DOE/10446 - FINAL

WELLBOTTOM FLUID IMPLOSION TREATMENT SYSTEMS

FINAL REPORT

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PREPARED FOR
THE UNITED STATES DEPARTMENT OF ENERGY
UNDER COOPERATIVE AGREEMENT
NO. DE - FG36 - 99GO10446

C O N T E N T S

FINAL REPORT

NARRATIVE

GRANT DE - FG36 - 99GO10446

by EMMET F. BRIEGER

I. INTRODUCTION

Because of the nature of this project, some of the "Final Report Format" instructions do not apply. However, I have complied with these instructions wherever possible in the preparation of this report.

This project was undertaken because of work done in the past by many people on such things as:

a. Downhole production flow meter logs and downhole videos which show the majority of existing perforations in some wells as non-productive--apparently plugged,

b. Laboratory flow testing of shaped charge perforations for oil and gas wells, which showed the extent of the perforation plugging problem,

c. Tubing conveyed underbalanced backsurge perforating on new completions of oil and gas wells, which showed the benefits of backsurging to unplug perforations and increase production,

d. The tubing conveyed bar-drop rupture disc method of backsurging perforated zones on new completions of oil and gas wells, which showed the same benefit as above, and

e. The wireline conveyed through the tubing first-generation method of backsurging perforated zones in existing producing wells, which showed the same benefits as above.

My project completed under this subject grant resulted in a second-generation version of the first-generation wireline system (item "e" above). Instead of using the term "backsurge" to describe the function of the system, we now use the term "wellbottom fluid implosion."

The problem intended to be alleviated or eliminated: Up to 85 percent of the total number of existing shaped charged penetrations (perforation tunnels) in oil and gas wells have remained plugged and non-producing since the original completion, with the total well production coming from only 15 percent of the total number of existing perforations. These wells are producing at a fraction of their capability.

The cause of this problem: The shaped charge jet particles traveling at 20,000 feet per second crush the formation into compacted low-permeability fines surrounding the penetration (perforation tunnel). Additionally, the perforation tunnel is filled with compacted low-permeability fines from the shaped charge itself. A finite differential pressure is necessary to start flow from the perforations--some may require less than 200 psi, some more than 500 psi. As casing pressure is reduced, some start flowing. The casing pressure then increases. The formation pressure decreases to a flowing pressure; hence the differential is reduced. Thus the majority of the perforations are never subjected to sufficient differential pressure to start flow, and they remain plugged and non-producing forever.

The method to remove the problem: These wells are identifiable and are serviced without pulling tubing. Formation fluid is made to "implode" into the casing, carrying with it debris and compaction from the plugged perforation tunnels within the formation, thus causing these perforations to start flowing for the first time. Thus well production rate is dramatically increased. Explosives or chemicals are not involved. It is all mechanical and hydraulic. This is accomplished as follows: The closed downhole tool named "implosion valve" is run in through the tubing and sealed and locked inside the tubing. Pressure above the implosion valve is reduced by several alternate techniques. At the pre-set differential pressure, the valve suddenly opens, causing fluid below to implode into the tubing above, thus causing a sudden pressure drop in the casing fluid. This causes the formation fluid to suddenly implode into the casing. Tubing pressure and casing pressure can be recorded before, during, and after the operation.

Field results with the first-generation wireline tools mentioned in "e" above were beyond expectations in terms of production increases, even in a zero production well, in already high production wells, and in injection rate increases--even in a zero injection well. Results outside the U.S.A. (Trinidad) using the tubing conveyed rupture disc system further validates the "fluid implosion" technique to improve well flow--even in wells up to thirty years old. These results are discussed further in PART VI.

Unfortunately, use of the first-generation wireline through tubing method was discontinued apparently because of tool damage which limited tool re-use and caused undesirably high operating costs. Another apparent cause of discontinuance was a conflict of interest with the acidizing method intended to stimulate well production--plus having to expose the deficiencies of shaped charge perforating in promoting the service.

