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BODCAU IN SITU COMBUSTION PROJECT
SECOND ANNUAL REPORT, JULY 1977-JUNE 1978

Date Published—February 1979

Prepared for the Department of Energy
Under Contract No. EY-76-C-03-1189

Cities Service Company
Southeastern E&P Region
Jackson, Mississippi

U. S. DEPARTMENT OF ENERGY

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BODCAU IN SITU COMBUSTION PROJECT

**Second Annual Report
for the Period
July 1, 1977—June 30, 1978**

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INTRODUCTION

The Bodcau In Situ Combustion Project is a cooperative venture between Cities Service Company and the United States Department of Energy (DOE). The project is governed by DOE Contract EY-76-C-03-1189, covering the period from June 1, 1976 through June 30, 1982. Primary objectives are to demonstrate the operations and economics of a commercial scale combustion process. The total estimated cost of this demonstration is \$8,229,898. DOE will fund a maximum of \$3,102,112, while Cities Service will bear the remaining cost.

The First Annual Report presented last year covered pre-contract work and construction, drilling, pattern ignitions, laboratory and field testing, monitoring, operations, performance and economics for the first 12 months under contract. This second annual report will mainly deal with project performance and economics during the second year of operations.

Five elongated inverted nine-spot patterns were developed for this demonstration on Cities Service Company's Bodcau Fee "B" lease in the Bellevue Field, Bossier Parish, Louisiana. Figure 1 shows the general location of the field in northwest Louisiana. Twenty-nine producers, five injectors and five temperature observation wells are included in the project.

The Bellevue Field was discovered in 1921 and is a dome-type structure covering approximately 900 productive acres.

The Upper Cretaceous Nacatoch Sand is the main producing zone, occurring at 300 to 400 feet. A set of type logs of the Nacatoch Sand are presented in Figure 2. Primary production by fluid expansion and gravity drainage amounted to only 5% of original oil in place. Many production stimulation techniques were attempted but none succeeded in increasing production of the heavy 19⁰ API crude until Getty Oil Company successfully tested combustion in 1966.

Cities Service began a combustion project of its own in 1971. The five-pattern DOE demonstration is a part of the continuing expansion of the Company's thermal operations in the Bellevue Field.

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SUMMARY

The five patterns included in the Bodcau In Situ Combustion Project are a portion of Cities Service Company's total combustion project on its acreage in the Bellevue Field. Pattern developments on Cities Service Company's Bodcau Fee "B" lease are shown in Figure 3. Patterns 12 through 16 comprise this demonstration area. The patterns cover 19 productive acres containing approximately 2 million barrels of 19° API crude. Reservoir properties and project area data are presented in Tables 1 and 2. Project area structure and net pay isopach maps are presented as Figures 4 and 5. During 1975 and 1976, 29 producers and five injectors were drilled and completed in the project area. A cost-sharing contract was signed by Cities Service and DOE (then ERDA) covering the five patterns which were being prepared for combustion operations.

Production gathering, treating, storage and sale facilities were installed during 1976. Between August 7 and September 24, 1976, the five patterns were ignited. Injection rates were increased to 1500 MCFD per pattern by February 1977 when injectors were recompleted for the simultaneous injection of air and water during the remainder of the combustion phase.

Through the first two years of the contract, cumulative air and water injection have been 4,197,331 MCF and 449,605 barrels. Resulting production has been 270,802 barrels of oil. This represents a recovery of 13.6% of the oil in

place since the start of combustion.

Research conducted has consisted of combustion tube tests, produced fluid analyses and pressure transient tests. Most of the combustion tube runs were conducted during the first year under contract as were the pressure transient tests. Fluid analyses are performed every six months with produced oil, water, emulsions and gases being sampled and analyzed from each well.

The six-year project has an estimated ultimate cost of \$8,229,898. Through the first two years, a total of \$3,610,356 has been spent. Current operating expenses at the field level for operations, maintenance, well service and Louisiana Severance Taxes are \$5.46 per gross barrel of oil produced.

COMPRESSION FACILITY

The facility for the compression and injection of air for use during the combustion phase is probably the single most important component of physical plant for the project. Efficient operation, proper maintenance and care are vital to project performance and economics.

Three compressors supply the air required for combustion on Cities Service Company's acreage in the Bellevue Field. A portion of the total deliverability is used for the DOE Demonstration Project. Descriptions of the three units and histories of their operation during the first two years of the contract follow.

Compressor No. 1:

This unit was initially installed under a rental/purchase agreement with Southwest Industries in 1970. The compressor is an Ingersoll Rand 4RDS-3. Originally this unit was equipped with a Waukesha L-7042 GSI Engine. The unit was rated for 3.18 MMSCFD at 314.4 psia and 742 BHP at a speed of 800 RPM.

Because of the shortages of natural gas supplies in past winters and the likelihood of future cuts in supply to the field, the Waukesha Engine was reclaimed in late 1977 and replaced by a 1000-HP, 900 RPM General Electric Motor. The total cost of this change in equipment was \$70,633. The unit was out of service from August 3, 1977 through April 20, 1978.

Following completion of work on this unit, it was put into service once again and has encountered no operating problems.

Compressor No. 2:

A second compressor was installed in 1973 on a rental/purchase agreement. This unit was also an Ingersoll-Rand 4RDS-3 with a 1250-HP General Electric Motor, capable of delivering 5.74 MMSCFD at 300 psig and 1170 HP at 885 RPM.

