% over the last nine years. This has not substantially reduced oil production. To some degree, we think in-situ formation water may be entrained in the heavy oil, reducing its ability to wet formation clays and reduce permeability.

D-1.3 FACILITY DESIGN

The design of the facility can best be explained through a series of photographs and schematic diagrams. Production and test hook-up manifolds, two-phase separators, and test tank are shown in Figure D-3. Injection and jetting hook-up manifolds, injection pumps, and meter loops are shown in Figure D-4. A wider angle photograph of the manifolds, pumps, and tank battery is presented as Figure D-5. Figures D-6 and D-7 show a wellhead with production and injection manifolds. Figure D-8 shows a two-stage, 1,000-psi, 300-cfm gas compressor. Figure D-9 shows the production and test separators. Figure D-10 shows the gas injection recorder. A schematic diagram of a wellhead is shown in Figure D-11.

Figure D-1 Cross plot of permeability and porosity in the Olmos Sand of the Taylor-Ina field (data from core analysis): line A = Schauetteet No. 10; line B = Hutzler No. 2; line C = Hutzler No. C44; and line D = Schauetteet No. 9.

Figure D-2 Taylor-Ina field map: Olmos sand and well locations

Figure D-3 Production and test manifolds. Six-well hookup manifolds on left: production upper, test lower. Flow lines from the wells are underground up through 1-inch 3,000 psi hydraulic hose into a 1-inch "T", outside of "T" through 1-inch 3,000 psi valve into the lower manifold. Test out top of 1-inch "T" through 3,000 psi valve into upper production manifold. By switching valves, a well can be switched from test separator to production separator. Immediately behind the manifolds are the test and production two-phase separators (see Fig. D-10). Behind the separators is a 100-bbl test tank.

Figure D-4 Injection and jetting equipment and manifolds. Six-well hook-up: in the foreground is a 5-hp variable drive gear box with a 1,000-psi condensate pump, to the lower right is a variable drive chemical pump. Immediately behind is the injection manifold lower and jetting lift manifold upper, similar to the production and test manifolds in Figure D-4. A well can be switched from injection to production by switching two valves. Immediately behind jetting and injection manifolds, the meter loop and dual pin recorder records injected gas only. Further behind, the meter loop dual pin recorder measures purchased gas.

Figure D-5 Separator, condensate, and storage tanks and gun barrel. At the far left behind the separator tanks is a 210-bbl condensate tank. At the far center are a gun barrel and storage tanks.

Figure D-6 Injection jetting and production manifolds. Additional detail is given in the caption for Figure D-7.

Figure D-7 Photo shows two manifolds : (1) left, the production manifold and (2) right, the injection and jetting manifold. Each manifold is a dual manifold consisting of two separate wings; each wing has interchangeable chokes. Chokes can be changed at any time without stopping flow. Dual manifold on right (2) is for either injecting or jetting wells and is connected to injection and jetting manifolds at the compressor station. For example, the well shown here is ready for injection (see the schematic in Fig. D-11). Valve on 0.75-inch IJ tubing is closed, and inlet valves on 0.75-inch tubing and 2.375-inch tubing annulus are opened. Desired size choke is installed in either side of the injection manifold. The corresponding valve is opened on the injection manifold at the compressor station, injection cycle is started. After injection cycle is finished, well is shut in for a soak period. When ready to put on production, the valves are switched at compressor station from high pressure injection to low pressure jetting manifold, 0.75-inch tubing valve is opened into dual production manifold on left (1), and proper sized chokes are installed in either side, and corresponding valve at compressor station manifold is switched to test tank, so well can be tested. After well quits flowing, jetting manifold (2) with proper sized choke installed is opened to jetting pressure, allowing gas from compressor station to enter 0.75 inch to 2.375-inch tubing annual displacing fluid down through annuals out through 0.75 inch IJ tubing through production manifold (1) test separator into test tank. Choke sizes are varied to furnish required volume of gas for jetting maximum amount of fluid.

Figure D-8 Gas compressor. Two-stage, 1,000-psi, 300-cfm gas compressor. In the immediate background is a two-phase fuel separator, and in the far background are the storage tanks and gun barrel.

Figure D-9 Production and test separators. The view has the test separator on the right and the production separator on the left. Behind the separators are the test and production manifold on the right and the injection and jetting manifold and the injection metering loop on the left. The office building is in the background.

Figure D-10 Gas injection recorder. In the background is the gas compressor and fuel separator.

Figure D-11 Schematic diagram of the wellhead (not to scale). Also, see Figures D-6 and D-7.

D-2.0 OPERATIONS

D-2.1 OPERATION AND PROBLEMS

The Taylor-Ina field, Medina County, Texas, production was established in 1961, in the Olmos horizon on the Hutzler-A lease.

Because of the large oil-in-place found in the Olmos sand, many wells have been drilled. The Olmos sandstone in the Taylor-Ina field correlates into adjacent West Fairfield and Adams fields; all are contained in a producing trend about 15 miles long and 4 miles wide.

Since 1962, various secondary recovery projects have been instituted. These tests included waterflood, in-situ combustion, gas injection, liquid carbon dioxide, huff 'n' puff with steam, hot water combustion products, and kerosene. To date, none of the projects have achieved engineering or economic success. A cursory review of the projects indicates that they were terminated before conclusive results were obtained. In most cases, poor technical planning, supervision, and operating techniques rendered little probability of a successful project.

A pilot project was initiated in late 1994 on Hutzler-A lease using natural gas condensate and chemical with a huff-and-puff method. Six wells were selected which had different types of completion to help determine the best type of completion for future wells added to the pilot project. The two newest wells No. 11 and No. 12 drilled in the early eighties were cemented top and bottom with high-temperature cement, perforated at 4 shots/foot, and fractured with 60,000 lb of 8-12 sand. Two older wells with open hole completions and no fractures (wells No. 9 and No. 13). The last two wells No. 4 and No. 7 were cemented, perforated, and fractured. No other records were available.

Work started in 1995. One mile of gas line to sales line, all related work equipment, wells, flow lines, injection and fuel gas line to all wells, tank battery, gun barrel, test tank, condensate tank, production and injection manifolds, separators, meter loops, and other necessary equipment were in place and tested. A 300-cfm gas compressor with related equipment was rented (June 1995), 200 bbl 62° API gravity condensate was purchased.

The first injection cycle started June 19, 1995, on well No. 12 was injected with approximately 100 Mcf gas with 1,500 gal of condensate and 4 gal of chemical at 280°F wellhead temperature. Injection time was 17 hours with a well shut-in soak time of 24 hours. The other five wells were treated in the same manner. Injection times varied from well to well. Wells No. 9 and 13 were very tight, and injection was slow since we didn't exceed fracturing pressure.

Wells No. 11 and 12 produced back best, wells No. 4 and 7 were fair, and wells No. 9 and 13 were poor. Wells No. 11 and 12 averaged approximately 10.5 bbl per day for the first 12 days, wells No. 4 and 7 produced approximately 6 bbl per day, and wells No. 9 and 13 produced about 1 bbl per day. According to the work schedule, we should have started another injection cycle in 7 days

but did not have the money to purchase more condensate. We did purchase more condensate at the end of July 1995 and started the injection treatment again. Well production again increased immensely. At this time it was determined that our fixed costs were too great for the four producing wells to carry, and the project was shut down in August 1995.