My project was undertaken to re-design the first-generation wireline tools to:

a. Eliminate the damage and thus reduce operating costs,

b. Improve accuracy of tool functioning pressures,

c. License operating rights to smaller companies having no conflict of interest, and

d. Provide other tool variations for alternate operating procedures found to be desirable during field use of the first-generation wireline through tubing system.

My basic objective has been to do those things necessary to re-start the service and keep it going. I believed (and still do) that the value of this system to the U.S.A. and to the world was already demonstrated with the first-generation system.

II. SUMMARY of PROJECT GOALS

TASK 1 - Complete design layouts and calculations for downhole equipment and surface test equipment. Complete manufacturing drawings and specifications for all equipment.

TASK 2 - Get bids from machine shops and other suppliers on all equipment. Order all equipment and receive delivery of same.

TASK 3 - Check equipment received and assemble. Conduct surface pressure tests and functioning tests under conditions simulating actual well conditions. File a patent application.

TASK 4 - Contact qualified candidate service companies with the objective to get commitment from one or more to conduct field tests and market/operate the service.

The project objectives would be met when all four tasks are complete.

III. VARIANCE FROM PROJECT GOALS

The basic goals remained unchanged throughout the project. There were some changes in the planned details of some of the tasks as follows:

1. It was found to be unnecessary to purchase the various types of standard "locking mandrels" made by Baker and Halliburton as these are normally owned and available to the service companies that will be operating the service. Locking mandrels are a basic part in the assembly necessary to run my system.

2. The Spartek downhole recording pressure gage was made a part of my system. Downhole pressure recordings before, during, and immediately after the operation of my system will provide valuable additional information. This addition had been considered in the past but was not anticipated as a part of this project in the beginning.

3. It was found to be unnecessary to build and equip a special trailer for storing, transporting, and demonstrating purposes. My extended minivan--with seats removed--served these purposes very well.

4. The several anticipated trips to service company locations for purposes of presentations and demonstrations did not materialize. Only a couple of presentations were made and only one demonstration.

5. I did not require the assistance of a technician in conducting the surface tests or for the demonstrations. Also, I did not require any drafting assistance.

IV. PROJECT RESULTS

This project was successfully completed ahead of schedule and within the cost estimates. The chronology of events in carrying out this project is documented in Part I of each of the twelve progress reports submitted during this project. Details of work done are reported in the journal under Part II of these same twelve reports. Additional project information is contained in the three Semi-Annual Reports submitted. Therefore, in this final report, I shall summarize only the major tasks or milestones.

TASK 1. DESIGN LAYOUTS/CALCULATIONS and MANUFACTURING DRAWINGS

All assembly drawings, detail drawings, schematic drawings, charts, and documents related to the downhole tool were completed in November 1999. Design, assembly drawings, detail drawings, and instructions for the surface test equipment were completed in December 1999.

With the information listed in A-805 Nomenclature, a qualified service company can enter into this service with only a small amount of consulting assistance.

TASK 2. MANUFACTURE of HARDWARE

Price quotations were obtained on all hardware, and orders were placed in December 1999 and January 2000.

I received machined parts for all downhole tools and the pressure vessel (for surface tests) in February 2000. I received the pressure control unit (also for surface tests) in March 2000.

TASK 3. SURFACE PRESSURE TESTS of DOWNHOLE TOOLS

These tests were successfully completed in March 2000. The patent application was filed March 15, 2000.

TASK 4. CONTACTING SERVICE COMPANIES WITH OBJECTIVE to GET COMMITMENT FROM ONE or MORE to CONDUCT FIELD TESTS

An exclusive license agreement was signed on October 18, 2000, by PRO Well Testing and Wireline, a small oil field service company located in Hobbs, New Mexico. This company has agreed to field test, market, and operate the service. They are to sub-license Spartek International (a U.S.A. company) and Spartek Systems of Canada. PRO has rights to sub-license others.