This unit had always been somewhat more troublesome than the first compressor, with numerous periods off line for repairs. On October 18, 1976, during an electrical storm, this unit failed to shut down after an electrical line surge and was virtually destroyed. The cause of the failure in the shutdown systems was not readily ascertained. However, considerable corrosion was observed at numerous electrical contacts due to the presence of H_2S in the atmosphere. The unit was dissassembled and shipped to Houston for repairs. It was returned to service on December 6, 1977. Total cost of the repairs was \$90,866.

Since repair of this unit, it has been maintained primarily as a standby unit, running only if either of the other two compressors are out of service. The additional air available from the unit cannot readily be injected into the existing patterns in the combustion phase without increasing operating pressures which could cause additional failures.

Compressor No. 3:

This unit was purchased in 1975 and installation was completed in May of 1976. The compressor is an Ingersoll-

Rand 4HHE-3-VG powered by a 3000-HP, 327 RPM General Electric motor. Rated capacity of this unit is 12.00 MMCFD at 265 psig.

After ordinary initial startup difficulties between May and October 1976, the unit has run very smoothly and without major problems. In August 1977, three 660-volt capacitors failed and had to be replaced. A three-week delay was involved because of delivery problems. From April 21 to May 15, 1978, the unit was shut down for routine preventive maintenance and painting. The unit returned to service with no problems.

RESEARCH SUPPORT

As reported in the First Annual Report for the project, a series of combustion tube tests have been performed in the Company's laboratory in Tulsa, Oklahoma, pressure transient tests have been conducted in the field, and produced oil, water and gases have been sampled and analyzed.

COMBUSTION TUBE TESTS: Additional combustion tube tests were performed during the year to verify results reported in the First Annual Report. The two primary variations in operating procedure were to reduce outside heater temperatures from 300° F to 200° F and to analyze effluent gas compositions with a gas chromatograph instead of an Orsat apparatus. Results of these tests have been summarized in Table 3. In addition, work has begun to define what can be expected due to alteration of formation rock composition by high temperatures. Analyses of Nacatoch mineral composition will be determined before and after combustion tube burning.

Use of the gas chromatograph verified that the values for gas compositions measured with the Orsat technique were accurate and the results of previous runs were not affected. The strip heater temperatures of 200° F did result in oxygen passing unreacted through the tube. Burning efficiency varied from 60-70%, compared to the 80-100% experienced with 300° F heater temperatures. However, the average burning temperature

and calculated process parameters were not significantly different from previous runs, indicating that the tube tests reflect the high temperature oxidation reactions observed in the field.

PRESSURE TRANSIENT TESTS: Results of the injection well falloff tests and pattern pulse tests were reported in the First Annual Report. The data have been analyzed and a topical report has been prepared for publication by the Department of Energy. The falloff test results are presented in Table 4 while pulse test responses are shown in Figures 6 through 10.

RESERVOIR FLUID ANALYSES: Complete analyses of produced oil, water and combustion gas are conducted at six-month intervals. Injection water is also analyzed to insure quality that will not cause formation damage and loss of injectivity. Also, special problems related to produced emulsions will be studied.

Oil and water were sampled from the 29 producing wells in May 1977 and January 1978. Determinations of crude oil acid number, percent sulfur, specific gravity, viscosity and chromatographic analyses were made. The chloride content and pH of produced water were measured. Produced combustion gases were analyzed on site in August 1977 and January 1978 for carbon dioxide, carbon monoxide, oxygen and hydrocarbon content by chromatography. The hydrogen sulfide concentrations in the well stream produced gases were measured by the Tutweiler Method while ambient H₂S was measured by the Molybdenum Blue Method.

Table 5 shows the composition of produced gases in January 1978. Hydrocarbons are further analyzed in Table 6. A plot of produced water salinity is presented as Figure 11. The pH of produced water analyzed in January 1978 ranged from 7.2 to 8.0. Crude oil gravity, acid number and sulfur content are shown in Table 7, while the average oil viscosities at varying temperatures are presented in Figure 12. A simulated distillation by chromatography is given in Figure 13.

Some general conclusions can be drawn from results of tests to date:

1. Crude oil acid numbers are being reduced during the combustion phase. Native crude acid numbers of 5 have been reduced to 4 in produced oil.
2. Hydrocarbon concentrations in produced gases have remained relatively constant at an average of one mole percent.
3. The average oxygen content in the effluent gas was 2.7% in January 1978.
4. The average well stream hydrogen sulfide concentration has increased from 1250 ppm in January 1977 to 2250 ppm in January 1978.
5. Approximately one-half of the sulfur in native crude is converted to hydrogen sulfide gas.
6. Chloride concentrations have been reduced by one-half as a result of mixing with increased volumes of cooling water at producing wells.

TEMPERATURE OBSERVATION WELL MONITORING

Five wells were drilled in December 1976 for use as temperature observation wells to monitor the progress of the combustion front and later, the heat scavenging water phase. Locations of the wells shown in Figure 14 were determined on the basis of pulse test results which were useful in determining directional permeabilities within each pattern. Each well has 5½-inch casing cemented to surface and a thermocouple is run inside the casing. Large diameter pipe is used to enable repair in the anticipated event of damage due to excessive temperature. Smaller size pipe can be run inside the 5½-inch casing and cemented for protection in the event of failure.