Originally we figured it would take eight to ten wells on the pilot program to generate sufficient money to expand the pilot to cover three leases. The equipment in place can handle approximately 30 wells other than flow and gas lines and well equipment.

In December 1995, we applied for a subcontract to continue the gas injection under the DOE Gas Repressurization program. BDM-Oklahoma, Inc., approved the subcontract for \$133,000. Work resumed in May 1996. Four additional wells were prepared for injection, for a total of 10 wells.

D-2.2 MONTHLY ACTIVITIES

The activities during the project can best be described chronologically. The material in this section is taken from monthly reports submitted during the course of the project.

June 1996

During June five tasks were pursued as highlighted on the accompanying milestone chart and as described below:

1. Reata Industrial Gas (Valero) deposit made for natural gas purchase
2. Compressor from Gaertner Leasing
3. Purchase wellbore tubing—2.375 inch and 1 inch; purchase flow and injection lines; purchase all materials, connections, valves, etc., for production and test manifolds and wellhead hookup
4. Installation and burying of gas injection and flow lines
5. Manufacture and assembly of test and production manifolds—estimated completion by June 1996
6. Well preparation for wells to be fractured. Tubing pulled, wells cleaned to T.D. Packers in place for fracturing: wells No. 4, 7, 9, 3 and 13. Well 10 is reperforated and ready. Wells 5 and 6 are being cleaned prior to fracturing. Wells scheduled to be fractured June 27 and 28, 1996.

The only problems which occurred during the completion of the above were the cleaning of the old wells and the fact that there were no true completion reports, which caused problems in preparing wells for fracturing.

July 1996

See Table D-1 for injection activities during July. Switched into wells No. 3, 5, and 10 using 0.125-inch orifice in each well.

Table D-1 Injection activities, July 1996

Date	Description
7/1/96	Move Workover Rig No. 6—fish, no luck
7/2/96	Fish on No. 6—no luck, quit well; 18 hours workover time
7/2/96	Move workover rig No. 10 4 1/2 hours
7/3/96	Fish on No. 10, caught fish, circulate and washed well clean 9 1/4 hours
7/8/96	No. 10 out of hole; ran tubing and set packer. 3 1/2 hours
7/8/96	Move rig No. 5—tried to wash down, pulled, wash pipe, ran taper tap
7/9/96	No. 5 fish
7/10/96	No. 5—fish; finally cleaned hole; ran and set packer; ready for fracture. 26 1/4 hours
7/11/96	Move rig No. 3—ran packer 2 1/2 hours
7/11/96	Move rig No. 2—fished; out of hole with fish; ran packer. 12 1/2 hours
7/12/96	Getting ready to fracture
7/13/96	Getting ready to fracture
7/15/96	Moved in fracture equipment; fractured wells No. 2, 5, 3, 7, 9, 10 and 13; packer turned loose on No. 4, did not fracture; pressure extremely high, friction down 2 inch tubing with Hutzler oil—average injection pressure about 1,800 psi—3 1/2 lb per minute tailed in with 5 lb sand per gallon. Had no problem carrying 5 lb sand per gallon. Afraid to increase rate and pressure with no fluid and pressure between tubing and packer. Averaged 60 bbl oil and 5,000 lb sand per well.
7/16/96	Let fracture heal
7/17/96	Opened all wells—all wells on vacuum. Moved rig in to clean fracture sand to bottom. First tried to sand pump wells—oil so vicious—it would take nearly one hour to run sand pump to bottom and pull out and not recover much sand. Decided to move in rig with circulating equipment. Ran 1 inch tubing to top of fracture, sand in tubing, down tubing annulus with water to circulate oil from wells extremely slow—not using over 400 psi—going down annulus with water, after oil circulated from well—wells were then washed to bottom with no problems. After washing wells to bottom, pulled wash string and then ran B.H.P. or jetting string. Rig worked 7/17, 18, 19, 20, and 21/96 to clean seven wells!! The Hutzler oil; working inside 2-inch tubing is not the way to complete Hutzler Lease wells. Either use surface tension reducer or use higher gravity oil to fracture with. Have drilled and completed 64 wells on Hutzler lease, but always worked inside 4-inch casing with 2-inch tubing and had no friction problems. We sure learned a good expensive lesson.
7/22/96	Started producing well to recover waste water and free oil before starting gas and condensate injection.
7/25/97	Injected into No. 9. 4.5 hours; gas (no condensate) 460–480 psi injected approximately 40 Mcf

Table D-1 Injection activities, July 1996 (Continued)

Date	Description
7/26/97	Injection No. 13 7:30 a.m.; started condensate at 10:30 a.m.; stopped injection at 5:00 p.m., 9.5 hours total; 6 hours with condensate and gas. Injected 220 gal condensate, 56 gal; injected approximately 60 Mcf gas.
7/27/96	Injected into well No. 12; 7:30 a.m. out at 5:00 p.m.; inject into No. 12 5:00 p.m. to 7:30 a.m., 14 ¹ / ₂ hours; 852 gal condensate approximately 110 Mcf gas.
7/28/97	Inject into No. 11 at 7:30 a.m. out at 4:00 p.m.; approximately 40 Mcf with 219 gal condensate.
7/29/96	Injected into well No. 9 at 7:30 a.m. until 5:00 p.m.
7/30/96	Inject into well No. 2, 10:00 a.m. to 7:30 a.m.; 7/31/96—76 Mcf with 385 gal condensate
7/31/96	Inject into well No. 7, 7:30 a.m. to 4:00 p.m.—104 Mcf with 308 gal condensate
7/31/96	Inject into well No. 12, 4:00 p.m. to 4:00 p.m. 8/1/96- 205 Mcf with 522 gal condensate

Since starting injection, we've had a problem trying to read volumes of gas injected using dual pin recorder on injection manifold. On July 25, 1996, called the only recorder service man in this area, Orange Grove, Texas. He would not be here until Monday, July 29, 1996. Arrived on location at 10:30 a.m., checked both recorders, purchased-gas recorder close bellows in injection recorder ruptured, will return on Tuesday morning with recorder.

At this time, it is difficult to determine production. Producing wells on choke and choke on casing. Wells are really gassy. This evening wells No. 13, 12, 11 and 9 started making more oil. After recorder (injection) is fixed, we will have a better idea of volume of gas injected. After all wells are injected, we will start the schedule over.

Injection recorder back on line, have recovered majority of wash water, percentage of oil is increasing. Production still does not look good.

August 1996

Injection activities for August are shown in Table D-2.

September 1996

Injection activities and production for September are described in Tables D-3 and D-4.

