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**LITTLE TOM THERMAL RECOVERY DEMONSTRATION PROJECT,
ZAVALA COUNTY TEXAS—FINAL REPORT**

By

Hanover Petroleum Corporation
Contract No. EY-76-C-02-0002.*000

Date Published—January 1977

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**LITTLE TOM THERMAL RECOVERY DEMONSTRATION PROJECT
ZAVALA COUNTY, TEXAS
FINAL REPORT**

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FOREWORD

The ERDA program for enhanced recovery of oil and gas is aimed at demonstrating new recovery technology and transferring it to the private sector. The program is designed to maximize the participation of private industry by awarding cost-sharing contracts to companies which have capability in enhanced oil and gas recovery.

This project was one of the first thermal recovery cost-sharing contracts awarded under this program. It did not proceed further than Stage 1 of the project for reasons that are completely described in this report. It does stand as an example of cooperation between the government and private industry.

When it finally became apparent that the method chosen to stimulate the heavy-oil formation in the Little Tom field had little chance of success, both parties were willing to agree to the termination of the project. All of the cooperative demonstration project contracts between ERDA and industry in the enhanced recovery program included this provision.

It is hoped that through publication of the results of the unsuccessful projects as well as the successful ones that industry can be more definitive in the selection and application of enhanced oil recovery methods. If others can gain from this experience, then the effort in itself will have been a success.

F. Sam Johnson
ERDA Technical Project Officer

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FINAL REPORT
LITTLE TOM THERMAL RECOVERY
DEMONSTRATION PROJECT
ZAVALA COUNTY, TEXAS

INTRODUCTION

This report is submitted in compliance with Sec. 2.5, Article II of Contract No. EY-76-C-02-002.*000 (originally HO252002 and later E(34-1)-0002) dated January 24, 1975 between Hanover Petroleum Corporation and the Energy Research and Development Administration of the United States (ERDA). Presented herein is a summary of work attempted and accomplished during the life of the project, and recommendations and conclusions based on the experience and the results obtained.

The objective of the Little Tom Thermal Recovery Project was to demonstrate the efficiency and economics of recovering low gravity, viscous crude oil from a relatively thin, low permeability reservoir utilizing a combination thermal drive process in conjunction with thermal stimulation of the producing wells. The combination thermal drive process combines forward in situ combustion with sequential water injection to provide maximum heat transfer efficiency along the burning front. Thermal stimulation (short term in situ combustion at the producing well) allows productivity increases to be realized long before the burning front approaches the producing well.

SUMMARY

The Little Tom Thermal Recovery Project was initially scheduled to be completed in four phases over a period of about 4 years; however, certain delays and events caused Phase I of the project to be extended from 4 months to 1-1/2 years.

During Phase I, thermal stimulation operations were conducted on two producing wells, Ned Matthews Nos. 8 and 9. In addition to these operations, considerable effort and monies were expended to upgrade lease and well test facilities, roads and locations, and to obtain a reliable gas supply for compressor fuel and formation ignition operations. The high injection pressures experienced in both wells, sometimes exceeding the 2,000 psig compressor design rating, resulted in frequent injection equipment repairs and high maintenance costs.

After the thermal stimulation operations proved unsuccessful, the Little Tom Thermal Recovery Project was terminated. The decision to terminate was based on the following technical and economic considerations:

1. Profitable producing rates could not be achieved in this field by normal stimulation methods, nor did high temperature thermal stimulation in two producing wells prove successful. It appears that the formation did not ignite.
2. Injection pressures were higher than anticipated.
3. Injection well surveys showed that the target oil contacted by a fireflood might be only about one-fourth the volume originally anticipated, since air entry into the formation appeared limited to certain sand intervals.

4. The oil produced from the San Miguel Sand formation in the pilot area appeared to be of much lower gravity and higher viscosity than originally estimated.
5. Operating costs proved to be higher than anticipated.
6. The oil price has been rolled back and controlled at a lower level since the project was initiated.

Contract No. EY-76-C-02-002.*000 authorized a total project cost of \$3,048,059 (\$2,096,334 to have been funded by Hanover, \$951,725 by ERDA). Total monies spent during the project were \$294,622 (\$56,713 by Hanover, and \$237,909 by ERDA). Total investment in the project was \$1,618,178 (\$1,380,269 by Hanover and \$237,909 by ERDA).

CONCLUSIONS AND RECOMMENDATIONS

Thermal recovery operations in the Little Tom field San Miguel reservoirs are not profitable under the current economic scenario. The low reservoir transmissibility will not permit achievement of the producing rates required to support the project without some sort of effective stimulation. Formation fracturing proved only partially successful with inconsistent and short-lived response. The thermal stimulation treatments in two wells conducted during Phase I of the Little Tom project did not ignite the San Miguel formation. Gas analysis data indicate that low temperature oxidation occurred, but a high temperature burning zone was never established. Thermal treatment did not improve oil production rates and casing was damaged in both wells.

Injection pressures as high as 2,300 psig were experienced. Unless the effective air permeability was greatly increased after flow was established to offset pattern producing wells, air injection at the high rates normally associated with in situ combustion drive would require injection pressures greater than the overburden pressure in the Little Tom field.

Fluid injectivity and production tests on several wells in the pilot area indicate that most, if not all, of the oil production to date from these wells has come from the San Miguel "B" zone, only one of the four zones originally targeted for thermal operations. The other three target zones, though perforated and indicated to be potentially productive in all wells by log and/or core data, either were not effectively stimulated by single stage hydraulic fracturing, or they are not productive. The productivity of the three zones is now questionable. The investment required to fireflood only one zone would not be significantly less than that required to fireflood four zones sequentially.