Well #12-7 is located 212 feet northeast of #12-1A injector, in line with #12-3 producer. Pulse test permeability towards Well #12-3 was only 26 millidarcies, the lowest of any permeability indicated in any pattern. No heating whatsoever was indicated in Well #12-7 until March 1978, as indicated in Figure 15. The maximum temperature recorded to date is still only 120° F. The slight heating is occurring in the upper 30 feet of pay, as expected.

Well #13-7, located 228 feet south of Well #13-1, is the only observation well to date which has been reached by the combustion front. Pulse test directional permeability from #13-1 to #13-6, which is the south producer in the pattern, was 413 md, the highest in the project area. Heating

was occurring by January 1977, as the upper 35 feet of pay had increased from reservoir temperature of 75° F to 170° F, indicated in Figure 16. By June 1977 the maximum temperature in the well was 430° F. Cumulative air injection into Pattern 13 on June 30, 1977 had been 362,222 MCF. By August 19-7, combustion front arrival was observed at Well #13-7 as 825° F was recorded at a depth of 340 feet. The heating was still concentrated in the upper 35 feet of the zone. Since that time the temperatures above and below 340 feet have risen somewhat more rapidly as the thickness of burned interval increases. The maximum recorded temperature in the wellbore had been 1060° F. In April 1978, a slight cooling was seen in the interval from 330 to 350 feet. This may be due to arrival of a steam front as a result of the water injection into the pattern. The temperature in this interval dropped 200° F on the average (to 800° F at 340 feet). In June 1978, the well developed a casing leak, which may be due to the rapid cooling effect of the steam or water phase arrival. This well will be repaired so that the advancing phases of the process can be observed.

Well #14-7 is located 255 feet southwest of Injector #14-1, on line with producer #13-5. Directional permeability towards Well #13-5 was 176 md. As expected, heating is indicated at Well #14-8, shown in Figure 17, but not to the extent that has been seen at Well #13-7. Slight temperature increases were seen beginning in February 1977, but the heating has been very slow. The current temperatures in the wellbore are slightly

less than 300⁰ and have essentially remained constant since February 1978. The heated interval is from 325 to 355 feet, at the top of the zone. Some expansion of the heated zone has occurred. Originally, only the interval from 325 to 345 feet was showing appreciable heat.

Well #15-7, shown in Figure 18, is another slowly heating well, located 258 feet southeast of Well #14-1 towards Well #15-5. The permeability towards Well #15-7 is 145 md. Much the same type of heating has occurred in this well as in Well #14-7 though the expansion of the heated interval has not occurred. Initial heating was seen in August 1977. The interval from 345 to 360 feet has heat with the maximum temperature of 280⁰ F at 350 feet. This heated zone is once again the uppermost section of pay.

Well #16-7 is located 224 feet northwest of Injector #16-1. This location is very near Well #15-3 and the directional permeability from Well #15-1 to Well #15-3 may be the primary cause of the heating in this well. Permeability from #15-1 to #15-3 was 92 md, while from #16-1 to #15-3 the indicated permeability was 45 md. No heating was seen at this location through February 1978, as seen in Figure 19. The thermocouple was found to be damaged and a new one was run which indicated that the zone was heated up between 385 and 410 feet. The maximum temperature was 400⁰ F at 390 feet. This heated zone is more towards the middle of the pay section at this location and the extent and actual temperatures have not changed since March 1978.

It is expected that the combustion front passage will be observed at all five of the observation wells before terminating the combustion phase. Also, the effects of steam front passage air cooling and finally waterflooding should be easily monitored during the remainder of the contract period.

INJECTION AND PRODUCTION PERFORMANCE

The five injection wells (12-1, 13-1, 14-1, 15-1 and 16-1) were ignited between August 7 and September 24, 1976. Initial injection rates of 200 MSCFD per well were increased after completion of ignition operations in five steps, as follows: 500 MCFD, 750 MCFD, 1.0 MMCFD, 1.25 MMCFD and 1.5 MMCFD.

By March 1977, the injection rate into each pattern had been stabilized at 1.5 MMCFD. Each injector was then recompleted to allow the simultaneous injection of air and water into the formation for the remainder of the combustion phase. Air is injected through 2-7/8-inch tubing into the base of the Nacatoch pay interval while produced water is reinjected above a packer down the casing into the top of the pay behind the combustion zone. Initial injection ratios were in the range of 100 to 150 barrels per MMCF of air. The water/air ratio was to be increased to 250 Bbls/MMCF in each well and then different ratios were to be tried in each of the five patterns. Problems arose at once at Wells 12-1, 13-1 and 14-1, making the injection of water simultaneously with air difficult.

Initially, Well #14-1 had packer trouble. The tension packer had not set properly and the pressures on casing and tubing were equalized. When the packer was pulled, calcium carbonate scale was found on the tubing and packer. A bit

and scraper run was made and the well was acidized with 250 gallons of HCl before putting the well back on line. Scale preventive chemical (VISCO 950) has been added to the injection water since this problem was found. No further scaling has been noted since starting the scale preventive treatment.

At Well #13-1 initial scaling was so severe that the packer could not be retrieved. The packer was pushed to bottom, a bit run and acid treatment were used to clean up the casing and perforations. Injection pressures are still higher at Well #13-1 than at any other injector but there has not been any more scale problem.