Table D-2 Injection activities, August 1996

Date	Description
8/1/96	Inject into well No. 13, 4:00 p.m. to 7:00 a.m. 8/2/96—104 Mcf with 308 gal condensate
8/2/96	Inject into wells No. 3, 5 and 10, 7:00 a.m. to 4:00 p.m. 8/3/96—285 Mcf with no condensate
8/3/96	Inject into well No. 3, 5 and 10, 4:00 p.m. to 7:00 a.m. 8/4/96—137 Mcf with 360 gal condensate
8/4/96	Inject into well No. 2, 7:00 a.m. to 4:00 p.m. 8/5/96—189.6 Mcf with surplus gas and no condensate
8/5/96	Inject into well No. 11, 4:00 p.m. to 4:00 p.m. 8/6/96—145 Mcf with 609 gal condensate
8/6/96	Inject into well No. 9, 66.4 Mcf with 504 gal condensate
8/7/96	Inject into well No. 12, 4:00 p.m. to 3:00 p.m. 8/8/96—125 Mcf with 285 gal condensate
8/8/96	Inject into well No. 7, 3:00 p.m. to 2:45 p.m. 8/9/96—112 Mcf with 268 gal condensate
8/9/96	Injection into well No. 3, 2:45 p.m. to 4:00 p.m. on 8/10/96; taking very little gas, went to 800 psi—32 Mcf, no condensate
8/10/96	Injection into well No. 5, 4:00 p.m. to 8:00 a.m. on 8/11/96; taking no gas, at 740 psi, increased pressure to 880 psi finally displaced oil from well 8/11/96 at 3:00 p.m. Injected 135 Mcf with 810 gal condensate at 480 psi
8/12/97	Injection into well No. 10, 7:30 a.m. to 2:30 p.m. Injected 25 Mcf with 206 gal condensate, out of condensate—shut down
8/13/96	No condensate—no injection
8/14/96	No condensate—no injection
8/15/96	Injection into well No. 13; injected 79 Mcf with 168 gal of condensate, 11 hours
8/16/96	Injected into well No. 9; injected 96 Mcf with 585 gal condensate
8/17/96	Injected into well No. 12; injected 132 Mcf with 780 gal condensate
8/18/96	Injected into well No. 11; injected 112 Mcf with 620 gal condensate
8/19/96	Injected into well No. 7; injected 102 Mcf with 755 gal condensate—flushed with gas for 1 hour 45 minutes
8/20/96	Injected into well No. 13; injected 98 Mcf with 586 gal condensate—flushed with gas 2 ¹ / ₂ hours
8/21/96	No injection
8/22/96	Injection into well No. 9; injected 115 Mcf with 414 gal condensate
8/25/96	Injected into well No. 11; injected 122 Mcf with 600 gal condensate—flushed with gas 4 hours
8/27/96	Injected into well No. 7; 8:00 a.m. to 10:00 a.m. gas only—10:00 a.m. condensate on. Injected 90 Mcf with 682 gal condensate. Total injected to date: 400 Mcf with 2239 gal condensate
8/30/96	Injected into well No. 13; injected 102 Mcf with 463 gal condensate—total injected to date: 402.7 Mcf with 1,930 gal condensate
8/31/96	Injected into well No. 5; injected 116 Mcf with 219 gal condensate—total injected to date: 257 Mcf with 839 gal condensate

Table D-3 Injection report, September 1996

Date	Description
9/1/96	Well No. 10 took no gas—wellbore plugged??
9/2/96	Injected into well No. 12; injected 112 Mcf with 390 gal condensate—total to date: 694 Mcf with 2,397 gal condensate
9/3/96	Injected into well No. 11; injected 107 Mcf with 438 gal condensate—total to date: 507 Mcf with 2,299 gal condensate
9/4/96	Injection into well No. 9; injected 101 Mcf with 398 gal condensate—total to date: 513 Mcf with 2,190 gal condensate
9/6/96	Injected surplus gas into No. 9. 9/7/96; no measurement
9/9/96	Injection into well No. 2; injected 122 Mcf with 438 gal condensate—total to date: 387.6 Mcf with 823 gal condensate
9/10/96	Injection into well No. 13; injected 146 Mcf with 538 gal condensate—total to date: 548.7 Mcf with 2,468 gal condensate
9/11/96	Injection into well No. 10; injected 148 Mcf with 690 gal condensate—total to date: 289 Mcf with 810 gal condensate
9/12/96	Injection into No. 3; injected 111 Mcf with 560 gal condensate—total to date: 259 Mcf with 680 gal condensate

Table D-4 Production report, September 1996

Date	Volume, bbl
9/24/96	13.00
9/25/96	9.60
9/26/96	8.50
9/27/96	8.16
9/28/96	15.08
9/29/96	11.60
9/30/96	12.76

October 1996

Injection activities and production for October are shown in Tables D-5 and D-6. As stated in last month's report, production was not good. This month's report is no better. Checking the two monthly workover reports, as of now we have pulled the 10 wells for a total of 27 times. We have encountered about every pumping problem known to man: formation, sand, fracture sand and some mechanical, but we now feel that gas locking has been and is our biggest problem. We have tried everything to solve this problem using 3 foot pneumatic pumping units which have many advantages over a conventional beam unit, but the wells still would not pump. When the

bottomhole pump is pulled, the well will kick oil and gas completely out of the hole, yet when a new pump is installed, the well still doesn't pump.

The last few times that wells have been pulled, we have had to load well formation with water to keep the well from making a big mess. Using water (formation water plus additional salt) is not the first choice, but in this case the well could not be pulled without it. Economics prevent us from being able to keep pulling the wells and replacing the bottomhole pumps.

On September 10, 1996, we started pulling the bottomhole pumps and running string back in hole to jet wells. As of September 26, 1996, all bottomhole pumps have been pulled, and we are now trying to jet load water from wells with some oil. Hopefully, after the wells are cleaned for a few days, production will improve. Injections of gas and condensate are not planned until we can resolve the well problem. Enclosed are records of all injection to each well and workover of wells.

Hopefully, from this information your staff might be able to give us some guidance during injection cycles. Fracture pressure has not been exceeded. Various volumes of gas and condensate have been injected, and soak intervals after injection have varied from 18 to 48 hours. Being unable to produce wells by pumping, we have no idea which is best.

Table D-5 Injection activities, October 1996

Date	Description
10/13/96	Injection into well No. 11; injected 203 Mcf, 20.5 hr with 660 gal condensate; total to date 710 Mcf with 2,959 gal condensate
10/14/96	Injection into well No. 7; injected 75 Mcf, with 520 gal condensate; total to date 475 Mcf with 2,759 gal condensate
10/15/96	Injection into well No. 9; injected 125 Mcf, with 630 gal condensate; total to date 638 Mcf with 2,820 gal condensate
10/16/96	Injection into well No. 13; injected 78 Mcf, with 490 gal condensate; total to date 626 Mcf with 2,958 gal condensate
10/17/96	Injection into well No. 2; injected 64 Mcf, with 450 gal condensate; total to date 451 Mcf with 1,273 gal condensate
10/18/96	Injection into well No. 12; injected 85 Mcf, with 510 gal condensate; total to date 779 Mcf with 2,907 gal condensate
10/19/96	Injection into well No. 3; injected 122 Mcf, with 520 gal condensate; total to date 381 Mcf with 1,200 gal condensate
10/20/97	Injection into well No. 5; injected 131 Mcf, with 540 gal condensate; total to date 388 Mcf with 1,379 gal condensate
10/21/96	Injection into well No. 10; injected 99 Mcf, with 410 gal condensate; total to date 388 Mcf with 1,220 gal condensate