A copy of the agreement was included with the third Semi-Annual Report in October 2000. The complete file of all items listed in Nomenclature A-805 has been sent to PRO Well Testing and Wireline Co.

V. POTENTIAL MARKET

This system applies to areas having consolidated formations (stone as opposed to loose sand), with low to good porosity/permeability (producible without fracturing), both oil and gas wells. The best candidates are wells which were perforated balanced or overbalanced. A production packer must be in place. The wells can be old or new, deep or shallow, high or low formation pressure, low to high production, gas lift wells, water or CO_2 flooding areas, land or offshore--worldwide. The number of such candidate wells is estimated to be in the tens of thousands in North America alone.

A market study done at Texas A & M University and paid for by the U.S. Department of Energy indicates large potential activity and significant energy impact. Research revealed this type service to be unavailable at the beginning of this project. The service fills the important need around the world to increase recovery from existing reservoirs by a cost-effective means.

VI. OIL/GAS WELL IMPROVEMENTS

Some specifics on field results (prior to this project) with the first-generation wireline system mentioned in Part I are as follows:

Approximately 25 operations were made in 10 wells over a 2 1/2-year period. The coordinator of the project stated production was increased on all wells with increases of 30 percent to 150 percent. I have specific information on only three wells. Results on the first two listed (below) are excellent and the third, startling:

1. An offshore Louisiana well having zero productivity and zero injectivity changed to a productive, commercially profitable well having injectability. Rates were not disclosed to me.

2. An Alaska well producing at 1,300 barrels per day (bpd) increased to 1,780 bpd--a 480 bpd (37 percent) increase. Differential pressure was set at 1,500 psi, but the tool opened at 1,250 psi. The differential pressure was created by simply bleeding off surface pressure.

3. Another Alaska well producing at 2,300 bpd increased to 5,600 bpd--a 3,300 bpd (143 percent) increase. Tubing size was 4 1/2".

Field results in Trinidad (also prior to this project) with a related system are also mentioned in PART I. Some details are as follows:

Backsurge methods similar to the first-generation wireline method have been used there on existing perforations to rejuvinate their existing producing wells in order to get their production rate up. Their methods involved dropping a bar down through the tubing to open the closure in the tubing. In some cases it involved pulling and rerunning the tubing. Their wells were shallow (2,000 - 4,000 ft.), low production (20 - 40 bpd), low formation pressure (around 750 psi), and most are old wells (some 30 years old). Production rate increases have been 80 percent to 300 percent.

In addition to the above already proven results, there are other potential benefits:

- Reduced water intrusion when producing perforations are near the water/oil interface by providing uniform flow across the zone,

- Reduced unwanted gas intrusion when producing perforations are near the gas/oil interface by providing uniform flow across the zone,

- Improved acid injectivity for more uniform coverage out into the formation from the wellbore to reduce clay swelling, etc.,

- Extended well production prior to need for artificial lift,

- Extended profitable well life after wells are put on artificial lift, resulting in more recovered oil before wells are plugged and abandoned,

- Application in existing pumping wells where installation of a packer is economically feasible--thus extending profitable well life of these wells,

- Application in conjunction with balanced or overbalanced wireline perforating in new completions, and

- Reduced migration of fines and formation plugging near the wellbore by reducing fluid velocity within the formation in providing uniform flow across the zone.

- The downhole pressure recordings provide useful build-up and draw-down information and determine tubing pressure necessary in subsequent operations.

- Experiments will be conducted to evaluate the feasibility of this system in packerless wells.

VII. POTENTIAL ENERGY and ECONOMIC IMPACT

It is in the U. S. national interest to get the U. S. well-production rate capability up, even though the wells may not be produced constantly at the maximum rate. This provides the advantage of more quickly making available larger quantities of oil in cases of national emergencies (such as provided by the strategic petroleum reserve underground storage). Also, some of the wells with increased production rate capability would be produced at higher rates periodically. This, plus the additional oil made available, would increase the U. S. oil supplies--thus reducing the amount of foreign oil purchases--thus, helping the U.S. economy.

