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BODCAU IN SITU COMBUSTION PROJECT

Fourth Annual Report
September 1, 1979—February 28, 1981

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Work Performed for the Department of Energy
Under Contract No. DE-AC03-76ET12057

Date Published—July 1981

Cities Service Company
Jackson, Mississippi

U. S. DEPARTMENT OF ENERGY

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BODCAU IN SITU COMBUSTION PROJECT

Fourth Annual Report
September 1, 1979—February 28, 1981

G. Hardin, *Author*
Conrad Joseph, *Principal Investigator*
Cities Service Company
Southeastern E&P Region
Jackson, Mississippi 39201
601/969-6970

Alan J. Leighton, *Technical Project Officer*
Fossil Energy Division
San Francisco Operations Office
1333 Broadway
Oakland, California 94612
415/273-7951

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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 DE-AC03-76ET12057, covering the period from June 1, 1976, through June 30, 1982. The objective of this project is to demonstrate the technical efficiency and economics of a commercial scale in situ combustion project in a shallow heavy oil reservoir.

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.

The Bellevue Field was discovered in 1921 and consists of a dome type structure covering approximately 900 productive acres. The Upper Cretaceous Nacatoch Sand is the producing formation at a depth of 300 to 400 feet. Net pay isopach and structure maps of the project area are presented in Figures 2 and 3. Primary and secondary production methods recovered only about 5% of the estimated oil in place. Reservoir properties and project area data are presented in Tables 1 and 2.

The five patterns comprising the demonstration project enclose 19 productive acres and consist of thirty-eight producing, five injection and five observation wells.

The purpose of the Fourth Annual Report is to briefly review the history of the project with emphasis on operations from September 1979 through February 1981. Sections on the air system explosion in February 1980 and the results from an evaluation well drilling program in Pattern 15 are highlights of this report.

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 into the base of the Nacatoch were gradually increased to 1.5 MMSCFD by March 1977. 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 through the casing into the top of the pay. A four to eight foot thick fossiliferous lime deposit provides a partial permeability separation between the two injected fluids. Initial injection ratios were in the range of 100 to 150 barrels per MMCF of air. This ratio was increased during the combustion phase of the project to 710 BW/MMCF in September 1980, when air termination was begun. Injection histories for each pattern are shown in Figures 4 through 8 while total project injection history is presented in Figure 9.

Injector 12-1 experienced a casing failure and a replacement, 12-1A, was drilled in October 1977. The only other remedial work performed on the injectors since that time, other than some small acid treatments to remove scale buildup, were the squeeze cement jobs following air termination in Patterns 14, 15 and 16. These injectors were then reperforated in the base of the Nacatoch for water injection during the heat scavenging phase of the project. Patterns 12 and 13 will be converted to water injection in a similar fashion.

The complete schedule of air termination is shown in Table 3. In February 1981, 2,487,232 barrels of water and 10,013,966 MCF of air had been injected into the project. Table 4 indicates the cumulative injection volumes for each pattern. Table 5 shows the estimated burn volumes in each pattern, assuming a wet combustion air requirement of 12,000 MCF/acre-foot.

Produced oil and water from the start of the project through February 1981 is plotted in Figure 10. Cumulative production through February 1981 was 620,893 barrels of oil and 3,773,732 barrels of water. Estimated oil recovery for the project is 700,000 barrels, of which 89% has already been produced. The monthly air-oil ratio (AOR) plot is displayed in Figure 11. The average AOR for the project through December 1980 was 16.2 MCF/BBL. Peak oil production rates were attained in March 1978 with 601 BOPD being produced. Producing rates have declined an average of 7.5 BOPD per month since that time. Increased water injection volumes in June of 1980 resulted in slightly higher oil and water production through September 1980. Production is expected to continue declining through the remainder of the project at similar rates.

TEMPERATURE OBSERVATION WELL MONITORING

In order to achieve maximum recovery from in situ combustion projects, a description of the burn front geometry is essential. Properly located temperature observation wells can provide such information about the reservoir. Thus, in December of 1976, five wells were drilled to serve as temperature observation sites. The locations of these wells are shown on Figure 12. All five wells were completed with 5-1/2 inch casing cemented to surface. Profiles are taken using a type K thermocouple run inside casing with stops at five foot intervals from 300 to 425 feet. Although 5-1/2 inch casing was used in each well in anticipation of casing failure problems caused by high temperatures, to date only one such failure has occurred. In June 1978, observation well 13-7 developed a casing leak which was repaired in August 1979 when a string of 3-1/2 inch casing was cemented inside the original 5-1/2 inch casing string.

During 1976 and 1977 pulse or interference test were performed on all five patterns of the project. The results of these tests were compiled in the Topical Report of January 1978 on Pressure Transient Testing. Directional permeabilities were calculated between the injectors in each pattern and the eight surrounding producers.

Observation well #12-7 is located 212 feet northeast of injection well #12-1A and eight feet lower on structure. The first indication of heat was noted March 1978 as indicated on Figure 13.

Recorded temperatures increased slowly to a maximum of 238° at 370' in December 1980. Temperatures in this well are lower than those observed in the other four observation wells. Three reasons can be given to explain this occurrence:

- (1) Well #12-7 was located in the direction of least permeability in pattern 12.
- (2) This well is the only observation site which is located down structure from the injector in the pattern. Due to the tendency of air migration up structure, the advance of the burn front would be greatest in the southwest direction, exactly opposite of #12-7.
- (3) Just as air tends to flow up structure, water injection prefers down structure movement. Therefore, a large portion of the injected water moves down dip, cooling the formation and probably leads to partially quenched combustion in this direction.

The directional permeability from injection well #13-1 to the south towards observation well #13-7 of 413 millidarcies is not only the largest in this pattern, but also greater than any other measurements taken in any of the five patterns. Well #13-7 is 228 feet south of #13-1 and 16 feet higher structurally. These facts considered, it is not surprising that as early as February 1977, the upper 35 feet of pay in #13-7 had been thermally stimulated with temperatures increasing from 75°F to 195°F as shown in Figure 14. By September 1977, arrival of the combustion

front was observed when a temperature of 825^oF was measured at a depth of 340 feet. Temperatures continued to increase until March 1978 when a maximum of 1060^o was recorded. The trends observed since that time include a cooling of upper part of the reservoir, probably due to the rapid cooling effect of the steam phase arrival and a continued rise in temperatures in the lower part of the formation. This increase in temperature is caused by air and thus combustion being forced into this section by the overriding water injection.

Observation well #14-7 is in the southwest corner of pattern 14, 255 feet from injector #14-1 and 20 feet higher on structure. Slight temperature increases were noticed in February 1977, as shown on Figure 15, at the top of the formation. Temperatures continued to increase in the top 30 feet of the Nacatoch through May 1979 when a maximum recorded temperature of 325^oF was taken at 335'. During the last of 1979 and all of 1980, temperatures in the top of the sand decreased slightly while steady gains were observed down in the base of the zone.

When the five observation wells were completed, air was used to blow fluids (water) from the hole to allow profiles to be run in air. If temperature profiles were taken in fluids, readings would not be accurate due to the cooling effects of the liquid. A convection cell would be formed with fluids boiling up, then cooling and falling. Observation well #15-7 is beside a creek which runs through the lease. Often in the spring, this creek overflows its banks. Since the well has no cover or valve on the surface, it is

possible for rainfall and this flood water to enter the wellbore. Lower than expected temperatures caused suspicions of the presence of such fluid in the hole. In October 1980, well #15-7 was jetted to total depth with air. The drastic change in temperatures recorded after this work confirmed our suspicions. This observation well is 258 feet southeast of the injector #15-1 and is 15 feet higher structurally. Initial response, Figure 16, occurred in August 1977. Temperatures gradually increased with maximums at the top of the formation; however, it would appear that all profiles prior to October 1980 were influenced by the presence of water. The latest profile shows the highest temperature recorded to date (347°F) occurring 28 feet below the top of the Nacatoch. This is probably not the highest temperature this well has seen, since higher temperatures may have been missed when earlier profiles were taken with water in the wellbore. Air injection was terminated into this pattern in October 1980, but no change has been seen in profiles since that time.

Well #16-7 is located 224 feet northwest of injector #16-1 and 80 feet southeast of well #15-3. Pulse test indicated that the directional permeability between 15-1 and 15-3 was greater than that from 16-1 to 15-3, which suggested that heating would primarily be due to stimulation from Pattern 16. Stimulation was not seen until March 1978, Figure 17. Temperatures gradually increased, reaching a peak of 420°F in December 1978. Since that time, temperatures have decreased throughout the zone with the profile showing no temperature greater than 120°F. This well is down dip from injector #15-1 and level with #16-1, therefore water injection

into these two wells probably caused the cooling observed. Air injection into pattern 16 was also stopped on November 3, 1980, but no change has been seen and due to the already low temperatures, little is expected.

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 oil increases. Unfortunately, combustion gases break through or channel to the producer before the entire reservoir interval can be stimulated. These hot gases, carrying sand, erode away the cement sheath surrounding the production casing and cause severe wear on downhole pumps and tubulars.

To limit the flow of combustion gases, the section of the Nacatoch where these gas breakthroughs occur is squeeze cemented and another portion is opened for fluid production. This method also improves sweep efficiency by forcing air into intervals which may have not previously been fully stimulated. Current volumes used vary from 20 to 200 sacks of Class A cement with 22% silica flour. A history of squeeze cement jobs by well is presented in Table 6. Figure 18 indicates the frequency and cumulative number of squeeze cement jobs by month for the project.

During 1977, the first full year of the project, 12 wells were squeezed for an average of 1 per month. Ten of these jobs were performed on wells along the north line of the project area. The frequency of remedial work increased rapidly in 1978 when 44 wells experienced combustion breakthrough. This average of 3.7 wells per month included 26 combustion breakthroughs in north line

wells. To solve this problem, in February 1979, it was decided to shut in wells 13-4, 14-2, 14-3, 15-2, 15-3 and 16-3 in order to optimize air use and force migration of heat to the south more quickly. These six wells had incurred 30 of the total 60 squeeze jobs for the project to that point. The success of this effort was apparent when in 1979 an average of only 2.4 wells were squeezed each month and south line producers became heat stimulated. Thirty percent of the remedial work that year was performed on south line producers. This trend of stimulation to the south continued through the first half of 1980, and, in July, the six shut-in producers along the north line were returned to production. During 1980, 37 wells were squeezed, including 2 on injection wells 15-1 and 16-1. Many of these were up dip as the southern producers became stimulated. With the termination of air injection, beginning in October 1980 and to be completed in April 1981, a reduction in remedial work is expected. For the first two months of 1981, only 1 remedial squeeze cement job has been performed. Note that as air injection is terminated, perforations in the upper section of the Nacatoch at injection wells are squeeze cemented. This insures that water injection during the heat scavenging phase will be into the lower part of the Nacatoch which has not been fully burned. These jobs are also included in the summary of remedial work.

AIR COMPRESSION AND DISTRIBUTION SYSTEM

The air compression-distribution system is probably the most important component of physical plant for the project. Smooth and efficient operation of this system is vital to overall project performance and economics.

Three Ingersoll Rand compressors with a total capacity of approximately 20 MMSCFD at 200 psig supply the air required for combustion on Cities Service Company's acreage in Bellevue Field. A portion of this total deliverability was used for the DOE Demonstration Project during the burn phases of the wet combustion process. With the termination of air injection into all patterns by April 10, 1981, it was felt that descriptions and histories of all three units along with an analysis of the air system explosion which occurred in February, 1980 would be appropriate and informative.

COMPRESSOR NO. 1

This Ingersoll Rand 4RDS-3 was initially installed under a rental/purchase agreement with Southwest Industries in 1970. Originally, this unit was equipped with a Waukesha L-7042 GSI engine. The unit is rated for 3.18 MMSCFD at 315 psia and 742 BHP at 800 RPM.