Table D-6 Production report, October 1996

Date	Volume, bbl	Description
10/1/96	5.22	
10/2/96	9.28	
10/3/96	9.28	
10/4/96	8.70	
10/5/96	7.83	
10/6/96	7.83	
10/7/96	9.86	
10/8/96	7.54	
10/9/96	6.45	
10/10/96	6.45	
10/11/96	7.20	
10/12/96	6.38	
10/13/96	9.86	Start injecting No. 11
10/14/96	5.06	Start injecting No. 7
10/15/96	8.00	Open No. 11—inject No. 9
10/16/96	6.20	Open No. 7—inject No. 13
10/17/96	39.50	Open No. 9—inject No. 2
10/18/96	29.75	Open No. 13—inject No. 12
10/19/96	15.75	Open No. 2—inject No. 3
10/20/96	20.00	Open No. 12—inject No. 5
10/21/96	18.10	Open No. 3—inject No. 10
10/22/96	12.42	Inject Excess gas into No. 9
10/24/96	15.00	Open No. 10—Excess gas into No. 9
10/25/96	16.00	Surplus gas into No. 9
10/26/96	12.40	Surplus gas into No. 9
10/27/96	11.20	Surplus gas into No. 9
10/28/96	10.50	Surplus gas into No. 9
10/29/96	8.50	Surplus gas into No. 9
10/30/96	11.40	
10/31/96	10.50	

After producing wells for a few days by jetting¹ and recovering load water, we believe wells will stabilize and we can then determine the best procedure for further injections. Determined the right restrictor size and jetting pressure required for each well; this seems to vary between 90 and 115 psi depending on well conditions. This pressure held against formation is restricting the flow of oil. To date, 505 bbl condensate have been purchased. Natural gas purchases for July were 853 gal at \$3.213 for a total of \$2,740.69; purchases for August were 2,866 bbl at \$2.923 for a total of \$8,377.32.

As stated in earlier reports, we had problems trying to pump wells. A combination of sand and gassy oil have made pulling wells a constant problem. The cost of the workover rig and bottomhole pump repairs are just too great for the project to be a success. Until we start injecting again, we have to keep injecting gas into No. 9 to keep from venting gas. Hopefully, we will have a load of condensate by October 31 and can resume injection cycles.

November 1996

The injection schedule and production reports for November are given in Tables D-7 and D-8. Production is still not what we had hoped for. On November 20, 1996, we changed our injections from 24 to 48 hours per well, hoping this might help production. Previously we injected for 24 hours and let well soak for 24 hours. Producing well may make 4 to 6 BOPD for a few days and then fall back to 1 to 1.5 BOPD. It appears that due to small volumes of gas injected that gas goes into same part of formation each time. In the early 1950s, while working with Halliburton, we used moth balls (naphthalene) as a diverting agent on fracture jobs. Moth balls being soluble in oil would dissolve in 24 to 48 hours, allowing plugged zones to produce.

1 Jetting is a method used on wells in this field for years. Normally air is used, but in our case gas was used (see the schematic in Figure D-11). Gas is injected through the manifold and a restrictor into the well annulus. The gas flows up the tubing blending with the produced fluid. By controlling the flow of gas with restrictors, the density of the fluid column in the tubing is adjusted for maximum recovery. Insufficient gas flow will result in slug-like production and additional pressure exerted against the formation. Too much gas will result in a mist-like spray of oil and gas at the surface. The volume of gas is critical and by using restrictors—chokes we make—and the double manifold, the adjustment of gas flow is easy and requires only a few minutes. The types of fluids and the tubing size affect the volume of gas required for efficient operation. In our case, about 100 psig was required. This constant pressure is exerted against the formation. We are hoping in this way to help in repressuring the formation. In fields with low bottom-hole pressure, if the tubing is allowed to load up gas will go into the formation rather than lift the fluid in the tubing. If this happens, the operator must switch gas pressure to the tubing, displace the fluid in the tubing back into the formation, then open the tubing through a choke. With gas in the annulus, the fluid in the tubing is kept gassy until the well is stabilized. For example, a 42-well lease was not economical to produce by pumping because the requirement for pulling wells and changing bottom-hole pumps. We switched to jetting and all that was required was a power source and lines to the wells. We were able to produce all 42 wells with one compressor station. The wells were about 900 ft deep at about 50 psig. We used PVC pipe, thus rust was not a problem. Once the wells were cleaned up and stabilized, any problems are moved from the bottom of the well to the surface—no pumps to pull.

Table D-7 Injection schedule, November 1996

Date	Description
11/7/96	Purchased 180 bbl condensate. Injected 97 Mcf with 244 gal condensate into No. 4; total to date = 245 Mcf with 460 gal condensate
11/8/96	Injected 110 Mcf with 365 gal condensate into No. 11; total to date = 820 Mcf with 3,324 gal condensate
11/9/96	Injected 85 Mcf with 361 gal condensate into No. 12; total to date = 864 Mcf with 3,268 gal condensate
11/10/96	Injected 133 Mcf with 310 gal condensate into No. 9; total to date = 771 Mcf with 3,310 gal condensate
11/11/96	Injected 149 Mcf with 268 gal condensate into No. 12; total to date = 775 Mcf with 3,226 gal condensate
11/12/96	Injected 152 Mcf with 365 gal condensate into No. 7; total to date = 627 Mcf with 3,124 gal condensate
11/13/96	Injected 122 Mcf with 325 gal condensate into No. 10; total to date = 510 Mcf with 1,545 gal condensate
11/14/96	Injected 134 Mcf with 134 gal condensate into No. 5; total to date = 522 Mcf with 1,739 gal condensate
11/15/96	Injected 146 Mcf with 365 gal condensate into No. 3; total to date = 527 Mcf with 1,565 gal condensate
11/16/96	Injected 161 Mcf with 340 gal condensate into No. 11
11/17/96	Injected 137 Mcf with 340 gal condensate into No. 11; total to date = 1,118 Mcf with 4,005 gal condensate
11/18/96	Injected 139 Mcf with 146 gal condensate into No. 2; total to date = 590 Mcf with 1,419 gal condensate
11/19/96	Injected 52 Mcf with 195 gal condensate into No. 4; total to date 297 Mcf with 655 gal. condensate
11/20/96	Injected 26 Mcf with 243 gal condensate into No. 7
11/21/96	Injected 112 Mcf with 73 gal condensate into No. 7; total to date = 765 Mcf with 3,440 gal condensate
11/22/96	Injected 123 Mcf with 292 gal condensate into No. 12
11/23/96	Injected 79 Mcf with 146 gal condensate into No. 12
11/24/96	Injected 101 Mcf with 97 gal condensate into No. 12; total to date = 1,167 Mcf with 3,803 gal condensate
11/25/96	Injected 120 Mcf with 98 gal condensate into No. 9
11/26/96	Injected 104 Mcf with 219 gal condensate into No. 9; total to date = 995 Mcf with 3,447 gal condensate
11/27/96	Injected 107 Mcf with 360 gal condensate into No. 11
11/28/96	Injected 65 Mcf with 219 gal condensate into No. 11; total to date = 1,290 Mcf with 1,584 gal condensate
11/29/96	Injected 103 Mcf with 190 gal condensate into No. 2
11/30/96	Injected 156 Mcf with 212 gal condensate into No. 2; total to date = 849 Mcf with 1,821 gal condensate