The gravity of the oil produced from the "B" zone is lower than originally estimated and may be too low to permit acceptable producing rates, even if thermally stimulated.

The locale of the Little Tom field is so remote from the sources of oil field services, supplies, and equipment that successful operation of a thermal project would require establishment of a rather complete on-site servicing and supply base with resident trained personnel. Such a base could only be justified by a very large, potentially profitable project.

Future economic incentives, such as much higher oil prices and an effective proven stimulation technique could make reservoirs such as Little Tom attractive thermal recovery prospects.

In the event that additional thermal stimulation treatments are conducted at Little Tom, certain changes in procedures and equipment are suggested:

1. Heat injected during burner ignition operations should be increased to well above the 10-12 MMbtu level to ignite the tight, low permeability San Miguel formation.
2. The downhole burner should be changed to a closed-end type that is run on tubing to eliminate possible air leaks from the well bore due to the high operating pressures.
3. Burner operating temperatures should be reduced to below 900-1,000°F and a water injection system installed to eliminate or minimize casing damage due to stresses caused by the high temperatures associated with the thermal process.

It is recommended that ERDA continue its attempts to demonstrate the technical and economic feasibility of thermal operations in the lower quality heavy oil reservoirs. Some 20 billion barrels of mobile oil-in-place, with API gravity of less than 20°, have been identified (U.S. Bureau of Mines 1967 estimate), primarily in California (7 billion) and Texas (12 billion), as unrecoverable by primary or thermal methods available in 1967.

FIELD HISTORY

This project was conducted by Hanover Petroleum Corporation on their 3,521 acre Ned Matthews lease, Little Tom field, Zavala County, Texas. The Little Tom field is located in the west central part of the county about 6 miles west of the town of LaPryor (Figure 1). Geologically, the field is in the Rio Grande embayment where oil production is found in a number of sands of upper Cretaceous Age.

The field discovery well was the D.S. Ring No. 1-J. L. Matthews, completed in the upper San Miguel sand section in 1950 with a potential of about 7 barrels per day of 20° API oil. No further attempts were made to produce the San Miguel sand until late 1972 when Mormac Oil and Gas Company completed the first of three wells. Production rates have declined from an initial rate of 30 barrels per day to a current rate of 7 to 10 barrels per day. Ultimate recovery from these wells is estimated to range from 15,000 to 20,000 barrels.

Beginning in late 1973, Mormac, acting as operator for Hanover, drilled the 14 wells on the Hanover lease. Eleven of the wells were completed utilizing the same technique. Each productive sand was perforated prior to fracture treating. The large volume of oil-water emulsion frac fluid was pumped in at high rates with ball sealers in an attempt to divert the treatment to each perforated interval. The twelfth completion was similar except that the frac fluid was lease crude. Completions of the remaining two wells were delayed pending evaluation of performance of the other wells.

The results were extremely disappointing, as only one well responded with a potential of better than 10 barrels per day. During Phase I of the thermal project, Well No. 13 was selectively completed in the San Miguel "C" zone sand utilizing an 800 barrel oil frac carrying 60,000 pounds sand. Unfortunately, the well produced only a trace of oil with 43 barrels water per day following this treatment.

RESERVOIR CHARACTERISTICS

The Little Tom field encompasses some 5,500 acres. The oil saturated San Miguel "A", "A-I", "B" and "C" sands are found at a depth of about 2,800 feet. The faulted elongated domal structure of the San Miguel can be seen in Figure 2. This structure is one of several in the area believed to overlie serpentine plugs.

A net isopach map, Figure 3, shows the distribution of total reservoir net pay throughout the field. The oil saturated sand thickness ranges from 30 to 40 feet in the pilot area. Figure 4 presents an electric log cross section through the pilot area.

Present mapping indicates approximately 77 million barrels of original oil in place, of which 40 million barrels underlie Hanover's lease. The Hanover lease contains about 73 percent of the oil in the thicker southern fault block.

The reservoir characteristics of the San Miguel sands are listed in Table 1. The average porosity is 22.3 percent. Conventional core analyses of samples from the Mormac wells indicated average permeabilities of the four zones to range from 31 to 115 md.

The reservoir is liquid filled as less than 15,000 barrels oil have been produced. Core data and log analysis indicated an average water saturation of about 40 percent. The formation volume factor is estimated at 1.05 and the solution gas-oil ratio is about 77 Scf per barrel at the estimated reservoir pressure of 750 psi. Reservoir temperature is 125°F.

The oil gravity is variable both with depth and laterally across the field. The Mormac wells produced 20 to 22° API oils; however, retort oil samples from sidewall cores taken from several of the Hanover wells indicated a gravity range from 16 to 20° API. Based on this data, the field average gravity was originally estimated to be 18° API. However, subsequent analysis of samples not diluted with the higher gravity frac load oil have indicated that the oil gravities from producing wells in the project have ranged from 12 to 22° API. The arithmetic average of samples taken from five wells in or near the pilot area was 14.3° API.

The predominant reservoir recovery mechanism is fluid expansion. Even if the reservoir were fully developed, it is doubtful that the primary recovery efficiency would exceed 3 percent.

The estimated thermal properties and displacement characteristics of the San Miguel "C" zone are presented in Table 2. Successful application of the combination thermal drive process was expected to result in a potential recovery of 32 to 42 percent of the oil in place, or the recovery of an additional 25 to 32 million barrels.

Success in the Little Tom field could have encouraged similar projects in numerous other similar heavy oil fields in Zavala and neighboring counties. Some of these fields are shown in Figure 5.