Anticipated shortages of natural gas supplies necessitated the replacement of the Waukesha engine in late 1977 with a 1000 HP, 900 RPM General Electric motor. The cost of this replacement

was \$74,029. The unit was out of service from August 3, 1977, until April 20, 1978. Following completion of this work, the unit was placed in service once again and has not encountered serious operating problems since that time.

COMPRESSOR NO. 2

Compressor No. 2 was installed in 1973 and consists of an Ingersoll-Rand 4RDS-3 driven by a 1250 HP General Electric motor. This equipment is capable of delivering 5.74 MMSCFD at 300 psig using 1170 HP at 885 RPM.

Problems with this unit have been numerous and serious. On October 18, 1976, during an electrical storm, this unit failed to shut down following an electrical line surge and was almost totally destroyed. The cause of the shutdown systems failure to function properly was difficult to ascertain. However, considerable corrosion was noted on numerous electrical contacts. The unit was disassembled and shipped to Houston for repairs. The unit was put back in operation on December 6, 1977, after \$90,866 in repairs. During May, 1979, the compressor was shut down for installation of a Resistance Temperature Detector (RTD). This additional automatic shutdown system provides added protection against another serious mechanical failure. Installation cost totaled \$10,310.

COMPRESSOR NO. 3

This unit was installed in May, 1976. The compressor is an Ingersoll-Rand 4HHE-3-VG powered by a 3000 HP synchronous

electric driver at 327 RPM. This unit, like the two others, uses 3 stages to compress air from atmospheric pressure to 205 psia - 225 psia. Rated capacity is 12 MMCFD at 265 psig. Following ordinary initial startup difficulties between May and October 1976, the unit has operated smoothly. In August, 1977, three 660-volt capacitors failed and were replaced. In February, 1979, the oil lubrication system failed to the third stage discharge cylinder. This failure caused the rod and piston to overheat and expand resulting in extensive damage to both and also damage to the cylinder wall. A new rod and piston were purchased and the cylinder repaired. The cost of these repairs was \$16,453. The unit was then returned to service and only routine maintenance was performed until the February, 1980 air system explosion.

AIR SYSTEM EXPLOSION

On February 17, 1980, an explosion occurred within the air distribution system. The explosion, which happened on a cool Sunday morning at around 10:00 a.m., is estimated to have caused approximately \$100,000 in damages to the piping, meter runs and air compressors at the facility. No personnel injuries were experienced.

On the morning the accident occurred, compressors #2 and #3 were operating, delivering a combined total of 17,000 MCFD to the injection wells. Facility employees had detected no abnormal operating conditions from Compressor #3, but Compressor #2 had shut down on Sunday morning for about 45 minutes on high liquid

level in the second stage cylinder suction bottle, and was re-started about 20-25 minutes prior to the explosion.

Production personnel stated that only a single, long, rumbling blast was heard during the explosion, indicating that the explosion was propagated throughout the air piping network almost instantaneously.

DAMAGES

A. Compressor No. 3

During the explosion, Compressor #3 sustained considerable damage to the second and third stage discharge pulsation bottles, to the bottle's supports, and to various piping systems on the compressor.

Compressor #3 utilized Anderol 500, which is a synthetic lubricant, within the compressor cylinders, and utilized Pace-maker 900 in the compressor crankcase. The two lubrication systems are separate and distinct and are incapable of contaminating each other. Anderol 500 is injected onto the cylinder's piston through the use of a Manzel force-feed lubricating system.

The compressor is equipped with a number of protective systems designed to shut down the compressor when abnormal operating conditions are encountered. In particular, the compressor is designed to shut down when the third stage discharge pressure exceeds 250 psig or the third stage cylinder temperature rises above 350°F.

The compressor's suction inlet for the air, located above the compressor's crankcase, is equipped with filters to remove

undesirable objects from the air flow. Air is compressed in three stages with cooling provided between stages by passing the air through an air-cooled heat exchanger. Water condensed from the air, as well as a portion of the oil carried over in the air stream from the cylinders, is also drawn off between the stages.

The 3rd stage discharge cylinder, which has a bore of 18-1/2 inches and a stroke of 15 inches, normally discharges air at temperatures ranging up to 260°F and at pressures ranging from 190-220 psig. On the day prior to the explosion, the compressor was discharging air at 160°F and 200 psig. The cylinder, rated for a maximum working pressure of 575 psig, and a maximum working temperature of 350°F, had been hydrostatically tested to 1150 psig.

Preventive maintenance is performed on Compressor #3 on a yearly basis. All shutdown devices, with the exception of the high temperature shutdown devices, are usually checked every two months.

B. Compressor #2

The shutdown systems for this compressor are similar to those for Compressor #3, except that the compressor is designed to shut down on high discharge pressure at 225 psig or a high 3rd stage cylinder temperature of 350°F.

Various Pacemaker lubricating agents were used in both the cylinders and crankcase of the compressor until about mid-1976, when the unit was involved in a fire and the cylinder's lubricant was changed to Anderol 500. The crankcase of this compressor continues to use Pacemaker 900 lubricating oil.

On the day prior to the explosion, Compressor #2 was discharging at a rate of 5,000 MCF of air per day at a discharge pressure of 160 psig and a temperature of 230°F. During the investigation, it was revealed that Compressor #2 had shut down on high liquid level in the suction bottle above the 2nd stage cylinder, at about 9:00 a.m. on the day of the explosion. It was restarted at 9:45 a.m. or just 20 to 25 minutes prior to the explosion. After the explosion, it was determined that Compressor #2 shut down upon detecting a high discharge pressure within the air piping system.

Damage sustained by this unit was minimal, although some of the 3rd stage cylinder's discharge valves were found covered with a gray powdery ash.

Approximately 120 feet downstream of the third stage cylinder of Compressor #2, a 4-inch weld cap on the end of a tee ruptured during the explosion. This was probably caused by liquids trapped in a segment of the weld cap.

C. Compressor #1

Compressor #1 was not operating at the time of the explosion and is normally used only as a spare. Pacemaker 150 is used to lubricate the compressor's cylinders and Pacemaker 900 is used within the unit's crankcase. This compressor sustained no damage due to the explosion.

D. Piping

A plot depicting damages to the compressed air piping network is found on Figure 19. Compressed air, which is delivered to the injection wells through a piping network containing pipes ranging

in size from 4 inch to 8 inch, is metered through 3 inch or 4 inch meter runs before being injected into the Nacatoch producing zone. Most piping is at least Schedule 40, which should be suitable for the normal operating conditions at the fireflood.

ANALYSIS OF EXPLOSION

By analyzing the damages caused by the explosion, it was determined that the failure of the various pieces of equipment could not have been accomplished by a simple overpressure in one section of the piping. Therefore, it must be assumed that an explosion of combustible vapors occurred at some point in the piping network and a detonation was propagated throughout the remaining piping.

Fires and explosions can only occur when both a fuel and oxygen are mixed in the proper proportions in the presence of an ignition source possessing sufficient energy to ignite the combustible vapors. The fuel consumed during the explosion must have been provided by the lubricating agent used in the compressor's cylinders.

Oxygen for the combustion process was, of course, provided by the compressed air in the piping, which in its compressed state, possessed the characteristics of an oxygen enriched atmosphere.

The following sections will provide additional details concerning the potential fuel and ignition sources responsible for this explosion.

FUEL

Anderol 500 is a synthetic lubricant manufactured by Tenneco, and is used in the cylinders of Compressors #2 and #3.

It is a 500 SUS diester-based lubricant designed to provide high temperature and/or long term lubrication with minimal residue formation. It offers the advantages of lower volatility and flammability when compared to conventional mineral oil based lubricants. At room temperature, the flash point of Anderol 500 is 510°F and its auto-ignition temperature is 770°F. Although Anderol 500 is reportedly less flammable than equal viscosity mineral oils, Tenneco has refrained from classifying this lubricant as a fire-resistant fluid. Table 7 summarizes the physical properties of Anderol 500.

During normal operation of the air compressors, some synthetic lubricant is carried over into the air discharge line, probably as a suspended mist. This mist will not normally be within the flammable range of the lubricant, due to the large volumes of air present¹, and the oil droplets will tend to settle out on the interior surfaces of the discharge piping, causing an oil film to build up.

A characteristic of compressed air systems is that the auto-ignition temperatures of air/fuel mixtures is decreased as the air pressure increases.² This is due to the formation of an oxygen enriched atmosphere where the partial pressure of the oxygen exceeds 160 torr (millimeters of mercury). The auto-ignition temperature is reduced even further when the air stream contains rust particles, which act as a catalyst promoting the oxidation of the lubricant. Figure 20 shows the effects of increasing pressure on the auto-ignition temperature.

Whereas the auto-ignition temperature of Anderol 500 in air is 770°F at 0 psig, it drops to 615°F at 200 psig air pressure and to 550°F at 300 psig air pressure. Despite the substantial drop in the auto-ignition temperature of the synthetic lubricant, the normal temperature of the discharged compressed air is still substantially lower than the depressed auto-ignition temperature of the lubricant at 200 psig.

Therefore this explosion was most likely caused by an "oil film detonation" as demonstrated experimentally by Mr. R. Loison in 1952.³ His experiment demonstrated that a very thin layer of oil in a ten inch diameter pipe containing air at 100 psig could support a flame process similar to gaseous detonations. Mr. Loison suggested that the passage of a shock wave into a pipe caused heating and evaporation of the oil film to a degree sufficient to support combustion. The increase in volume produced by the combustion could then reinforce the shock waves and thereby cause the process to be self-sustaining.

A minimum thickness "t" in meters is required to produce an explosive mist in a pipe of diameter "D" meters and is determined by the equation

$$t = \frac{CDP}{4d}$$

where C = Constant = 138 gm/m³

P = Pressure in Atmospheres

d = Oil density in gm/m³

Given the variables of a pipe 8" in diameter at 200 psig, and an oil density for Anderol 500 of 59.3 pound per cubic foot, an oil thickness of about 4 thousandths of an inch (.004 inch) would be sufficient to support an oil film detonation in this piping. A thickness of 3 thousandths of an inch (.003 inch) would be required at the same operating conditions to produce an oil film detonation in a 6 inch pipe, and a 4 inch pipe would require only 2 thousandths (.002 inch) of an inch to support such a detonation.

Thicknesses in excess of this minimum amount will reportedly cause more violent explosions. Obviously, it is possible that such a small oil film thickness was present on the inner surface of the discharged air piping.

IGNITION SOURCE

It is unlikely that the auto-ignition temperature of the Anderol 500 lubricant was exceeded during normal operation of the compressors. Even if the discharge temperature was raised by some abnormal operating condition within the compressor, the high discharge temperature shutdown on the 3rd stage cylinders should have shut down the compressor at 350°F, still well below the minimum auto-ignition temperature of the synthetic lubricant at 200 psig.

However, experiments conducted by the U. S. Bureau of Mines have indicated that the residues deposited by oxidized lubricating agents may self-heat to ignition at temperatures as low as 320°F.⁴

The Bureau of Mines experiments indicate that a "carbon-oxygen" complex is formed on carbon deposits in air compressors. The

formation of this complex, which also causes the spontaneous heating of coal, is exothermic in nature and is caused whenever oxygen unites with carbon. It is often followed by the formation of organic peroxides. It appears that the overall thermal effects produced by the formation of the "carbon-oxygen" complex may be represented as follows:

Below a minimum temperature of 300°F the complex is relatively stable and insufficient heat is produced to ignite the residue. The introduction of metallic oxides into the carbonaceous deposits, as well as contact with the bronze rings on the compressor pistons, has been determined to act as a catalyst in the oxidation of the lubricant.

Analysis of the residues used by the Bureau of Mines in their experiments revealed that compounds or elements were present in the following percentages by weight: Carbon: 49-54%; oxygen: 19-34% and iron (as ferric oxide): 6-30%.