Table D-8 Production Report, November 1996

Date	Volume, bbl	Description
11/1/96	14.00	
11/2/96	13.50	
11/3/96	13.00	
11/4/96	11.40	
11/5/96	11.00	
11/6/96	15.00	
11/7/96	10.20	Inject No. 4
11/8/96	7.60	Inject No. 11
11/9/96	5.00	Inject No. 12—open No. 4
11/10/96	18.50	Inject No. 9—open No. 11
11/11/96	15.60	Inject No. 13—open No. 12
11/12/96	13.50	Inject No. 7—open No. 9
11/13/96	17.80	Inject No. 10—open No. 13
11/14/96	13.00	Inject No. 5—open No. 7
11/15/96	7.80	Inject No. 3—open No. 10
11/16/96	11.20	Inject No. 11—open No. 3
11/17/97	7.10	Inject No. 11—open No. 5
11/18/96	18.60	Inject No. 2
11/19/96	24.60	Inject No. 4—open No. 11
11/20/96	6.60	Inject No. 7—open No. 2 (compressor down)
11/21/96	17.30	Inject No. 7—open No. 4
11/22/96	12.80	Inject No. 12
11/23/96	10.20	Inject No. 12—open No. 7
11/24/96	12.40	Inject No. 12
11/25/96	12.00	Inject No. 9
11/26/96	13.00	Inject No. 9—open No. 12
11/27/96	16.50	Inject No. 11
11/28/96	10.50	Inject No. 11—open No. 9
11/29/96	9.00	Inject No. 2

Realizing that something had to be done to try and improve production, we decided to try using moth balls (crumbled) with gas condensate. A double valve injector was assembled. Well No. 7 was injected with 18 lb of mothballs on December 6, 1996. Gas volume and condensate rates were increased to the maximum, and moth balls were injected one pound at a time. After injecting 18 lb at one time, we had 16 distinct pressure increases. On December 9, 1996, we injected well No. 11 the same as well No. 7, pressure reaction was not the same. Well No. 12 was treated the same as well No. 11 on December 11, 1996, with the same results. On December 13,

1996, we injected well No. 4 with 18 lb of moth balls and again had perfect chart and pressure increases that occurred with well No. 7.

The injections on wells No. 4 and 7 were down 1-inch ID tubing, on wells No. 11 and 12 injection was done down annulus of 1-inch and 2-inch tubing. It appears that moth balls clung to the outside of the 1-inch tubing and to the inside of the 2-inch tubing and did not get to the formation to do any diverting.

Wells No. 4 and 7 have responded very well after the soak period. After soak period, No. 7 was opened into test tank (12/9/96) and made 5 bbl, 12/10/96 made 9 bbl, 12/6/96 made 6 bbl, 12/12/96, made 10 bbl, 12/13/96 made 9 bbl, 12/14/96 made 10 bbl and 12/15/96 made 9 bbl. Wells were shut down due to freezing weather.

On December 20, we opened No. 4 after moth ball injection—it was produced into test tank with No. 7, both wells made 17 bbl. On December 21 wells No. 4 and 7 made 16 bbl and on December 22 both made 15 bbl.

It certainly appears that moth balls did a good job and let us put gas condensate into different parts of the formation and increased production. No response was noted on wells No. 11 and 12.

Wells No. 4 and 7 have responded very well and are being produced by jetting. It appears that bottomhole pumps will have to be removed, so moth balls can be injected down 1-inch tubing to get desired results using moth balls as a diverting agent.

After dropping moth balls, gas condensate at high rate then injection rates were slowed to normal rate. It certainly appears at this writing, moth balls might be our salvation.

Gas purchased November 1996 equaled 1,645 MMBtu at \$3.262 for a total of \$5,365.99. A load of condensate cost \$3,507.00. I imagine gas prices will be above \$4.50 until after February. We will have to curtail our purchase of natural gas until prices drop back down.

The end of last month we had problems selling our oil. When the oil haulers shook out the tank samples, an emulsion was apparent in the bottom of the sample. It felt slick unlike the crude. It was suggested trying a paraffin solvent to break the emulsion.

We rolled one load of oil with a paraffin solvent and let the load sit six days. Load was again sampled and rejected. The emulsion was still apparent. Notified a chemical company and supplied them with oil samples. These were tested and a new de-emulsifier was suggested. We rolled tanks, waited five days. Oil and water separated and chemical appears to have broken the emulsion. Is it possible that we are forming some type of emulsion in the formation as we inject and produce the wells?

We resumed our injection cycle on the 7th. We are injecting 110–130 Mcf/D. During the first round of injecting, most of the gas had to be purchased. The wells still don't seem to be responding as we had thought. We pulled the jetting strings out of two of the wells and found

approximately 300 ft of fluid in each of the wells. We ran bottomhole pumps back in these wells and put them back on pump. The two wells have been pumping two weeks without any downhole problems. After injection cycle is completed, it appears jetting wells will produce 3-5 BOPD then drop off to about 1 BOPD.

Wells No. 11 and 12 are on pump. They appear to be producing better than the jetting wells, but were better wells before the project was started. Initially we had downhole problems with these two wells. It appears that after jetting the wells over a period of time the wells have cleared up. If No. 11 and 12 continue to do well on pump, other wells will also be put on pump. Hopefully, without bottomhole problems and with an increase in production. During the second round of injections this month, we have been able to adjust compressor speed with suction pressure on compressor and inject about 100 Mcf/D without buying much outside gas. The wells seem to be producing more gas as we continue the cycle. We have extended the injection cycle to two days injecting about 200 Mcf/D and 500 gal condensate. Very little gas is having to be purchased possibly the longer cycle will increase production.

December 1996

Injection activities and production for December are shown in Tables D-9 and D-10. No injections have been done since No. 3 was injected due to the high price of natural gas. Our December 1996 gas price was \$4.2810, and it looks as if January prices will be higher. There is no way we can inject this expensive gas in wells. The anticipated gas price for the program was \$2.40. We have talked to our supplier about future prices, they feel prices will be back below \$3.00 by mid-March, and at that time we will resume injections.

This high potential recovery by gas repressurization has not been as successful as we had hoped. Also, problems were encountered that had not been anticipated, but finally thought our mechanical pumping producing problems were solved and the use of moth balls (naphthalene) as a diverting agent we could make this project a successful one.

Now the price of natural gas has us temporarily shut down. We hope to continue injections by April at the latest. Is there any possibility that we could be granted a three month extension to our existing contract? We feel with three additional months we will be able to turn this into a very viable project.

Table D-9 Injection activities, December 1996

Date	Description
12/1/96	Injected 93 Mcf with 197 gal condensate into No. 4
12/2/96	Injected 75 Mcf with 201 gal condensate into No. 4; total to date = 465 Mcf with 1,053 gal condensate
12/3/96	Injected 85 Mcf with 223 gal condensate into No. 3
12/4/96	Injected 93 Mcf with 189 gal condensate into No. 3; total to date = 705 Mcf with 1,977 gal condensate
12/5/96	Injected 70 Mcf with 227 gal condensate into No. 5; total to date = 592 Mcf with 1,966 gal condensate
12/6/96	Injected 133 Mcf with 241 gal condensate and moth balls into No. 7
12/7/96	Injected 128 Mcf with 193 gal condensate into No. 7
12/8/96	Injected 101 Mcf with 201 gal condensate into No. 4; total to date = 1,127 Mcf with 4,075 gal condensate
12/9/96	Injected 110 Mcf with 231 gal condensate and moth balls into No. 11
12/10/96	Injected 87 Mcf with 181 gal condensate into No. 4; total to date = 1,487 Mcf with 4,996 gal condensate
12/11/96	Injected 139 Mcf with 240 gal condensate and moth balls into No. 12
12/12/96	Injected 126 Mcf with 219 gal condensate into No. 12; total to date = 1,432 Mcf with 4,262 gal condensate
12/13/96	Injected 168 Mcf with 291 gal condensate and 18 lb moth balls into No. 4.
12/14/96	Injected 122 Mcf with 239 gal condensate into No. 4; total to date = 755 Mcf with 1,583 gal condensate
12/15/96	Injected 125 Mcf with 228 gal condensate into No. 13; total to date = 900 Mcf with 3,454 gal condensate. Shut down injection due to freezing weather. Not equipped to operate with temperature in teens
12/20/96	Injected 112 Mcf with 280 gal condensate and 18 lb moth balls into No. 10
12/21/96	Injected 87 Mcf with 265 gal condensate into No. 10; total to date = 709 Mcf with 2,091 gal condensate
12/22/96	Injected 84 Mcf with 195 gal condensate and 17 lb moth balls into No. 3. Moth balls injected down 1" tubing with fair response on pressure recorder
12/23/96	Injected 91 Mcf with 201 gal condensate into No. 3; total to date = 880 Mcf with 2,373 gal condensate.