SUMMARY OF WORK PERFORMED

All work performed during the project was aimed toward accomplishing the following objectives of Phase I:

- (1) Establish the productivity of thermally stimulated producing wells.
- (2) Evaluate the injectivity of air into the San Miguel formation.

Failure to accomplish the first objective precluded completion of the injectivity evaluation.

Thermal Stimulation

Attempts to thermally stimulate two producing wells in the pilot area demanded most of the effort and funds expended during this project. Attempts on both wells, Nos. 8 and 9, ended when the casing collapsed onto the heat shield.

Successful thermal stimulation by insitu combustion requires actual formation ignition and creation of a high temperature zone extending for some distance away from the well bore. In place oil can then flow back to the well bore due to the reduced viscosity effects of the high temperature.

Ned Matthews No. 9

The first well selected for thermal stimulation was Ned Matthews No. 9, located near the pilot area (Figure 2). Injection pressures and rates to be experienced at this well were believed to be typical for the project. Prior to commencing the work in May 1975, the well was tested at a rate of 1.00 barrels of oil and 5.85 barrels of water per day. Rods and tubing were pulled from the well and a static bottom hole pressure was recorded. The 12.5 hour shut-in pressure was 378 psig at 2,800 feet. The shut-in time was insufficient for buildup to the average reservoir pressure, estimated to be about 750 psig.

To prepare Well No. 9 for ignition, the screen liner was removed and the well sand pumped clean to a depth of 2,824 feet. Diesel fuel was circulated to clean heavy oil from the well bore. Prior to running the heat shield, the perforations were acidized with 15 percent hydrochloric acid.

Preliminary air injection rates were established during early June 1975 at 300 MCFD with an injection pressure of 1,300 psig. Air injection was continued for only a short period and a temperature log was run under pressure to total depth. The fluid level was located at 2,784 feet, which is the approximate top of the San Miguel "C" zone. An attempt was made to run a gamma ray neutron log while injecting air; however, the downhole heat shield was too small to pass the logging sonde. Since injection pressures were fairly high, the main San Miguel zones were re-perforated after tubing was pulled to install a larger heat shield.

Figure 6 shows the heat shield setting depths for this well, down hole temperatures and perforations. Preliminary air injection prior to ignition was started in early July 1975 and gas was injected down the tubing to displace air through the heat shield. After several delays caused by compressor repairs and gas well delivery problems, pressures and rates were stabilized and the down hole burner was ignited.

Figure 8 shows air and gas rates and the associated pressures during the well bore heating period. Air injection rates prior to ignition were 7 to 8 Mcf per hour. The air injection pressure climbed rapidly from a stabilized, shut-in pressure (with no well head leaks) of 1,160 psig to almost 1,400 psig by the time the air rate stabilized. Just prior to ignition the gas rate was reduced from 0.5 to 0.16 Mcf per hour, resulting in an air-gas ratio of about 60. The air-gas ratio is also plotted in Figure 8. The first heating period was terminated shortly after midnight on July 21 due to a gas supply failure.

Substantially lower injectivity was experienced during the second heating period. The initial air injection rate of 6 Mcf per hour was gradually decreased to 4.5 Mcf per hour to maintain an acceptable well head pressure of between 1500 and 1600 psig. On July 24 the air compressor was down for about a 15 minute interval and it is possible that the burner went out at this time. On July 25, when no elevated burner temperature could be detected, the burner was re-ignited. Both air and gas rates were fairly constant throughout this period and the pressures gradually continued to rise. Early on July 26, a crack developed in the air injection line and interrupted injection. Four hours later the burner was re-ignited after stabilizing the gas and air injection rates. Final burner ignition was on July 27 after a gas supply failure. As Figure 8 shows, the stabilized gas rate during most of the heating periods was about 0.09 Mcf per hour and the corresponding air rate 4.8 Mcf per hour. The final air injection pressure was 1,620 psig. Formation ignition operations were terminated on the morning of July 28.

Gas pressures shown on Figure 8 consistently run about 150 psig higher than the air pressures due primarily to the difference in gravities. However, the gauge used to measure gas pressure was more sensitive than the air pressure gauge. The pressures recorded by the gas gauge more nearly reflect the pressure variations experienced during well bore heating.

Total air used during the heating period was 838 Mcf. The overall air-gas ratio averaged 62, resulting in a combustion temperature differential below the heat shield of 778 Fahrenheit degrees. Since the bottom hole formation temperature was 124° F, the temperature of air entering the perforations was calculated to be 902° F. The air-gas ratio controls the bottom hole temperature and, as Figure 8 shows, this ratio ranged from 70 to 54 at various times during the burn. These ratios would result in a temperature differential of 700-900° during the heating period. Total heat delivered to the formation was estimated to be 12.58 MMBtu based on the heating value of the gas.

Air injection rates were intentionally held quite low, around 110 MCFD, to maintain injection pressure at 1,500 to 1,600 psig during the burn. Some concern existed as to whether sufficient heat could be transferred at these low rates because the heat shield was set 50 feet above the main sand sections which were the targets for thermal stimulation (see Figure 6).

The reason the heat shield was initially set at 2,668 feet was to include the top perforation in a 3 foot thick stray sand in the heated interval. Since at these low injection rates considerable amounts of heat could be lost in transit before reaching the main perforated intervals, it was highly desirable to measure temperatures at the formation. This opportunity was afforded shortly after ignition when a low pressure, inter-stage hose failed on the air compressor. Well head pressures were reduced, and gases and liquids flowed back to the well bore because check valves failed to close.