Anderol 500, as a synthetic lubricant, produces minimal residue deposits. One source at Tenneco stated that the oil could be used for over 8,000 operating hours before the cylinder valves should be taken out for cleaning.

Over a period of 15 months it appears possible that enough carbonaceous residue was built up by the synthetic lubricant to provide a sufficient energy pool to ignite the oil film on the piping when the residue's auto-ignition temperature was exceeded.

Compressor #2 has used various Pacemaker lubricants in both the cylinders and compressor crankcase prior to switching to Anderol 500 in the cylinders in 1976. Although the compressor's cylinders were cleaned prior to the switch to Anderol 500 in 1976, all discharge air piping, which might contain accumulated carbonaceous residues, has not been cleaned since the project was initiated.

It is possible that enough quantities of carbonaceous residues were present to provide an energy pool sufficient to trigger an oil film detonation when the auto-ignition temperature of the residues was exceeded. It should be remembered that Compressor #2 discharges air at a higher temperature than Compressor #3, and this would reduce the temperature differential required to exceed the auto-ignition temperature of the residue.

EXPLOSION PROPAGATION MECHANISM

Although the serious damage sustained by Compressor #3 would seem to indicate that the explosion was initiated near this location, damages to the valve seat for the 8" main line check valve, and to the concrete support for the 3rd stage pulsation bottle at Compressor #3, indicate that the explosion occurred elsewhere. Since one characteristic of compressed air piping explosions is that they most frequently occur soon after a compressor is restarted, it seems probable that the explosion was initiated at Compressor #2. The following paragraphs detail one possible sequence of events to explain the initiation of the explosion at Compressor #2.

1. On the morning of the explosion, Compressor #2 shut down when the liquid level switch on the suction bottle of the 2nd stage

cylinder was activated. This was at approximately 9:00 A.M.

2. Once the compressor shut down, the jacket cooling water for the cylinder ceased to flow, permitting the temperature of the cylinder to rise for a short period of time. Prior to shutdown, the compressor had probably been discharging air at approximately 230°F.
3. Lubricant, still under pressure in the lubricating lines running to the cylinders, began to seep onto the piston until the oil line pressure was reduced. This lubricant leaked past the piston rings, and accumulated in the low spots of the cylinders or their discharge valves.
4. As the temperature of the 3rd stage cylinder rose, it may have exceeded the auto-ignition temperature of any carbonaceous residues deposited on the cylinder's discharge valves or piping.
5. Once its auto-ignition temperature was exceeded, the residues ignited, causing a smouldering fire.
6. At about 9:45 a.m., Compressor #2 was restarted. Lubricant which had been accumulating in the low spots of the cylinder and discharge valves began to be carried over in the air stream, in greater quantities than was normal for the compressor's operation. As the lubricant passed through the 3rd stage cylinder's discharge valves the air turbulence possibly transformed the liquid lubricant into a finely divided oil mist. This mist may have formed an air/fuel mixture which was within the flammable range for the lubricant.

7. Fanned by the swiftly moving oxygen enriched air flow, the smouldering fire in the carbonaceous residues over a 25-minute interval intensified and ignited the combustible air/fuel mixture downstream of the 3rd stage cylinder, causing a low order explosion and shock wave to be propagated. It is also possible that an air/fuel mixture within the flammable range was not produced until the compressor had been running for a period of time.
8. The shock wave produced from this minor explosion was sufficient to propagate a larger oil film detonation which then traveled throughout the air discharge piping system.

It seems plausible that an explosion caused by the above-mentioned mechanism would produce only minor damage to Compressor #2 since the oil film explosion's combustion wave must travel through some length of piping to build up sufficient force to rupture the pipe. It should also be remembered that a grey ash was found on the 3rd stage cylinder discharge valves at Compressor #2, indicating that the valves had been in a fire, or exposed to a heat wave.

PREVENTION OF FUTURE PROBLEMS

In order to prevent similar problems in the future, Cities' approach was to eliminate the fuel and environment for combustion. This will involve:

- (1) Periodic wash of the entire air distribution system with a 5% (by weight) solution of NaOH and NaNO_2 . Frequent checks of possible lubricant collection points will be made between washes.

- (2) A careful check for buildup of carbonaceous materials on discharge valves and cylinder will be included in the routine maintenance of all three compressors.
- (3) High temperature shutdown switches will be lowered to 300°F and discharge pressure kept at the minimum.
- (4) Compressor #1 cylinder lubricant will be changed from the current mineral oil type to Anderol 500.

RESEARCH SUPPORT

Cities Service Research Laboratory in Tulsa, Oklahoma, has provided information for topical reports covering ignition, combustion tube tests, pressure transient tests and, most recently, produced fluids analysis. These reports contained detailed information on these individual topics which were only briefly discussed in past annual reports.

RESERVOIR FLUID ANALYSIS

Produced oil, gas and water samples were collected eight times from 1976 to 1980 and analyzed to evaluate changes which each has undergone during the burn phase of the wet combustion process. As previously mentioned, these results have been detailed in a topical report, but the following trends were observed.

1. The oil produced during the fireflood was lighter compared to native oil. The viscosity decreased from native oil viscosity and the API Gravity increased slightly.
2. The sulfur content of the crude oil decreased during the early part of the fireflood and then increased. Native oil had 0.9 percent sulfur compared to 0.62 percent sulfur in May 1979 oil. The increase in the hydrogen sulfide in the produced gas shows that crude oil sulfur is being converted to hydrogen sulfide by the fireflood. Increased sulfate in produced waters

was found in 1980 indicating that part of the sulfur in oils has been converted to sulfate in water.

3. The crude oil acid number decreased from 5.1 in native oil to 2.9 in May 1979. The acid number decrease shows that there is no oxidation of the crude oil by air. Apparently, the heat passes ahead of the firefront to lower the crude oil viscosity with little or no oxidation. The lowering of the acid number is due to hydrothermolysis of sulfur and other components from the crude oil. The acid number in March, 1980, oils increased to 4.3 indicating that native oils that are relatively unchanged by the fireflood are produced late in the project. This acid number increase made the water in oil emulsion more difficult to break.
4. Comparison of oil viscosities with emulsified water to the viscosities after the water is removed shows that the emulsions have higher viscosities. The emulsions also have viscosity variations with shear rate (non-Newtonian behavior) compared to Newtonian viscosities of the oil without emulsified water.
5. The produced combustion gas was a mixture of nitrogen, carbon dioxide, carbon monoxide, oxygen, hydrogen sulfide and hydrocarbons. No ammonia or nitrogen oxides were found. The average carbon monoxide concentration varied from 0.34 to 0.61 percent. The low carbon

monoxide concentration indicates that any excess carbon monoxide initially formed further reacts to form carbon dioxide or methane.

6. The methane concentration increased during the wet combustion phase of the fireflood. There was no corresponding increase in other hydrocarbon gases. The lack of evidence of oil cracking indicates that the increased methane concentration was a result of the reduction of carbon monoxide.
7. The water salinity decreased throughout the project. Salinity changes were a result of injection of fresher water into producing wells to cool bottomhole equipment and from the evaporation and condensation of injected water passing through the heated zone.

FALLOFF TESTS

Pressure falloff tests were performed on the five injection wells on August 28-29, 1980, prior to the termination of air injection. Reservoir data used in these calculations and results are shown in Table 8. Conventional semi-log analysis technique (Miller-Dyes-Hutchinson) was used to determine formation flow capacity, formation permeability and wellbore skin factor. Permeabilities to air varied from 358 to 785 and wellbore skin factors from -0.3 to +7.6. A positive skin normally indicates wellbore damage.

A recent technical paper on "Interpretation of Injection Well Pressure Transient Data in Thermal Oil Recovery", by Eggenschwiller, Ramey, Satman and Cinco-Ley⁽⁵⁾ presented a new method for determining burned volume from a pressure transient test of an injection well. Previously, the determination of burned volume, from pressure transient data relied upon radius of investigation calculations⁽⁶⁾ or computer history matching of the pressure data⁽⁷⁾. This new technique employs a material balance to determine the burn volume. An attempt was made to analyze the above noted falloff test data using the Eggenschwiller-Ramey-Satman-Cinco-Ley method. Problems were encountered because in the wet combustion process used, the pore volume in the burned zone is partially resaturated by injected water. This new method allows for calculation of the air volume in the burned area, but since it is not known what fraction of the pore space is water filled, the total burned volume cannot accurately be determined. Other applications of this method may be found in dry combustion projects.

EVALUATION WELL PROGRAM

The Evaluation Well Drilling Program was conducted to determine the volumetric sweep effect of the wet combustion process and investigate the effects of structure and reservoir heterogeneties upon the process.

Pattern 15 was selected as a model pattern. Total pattern productive volume of 158.7 acre-feet had been processed by 1.904 MMCF of air and 520M barrels of water through December 1980. Four wells were drilled at the locations shown in Figure 21, in order to describe the areal and vertical coverage of the combustion process. All four wells were logged open hole with dual induction, compensated neutron, formation density and gamma ray logs plus a new tool, Schlumberger's electromagnetic propagation tool⁽⁸⁾ which was designed to indicate the residual hydrocarbon saturations without knowledge of the formation water resistivity, which is relatively difficult to determine in the combustion process.

Well #15-10 was drilled to a depth of 476'. Conventional cores were attempted, but of the 52' cut only 22' were recovered, mostly in hard, tight streaks. The core was analyzed by CORE Laboratories and the analysis is provided in Table 9. Results of the open hole logging program are shown in Figure 22. Maximum BHT recorded while logging this well was only 110°F. Well #15-11 was drilled next, to a total depth of 474'. Rubber sleeve cores were cut and full recovery of the 52 feet pay interval was achieved. Sidewall core samples were also taken to compare with values obtained

from the full rubber sleeve core. Location Sample Service, Inc., provided the analysis of the sidewall cores. The comparative values for rubber sleeve and sidewall coring are displayed in Tables 10 and 11. Results of the open hole logs are shown in Figure 23. The maximum recorded BHT during logging was only 102°F.

Both 15-10 and 15-11 were located north of the injector 15-1, and were both structurally low to the injector. The third well drilled was #15-13 which was structurally high to 15-1 by 20 feet. Total depth was 464 feet. Forty-five sidewall cores were shot and 42 were recovered. Analysis of these samples is shown in Table 12. Results of the logging program are depicted in Figure 24. In this well, a maximum temperature of 220°F was recorded. Well 15-12 was the last evaluation well drilled. This well was located only 50 feet from 15-1. Total depth drilled was 470'. A rubber sleeve core was obtained covering 60' of the pay interval. The analysis is shown in Table 13 while results of the logging program are shown in Figure 25. Maximum BHT recorded was only 110°F.

The data obtained from these evaluation wells are being further analyzed by Cities Service Research and Engineering personnel. Clay alteration as a result of exposure to high temperatures is one area being investigated to aid in determining the actual coverage of the combustion front as it passed these wells. Final results and ultimate conclusions from this program will probably not be available for some time, but will be fully reported in the final project report. Several obvious conclusions have been reached and are discussed below.

1. The electromagnetic propagation tool was not helpful in determining the residual oil saturations at the four well locations in this case. Wellbore roughness and geometry influences were severe as was drilling fluid invasion in this highly unconsolidated formation.
2. Analysis of data obtained from sidewall and rubber sleeve core samples showed good general agreement. The variations in porosity and saturations may be partly attributed to compaction and flushing differences in obtaining the sample as well as slight differences in methods of saturation determination by the two companies. Log and core saturation show varying degrees of difference, resulting from invasion, difficulty in ascertaining values for formation water resistivity, gas effects and core flushing. A comparison of log and cores saturation values is shown in Figure 26.
3. A comparison of native condition resistivity logs and logs obtained following combustion indicates a significant reduction in oil saturation over much of the producing interval. Figures 27 through 30 depict the reduced oil saturations observed in pattern 15.
4. All available data indicates that the entire interval from caprock to the base of the zone is processed by combustion to a distance of at least 50 from the injector, as observed in well #15-12, but that gravity segregation

and permeability variations cause the combustion front to migrate upwards within 100 feet of the injector, as shown in wells #15-10, 15-11 and 15-13.

