
GAS INJECTION/WELL STIMULATION PROJECT

**EAST EDNA FIELD,
OKMULGEE COUNTY, OKLAHOMA**

FINAL TECHNICAL REPORT

10 JULY 2002 – 09 OCTOBER 2003

JOHN K. GODWIN

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Driver Production, Inc.

PO Box 696

Okmulgee, Oklahoma 74447

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Note

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ABSTRACT

Driver Production proposes to conduct a gas repressurization / well stimulation project on a six well, 80-acre portion of the Dutcher Sand of the East Edna Field, Okmulgee County, Oklahoma. The site has been location of previous successful flue gas injection demonstration but due to changing economic and sales conditions, finds new opportunities to use associated natural gas that is currently being vented to the atmosphere to repressurize the reservoir to produce additional oil.

The established infrastructure and known geological conditions should allow quick startup and much lower operating costs than flue gas. Lessons learned from the previous project, the lessons learned from cyclical oil prices and from other operators in the area will be applied. Technology transfer of the lessons learned from both projects could be applied by other small independent operators.

TABLE OF CONTENTS

TITLE PAGE	1
DISCLAIMER	2
PUBLIC ABSTRACT	3
TABLE OF CONTENTS	4
EXECUTIVE SUMMARY	5
EXPERIMENTAL	5
RESULTS AND DISCUSSION	6
CONCLUSION	9
REFERENCES	10

EXECUTIVE SUMMARY

Driver Production (DP) operates a number of oil and gas producing properties in Eastern Oklahoma as a small independent producer. DP conducted a gas-repressurization project in a low-pressure oil lease using flue gas as part of a USDOE demonstration gas repressurization program in 1995-97 in response to PRDA No. OKL-5204-01. This project was initiated when oil prices were low but oil prices declined even further through 1998-99. Results of the flue gas project was presented as an SPE paper¹, highlighted in SPE Journal of Petroleum Technology.² Results were described in numerous presentations at Oklahoma Marginal Well Commission and Oklahoma Independent Petroleum Association workshops. The project was also described as part of BDM-Oklahoma's report to USDOE of the gas repressurization program that they managed for USDOE³. A description of the location, geology, injection problems, economics, photos of the flue gas generator and associated equipment, lessons learned and a summary of the technology transfer program up to the date of the projects final report are in the USDOE Fossil Energy Report.

1. Godwin, J; T. Lyons; N. Richardson and D. K. Olsen. "A Small Independent Producer's Design, Construction and Operation of Flue Gas Injection Project, East Edna Field, Okmulgee County, Oklahoma," SPE 39637 in proceedings of 1998 SPE/DOE Eleventh Symposium on Improved Oil Recovery, Tulsa, Oklahoma, USA, 19-22 April, 1998.
2. Godwin, J; T. Lyons; N. Richardson and D. K. Olsen. "A Small Independent Producer's Design, Construction and Operation of Flue Gas Injection Project, East Edna Field, Okmulgee County, Oklahoma," SPE Journal of Petroleum Technology, August 1998, pp .
3. Madden, M.P. "High Potential Recovery – Gas Repressurization, " USDOE Fossil Energy Report NIPER/BDM-0350, July 1998, pp.65-90.

DP's gas-repressurization project had dozens of visitors inspect and analyze the flue gas project. Some may have profited from the difficult lessons we learned from our project. There are a number of oil producers that now have similar truck or trailer-mounted portable and skid-mounted flue gas injectors in the Midcontinent and Appalachian Basins that were site visitors. USDOE reports numerous requests for copies of the Fossil Energy report. The project also provided DP with knowledge that could be used in our other leases.

EXPERIMENTAL

Changing conditions pose both challenges and can create opportunities. The proposed project technology is both secondary oil recovery (leases have not been waterflooded) and production management (conservation of resource and application of best practices). The objective is to use the currently available natural gas that is currently being vented and to repressurize the reservoir to produce additional oil. Since methane is much more soluble in oil than flue gas used in the previous project, and anticipated costs for startup using the existing infrastructure, a new electric compressor, profile control, and using lessons learned from the previous project, the proposed project should require much lower manpower and supervision. Bottom line the return on investment should be much higher. Lessons learned from both projects could be compared. The application of new Downhole chemical treatments and fluid

diversion (gelled polymer or foam) treatment of producing well(s) can be evaluated.

Gas injection is not new but to many of the surrounding operators it is. This operator knows of only two operators, out of a few hundred producers in Eastern Oklahoma, that have consistently, long-term (decades) operated their oil leases and reinjected produced gas to maintain pressure. Most vent or if a gas collection line is available, sell produced gas. Nearly all the leases are a fraction of original pressure. Without pressure there is only gravity drainage or capillary forces to drive the oil from the reservoir to the wellbore. Repressurization with cheap gas (essentially gas for the cost of paying the royalty to the landowner and compression) is an opportunity that was not previously available and cost effective.