Figure 6 shows a temperature survey run prior to the first burner ignition, and a four point survey run on August 6 after the burn. The well remained static for 9 days prior to this temperature survey. The maximum temperature recorded was 154°, about 30 degrees above the original formation temperature. Higher than normal temperatures were observed to 2,800 feet, the bottom point on the survey. This indicates that the initial fluid level dropped during the burn so that some air was probably injected in all of the San Miguel sand sections. Gas samples were obtained on August 1. Although very little carbon dioxide was found in the samples, the oxygen content indicated a burning efficiency of 54 percent. Also encouraging was the fact that oil entered the well bore during the backflow period. A fluid level was noted at 2,250 feet from the surface and tools were covered with viscous oil.

Since all factors, i.e., bottom hole temperature, gas analysis, pressure response and productivity, indicated a successful formation ignition, air injection was resumed in this well as soon as possible, but this was in late August, almost a month after running the burner. When air injection was resumed, the air rates were held to about 150 to 160 MCFD to limit pressures to about 1,560 psig (Figure 9). The total air injected was 2,479 Mcf over the 2 month period.

The pack-off rubber on the Matthews No. 9 well head blew out and air injection was stopped on September 5. Gas samples were obtained. Analysis of these samples, presented in Table 3, showed 70 percent oxygen utilization efficiency; but, again, the carbon dioxide level was on the order of 1 percent. This "efficiency" is based on the stoichiometric equation which reflects oxygen in the injected air that corresponds to the produced gas analysis.

The low carbon dioxide concentration found in these samples indicates that the reaction within the formation was probably a "low temperature" type reaction. This type reaction oxidizes the formation crude, but doesn't create a "burning zone" which generates a high concentration of carbon dioxide in the produced gases. The heat released by either reaction is of the same order of magnitude but resulting temperature levels differ greatly. For thermal stimulation, a high temperature reaction is desired.

The earlier indications of formation ignition were not supported by the gas analysis results obtained after the treatment was terminated; although, as discussed above, an increase in oxygen utilization was observed. Well No. 9 was tested as soon as a pulling unit became available several days later. Since heat dissipation in the formation is a function of time, delays in the scheduled operations further reduced the probability of a successful thermal treatment. Fluids in the hole were mostly water with some heavy oil accumulation. Fluid entry appeared too small to justify running pumping equipment. Very little gas was produced.

Preparations were immediately begun for another stimulation of Well No. 9. The tubing was pulled and the heat shield inspected. Found to be in good condition, the same heat shield was re-run and set at 2,715 feet, 47 feet lower than its prior location and below the stray sand. By reducing the length of the hole to be heated by the

gas burner, chances for achieving ignition in the formation at the low air injection rate associated with this well were improved. The stripper type tubing head on Well No. 9 was replaced with a flange type tubing head rated at 2,000 psi working pressure (4,000 psi test) to allow injection at higher pressures.

Surface and downhole work were not completed until the latter part of November. A standby compressor was acquired for emergency use. Air and gas injection rates were stabilized and wireline ignition tools were run December 11 to ignite the burner.

A rapid pressure rise of about 100 psig was noted when the wireline tool carrying the ignition chemical reached the heat shield. The sudden, abrupt pressure increase broke the wireline, leaving the ignition tool and 45 feet of wireline in the tubing. The sudden pressure rise indicated that the downhole air-gas ratio was not at the desired level of about 60:1 and it was suspected that some of the injected air leaked from the well bore before it reached the burner, resulting in a lower air-gas ratio.

The tubing was pulled to recover the wireline ignition tool. Plugging of the lower five joints of tubing with rust, coke and heavy oil was observed. The well was circulated clean with heated diesel fuel and a radioactive tracer log run while injecting diesel fuel showed a leak in a casing collar at 2,701 feet, between perforations in the San Miguel stry and "A" zones and about 10 feet above the top of the shield. A packer was run on tubing and set below the indicated leak. Neither the leak nor the stry zone perforations above would take diesel fuel at 1,800 psi. The packer was pulled and the heat shield re-run and hung at 2,699 feet, as shown on Figure 6.

The third stimulation attempt on Well No. 9 was started in January 1976. During the first igniter run, a slow but noticeable 50 psig pressure rise occurred after the igniter tool reached the heat shield, preventing stable ignition. On the second run, the igniter tool was stopped before reaching the heat shield. Gas injection was stopped and air injection was continued 30 minutes to purge the well bore below the heat shield. Gas injection was then resumed and stable burner ignition occurred when the tool reached the heat shield on January 24.

The burner operated several hours and generated 2.1 MMBtu of heat before air injection was momentarily interrupted. An automatic shut down switch stopped the compressor. When the wireline igniter was re-run to re-ignite the burner, the tubing was collapsed at the top of the heat shield so that the tool could not reach the heat shield. Air injection was continued for several more days. Additional runs of the wireline tool were made to attempt re-ignition; however, they only confirmed that the tubing was damaged to the extent that burner re-ignition was impossible. The total air injected during this phase was 1,257 Mcf. Since it was doubtful that formation ignition could have been achieved, air injection in this well was terminated.