5. Formation structure within the pattern plays a much more significant role than previously suspected, causing a variation in the in situ combustion process with direction from the injector. Processes ranging from dry to partially or even fully quenched combustion may exist simultaneously within the pattern, depending upon the structural style, timing, and rates of water and air injection.

PROJECT ECONOMICS

The Cities Service-DOE cost sharing agreement provides for an estimated \$8,229,898 expenditure over the six year life of the demonstration project. Cumulative expenditures through February 1981 have been \$8,613,230, Figure 31. The DOE portion of these expenses has been \$2,897,937 with Cities Service providing the remaining funds.

PROJECT INVESTMENTS

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

Cumulative investment expenditures through February 1981 have been \$1,661,462. Of this total, the Department of Energy contributed \$662,591 or 40%. Project investments are summarized in Table 14.

OPERATING EXPENSES

The remaining \$6,951,768 which has been spent to date is summarized in Table 15. These are expenses incurred in routine operation of the project, maintenance of wells and facilities, research and production services, taxes and overhead expenses. These expenditures are compared on a cost per barrel basis in Table 16. To provide a better understanding of the drastic impact of the crude oil decontrol tax on project economics, a comparison has been included of operating cost before this tax (through March 1980) and since that time (April 1980 - February 1981) in Tables 17 and 18.

Operating costs increased from \$11.52/barrel before decontrol tax to \$34.60/barrel afterwards. Direct lease operation and maintenance expenses have been further broken down in Table 19 and shown on a cost per barrel basis. Of the categories included, 65% of the total is attributed to utilities and well service.

APPENDIX A

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
Dip Angle	4.5°

TABLE 3
AIR TERMINATION SCHEDULE

<u>WELL</u>	<u>DATE AIR INJECTION TERMINATED</u>
12-1	April 10, 1981
13-1	March 2, 1981
14-1	February 9, 1981
15-1	October 1, 1980
16-1	November 3, 1980

TABLE 4

CUMULATIVE INJECTION SUMMARY

<u>PATTERN</u>	<u>INJECTION</u>		<u>RATIO</u>
	<u>MCF</u>	<u>BBLS</u>	<u>BBLS/MMCF</u>
12	1,954,275	618,617	316
13	2,057,349	320,964	156
14*	2,042,579	377,158	185
15*	1,904,564	452,842	238
16*	1,861,261	462,250	248

TABLE 5

ESTIMATED BURNED VOLUMES

<u>PATTERN</u>	<u>NET AF</u>	<u>BURNED AF**</u>
12	237	162.9
13	225	171.4
14	212	170.2
15	178	158.7
16	187	155.1

* Cumulative volumes until termination of air injection. See Table 3.

** Note: Assumes Wet Combustion Air Requirement of 12 MMSCF/Acre-Foot

TABLE 6

SUMMARY OF WELL REMEDIAL WORK

<u>WELL</u>	<u>NO. JOBS</u>	<u>MONTH/YEAR</u>
2-4	1	October 1978
2-5	1	June 1979
12-2	4	April 1977; April 1978; May 1978; July 1978
12-3	4	April 1978; July 1978; May 1979; March 1980
12-4	4	March 1978; May 1978; May 1979; March 1980
13-2	5	July 1977; October 1977; January 1978; June 1978; June 1980
13-3	2	September 1978; November 1979
13-4	17	March 1978; April 1978; July 1978; September 1978; January 1979; April 1979; May 1979; June 1979; September 1979; October 1979; March 1980; April 1980; May 1980; June 1980; July 1980; August 1980; November 1980
13-5	4	April 1979; September 1979; November 1979; January 1980
13-6	9	August 1977; February 1978; April 1978; August 1979; September 1979; March 1980; April 1980; August 1980; September 1980
13-8	1	August 1979
13-9	1	May 1979
14-2	4	September 1977; September 1977; December 1977; January 1978
14-3	4	December 1977; March 1978; September 1978; November 1978
14-4	4	June 1979; July 1979; May 1980; June 1980;
14-6	4	June 1978; November 1978; October 1979; March 1980
14-8	2	May 1979; July 1979
15-1	1	December 1980
15-2	6	February 1977; April 1977; April 1977; August 1977; April 1978; July 1978
15-3	6	February 1978; June 1978; July 1978; August 1978; November 1978
15-4	8	April 1978; June 1978; May 1978; November 1979; January 1980; March 1980; April 1980; June 1980
15-6	4	May 1979; March 1980; April 1980; September 1980
15-8	1	May 1979
15-9	4	December 1979; June 1980; July 1980; October 1980
16-1	1	December 1980
16-2	6	February 1978; March 1978; August 1978; October 1978; November 1978; July 1980
16-3	1	October 1978
16-4	7	December 1978; May 1979; March 1980; May 1980; July 1980; January 1981
16-6	3	May 1978; July 1978; July 1979

TABLE 6
SUMMARY OF WELL REMEDIAL WORK

Page 2

<u>WELL</u>	<u>NO. JOBS</u>	<u>MONTH/YEAR</u>
16-8	3	December 1979; June 1980; March 1980
16-9	1	June 1980
	<hr/>	
TOTAL	123	CEMENT SQUEEZE REPAIRS

Wells not squeezed as of February 1981: 2-3; 2-8; 12-5; 12-6; 12-8;
12-9; 14-5; 15-5; 16-5

TABLE 7

PROPERTIES OF ANDEROL 500
SYNTHETIC RECIPROCATING COMPRESSOR OIL

Anderol 500[®] is a 500 SUS diester-based lubricant designed to provide high temperature and/or long term lubrication with minimal deposit formation. It offers lower volatility and flammability than conventional mineral oils.

TYPICAL PROPERTIES

Optimum Operating Range, °F (°C)		0 to 450 (-18 to 23)
Viscosity @100°F, (38°C) cSt	ASTM D445	106 (491 SUS)
Viscosity @210°F, (99°C), cSt	ASTM D445	9.3 (57.8 SUS)
Viscosity @ 0°F, (-17.8°C) cSt	ASTM D445	20,000
Viscosity Index	ASTM D2270	61
Pour Point, °F (°C)	ASTM D97	-30 (-34)
Flash Point, °F (°C)	ASTM D92	510 (266)
Autoignition Temperature, °F (°C)	ASTM D2155	770 (410)
Specific Gravity, 77°F (25°C)	ASTM D1298	0.95
Evaporation, 22 hours @ 210°F (99°C), %	ASTM D972	0.4
Demulsibility @ 130°F (54°C) ml oil/ ml water/ml emulsion (minutes)	ASTM D1401	39/38/3 (60)
Four-Ball Wear, 1200 rpm, 167°F (75°C), 40 kg, hr., mm	ASTM D2266	0.8
Four-Ball EP, Weld Point, kg	ASTM D2783	100

TABLE 8
POST-BURN FALLOFF TEST
RESERVOIR DATA AND RESULTS

	<u>12-1</u>	<u>13-1</u>	<u>14-1</u>	<u>15-1</u>	<u>16-1</u>
<u>Reservoir Data</u>					
h (ft)	64	61	56	47	44
ϕ (fraction)	.32	.33	.33	.32	.33
$\bar{T}$ ($^{\circ}\text{F}$)	350	450	375	400	375
P_{wf} (psig)	118	115	118	140	107
q_{inj} (MMCFD)	1.386	1.058	1.030	1.050	0.935
μ (cp)	.0248	.0269	.0253	.0285	.0253
B (RB/STB)	.420	.322	.262	.270	.249
c_g (psi^{-1})	.0167	.0125	.0111	.0111	.0105
r_w (ft)	.3	.3	.3	.3	.3
<u>Test Results</u>					
Formation Capacity (md-ft)	47132	22226	22804	36905	15735
Permeability (md)	736	364	407	785	358
Skin Factor	5.1	1.5	0.9	7.6	-.3

TABLE 9

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
Dallas, Texas

(Page 1 of 2)

CITIES SERVICE COMPANY
NO. B-15-10 BODCAU
BELLEVUE FIELD
BOSSIER PARISH, LA

FORMATION : NACATOKH
DRLG. FLUID: WATER BASE MUD

CONVENTIONAL CORE ANALYSIS

SMP NO	DEPTH	PERM MD HORZ (KA)	POR %	OIL% PORE	WTR% PORE	DESCRIPTION
	381.0-385.0	CORE NO. 1	CUT 4 FT.	REC. 4 FT.		
1	381.0- 82.0	<0.01	18.5	30.8	59.0	LS FOS SHY G ODR GLD FLU
2	382.0- 83.0	28.	31.9	39.2	43.0	SD VF-FG SSLTY SHY G ODR GLD FLU
3	383.0- 84.0	44.	34.8	36.1	44.2	SD VFG SSHY CLN G ODR GLD FLU
4	384.0- 85.0	21.	27.2	38.5	50.0	SD VFG SSHY CLN G ODR GLD FLU
	385.0-397.0	CORE NO. 2	CUT 12 FT.	REC. 4 FT.		
5	385.0- 86.0	2.83	31.4	27.0	52.1	SD VFG SSLTY CLN G ODR GLD FLU
6	386.0- 87.0	<0.01	10.4	28.9	36.2	LS XLN V/FOS VUG G ODR GLD FLU
7	387.0- 88.0	<0.01	11.7	27.1	41.6	LS XLN V/FOS VUG G ODR GLD FLU
8	388.0- 89.0	<0.01	17.8	34.6	50.6	SD VFG SLTY SSHY V/LMY G ODR GLD FLU
	389.0- 97.0					LOST CORE
	397.0-408.0	CORE NO. 3	CUT 11 FT.	REC. 9 FT.		
9	397.0- 98.0	<0.01	7.8	52.9	26.4	LS XLN FOS SDY ASPH G ODR GLD FLU
10	398.0- 99.0	0.93	21.2	32.1	46.1	SD BLK VFG S/VUG V/ASPH G ODR N FLU
11	399.0- 00.0	274.	32.6	31.0	49.6	SD BLK VFG V/ASPH G ODR N FLU
12	400.0- 01.0	81.	27.8	26.2	58.4	SD RED VFG SLTY G ODR N FLU
13	401.0- 02.0	94.	36.3	0.3	78.8	SD GRY VFG SSLTY CLN N FLU N FLU
14	402.0- 03.0	102.	34.6	0.4	80.8	SD BRN VFG SSLTY CLN N ODR N FLU
15	403.0- 04.0	136.	36.1	2.7	79.4	SD BRN VFG SSLTY CLN N ODR N FLU
16	404.0- 05.0	147.	24.7	8.9	66.0	SD BRN VFG SSLTY S/ASPH N ODR N FLU
17	405.0- 06.0	<0.01	16.5	28.9	49.1	LS XLN FOS SDY/LAM N ODR SPT FLU
	406.0- 08.0					LOST CORE

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
Dallas, Texas

(Page 2 of 2)

CITIES SERVICE COMPANY
NO. B-15-10 BODCAU

CONVENTIONAL CORE ANALYSIS

<u>SMP NO</u>	<u>DEPTH</u>	<u>PERM MD HORZ (KA)</u>	<u>POR %</u>	<u>OIL% PORE</u>	<u>WIR% PORE</u>	<u>DESCRIPTION</u>
	408.0-433.0	CORE NO. 4	CUT 25 FT.	REC. 4 FT.		
18	408.0- 09.0	0.16	18.7	25.4	54.6	LS XLN FOS VUG SDY G ODR GLD FLU
19	409.0- 10.0	<0.01	19.2	30.1	57.8	LS XLN FOS VUG SSDY G ODR GLD FLU
20	410.0- 11.0	0.30	27.6	23.7	65.7	SD VFG SSLTY CLN G ODR GLD FLU
21	411.0- 12.0	<0.01	20.9	27.7	60.9	LS XLN FOS SDY G ODR GLD FLU
	412.0- 33.0					LOST CORE