Well #12-1 was originally thought to have similar scale problems but when the packer was pulled, no appreciable scaling was found. The pressure was building up on the water injection system rapidly enough to indicate either packer, casing or cementing failures allowing the full effect of the air injection to feed back onto the casing in the well. A bit and scraper run showed that chunks of cement and sand were inside the well, indicating a split in the casing. During ignition of Well #12-1, excessive temperatures caused by the ignition of oil remaining inside the well caused the failure of the casing. The burning oil inside the well generated 1300°F temperatures which over-stressed the casing. Water injection was abandoned in this pattern until a replacement injector could be drilled. Well #12-1A was drilled in October 1977. No problems have been encountered with simultaneous air and water injection into this replacement well.

Because of these problems, the injection rate of the water has not been nearly as high as the planned ratios. The cumulative injection water/air ratios for the five patterns are, as follows: 166 Bbls/MMCF in Pattern 12, 98 Bbls/MMCF in Pattern 13, 99 Bbls/MMCF in Pattern 14, 136 Bbls/MMCF in Pattern 15 and 89 Bbls/MMCF in Pattern 16. Current injection ratios are in the 200 Bbls/MMCF range but must still be increased to observe the benefits of increased heat transport and volumetric sweep improvement that have been seen in previous laboratory and field tests.

Cumulative air and water injected into the project have been 4,197,331 MCF and 449,605 barrels. Individual performance curves for the five patterns are presented as Figures 20 through 29. A comparison of the status of each pattern is shown in Table 8.

The injection has resulted in the production of 270,802 barrels of oil. This represents a recovery to date of 13.65% of the oil present at the start of combustion, based on an average oil saturation of 1909 barrels in each of the 1039 acre-feet of pay. The anticipated recovery during the six-year contract period is 700,000 barrels, roughly 35% of the oil in place. Cumulative injection and recovery per acre-foot is shown in Figure 30.

Production reached a peak of 601 BOPD during March 1978. During April and May, lack of injection while maintenance and painting of compressors was done, caused a decline in production to less than 500 BOPD. It is expected that the producing

rate will eventually climb back to the 600 BOPD range if injection is sustained and producing wells can be maintained throughout the remainder of the combustion phase by continued remedial work. Figures 31 and 32 present the production performance of the project to date.

ANALYSIS OF COMBUSTION PHASE

The objectives of the combustion phase of the process are to stimulate producing wells to increase production rates, to create a mobile oil bank within the patterns and to generate sufficient heat within the patterns to sustain producing rates by maintaining viscosity reduction throughout the water injection phase to follow. Accomplishing these three objectives will ensure success in commercial combustion projects.

All 20 producing wells have been stimulated by the combustion process to varying degrees. In 14 of the wells, the combustion front has arrived at the well while at the remaining 15 wells, flowline temperatures in excess of 200°F are evidence of the stimulation.

As indicated by the dramatic increase in oil producing rates, the mobility of the oil in the reservoir has been greatly increased. Figure 33 shows the effects of temperature on Bellevue crude viscosity. Without direct observation of the fluids in the reservoir, one cannot conclusively state that banking up of the displaced oil is occurring, though it does seem likely. Cumulative injection of 4,197,331 MSCF of air, burning at the rate of 17 MMSCF per acre-foot, should displace 408,000 barrels of reservoir crude. Since production to date is only 270,802 barrels, it is highly probable that the displaced crude is banking up either between wells or below the burned zone as it moves across the upper section of the

reservoir due to gravity segregation. If crude is banking up in the reservoir below the overriding combustion zone, most of this crude should be produced in the latter stages of the combustion phase as the simultaneous injection of water with air improves the vertical sweep by forcing more combustion in the lower section of the reservoir. On the other hand, if the crude is moving between wells, it will have to be recovered during the heat scavenging water injection phase.

The burned sections of the reservoir contain great quantities of heat evidenced by the temperature profiles at observation Well #13-7. The cooling effects of injected air through burned intervals diminishes with increasing distance from the injector. Water injected during the combustion phase picks up much of the heat near the injectors as it is vaporized and carried forward with the air to the combustion zone. The continuing combustion replenishes and increases the total amount of heat stored in the zone until final quenching occurs during the heat scavenging water injection phase. Economics are considered in determining the optimum burned volume required for commercial project success.

Continuing well operating problems as a result of combustion limit the withdrawal capability as the combustion progresses, hampering project economics both by increasing operating costs and reducing income from crude sales. The producing air-oil ratio curve is a useful tool in determining when to cease air injection and begin the heat scavenging phase. The project air-oil ratio curves are presented in Figure 34. This

ratio should continue on a decline during the combustion phase up to the point of diminishing returns as a result of the operating problems at producers. The curve will level off for a time and then begin to increase in the amount of air injection required to produce a barrel of crude. For this project, initial air-oil ratios ranged from 20 to 25 MCF per barrel. The ratio has steadily declined to a minimum level of 12.6 MCF/bbl in May 1978. The cumulative air-oil ratio for the project has been 15.5 MCF/bbl since the start of operations. Theoretical air-oil ratios determined from combustion tube tests in the laboratory are 10.0 MCF/bbl for dry combustion and 8.5 MCF/bbl ratio in field operations; however, it is expected that the operating air-oil ratio will continue to decline for at least the next six months before beginning an upward trend. By that time, there should be sufficient heat stored in the project area to sustain high producing rates for several years. Fifty percent of the net pattern volume should be burned by the time of conversion to the heat scavenging phase.