Figure 9 shows a general deterioration in air injectivity since the first stimulation effort in July 1975. The injection pressures increased from 1,500 psig to about 2,200 psig at air rates of about 150 MCFD. Shut-in pressures also increased. The total air injected at Well No. 9 was 4,373 Mcf; gas production from the well was negligible. Air injectivity can usually be expected to decrease during ignition due to increased downhole temperatures. During the July 1975 burn, calculations based on a stable shut-in well head pressure of 1,160 psig show injectivity dropped 40 percent after

burner ignition. The effective air permeability was estimated from steady state equations at 1.2 md before ignition, assuming a 10 foot injection interval. This estimate would be even less if calculations were based on prior formation pressure measurements. Air permeability should have increased after air communication to other wells, but air breakthrough did not occur. By January 1976 air injectivity was only 0.005 SCFD/ P² and it was obvious that if the trend of pressure increase continued, formation pressure limits would be exceeded at air injection rates required for the thermal drive phase of the Little Tom project.

Benchmark I meeting was held in early February 1976 and another well was selected for thermal treatment. Injection at Well No. 9 was terminated because of excessive pressures and probable casing damage. About 1 month later when a pulling unit became available, the well was pulled. The lower end of the tubing collar was found to be collapsed in a "half-moon" like shape for a few inches just above the top of the heat shield. The stainless steel heat shield and seating nipple remained in the hole. Tubing and pump were run, but subsequent productivity tests indicated no improvement in oil rates.

Ned Matthews No. 8

Well No. 8 was selected for the next thermal stimulation treatment because it was one of the better performing oil producers in the field. Production tests also had indicated that No. 8 produced only minimal amounts of water compared to the other wells. The location of this well is shown on Figure 2.

Well No. 8 was converted to air injection in late February 1976. Prior to conducting the air injectivity tests, the hole was circulated clean with hot diesel fuel and the heat shield was set at a depth of 2,704 feet at the top of the San Miguel "A" sand. On the initial injection test, air was injected into the San Miguel sand at Well No. 8 at pressure of 1,560 psi and a rate of 300 Mcf air per day.

On April 10, a temperature log, gamma ray log, and radioactive tracer survey were run while injecting air. The tracer survey indicated that 13 percent of the air was entering the upper "A" zone (2,714 to 2,720 feet), 10 percent in the basal "A" zone (2,729 to 2,734 feet), and 77 percent in the "B" zone from 2,761 to 2,770 feet. No air entered the "C" zone. The tracer survey is illustrated in Figure 7.

Figure 10 shows details of air injection data associated with the attempted stimulation of Well No. 8. The well bore heating period was from April 21 to April 26. Air rates during this burn were on the order of 330 to 340 MCFD. Pressures during burner operation increased rapidly from 1,300 psig to 1,820 psig by the time the burn was terminated. Prior to ignition air was injected at 320 MCFD and 1,640 psig. Injectivity at this well was considerably higher than at No. 9. The well was shut-in on April 10, and the static well head pressure decreased over a 10 day period to 1,280 psig just prior to ignition. Figure 10 indicated that the air injection rate gradually decreased after burner ignition from 340 MCFD to 210 MCFD as the pressure increased. The maximum pressure was 1,890 psig at the time air injection was terminated. Total air injected in Well No. 8 was 6,099 Mcf. The air injected during the burn was 5,228 Mcf.

The bottom graph on Figure 10 indicates compressor downtime was nearly eliminated on this project due to thorough and extensive repairs on the air compressor. Only 6 hours actual downtime due to mechanical trouble were experienced during continuous injection operations. The air injection rate shown on Figure 10 reflects the total air injected during the 24 hour period.

The first burner ignition was on April 22. The burner was unintentionally extinguished after 6 hours, due to a momentary, but abrupt, change in air rate at the compressor. This disturbance was probably caused by manual bleedoff of water knockout bottles at the air compressor. Since the burner did not re-ignite after the brief interruption, the burner operating temperature was probably well within safe limits. Re-ignition would no doubt have been obtained had the downhole temperature reached the calculated 934° F temperature.

The igniter tool was again run on April 23. Air injection pressure had increased from 1,590 to 1,650 psig. Burner operation continued for a 22 hour period until a leak developed in the discharge hose at the air compressor. A standby air compressor was placed in service while repairs were made to the injection line, and the air injection rate was reduced from 300 to 100 MCFD because of the smaller capacity of the standby machine. It is not certain that the burner continued to operate after the main compressor was returned to service. It is possible that the abrupt pressure increase at the burner caused by increasing the air rate from 100 to 300 MCFD blew the flame out. Several igniter runs were made on April 25 to re-establish or confirm burning. It was obvious during these ignition runs that the tubing was damaged at or near the heat shield; therefore, on April 26 gas injection was discontinued. Air injection continued until May 12 with 5,228 Mcf of air injected after the burner ignition. The cumulative air injected was 6,099 Mcf.

The well remained shut-in from May 12 to May 19, 1976 to allow heat dissipation into the formation. Blowdown began on May 19. Just before gas flow from the tubing ceased on May 20, samples of the produced gas were taken. Analysis of the samples, presented in Table 4, identified a 1.7 percent carbon dioxide content with only 3.6 percent oxygen. These concentrations indicated that 80 percent of the air reacted with the formation oil. The low level of carbon dioxide in the produced gas indicated a low temperature oxidation type reaction in the formation. The fluid level in the well was approximately 1,000 feet above the sand when the gas flow ceased. Only 52 Mcf of gas was produced during the 5 hour blowdown.

Tubing was pulled from Well No. 8 and the seating nipple inside the heat shield was recovered. The outer 5-1/2" stainless steel portion of the heat shield remains in Well No. 8. Pipe damage did not seem as severe as in Well No. 9 and it occurred at a slightly lower depth.

Well No. 8 was equipped with tubing, rods and pump for production testing. Test results on June 10 indicated the productive capacity of the well was severely damaged by the thermal stimulation attempt. No oil has been produced and gas production has been negligible. Production during July averaged about one barrel water per day. Prior to the stimulation attempt, the well produced 7.5 barrels oil and 7.0 barrels water per day on one test and fair amounts of oil on several prior tests as shown by Figure 12.