Increased natural gas production will increase its availability which may increase its use thus decreasing pollution and bringing other benefits.

My proposed system--when compared to the energy expenditure required for a fracturing or acidizing treatment which usually requires the use of large horsepower pumps for extended periods of time--should provide some energy conservation advantages.

With regard to oil wells, the main application of my system will correspond to flowing wells and wells which are produced by means of gas lift. This is principally due to the requirement of having completed the wells with a packer at the bottom of the tubing in order to isolate the lower part of the annulus and apply the differential. Although this eliminates wells being produced by pumping, it still leaves a large number of potential candidates. (Experimental tests are planned in pumping wells.) It is estimated that the total number of flowing and gas-lift wells in the U. S. is over 75,000; and these wells produce over one half of the national production of 6.3 million bpd. It thus can be seen that even if a percentage of these wells were to be treated by my system, the production increase and energy savings potential could be substantial.

In addition, my system has the potential of prolonging the flowing life of a well by maintaining a naturally flowing condition even in the face of declining reservoir pressure. Indirect energy savings can be realized by delaying the need of artificial lift such as pumping or gas injection.

Providing higher production rates at depleted pressures after wells have been put on pumps will extend profitable well life. Thus more oil will be produced from wells before they are plugged and abandoned.

Increased production (oil and gas) will bring more revenues to royalty owners, including the federal government, plus increased tax revenues. This can increase funds available for alternate energy research, and pollution control research.

This technique can be applied in many foreign countries. It can improve the economy in some countries such as Mexico and some South American countries, etc.

VIII. FOLLOW ON TECHNOLOGY

The system developed under this project does not permit "swabbing" the fluid out of the tubing in the operation. Swabbing is less expensive in some areas (and preferred by some small companies) than use of coiled tubing and/or nitrogen as required in some cases with the present system. A tool designed to be compatible with swabbing will probably be developed in the future. It has already been determined that such a system can expedite field evaluation of the fluid implosion technique.

Also, the present system does not permit repeat operations without retrieving and re-running the tool. A repeat operation device may be developed if there appears to be sufficient interest.

Both of the above systems are included in the patent application--along with the systems developed under this project.

IX. SUPPLEMENTAL INFORMATION

Following is a list of drawings, documents, charts, etc., previously submitted in Progress/Status/Expenditure Reports, Semi-Annual Reports, and direct mail to the DOE Office of Intellectual Property Law. Also listed and explained is the video included with this Final Report:

Progress/Status/Expenditure Reports

- #2 - A-801 - Schematic of Tool Arrangement
- #6 - Advertisement placed in Hart's E & P magazine
- #12 - Letter of 09-11-00 regarding type B tool (to licensee)

Semi-Annual Reports

- #1 - Overview of Wellbottom Fluid Implosion System
- #2 - A-805 - Nomenclature (list of all drawings and documents)
- #3 - License Agreement

Cover letter, dated 04-03-2000, mailed to DOE Office of Intellectual Property Law

Copy of patent application

Final Report (this report)

A video presentation give by me to a group at the DOE Commercialization Planning Workshop at the Denver Hilton March 25 - 28, 1998--prior to my receiving this grant. The video provides background information on this subject. It is 28 minutes long. The first half is the presentation, and the second half is questions and answers. The audio on the words "Otis" and "Halliburton" should be blanked out before letting this video outside of DOE.

X. REMARKS

The objectives specified under this grant have been successfully completed. The oil/gas well field service resulting from the second generation equipment/systems developed under this grant are now ready for field evaluation to confirm the benefits previously demonstrated with the first generation system (prior to this grant).

I wish to express my sincere appreciation to the I & I group of DOE in Golden, Colorado, for approving and awarding this grant. I also wish to thank the outside evaluators for their effort in studying, understanding, and recommending my project.