The present burned volume of reservoir is estimated to be 247 acre-feet, roughly 24 percent of the total pattern volume. Estimated burned volumes for each pattern are shown in Table 9. Burned volumes should increase more rapidly as the effects of simultaneous air and water injection are felt during the next six months. Greater reductions in air requirement will be noticed as more water is injected into the project patterns. The cumulative injection water-air ratio of 107 bbls/ MMCF

should be increased to 250 bbl/MMCF by the end of the combustion phase. The cumulative injection into each pattern is summarized in Table 10.

WELL REMEDIAL WORK

With the advance of the combustion front towards producing wells, the area surrounding the well becomes thermally stimulated, allowing producing rates to greatly increase as the mobility of the oil increases. Commercial producing rates cannot be attained without this stimulation. Unfortunately, the combustion front will break through, or channel, to the producer before the entire reservoir can be thermally stimulated. When this happens, unreacted oxygen which would otherwise be available to generate more heat by continuing combustion is produced. This reduces the overall efficiency of the process and requires that additional air be injected to accomplish what the escaping oxygen does not.

In addition to this loss of oxygen, the hot gases entering the perforated wellbore will erode away the burned, unconsolidated sandface and the protective primary cement sheath. The produced sand and gases cause extreme wear and tear of bottomhole tubulars and pumping equipment. A quench water system shown in the producing well schematic, Figure 35, enables the equipment to operate under adverse conditions for as long as possible. The water cools the pump and tubing and helps to carry the sand out of the wellbore so that wells do not sand up daily. The flowline temperature at the producing wellhead is the control for quench water useage. Water is pumped down the tubing annulus to maintain a 200° F flowline temperature.

Wells are checked daily to ensure that all wells are pumping fluid. Wells that are not pumping are pulled and the pumps and hollow rods are inspected for signs of damage resulting from sand cut tubing. If damage is present, the tubing is pulled. Typically, there will be holes in the tubing opposite the perforations through which the hot gases carrying the sand are produced. The depths of these intervals are determined and then are squeeze cemented.

After drilling out the cement, intervals which were not cutting the tubing are reperforated and the well is put back on production. Remedial squeeze jobs are often repeated on the same well in the same intervals since the quality of the cement job obtained by squeezing is not nearly as good as the primary cement job.

Through the first two years of the project, a total of 14 wells have been squeeze cemented at least once. Many have been squeezed two, three or more times. The first well which required squeezing was Well #15-2, located 165 feet north of the Pattern 15 injector. This well experienced premature breakthrough on February 18, 1977. The injected air seemed to be channelling through the water section below the oil zone causing a premature arrival. Since initial breakthrough, this well has been squeezed seven times.

Well #12-2 also broke through early (April 19, 1977) but has only been squeezed twice. Apparently the combustion front channeled through a highly permeable streak near the top of the zone and was effectively stopped by the first squeeze job. The second squeeze was done on April 6, 1978, and covered a slightly thicker interval.

Well #13-2 was the third well to require a cement squeeze (July 5, 1977). This well behaves more typically than the earlier two wells squeezed. The squeeze lasted until October 27, 1977 when it was resqueezed. Two more treatments followed on January 5, 1978 and June 26, 1978. The quality of these jobs has been fairly consistent, as indicated by the length of time between them.

At just about the same time as the initial squeeze at Well #13-2, Well #13-6 was treated. This was expected from results of the pulse tests which indicated virtually the same response times for the two wells, although Well #13-6 is twice as far from the injector. Also, observation Well #13-7 had been showing combustion temperatures since early July 1977. The first squeeze job on Well #13-6 was done on August 16, 1977. Two more treatments have been required (February 8, 1978 and April 16, 1978).

A summary of the wells which have been squeeze cemented is presented as Table 11. It should be noted that eight of the 14 wells squeezed are along the north line of wells and that only three lie along the south line. This would seem to contradict the results of pulse tests which indicated much higher permeabilities towards the south. As mentioned earlier, however, the pulse test results in Pattern 13 matched almost exactly the combustion front movement towards Wells 13-2 and 13-6. Further study of directional permeability determinations may be needed to more accurately predict the migration and growth of combustion zones.

It is expected that all or most of the remaining 15 producers will require squeezing before terminating air injection in the project. The frequency of squeeze jobs on the first 14 wells will probably increase also.

PROJECT ECONOMICS

DOE Cost-Sharing Contract Number EY-76-C-03-1189 provides for DOE funding a maximum of \$3,102,112 for the six-year demonstration. The total estimated project cost is \$8,229,898. Cumulative expenditures to date have been \$3,610,356, shown in Figure 36, of which Cities Service Company's share has been \$2,254,909.

Project Investments

The contract provides for the funding of investments for wells and facilities on the basis of tangible or intangible charges. All tangible equipment is paid for by Cities Service Company while intangible charges are funded by the DOE.

Precontract estimates for development costs were \$1,205,600. Of this total, tangible and intangible portions were \$704,324 and \$501,276, respectively. Several changes in project facilities have increased the actual development costs beyond the original estimates; however, these changes should not affect the overall project funding.

Electrification of Compressor #1, necessitated by natural gas curtailments to industrial users during peak demand periods, amounted to an increase in overall investments of \$70,633.

Cumulative expenditures for wells and facilities through June 30, 1978 have been \$1,304,680. Of this total, Cities Service Company's share has been \$751,107 or 57.6%, while the Department of Energy has contributed \$553,573. Project investments are summarized in Table 12.