The possibility that pipe damage is restricting fluid flow exists, but such a hypothetical restriction did not appear to grossly affect injection into this well, nor did it prevent liquid fill up during the blowdown period. Therefore, clean out procedures were not conducted, and further work in this well was terminated after production testing.

Discussion

In both wells at Little Tom, the downhole temperatures were most certainly at levels sufficient to ignite the San Miguel formation. In both cases, 10-12 MMBtu of heat were generated at the burner with no evidence that the formation was ignited. The amount of injected air that entered the oil formation is not known. Gases produced from the formation were only a small fraction of the total injected. As previously discussed, however, oxygen utilization appeared fairly high even though little gas was produced. If it is assumed that most of the injected air entered the oil sand, then it appears that a much longer burner operating time and/or greater heat generation is required to ignite the San Miguel. Furthermore, the upper temperature limit at the burner should be reduced to below 900°F to minimize high temperature expansion of the tubular goods. In both Little Tom wells, the hot gases heated about 100 feet of pipe between the burner and the perforations. Thermal expansion of unrestrained pipe caused by a 700° temperature increase is on the order of 5 inches. Much of the thermal stress is usually absorbed internally, at collars or at the perforations opposite ignited sand intervals, so that pipe movement of a few inches seldom causes any future operating problems. At Little Tom, however, the pipe damage was at the top of the heat shield where the burner temperature should have been at a minimum, due to the cooling effect of the injected air. This could be caused if some of the injected air was leaked from the hole above the burner. Such a leak would reduce the air-gas ratio, causing an increase in burner temperature. It is suggested that for any future thermal stimulation attempts at Little Tom, a closed end heat shield be used whereby air is injected down tubing and gas is injected down a concentric 1 inch tubing string. This insures that both air and gas reach the burner in the correct ratio. In addition, a packer may be required.

Of course, if oil burns in the well bore, high temperatures will result, but well cleaning procedures at Little Tom appeared adequate. Very little formation oil was found on the wireline tools during any of the ignition runs, except those in December.

Higher than desired downhole temperatures are also caused when air injection unexpectedly stops. Afterflow of gas and air causes high well bore temperatures that last for a few minutes. These temperature spikes usually don't affect ignition operations. For example, in Well No. 9 at Little Tom, formation ignition procedures were interrupted several times; yet the same heat shield was run in the well on three different occasions, and the igniter tool was run eight times, generating nearly 15 MMBtu of heat before pipe damage was experienced. These temperature increases, however, appear to have more serious effect at the Little Tom field than in other oil fields, perhaps because of the unusually high pressures experienced in the Little Tom project. In future operations in this field, the installation of a water injection system to quench downhole temperatures when air injection is interrupted should be considered.

Other Project Work

In addition to the thermal stimulation efforts, a considerable amount of other work was accomplished during the project. This work was oriented toward improving production operations in the pilot area in anticipation of successful thermal stimulation.

Screen liners were pulled from Wells No. 8 and 12 (during the thermal stimulation attempt on Well No. 9) and the tubing was lowered. Larger rod strings (3/4 inch) were installed on both wells to improve pump operations and prevent stress failures. The heavier rod string falls faster through the viscous crude on the pump downstroke, helping to maintain a smoother, more efficient pump action.

Well tests indicated productivity was significantly improved by these procedures. Total lease production and the periodic well tests of all project wells are presented in Figures 11 and 12.

Valves were installed on the casingheads of Well Nos. 5, 6, 8, 12 and 13 to allow monitoring of casing pressures and collection of gas samples.

A dependable natural gas supply was obtained by recompletion of the Electrothermic Company Matthews Navario Gas Unit No. 1 in a sand at 1,553 to 1,560 feet. This well, with an absolute open flow potential of 6,300 Mcf per day, should have been capable of supplying ignition, crude treating and compressor fuel gas requirements for the life of the project. Although the well belongs to Electrothermic, Hanover has first call on the gas produced from this well. A previous attempt to recomplete Hanover Matthews No. 2 in two gas sands was unsuccessful.

A 500-barrel storage tank and treater were moved to the pilot area from the central battery located about 1 mile away. This move was made to shorten the flow lines, lowering the pressures required to pump the viscous produced oil to the tanks. High pumping wellhead pressures had caused frequent stuffing box blowouts at the pilot area producing wells. Flow lines occasionally became plugged as the heavy crude cooled on the way to the tanks.

Gas supply lines were installed to serve the tank battery during emulsion treating operations. Extensive heating and chemical treatment is required to meet purchaser specifications because of the heavy composition of the oil. Emulsions are difficult to break, particularly in such a viscous low gravity oil. As the API gravity approaches 10° , separation of water from the oil becomes more difficult. Several of the wells are known to produce 12 to 13 $^{\circ}$ API gravity oil. Figure 13 illustrates the viscosity-temperature relationship for oil produced from project wells.

Operating Problems

Many of the delays incurred during this project were attributable to the remoteness of the project site. The nearest location which offers a full line of oil field services, supplies, and equipment is at Alice, Texas, some 125 miles to the southeast.

Delays of up to several weeks were experienced in waiting on well servicing units. The general increase in oil industry activity following the Arab oil embargo and oil price increases of 1973 has continued to outstrip trained labor and equipment availability.

The lease roads became slick and impassable for several days following rain. Upgrading to all weather roads could not be economically justified during Phase I. Violent electrical storms on several occasions damaged the electrical distribution systems, requiring a total shut down of operations until repairs were made.