TABLE 10

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
Dallas, Texas

(Page 1 of 3)

CITIES SERVICE COMPANY
NO. 15-11 BODCAU
BELLEVUE FIELD
BOSSIER PARISH, LOUISIANA

FORMATION : NACATOKH
DRLG. FLUID: WATER BASE MUD

CONVENTIONAL CORE ANALYSIS

SMP NO	DEPTH	PERM MD HORZ (KA)	POR %	OIL% PORE	WTR% PORE	DESCRIPTION
	374.0-385.5	CORE NO. 1	CUT 11.5 FT	REC 11.5 FT		
1	374.0- 75.0	<0.01	13.6	36.6	44.0	LS XLN FOS SDY G ODR GLD FLU
2	375.0- 76.0	0.21	19.0	29.6	49.4	SD VF-FG ASHY LS/LAM G ODR SPT GLD FLU
3	376.0- 77.0	554.	23.6	58.2	30.1	SD VF-FG ASHY G ODR GLD FLU
4	377.0- 78.0	137.	32.8	41.9	37.0	SD VF-FG ASHY G ODR GLD FLU
5	378.0- 79.0	32.	21.4	39.9	42.0	SD VF-FG ASHY LS/LAM G ODR GLD FLU
6	379.0- 80.0	692.	21.1	29.6	35.9	SD VF-FG ASHY LS/LAM G ODR SPT FLU
7	380.0- 81.0	880.	34.1	37.9	35.5	SD VF-FG S/ASHY S/LMY G ODR GLD FLU
8	381.0- 82.0	815.	25.8	46.7	30.0	SD VF-FG S/ASHY S/LMY G ODR GLD FLU
9	382.0- 83.0	649.	36.3	36.0	39.3	SD VF-FG SSHY S/LMY G ODR GLD FLU
10	383.0- 84.0	1033.	30.4	35.2	35.2	SD VF-FG SSHY S/LMY G ODR GLD FLU
11	384.0- 85.0	26.	26.9	25.3	47.4	SD VFG SHY S/LMY FT ODR DUL GLD FLU
12	385.0- 85.5	2407.	33.8	30.3	48.5	SD VFG SHY FOS LS/LAM FT ODR DUL FLU
	385.5-405.5	CORE NO. 2	CUT 20 FT	REC 20 FT		
13	385.5- 86.5	2214.	37.7	23.6	38.4	SD FG CLN G ODR GLD FLU
14	386.5- 87.5	1570.	35.8	29.4	43.5	SD FG CLN G ODR GLD FLU
15	387.5- 88.5	1543.	38.9	31.7	36.6	SD FG S/ASHY G ODR DUL GLD FLU
16	388.5- 89.5	1930.	39.8	38.1	27.9	SD FG S/ASHY G ODR DUL GLD FLU
17	389.5- 90.5	1697.	34.4	35.8	23.5	SD VFG S/ASHY G ODR DUL GLD FLU
18	390.5- 91.5	607.	33.9	24.1	40.1	SD VFG SHY G ODR DUL GLD FLU
19	391.5- 92.5	567.	37.9	34.4	35.4	SD VFG SHY G ODR DUL GLD FLU
20	392.5- 93.5	454.	32.9	30.6	39.2	SD VFG SHY G ODR DUL GLD FLU
21	393.5- 94.5	1822.	32.9	40.9	42.1	SD VFG SHY G ODR STK GLD FLU
22	394.5- 95.5	0.08	16.4	28.5	48.5	SD VFG SHY FT ODR STK GLD FLU

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
Dallas, Texas

(Page 2 of 3)

CITIES SERVICE COMPANY
NO. 15-11 BODCAU

CONVENTIONAL CORE ANALYSIS

SMP NO	DEPTH	PERM MD HORZ (KA)	POR %	OIL% PORE	WTR% PORE	DESCRIPTION
23	395.5- 96.5	401.	20.1	5.5	46.6	SD VFG SHY V/LMY FT ODR DUL FLU
24	396.5- 97.5	1905.	36.7	21.0	41.9	SD VFG V/LMY FT ODR DUL GLD FLU
25	397.5- 98.5	(1)	25.8	4.0	48.5	SD VFG VSLTY V/LMY FT ODR STK FLU
26	398.5- 99.5	2037.	36.5	5.2	60.6	SD VFG SSLTY FT ODR SPT GLD FLU
27	399.5- 00.5	1950.	35.4	1.7	79.1	SD VFG SSLTY N ODR N FLU
28	400.5- 01.5	728.	36.7	15.6	52.1	SD VFG SSLTY FT ODR DUL GLD FLU
29	401.5- 02.5	1257.	36.5	2.7	81.2	SD VFG SSLTY N ODR N FLU
30	402.5- 03.5	617.	37.3	11.7	67.7	SD VFG SSLTY FT ODR DUL FLU
31	403.5- 04.5	25.	36.8	10.8	69.2	SD VFG SSLTY N ODR N FLU
32	404.5- 05.5	1127.	32.7	36.3	43.8	SD VFG SSLTY G ODR GLD FLU
	405.5-425.0	CORE NO. 3	CUT 20 FT	REC 19.5 FT		
33	405.5- 06.5	385.	24.9	24.8	58.5	SD VFG SLTY V/LMY N ODR N FLU
34	406.5- 07.5	357.	21.5	23.5	54.6	SD VFG SLTY V/LMY G ODR DUL GLD FLU
35	407.5- 08.5	1077.	33.4	16.6	66.4	SD VFG LMY N ODR N FLU
36	408.5- 09.5	197.	15.7	15.3	67.2	SD VFG SLTY V/LMY G ODR SPT GLD FLU
37	409.5- 10.5	915.	36.8	36.8	43.3	SD VFG SLTY V/LMY G ODR SPT GLD FLU
38	410.5- 11.5	1676.	39.3	44.1	34.3	SD VFG SLTY V/LMY G ODR DUL GLD FLU
39	411.5- 12.5	1822.	41.3	49.9	35.1	SD VFG SLTY V/LMY G ODR DUL GLD FLU
40	412.5- 13.5	1498.	37.8	46.1	41.9	SD VFG SLTY V/LMY G ODR DUL GLD FLU
41	413.5- 14.5	498.	36.1	48.4	42.8	SD VFG SLTY V/LMY G ODR DUL GLD FLU
42	414.5- 15.5	1548.	35.0	48.9	44.3	SD VFG SLTY V/LMY G ODR DUL GLD FLU
43	415.5- 16.5	3105.	31.2	29.1	52.9	SD VFG SLTY V/LMY G ODR DUL GLD FLU
44	416.5- 17.5	1808.	28.4	37.1	44.5	SD VFG SLTY V/LMY G ODR DUL GLD FLU
45	417.5- 18.5	621.	40.7	26.5	26.5	SD VFG SLTY V/LMY G ODR DUL GLD FLU
46	418.5- 19.5	133.	36.2	37.0	32.7	SD VFG SLTY V/LMY G ODR DUL GLD FLU
47	419.5- 20.5	1841.	39.2	28.1	35.6	SD VFG SLTY V/LMY G ODR DUL GLD FLU
48	420.5- 21.5	95.	39.9	52.4	28.6	SD VFG SLTY V/LMY G ODR DUL GLD FLU
49	421.5- 22.5	96.	37.9	46.0	30.0	SD VFG SLTY V/LMY G ODR DUL GLD FLU

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
Dallas, Texas

(Page 3 of 3)

CITIES SERVICE COMPANY
No. 15-11 BODCAU

CONVENTIONAL CORE ANALYSIS

<u>SMP NO</u>	<u>DEPTH</u>	<u>PERM MD HORZ (KA)</u>	<u>POR %</u>	<u>OIL% PORE</u>	<u>WTR% PORE</u>	<u>DESCRIPTION</u>
50	422.5- 23.5	1118.	35.2	38.6	45.4	SD VFG SLTY V/LMY G ODR DUL GLD FLU
51	423.5- 24.5	494.	38.6	43.1	41.0	SD VFG SLTY V/LMY G ODR DUL GLD FLU
52	424.5- 25.0	40.	37.9	48.2	36.7	SD VFG SLTY V/LMY G ODR DUL GLD FLU

(1) UNCONSOLIDATED SAMPLE - NO PERMEABILITY MEASUREMENT POSSIBLE
GRAVITY OF RETORTED OIL: 23.0 API

Table 11
LOCATION SAMPLE SERVICE, INC.

SIDEWALL CORE ANALYSIS REPORT

(Page 1 of 3)

BODCAU FEE B 15-11

Depth Feet	Permeability Milidarcys, Horizontal	Porosity Percent	Residual Liquid Saturations % of Pore Space	
			Oil	Total Water
373	117.0	26.5	15.6	76.5
374	38.6	21.2	20.0	71.0
375	41.9	25.8	19.8	68.8
378	333.0	31.5	21.6	75.2
379	145.0	27.9	21.4	70.0
380	12.8	15.4	16.5	80.5
381	89.0	26.9	22.2	74.6
382	288.0	30.7	18.8	69.4
383	402.0	31.5	25.4	73.4
384	18.6	18.9	27.1	70.0
385	571.0	32.9	18.4	74.5
386	810.0	35.4	20.5	76.1
387	974.0	34.2	22.7	73.5
388	382.0	31.7	28.4	68.7
389	251.0	30.0	25.6	70.3
390	163.0	29.9	19.1	77.7
391	412.0	32.6	22.4	73.2
392	148.0	27.5	24.8	65.2
393	156.0	27.0	15.2	54.4
394	40.6	15.6	TR	82.3
395	TR	9.0	1.6	58.5
396	4.1	11.8	0	85.8
397	851.0	30.4	TR	72.4
398	782.0	33.5	0	85.9
399	980.0	34.0	0	86.6
400	SAMPLE TOO CRUMBLD FOR ANALYSIS			
401	381.0	28.6	0	80.4
403	1036.0	35.1	10.1	78.8
404	210.0	28.6	15.8	69.0
405	27.4	16.7	8.3	61.5
406	3.8	12.1	TR	72.6
407	52.2	19.7	3.7	84.4
408	124.0	27.5	.5	86.8
409	339.0	30.2	18.0	78.1
410	183.0	25.0	22.2	62.5
411	360.0	29.1	28.4	58.2
412	503.0	34.0	29.1	62.8
413	367.0	35.3	22.4	60.0
414	61.7	27.3	25.0	71.9
415	879.0	34.0	21.2	74.4

LOCATION SAMPLE SERVICE, INC.
 SIDEWALL CORE RECORD
 BODCAU FEE B 15-11

(Page 2 of 3)