Additional investments are planned for the coming year. Four wells will be drilled as additional producers. These wells will be used to study the effects of well density on recovery and to determine the saturations in areas between present producers. The estimated additional cost for these wells is \$102,200. Also, addition of a second free-water knockout or replacement of the existing vessel with a larger one is being studied. Cost estimates for this work are being developed.

Based on ultimate production of 700,000 barrels, recovery of the \$1,304,680 investment to date will occur at the rate of \$1.86 per gross barrel of oil produced. Cumulative production to date of 270,802 barrels has thus recovered \$504,728 or 38.7% of investments.

Operating Expenses

The remaining \$2,305,676 which has been spent to date are summarized in Table 13. These are expenses incurred in routine operation of the project, maintenance of wells and facilities, research and production services, taxes and overhead expenses. Based on the cumulative production of 270,802 barrels, the expenditures amount to \$8.51 per gross barrel.

Research and production services through June 30, 1978 have cost \$472,281 or \$1.74 per barrel. These are charges borne by the project for laboratory and field work conducted by Company personnel. In addition to these charges, the Company's overhead rate amounts to \$355,997 or \$1.21 per barrel.

Louisiana severance taxes, paid as a percentage of gross sales, have amounted to \$436,403 or \$1.61 per barrel.

The remaining charges can be grouped under the general category of direct lease operations and maintenance. Expenditures to date of \$1,040,994 amount to \$3.84 per barrel of oil produced. This includes charges for replacement materials, labor, chemicals, utilities and well servicing. These expenditures have been summarized in Table 14.

The expenditures for utilities and well servicing will vary drastically over the course of the six-year project. Eighty percent of the utility charges are for the operation of the compression facility. With cumulative injection of 4,197,331 MCF of air to date, this amounts to a cost of \$0.078 per MCF. Upon completion of the combustion phase, compression facility charges will be zero.

Well servicing is another cost which will vary greatly. These charges have been steadily increasing, from \$3,500 per month in late 1976 to over \$21,000 per month during the period from March through June 1978. These monthly charges are shown in Figure 37. As the combustion front affects an increasing number of producing wells, requiring frequent remedial work, these costs will increase. After air injection ceases, these costs should gradually decline.

APPENDIX A

FIGURE 1

FIGURE 2

TYPE LOGS

DOE - CITIES SERVICE

IN SITU COMBUSTION PROJECT

INDUCTION - ELECTRICAL LOG FOR WELL 13-3

DETAIL LOG 5" = 100'			
SPONTANEOUS-POTENTIAL - 15 + MILLIVOLTS	HOLE DIAM.	6 PF40 INDUCTION	CONDUCTIVITY MILLIMHOS M - 1000 OHMS M/IN
		3000	2000 1000 0
		RESISTIVITY OHMS M/IN AMP. SHORT NORMAL	
		0 4	
		SHORT NORMAL A-16" - M	
		0 20	
		0 -200	
		6 PF40 INDUCTION	
		0 20	
		0 200

COMPENSATED FORMATION DENSITY LOG FOR WELL 13-3

CALIPER HOLE DIAM. IN INCHES	DEPTH	CORRECTION GRAMS/CC
16		-25 0 25
GAMMA RAY API UNITS		BULK DENSITY GRAMS/CC
C 100	2.0 2.5 3.0	1.0 1.5 2.0

GAMMA RAY - NEUTRON LOG FOR WELL 13-3

LOGGING DATA											
GENERAL		SPEED		T.C.	SEMI	PERO	API G R UNITS		T.C.	SEMI	NEUTRON
DATE	DEPTH	FT. MIN	SEC	SEC	SETTINGS	DIV. 1 OR 2	PER LOG DIV	SEC	SEC	SETTINGS	PER LOG DIV
1	461	50	23	4	100/1.00	2 L		2	500/1.00	74 L	
REFERENCE LITERATURE											
REMARKS											
GAMMA RAY				DEPTH AND CASING COLLARS		NEUTRON					
API UNITS						API UNITS

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FIGURE 5

PROJECT AREA NET PAY MAP
BODCAU FEE FIREFLOOD

FIGURE 6

BODCAU IN SITU COMBUSTION PROJECT
RESULTS OF PATTERN 12 PULSE TEST

FIGURE 7

BODCAU IN SITU COMBUSTION PROJECT RESULTS OF PATTERN 13 PULSE TEST

FIGURE 8

BODCAU IN SITU COMBUSTION PROJECT
RESULTS OF PATTERN 14 PULSE TEST

FIGURE 9

BODCAU IN SITU COMBUSTION PROJECT RESULTS OF PATTERN 15 PULSE TEST

FIGURE 10

BODCAU IN SITU COMBUSTION PROJECT RESULTS OF PATTERN 16 PULSE TEST

15-3

16-2

16-3

45 MD

27 MD

NO RESPONSE

49 MD

81 MD

15-4

16-4

46 MD

NO RESPONSE

235 MD

15-5

16-6

16-5

FIGURE II

FIGURE 12

FIGURE 13

FIGURE 14

**PROJECT PATTERN MAP
BODCAU FIE FIREFLOOD**

○ TEMPERATURE OBSERVATION WELL

FIGURE 15

FIGURE 16

FIGURE 17

FIGURE 18

FIGURE 19

BODCAU IN SITU COMBUSTION PROJECT
TEMPERATURE OBSERVATION WELL

#16 - 7

FIGURE 20

FIGURE 21

FIGURE 22

FIGURE 23

FIGURE 24

BODCAU IN SITU COMBUSTION PROJECT PATTERN 14 INJECTION PERFORMANCE

FIGURE 25

BODCAU IN SITU COMBUSTION PROJECT WELL # 14-1 INJECTION HISTORY

FIGURE 26

FIGURE 27

BODCAU IN SITU COMBUSTION PROJECT WELL # 15-1 INJECTION HISTORY

FIGURE 28

FIGURE 29

BODCAU IN SITU COMBUSTION PROJECT PATTERN 16 INJECTION PERFORMANCE

FIGURE 30

FIGURE 31

FIGURE 32

FIGURE 33

FIGURE 2, VISCOSITY-TEMPERATURE RELATIONSHIP
(19° API, BELLEVUE CRUDE)