A lack of adequate natural gas supply hampered ignition attempts in Matthews Well No. 9 until a successful recompletion of the Electrothermic gas well. Prior to the recompletion the well had to be swabbed intermittently at great expense in order to maintain flow.

Sustained operation of the project producing wells in the pilot area proved impossible until a tank battery was moved to the pilot area. The high pressures required to move the viscous crude through the long flow lines caused numerous stuffing box failures at the producing wells.

Air injection pressures in Well No. 9 were much higher than anticipated. To keep within the pressure rating of the main compressor, air rates were limited; however, at pressures as high as 2,400 psi, frequent repairs were necessary.

PROJECT COST

A total of \$294,622 was spent during Phase I of the Little Tom Thermal Recovery Project as follows:

Thermal Stimulation			\$133,807
Air Injection		\$38,110	
Compressor Installation	\$5,585		
Compressor Rental	17,181		
Compressor Repairs	10,749		
Compressor Operating Service	4,595		
Well Preparation		28,908	
Ignition Operations		39,249	
Fuel		27,540	
Propane	8,197		
Swabbing Gas Well	1,181		
Gas Well Recompletions	18,162		
Lease Operations			57,865
Contract Pumping Service		5,927	
Electric Power		3,543	
Repairs and Maintenance		48,395	
Surface	18,472		
Subsurface	29,923		
Overhead and Technical Expense			102,950
Hanover		66,243	
Consultants		36,707	

ACKNOWLEDGEMENT

Hanover and its subcontractors would like to express their appreciation for the fine attitude displayed by the ERDA staff throughout the duration of this project under often exasperating circumstances. It was a distinct pleasure to work with Mr. F. Sam Johnson, Technical Project Officer, and the other ERDA people associated with this project. The following key personnel participated in the planning, management and operation of the Little Tom Thermal Recovery Demonstration Project:

<u>Organization</u>	<u>Name</u>	<u>Title</u>
ERDA	F. Sam Johnson	Technical Project Officer
Hanover Petroleum Corporation	Glenn R. Moore Elmer T. Ireton Wayne D. Thornton C.W. Fuqua	President Chief Engineer Chief Geologist Field Superintendent
Hanover Sub-Contractors:		
LaRue, Moore & Schafer	John D. LaRue T. Dale Badgwell	Partner Engineer
Tejas Petroleum Engineers	Jon T. Moss	Partner

TABLE 1

RESERVOIR CHARACTERISTICS
LITTLE TOM FIELD
ZAVALA COUNTY, TEXAS

<u>Little Tom Field</u>	<u>San Miguel Sand Member</u>				<u>Field</u>
	<u>A</u>	<u>A-1</u>	<u>B</u>	<u>C</u>	
Average Depth, ft					2,800
Productive Area, ac					5,500
Average Porosity, percent	22.3	23.1	23.4	21.3	22.3
Average Permeability, md	99	115	62	31	64
Average Water Saturation, percent					40
Reservoir Pressure(a), psi					750
Oil Gravity(b), °API					18
Solution Gas-Oil Ratio(a), cu ft/bbl					77
Reservoir Temperature, °F.					125
Oil Viscosity (dead), cp					230
Oil Viscosity (reservoir), cp					90
Formation Volume Factor, vol/vol					1.05
Pore Volume, bbl/acre-ft					1,730
Initial Oil In Place, bbl/acre-ft					988
Primary Recovery Factor, percent					3
Reservoir Volume, acre-ft					77,675
Initial Oil In Place, Mbbl					76,768
Potential Thermal Oil Recovery					
Recovery Factor (low range), percent					32
Recovery Factor (high range), percent					42
Oil Recovery (low range), Mbbl					24,565
Oil Recovery (high range), Mbbl					32,242

Hanover Petroleum Corporation Leases

Productive Area, ac	3,521
Initial Oil In Place, Mbbl	40,280
Potential Thermal Oil Recovery(c), Mbbl	12,900

(a) Estimated

(b) Initial estimated average for the four sand members

(c) Low range (32 percent recovery factor)

TABLE 2

ESTIMATED THERMAL PROPERTIES AND
DISPLACEMENT CHARACTERISTICS
SAN MIGUEL "C" ZONE
LITTLE TOM FIELD
ZAVALA COUNTY, TEXAS

Molecular Weight of Fuel Unit CH_x	13.8
Apparent Atomic Hydrogen Carbon Ratio	1.8
Fuel:	
lbs/cu ft	1.50-1.98
bbl/acre-ft	197-260
Estimated Combustion Efficiency, percent	85
Air Required for Combustion	
Scf/cu ft	300-396
Mcf/acre-ft	13,000-17,250
Oil Displaced by Combustion, bbl/acre-ft	791-728
Air-Oil Ratio, Mcf/bbl	16.4-23.7
Water Formed by Combustion, bbl/acre-ft	225
Combustion Temperature, $^{\circ}\text{F}$.	950
Heat Capacity of Reservoir, Btu/cu ft - $^{\circ}\text{F}$	
Saturated Sand	36.5
Dry Sand	26.0
Thermal Conductivity, Btu/hr - Ft - $^{\circ}\text{F}$	
Saturated Sand	0.85
Dry Sand	0.62
Thermal Diffusivity, sq ft/day	
Saturated Sand	0.56
Dry Sand	0.57
Overburden	0.74
CTD Zone Conditions, bbl/acre-ft	
Oil 30 percent	519
Water 50 percent	865
Volume Ratio, CTD Zone/Burned Vol.	0.73
CTD Water-Air Ratio, bbl/MMcf	210
CTD Air-Oil Ratio, Mcf/bbl	11.5-16.1
Residual Saturations after Water Fill-Up, percent	
Oil	18
Water	70
Ultimate Air-Oil Ratio, Mcf/bbl	10.1-14.1
Total Water Injected, bbl/acre-ft	1,341