<u>Depth</u>	<u>Description of Recovery</u>
373	SAND, BRN, VF-FG, FAIR P&P, SILTY, SLI CALC, EVEN BRN OIL STAIN, GOLD FLUO, MILKY YELL CUT
374	SAND, LT GRY TO BRN, VF-FG, POOR TO FAIR P&P, SILTY, MOD CALC, SCATTERED SMALL FOSS W/LARGE LT GRY LIME CONCRETIONS, IRREG BRN OIL STAIN, DULL GOLD FLUO, MILKY YELL CUT
375	SAND, LT GRY TO BRN, FG, POOR P&P, SILTY, VERY LIMEY, NUMS FOSS, IRREG BRN OIL STAIN, DULL GOLD FLUO, MILKY YELL CUT
376	NO RECOVERY
378	SAND, BRN, FG, FAIR P&P, SILTY, NUMS SMALL FOSSIL, EVEN BRN OIL STAIN, DULL FLUO, MILKY YELL CUT
379	SAND, AS ABOVE
380	SAND, LT GRY TO BRN, FG, POOR P&P, MOD CALC, FOSSIL, IRREG BRN OIL STAIN, DULL GOLD FLUO, MILKY YELL CUT, 2/3 OF SAMPLE IS LIME, LT GRY, FNLY XLN TO FOSSIL, TITE, NO SHOW
381	SAND, GRY TO BRN, FG, POOR TO FAIR P&P, SILTY, MOD ARGIL, SCAT BRN OIL STAIN, DULL GOLD FLUO, MILKY YELL CUT
382	SAND, AS ABOVE
383	SAND, BRN, VF-FG, FAIR TO GOOD P&P, SILTY, SLI CALC, EVEN BRN OIL STAIN, DULL GOLD FLUO, MILKY YELL CUT
384	SAND, LT GRY TO BRN, FG, POOR P&P, MOD TO VERY CALC, SILTY, SLI GLAUC, IRREG BRN OIL STAIN, GOLD FLUO, MILKY YELL CUT
385	SAND, BRN, FG, FAIR TO GOOD P&P, SILTY, SLI ARGIL, EVEN BRN OIL STAIN, VERY DULL GOLD FLUO, MILKY YELL CUT
386	SAND, LT BRN, FG, FAIR TO GOOD P&P, BRN OIL STAIN, DULL BRONZE FLUO, MILKY YELL CUT
387	SAND, AS ABOVE
388	SAND, AS ABOVE
389	SAND, LT BRN, FG, FAIR TO GOOD P&P, SILTY, SLI ARGIL, GOLD FLUO, MILKY YELL CUT
390	SAND, GRY TO BRN, VF-FG, FAIR P&P, SILTY, ARGIL, BRN OIL STAIN, DULL GOLD FLUO, MILKY YELL CUT
391	SAND, AS ABOVE
392	SAND, AS ABOVE
393	SAND, DR BRN FG, POOR TO FAIR P&P, SILTY, HEAVY DK BRN OIL STAIN, VERY DULL BRONZE FLUO, MILKY YELL CUT
394	LIME, LT GRY TO GRY, POOR P&P, MOD SANDY, FOSSIL, SCAT VUGS, NO FLUO, FNT MILKY YELL CUT
395	LIME, AS ABOVE, W/PALE BLUE FLUO, MILKY YELL CUT
396	SAND, LT GRY TO GRY, F-MG, POOR P&P, VERY CALC, FOSSIL, NO SHOW
397	SAND, GRY TO BRN, FG, FAIR P&P, SILTY, SLI ARGIL, OCCAS THICK GRY SHALE LAM, NO FLUO, FNT MILKY YELL CUT
398	SAND, REDDISH BRN FG, FAIR P&P, SILTY, SLI ARGIL, NO SHOW
399	SAND, AS ABOVE
400	SAND, AS ABOVE
401	SAND, LT REDDISH BRN, FG, FAIR TO GOOD P&P, SILTY, SLI ARGIL NO SHOW
402	NO RECOVERY

LOCATION SAMPLE SERVICE, INC.
SIDEWALL CORE RECORD
BODCAU FEE B 15-11

(Page 3 of 3)

<u>Depth</u>	<u>Description</u>
403	SAND, BRN FG, FAIR TO GOOD P&P, SILTY, BRN STAIN, DULL BRONZE FLUO, MILKY YELL CUT
404	SAND, AS ABOVE
405	SAND, GRY TO BRN, VF-FG, POOR P&P, SLI TO VERY CALC, IRREG STAIN, DULL BRONZE FLUO, MILKY YELL CUT
406	SAND, REDDISH BRN TO GRY, FG, POOR P&P, MOD TO VRY CALC, VRY DULL BRONZE FLUO, MILKY YELL CUT
407	SAND, BRN, FG, FAIR P&P, SILTY, POOR P&P, SLI TO MOD CALC, HEAVY BRN RESID STAIN, NO FLUO, MILKY YELL CUT
408	SAND, AS ABOVE
409	SAND, BRN, FG, FAIR TO GOOD P&P, SILTY, HEAVY DRK BRN OIL STAIN, DULL BRONZE FLUO, MILKY YELL CUT
410	SAND, AS ABOVE, W/OCCAS LARGE SANDY LIME CONCRETIONS W/NO SHOW
411	SAND, BRN, FG, GOOD P&P, HEAVY DRK BRN OIL STAIN, GOLD FLUO, MILKY YELL CUT
412	SAND, AS ABOVE
413	SAND, AS ABOVE
414	SAND, BRN, FG, FAIR TO GOOD P&P, SILTY, EVEN BRN OIL STAIN, GOLD FLUO, MILKY YELL CUT
415	SAND, AS ABOVE

TABLE 12

LOCATION SAMPLE SERVICE, INC.

SIDEWALL CORE ANALYSIS REPORT

(Page 1 of 4)

BODCAU FEE "B" 15-13

DEPTH FEET	PERMEABILITY MILIDARCYS, HORIZONTAL	POROSITY PERCENT	RESIDUAL LIQUID SATURATIONS % OF PORE SPACE	
			OIL	TOTAL WATER
352	SHALE			
354	13.6	22.5	38.1	60.2
356	10.5	23.8	32.5	55.4
358	SAMPLE TOO SMALL FOR ANALYSIS			
362	1.9	14.0	8.7	71.8
364	17.1	24.5	15.6	75.7
366	25.5	27.0	20.2	72.9
368	TR	9.4	TR	66.3
370	81.4	33.6	2.5	71.4
372	141.0	35.0	1.0	85.8
374	5.2	25.5	TR	88.0
376	55.0	26.7	TR	82.1
378	40.0	30.3	0	91.4
380	135.0	30.5	0	88.3
382	121.0	33.0	0	82.9
384	212.0	31.4	0	88.0
386	250.0	34.7	TR	80.7
388	SAMPLE TOO CRUMBLED FOR ANALYSIS			
392	TR	15.8	16.4	75.5
394	64.0	27.0	31.5	60.0
396	180.0	30.2	29.0	55.4
398	10.9	25.9	25.1	60.9
400	952.0	36.7	32.4	54.5
402	800.0	34.1	20.0	75.9
404	712.0	32.4	20.0	75.9
406	830.0	33.8	25.0	61.4
408	400.0	34.3	22.6	68.8
410	451.0	26.6	28.2	70.0
412	432.0	33.9	25.6	68.4
414	510.0	35.5	28.7	71.6
416	401.0	34.0	22.4	64.4
418	984.0	35.4	20.1	63.0
420	500.0	34.3	31.2	60.9
422	485.0	33.7	29.8	58.5
424	300.0	33.4	18.4	75.6
426	372.0	33.8	17.6	71.9
428	284.0	33.1	15.0	75.3
432	134.0	31.5	22.4	60.8

TABLE 12
LOCATION SAMPLE SERVICE, INC.
SIDEWALL CORE ANALYSIS REPORT
BODCAU FEE "B" 15-13

(Page 2 of 4)

<u>DEPTH FEET</u>	<u>PERMEABILITY MILIDARCYS, HORIZONTAL</u>	<u>POROSITY PERCENT</u>	<u>RESIDUAL LIQUID SATURATIONS % OF PORE SPACE</u>	
			<u>OIL</u>	<u>TOTAL WATER</u>
434	39.4	26.0	28.1	58.5
436	33.1	27.6	11.2	78.4
438	58.5	30.4	10.0	71.2
440	68.7	28.4	18.2	69.5

TABLE 12
LOCATION SAMPLE SERVICE, INC.
SIDEWALL CORE ANALYSIS REPORT
BODCAU FEE 'B' 15-13

(Page 3 of 4)

DEPTH	DESCRIPTION OF RECOVERY
352	SHALE, SK BRN, WAXY, NO SHOW
354	SAND, BRN, FG, POOR P&P, SILTY, VRY CALC, FOSS, EVEN BRN OIL STAIN, GOLD FLUO, MILKY YELL CUT
356	LIME, BRN, FOSS TO GRAN, POOR TO FAIR P&P, VUG, SANDY, EVEN BR OIL STAIN, GOLD FLUO, MILKY YELL CUT
358	LIME, LT GRY TO GRY, VFG, TITE, NO SHOW
360	NO RECOVERY
362	LIME, LT BRN, FNLY, XLN TO VRY FOSS, POOR P&P, SCAT SMALL VUGS, IRREG BRN OIL STN, LT YELL FLUO, MILKY YELL CUT
364	SAND, DK GRY, FG, POOR P&P, SILTY, SLI TO MOD ARGIL, DK BRN STN. FOSS. YELL FLUO, MILKY YELL CUT
366	SAND, AS ABOVE
368	LIME, GRY, VRY FNLY XLN TO SILTY, POOR P&P, DULL YELL FLUO, FNT MILKY YELL CUT
370	SAND, DK GRY, FG, FAIR P&P, SILTY, SLI, CALC, DK BRN RESID STN, MILKY YELL CUT
372	SAND, AS ABOVE
374	SAND, DK BRN, FG, POOR P&P, SILTY, ARGIL, SLI CALC, NO FLUO, FNT MILKY YELL CUT
376	SAND, AS ABOVE
378	SAND, GRY, FG, POOR P&P, SILTY, ARGIL, OCC FOSS, NO SHOW
380	SAND, AS ABOVE
382	SAND, LT REDDISH GRY, FG, FAIR P&P, SILTY, SLI ARGIL, NO SHOW
384	SAND, AS ABOVE
386	SAND, LT BRN, FG, FAIR TO GOOD P&P, SILTY, SOME SCAT LT BRN OIL STAIN, FNT MILKY YELL CUT
388	SAND, AS ABOVE
390	NO RECOVERY
392	SAND, BRN, F-MG, POOR TO FAIR P&P, MOD TO VRY CALC, IRREG BRN OIL STAIN, YELL FLUO, MILKY YELL CUT
394	SAND, BRN, FG, POOR TO FAIR P&P, SILTY, NUM LARGE TITE SAND INCLU, GOLD FLUO, MILKY YELL CUT
396	SAND, BRN, FG, POOR TO FAIR P&P, SILTY, BRN OIL STAIN, GOLD FLUO, MILKY YELL CUT
398	SAND, AS ABOVE
400	SAND, BRN, FG, FAIR TO GOOD P&P, SLI ARGIL, EVEN BRN OIL STAIN, MILKY YELL CUT
402	SAND, AS ABOVE
404	SAND, BRN, F-MG, FAIR TO GOOD P&P, SLI CALC, SLI ARGIL, NO SHOW
406	SAND, AS ABOVE
408	SAND, BRN, FG, FAIR TO GOOD P&P, SILTY, SLI CALC, EVEN BRN OIL STAIN, DULL GOLD FLUO, MILKY YELL CUT
410	SAND, AS ABOVE, W/OCC FOSS, SLI CALC
412	SAND, BRN, FG, SILTY, VRY SLI CALC, EVEN BRN OIL STN, GOLD FLUO, MILKY YELL CUT

TABLE 12
LOCATION SAMPLE SERVICE, INC.
SIDEWALL CORE ANALYSIS REPORT
BODCAU FEE "B" 15-13

(Page 4 of 4)