Table D-10 Production report, December 1996

Date	Volume, bbl	Description
12/1/96	21.5	Inject No. 4, open No. 2
12/2/96	9.5	Inject No. 4
12/3/96	10.5	Inject No. 3, open No. 4
12/4/96	4	Inject No. 3
12/5/96	8.2	Inject No. 5, open No. 3
12/6/96	16.8	Inject No. 7, open No. 5
12/7/96	3	Inject No. 7
12/8/96	9	Inject No. 7
12/9/96	8.7	Inject No. 11, open No. 7
12/10/96	14.7	Inject No. 11
12/11/96	10.8	Inject No. 12, open No. 11
12/12/96	18.5	Inject No. 12
12/13/96	17	Inject No. 4, open No. 12
12/14/96	22	Inject No. 4
12/15/96	18	Inject No. 13, open No. 4
12/16/96		Shut down controls—freezing
12/17/96		Shut down controls—freezing
12/18/96		Shut down controls—freezing
12/19/96		Shut down controls—freezing
12/20/96	24	Inject No. 10, open No. 13
12/21/96	23	Shut down controls—freezing
12/22/96	22	Inject No. 3
12/23/96	18	Inject No. 3, open No. 10
12/24/96	16	
12/25/96	16.4	Open No. 3
12/26/96	14.2	
12/27/96	12.3	
12/28/96	13.6	
12/29/96	11.1	
12/30/96	12.5	
12/31/96	12.1	

January and February 1997

The injection and production report for January and February is given in Table D-11. No injection done this month due to the price of natural gas. Gas purchased January 1997, 449 MMBtu at \$4.568 for a total of \$2,102.39, which was used as fuel to run compressor for production. Our gas supplier informed us on 2/24/97 that the current price was \$3.37, hopefully it will be below \$3.00 by mid-March and we can resume injection.

Table D-11 Injection and production report, January-February 1997

Date	Volume, bbl	Description
1/1/97	11.1	
1/2/97	9.6	
1/3/97	10.2	
1/4/97	7	
1/5/97	12	
1/6/97	13	
1/7/97	10.5	
1/8/97	5.4	
1/9/97	6.1	
1/10/97	4.9	
1/11/97		Shut down compressor—below freezing
1/12/97		Shut down compressor—below freezing
1/13/97		Shut down compressor—below freezing
1/14/97		Shut down compressor—below freezing
1/15/97		Restarted compressor at 9:00 a.m.
1/16/97	10.4	
1/17/97	8.7	
1/18/97	7.9	
1/19/97	8.5	
1/20/97	6.2	
1/21/97	7.7	
1/22/97	6.8	
1/23/97	5.9	
1/24/97	7	
1/25/97	5.5	
1/26/97	6.1	
1/27/97	6	
1/28/97	6	Shut compressor down—controls freezing
1/29/97	3.1	
1/30/97	5.3	
1/31/97	6.2	
2/1/97	5.5	

Table D-11 Injection and production report, January–February 1997 (Continued)

Date	Volume, bbl	Description
2/2/97	5.2	
2/3/97	5.6	
2/4/97	5.5	
2/5/97	5.2	
2/6/97	5.2	
2/7/97	4.7	
2/8/97	4.5	Shut compressor down—controls freezing
2/9/97	4.0	Shut compressor down—controls freezing
2/10/97	3.7	Shut compressor down—controls freezing
2/11/97	4.4	
2/12/97	5.4	
2/13/97	5.2	
2/14/97	5.2	
2/15/97	6	
2/16/97	5.4	
2/17/97	4.9	
2/18/97	5.5	
2/19/97	5.7	
2/20/97	5.4	
2/21/97	5	
2/22/97	5.9	
2/23/97	5.5	
2/24/97	4.9	
2/25/97	5.3	
2/26/97	2.5	
2/27/07	4.7	
2/28/97	5.3	

Received information from Dr. Olsen which may explain why this project has not responded as we had hoped. From literature material received from Dr. Olsen, there is good reason to believe that the condensate we have been using is not providing sufficient solubility and is flocculating the asphaltenes. The asphaltenes could then precipitate in the wellbore region, causing a reduction in oil production.

In viewing our past production, since we first started injection of natural gas and condensate. When we should be enjoying a production increase due to volumes of gas injected. The Taylor–Ina, Olmos, oil field with a tremendous amount of oil in place, has had a multitude of secondary projects tried, and none has been a financial success.

Common consensus is, failures are due to a lack of proper engineering, with which I have certainly agreed. Now it looks as if this project will be added to the list of failures, unless something can be done at this late date to salvage this project. What can be done at this time to correct this asphaltene plugging, which I believe we have done with our ignorance.

1. Could we hope to overcome this problem with mini fracs which we did at the beginning of the project at a cost of \$3,000.00 per well using 5,000 lb of No. 12/16 mesh sand?
2. Using some type of solvents we have located two types of aromatic naphtha—one 13.5% at \$1.15/gal and one at 80% for \$1.78/gal, diesel at \$0.70/gal. Is there some other solvent that can be used or other type of treatment?

March 1997

The production report for March is given in Table D-12. Samples of our lease crude and condensate were shipped to Dr. Olsen on February 24, 1997. We received a report from Dr. Olsen on March 4, 1997, with an analysis showing that the crude contain 5.5% asphaltenes. This was a complete surprise to us and other operators in the Taylor-Ina field who have reviewed Dr. Olsen's report. We knew the crude was asphalt based, but had no idea the percentage was this high. We talked to Dr. Olsen about a better solvent than condensate for us to use.

On March 10 we received a call from Kyle Byron with AGE Refining in San Antonio, Texas. We discussed our thoughts and problems, and Byron seemed quite knowledgeable about asphalt problems in other fields. A 70% aromatic solvent had worked quite well in other fields. Before he would sell us the solvent, he wanted samples of our crude and condensate. His chemist would run some tests to define which solvent would work best with our crude. Samples of our crude and condensate were delivered to them March 14. Byron thought we should have the results within 10 to 14 days.

April 1997

The production report for April is given in Table D-13. On April 11, we received a call from AGE Refining, San Antonio, Texas, concerning samples of our lease crude we delivered to their lab on March 14 for analysis. They recommend using a blend of 350 gal light virgin naphtha (LVN), a mixture of C₃-C₇ aliphatic, olefinic, and aromatic hydrocarbons, with 150 gal heavy aromatic naphtha (HAN) for a 500-gal mixture. On April 14 we ordered 500 gal of the mixture and picked it up the next day.