RESULTS AND DISCUSSIONS

The proposed scope of work is shown schematically in Figure 1 with anticipated timeline, tasks, with milestones and tasks highlighted. Overall supervision of the project will be John Godwin. Letters of commitment from project team members are included in the financial volume. Dates are in months from the date of award. Delays in implementation may be encountered if weather or supply factors prohibit implementation of the field test in the time period designated.

The technical portion of the project consists of major tasks (starting with task 1) that are broken out into subtasks, where applicable. Anticipated time in months on a task is shown by an (x), milestones are shown by (M) and major decision point or deliverable are shown as (D).

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Figure 1: Schedule of project by task and by month assuming a July 2002 start.

TASKS DESCRIPTION

Task 0: Establish and Fund Project (project from 12 to 18 months) Not part of Project Work

- Subtask 0a: Preparation of proposal and submission to USDOE by (December 20, 2001).
- Subtask 0b: Evaluation of proposal by USDOE. Anticipated selection date (April, 2002).
- Subtask 0c: Negotiation/award of contract by USDOE. Project may be delayed if protracted negotiation of contract terms are required. **Milestone – Start or not.**
- Subtask 0d: Pull together production records and costs from recent months operation of lease to build background database of operation.

Task 1: Preparation of injection site and producing wells. Start of Project Work.

- Subtask 1a: Gather equipment at location for project.
- Subtask 1b: Prepare raised (above 50 year flood line for Deep Fork River at injection well) compressor platform.
- Subtask 1c: Install 440 Volt electric compressor on platform.
- Subtask 1d: Check locations collection lines and replace polypipe as required.
- Subtask 1e: Plumb collection lines from each well to thier individual tank so that individual well production can be gauged during project.
- Subtask 1f: Clean tanks, repair/paint as necessary.
- Subtask 1g: Shoot fluid levels before and after shut in test on each producing well.
- Subtask 1h: Install pressure/flow monitors on each producing well as required.

Task 2: Preparation of gas gathering system.

Subtask 2a: Check gas collection lines and replace polypipe as required. Probably conducted early 2002 (Winter months) as some pipelines run through the bottoms and snakes along the collection line would be hibernating. Estimated 25 to 30 wells with the following available gas volumes: Godwin leases 15 - 20 Mcf/d, oil wells south of project 15 - 20 Mcf/d, oil wells west of project 40 - 60 Mcf/d, gas well that produces 40 - 80 Mcf/d but with 18 % N2. Project gas availability of > 100 Mcf/d., the anticipated gas injection volume per day.

Subtask 2b: Connect gas collection system to knockout and compressor as required.

Task 3: Rework wells as required.

Subtask 3a: Based on current oil production, fluid levels and pump operation, some wells may need pulled, pumps reworked and/or chemically treated including experimental chemical treatments.

Task 4: Startup of compressor and gas injection.

Subtask 4a: Fire-up compressor and start slow gas injection while monitoring pressures. Adjust gas injection as wells respond. **Milestone – Startup of injection with second milestone completion of project injection one year later.**

Subtask 4b: Based on well performance, profile modification treatment of

producer well(s) may be required based on previous experience in the leases, especially well Nash No. 1. A foam or gel polymer treatment may be required.

Task 5: Monitor of gas injection and oil/water/gas production.

Subtask 5a: Monitor of gas injection and oil/water/gas production.

Task 6: Rework wells as required during project.

Subtask 6a: Based on oil production, fluid levels and pump operation, some wells may need pulled, pumps reworked and/ or chemically treated during the course of the project. A variety of new stimulation treatments, including monitoring can be included.

Task 7: Analysis project results.

Subtask 7a: Analyze oil, water, gas production; gas injection; fluid levels, pump and compressor operation, economics during the course of the project.

Milestone – analysis of project data completed.

Task 8: Project reporting to DOE.

Subtask 8a: Report progress quarterly to DOE Technical Project Manager in the form of electronic letter with or without attachments of figures as required.

Subtask 8b: Annual report of progress to DOE Technical Project Manager in the form of electronic letter report with attachments of figures.

Subtask 8c: Presentation at semi-annual DOE contractors review meeting (Morgantown, WV or Pittsburgh, PA) if during the time period for this project and that this project has made enough progress to warrant presentation. Usually held summers of even numbered years.

Subtask 8d: Final report on project to DOE Technical Project Manager in the form of electronic report with attachments of figures.

Task 9: Technology transfer of project results.