<u>DEPTH</u>	<u>DESCRIPTION OF RECOVERY</u>
414	SAND, AS ABOVE
416	SAND, AS ABOVE
418	SAND, AS ABOVE
420	SAND, AS ABOVE
422	SAND, AS ABOVE
424	SAND, BRN, FG, POOR TO FAIR P&P, SILTY, SLI ARGIL, EVEN BRN OIL STAIN, DULL YELL FLUO, MILKY YELL CUT
426	SAND, AS ABOVE
428	SAND, AS ABOVE
430	NO RECOVERY
432	SAND, AS ABOVE
434	SAND, BRN, FG, POOR TO FAIR P&P, SILTY, ARGIL, BRN OIL STAIN, DULL BRN FLUO, MILKY YELL CUT
436	SAND, AS ABOVE, BECOMING MOD ARGIL
438	SAND, AS ABOVE
440	SAND, BRN, VF-FG, POOR P&P, SILTY, ARGIL, BRN OIL STAIN, DULL BRN FLUO, MILKY YELL CUT

TABLE 13

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
Dallas, Texas

(Page 1 of 3)

CITIES SERVICE COMPANY
NO. 15-12 BODCAU FEE "B"
BELLEVUE FIELD
BOSSIER PARISH, LOUISIANA

FORMATION : NACATOCH
DRLG. FLUID: WATER BASE MUD

CONVENTIONAL CORE ANALYSIS

SMP NO	DEPTH	PERM MD HORZ (KA)	POR %	OIL% PORE	WTR% PORE	DESCRIPTION
	364.0-384.0	CORE NO 1	CUT 20	FT	REC 17.5 FT	
1	364.0- 65.0	90.	26.3	22.5	48.3	SD VFG SLTY S/ASHY SSHY LMY G ODR GLD FLU
2	365.0- 66.0	100.	27.2	20.3	62.3	SD VFG SSLTY S/ASHY SSHY LMY G ODR GLD FLU
3	366.0- 67.0	<0.01	9.4	0.0	53.6	SD VFG V/SLTY V/LMY N ODR N FLU
4	367.0- 68.0	1902.	30.1	0.0	82.2	SD VFG SLTY LMY N ODR N FLU
5	368.0- 69.0	345.	28.2	0.0	73.3	SD VFG SLTY LMY N ODR N FLU
6	369.0- 70.0	206.	31.5	0.0	81.2	SD VFG SSLTY LMY N ODR N FLU
7	370.0- 71.0	1889.	29.5	0.0	77.5	SD VFG SSLTY LMY N ODR N FLU
8	371.0- 72.0	9.20	18.8	0.0	71.0	SD VFG ASHY V/LMY N ODR N FLU
9	372.0- 73.0	4.10	18.1	0.0	75.8	SD VFG ASHY V/LMY N ODR N FLU
10	373.0- 74.0	756.	28.2	0.0	72.9	SD VF-FG SSHY/LAM N ODR N FLU
11	374.0- 75.0	972.	39.6	0.0	76.0	SD FG CLN N ODR N FLU
12	375.0- 76.0	474.	34.3	0.0	82.7	SD FG CLN N ODR N FLU
13	376.0- 77.0	488.	35.5	0.0	90.0	SD FG SSHY N ODR N FLU
14	377.0- 78.0	1763.	35.3	0.0	83.7	SD FG SSHY N ODR N FLU
15	378.0- 79.0	2247.	32.3	0.0	89.4	SD VF-FG SSHY N ODR N FLU
16	379.0- 80.0	1247.	31.0	0.0	80.8	SD VF-FG SSHY N ODR N FLU
17	380.0- 81.0	87.	24.1	0.0	82.3	SD VF-FG S/ASHY V/LMY N ODR N FLU
18	381.0- 81.5	1.46	18.8	0.0	46.2	SD VFG FOS V/LMY N ODR N FLU
	381.5- 84.0					LOST CORE
	384.0-404.0	CORE NO 2	CUT 20	FT	REC 20 FT	
19	384.0- 85.0	0.96	7.1	0.0	77.7	SD VFG SLTY V/LMY N ODR N FLU
20	385.0- 86.0	23.	22.9	0.0	80.9	SD VFG V/ASHY LMY N ODR N FLU
21	386.0- 87.0	1439.	33.2	0.0	65.1	SD VF-FG S/ASHY N ODR N FLU

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
Dallas, Texas

(Page 2 of 3)

CITIES SERVICE COMPANY
NO. 15-12 BODCAU FEE "B"

CONVENTIONAL CORE ANALYSIS

SMP NO	DEPTH	PERM MD HORZ (KA)	POR %	OIL% PORE	WTR% PORE	DESCRIPTION
22	387.0- 88.0	1301.	34.4	0.0	79.5	SD VF-FG S/ASHY N ODR N FLU
23	388.0- 89.0	3782.	37.5	0.0	81.0	SD VF-FG S/ASHY N ODR N FLU
24	389.0- 90.0	3437.	38.2	0.0	79.9	SD VF-FG CLN N ODR N FLU
25	390.0- 91.0	3620.	37.8	0.0	79.6	SD VF-FG CLN N ODR N FLU
26	391.0- 92.0	3731.	36.8	0.0	72.5	SD VF-FG CLN N ODR N FLU
27	392.0- 93.0	2774.	38.3	0.0	67.8	SD VF-FG CLN N ODR N FLU
28	393.0- 94.0	2820.	35.1	0.0	77.1	SD VF-FG CLN LMY N ODR N FLU
29	394.0- 95.0	3236.	35.6	0.0	75.8	SD FG CLN N ODR N FLU
30	395.0- 96.0	1352.	32.2	0.0	82.3	SD FG CLN LMY N ODR N FLU
31	396.0- 97.0	4.00	19.8	0.0	68.5	SD VF-FG ASHY LMY N ODR N FLU
32	397.0- 98.0	2968.	34.5	0.0	47.9	SD VF-FG ASHY LMY N ODR N FLU
33	398.0- 99.0	2754.	37.7	0.0	77.8	SD VF-FG SSLTY LMY N ODR N FLU
34	399.0- 00.0	3043.	38.9	0.0	73.1	SD FG CLN N ODR N FLU
35	400.0- 01.0	0.22	16.4	0.0	66.4	SD VFG SLTY LMY N ODR N FLU
36	401.0- 02.0	0.10	14.8	0.0	79.7	SD VFG SLTY LMY N ODR N FLU
37	402.0- 03.0	0.18	15.2	0.0	60.3	SD VFG SLTY LMY N ODR N FLU
38	403.0- 04.0	30.	20.7	0.0	73.5	SD VFG SLTY LMY N ODR N FLU
	404.0-425.0	CORE NO 3	CUT 21 FT	REC 21 FT		
39	404.0- 05.0	0.15	11.4	0.0	63.5	SD VFG SLTY LMY N ODR N FLU
40	405.0- 06.0	1699.	33.9	0.0	76.2	SD FG CLN N ODR N FLU
41	406.0- 07.0	782.	32.0	0.0	77.1	SD FG CLN N ODR N FLU
42	407.0- 08.0	38.	22.5	0.0	77.2	SD VFG SLTY LMY N ODR N FLU
43	408.0- 09.0	1710.	34.0	0.0	69.4	SD FG CLN N ODR N FLU
44	409.0- 10.0	2850.	35.9	0.0	63.2	SD FG CLN N ODR N FLU
45	410.0- 11.0	1440.	34.2	0.0	69.7	SD FG CLN N ODR N FLU
46	411.0- 12.0	1400.	33.6	0.0	71.3	SD FG CLN N ODR N FLU
47	412.0- 13.0	1810.	34.3	0.0	68.2	SD FG CLN N ODR N FLU
48	413.0- 14.0	1176.	32.1	0.0	70.9	SD FG CLN N ODR N FLU

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
Dallas, Texas

(Page 3 of 3)

CITIES SERVICE COMPANY
NO. 15-12 BODCAU FEE "B"

CONVENTIONAL CORE ANALYSIS

SMP NO	DEPTH	PERM MD HORZ (KA)	POR %	OIL% PORE	WTR% PORE	DESCRIPTION
49	414.0- 15.0	1212.	31.3	0.0	63.7	SD FG CLN N ODR N FLU
50	415.0- 16.0	1251.	33.8	0.0	70.8	SD FG CLN N ODR N FLU
51	416.0- 17.0	3752.	36.0	0.0	66.7	SD FG CLN N ODR N FLU
52	417.0- 18.0	3220.	36.1	0.0	62.0	SD FG CLN N ODR N FLU
53	418.0- 19.0	3105.	35.6	0.0	68.7	SD FG CLN N ODR N FLU
54	419.0- 20.0	3100.	37.4	0.0	75.5	SD FG CLN N ODR N FLU
55	420.0- 21.0	3357.	39.7	41.6	39.7	SD VF-FG CLN G ODR DUL FLU
56	421.0- 22.0	1110.	32.8	66.5	20.1	SD VF-FG CLN G ODR DUL FLU
57	422.0- 23.0	2520.	35.9	37.0	56.1	SD VF-FG CLN G ODR DUL FLU
58	423.0- 24.0	2620.	36.7	35.2	53.4	SD VF-FG CLN G ODR DUL FLU
59	424.0- 25.0	2820.	37.9	41.1	45.2	SD VF-FG CLN G ODR DUL FLU

TABLE 14
SUMMARY OF PROJECT INVESTMENTS
FEBRUARY 1981

<u>DESCRIPTION</u>	<u>CUMULATIVE COSTS</u>	<u>ORIGINAL ESTIMATE</u>
<u>Drill and Equip Wells</u>		
Evaluation Wells	\$ 138,850.26	\$ 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	16,246.20	
Drill 9 Line Wells	<u>236,781.78</u>	
Sub-Total	\$1,168,531.87	\$ 707,713.00
<u>Install Facilities</u>		
Production and Injection Facilities	\$ 484,291.17	\$ 497,888.00
Electrify Compressor #1	<u>8,639.17</u>	
Sub-Total	\$ 492,930.34	\$ 497,888.00
 TOTAL INVESTMENTS	 <u>\$1,661,462.21</u>	 <u>\$1,205,601.00</u>

TABLE 15
SUMMARY OF PROJECT EXPENSES
FEBRUARY 1981

<u>DESCRIPTION</u>	<u>CUMULATIVE COST</u>	<u>ORIGINAL ESTIMATE</u>
<u>Exploration and Production Services</u>		
Region Expense	\$ 409,518.38	\$ 747,642.00
Production Foreman Expense	<u>216,769.25</u>	<u>256,179.00</u>
Sub-Total	\$ 626,287.63	\$ 1,003,821.00
<u>Research Services</u>		
Research and Development	\$ 277,055.48	\$ 360,835.00
Environmental Assessment	<u></u>	<u>50,000.00</u>
Sub-Total	\$ 277,055.48	\$ 410,835.00
<u>Lease Operations and Maintenance</u>		
Direct Lease Expenses	\$ 3,384,174.63	\$ 3,877,000.00
Producing Well Overhead	1,039,095.58	1,257,080.00
Louisiana Severance Taxes	1,625,154.94	475,561.00
Decontrol Tax *	<u>997,030.00</u>	<u></u>
Sub-Total	\$ 7,045,455.15	\$ 5,609,641.00
<hr/>		
TOTAL EXPENSES	\$ 7,948,798.26	\$ 7,024,297.00

* This cost is not carried as part of the cumulative expenditures.

TABLE 16
PROJECT EXPENDITURES
FEBRUARY 1981

<u>CATEGORY</u>	<u>COST THRU 2/81</u>	<u>COST PER BARREL*</u>
Lease Operation **	\$ 770,795.25	\$ 1.42
Lease Maintenance **	1,436,770.21	2.64
Compression Facility **	1,176,609.17	2.17
LA Severance Tax	1,625,154.94	2.99
CSC Overhead	1,039,095.58	1.91
Depletion & Depreciation	1,215,803.00	2.24
Decontrol Tax	997,030.00	1.84
	<hr/>	<hr/>
TOTAL	\$ 8,261,258.15	\$ 15.21

*NOTE: Costs were determined on a net barrel basis assuming a normal 1/8 royalty.