April 16, 1997—We started injection on Hutzler No. 11. First displaced all oil from casing and wellbore with natural gas and started injecting approximately 180 cfm with 5 gpm LVN and used 18 lb of moth ice crystals (paradichlorobenzene) during the injection period. Prior to injection, samples of ice crystals were immersed in LVN. To our amazement, samples were completely dissolved in 25 minutes). We hoped to get some diverting done before crystals dissolved after the injection well was shut in for 24 hours.

Table D-12 Production report, March 1997

Date	Volume, bbl
3/1/97	5.4
3/2/97	5.5
3/3/97	4.9
3/4/97	4.8
3/5/97	4.9
3/6/97	5.2
3/7/97	5.6
3/8/97	5.2
3/9/97	5.2
3/10/97	4.9
3/11/97	5.5
3/12/97	5.5
3/13/97	5.6
3/14/97	5.4
3/15/97	5.5
3/16/97	4.9
3/17/97	5.6
3/18/97	5.4
3/19/97	5
3/20/97	5.2
3/21/97	4.9
3/22/97	5.7
3/23/97	5.4
3/24/97	5.6
3/25/97	4.9
3/26/97	4.5
3/27/97	4.9
3/28/97	5.4
3/29/97	5.7
3/30/97	5.2
3/31/97	5.2

Table D-13 Production report, April 1997

Date	Volume, bbl	Description
4/1/97	5.4	
4/2/97	4.8	
4/3/97	5.3	
4/4/97	5	
4/5/97	5.4	
4/6/97	5.6	
4/7/97	5.2	
4/8/97	5.4	
4/9/97	5	
4/10/97	5.1	
4/11/97	5.4	
4/12/97	5.4	
4/13/97	6.1	
4/14/97	6.2	
4/15/97	5.4	
4/16/97	6.5	
4/17/97	6.1	
4/18/97	6.5	
4/19/97	6	
4/20/97	6.4	
4/21/97	6.7	
4/22/97	9.6	
4/23/97	11.3	
4/24/97	2.5	Compressor down for 20 hours
4/25/97	11.2	
4/26/97	11	
4/27/97	8.2	
4/28/97	6.5	
4/29/97	8.4	
4/30/97	8	

April 17, 1997—We injected well No. 12 using the same procedure as with No. 11. On April 18, injected well No. 7 with the same process as with wells No. 11 and No. 12. On April 21, we injected well No. 9 using the same process as before. After each well was injected and shut in for 24 hours, it was put on production. At this time it is too early to determine the results. The lease has been averaging about 6 BOPD. On April 22, production was 9.6 BOPD, April 23, 11.3 BOPD,

and April 24 2.5 BOPD. The compressor was off for 20 hours. On April 25, production was 11.2 BOPD and April 26 production was 11 BOPD.

We will continue to monitor these four wells. Hopefully, production will increase and will warrant the purchase of 4,200 gal of LVN with natural gas as we inject each well on continuing cycles. Resumption of injection of natural gas with LVN will be by May 5, 1997.

May 1997

The production report for May is given in Table D-14. Last month wells No. 11, 12, 9, and 7 were treated with 125 gal each of 75% LVN and 25% HAN. Wells were allowed to soak for 24 hours then put on production. Wells were tested periodically. The results were not very good. We discussed the results with Dr. Olsen and decided to give the wells another injection using 100% HAN.

Table D-14 Production Report, May 1997

Date	Volume, bbl	Description
5/1/97	7	
5/2/97	7.5	
5/3/97	6.2	
5/4/97	11.2	
5/5/97	6.4	
5/6/97	7.2	
5/7/97	6.9	
5/8/97	8.4	
5/9/97	13.2	
5/10/97	13.7	
5/11/97	15.2	
5/12/97	11.4	
5/13/97	13.7	
5/14/97	11.1	
5/15/97	10.1	
5/16/97	8.5	
5/17/97	8.1	
5/18/97	7.2	
5/19/97	8.4	
5/20/97	7.6	
5/21/97	8	
5/22/97		Shut project down

May 2, 1997—We ordered 4,200 gal of 100% HAN from AGE Refining in San Antonio, Texas, which was delivered to the Hutzler lease May 6, 1997. Started injection procedure on well No. 11, displaced all fluid from tubing an annulus with natural gas and pumped into formation with gas for approximately 10 minutes, then started pumping 75 gal HAN down 1-inch tubing. Well was shut in and allowed to soak. HAN in tubing was not displaced at this time. Then we switched to well No. 12 and repeated the same procedure as well No. 11.

Treated wells No. 13, 5, and 10 the same. One hour after HAN was injected, gas was pumped into wells with full capacity of gas compressor for one minute, then left to soak. On May 7, the same procedure was repeated on wells No. 3, 9, 7, 2 and 4 with 75 gal HAN. During the day, natural gas was pumped into wells No. 11, 12, 13, 5, and 10 to displace HAN into the formation. Treatment on wells No. 3, 9, 7, 2, and 4 was completed at 2:30 p.m., then repeated HAN injection on wells No. 11 and 12. Increased volume of HAN to approximately 150 gal for a total of 225 gal in each well.

May 8, 1997—Injected additional volume of 150 gal HAN into wells No. 19, 9, 7, 5, 4, 3, 2, and 13. All wells allowed to soak overnight.

May 9, 1997—Displaced HAN into formation on all wells, one well at a time with full capacity of compressor for 10 minutes. Started injecting gas and HAN into well No. 11 at 4:00 P.M. All other wells were shut in.

May 10, 1997—Switched out of well No. 11 into well No. 12 with gas and HAN injection at 8:00 a.m. Injected 292 gal of HAN with 76 Mcf gas into well No. 11. Total to date: 1,563 Mcf gas with 4,996 gal condensate and 125 gal LVN and 517 gal HAN. Put other eight wells back on production.

May 11, 1997—Switched out of well No. 12 into well No. 9 with gas and HAN injection. Injected 72 Mcf gas with 171 gal HAN. Total to date: 1,504 Mcf gas with 4,262 gal condensate, 125 gal LVN and 396 gal HAN. Opened well No. 11 and started jetting.

May 12, 1997—Switched from well No. 9 to well No. 7 for injection. Well No. 9 shut in. Opened well No. 12 and started jetting. Total injected to date on well No. 9: 995 Mcf gas with 3,447 gal condensate, 125 gal LVN, and 358 gal HAN.

May 13, 1997—Switched out of well No. 7 and started injection on well No. 13. Opened well No. 9 and started jetting. Total injected into well No. 7 to date: 1,192 Mcf gas with 4,075 gal condensate and 180 gal HAN.

May 14, 1997—Switched out of well No. 13 and started injection into well No. 4. Total injected to date in well No. 13: 970 Mcf gas with 3,454 gal condensate and 270 gal HAN. Opened well No. 7 and started jetting.

May 15, 1997—Switched out of well No. 4 and started injection into well No. 2. Total injected to date in well No. 4: 813 Mcf gas with 1,583 gal condensate and 268 gal HAN. Opened well No. 13 and started jetting.

May 16, 1997—Switched out of well No. 2 and started injection into well No. 2. Total injected to date in well No. 2: 849 Mcf gas with 1,821 gal condensate and 280 gal HAN. Opened well No. 4 and started jetting.

May 17, 1997—Switched out of well No. 5 and started injection into well No. 10. Total injected to date in well No. 5: 653 Mcf gas with 1,996 gal condensate and 260 gal HAN. Opened well No. 2 and started jetting.