FIGURE 34

BODCAU IN SITU COMBUSTION PROJECT
AIR - OIL RATIO CURVES

FIGURE 35

Production Well Schematic

Dry & Simultaneous Burning Phases

FIGURE 36

BODCAU IN SITU COMBUSTION DOE PROJECT

CUMULATIVE EXPENDITURE VS TIME

FIGURE 37

WELL SERVICE COST PER MONTH (M)

APPENDIX B

TABLE 1

BELLEVUE FIELD AVERAGE RESERVOIR PROPERTIES

Porosity	33.9%
Permeability	700 md
Water Saturation	27.4 %
Reservoir Temperature	75°F
Reservoir Pressure	40 psig
Crude Gravity	19° API
Crude Viscosity	676 CP

TABLE 2

PROJECT AREA DATA

Pattern Area	19 acres
Average Thickness	54 feet net
Net Pay Volume	1039 acre-feet
Oil Saturation	1909 bbls/acre-foot
Oil in Place	1,984,000 barrels
Estimated Recovery	700,000 barrels

TABLE 3

SUMMARY OF COMBUSTION TUBE RESULTS FOR
TESTS CONDUCTED DURING YEAR #2 OF PROJECT

	<u>RUN #19</u>	<u>RUN #20</u>	<u>RUN #23</u>	<u>RUN #24</u>	<u>RUN #25</u>
<u>PACKING CONDITIONS</u>					
Porosity, %	46	52	47	48	46
Oil Saturation, %	23	21	19	18	25
Sand Weight, Grams	6799	6141	6761	6568	6905
Oil Weight, Grams	481	479	401	390	508
Weight % Oil	7	8	6	6	7
<u>OPERATING CONDITIONS</u>					
Air Flux, SCF/HR/FT ²	513	473	437	512	473
Combustion Temp., °F	967	976	1048	1199	1361
Burning Efficiency, %	62	74	61	58	66
Water/Air Ratio, BBLs/MMCF	0	225	192	188	182
<u>RESULTS</u>					
Fuel Deposit, LB/FT ³	1.57	1.65	1.33	1.57	2.04
Air Requirement, MMCF/AF	10.2	10.6	8.7	10.4	12.4
Hydrogen/Carbon Ratio	0.05	0.06	0.05	0.06	0.02
Air/Oil Ratio, MCF/BBL	24.2	7.7	6.1	7.4	9.3

TABLE 4

SUMMARY OF FALLOFF TEST RESULTS

PRE-IGNITION TESTS

<u>PATTERN</u>	<u>CUMULATIVE INJ. -MCF</u>	<u>CAPACITY MD-FT</u>	<u>PERMEABILITY MD</u>	<u>INJECTION PRESSURE-PSIA</u>
12	3,010	897	14.5	145
13	4,068	761	12.5	135
14	3,520	320	5.9	181
15	3,798	594	13.5	162
16	4,532	1,338	32.0	141
16	11,536	3,434	82.0	90

SECOND TESTS

<u>PATTERN</u>	<u>CUMULATIVE INJ. -MCF</u>	<u>CAPACITY MD-FT</u>	<u>PERMEABILITY MD</u>	<u>INJECTION PRESSURE-PSIA</u>
12	158,618	8,418	136	115
13	170,010	12,828	210	138
14	150,461	6,038	112	171
15	152,684	8,459	192	138
16	123,841	22,862	544	84

TABLE 5

ANALYSIS OF PRODUCED GASES IN JANUARY - 1978
MOLE PERCENT

<u>COMPONENT</u>	<u>RANGE</u>	<u>AVERAGE</u>
Nitrogen	74.3 - 82.6	80.1
Oxygen	1.0 - 10.6	2.7
Carbon Dioxide	9.1 - 14.6	12.4
Carbon Monoxide	0.4 - 1.1	0.5
Hydrogen Sulfide	0.03 - 0.41	0.22
Hydrocarbons	0.5 - 4.6	1.3

TABLE 6

ANALYSIS OF HYDROCARBONS IN PRODUCED GAS
JANUARY - 1978

<u>COMPONENT</u>	<u>AVERAGE MOLE PERCENT</u>
Methane	1.108
Ethane	0.104
Propane	0.064
Butanes	0.048
Pentanes	0.012

Average heating value of gas = 16.7 BTU/SCF

TABLE 7

ANALYSES OF PRODUCED CRUDE OIL

<u>SAMPLE</u>	<u>API GRAVITY</u>	<u>ACID NUMBER</u>	<u>PERCENT SULFUR</u>
Native	19.0	5.1	0.90
May, 1977	19.6	4.0	0.36
January, 1978	18.0	4.0	0.47

TABLE 8

PROJECT PATTERNS STATUS SUMMARY

<u>PATTERN</u>	<u>INJECTION</u>			<u>INDEX</u>
	<u>MCF/AF</u>	<u>BBL3/AF</u>	<u>DBLS/MMCF</u>	<u>DBLS/MMCF/AF</u>
12	3406	394	116	0.489
13	3996	392	98	0.436
14	3978	394	99	0.467
15	4490	612	136	0.766
16	4538	404	89	0.476

TABLE 9

PATTERN ESTIMATED BURNED VOLUMES.