**NOTE: See Table 19 for detailed breakdown of these costs.

TABLE 17
PROJECT EXPENDITURES
Through March 1980

<u>CATEGORY</u>	<u>COST Thru 3/80</u>	<u>COST PER BARREL*</u>
Lease Operation	\$ 522,299.76	\$ 1.12
Lease Maintenance	979,271.74	2.10
Compression Facility	937,839.96	2.01
LA Severance Tax	1,175,085.40	2.51
CSC Overhead	767,010.18	1.64
Depletion & Depreciation	1,001,255.00	2.14
	<hr/>	<hr/>
TOTAL	\$ 5,382,762.04	\$ 11.52

*NOTE: Costs were determined on a net barrel basis assuming a normal 1/8 royalty.

TABLE 18
PROJECT EXPENDITURES
APRIL, 1980 - FEBRUARY, 1981

<u>CATEGORY</u>	<u>COST 4/80 - 2/81</u>	<u>COST PER BARREL*</u>
Lease Operation	\$ 248,495.49	\$ 2.99
Lease Maintenance	457,498.47	5.50
Compression Facility	238,769.21	2.87
LA Severance Tax	450,069.54	5.41
CSC Overhead	272,087.40	3.27
Depletion & Depreciation	214,548.00	2.58
Decontrol Tax	997,030.00	11.98
	<hr/>	<hr/>
TOTAL	\$2,878,498.11	\$ 34.60

*NOTE: Costs were determined on a net barrel basis assuming a normal 1/8 royalty.

TABLE 19
SUMMARY OF DIRECT LEASE OPERATIONS AND
MAINTENANCE EXPENSES

FEBRUARY, 1981

<u>CATEGORY</u>	<u>TOTAL EXPENDITURES</u>	<u>COST PER BARREL*</u>
Materials	\$ 361,944.97	\$.67
Chemicals	272,937.31	.50
Labor	540,626.53	1.00
Utilities	1,212,127.49	2.23
Well Service	<u>996,538.33</u>	<u>1.83</u>
TOTAL	\$ 3,384,174.63	\$ 6.23

*NOTE: Based on net cumulative oil production, assuming a normal 1/8 royalty, of 543,281 barrels through February, 1981.

FIGURE 1

FIGURE 2

PROJECT AREA NET PAY MAP

PROJECT AREA STRUCTURE MAP

**BODCAU IN SITU COMBUSTION PROJECT
WELLS 12-1 AND 12-1A HISTORY**

FIGURE 4

**BODCAU IN SITU COMBUSTION PROJECT
WELL 13-1 HISTORY**

FIGURE 5

FIGURE 6

**BODCAU IN SITU COMBUSTION PROJECT
WELL 15-1 HISTORY**

FIGURE 7

**BODCAU IN SITU COMBUSTION PROJECT
WELL 16-1 HISTORY**

FIGURE 8

BODCAU IN SITU INJECTION HISTORY
 JULY 1976-FEBRUARY 1981

FIGURE 9

BODCAU IN SITU PRODUCTION HISTORY
JULY 1976 - FEBRUARY 1981

FIGURE 10

**BODCAU IN SITU COMBUSTION PROJECT
AIR-OIL RATIO CURVES**

FIGURE 11

FIGURE 12

PROJECT PATTERN MAP

○ TEMPERATURE
OBSERVATION
WELL

FIGURE 13

**BODCAU IN SITU COMBUSTION PROJECT
TEMPERATURE PROFILE WELL #12-7**

FIGURE 14

**BODCAU IN SITU COMBUSTION PROJECT
TEMPERATURE PROFILE WELL #13-7**

FIGURE 15

**BODCAU IN SITU COMBUSTION PROJECT
TEMPERATURE PROFILE WELL #14-7**

FIGURE 16

**BODCAU IN SITU COMBUSTION PROJECT
TEMPERATURE PROFILE WELL #15-7**

FIGURE 17

**BODCAU IN SITU COMBUSTION PROJECT
TEMPERATURE PROFILE WELL #16-7**

**BODCAU IN SITU COMBUSTION PROJECT
JANUARY 1977-FEBRUARY 1981**

FIGURE 18

DAMAGES FROM AIR SYSTEM EXPLOSION

**AUTOIGNITION TEMPERATURES OF MINERAL OIL (MO) AND
FIRE RESISTANT (FR) FLUIDS AS A FUNCTION OF PRESSURE**

FIGURE 21
BODCAU IN SITU
EVALUATION WELL LOCATIONS
BOSSIER PARISH, LA.
Sec. 11 T19N - R11W

BODCAU IN SITU COMBUSTION PROJECT EVALUATION WELL LOGS WELL #15-10

INDUCTION ELECTRICAL LOG

SP (IN)		0.000	ILP (BPPH)	0000
ILN (BPPH)		0.000	ILN (BPPH)	0000
SCAL (BPPH)		0.000	SCAL (BPPH)	0000

PARAMETERS					
NAME	UNIT	VALUE	NAME	UNIT	VALUE
SDR	BPPH	1.000	BSEC	HR/H	6.600
FPHI	PHI	0.0	BSEC	HR/H	7.000
BO			BHS	OPEN	
			DS	INCH	9.875

COMPENSATED FORMATION DENSITY LOG

CALI (IN)		16.00	DENSITY (G/CC)		0.000
CALI (IN)		16.00	DENSITY (G/CC)		0.000
DENSITY (G/CC)		0.000	DENSITY (G/CC)		0.000

PARAMETERS					
NAME	UNIT	VALUE	NAME	UNIT	VALUE
HC	INCH	9.875	DS	INCH	9.875
FPHI	PHI	0.0	FPHI	PHI	0.0
BO			BO

ELECTROMAGNETIC PROPAGATION LOG

SDR (BPPH)		0.0	EATT (BPPH)		0.0
EATT (BPPH)		0.0	EATT (BPPH)		0.0
EATT (BPPH)		0.0	EATT (BPPH)		0.0

PARAMETERS					
NAME	UNIT	VALUE	NAME	UNIT	VALUE
SDR	BPPH	1.000	BSEC	HR/H	6.600
FPHI	PHI	0.0	BSEC	HR/H	7.000
BO			BHS	OPEN	
			DS	INCH	9.875

FIGURE 22

BODCAU IN SITU COMBUSTION PROJECT

EVALUATION WELL LOGS WELL #15-11

INDUCTION ELECTRICAL LOG

		0.2000	ILB (OHMM)	2000.
		0.2000	ILM (OHMM)	2000.
SP (MV)		0.2000	SFLU(OHMM)	2000.
NO. 00	20.00	0.2000		2000.
PARAMETERS				
NAME	UNIT	VALUE	NAME	UNIT VALUE
SDP	OHMM	1.000	DSEC	MV/M 5.300
FPHI	PHI	0.0	BSEC	MV/M 7.980
BO			BHS	OPEN
			BS	INCH 9.875

COMPENSATED FORMATION DENSITY LOG

0.000	BS (CM)	10.00			
0.000	CAL (CM)	10.00	0.4500	PHI (G)	-0.15
00.00	GR (GAP)			PHI (G)	-0.15
00.00	GR .01		0.5000		

PARAMETERS								
NAME	UNIT	VALUE	NAME	UNIT	VALUE	NAME	UNIT	VALUE
MC		CAL	PHI		2.223	BS	INCH	9.875
MBEN	G/C3	2.719	FB	G/C3	1.000	MATR		LINE
BO		0.0	BHS		OPEN	FPHI		PHIX

ELECTROMAGNETIC PROPAGATION LOG

20.00	EMPR (OHM)				EMPR (OHM)	0
20.00	EMPR (OHM)				EMPR (OHM)	-0.15
20.00	GB (GAP)				GB (GAP)	5.81
PARAMETERS						
NAME	UNIT	VALUE	NAME	UNIT	VALUE	
EMPR	OHM	1.000	DSEC	MV/M	5.300	
BHS	OPEN	0.0	BHS	MV/M	7.980	
BO			BHS	OPEN

FIGURE 23

BODCAU IN SITU COMBUSTION PROJECT EVALUATION WELL LOGS WELL #15-13

INDUCTION ELECTRICAL LOG

SP (IN)	0.000	1.0 (INCH)	0.000
SP (IN)	0.000	1.0 (INCH)	0.000
SP (IN)	0.000	1.0 (INCH)	0.000

PARAMETERS					
NAME	UNIT	VALUE	NAME	UNIT	VALUE
SP	INCH	1.000	SP	INCH	7.000
PPH1	PPH	0.0	PPH1	PPH	0.0

COMPENSATED FORMATION DENSITY LOG

SP (IN)	0.000	1.0 (INCH)	0.000
SP (IN)	0.000	1.0 (INCH)	0.000
SP (IN)	0.000	1.0 (INCH)	0.000

PARAMETERS					
NAME	UNIT	VALUE	NAME	UNIT	VALUE
SP	INCH	1.000	SP	INCH	7.000
PPH1	PPH	0.0	PPH1	PPH	0.0

ELECTROMAGNETIC PROPAGATION LOG

SP (IN)	0.000	1.0 (INCH)	0.000
SP (IN)	0.000	1.0 (INCH)	0.000
SP (IN)	0.000	1.0 (INCH)	0.000

PARAMETERS					
NAME	UNIT	VALUE	NAME	UNIT	VALUE
SP	INCH	1.000	SP	INCH	7.000
PPH1	PPH	0.0	PPH1	PPH	0.0

FIGURE 24

BODCAU IN SITU COMBUSTION PROJECT

EVALUATION WELL LOGS WELL #15-12

INDUCTION ELECTRICAL LOG

SP (IN)		0.0000	ILH (INCH)	0.0000
SP (IN)		0.0000	ILH (INCH)	0.0000
SP (IN)		0.0000	ILH (INCH)	0.0000
PARAMETERS				
NAME	UNIT	VALUE	NAME	UNIT
SDR	INCH	1.000	DEEC	INCH
PPH1	PPH1	0.0	DEEC	INCH
SD	SD	0.0	DEEC	INCH
PARAMETERS				
NAME	UNIT	VALUE	NAME	UNIT
SDR	INCH	1.000	DEEC	INCH
PPH1	PPH1	0.0	DEEC	INCH
SD	SD	0.0	DEEC	INCH

COMPENSATED FORMATION DENSITY LOG

DE (IN)		0.000	DE (IN)	0.000
DE (IN)		0.000	DE (IN)	0.000
DE (IN)		0.000	DE (IN)	0.000
PARAMETERS				
NAME	UNIT	VALUE	NAME	UNIT
HC	INCH	2.310	DE	INCH
DECH	INCH	2.310	DE	INCH
DECH	INCH	2.310	DE	INCH
DECH	INCH	2.310	DE	INCH

ELECTROMAGNETIC PROPAGATION LOG

DE (IN)		0.000	DE (IN)	0.000
DE (IN)		0.000	DE (IN)	0.000
DE (IN)		0.000	DE (IN)	0.000
PARAMETERS				
NAME	UNIT	VALUE	NAME	UNIT
EMT	INCH	7.000	DE	INCH
DE	INCH	7.000	DE	INCH
DE	INCH	7.000	DE	INCH
DE	INCH	7.000	DE	INCH

FIGURE 26

FIGURE 26

**BODCAU IN SITU EVALUATION WELL
SATURATION COMPARISON WELL #15-11**

FIGURE 27

**BODCAU IN SITU COMBUSTION PROJECT
EVALUATION WELL #15-10**

FIGURE 28

**BODCAU IN SITU COMBUSTION PROJECT
EVALUATION WELL #15-11**

FIGURE 29

**BODCAU IN SITU COMBUSTION PROJECT
EVALUATION WELL #15-12**

FIGURE 30

**BODCAU IN SITU COMBUSTION PROJECT
EVALUATION WELL #15-13**

FIGURE 31

BODCAU IN SITU COMBUSTION D.O.E. PROJECT

CUMULATIVE EXPENDITURE VS TIME

APPENDIX C
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