May 18, 1997—Switched out of well No. 10 and started injection into well No. 3. Total injected to date in well No. 10: 774 Mcf gas with 2,091 gal condensate and 285 gal HAN. Opened well No. 5 and started jetting.

May 19, 1997—Switched out of well No. 3. Total injected to date: 705 Mcf gas with 1,977 gal condensate and 250 gal HAN. Opened well No. 10 and started jetting.

May 20, 1997—Opened well No. 3 started producing. All wells producing, jetting.

All wells have been treated with HAN as a flush, then injected with natural gas and a small concentration of HAN—hoping to dissolve asphaltene that may have been precipitated around wellbore during production. After injection, treatment with natural gas and condensate. From May 6 through May 22, injected approximately 75 bbl HAN, wells produced approximately 160 bbl, about 85 bbl net.

Called Dr. Olsen, informed him that I had no other alternative, the lease had to be shut down and the project terminated. The total volumes of gas, condensate, and naphtha injected into each well is given in Table D-15.

Table D-15 Total volumes injected into each well

Well Number	Gas, Mcf	Condensate, gal	LVN, gal	HAN, gal
9	995	3,447	125	358
7	1,192	4,075	125	340
13	970	3,454		370
4	813	1,583		385
2	849	1,821		380
5	653	1,966		360
10	774	2,091		350
3	705	1,977		350
11	1,563	4,996	125	517
12	1,504	4,262	125	396

D-3.0 PROJECT ECONOMICS

Biggest cost of monthly injection was the price of natural gas. At the start of the project, everything was based on a price of \$2.40/MMBtu. Our lowest cost for purchased gas was \$2.92/MMBtu in June 1996. By January 1997 gas was \$4.56/MMBtu, this averaged a monthly price of \$3.269/MMBtu. From July 28, 1996, through September 10, 1996, the 10 wells were pulled for a total of 27 times: tubing pulled, pumps changed and run back to bottom. September 10-26, 1996, pulled all 10 wells, removed bottomhole pumps, and ran jetting strings back in wells. During the life of the project, the 10 wells were pulled at least 41 times. Our own workover rig was used, and our men rebuilt bottomhole pumps. Cost approximately \$300.00 per well each time for a total of \$12,000.00 our cost. The cost of equipment and supplies is shown in Table D-16. A production summary is given in Table D-17. An injection summary is given in Table D-18. A comparison of expenses and revenue is given in Table D-19.

Table D-16 Cost of equipment and supplies

Description	Cost, \$
Compressor rental	1,885
Project operator	2,000
Project manager and exp.	3,500
Electricity (approximate)	400
Compressor fuel—natural gas (approximate)	2,000
MONTHLY COST	9,785
Operating cost over 10 months	97,850

Table D-17 Production summary

Month	Volume, bbl	Produced Unit Price, \$/bbl	Net, \$
Aug. 96	471.36	17.92	7,049.28
Sept. 96	262.69	19.80	4,836.34
Oct. 96	180.44	20.89	3,146.73
Nov. 96	293.94	19.54	4,793.59
Dec. 96	305.63	20.93	5,340.24
Jan 97	320.24	21.03	5,621.40
Feb. 97	150.98	18.02	2,270.83
Mar 97	140.30	16.63	1,947.14
Apr. 97	0.00		0.00
May 97	302.41	16.53	4,170.44
TOTAL SOLD	2,427.99		39,175.99
10 Month Avg.	242.80		3,917.60

Projected oil production at the end of 10-month project was 5 bbl/day per well, total 1,500 bbl/month averaging \$16/bbl. Total monthly income from oil \$24,179. Actual oil production during the 10-month project was 0.8 bbl per well per day with a monthly total of 242.79 and income of \$3,917.59.

Table D-18 Injection summary

Well No.	Gas, Mcf	Condensate, gal	LVN, gal	HAN, gal
Volume Injected Into Each Well				
9	995	3,447	125	358
7	1,192	4,075	125	340
13	970	3,454		370
4	813	1,583		385
2	849	1,821		380
5	653	1,966		360
10	774	2,091		350
3	705	1,977		350
11	1,563	4,996	125	517
12	1,504	4,262	125	396
TOTAL	10,018	29,672	500	3,806
Cost				
	\$31,809.97	\$14,150.07	\$435.00	\$3,024.00
Unit Price				
	\$3.18	\$0.48	\$0.87	\$0.79

Table D-19 Total cost of 10-month project and total money received

Equipment and Supplies	Cost, \$	Income, \$
Operating Costs	97,850.00	
Condensate	14,150.07	
Natural Gas	31,809.97	
LVN	435.00	
HAN	3,024.00	
Workover Rig	12,000.00	
Oil Sold		39,175.99
Funds from BDM-Oklahoma (DOE)		43,726.00
TOTALS	159,269.04	82,901.99

D-4.0 LESSONS LEARNED THAT CAN BENEFIT OTHER OPERATORS

When a new project is planned, all aspects of the complete program are decided on. Stop right then and take a fresh look at each and every part of the program before any dollars are spent. In retrospect of our program, two petroleum engineers and myself spent approximately 3 months working on each and every detail of this project before any work was performed and everything looked great.

- Planned to heat natural gas with condensate injected into formation and hoped to get benefit from heat in reservoir at 1,200 feet depth
- 500,000 Btu heater was purchased and mounted onto a trailer. Heater could then be moved to each well and connected to tubing with a short insulated flex hose to prevent heat loss in flow lines. Fuel gas line was laid to each well. During injection cycle, shell temperature was set at 450°F. The temperature going into the tubing was about 250° to 300°F with approximately 150 cfm gas and 10% condensate. We now believe that we carried no heat to the 1,200-ft reservoir.
- It was common knowledge to all operators in Taylor-Ina field that the crude is asphalt based, but no one to our knowledge had any idea of the severity [of the consequences] of injecting natural gas and condensate into the formation. It didn't provide sufficient solubility to keep the asphaltenes from flocculating and plugging the formation around the wellbore. The more we injected, the more our production declined. We did not find out about this problem until late in the project. The last month of the project we tried injecting gas with LVN, finally injecting HAN with gas. At this point, we were out of funds and the project was terminated. This was a result of a lack of understanding of the reservoir fluids.
- Never fracture wells down 2-inch tubing with this type of oil without using friction reducers or higher gravity crude. After fracturing eight wells at 1,200 feet, we tried using a 1.5-inch sand pump. This would take at least an hour per trip. Ran 0.75-inch IJ tubing and had to reverse the oil from the tubing with formation water. Then reverse fracture sand from well, pull tubing, and run bottomhole pump for approximately 8 hours per well. We have fractured a couple hundred wells in this area down 4-inch casing reverse-circulating fracture sand through 2-inch tubing without problem. These wells had to be fractured through tubing and packer due to the age of the casing.
- Late in the project, we realized we were in trouble and needed to get gas and LVN into different parts of the formation, or through the damage we had created. Back in the early fifties while employed with Halliburton, we had used moth balls (naphthalene) as a temporary diverting agent while fracturing. Realizing we would not have velocity or density to carry the balls into the formation, the balls were crumbled, a double valve injection was built while injecting approximately 150 cfm gas-19% LVN, 2 lb of crushed balls were dropped periodically, we used 18 lb per well. This cut a picture-perfect chart on pressure recorder and did help production, but nothing could save the project by this time.