<u>PATTERN</u>	<u>NET AF</u>	<u>BURNED AF*</u>	<u>PERCENT</u>
12	237	47.5	.200
13	225	52.9	.235
14	212	49.6	.234
15	178	47.0	.264
16	187	49.9	.267

*Note: Assumes Dry Combustion Air Requirement of
17 MMSCF/Acre-Foot

TABLE 10

CUMULATIVE INJECTION SUMMARY

<u>PATTERN</u>	<u>INJECTION</u>		<u>RATIO</u>
	<u>MCF</u>	<u>RBLS</u>	<u>BBLS/MMCF</u>
12	807,177	93,452	116
13	899,103	88,121	98
14	843,289	83,524	99
15	799,199	108,995	136
16	848,583	75,513	89

TABLE 11

SUMMARY OF WELL REMEDIAL WORK

<u>WELL</u>	<u>NO.</u>	<u>JOBS</u>
2-3	0	
2-4	0	
2-5	0	
2-8	0	
12-2	2	April 19, 1977; April 6, 1978
12-3	1	April 10, 1978
12-4	2	March 30, 1978; May 25, 1978
12-5	0	
12-6	0	
13-2	4	July 5, 1977; Oct. 27, 1977; Jan. 5, 1978; June 26, 1978
13-3	0	
13-4	2	March 28, 1978; April 20, 1978
13-5	0	
13-6	3	August 16, 1977; Feb. 8, 1978; April 16, 1978
14-2	5	Sept. 21, 1977; Sept. 27, 1977; Dec. 19, 1977; January 3, 1978; February 23, 1978
14-3	2	December 28, 1977; March 2, 1978
14-4	0	
14-5	0	
14-6	1	June 29, 1978
15-2	5	February 18, 1977; April 15, 1977; April 19, 1977; August 2, 1977; April 19, 1978
15-3	3	February 16, 1978; June 19, 1978; June 28, 1978
15-4	2	April 18, 1978; June 21, 1978
15-5	0	
15-6	0	
16-2	2	February 8, 1978; March 17, 1978
16-3	0	
16-4	0	
16-5	0	
16-6	1	May 15, 1978
<u>TOTAL</u>	<u>35</u>	Cement Squeeze Repairs

TABLE 12

SUMMARY OF PROJECT INVESTMENTS

<u>DESCRIPTION</u>	<u>CUMULATIVE COSTS</u>	<u>ORIGINAL ESTIMATE</u>
<u>Drill and Equip Wells</u>		
Evaluation Wells	\$ 36,759.26	\$ 34,544.00
Development Wells	717,813.18	624,237.00
Observation Wells	43,304.47	35,700.00
Saltwater Disposal	15,535.98	13,232.00
Redrill Well #12-1A	<u>16,246.20</u>	
Sub-Total	\$829,659.09	\$707,713.00
 <u>Install Facilities</u>		
Production and Injection Facilities	\$475,021.32	\$497,888.00
Electrify Compressor #1	<u>70,633.08</u>	
Sub-Total	\$545,654.40	\$497,888.00
TOTAL INVESTMENTS	\$1,375,313.49	\$1,205,601.00

TABLE 13

SUMMARY OF PROJECT EXPENSES

<u>DESCRIPTION</u>	<u>CUMULATIVE COST</u>	<u>ORIGINAL ESTIMATE</u>
<u>Exploration and Production Services</u>		
Region Expense	\$203,934.05	\$747,642.00
Production Foreman Expense	<u>100,354.65</u>	<u>256,179.00</u>
Sub-Total	\$304,288.70	\$1,003,821.00
<u>Research Services</u>		
Research and Development	\$167,992.36	\$ 360,835.00
Environmental Assessment	<u> </u>	<u>50,000.00</u>
Sub-Total	\$167,992.36	410,835.00
<u>Lease Operation and Maintenance</u>		
Direct Lease Expenses *	\$1,040,993.85	\$3,877,000.00
Producing Well Overhead	355,997.24	1,257,080.00
Louisiana Severance Taxes	<u>436,403.20</u>	<u>475,561.00</u>
Sub-Total	1,833,394.29	5,609,641.00
TOTAL EXPENSES	<u>\$2,305,675.35</u>	<u>\$7,024,297.00</u>

*See Table 14

TABLE 14

SUMMARY OF DIRECT LEASE OPERATIONS AND
MAINTENANCE EXPENSES

<u>CATEGORY</u>	<u>TOTAL EXPENDITURES</u>	<u>COST PER BARREL*</u>
Materials	\$ 110,153.03	\$ 0.41
Chemicals	98,357.03	0.36
Labor	178,516.57	0.66
Utilities	406,931.71	1.50
Well Service	<u>247,035.51</u>	<u>0.91</u>
TOTAL	\$1,040,993.85	\$ 3.84

* NOTE: Based on gross cumulative oil production of
270,802 barrels through June 30, 1978