Subtask 9a: Preparation and presentation at technical meeting (Petroleum Technology Transfer Council, Oklahoma marginal Well commission Workshop, Oklahoma Independent Producers Workshop, in 2004 with variable dates).

Subtask 9b: Submission of abstract from SPE/DOE IOR Symposium.

Subtask 9c: If abstract is accepted, prepare paper for April 2004 presentation.

Subtask 9d: Presentation at technical meeting (e.g., SPE/DOE IOR Symposium, April 2004). This is beyond the schedule for project but the IOR Symposium is held in April in even number years in Tulsa, Oklahoma.

CONCLUSION

Since completion of the flue gas demonstration project in June 1997, a number of factors on and around the project site have changed:

- Oil prices declined 1997-1998, increased significantly by 2000 and have again declined during most of 2001. This makes future projections of profitability on investments difficult to predict and forces adoption of conservative projects, permitting limited experimentation on wells that are low oil producers. Fear of fouling up better wells that have significantly higher production, although lower than only a few years ago, but still declining, keeps one from treating better candidates.
- Gas prices reached an all time high during the winter of 2000 and spring of 2001 but gas prices. During the summer of 2001 yielded only \$1.25/Mcf. Gas sales price seems to be a very unreliable benchmark upon which to make project investment decisions. Gas prices are very weather dependant. The gas purchasing company that was buying our gas and that of surrounding producers went bankrupt. The gas produced is now vented to the atmosphere, just as it had been before the low-pressure gas gathering system was installed more than a decade ago. Thus, not only are surrounding oil operators whose associated gas (gas produced as result of oil production) being vented and generating no income, it contributes to increased global warming as a methane molecule has the impact of over 20 carbon dioxide molecules. The few gas wells along the segment of the gas collection system are shut in and operators face loss of the well to the royalty land holder (surface and oil and gas rights are separate) due to non-production.
- Declining low oil prices of last half of the 1990's caused the company to reduce staff to the owner, a part-time bookkeeper (owners wife) and part-time pumper. The second pumper/mechanic/welder/right hand man who lived on location and essentially manned the flue gas injection project nearly full-time could not be maintained.
- Since suspension of flue gas injection in 1997 due to gas breakthrough to one well to the west, oil production has dropped to pre-flue gas project startup of 4 bbl/d for the 6 well group (previous injector not being pumped). During flue gas injection oil production had tripled and gas production (gas to sales) was 2.5 times higher before gas (mostly nitrogen and some carbon dioxide) breakthrough to the west in well Nash No. 1. The increase in produced gas above does not include the gas that was used to generate flue gas. Offset lease holders with wells to the west experienced significant increased oil and gas production after shutdown of our injection that they attribute in-part to our project. Even today, the Nash No. 1 well that experienced gas breakthrough is held at a higher annulus backpressure to discourage fluids to balance pressure.
- Flue or exhaust gas injection is one method to repressurize an oil reservoir to provide drive (energy) to move oil to the wellbore. Flue gas is about 86 % nitrogen and 14% carbon dioxide. Like methane these gases have lower viscosity than oil. Displacement suffers from the unfavorable mobility ratio. Premature breakthrough of injected gas at producing wells, due to the variation in reservoir in permeability are one limitation. Natural gas (methane) higher solubility in oil as compared to the immiscible (at the reservoirs pressure of

500 psi) carbon dioxide which dissolves more so in water than oil, and nitrogen which is nearly insoluble at reservoir pressure, makes gas, especially low cost gas an attractive displacing agent for this oil reservoir. Later the reservoir can be blown down and the gas recovered if a market develops.

- Hindsight is always informative and some of the lessons learned from the flue gas project that need restated:
 - Flue gas is corrosive. Past experience has shown that operation of the flue gas generator at temperatures below freezing are uneconomic as the air cooled water knockout freezes and the exhaust gas does have enough moisture removed to prevent excessive corrosion downstream toward the injection well. The carbonic, nitric and sulfurous acids formed by combustion of lease gas required additional repair long after flue gas injection was terminated.
 - The previous flue gas project had a one-year performance schedule to show significant oil production and demonstrate the technology can be employed by a small operator. Flue gas was probably injected at a rate higher than it should have been and future injection will be at a lower rate.
 - During the winter natural gas prices are also higher and thus the economics of gas sales may outweigh the economics of using the produced gas to operate the flue gas generator.
 - During the spring, parts of the lease are sometimes under water due to flooding of the Deep Fork River and some wells are not produced. Roads to the lease (located a few miles from the nearest gravel county road) are best walked rather than fighting hours or days to retrieve a 4-wheel drive vehicle. Late spring, summer and fall field operations have proven more economic. Winter could also be economic if air coolers are not required to remove water from injected gas (natural gas injection should not require dry gas).

REFERENCES: NONE