TABLE 3

ANALYSES OF GAS SAMPLED
DURING ATTEMPTED THERMAL STIMULATION OF WELL NO. 9
HANOVER PETROLEUM CORPORATION
NED MATTHEWS LEASE
LITTLE TOM FIELD
ZAVALA COUNTY, TEXAS

Well No.	Sampling Date	Constituent, Mol Percent								
		C ₃	C ₄	CH ₄	C ₅	CO ₂	O ₂	N ₂	CO	Ar
5	July 8	18.1	-	66.2	1.2	-	2.7	11.6	-	0.2
6	July 8	16.9	4.1	78.0	0.7	-	-	-	-	-
8	July 24	7.8	2.6	89.1	0.5	-	-	-	-	-
	August 28	15.4	2.4	81.6	0.6	-	-	-	-	-
	September 19	2.2	4.7	92.6	0.5	-	-	-	-	-
	September 19	2.5	3.9	93.0	0.6	-	-	-	-	-
9	August 1	-	-	6.4	-	1.0	10.1	81.5	0	1.0
	September 19	-	-	12.8	1.8	0.9	6.8	76.7	-	1.0
	September 19	-	-	14.8	-	0.9	4.9	78.4	-	1.0
12	July 8	20.1	Tr	78.0	1.0	-	-	-	-	-
	July 24	18.1	3.6	78.0	0.3	-	-	-	-	-
	August 28	17.9	3.5	77.5	1.1	-	-	-	-	-
	September 19	3.3	4.5	91.0	1.2	-	-	-	-	-
13	July 8	15.1	4.1	80.4	0.4	-	-	-	-	-
	July 24	19.9	-	35.1	-	-	9.4	35.1	-	0.5

TABLE 4

ANALYSES OF GAS SAMPLED
DURING ATTEMPTED STIMULATION OF WELL NO. 8
HANOVER PETROLEUM CORPORATION
NED MATTHEWS LEASE
LITTLE TOM FIELD
ZAVALA COUNTY, TEXAS

Well No.	Sampling Data	Constituent, Mol Percent								
		C ₃	C ₄	C ₅ +	CH ₄	CO ₂	O ₂	N ₂	CO	Ar
8	May 20, 1976									
	2:00 PM	-	-	-	10.2	-	4.7	84.1	Tr	1.0
	3:00 PM	-	-	-	8.9	1.7	3.6	84.7	Tr	1.0
9	May 6, 1976	-	-	-	6.7	-	10.8	81.5	-	1.0
12	April 27, 1976	2.7	3.1	0.4	93.8	-	-	-	-	-
	May 6, 1976	2.2	9.1	1.1	87.6	-	-	-	-	-

FIGURE 1
LOCATION MAP
LITTLE TOM FIELD
ZAVALA COUNTY, TEXAS

HANOVER PETROLEUM CORPORATION

HANOVER
Matthews No. 9

HANOVER
Matthews No. 8

HANOVER
Matthews No. 12

HANOVER
Matthews No. 13

HANOVER
Matthews No. 14

FIGURE 4

STRATIGRAPHIC CROSS SECTION
PROJECT PILOT AREA
LITTLE TOM FIELD
ZAVALA COUNTY, TEXAS

DATUM: TOP OLMOS SCALE H: NONE
AUGUST, 1976 V: 1" = 200'

HANOVER PETROLEUM CORPORATION

FIGURE 6
 TEMPERATURE SURVEYS
 NED MATTHEWS NO. 9
 LITTLE TOM FIELD
 ZAVALA COUNTY, TEXAS

HANOVER PETROLEUM CORPORATION

FIGURE 7

RADIOACTIVE TRACER INJECTION
PROFILE SURVEY
NED MATTHEWS NO. 8
LITTLE TOM FIELD
ZAVALA COUNTY, TEXAS

HANOVER PETROLEUM CORPORATION

FIGURE 8

INJECTION PERFORMANCE DURING JULY 1975 IGNITION

NED MATTHEWS NO. 9

LITTLE TOM FIELD

ZAVALA COUNTY, TEXAS

HANOVER PETROLEUM CORPORATION

FIGURE 9

INJECTION PERFORMANCE HISTORY

NED MATTHEWS NO. 9

LITTLE TOM FIELD

ZAVALA COUNTY, TEXAS

HANOVER PETROLEUM CORPORATION

FIGURE 10

AIR INJECTION HISTORY

NED MATTHEWS NO. 8

LITTLE TOM FIELD

ZAVALA COUNTY, TEXAS

HANOVER PETROLEUM CORPORATION

WELL NO.	PRODUCED WATER		PRODUCED OIL GRAVITY, °API AT 60° F.
	CL ⁻ , PPM	PH	
5	17,400	7	19.9
6	18,000	7	12.4
8	18,750	7	12.5
9*	18,750	7	12.2
12	17,400	7	14.5

*SAMPLE TAKEN MAY 9, 1975. ALL OTHER
SAMPLES TAKEN JULY 26, 1975.

FIGURE 13
LIQUID SAMPLE ANALYSES
NED MATTHEWS LEASE
LITTLE TOM FIELD
ZAVALA COUNTY, TEXAS

HANOVER PETROLEUM CORPORATION